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defined in the BRP Plant Technical Specifications). However, during a short duration cold shutdown we will not begin testing of any valves if it is decided, by appropriate plant management, that testing may result in delaying attempts to startup and extending the shutdown period. One additional Relief Request was included in this response.

Two Relief Requests were submitted by CPCo by letter dated April 10, 1985 and were approved by the NRC in their December 12, 1985 letter.

By letter dated October 15, 1986 the NRC requested additional information regarding Pump and Valve Inservice Testing. The basis for the request was the Technical Evaluation Report prepared for the NRC by EG&G Idaho National Engineering Laboratory dated October 1985 which was attached to the NRC letter and a telephone conference on September 3, 1986. In this letter, the NRC requested a re-review of the BRP IST Program in preparation for issuance of an NRC Staff Safety Evaluation.

CPCo, by letter dated December 22, 1986 supplemented our original January 21, 1983 IST submittal, responded to the above request, and provided responses to the program anomalies identified in Appendix "D" of the Technical Evaluation Report. Further, a review of all previously submitted Relief Requests was completed. As an Attachment 2 to the submittal, CPCo included all the Relief Requests applicable to the IST Program. Any changes to these requests as a result of the review effort were also described in Attachment 2. This listing superseded all previous Relief Request submittals. Revisions in the IST Program involved the frequency of pump testing, which was changed from monthly to every three months and the formalization of the current practice of not restricting startup due to pump and valve testing as stated in a October 4, 1984 letter. Also, permissible leakage rates will be established for each containment isolation valve prior to the next Local Leak Rate Tests for these valves.

CPCo, by letter dated June 24, 1988 responded to NRC Region III November 25, 1987 Inspection Report concerns. In response to these concerns we have reviewed all of our relief requests and have revised them where necessary. New relief requests have been included for flow rate measurement and bearing temperature measurement as committed to in our December 28, 1987 response to the inspection report. The relief request for exemption of pump flow measurement was withdrawn in response to Generic Letter 89-04, dated December 21, 1989. Flow measurement equipment was installed and tested in November 1990 via FC-663. An attachment to the September 29, 1989 letter provides the revised complete listing of all Ist relief requests and supersedes the listing provided June 24, 1988.

3.9.3 INTERGRANULAR STRESS CORROSION CRACKING (IGSCC) INSPECTION PROGRAM

Background

Nuclear Regulatory Commission Generic Letter 84-11, Inspections of BWR Stainless Steel Piping, dated April 19, 1984 required Consumers Power Company to submit plans relative to inspections for intergranular stress corrosion cracking (IGSCC) of stainless steel piping and to submit a plant specific leakage detection information. Our response to this request was submitted by letter dated May 25, 1984 and additional clarifying information was provided by letter dated July 2, 1985. The results of the IGSCC weld inspections, which were completed as committed to in our response, were submitted by letter dated October 31, 1985. By letter dated February 4, 1986, the NRC provided an evaluation of our responses and requested additional information. Our letter dated October 13, 1986 provided the additional information and we committed to perform additional IGSCC inspections during the [illegible] refueling [illegible]. This letter also informed the NRC of our inte[illegible] conduct a study to determine the basis for the lack of IGSCC problems at Big Rock Point. By letter dated October 28, 1986, the NRC accepted our inspection sample size and informed us that the leakage detection concerns remain under NRC technical staff review. Having completed our study, we were not able to ascertain why Big Rock Point is unique in that IGSCC is not a problem at our facility. By letter dated September 30, 1987 we submitted an on-going IGSCC Inspection Program to be implemented beginning with the 1988 refueling outage.

Big Rock Point has sampled IGSCC susceptible welds on three different occasions involving 59 examinations on 41 of the 65 welds that are accessible. In all cases, no indication of IGSCC was observed. Big Rock Point has significant design differences from the newer design BWRs. Industry experience has shown BWRs do develop IGSCC in less than 10 years of operation. The weld sensitization at Big Rock Point is no less than that of other BWRs, and yet, IGSCC has not affected recirculation piping in over 24 years of operation. While it is not fully understood why Big Rock Point does not experience IGSCC, the examination history for IGSCC at Big Rock Point lends support to this not being a significant concern. Consumers Power Company's position regarding IGSCC has not changed from earlier submittals.

Program

Attachment 1 of the September 30, 1987 submittal contains the IGSCC Inspection Program for Big Rock Point. This program has been developed from the guidance offered by IE Bulletin 83-02, Generic Letter 84-11, and NUREG 0313, as well as practical considerations for the plant. This program establishes the sample size for Big Rock Point such that all accessible welds will have been examined for IGSCC by the end of the next two refueling outages. After all accessible IGSCC susceptible welds have been examined, a re-exam schedule will be established.

The number of examinations during any refueling will escalate per the requirement of IWB-2400, if IGSCC is found. In that case, evaluation of the observed IGSCC will be per IWB-3500 and analysis, if required, will be per IWB-3600. Repairs will be by weld overlay reinforcement, partial weld replacement or full weld replacement, depending on the conditions at the time. Flaw repairs will be handled on a case by case basis.

All examinations for IGSCC will utilize qualified examiners and procedures as required by IE Bulletin 83-02. Documentation of qualifications and procedures will be maintained with the records of the ISI final reports. Pending NRC evaluation and response to our October 13, 1986 submittal, leakage detection measures will not be enhanced. (Refer to Section 5.2 of this Updated FHSR for a description of the Reactor Coolant leak detection methods.)

3.9.4 REACTOR VESSEL MATERIAL SURVEILLANCE PROGRAM (REFERENCE 36)

A materials exposure program has been established in the Big Rock Point Nuclear Plant to measure the effect of neutron irradiation and time at temperature on the mechanical properties of the reactor pressure vessel steel. Base metal specimens were made from portions of the pressure vessel steel, and weld heat-affected zone and weld metal samples were taken from a weldment made from the pressure vessel steel and simulating a pressure vessel longitudinal weld. Tensile property changes will be measured by pre- and post-irradiation tests on small tensile specimens. Fracture characteristic changes will be measured in similar fashion by Charpy V-notch impact tests. The program was planned to cover a 32 year period, with specimens to be removed for test at intervals of 1, 2, 4, 8, 16, and 32 years.

For details on the program, refer to CPCo Letter dated June 12, 1978 including attached General Electric, "GECR-4442 Reactor Pressure Vessel Material Surveillance Program at the CPCo BRP Nuclear Plant," Report dated December, 1963; and the Naval Research Laboratory Report, "Mechanical Property and Neutron Spectral Analyses of the BRP Reactor Pressure Vessel" published in Volume 11, April 1970 Nuclear Engineering and Design. (Extracted pages 393-415 are included in the June 12, 1978 submittal.)

The Systematic Evaluation Program (SEP) Topic V-6, "Evaluation of the Integrity of SEP Reactor Vessels," was completed by the NRC in October 1979 and published as NUREG-0569 in December 1979. Appendix C of the NUREG provided an Evaluation of Big Rock Point which also addressed the Material Surveillance Program as follows:

<u>Reactor Vessel Fluence</u>

Based upon the Naval Research Laboratory (NRL) calculations, an extrapolated and projected fluence for the BRP 40 year full power service limit of the reactor was 8.1×10^{19} n/cm^2>0.5MeV, (refer to the NRL Report included in the June 12, 1978 submittal).

Additional capsules were removed and analyzed in 1979 and results were reported in Electric Power Research Institute (EPRI) Report 1021-3, submitted to the NRC by letter dated December 18, 1981.

Currently there are two capsules remaining in the reactor vessel, (a partial thermal capsule set and a complete wall capsule), the estimated removal date established for these is 1995 based upon the 32 year General Electric Surveillance Program.

NRC Evaluation

The material surveillance program for Big Rock Point was planned prior to the initial issuance of Appendix H, 10 CFR Part 50. The program is based on ASTM Recommended Practice E-185 dated 1964.

The program consisted of 12 capsules having tensile and Charpy specimens from base, heat affected zone (HAZ), and weld materials. There were four wall capsules placed at the core midplane at positions where the core corners are closest to the vessel wall. These capsules were located close to the vessel wall where they would receive a fluence only slightly higher than the vessel wall ID. Three capsules were located inside the thermal shield at positions about 6 inches from the flat faces of the core. These accelerated capsules will see a fluence from 20 to 50 times that on the vessel wall ID. The program also included five thermal control capsules located on top of the baffle plate. These capsules are exposed to the temperature cycles of the vessel and to a neutron flux three or four decades lower than the vessel wall. The main purpose of these specimens is to monitor any aging effect experienced by vessel materials.

The Big Rock Point material surveillance program conforms to almost all the rules of Appendix H, 10 CFR 50. Some of the capsules contained less than the required number of 12 Charpy specimens for each material type. However, the program contained more than the required number of capsules and total number of specimens. Some capsules also contained only two tensile specimens instead of the required three. From our review of this program, it is concluded that it is very good and will provide sufficient data to monitor the radiation damage on the reactor vessel materials throughout their service life.

At the time of issuance of NUREG-0569, five capsules had been removed from the vessel. Accelerated capsules were removed in 1964 and in 1967. Wall capsules were removed in 1964 and 1968. One thermal control capsule was removed in 1968. Tests on these surveillance specimens were conducted at the Naval Research Laboratory. The two wall capsules received fluences of 1.5 and 7.1×10^{18} n/cm². The two accelerated capsules received fluences of 2.3×10^{19} and 1.07×10^{20} n/cm². From these tests, we concluded that weld metal is the limiting vessel material. Its RT_{NDT} increases 135°F at a fluence of 7.1×10^{18} n/cm², and increases by 190°F at a fluence of 2.3×10^{19} n/cm². At the above fluence levels, the upper shelf energy of the weld metal decreases from about 90 to about 60 ft-lbs. At a fluence of 1.07 x

10^{20} n/cm², the upper shelf energy is still almost 60 ft-lbs. The shelf energy of plate material also drops to about 60 ft-lbs at a fluence of 2.3×10^{19} n/cm². These test results do not show any rate effect on the degree of radiation damage. Thus, the results of accelerated capsules are considered to be comparable to those of the wall capsules.

The SEP report also concluded, based on the low primary vessel stresses and the use of materials with adequate fracture toughness, that assurance is provided that brittle fracture will not occur.

3.9.5 REACTOR PRESSURE VESSEL INTERNALS

Systematic Evaluation Program (SEP) Topic III-8.C was initiated to provide an evaluation of Irradiation Damage, Use of Sensitized Stainless Steel, and Fatigue Resistance of BRP reactor vessel internals.

By letter dated June 23, 1982 the NRC Staff provided the final evaluation on this topic. The final evaluation was based upon the February 5, 1980 Staff evaluation and comments submitted by CPCo letter dated December 23, 1981.

Evaluation (Reference 37)

SEP Topic III-8.C is intended to determine if the integrity of the reactor internal structures has been degraded through the use of sensitized steel.

The effect of neutron irradiation and fatigue resistance on material of the internal structures was eliminated from the safety objective of Topic III-8.C in memorandum to D. G. Eisenhut from D. K. Davis and V. S. Noonan dated December 8, 1978. The memorandum concluded that operating experience indicated that no significant degradation of the materials of the reactor internal structures had occurred as a result of either irradiation damage or fatigue resistance.

The reactor internal structures were described in Sections 4 and 5 of the 1961 Final Hazards Summary Report for the Big Rock Point Nuclear Plant. The internal components were designed to provide support for the fuel and maintain structural clearances during normal and accident conditions. In addition, the internal components provide passageways for the coolant to cool the fuel and means for adequately separating the steam from the coolant water.

Components of the reactor coolant pressure boundary of the Big Rock Point Nuclear Plant were designed, fabricated, inspected and tested to the requirements of Section I and Section VIII of the ASME Boiler and Pressure Vessel Code, 1959 Edition, including applicable code case rulings. Where the Code was not applicable, the design was evaluated from the principle described in the U. S. Navy Bureau of Ship Publication, "Tentative Structural Design Basis for Reactor Pressure Vessels and Directly Associated Components," April, 1958.

The primary criteria for material selection for the reactor internal components were the mechanical properties, the material stability and corrosion resistance in the reactor environment. The materials used for the construction of the reactor internals were identified in the Final Hazards Summary Report as Type 304 stainless steel, Inconel, and minor quantities of special purpose materials, such as Stellite, Colmonoy, Graphitar, and 17-4 PH alloy. The structural materials identified have proven adequate for reactor internal construction as a result of extensive tests, prior usage, and satisfactory performance.

As a result of the discovery of a leak in the feedwater inlet nozzle of the LaCrosse reactor vessel in October, 1969, and in reply to questions from the staff, the licensee, in letters dated September 11, 1970, and January 12, 1971, identified all the furnace sensitized stainless steel components and the maximum calculated levels to which the components would be stressed in service. The reactor internal components were furnace sensitized, but the maximum level of stress intensity did not exceed 90% of the material yield strength (code allowable) at operating temperature.

Experience has shown that at least three elements in combination are necessary to cause cracking in sensitized stainless steel components. These are material susceptibility, an oxygenated water environment, and a threshold total stress. The Big Rock Point Nuclear Plant reactor internal components contain sensitized stainless steel in contact with an oxygen saturated water coolant environment. However, the calculated stresses do not exceed the threshold stress values associated with intergranular stress corrosion cracking. The threshold stress values are near or greater than the 0.2% off-set yield stress at temperature. Further, in the reactor environment, stress relaxation may occur due to irradiation and temperature effects.

The Licensee Event Reports and the BWR <u>Nuclear Power Experience</u> were reviewed for the Big Rock Point Nuclear Plant with regard to reactor internal materials problems. The events are summarized as follows:

> Beginning with the 1965 refueling outage, roller failure was observed in the peripheral control rod blades. The failure was attributed to severe coolant turbulence in these locations. Stress corrosion cracking was not a factor. In a letter of M[illegible] 1972, the staff concluded that this failure did not endanger [illegible] health and safety of the public.
>
> Stress corrosion cracking caused the failure of Type 304 stainless steel beryllium-antimony neutron source capsules (1973). An internal pressure build-up of helium-tritium occurred from the n, α and n, 2n reactions. The problem was corrected by replacing the stainless steel with Zircaloy capsules. During the reactor clean-up of beryllium oxide following this failure, the reactor internal components were removed and inspected. The examination showed neither intergranular stress corrosion cracking nor evidence of material degradation in the components.

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4.4.3 NRC Bulletin 88-07, Power Oscillations in BWR's

NRC Bulletin 88-07 requested licensees to take actions to prevent the occurrence of uncontrolled power oscillations during all modes of BWR operation. Plant alarm procedures were revised to require operators to reduce power or trip the reactor if power oscillations approach Technical Specification limits. Off-normal procedures also require a manual reactor trip when both recirculating water pumps are removed from service (reference section 15.3.3.3 of the Updated FHSR).

Supplement 1 of the Bulletin dated December 30, 1988 requested licensees to take action to ensure that the safety limit for the plant MCPR is not violated. The NRC determined that the recommendations and provisions of the supplement were not applicable to Big Rock Point because of unique design features involving a lack of flow control capability, and because existing operating limitations enforced by Technical Specifications address the stability concerns which are the subject of the supplement.

4.5 OPERATION WITH LESS THAN ALL LOOPS

Topic IV-1.A of the Systematic Evaluation Program deals with operating the reactor at power with one of the recirculation loops out of service. NRC letter of October 9, 1979 to David Bixel from DLZiemann presents the safety assessment of this topic. Consumers Power Company letter dated October 15, 1990 discusses an update to the October 9, 1979 letter. The acceptability of operating with one loop out of service was contingent upon satisfying certain conditions. The discharge and discharge bypass valves of the inactive loop must be closed and caution tagged. The suction valve is to be left open to maintain system pressure on the seals, protecting them from degradation. This requirement is to be controlled by procedure. A determination of the maximum allowable reactor power permitted by Technical Specification for one loop operation must also be made. MAPLHGR limits for N-1 loop operations have been incorporated into the Technical Specifications.

NRC letter dated June 9, 1981 included a safety evaluation of the revised MAPLHGR limits for Exxon fuel for a one loop operation. At that time evaluation of the one loop MAPLHGR limits for Exxon fuel was not complete. A follow-up letter in response to NRC questions was issued by Consumers Power Company to DMCrutchfield on June 19, 1981. A new MAPLHGR limit for Exxon fuel with a one loop operation was proposed. This change is further documented by letter to DMCrutchfield from GCWithrow on July 22, 1981.

The incorporation of these contingencies pending approval of the Technical Specification change was reported to the NRC by letter dated September 3, 1981 from TCBordine to DMCrutchfield.

Topic IV-1A was acceptably resolved and documented by letter to DPHoffman from DMCrutchfield on October 8, 1981. With the conditions previously mentioned, it is permissible to operate the Big Rock Point reactor with only one recirculation loop in service.

Neutron sources may be provided to assure neutron visibility is sufficient to satisfy the requirements of the Technical Specifications. If neutron sources are used to assist in providing this visibility, location of these sources shall be as follows:

Location

The initial (start-up) neutron sources are placed in core positions 02-50 and 09-52 in vacant fuel channels at the core periphery.

Up to four auxiliary neutron sources may be contained within fuel bundles in rod locations normally occupied by fuel rods or inert rods.

Physical Description

The initial (start-up) neutron sources consist of a steel-jacketed antimony pin, 1-inch diameter by 12 inches long, centrally located on the vertical axis of a steel-jacketed (Type 304 SS) beryllium cylinder 5 1/2 OD by 16 inches long. The entire assembly, including support structure, is a cylinder 79 7/16 inches long by 6 inches diameter which rests on a special orifice in a standard support-tube-and-channel assembly. A lifting bail is provided for handling purposes. The assembly design allows adequate cooling along the surface of the source pin and the outer surface of the assembly.

The auxiliary neutron sources each consist of a homogeneous 50-50 mixture of antimony-beryllium first encapsulated in a steel tube (Type 304L SS), then secondarily encapsulated in a zirconium alloy tube.

Initial (Start-Up) Neutron Source Design

The two initial (start-up) neutron sources having 1660 curies total minimum strength design details were originally submitted in 1962, (Reference 1). By letter dated March 26, 1974, CPCo addressed the replacement of the original design start-up neutron sources with sources of essentially the same design. The design changes were depicted on drawings attached to the letter. The change consisted of modifying the gamma source hold-down device to provide a means of irradiating a new antimony pin while utilizing the original neutron sources. This will enable changeover from the original neutron sources to the new neutron sources.

Primary Neutron Source Removal from Reactor Core during Power Operation

During the 1990 Refueling Outage, a test was performed to show that source neutron strength was sufficient without contribution by the primary sources (ref. O-RVI-NST). This result allows the removal of the primary sources from the reactor core during operation. In their place an antimony pin holder is substituted. These pin holders will perform two important functions.

a. Their design is similar to the Primary Neutron Sources, so that core flow through core positions 02-59 and 09-52 will not be altered.

b. The irradiation of the antimony pin in the holder will ensure a charged source for fuel loading during the next refueling operation.

Auxiliary Neutron Source Design

Two additional auxiliary neutron sources contained in fuel bundles were approved for use by the Atomic Energy Commission (AEC) by Change Number 23 to the Technical Specifications, dated February 22, 1971 based upon CPCo Proposed Change dated January 18, 1971. The auxiliary neutron sources were proposed in order to improve the start-up count rate and improve the ability to measure (fission) neutron count rate. The design of these additional auxiliary neutron sources was also provided in the proposed change.

A design change of these sources was requested February 2, 1973 and approved by the AEC March 2, 1973 as Technical Specification Change No. 35. The change was necessary to make the sources compatible with new 11 x 11 rod array fuel bundles and to prevent secondary encapsulation weld failure. This change also allowed two new auxiliary sources (in additi to the two additional auxiliary sources allowed by Change No 23 above) for a total of four auxiliary neutron sources to be placed in the core until the activity of the new sources builds up to a useful level (1 to 3 years) at which time the two original auxiliary neutron sources will be removed. The location of these four sources was limited by the change also.

Thus, the Technical Specification basis for up to four auxiliary sources allows for activation of new sources and the number of auxiliary sources will normally be two.

A Technical Specification Change Request was submitted September 25, 1980 to remove the restrictions on fuel bundle auxiliary neutron source rod location and to allow additional fuel management flexibility with respect to future location of auxiliary neutron sources. This request addressed a change of auxiliary source rods in that replacement source rods will not be "removable" but will require bundle disassembly in order to move them from one bundle to another. This change request was approved January 12, 1981 via Amendment Number 36.

The amendment (1) removed the restrictions on allowable locations for auxiliary neutron sources, and (2) modifies the physical description of the auxiliary neutron sources to allow the source to be placed in the center of a fuel assembly rather than in the corner location previously used.

CPCo by letter dated January 18, 1971 provided information which indicates that the startup channels will respond to fission neutrons rather than source neutrons even when the auxiliary neutron sources are placed very close to the start-up detectors. This indicates that the restriction on the location of the fuel bundles with auxiliary neutron sources is unnecessary.

In terms of changing the source location to the center of the fuel assembly, the licensee has performed analyses to demonstrate that there will be no reduction in safety margin associated with the thermal hydraulic, fuel design limits (minimum critical heat flux ratio) or the ECCS performance analyses (maximum average planer linear heat generation rate).

Auxiliary Neutron Source Design (Reference 19)

The neutron source material is a homogeneous mixture of 50-50, by volume, antimony-beryllium compacted to a minimum packing fraction of 80%. The source material is first encapsulated in a 0.374 inch OD steel tube (Type 304L SS) with a 0.028 inch wall thickness. The overall length of the source tube is 70.110 inches with the source material located in the middle 44.26 inches, held there by a hollow, steel tube spacer at each end. The remaining space in the source tube is void volume. The source tube is encapsulated in a zirconium alloy fuel tube of the same quality and dimensions as tubing used for fuel rods.

Design Life (Reference 19)

The in-reactor design life of the auxiliary neutron sources is 15 years. Sufficient void volume has been incorporated into the design to attain this objective. Based on an assumption of 1.5 x 10 n/cm^2-s for the flux of neutrons with energies greater than the 2.7 MeV threshold for the (n, 2n) and (n, alpha) reactions in beryllium, approximately 2.5 x 10 He atoms would be generated in 15 years. Using 799.5°F as the temperature of the outer surface of the stainless steel capsule and assuming conservative conductivity 13
values, the peak temperature in the source material would be 870°F. The internal capsule pressure developed, after 15 years of irradiation, would be 1127 psia. The minimum wall thickness of 0.027 inch exceeds the minimum thickness specified by the ASME Pressure Vessel Code for 304L SS stressed under the above conditions of pressure and temperature. (Rules of Construction of Pressure Vessels, Division 1, 1971 Edition, ASME Boiler and Pressure Vessel Code Section VIII and supplements through summer 1972.)

5.3.1.9.10 Control Rod Blade Assemblies

The 32 cruciform-shaped control rods are guided and provided lateral support by the "fuel channel and support (guide) tube" assemblies. Vertical support is provided by the control rod drive mechanisms. These rods move up and down between the fuel channels and support tubes and are the primary means of controlling reactor power. Each control rod blade assembly is approximately 11 1/2 inches wide and 5/16 inch thick.

The neutron absorbing material is solid hafnium (Hf) or Carbide (B_4C) Powder and have an effective poison length of approximately 68 inches.

Types of Control Rod Blade Assemblies

Type 1 Blades (Peripheral Positions)

The sixteen peripheral control blades contain one hundred and four 304 stainless steel tubes filled with B_4C powder.

Type 2 Blades (Interior Positions)

The sixteen interior control blades contain sixty four 304 stainless steel tubes filled with B_4C powder and forty 304 stainless steel empty tubes open at each end. Each wing of the cruciform blade contains ten empty tubes and the outer sixteen tubes are B_4C filled. These blades are referred to as type 2A.

Also present are blades of a newer design utilized in the sixteen interior positions. These blades are referred to as Hybrid Control Rods and are type 2. These control blades contain sixty four 348 stainless steel tubes filled with B_4C and forty 348 stainless steel empty tubes open on each end. Each wing of the cruciform blade contains ten empty tubes and the outer fourteen tubes are B_4C filled followed by two exterior tubes consisting of B_4C filled tubes (bottom 75% and solid hafnium (Hf) metal rodlets (top 25%). Approval for utilization of these Hybrid control blades was provided by Technical Specification Amendment Number 88 dated February 17, 1987. Use of hafnium and 348 stainless will provide longer blade life.

Sheath Material

All control rod blade assemblies are enclosed in a perforated 304 stainless steel sheath welded to a central tie rod.

Control Rod Blade Rollers and Pins

Each control rod contains a maximum of eight (8) rollers to a minimum of four (4) rollers of either a nominal 0.485 inch or 0.567 inch diameter. The bottom four (4) rollers, which can be eliminated, move in a minimum interfuel channel space of 0.628 inch.

After the loss of several bottom rollers, (described in the February 11, 1965 Technical Specification Change), a decision was made to remove the bottom four (4) rollers and/or to reduce the diameter of the rollers for new control rods. The function of the rollers on the control rod is to reduce the metal-to-metal contact between the control rod sheath and the support-tube-and-channel assemblies and thus minimize long term wear. A reduction in the diameter of these rollers has not increased the wear noticeably. Also, the operation of control rods with bottom rollers missing has not changed the wear pattern significantly and has had no adverse effect on scram time or normal operating characteristics of the control rods.

Technical Specification Amendment Number 6 dated July 18, 1974 allowed removal of all four bottom rollers on the peripheral (type 1) blades. When new type 1 blades were installed for cycle 18 core reload, the bottom rollers were removed via Specification Field Change 82-004.

The type 1 and 2A control blades utilize Haynes 25 Pins and Stellite 3 Rollers. The Hybrid type 2 control blades utilize PH13-8 Mo Pins and Inconel x 750 rollers.

Control Rod Blade Poison Tubes

Poison tubes are type 304 or 348 stainless steel tubes, with welded end plugs and with approximately 68" poison length of natural boron carbide powder or 51" boron carbide powder plus 17" Hafnium. The poison tubes also contain steel balls, crimped in position at regular intervals to compartmentalize the boron carbide and minimize the possible effects of densification or settling of the B_4C powder.

The poison tubes are contained in a structure composed of a central core and four sheaths which form the cruciform shape. This cruciform, along with a handle, and a connector which contains the coupling to the drive, make up the control rod. Holes are placed in the sheaths to allow coolant to flow by the poison tubes.

Control Rod Stress and Distortion Analysis

The probable limit to the life of the control rod is internal pressure build-up due to release of helium formed by $B^{10}(n, \alpha) Li^{7}$ reaction.

The pressure build-up and stress in each individual poison tube of each control rod will depend on its integrated exposure.

In order to give an indication of minimum life expected for any individual control rod, hoop stress in the worst tube due to internal pressure has been calculated as a function of time based on the following assumptions:

a. Internal pressure is present due to 1500 ppm volatile content in the B_4C (assumed to be H_2O which subsequently dissociates completely to H_2 and O_2), and helium which is introduced during fabrication.

b. The control rod is inserted continuously in the highest flux region of the reactor (1.3 times average flux), being fully inserted for a fraction of each operating cycle and being gradually withdrawn at the end of each operating cycle. (The operating cycle is the time between reactivity additions - refueling or steel channel removal.)

c. Reactor is operating at .8 load factor.

d. Of the He atoms formed, 30% are released from the B_4C powder and contribute to the internal pressure within the poison tubes.

If a control rod is inserted in the highest flux region continuously as described above, the resultant life, or time for the hoop stress in the worst tube to reach 50,000 psi (90% of expected yield strength), is greater than 1 year.

The stress in the worst tube has also been calculated as a function of time for "normal operation." In "normal operation" all control rods are used to control excess reactivity for burn-up and fission product poisoning such that the worst control rod captures 1.3 times as many neutrons as the average control rod and the worst poison tube in the worst control rod captures 2.9 times as many neutrons as the average tube in that rod. Assumptions for helium release from B_4C, initial pressure in tubes, and plant load factor are as given above. Resultant control rod life if limited by internal pressure is greater than 10 years.

An analysis was made to determine whether temperature gradients could exist in the structure of the control rod sufficient to cause thermal distortions. It was calculated that even with the control rod bowed close to the fuel channel in the worst expected tolerance condition (1/16" gap between control rod and fuel channel along their full length) there was sufficient natural circulation flow (with local boiling) to keep all surfaces of the control rod at essentially uniform temperature.

5.3.1.9.11 Fuel Bundles

The fuel bundles used in the reactor core are described here only in general terms. Each bundle weighs about 440 pounds and has an active fuel length of about 70 inches. Present fuel bundles use 121 rods in an 11 by 11 array. The enrichment in each rod varies depending on the intended positions of the rod within the bundle. A normal core will contain 84 fuel bundles. For a detailed description refer to Chapter 4.

Fuel cladding will, in addition to 304 stainless steel and Incaloy-800, include Zircaloy 2, Inconel-600, and Zr-3Nb-1Sn.

The fuel (Sintered Pellets or Compressed Powder) are UO_2 or UO_2-PuO_2.

5.3.1.9.12 In-Core Flux Detector Assembly

The eight in-core flux monitoring detector assemblies are mounted through a nozzle and encasement, which penetrates through the bottom of the reactor vessel. The in-core flux detectors are encased in guide tubes located in eight radial positions located throughout the core and are used to evaluate, under varying power conditions, the predicted neutron flux profile throughout the reactor core. Each assembly consists of three individual fission chambers located at different elevations. Calibration tubes run inside the incore flux detector assemblies. The calibration flux wire system provides the flux level data for comparison with predicted reactor core conditions. The detector assemblies are ~19.5 feet long and are inserted from the top of the core and are supported by the incore flux monitor nozzles. The detector assemblies are guided by the channels within the reactor core. The detector element is a fission chamber consisting of a fissile coating on the cathode separated from the anode by a gas gap.

5.3.1.9.13 Neutron Window Assemblies

Four 304 Stainless Steel neutron windows are supported by the thermal shield within storage baskets located at the core periphery and positioned approximately 90° from the neutron sources and near the location of the source range channel monitors. The windows are 6 inch schedule 160 pipe with end caps and lifting handles. The windows were slightly modified from original design. Refer to Specification Field Change SFC 79-035.

5.3.1.10 Biological Shield Cooling and Reactor Shielding

A cooling jacket is provided at the inner face of the reactor shield structure. The coolant flowing through the jacket removes the major portion of heat lost by conduction and radiation from the reactor vessel and the heat generated within the shield due to energy absorption. The jacket is water cooled with a design inlet water temperature of 68°F; cooling water is supplied from the closed loop reactor cooling water system. The cooling water system is designed to remove 60,000 Btu per hour at this design inlet water temperature. In the event a leak should develop, it will be possible to convert to air as the cooling medium.

The cooling jacket is a carbon steel, annular tank divided into eight segments. It extends vertically from a point opposite the bottom of the reactor vessel to an elevation just below the reactor supports. There is a two inch annular water filled space between the inside and outside faces of the tank. Water enters the jacket at the bottom and leaves at the top.

The maximum expected temperature within the shielding is 110°F with temperature gradient of 13°F per foot within structural portions of the shielding. The maximum thermal gradient occurs within the inner 6 inches of the shield and is approximately 80°F per foot. Complete disintegration of the inner 6 inches of the concrete opposite the core can occur without affecting the structural elements.

Reactor shielding is ordinary concrete with a density of approximately 150 lb/ft^3. Thickness varies in plan and elevation to suit structural requirements. The shielding thickness directly opposite the core is approximately 9 feet, 6 inches. The control rod drive room, which is directly beneath the reactor, has ordinary concrete walls which are approximately 4 feet thick. A removable shield plug of a thickness 4 feet, 6 1/2 inches, consisting of 4 feet, 4 inches of concrete and 2 1/2 inches of lead, closes the opening above the top of the reactor.

5.3.2 REACTOR VESSEL PRESSURE-TEMPERATURE LIMITS

The Big Rock Point reactor pressure-temperature limits for Hydrostatic Test, Cooldown, and Heatup Conditions are included in License DPR-6, Docket No. 50-155, Appendix "A", Technical Specifications. These limits were based upon Amendment No. 66 dated April 12, 1984 as corrected September 24, 1984, in response to a CPCo request dated October 24, 1983. The CPCo request included an analysis and basis for the change to the reactor vessel pressure/temperature limits to account for accumulated neutron radiation dose to the vessel metal up to 18 Effective Full Power Years (EFPYs) which is approximately 1993. Based upon information provided in Section 3.9.4 of this Updated FHSR, "Reactor Vessel Material Surveillance Program," the two remaining surveillance capsules are not scheduled for removal and analysis until approximately 1995.

5.3.2.1 NRC Safety Evaluation (Reference 20)

The NRC Safety Evaluation for this issue was based upon the CPCo October 24, 1983 request and analysis. The NRC Staff revised the CPCo limits to meet their evaluation requirements and CPCo agreed with the revisions.

Evaluation

Pressure-temperature limits must be calculated in accordance with the requirements of revised Appendix G, 10 CFR 50, which became effective on July 26, 1983. Pressure temperature limits that are calculated in accordance with the requirements of Appendix G, 10 CFR 50 are dependent upon the initial RT_{NDT} for the limiting materials in the beltline and closure flange regions of the reactor vessel and the increase in RT_{NDT} resulting from neutron irradiation damage to the limiting beltline material.

The BRP reactor vessel was fabricated to ASME Code requirements, which did not specify fracture toughness testing to determine RT_{NDT} for each reactor vessel material. Hence, the initial RT_{NDT} for materials in the closure flange and beltline region of the BRP reactor vessel could not be determined in accordance with the test requirements of the ASME Code. Therefore, the initial RT_{NDT} for these materials must be estimated from material test data for other similar materials used for fabrication of reactor vessels in the nuclear industry. The licensee, in developing the pressure-temperature limits proposed in the October 24, 1983 submittal, estimated the initial RT_{NDT} of the limiting closure flange material as 30°F. The licensee indicated that the limiting closure flange region material is the base metal, which was fabricated to the ASME Code requirements of SA 336 Code Case 1236 and was heat treated to the quenched and tempered condition. The chemical composition and heat treatment requirements of ASME SA 336 Code Case 1236 material are similar to that of ASME Code SA 508 Class 2 material. Hence, a conservative estimate of the initial RT_{NDT} of the licensee's closure flange base material may be based upon a conservative estimate of RT_{NDT} for quenched and tempered SA 508 Class 2 material. According to Table 4.4 of NUREG-0577, "Potential for Low Fracture Toughness and Lamellar Tearing on PWR Steam Generator and Reactor Coolant Pump Supports," the upper bound RT_{NDT} for quenched and tempered ASME SA 508 Class 2 material is 40°F. Thus, the staff concluded that the initial RT_{NDT} of 30°F estimated by the licensee for the closure flange region was not conservative and unacceptable. Accordingly, the staff revised the proposed limits using an initial RT_{NDT} of 40°F.

The licensee indicated that the limiting beltline region material is weld material fabricated using Arcos B-5 flux, which has a chemical composition of .27 percent copper and .10 percent nickel. The licensee in their January 29, 1982 letter to D. M. Crutchfield indicated that Arcos B-5 flux weld material has a high initial upper shelf and an initial maximum RT_{NDT} of -50°F. The basis for this estimate was EPRI fracture toughness data for welds with high upper shelf properties. However, to conservatively estimate the initial RT_{NDT} for the Arcos B-5 flux weld material, the applicant has used the staff's estimate for Linde 0091 flux weld material which is reported in Appendix E of SECY-82-465, "Pressurized Thermal Shock." The estimated initial RT_{NDT} for this material was -56°F with a standard deviation of 30°F. Since Linde 0091 flux welds have high initial upper shelf properties and have an initial RT_{NDT} similar to that of Arcos B-5 flux weld materials, the staff concludes that SECY-82-465 material data for Linde 0091 flux welds will conservatively predict the initial RT_{NDT} of the Arcos B-5 weld materials.

The increase in RT_{NDT} resulting from neutron irradiation damage was estimated by the licensee using an empirical relationship, which was reported by Dr. Randall of the staff at the ANS Annual Meeting in Detroit, Michigan, on June 14, 1982. The empirical relationship reported by Dr. Randall depends upon the amount of neutron fluence, and the amount of copper and nickel in the weld material. This empirical relationship has a standard deviation of 30°F for weld metals. The BRP surveillance weld metal test results are reported in Table 5-5 of WCAP-9794 (Reference 21). The empirical relationship reported by Dr. Randall, provides a conservative estimate of the effect of neutron irradiation damage on weld material, because the increase in RT_{NDT} predicted by the mean empirical relationship exceeds that from the surveillance weld material for four out of five neutron fluences.

The applicant has estimated the neutron fluence to be received by the reactor vessel beltline materials in accordance with the methods described in Westinghouse Topical Report WCAP-9794. This method is currently under review by the staff. The licensee originally proposed the pressure/temperature limits in the form of a table.

After reviewing the table, the staff concluded 1) that the table did not accurately show the lower limit temperature restrictions imposed by Appendix G to 10 CFR Part 50; and 2) that table format was difficult to read and understand. Therefore, the staff revised the limits from a table format to a graph format and included the appropriate lower limit temperature restrictions.

The amount of time that pressure-temperature limits are effective depends upon the amount of neutron irradiation damage. The applicant has used the method described in Appendix E of SECY-82-465 to predict the amount of neutron irradiation damage. This method of predicting neutron irradiation damage depends upon the predicted amount of neutron fluence, the amount of nickel and copper in the weld, the standard deviation for the initial RT_{NDT} and the standard deviation for the empirical relationship, which was used to predict the amount of neutron irradiation damage. The staff concludes that the method used by the applicant for predicting neutron irradiation damage is acceptable and that the proposed pressure-temperature limit curves meet the safety margins of Appendix G, 10 CFR 50, for a period of time corresponding to 18 EFPY. Hence, the revised pressure/temperature limit curves are acceptable.

As indicated previously, the method of estimating neutron fluence is currently under review by the staff. Since there is considerable margin between the method utilized to predict radiation damage and the amount reported from the surveillance weld metal samples, the result of the staff's review of the licensee's method of predicting neutron fluence should not significantly impact the licensee's pressure-temperature limits curves for several years. If the staff's review of this method indicates that the predicted neutron fluence for the BRP reactor vessel are significantly non-conservative, the staff will revise the effective period for the licensee's pressure temperature limit curves.

Conclusion

The staff has further concluded, based on the considerations discussed above, that: 1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner; and 2) such activities will be conducted in compliance with the Commission's regulations and the issuance of these amendments will not be inimical to the common defense and security or to the health and safety of the public.

5.3.2.2 Operational Requirements (Reference 21)

Vessel metal temperature is normally measured by four (4) thermocouples located at 0°, 90°, 180°, and 270° at the 604' elevation. The thermocouples measure outside vessel temperature from which the pressure temperature limits are based upon. Temperature measurement of the reactor vessel with the above four thermocouples will normally govern heat up and cool down conditions.

Temperature measurement during NSSS Hydrostatic Testing will be governed by thermocouples on the reactor vessel and temperature measurement systems on the steam drum.

In both cases, conservative temperature margins exist to ensure the integrity of associated components.

It should be noted that there are fourteen thermocouples on the reactor vessel and six on the steam drum, it will not be necessary to assure that all are greater than the required temperature limit, thereby allowing for thermocouple failures. Access limitations to these thermocouples should failure occur necessitates allowance for failures (Reference 22).

Other operational limitations are as described in the Technical Specifications.

5.3.3 REACTOR VESSEL INTEGRITY (NUREG 569)

The NRC performed a documented review of the integrity of the reactor pressure vessel in NUREG-0569, "Evaluation of the Integrity of SEP Reactor Vessels," published December 1979. Appendix "C" of the NUREG provided the BRP evaluation. The important supplementary requirements of the reactor design are as follows:

- The vessel stress analysis included analysis of thermal transient and fatigue effects. The method used was based upon the method of analysis developed for Naval Reactors. The method is given in PB-15987, "Tentative Structural Design Basis for Reactor Pressure Vessels and Associated Components." The vessel stress analysis performed to the procedures outlined in this document together with the Code and Code case requirements is essentially equivalent to that required by ASME Section III for Class 1 vessels.
- The vessel was constructed of SA-302, Grade B, plate and SA-336 forging material. These materials were Charpy V-notch impact tested. A minimum Charpy impact energy of 30 ft-lbs was required at a temperature of 10°F or lower. These materials are essentially equivalent to the SA-533, Grade B, Class 1, and SA-508, Class 2, materials being used today.
- All forging material in the vessel pressure boundary was magnetic particle and ultrasonicly inspected.
- All stainless steel cladding was dye penetrant inspected after final stress relief. In addition, the cladding was ultrasonicly inspected for bonding to the base metal.
- The surfaces of completed pressure boundary welds were magnetic particle or liquid penetrant inspected.
- The weld preparations in ferritic materials were magnetic particle inspected prior to deposition of weld metal.
- All welds in the beltline region were made by the submerged metal arc process. The post-weld heat treatment was 21 hours of total stress relief treatment at 1125°F ± 25°F. The nominal chemical composition of weld metal is 0.27% copper and 0.014% phosphorus. The chemical composition of plate metal in the beltline region is 0.10% copper and 0.016% phosphorus. No drop weight tests were conducted on these materials. Charpy tests were conducted on weld and plate material at one temperature, 10°F. Plate material was tested in both the transverse and longitudinal directions. The Charpy energy for weld metal was over 50 ft-lbs, which is considered very good. The Charpy

energy for plate materials varied from 27 [illegible] 30 ft-lbs in the transverse (weak) direction. These values are considered to be about average for this type of steel.

- Based on chemistry and expected fluence, the limiting material is estimated to be weld metal. There is limited information (refer to Section 5.3.1 above) on the type or batch of filler metal or flux used to make the vessel welds. Therefore, at present we will consider all welds to be representative of the material surveillance weld and having the chemistry reported above. Based on data from unirradiated specimens in the material surveillance program, the initial value of RT_{NDT} of the weld material is about -50°F. The initial upper shelf energy of the weld metal is about [illegible] ft-lbs.

5.3.3.1 Generic Safety Items Applicable to the Reactor Vessel (NUREG-0569)

Generic safety items applicable to Big Rock Point are vessel material low upper shelf toughness and sensitized stainless steel safe ends. The feedwater nozzle and CRD return line nozzle cracking problems are not applicable to this plant. There is no CRD return line to the reactor vessel. The excess water from the control rod drive system flows into either the recirculation system or the cleanup system. The feedwater nozzles on Big Rock Point are located on the steam drum. Condensate from the turbines is pumped by the feedwater pumps to the steam drum. Water from the steam drum is pumped to the reactor vessel by the recirculation pumps. At normal operating conditions, the temperature of the water entering the vessel is 570°F. This is about 12°F lower than the vessel temperature so thermal stresses will be very low. For transient conditions the temperature differential between the inlet fluid and the vessel wall is also relatively low. Since the initial crack growth in feedwater nozzles is due to thermal stresses, Big Rock Point should have no problem regarding cracks in the recirculation nozzles on the reactor vessel (the feedwater inlet nozzles are called recirculation nozzles). To date, no flaws have been detected in the recirculation nozzles of Big Rock Point.

There are sensitized stainless steel safe ends on the Big Rock Point reactor vessel. These safe ends are made from 304 stainless steel. We requested information on these safe ends and Consumers Power Company responded by letter dated September 11, 1970. Through 1970, no flaws had been detected in these safe ends. The 304 stainless steel was made with low carbon content which increases its resistance to stress corrosion cracking. Since the 1970 review of the safe ends, no flaws or cracks have been found in the sensitized safe ends. We conclude that, since the vessel has been operating for 15 years (currently over 25), if a corrosion problem existed there would be throughwall flaws in these safe ends by now. We also realize that inservice examinations of these safe ends have been limited (as of the date of the NUREG).

However, from this present review it is concluded that there is no evidence of any stress corrosion cracking on these safe ends. Furthermore, we believe that there are no major flaws in these safe ends because of their low carbon content.

5.3.3.2 Evaluation Conclusions (NUREG-0569)

The Big Rock Point reactor vessel was designed to ASME Code Sections I and VIII. However, the requirements of these sections were supplemented by the requirements of Nuclear Code cases, the Navy Code and purchase specifications so that the quality control and design criteria utilized were essentially in accordance with the rules of ASME Code Section III. Therefore, the initial integrity of the vessel is considered acceptable. The primary stresses in the beltline region of the vessel are low, approximately 70% of those permitted by Section III. These low stresses, along with the use of materials with adequate fracture toughness, provide assurance that brittle fracture will not occur. Inservice examinations have been performed on components of the reactor vessel in accordance with ASME Code Section XI since 1973.

The reactor vessel is currently operating with pressure-temperature operating limits that are in accordance with Appendix G, 10 CFR Part 50. The staff will continue to review and update these operating limits to account for further radiation damage on vessel materials. The amount of radiation damage will be determined from the results of tests on Big Rock Point's surveillance specimens. The material surveillance program has been reviewed and is considered acceptable. The combination of inservice inspections, conservative operating limits, low vessel stresses and the use of materials having adequate fracture toughness properties provides assurance that the integrity of the reactor vessel will be maintained at acceptable levels throughout service life. The generic safety items applicable to Big Rock Point (low upper shelf energy and sensitized stainless steel safe ends) have been successfully resolved and will not adversely affect the vessel integrity.

For additional information (since issuance of NUREG 0569) on safe-ends, refer to Section 5.2.3.4 of this Updated FHSR.

5.4.1.2 Load Rejection/Automatic Recirculating Pump Trip

In November 1990, Consumers Power Company installed a reliability based RPT scheme designed to trip one selected reactor recirculation pump upon either a turbine load rejection or high reactor pressure condition resulting in emergency condenser operation. The intent of this modification is to lower reactor power by approximately 40% and place the reactor at a power level near that for which a successful load rejection has been demonstrated (~38 MWe) and by computer modeling, indicates that tripping of one recirculation pump has a beneficial effect on keeping feedwater available during such transients.

Automatic tripping of one reactor recirculation pump acts to 1) lower the reactor power and associated steam flow to the turbine/main condenser, 2) lessen the perturbations in the main condenser associated with load rejection and 3) reduce feedwater flow requirements. These three resultant action tend to eliminate secondary side instabilities inherent to load rejections occurring at higher power levels.

The intent of the second feature of this scheme (ie, tripping of one reactor recirculation pump upon emergency condenser operation) is to reduce reactor power as an anticipatory action following reactor scram in the event that a multiple rod insert failure has occurred. The automatic tripping of one pump supplants the correct operator action to reduce reactor power in a more rapid fashion, thus, giving the operator more time to combat this scenario. This change was completed via FC-664.

5.4.2 STEAM DRUM AND STEAM DRUM RELIEF VALVES

The steam drum, with its piping, is mounted high up inside the enclosure to perform the following functions:

Separate the steam from the steam-water mixture generated in the reactor core. The design criteria calls for drum exit steam quality of 99.9%.

Provide water storage to accommodate surges of water level and pressure between the reactor vessel and the drum.

Provide natural circulation driving head to maintain flow in case the recirculating pumps are inoperative. It has been calculated that it will be possible to run at over 50% load on natural circulation alone with both pumps inoperative but free to rotate.

Assure net positive suction head for the recirculating pumps to meet their design requirements. Drum water level is 65 feet above the center line of the pump suctions. The static head is sufficient to maintain flow during normal operation without pump cavitation; during transient conditions limited pump cavitation may occur.

Serves as a mixing tank for the cooler feedwater and hot recirculating water. This aids in smoothing (or absorbing) part of the reactivity changes due to moderator temperature changes.

Approximately 500 cubic feet of water are stored in the drum. If, at full load operation, all steam voids in the core, reactor vessel and riser piping collapsed, the water storage available is sufficient to keep the downcomer piping inlets covered. Operational transients and pump vibration will not occur as a result of steam drawn into the pump suction, and the supply of reactor recirculating water will be maintained.

5.4.2.1 Design Information

Combustion Engineering (CE) Incorporated designed, fabricated and tested the steam drum in accordance with the requirements of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section 1 - 1959 edition utilizing Code Cases 1270N and 1273N and Part UCL of Section VIII - 1959 edition for internal cladding weld overlay. The design was in accordance with General Electric Company Specification DP-19890, Revision 0, with modifications as shown on detailed drawings and as noted in C.E. Book No. 6460-D, September 1961, Instruction Manual - Primary Steam Drum.

The drum is a horizontally mounted "Code Stamped" cylindrical pressure vessel with internal steam drying and auxiliary equipment. Base material for shell and heads is SA-212-B, Fire Box, carbon steel clad with 5/32 inch (TP-304 stainless steel) minimum weld deposited with type 309 and type 308 stainless steel weld rod with equal to or better than 250 RMS surface finish on all internal surfaces. The cladding thickness is not considered in wall thickness calculations. Nozzles four inches and over are SA-105-Gr. II carbon steel forgings clad internally with stainless steel. Nozzles under four inches are solid inconel SB-166. The drum internals are essentially stainless steel and inconel plate and strip, A-167 and A-276 type 304 and SB-166 and SB-168. The Manway pad and cover are SA-105-GR. II carbon steel, hex nuts are A-194-2H and studs are A-193-B7 for the Manway closure.

Design Calculations

Design calculations for the drum have been made to cover the following:

ASME Code allowable stresses.

A detailed structural analysis of the shell nozzles and attachments to account for principal stresses and their combination for normal and transient power operation.

A transient analysis that concerns itself with the fatigue limits of the design (refer to CE Book No 6460D, Instruction Manual).

5.4.2.2 Steam Drum Characteristics

Table 5.6 Steam Drum General Characteristics

Length, Overall, Feet	40
Inside Diameter, Inches	78
Wall Thickness, Excluding Cladding, Inches	4-3/8 [1]
Cladding Thickness; Minimum, Inches	5/32
Design Pressure, Psia [2]	1700
Design Temperature, °F	650

Weights, Lbs

Dry Weight, Actual (in8luding internals)	199,100
Wet Weight, Calculated @100% Load, @600°F	225,100
Flooded Weight, Calculated @600°F	251,100
Hydrostatic Test Pressure, psig	2,528
Cycles of normal start-up and shutdown	2,000
Cycles of Emergency Shutdown	100

4

1. Does not include manufacturing tolerances per "As Built" drawings.
   5
2. As Built overall length including M8nways is about 40 feet 9 inches.
   6
3. Design Temperature at Design Pressure equals 614°F saturated.
4. 100% Load Design Pressure equals 1470 psia
5. After fabrication, and prior to shipment, the current hydrotest limits are contained in the Technical Specifications.
6. The drum will withstand a normal (100 degrees/hour - from and to 100% power and 594°F) start-up and shutdown approximately 2000 times, and approximately 100 emergency shutdowns from 100% power with a cooling rate of 6.4°F/min (384 degrees/hr). Normal cooling of the drum will be limited to 100 degrees/hour, but, 300 degrees/hour will be allowed in an emergency shutdown.

5.4.2.3 Steam Drum Penetration Nozzles

Table 5.7 Steam Drum Penetration Nozzles

Heads (2 Penetrations - 1 in Each End)	
2 Manway Openings	18" ID
Drum Shell (35 Penetrations)	
6 Steam Riser Nozzles A-105 Gr.II with TP-316 extensions	14"
2 Feedwater Inlet Nozzles A-105 Gr.II with type 304 stainless steel sleeves	8"
4 Steam Outlet Nozzles A-105 GR.II	8"
4 Downcomer Nozzles A-105 Cr.II with TP-316 extensions	17"
6 Safety Relief Valve Openings SB-166 Inconel with A-105Gr.II flange	3" ID
2 Condensate Return Nozzles (From Emer Cond) A-105 Cr.II with carbon steel extensions	4"
2 Remote Level Indicators (Upper) SB-166 Inconel with Carbon steel extensions	1 1/2"
Head (2 Penetrations - 1 in Each End)	
2 Remote Level Indicators (Lower) A-105 Gr.II with carbon steel extensions	4"
1 Vent From Reactor SB-166 Inconel with TP-304 extensions	1 1/2"
2 Vents From Steam Drum SB-166 Inconel with carbon steel extensions	1"
1 Sample Nozzle SB-166 Inconel with carbon steel extensions	1"
1 Decontaminating Nozzle SB-166 Inconel with carbon steel extensions	2"
2 Gage Glass Nozzles SB-166 Inconel with carbon steel extensions	1 1/2"

Nozzle Cyclic Stress Analysis (Reference 1 and 24)

A summary of the cyclic stress analysis for one of the most critical nozzles (17" downcomer), including the loading imposed on the nozzle from the piping was supplied to the NRC by letter dated May 3, 1962 and again by letter dated March 12, 1975 in response to a February 24, 1975 request for stress analyses. This February 24, 1975 letter also included the Manufacturers Data Report.

5.4.2.4 Steam Drum Support

Eighteen 1 1/2 inch support lugs are provided for supporting the drum during operation.

The drum is supported from the concrete overhead structure by 8 constant support hangers. Movement of the drum due to thermal expansion of the piping and reactor vessel is compensated for by a specially designed support system which makes the downcomers, anchored at the same elevation as the reactor vessel, into thermal rams to move the drum up as the rising temperature expands the components. Sidewise movement is controlled by guide rods that make the drum move on a line between the center of the drum and the reactor vessel anchor point. Additional rods keep the drum from rotating or skewing. The suspension and support system as designed for maintaining the position of the steam drum is capable of withstanding the forces developed by a riser or downcomer line break.

5.4.2.5 Miscellaneous Externals

Six peen pads and brackets are provided for attachment of thermocouples. Angles that extend circumferentially and longitudinally, are furnished for supporting the external three inch thick insulation.

5.4.2.6 Steam Drum Internals

The steam-water mixture from the reactor passes through the riser piping to the steam drum.

The internals of the drum provide for three stages of steam separation, with a steam exit quality of about 99.9%. Sixty stainless steel turboseparators provide the first stage separation. The turbo steam separators are located in two rows of 30 each on top of the riser baffle boxes. The riser baffle boxes direct the steamwater mixture from the six risers into the bottom of the turboseparators where the moisture is removed from the steam by centrifugal action. Secondary steam separation is provided by stainless steel steam dryers on top of the turboseparators. The final stage of steam separation is by the screen dryer assemblies located at the top of the steam drum through which the steam must pass to the steam outlet nozzles. The steam then passes to the turbine, while the water is returned to the bottom of the drum. The water passes down the downcomers into the recirculating pumps where it is then pumped into the reactor vessel.

spray and core spray recirculation systems is verified by a series of tests and inspections performed monthly and additional tests and inspections performed at each major refueling outage. These required activities are described in the Big Rock Point Technical Specifications.

The tests and inspections performed during each operating cycle and at each refueling outage to verify operability of the Enclosure Spray System are detailed in the Technical Specifications.

6.3.3.1 NRC Bulletin 88-04, Potential Safety Related Pump Loss

Dated May 5, 1988, this NRC Bulletin required Consumers Power Company to determine if pump-to-pump interactions could result in dead-heading, and if so, to perform an evaluation of the dead-heading impact on safe plant operation. It also required an evaluation of the adequacy of the minimum flow requirements for safety related pumps.

Consumers Power Company identified both core spray pumps, the electric fire pump and diesel driven fire pump to be within the scope of the bulletin. An evaluation was conducted, and the concerns recognized within the NRC Bulletin were not perceived to risk existing pump reliability.

The concerns of the bulletin are primarily applicable at Big Rock Point during testing and fire fighting activities when reduced flow conditions could exist. Plant Technical Specifications limit use of the system in this configuration to less than 30 hours/year. Based upon this limited low flow use and the periodic flow and vibration testing which has not identified an undesirable performance trend, plant modifications or operating practice changes are not warranted. Even though the fire pumps do operate at limited times below the vendor recommended minimum flow values, testing and inspections completed have not identified damage or significant performance degradation. Consumers Power Company letters dated July 7, 1988 and June 29, 1989 and NRC letter dated November 18, 1988 discuss resolution of this issue.

6.3.4 PERFORMANCE EVALUATION

6.3.4.1 Core Spray

The core spray consists of two automatically actuated independent double capacity piping headers capable of cooling reactor fuel for a range of Loss of Coolant Accidents (LOCAs). Either system by itself is capable of providing adequate cooling for postulated large breaks in all locations. When adequate depressurization rates are achieved in the postulated small break situation, either core spray system provides adequate cooling. For the largest possible pipe break, a flow rate of approximately 400 gpm is required after about 20 seconds.

Each core spray system has 100% cooling capacity from each spray header and each fire pump set. Specifying both systems to be fully operational assures, to a high degree, core cooling if the core spray system is required. Also, the primary core spray is required to be operable during refueling operations to provide fuel cooling in the event of an inadvertent draining of the reactor vessel. Water flow from the fire suppression system for fire suppression or for normal uses and testing for which the time and flow are restricted has a negligible effect on availability and is not a cause for declaring the systems inoperabl-

6.3.4.2 Core Spray Recirculation

The core spray recirculation system will be initiated to prevent excessive water build-up in the containment sphere. It will provide long-term post-accident cooling for those accidents in which core spray was utilized. If a passive failure of underground fire main piping should occur during long-term cooling, the capability exists to bypass the effected portion of the piping utilizing a fire hose to ensure the continuation of long-term cooling.

6.3.4.3 Enclosure Sprays

The enclosure spray system is not required to prevent exceeding the containment design pressure of 27 psig during loss of coolant or steam line break events. The principal purpose of the enclosure spray system is to maintain the containment temperature below the profile associated with electrical equipment qualification (EEQ) assumptions.

Loss of coolant events do not result in a challenge of the peak EEQ design temperatures even if enclosure sprays are not actuated for some time (on the order of 15 minutes). Steam line breaks, however, result in superheated steam leaving the break causing the containment temperature to exceed 235°F. This condition was verified in analyses performed as part of the Systematic Evaluation Program and is reflected in an August 26, 1980 submittal to the NRC. The break analysis assumed that no enclosure spray occurs for the first 15 minutes of the steam line break event. The current design of the enclosure spray system was established mainly as a result of these analyses. The primary enclosure spray was made to actuate automatically with no time delay when the high containment pressure spray set point is reached. Power was provided to the backup spray valve permitting it to be actuated from the control room.

The enclosure spray is therefore required principally for the spectrum of breaks associated with the main steam line. Only one of the spray headers is required with the backup spray needed only during a steam line break coincident with the failure of the primary enclosure spray valve. Emergency Procedures reflect the use of the enclosure spray system in this manner (reference CPCo Submittal dated September 19, 1986).

6.3.5 10 CFR PART 50, 50.46, APPENDIX K EXEMPTION AND ECCS OPERABILITY

By Commission Memorandum and Order dated May 26, 1976 Consumers Power Company (CPCo) was granted a plant life exemption from the requirements of 10 CFR, Part 50, 50.46 and Appendix K, Paragraph I.D.1 as applied to a Loss of Coolant Accident (LOCA) caused by a break in a core spray line and a concurrent single failure of a valve in the remaining core spray system. This exemption was based on conditions specified in the Memorandum and Order and supporting documents, with which Consumers Power Company has complied.

CPCo by letter dated August 12, 1977 provided an ECCS Technical Specification Change Request which discussed the exemptions as follows:

In the Commission's Memorandum and Order dated May 26, 1976 three specific concerns pertaining to the Big Rock Point Emergency Core Cooling System (ECCS) were addressed. These included: 1) Vulnerability to a single failure disabling a core spray line, following a break in the alternate core spray line; 2) vulnerability to a single failure disabling the on-site power supply, following a Loss of Coolant Accident, in the event off-site power is unavailable; and 3) uncertainty regarding adequacy of the nozzle spray distribution. Based on these concerns Consumers Power Company was required to perform specific procedural, system and component modifications as specified in the Memorandum and Order and supporting documentation.

The Commission's resolution, therefore, was granting a plant life exemption for the ECCS vulnerability to a single failure disabling a core spray line following a break in the alternate spray line and granting a limited exemption concerning the uncertainty regarding adequacy of the nozzle spray distribution allowing ECCS credit for feed system makeup.

CPCo qualified the nozzle spray distribution through a detailed testing program which is addressed in Sections 6.3.3 and 6.3.4 above and the limited exemption is no longer in effect.

One specific requirement of the May 26, 1976 Memorandum and Order was to augment the surveillance of the ECCS to enhance its reliability. This requirement was based on both the plant life exemption and the limited exemption which gave no credit for the backup core spray distribution. On May 10, 1976 Consumers Power Company requested a change to the Technical Specifications for Big Rock Point which contained the augmented ECCS surveillance requirements. Those changes were approved by the Director in Amendment 10 to the Big Rock Point Technical Specifications dated June 4, 1976. However, since Consumers Power Company has qualified the backup core spray system to the satisfaction of the Commission, it became both desirable and necessary to modify the ECCS Technical Specifications to account for this. Thus, the purpose of the August 12, 1977 change request was to update the ECCS Technical Specifications consistent with current industry standards based on a fully qualified backup core spray system, the limitations imposed by the plant life exemption, and system modifications made in compliance with the Memorandum and Order and supporting documentation.

A limiting condition of operation that remains in effect in the Technical Specifications, requires that a plant shutdown be initiated within 24 hours, the reactor shutdown within 12 hours, and a full plant shutdown within the following 24 hours if the following conditions cannot be met:

1. Both core spray systems operable when in power operation condition. The original core spray system (Ring Spray Sparger) will also be operable during refueling operations,

2. the core spray recirculation system will be operable whenever the plant is in a power operation condition,

3. the core spray recirculation heat exchanger will not be taken out of service during power operation for periods exceeding four hours, the heat exchanger will be considered inoperable and out of service if tube bundle leakage exceeds 0.2 gpm,

4. and both fire pumps (diesel and electric) and associated piping system to the core spray system tie-ins (reference Section 9.5.1 of this Updated FHSR) will be operable whenever the plant is in a power operation condition or refueling condition.

CPCo August 12, 1977 letter stated that the basis for the above requirements were considered to be significantly more restrictive than those imposed in current industry standards. The General Electric Boiling Water Reactor Standard Technical Specifications require restoring an inoperable core spray system component to operation within seven days prior to initiating shutdown. Maintaining this severely restrictive Limiting Condition for Operation ensures the continued safety of operation of the Big Rock Point Plant by restricting the allowable time for power operation with an inoperable ECCS component and, therefore, adequately compensates for any margin of tolerance gained by the plant life exemption.

The changes addressed in the August 12, 1977 Technical Specifications Change Request were included in Amendment 15, dated October 17, 1977 which provided an evaluation of certain conditions specified within the May 26, 1976 Memorandum and Order and based upon the NRC Safety Evaluation Report, found that the requirements of the Commission Order and the June 4, 1976 Staff Concerns have been satisfactorily answered by CPCo. The significant conditions involved and their resolution are discussed in the following subsections.

6.3.5.1 Underground Piping

A portion of the Fire Protection System piping is buried, 6" diameter, cast iron pipe with limited inspectability and repairability. This part of the system is essential for long term cooling following all LOCA events and is vital in achieving safe shutdown for many other conditions. The NRC Commissioners stated in paragraph 3i, page 17 of their Memorandum and Order:

> "Prior to return to operation following the refueling outage presently scheduled for Spring 1977, Consumers Power Company shall... i) Modify the fire protection system such that long term cooling can be accomplished without relying on the underground piping."

Evaluation: In a letter to the Commissioners, dated February 4, 1977, CPCo documented completion of the requirement. Fittings were added to the post incident heat exchanger inlet for hook-up of 2 1/2" hose to bypass the underground piping. CPCo advised that the 275 feet of fire hose would be kept in protected racks.

NOTE: Subsequent to the above, CPCo by letter dated March 21, 1979 increased the length from 275 feet to 300 feet to assure the hose will reach the heat exchanger when snow piles may obstruct the original hose routing.

Flow testing of the hose is performed to ensure acceptable performance of the core spray portion of the ECCS. The hose is stored on an "ECCS hose cart" in the screenhouse and is dedicated for this purpose.

Surveillance requirements for this ECCS hose is discussed in Section 9.5.1.2 of this Updated FHSR.

6.3.5.2 Emergency Diesel Generator/Diesel Driven Fire Pump Trips

CPCo and NRC resolution of this issue is addressed in Section 9.5.5 of this Updated FHSR.

6.3.5.3 ECCS Indication/Annunciation Circuitry

Discussion: The Commission's Memorandum and Order, dated May 26, 1976, directed CPCo to:

> Protect the controls indication and annunciation circuitry associated with the ECCS, including the core spray valves, against the consequences of flooding following a LOCA which affects the ability of the ECCS to perform properly or the plant operator to take corrective action during the course of a LOCA.

By letter dated May 5, 1977 CPCo summarized the ECCS indication/ annunciation circuitry modifications made at BRP.

Evaluation: The ECCS indication/actuation functions susceptible to failure due to flooding from a LOCA are listed below:

1. Station service annunciator panel (includes ECCS indication and alarms);

2. Nuclear steam supply annunciator panel;

3. Fire system annunciator panel;

4. Containment isolation valve indication; and

5. Core spray valves control and indication.

Items one through four above have been corrected through the use of selective fusing. The time-current characteristics of the fuses are such that the individual load fuses will clear before the supply circuit breakers trip. The newly added fuses are installed in the back of the control panels such that they are easily accessible for inspection. A blown fuse is readily detectable by observing the fuse pin indicator in the extended position.

Item five above would no longer be required, since the valves were relocated to be above the flooding level (reference 6.3.5.5 below).

In addition to the changes required by the Commission Order, the staff, by letter dated June 4, 1976, directed CPCo to: 1) install and calibrate flow recording instruments for the core nozzle spray flow and the core ring spray flow; and 2) provide electrical switching circuitry outside of containment to enable connecting either the ring spray flow transmitter or the nozzle spray flow transmitter to either spray line flow instrument channel. The modifications have been completed. The new core spray flow recording instrumentation provides the operator with a continuous recording of core spray flow during a LOCA. The electrical switching provides a means of identifying a failure in either flow recording channel exclusive of the flow transmitter.

These changes eliminate electrical single failures which could disable the core spray systems indication and annunciation channels. Thus, the changes substantially increase the reliability of information necessary for operator review during a LOCA. The staff considers the requirements of the Commission Order of May 26, 1976 and staff concerns of the June 4, 1976 letter have been satisfactorily answered by CPCo.

6.3.5.4 ECCS On-Line Testability

Discussion: The Commission's Memorandum and Order, dated May 26, 1976, directed CPCo to:

> Provide complete on-line testability at the ECCS, including testability of the actuation system.

Evaluation: Automatic actuation of the ECCS primary and redundant core spray systems isolation valves requires a low reactor water level signal coincident with a low reactor pressure signal. The BRP design had no means available to test the sensors operability while at power. This was primarily due to the lack of two-valve isolation protection between the sensors and the nuclear steam supply equipment and due to the lack of test connections which would allow controlled bleed-off and test equipment installation.

CPCo has completed piping modifications to the ECCS low water level and low primary pressure sensors which corrected the deficiencies noted above. The design now provides the capability for on-line ECCS sensor testing. CPCo proposed Technical Specifications requiring on-line testability surveillance of the ECCS actuation circuitry (which are currently in place).

The staff has reviewed the modifications to the ECCS which now provide complete on-line testability of the system. We conclude that the modifications are acceptable and comply with the conditions required by the Commission Order of May 26, 1976.

6.3.5.5 Ring Spray Isolation Valves Location

Discussion: The two motor-operated ring spray isolation valves, MOV-7051 and 7061, were located inside containment at an elevation of 586 feet. Since the water level in the containment may rise to the 586 foot elevation about two hours after a LOCA the valves and valve operators would be flooded. Therefore, the ring spray isolation valves would be considered inoperable.

Since positioning of these valves may be necessary following the LOCA, CPCo agreed to relocate the core ring spray valves above the flooding level prior to return to power following the 1977 refueling outage.

Evaluation: The two ring spray valves were relocated by CPCo. The valves are now located at the 596 foot elevation, significantly above the level which would flood the valves. Relocating the ring spray isolation valves at 596 feet ensures their operability following the LOCA. The staff concludes that this change is acceptable.

6.3.5.6 900# Class Valves

Discussion: The NRC staff comments to the Commission dated April 19, 1976, entitled "Staff Views Regarding Consumers Power Company Report on Evaluation of Adequacy of ECCS for Big Rock Point," identified a concern regarding the use of 900 lb class valves in the ring spray line. Although the downstream ring spray isolation valve is a 1500 lb. class motor operated gate valve, two 900 lb. class valves are located immediately upstream. The staff concluded that a modified overpressure protection analysis of the reactor pressure boundary was required. However, the staff considered the existing safety margins adequate assurance of the integrity of the valves for the period of time required for CPCo to obtain and for the staff to review the modified analysis.

Evaluation: In a letter dated August 24, 1977 CPCo states that the most limiting overpressurization event for Big Rock Point is the safety valve sizing event (turbine trip without bypass) as specified in the General Electric Report "Anticipated Transients Without Scram Study for Big Rock Point Power Plant" (NEDE-21065 dated October 1975). This assumed event results in a peak reactor vessel pressure of 1587 psig for approximately three seconds and a transient peak temperature of 604°F. CPCo states that the temperature at the valves for the peak reactor pressure is 140°F. The pressure-temperature ratings for the 900# class valves are 1640 psig at 600°F or 2136 psig at 140°F. Based on our review, we conclude that these valves can withstand the effects of the most limiting overpressurization event and therefore are acceptable.

6.3.5.7 Nozzle Spray System Performance

Discussion: In the Commissioners' Memorandum and Order of May 26, 1976, CPCo (BRP) was granted a one cycle exemption from the single failure requirements of 10 CFR 50, paragraph 50.46 and Appendix K, paragraph I.D.1 for an LOCA followed by a single failure in the ring spray system. CPCo (BRP) was also granted a lifetime exemption from the same criterion as applied to a LOCA caused by a break in either core spray system.

These exemptions were granted by the Commission subject to several conditions, some having to be satisfied prior to the cycle 15 startup. In paragraph d3 of the Order, the Commission stated:

> "Prior to return to operation following the refueling outage currently scheduled for Spring 1977, Consumers Power Company shall:
>
> (ii) Provide test data showing the adequacy of the nozzle spray system to provide adequate spray distribution during expected usage conditions, or modify the nozzle spray system to provide adequate spray distribution."

Evaluation: CPCo stated in a letter to the staff dated January 19, 1977, that the nozzles used in the BRP nozzle spray and ring spray systems provide course spray (large diameter droplets) and should not be significantly affected by the presence of a steam environment. However, to verify the adequacy of the nozzle spray system, as required by the Commission Order, CPCo conducted a test program to measure experimentally the spray distribution in a steam environment. The tests showed that the existing single nozzle did not provide adequate spray distribution; therefore, a new nozzle design was constructed and tested. The results were presented to the staff in a report, "Big Rock Point Core Spray Test Report, Single Nozzle Test and Development Program," August 1977.

The staff has evaluated the performance of the BRP nozzle spray system, as described in the CPCo submittals dated August 1977 and September 15, 1977. Based on our evaluation, as discussed in the supplementary Safety Evaluation Report, the staff concludes that the BRP nozzle spray system is acceptable.

6.3.5.8 Ring Spray System Performance

The adequate performance of the ring spray system at BRP was an inherent assumption in the Commission's granting the lifetime exemption discussed above. However, information recently submitted to the staff regarding steam effects on spray distribution, including the report on the performance of the BRP nozzle spray system, led the staff to request CPCo to investigate the ring spray performance in a steam environment.

As a result of scoping calculations that indicated questionable ring sparger performance, and the lack of sufficient test or design data to prove the ring sparger adequacy, CPCo requested an exemption until the 1978 Cycle 16 startup from the failure criterion requirements of 10 CFR 50.46 and Appendix K as applied to the nozzle spray system. The exemption requested under the provisions of 10 CFR 50.12 by CPCo letter dated September 15, 1977 would allow sufficient time for CPCo to complete testing of the ring sparger system.

CPCo Clarification

As discussed in Sections 6.3.1 through 6.3.4 above, testing was completed. NRC Amendment 26 to the Operating License dated April 10, 1979 determined that the core ring spray system was acceptable.

NRC Amendment 26 Summary

The tests performed at the Bartwo test facility resulted in an optimized sparger aiming pattern which delivered maximum bundle spray flow at all LOCA usage conditions. Two bundles received flows slightly below the Minimum Allowable Bundle Spray (MABS), but the licensee has developed maximum bundle power technical specifications which conservatively ensure the reactor will be operated within the capability of either the Nozzle Spray System and Ring Spray System and therefore are acceptable.

The licensee's techniques and checks will result in a production sparger whose aiming pattern closely duplicates the test sparger's aiming pattern, and therefore, the production sparger's aiming pattern is acceptable.

6.3.5.9 Standby Diesel Generator Availability

One condition imposed by the Director, Nuclear Reactor Regulation, included in the May 26, 1976 Memorandum and Order, required CPCo to:

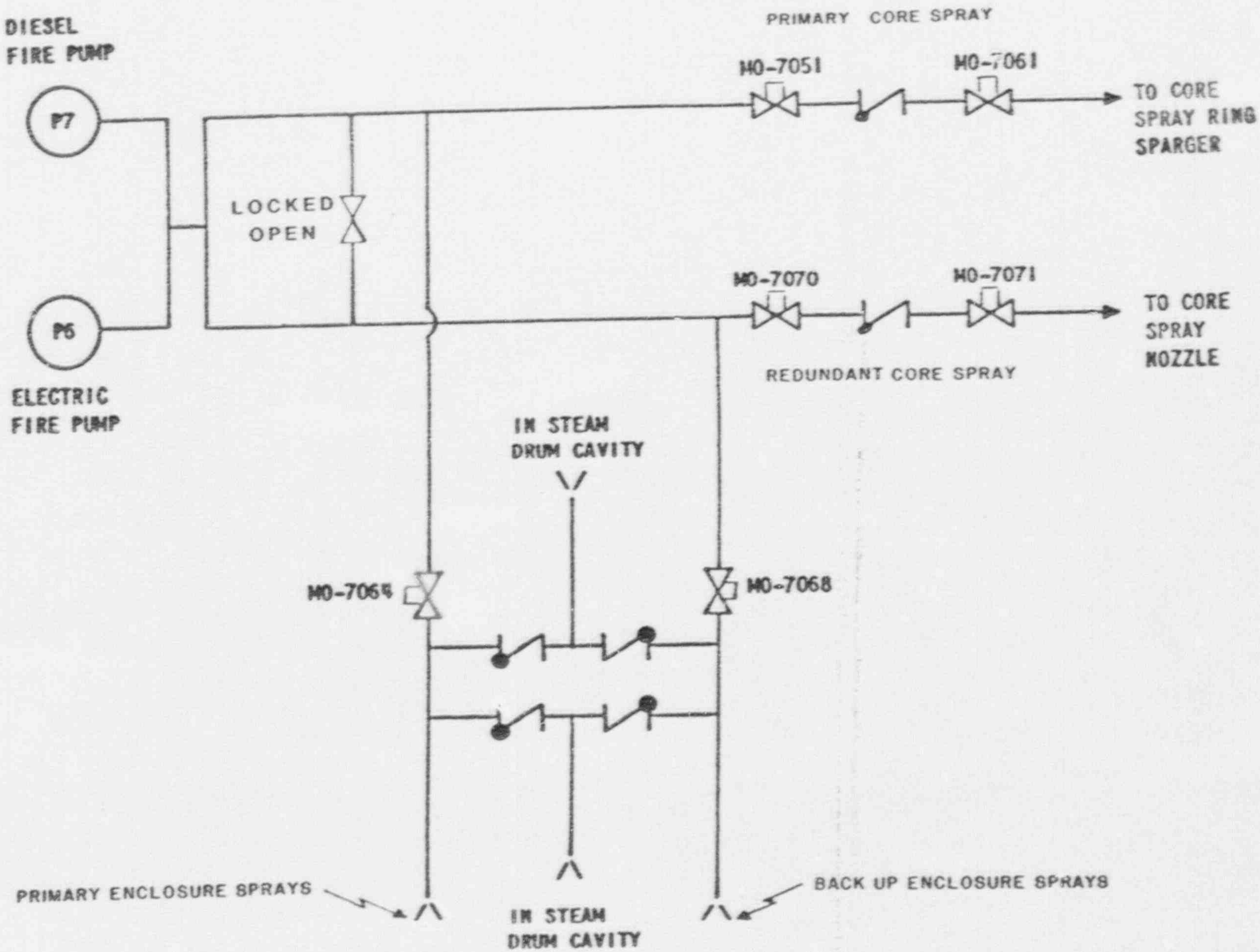
> Modify the emergency procedures to assure a second emergency diesel will be obtained and operational within 24 hours after a LOCA.

The basis for imposing this condition indicated that:

> With respect to the on-site electric power supply, Big Rock Point has only one on-site diesel generator and does not meet the failure criterion requirement that the ECCS short term and long term cooling functions be invulnerable to a single failure which disables on-site power, assuming off-site power is not available. In view of the unusually high availability of off-site power at Big Rock Point *(see note below), together with improved reliability of the on-site diesel and guaranteed availability of a back-up diesel for long term cooling pursuant to the conditions the Director would impose, the Director likewise finds good cause to exempt Big Rock Point from this requirement.
>
> *NOTE: The Director's comments note that in view of the small size of this plant compared with the system capacity, trips of the plant due to internal causes are relatively unlikely to cause a loss of off-site power.

Currently, BRP assures the availability of a second emergency diesel generator by providing the "Standby Diesel Generator" in a semi-trailer located at the wellhouse area. Details on the standby diesel generator are provided in Chapter 8 - Electric Power Systems, further details on Fuel Oil Storage and use during Alternate Safe Shutdown are provided in Chapter 9, Subsection 9.5.4 of this Updated FHSR.

FIGURE 6.3-1 CORE & ENCLOSURE SPRAYS



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A modification to the emergency condenser initiation logic was completed via Facility Change FC-509, to improve availability of the emergency heat sink, by providing an automatic opening signal to the condenser loop inlet valves. This will address the unusual situation in which an inlet valve is closed even though the tube bundle is intact (eg, when leakage through the normally closed outlet valve is detected and the inlet is closed to prevent water or steam cutting of the outlet valves). The motor operated inlet valves will receive an automatic opening actuation signal upon the opening of the associated outlet valve through an auxiliary relay.

A modification was installed in November 1990, to provide an automatic reduction in reactor power in the event of a high reactor pressure condition which results in emergency condenser operation. This modification provides tripping on one reactor recirculation pump (providing both are in service) upon emergency condenser outlet valve opening. Tripping of one recirculation pump will lower reactor power by approximately 40% and provide an anticipatory action following reactor scram in the event that a multiple rod insert failure has occurred. The automatic tripping of one recirculation pump suppliants the correct operator action to reduce reactor power in a more rapid fashion, thus, giving the operator more time to combat this scenario. This change was completed via FC-664.

The motor operated inlet valves are normally open during power operation and the motor operated outlet valves open in about nine seconds and the system is in full operation within 20 to 30 seconds. In the event one tube bundle is isolated as discussed in the previous paragraph, the operable tube bundle will operate as described within 30 seconds. However, the motor operated inlet valve on the isolated loop requires about 31 seconds to open, thus the isolated but serviceable loop would come into service to remove decay heat in about 31 seconds as opposed to the 30 second minimum established for an operable loop. In the event one tube bundle is isolated but serviceable and the inlet valve is closed, AC power would be required to open the inlet valve, thus, on loss of station power only the outlet valve would open automatically and no steam flow would occur in this loop.

During this time, the pressure continues to rise for several seconds until the emergency condenser absorbs all of the decay heat generated and thereafter the pressure declines as the decay heat load falls off. The time lag and the heat transfer rate of the emergency condenser are selected to insure that the peak pressure reached during this transient is substantially below the lowest setting of the drum safety valves even during single tube bundle operation.

After the decay heat load has fallen off, one of the condensate return outlet valves is closed by a remote manual switch in the control room to keep the cooling rate below 100°F/hr.

The water storage in the emergency condenser is sufficient for about four hours operation without make up, thus, initial operation is dependent only upon DC power to operate the outlet valves, as the AC powered inlet valves are normally open.

Make up is supplied to the tank by the demineralized water (DMW) pump. A makeup valve at the condenser is opened and closed automatically by a level switch so that, once the demineralized water pump is started, makeup is automatic. In addition, a remote manual makeup connection is provided from the fire system in the event of failure of the demineralized water pump, this method of makeup is controlled from the control room or Alternate Shutdown Building.

Original design considered a single tube bundle as sufficient to remove reactor decay heat when the heat rate drops to 2% of 240 Mwt following shutdown. Refer to Section 6.8.4 below for analyses/ evaluations of demonstrated capacity based on system testing.

6.8.3 EMERGENCY CONDENSER VENT MONITORS

Heat removed by the emergency condenser is released as steam vented to the atmosphere. Radiation detectors monitor the steam release from the shell side of the emergency condenser to the atmosphere. There are no radiation monitors on the steam supply lines to the tube bundles and there are no automatic tube bundle isolation functions. Should tube bundle leakage occur, the operator isolates the tube bundles individually to eliminate the source of leakage to the atmosphere while leaving the redundant loop in service as a heat sink. The system is isolated one loop at a time by closing the condensate return and steam inlet valves associated with each tube bundle.

The vent monitors are physically located in the containment building slightly above the emergency condenser shell. If the water inventory within the shell depletes, the shine from the tube bundles raises background radiation levels in the vicinity of the vent monitors. This background rise was determined to be sufficient to result in vent monitor annunciation and a false indication of tube bundle leakage.

As discussed in Section 6.8.4.1, it should be noted that total loss of water to the condenser is not considered credible. Nevertheless, CPCo in response to NUREG-0737 Item II.K.3.14 examined methods to reduce the probability of false indication of tube rupture due to shine from the emergency condenser tube bundles. CPCo addressed this concern in the February 5, 1982 update to Three Mile Island NUREG-0737 and provided a Probabilistic Risk Assessment March 31, 1981 which included an assessment for this item. As a result of these issues, CPCo moved the condenser vent radiation monitors away from the vent pipe, provided additional monitor shielding, and reset the monitor setpoint to account for these changes. This modification was performed via Specification Change SC-83-006. By moving the monitor back about two inches from the vent pipe, the geometry was changed such that tube bundle leakage detection was improved while reducing the potential for tube shine affects on the detector. The additional shielding to the rear of the detectors reduces the potential for airborne activity adding to the radiation coming from a condenser tube bundle leak. This further reduced false indications of tube bundle leakage.

6.8.3.1 Emergency Condenser Vent Monitor Operability Requirements

The emergency condenser vent will be monitored to detect a significant release of radioactive material. Monitoring will be supplied by two independent gamma sensitive instrumentation channels employing scintillation crystal sensing devices. These channels have a range of 0.1 to 100 mr/hr and are provided with an alarm which annunciates in the control room to inform the operator of a release of radioactive material.

One of the emergency condenser vent monitors will be in service at all times during power operation. The monitors will be set to alarm at 72 mr/hr which is approximately 10 mr above the maximum expected background during operation of the emergency condenser. The calibration is checked at least monthly.

6.8.3.2 Emergency Condenser Isolation on High Radiation

Requirements for automatic isolation of the Reactor Core Isolation Cooling (RCIC) System Isolation Condenser (IC) on boiling water reactors was specified as a post-Three Mile Island (TMI) requirement in NUREG-0737 Item II.K.3.14.

The equivalent RCIC system at BRP is the Emergency Condenser System (ECS). CPCo letter dated July 9, 1981 responded to this TMI Item. The response was based upon the March 31, 1981 Probabilistic Risk Assessment evaluation which determined that the risk resulting from emergency condenser tube leaks does not warrant the installation of an automatic system of the type recommended by NUREG-0737.

Installation of an automatic system which fails the emergency condenser when it may be the only heat sink available to cool the primary system compromises the reliability of this system.

The incident for which this automatic feature was to be installed does not occur frequently and results in core damage only if the operator fails to take appropriate action to isolate the leak, given information already available to him in the plant as it exists. In addition, cooling systems designed to mitigate an event of this type (RDS, core spray) would have to fail to perform their functions in preventing damage to the core before serious consequences would result.

On this basis, it was concluded that an automatic system to isolate the emergency condenser tube bundles appears to have little benefit in reducing the risk resulting from emergency condenser tube bundle leakage while creating a potentially detrimental effect on the reliability of the emergency condenser as a heat sink. Equipment and procedures designed to deal with ruptured tubes are already in place. Monthly surveillance of the emergency condenser shell inventory is performed to detect tube degradation as it develops. The risk resulting from emergency condenser tube leaks does not warrant installation of an automatic system to cope with it.

The NRC, by letter dated December 15, 1981, provided a Safety Evaluation for this issue as follows:

> Based on our review of individual licensee submittals, the staff concludes that since the subject plants do not have isolation condenser (IC) isolation on high radiation signals in the steam lines, the design modification as specified in NUREG-0737 Item II.K.3.14 is not relevant and does not increase the availability of the ICs as heat sinks. The staff also agrees with the position of one licensee that manual isolation allows the operator a greater amount of flexibility and system availability to cope with all anticipated and unanticipated operation transients.
>
> Regulatory Position
>
> We have reviewed the responses by six utilities to the NUREG-0737 Item II.K.3.14 requirements for automatic isolation of the isolation condensers (IC) on a high radiation signal at the IC atmospheric vents. Based on the results of our review as discussed in the above staff evaluation, we conclude that the manual trip on high radiation levels at the vents is sufficient to provide the amount of flexibility and system availability intended by the NUREG-0737 requirement.
>
> We conclude that the licensee's present positions, as stated in their respective submittals, are acceptable (Reference CPCo July 9, 1981 submittal).

CPCo March 31, 1981 PRA proposed to examine methods to reduce the probability of false indication of tube rupture resulting from shine from the emergency condenser tube bundles. This will increase the reliability of operator information with respect to the integrity of the emergency condenser system. Additional assurance that fatigue is not a significant contributor to the likelihood of tube bundle failure will be pursued.

False indication of tube rupture is addressed in Section 6.8.3 above. A study of fatigue will show that thermal stresses combined with normal operating loads do not appear to contribute to the likelihood of tube bundle failure (Reference CPCo February 5, 1982 TMI Update).

NOTE: Subsequent to the above submittals, CPCo letter dated February 10, 1986 provided fatigue calculations for emergency condenser piping elbow on the condensate return. The analysis indicates that there is adequate safety margin inherent in the design of the system with respect to piping fatigue. CPCo letter dated August 29, 1986 provided a thermal stress analysis and fatigue usage calculation for an emergency condenser outlet nozzle. The results indicate that the components design, conservatively, have a life of 427 cycles which is in excess of any postulated emergency usage.

6.8.4 EMERGENCY CONDENSER ANALYSES/EVALUATIONS

6.8.4.1 Failure to Replenish Cooling Water in Emergency Condenser

Gradual evaporation of the shell-side water in the emergency condenser will occur during its operation. Protection against failure to replenish cooling water in the emergency condenser is afforded by an initial water supply sufficient to last for about four hours and indefinitely with makeup cooling water supplied by the motor driven demineralized water pump, which is automatically controlled by level sensors. In addition, a low water level alarm is provided in the control room to initiate operator attention. If the operators do neglect to replenish the cooling water, the reactor pressure and temperature recorders in the control room will indicate that the system is gradually heating up. Thus, there are several indications of this situation available in the control room to the operators in such a situation and appropriate action is expected to be taken.

In order to increase the reliability of the emergency condenser as a heat sink for short and long term cooling, the original manual fire water makeup capability was modified to a remotely operated solenoid valve in series with the original manual valve which is now locked open. This make up capability is controlled from the control room or alternate shutdown building. Upon actuation, a timer (currently set at 10 minutes) will hold the valve open for the preset time and reclose the solenoid operated valve automatically. The timer prevents overfilling the system and limits any potential for reduction of core or enclosure spray flow capacity, (Reference Facility Change(s) FC-538 and FC-462J). This solenoid operated valve may also be manual operated (locally).

In the event that the demineralized water and fire water supply are both unavailable, a portable pump may be utilized in an emergency to feed a yard hydrant and fire protection piping network which feeds the solenoid valve for fire water makeup addressed above. The portable pump modification is discussed in Chapter 3, Section 3.3.2.1 of this Updated FHSR.

6.8.4.2 Basis For Emergency Condenser Tube Bundle Operability - Operation With One Bundle

CPCo proposed Technical Specification Changes to allow the plant to operate with one tube bundle in the emergency condenser valved out of service (Reference March 23, 1973 submittal).

The "discussion" in support of this submittal stated that the availability to operate with one emergency condenser loop out of service had been permissible since BRP became operational in 1962. Based upon the 1961 original and 1962 revised FHSR, CPCo concluded that valving one emergency condenser loop out of service during power operation at the Big Rock Point Plant did not present a change in the hazards considerations described or implicit in the FHSR. The change was made solely to clarify the interpretation of the Technical Specifications.

The Atomic Energy Commission (AEC) by letter dated April 11, 1973 provided the following evaluation(s) of this change:

Directorate of Licensing Evaluation

CPCo proposed a change to the Technical Specifications for the Big Rock Point Plant to clarify the original intent of the specification related to emergency condenser requirements. The proposed change would: (1) arbitrarily require both emergency condenser tube bundles to be operable whenever the plant is started up from the cold depressurized condition to provide one out of two reliability if the plant is isolated from its normal heat sink, and (2) allow continued reactor operation, with one of the two tube bundles isolated because of leaks, until repairs can be made during the next outage. With both emergency condenser tube bundles in service at the time of a coincident 100% load rejection and loss of main condenser, General Electric calculations reveal that the main coolant pressure increase will activate the emergency condenser by opening the condensate return outlet valves from both tube bundles within 9 (CPCo corrrection) seconds and that the pressure will subsequently peak "well below" the set points of the 6 safety valves. Natural circulation of water through the core (no external power required to move coolant) removes decay heat from the fuel rods. Heat, in the form of steam, flows to the emergency condenser where the absorbed decay heat is released through tube bundles to the atmosphere and the condensate returns by gravity to the reactor vessel. If only one tube bundle is operational rather than two, the resultant increased pressure could cause coolant system relief through the safety valves for a short period of time - until reactor decay heat falls within the heat removal capability of the single tube bundle (about 5 minutes after accident initiation). Since the primary system stresses under such condition are not excessive and since the core remains covered during such a transient, the primary system integrity will not be diminished and the core will not be damaged. (See CPCo clarification below).

We have concluded that the proposed change is accept le since it is consistent with the original design intent and within the spectrum of accidents described in the Final Safety Analysis Report (FSAR). The historically high reliability of the emergency condenser redundant tube bundles is evidenced by the observation that more than ten years of plant operation elapsed before it was necessary to isolate one of the two tube bundles during operation. Even in this single instance, investigation revealed that the leakage occurred through a flexitallic header gasket during a transient thermal condition and was easily corrected by tightening the flange bolts. It has never been necessary to plug leaky tubes.

The change as proposed is consistent with the existing principals of operational reliance on redundant systems. We have concluded that there are no changes in the hazards considerations described or implicit in the FSAR since for accident evaluation purposes it was conservatively assumed that the emergency condenser would be inoperable during all of the accident situations analyzed in the FSAR.

NRC Conclusions

The Final Safety Analysis Report considered loss of the normal heat sink accompanied by reactor scram without reliance on either of the emergency condenser tube bundles. On this basis we conclude that continued reactor operation with only one emergency tube bundle available for service, as proposed, does not increase the probability of or change the consequences of such an accident and therefore it does not present significant hazards considerations not described or implicit in the Big Rock Point Safety Analysis Report. There is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner.

CPCo Clarification

Based upon testing and calculations described in following subsections of this Updated FHSR, conservative analysis of one bundle operation indicate that the safety relief valves will not lift. Refer to Section 15.2.2 of this Updated FHSR and the following Analyses/ Evaluations subsections.

6.8.4.3 Emergency Condenser Modifications, Testing, and Analyses

6.8.4.3.1 Significant Emergency Condenser Tube Bundle Modifications

CPCo Special Report submitted August 15, 1963 provided a summary of operating experience which discussed replacement of the emergency condenser tube bundles after it was discovered that the upper section of each tube bundle was permanently deformed. Preoperational testing September 5, 1962 showed the original design to be inadequate in allowing for differential temperatures on the upper and lower tubes. Replacement tube bundle design is based upon using bent tubes which are vertically restrained and guided to allow further bending in a horizontal plane. Since replacement, the emergency condenser performed as designed with no difficulties and successful testing of the unit was conducted during the power test program.

CPCo letter of December 21, 1973 reported two problems found with the Big Rock Point Emergency Condenser and identified corrective action that was being taken. CPCo January 17, 1974 letter provided an updated description of the corrective action taken and also described one further problem that was discovered and corrected concerning the condenser.

The original water box divider plates were replaced with a redesigned divider plate. The redesign consisted of replacing the center section of the baffle plate with a bolted panel and the Flexitallic gasket with a narrow plate welded to the tube sheet. This design was selected to reduce thermal stresses, resultant plate bowing and subsequent loss of the seal provided by a Flexitallic gasket. Seven 1/2 inch bolts in 9/16 inch holes, initially torqued to one-half yield strength, will permit slippage between the baffle plate sections and limit fixed end moment to bolt yield stress. This design will significantly reduce baffle plate stresses as compared to the original design. The bolting is ductile, and, after an initial cycle, the plate and bolting will come to suitable alignment for service without overstressing the baffle plate and bolts. The modification was performed via Facility Change FC-238.

6.8.4.3.2 Emergency Condenser Baseline Test

CPCo submitted the 20th Semi Annual Report August 29, 1974 which included results of the January 12, 1974 Emergency Condenser Baseline Test.

An operational test was performed on the north tube bundle. The test's primary purpose was to obtain baseline data against which future performance characteristics could be compared. Prior to the test, the unit was on line for approximately 35.8 MWe (gross) (Reactor output of 112 MW_t). The IPR (Initial Pressure Regulator) was in the pressure control mode and the feedwater controller was on "automatic." The tube bundle's outlet valve, MO-7053, was fully opened in a jogging fashion and the system was allowed to come to thermal equilibrium, concurrent with automatic demineralized water makeup. The water supply was then isolated and boil-off was then allowed for a determination of the heat transfer capacity of that tube bundle. At the described test conditions, about 41 x 10^6 Btu/h heat transfer rate caused the boil-off of approximately 1,000 gallons in 13 minutes.

Subsequent analyses showed that this amounted to a 3.78 hour "No Makeup" capability to the top of the tube bundles from the normal water level maintained in the condenser. Further heat removal capability beyond the three hours and 47 minutes is available to the bottom of the tube bundle, to provide over four hours "No-Makeup" as described in the Original FHSR and Technical Specifications, although it is not desirable to uncover the tube bundles.

Calculations performed as a result of the baseline test, which essentially maintained the primary system temperature constant, and only removing generated decay heat indicate that the heat removal capacity of the emergency condenser, without shell-side makeup, is 47.5×10^6 Btu. This figure includes the transient heatup of the entire contents (about 8300 gallons) of the condenser from 100F to 212F, and the evaporation of approximately 5000 gallons of water above the bottom of the tube bundles.

Additional internal analysis calculated the fission shutdown and decay heat output for the first four hours following shutdown to be 39.5×10^6 Btu, neglecting the +20% conservatism in the decay heat calculation. (These calculations were based upon American Nuclear Society ANS Standard 5.1 - Proposed October-1971.)

Including the +20% conservatism provides 47.4×10^6 Btu fission shutdown and decay heat output. Thus, the emergency condenser is capable of removing the four hour "No-Makeup" fission shutdown and decay heat output including the calculated 120% conservatism to the bottom of the tube bundles.

If boil-off to the top of the tube bundles is the limiting condition, this represents the total heat removal available as 31.8×10^6 Btu which is approximately 19% less than the fission shutdown and decay heat output calculated above.

The results of these calculations were communicated with the Atomic Energy Commission Director of Reactor Operations (DRO) by telephone on April 26, 1974 to verify agreement that the 3.78 hour "No-Makeup" condition was not considered a substantial variance from the performance specifications contained in the Technical Specifications, DRO Region III agreed.

6.8.4.3.3 <u>Emergency Condenser Capacity Analysis</u>

Appendix XVI of the BRP March 31, 1981 Probabilistic Risk Assessment (PRA) included a discussion on Supporting Analyses for the PRA. Section XVI.1 included the results of the Emergency Condenser Capacity Analysis - BRP - PRA-001 which found that (based on demonstrated capability) one tube bundle of the emergency condenser is more than sufficient to prevent reactor pressure from reaching the safety relief valve setpoint of 1550 psia.

The internal analyses compared the emergency condenser single bundle design capability to the demonstrated capability which was obtained from the "Baseline Test" discussed above. These values are:

16×10^6 Btu/hr @ 600°F - Design/Bundle

41×10^6 Btu/hr @ 580°F - Demonstrated Capability/Bundle

The comparative results also determined that the design capacity of one tube bundle is not sufficient to prevent safety relief valve lifting with all the conservatisms assumed in the analyses. However, the design capacity would be sufficient if the 20% uncertainty (of General Electric Licensing Topical Report NEDO-10625 - March 1973) decay heat curve is ignored.

These conclusions correspond to the analyses conclusions discussed in 6.8.4.3.2 above.

6.8.4.4 Emergency Condenser Water Hammer Evaluation

CPCo letter dated February 14, 1983 provided a status report on Unresolved Safety Issues (USI's). USI A-1 "Water Hammer," included the following discussion in reference to the Emergency Condenser:

During an emergency condenser capacity test in 1974, unusual vibration of the inlet piping was observed when the No. 2 Loop outlet Valve MO-7053 was jogged closed following full flow operation of the emergency condenser. The primary system was at normal operating pressure. One loop of the unit was being tested following repair work. The emergency condenser had been used for pressure control and shutdown cooling on many occasions prior to this event. The primary system was inspected following the event and no damage was found. Analysis indicates that water hammer should not be a problem using the existing outlet valves with a closure time of about 9 seconds. Also, when the emergency condenser is used for plant cooldown (other than testing) the outlet valves close at significantly lower plant pressure and energy output. Plant procedures currently minimize use of the emergency condenser.

6.8.5 EMERGENCY CONDENSER OPERABILITY AND TESTING REQUIREMENTS

The emergency condenser will be operable and ready for service at all times during power operation. However, should one emergency condenser tube bundle develop a leak during power operation, it will be permissible to isolate the leaking tube bundle until the next outage. Both bundles of the emergency condenser will be available for service during cold to hot plant heatup for power production. If both emergency condenser loops become inoperable the plant will be brought to shutdown condition within 12 hours and to cold shutdown condition within the following 24 hours.

The emergency condenser system control initiation sensors will be functionally tested at each major refueling shutdown but not less frequently than once every 18 months.

Requirements for leak detection testing of the emergency condenser is discussed in Section 6.2.5 of this Updated FHSR. Current testing for the emergency condenser tube bundles and emergency condenser shell integrity are discussed in the following subsections.

Requirements for the emergency condenser vent monitors are addressed in 6.8.3 above.

Basis for the emergency condenser tube bundle operability is provided in 6.8.4 above.

6.8.5.1 Emergency Condenser Tube Integrity Testing

The NRC Inspection and Enforcement Branch IE Bulletin 76-01 required a description of the steps being taken to (1) assure the integrity of the emergency condenser tubes during operation, (2) assure that the margin of emergency condenser tube integrity is maintained, and (3) assure prompt detection and operator response to an emergency condenser tube leak.

CPCo letter dated April 5, 1976 provided the following response:

In order to assure the integrity of the emergency condenser tubes during operation, we plan to conduct daily water level checks of the emergency condenser shell side, and to sample the shell side water to determine its gross beta gamma activity on a monthly basis. These checks will be performed whenever the reactor is at operating pressure. It should be noted that whenever a shell side water sample is taken, the shell side must be opened to the containment atmosphere. This means that containment integrity is provided by the inventory of water in the emergency condenser shell side (CPCo clarification - and the check valve which was added via Facility Change FC-355 in 1977).

In order to assure that a margin of condenser tube integrity is maintained, the IE Bulletin proposes nondestructive testing, or as an alternative, hydrostatic testing of the emergency condenser tubes. For the reasons given below, we feel that neither method is practicable. In order to perform nondestructive testing, the reactor coolant piping to the emergency condenser must be cut in order to permit access to the tube side of the condenser. This is a significant work project. Hydrostatic testing could be accomplished in conjunction with the Nuclear Steam Supply System hydrostatic test which is performed during each refueling outage; however, because of the large volume of the emergency condenser shell side, the smallest leak which could be detected is on the order of one gallon per minute. A consideration which obviates the need for a hydrostatic test is that during reactor operation, the emergency condenser is continuously exposed to a pressure of about 1,328 psia. (CPCo clarification -

Nevertheless, BRP currently tests the tube side of the condenser during the system hydrostatic test each refueling outage).

The condenser vent radiation monitors with alarms in the control room backed by the daily water level checks and monthly gross beta gamma samples will assure prompt detection of tube leakage. Procedures are already in effect to require operator action to determine which tube bundle is leaking and to effect its isolation.

In addition to the above response, CPCo letter dated May 19, 1987 addressed additional actions in response to minor leakage of an emergency condenser tube bundle and determined that:

Analysis for xenon will be performed approximately one week after startups from cold shutdown since past analyses have shown this to be the optimum time for xenon detection should leakage occur.

6.8.5.2 Emergency Condenser Leak Detection Testing

As discussed in Section 6.2.5 of this Updated FHSR, a leak detection test in lieu of an individual component leakage rate or integrated leakage rate test for assuring containment integrity following disassembly of the emergency condenser may be employed.

Current tube bundle leak detection testing is accomplished in cold shutdown condition using helium or air bottles at a system pressure of between 1330 and 1400 psig, not to exceed 1400 psig on the tube side while observing for leakage.

After this testing is complete and the manway has been reinstalled, secondary side leak testing is accomplished by installing the blank flange and gasket (added via Specification Change SC-87-026), to the top of the emergency condenser vent piping. The secondary side valves are then closed and the emergency condenser is pressurized at a pressure of 10 +2 -1 psig for ten minutes. The manway gasket is snooped for leakage during this testing.

6.8.5.3 Emergency Condenser Leakage Rate Testing

Leakage rate testing of the emergency condenser shell side sample point isolation valves and gauge glass is required during reactor shutdown for refueling to meet American Society For Mechanical Engineers Section XI-1977 Summer 1978 Boiler and Pressure Vessel Code for Section IWV-3420 Containment Isolation Valve Leakage.

Testing is performed at a regulated air pressure input of 27 psig with a test volume between 24 and 30 psig for the sample line check valve, gauge glass, and gauge glass vent valve.

6.8.6 EMERGENCY CONDENSER HIGH POINT VENTS

CPCo letter dated July 1, 1982 addressed NUREG 0737 Item II.B.1 - High Point Vents. The requirement for remotely-operated Reactor Coolant System (RCS) high point vents was originally presented in NRC letter dated September 13, 1979. These RCS vents were to provide a method of remotely purging the reactor vessel and the PCS of non-condensible gases that could interfere with natural circulation cooling. At Big Rock Point, the reactor vessel is continuously vented to the steam drum, therefore no isolated pocket of gas could exist in the vessel. For those accident situations in which non-condensible gases are generated, the Reactor Depressurization System (RDS) would vent these gases to the containment building. Nevertheless, the RDS cannot vent non-condensible gases that may collect in the Emergency Condenser (EC) since it is the high point of the RCS. However, the design of the RDS precludes the use of the high point vents and the EC during core damage situations in which the RDS is actuated. Furthermore, the RDS provides a much larger heat sink than the Emergency Condenser. As a result, no credit is taken for the use of the ECS following core uncovery and RDS actuation.

By letter dated October 30, 1979 the NRC expanded the requirement for remotely-operated RCS high point vents to include venting of isolation condensers (or any system in which a large amount of non-condensible gas would cause a loss of function of that system). At that time, Consumers Power Company believed that since there was a remote chance for non-condensible gas to collect in the EC when the EC would be needed for cooling, we committed to install high point vents on the lines connected to the tube bundles in the EC.

Since that time, further analysis has shown that the usefulness of the high point vents is limited. Venting would only be useful in the isolated incident when the EC is the only means of removing heat from the RCS following shutdown (ie, the main condenser and the Shutdown Cooling System have failed). In this situation, non-condensible gases could build up to the point where the gases fill the EC and degrade the effectiveness of the EC to the point where RCS pressure and temperature can no longer be controlled. Venting would then be required to prevent actuation of the safety relief valves. Analysis shows, however, that it would require a significant amount of time (more than two weeks) before such venting would be required. This time period is sufficient to allow repairs to the Shutdown Cooling System and/or to the main condenser since containment would remain accessible.

Based on this analysis, Consumers Power Company has concluded that the high point vent system would not serve any useful purpose as a means of mitigating core damage or promoting natural circulation in the event of an accident in which non-condensible gases are generated.

The high point vents were installed, and subsequently removed as discussed in Section 5.4.7 of this Updated FHSR.

The normal output of the logic unit is a low-voltage dc signal to the control rod scram circuitry and the reactor containment penetration closure circuitry of the power switch. This output drops to less than one volt upon receipt of appropriate trip signal inputs to the logic unit.

7.2.6.2 Power Switches

The power switches (CB-RE04A and CB-RE17A for Channel 1 and CB-RE04B and CB-RE17B for Channel 2) perform a rapid electrical switching function through the use of a combination of five relays. These power switch coils (K1 through K5) are all normally energized. Upon loss of input from the logic unit, the coils will de-energize to initiate RPS actions.

7.2.7 REACTOR PROTECTION SYSTEM ANNUNCIATOR CONTROL UNITS AND OPERATIONS RECORDER

7.2.7.1 Annunciator Control Units

Each protection Channel contains two annunciator control units (ACU-RE02A and ACU-RE02C for Channel 1 and ACU-RE02B and ACU-RE02D for Channel 2) which contain 26-volt, dc relays and 115-volt, ac relays. These relays perform annunciator functions as well as trip bypass control functions associated with Mode Selector Switch S4 located on the control console, (refer to 7.2.4 above).

7.2.7.2 Operations Recorder

All protection system sensor circuits are continuously monitored so that an operation or failure is recorded for later reference or for identifying spurious single-channel trips which would not be annunciated on the Station Annunciator. The monitoring is provided by two, Thirty-Channel Operations Recorders OR-RE01A and OR-RE01B, one for each protection channel. These recorders normally operate with a chart speed of approximately 1 1/2 inches per hour. When the first trip signal is received, the chart speed is increased to 1.5 inches/min to permit identification of trip sequence.

Upon application of the trip signal, the Operations Recorder pen relay, corresponding to the particular sensor, de-energizes, initiating a pen travel offset. Subsequent sensor operations initiate offsets also and thus trip sensor action can be more accurately timed at the faster chart speed.

7.2.8 REACTOR PROTECTION SYSTEM POST-TRIP REVIEW

The Plant Manager or his designated alternate will be notified immediately of all reactor scrams and will approve subsequent start-ups. Start-up of the reactor following a scram will not proceed until the cause of the scram has been determined and the necessary corrective action taken. The evaluation and approval of the Consumers Power

Company General Office will be required for all start-ups following an unexplained scram.

Plant Administrative and Operating Procedures require designated personnel complete a Reactor Trip Report which provides:

1. A description of the initiating event.

2. A verification that all automatic scram sensors that should have actuated, did indeed actuate.

3. Verification that the automatic trip of the RPS did indeed trip the safety system (and not the follow-up action by the Operator via the manual scram).

7.2.8.1 Reactor Trip Report

The Reactor Trip Report is utilized for evaluation and review of each unscheduled reactor trip involving control rod blade motion. The trip report is required to determine that response was proper and that anomalies are corrected prior to returning the reactor to power operation. The cause of the trip is determined, the proper operation of safety-related equipment that was challenged must be verified, and assurance established that the trip event did not have any other detrimental effect on the plant in terms of nuclear safety.

The trip report assures that RPS or ESF equipment which appears to have been challenged without operation, is tested for proper operability prior to restart after a scram.

7.2.8.2 Post-Trip Review (Data and Information Capability)

The NRC issued a Safety Evaluation Report (SER) dated July 11, 1990 documenting acceptance of Big Rock Points' post-trip review data and information capabilities.

Plant parameters and equipment actuations are monitored primarily by pen-type recorders. Sequence of event recorders for post trip review are limited to the Operations Recorder and the 138 KV line volts/amps Recorder. A summary description of these recorders and the parameters monitored is provided below:

Operations Recorder (Reference Section 7.2.7.2 above)

The Operations Recorder system consists of four strip chart ink pen event (on-off) recorders. The system monitors the voltage (on-off) to the scram pilot valves and the relay coil voltage that controls the closure of the dump tank isolation valves, the turbine stop valve, and the containment ventilation isolation valves. The recorders are powered by the reactor protection motor generator sets.

The trip inputs monitored are:

1. High reactor building pressure
2. Low reactor water level
3. High reactor pressure
4. Recirculation valve partial closure
5. Main steam isolation valve partial closure
6. High scram dump tank level
7. High neutron flux (power (wide) range)
8. High condenser pressure
9. Low steam drum water level
10. Manual trip

138 KV Line Volts/Amps Recorder

The strip chart recorder monitoring the 138 kV transmission line has event (on-off) indicators which show the 138 kV line oil circuit breaker (199 OCB) trips and closures and the main generator output oil circuit breaker (116 OCB) trips and closures as well as other tone relay control signals.

Time History Recorders

Certain other parameters are either continuously recorded on circular ink pen recorders; continuously printed on strip charts; continuously recorded on strip chart ink pen recorders; and intermittently printed on strip chart recorders.

Although not all the parameters recommended by Generic Letter 83-28 are recorded, alternative parameters are available for post trip review. These sources are discussed at length in part 4B of the July 11, 1990 letter.

Certain of these recorders are powered from 480 Volt Bus 1A through I&C transformer 1A and backup power is supplied automatically from the Emergency bus 2B which is supplied by power from the emergency diesel generator on loss of normal station power supply to bus 2B.

Data Retention

Circular charts and selective strip charts (stack gas, liquid process monitors, continuous air monitor) are stored for life of the plant. Control room logbooks and log sheets are filmed and returned for life of the plant. BRP Technical Specification 6.10 specifies additional date retention requirements.

BRP compiles files of all reactor trips for subsequent review. These files are maintained at the plant site for post-trip review comparison of subsequent events.

Other Data

Other data available to assess operational events include operator log sheet information and log books maintained by the #1 Control Operator, Shift Supervisor, and Auxiliary Operators. When conditions warrant, written statements from operators and other plant personnel are obtained for assessment. Also, off-site technical groups provide evaluations of transmission line and other electrical equipment transients when requested by plant management.

7.2.9 REACTOR PROTECTION SYSTEM ISOLATION FROM NON-SAFETY SYSTEMS

The NRC Systematic Evaluation Program (SEP) Topic VII-1.A, Isolation of Reactor Protection System From Non-Safety Systems - Final Safety Evaluation Report (SER) dated September 2, 1982 included a technical evaluation and review of the isolation of the RPS from the controls and non-safety systems.

Discussion and Objectives

Non-safety systems generally receive control signals from the reactor protection system (RPS) sensor current loops. The non-safety circuits are required to have isolation devices to insure the independence of the RPS channels. The objective of our review was to verify that operating reactors have RPS designs which provide effective and qualified isolation of non-safety systems from safety systems to assure that safety systems will function as required.

The RPS parameters identified in the Big Rock Point Technical Specifications and reviewed are as follows:

High Reactor Building Pressure
Low Reactor Water Level
Low Steam Drum Water Level
High Reactor Pressure
Main Steam Line Valve Closed
High Condenser Pressure
High Scram Dump Tank Level
Recirculation Line Valves Closure
High Neutron Level Flux
Short Reactor Period (same contacts as High Neutron Flux - reference FC-599)
Manual Scram

Protection Against Picoammeter Circuit Failure (Power Range Monitor Circuit Failure - reference FC-599)
RPS Bus Undervoltage

Review Criteria

General Design Criterion 24, "Separation of Protection and Control Systems," of Appendix A, "General Design Criteria for Nuclear Power Plants," 10 CFR Part 50, "Domestic Licensing of Production and Utilization Facilities."

IEEE Standard 279-1971, "Criteria for Protection Systems for Nuclear Power Generating Stations," Section 4.7.2.

NRC Safety Evaluation Conclusions

Based on current licensing criteria and review guidelines, the plant reactor protection system complies with all current licensing criteria listed above, except that the power supplies for the RPS channels do not satisfy the single failure criterion.

The staff finds that the reactor protection system is adequately protected by suitably qualified isolators with the exception of the possible effects from the motor generator sets.

The concern voiced by the NRC related to the potential for a sustained voltage or frequency transient in the RPS Power Supply (MG set or alternate feed) to overheat half of the scram valves and prevent a scram.

CPCo letter dated March 11, 1983 provided a response addressing the above NRC concerns. In the submittal, the resolution involved reduction of the setpoint of RPS MG set over-voltage relays to 125 VAC and the setpoint of the MG set regulators to 115 ± 2 VAC. The Set Point Changes were accomplished via SPC-83-037 and 83-038.

7.2.9.1 Reactor Protection System Isolation From Non-Safety Systems Final Resolution

The NRC Final Integrated Plant Safety Assessment Report (IPSAR) NUREG-0828 - May 1984, Section 4.22 for SEP Topic VII-1.A provided the resolution for this issue.

By a letter dated March 11, 1983, the licensee submitted an analysis of the protection provided. As a result of this analysis, the licensee has reduced the voltage regulator and the overvoltage protection relay setpoints to limit the maximum sustained voltage. In addition to the setpoint change, testing has shown that scram solenoid power requirements are less than the minimum rated operating conditions for all voltages below rated operating voltage down to plunger dropout. (As a result, the coil cannot overheat before a scram is initiated.) Finally, the analysis showed that motor thermal overloads provide protection against underfrequency events resulting from mechanical failure of the motor-generator sets. Underfrequency events from degraded plant bus conditions have been reviewed under Topic VIII-1.A (Section 3.1 of this IPSAR).

In view of the protection provided, the fact that the equipment is of the same quality as that used in other engineered safety features, and the fact that the plant has experienced several undervoltage transients (to scram valve plunger dropout) without equipment damage, the staff concludes that modifications to provide additional protection beyond those made by the licensee will not provide a significant increase in protection. Also, as noted in the licensee's letter of March 11, 1983, periodic replacement and testing programs for these solenoid valves have been effective in preventing multiple failures. The staff finds the modifications made by the licensee acceptable.

The staff has also determined that required instrument calibration is performed in accordance with plant procedures, however, some of these tests are not included in the plant Technical Specifications. The need to revise the plant Technical Specifications will be determined during the integrated assessment.

7.5.1 RPS AND ESF TESTING, SEP TOPIC VI-10.A RESOLUTION

The NRC Integrated Plant Safety Assessment Report (IPSAR) NUREG-0828, May 1984 Final Report in Section 4.21 provided the following resolutions for this issue.

10 CFR 50 (GDC 21), as implemented by Regulatory Guide 1.22 and the BWR Standard Technical Specifications (STS) (NUREG-0123), requires that the Reactor Protection System (RPS) be designed to permit periodic testing of its functioning, including a capability to test channels independently. During the topic review, the following issues were identified.

7.5.1.1 <u>Surveillance Frequency Requirements Resolution</u>

The Big Rock Point Technical Specifications do not require calibration of the initiation channels for the RPS, the emergency condenser system, and the containment isolation system. Calibration of these systems is controlled by plant test procedures, which are scheduled in the Technical Specifications.

The Big Rock Point Technical Specifications specify response times but do not require response-time testing of the RPS and Engineered Safety Features (ESF) systems. Response-time tests are controlled by plant test procedures; RPS response-time test intervals are greater than that specified in the STS. For Big Rock Point, the staff agrees with the licensee position that operating experience justifies a test interval that is greater than that specified in the STS.

7.5.1.2 <u>Reactor Protection System Response-Time Testing Resolution</u>

Refer to Section 7.2.2 of this Updated FHSR.

7.5.1.3 <u>Safety Evaluation Report - Generic Letter 83-28, Item 4.5.2, Reactor Trip System Reliability On-Line Testing</u>

The staff reviewed Big Rock Point's response(s) to Generic Letter 83-28, Item 4.5.2, and issued a SER dated February 13, 1989. The reliability of the Big Rock Point Reactor Protection System (RPS) including the Reactor Trip System (RTS), was reviewed as part of the Systematic Evaluation Program (Topic VI-10.A) and as a result of that review, Consumers Power Company has concluded that the present Big Rock Point Technical Specification requirements for functional testing of the RPS are adequate to ensure reliable operation of the Big Rock Point RPS. Based upon this testing, which includes weekly and monthly functional testing of the RPS, the staff concludes this meets the requirements of Item 4.5.2 of Generic Letter 83-28.

7.5.1.4 Safety Evaluation Report - Generic Letter 83-28, Item 4.5.3, Reactor Trip Reliability On-Line Functional Testing of the Reactor Trip System

The staff reviewed Big Rock Point's response(s) to Generic Letter 83-28, Item 4.5.3 and issued a SER dated August 10, 1989. The staff feels the currently configured RPS is highly reliable based on past Big Rock Point experience, the weekly and monthly functional tests, the sensor calibrations and the RPS scram sensor test performed at every refueling outage. In addition, the analyses in NUREG-0460 have shown that, for a number of reasons, more frequent testing than monthly will not appreciably lower the estimates of failure probability.

The staff concludes the existing intervals for on-line functional testing are consistent with achieving high RPS availability at Big Rock Point.

Chapter 3, Table 3-1 of this Updated FHSR). Although the safety-related systems at Big Rock were not designed, fabricated, erected, and tested using RG 1.26, the maintenance and modification of certain systems is currently conducted in accordance with portions of this guide. For example, the RDS was designed and built to the standards of those regulatory guides.

- At the time the Big Rock Point Plant was licensed, the NRC criteria for QA were not developed. The QA program for operation of Big Rock, SEP Topic XVII, was approved by the staff on September 17, 1976 and the current QA program is addressed in Chapter 17 of this Updated FHSR.

GDC 2 states that structures and equipment important to safety shall be designed to withstand the effects of natural phenomena without loss of capability to perform their safety function. Natural phenomena considered were:

- The effects of tornadoes which were reevaluated during the course of the SEP in Topics II-A "Severe Weather Phenomena," III-2 "Wind and Tornado-loadings," and III-4.A "Tornado Missiles." These are addressed in Chapter 2 and 3 of this Updated FHSR.

- Floods and flood effects which were reassessed in the SEP review under Topics II-3.B "Flooding Potential and Protection Requirements," and III-3 "Hydrodynamic Loads." These are addressed in Chapter 2 and 3 of this Updated FHSR.

- Within the SEP review, the potential for and consequences of a seismic event at the Big Rock Point site were reassessed under several review topics. The seismic potential and consequences are addressed in Chapters 2 and 3 of this Updated FHSR.

GDC 3 requires structures, systems, and components important to safety to be designed and located to minimize the effects of fires and explosions.

- BRP received an exemption from the requirements of Section III.G.1.a of Appendix R to 10 CFR 50 for having one train of systems necessary to achieve and maintain hot shutdown be free of fire damage. A severe screenhouse fire would result in unavailability of the diesel fire water pump driver, the electric fire water pump motor, and both service water pump motors and their power supply cables. Consequently, a severe screenhouse fire will compromise the ability to maintain hot shutdown due to loss of emergency condenser make-up resulting from lack of cooling to the plant air compressor. However, after review, the Commission granted Big Rock Point an exemption from the requirements stated above on February 8, 1990 to allow a hot shutdown repair to maintain hot shutdown following a worst case fire in the plant screenhouse. The repair involves connecting an on-site store cooling water hose to the air compressor from the demineralized water system (DWS). Operating procedures include instructions to utilize a fire department truck to fill the DWS tank if ECS make-up is required beyond 36 hours. Regarding cold shutdown, a spare SW pump motor will be stored on-site in an accessible location and inspected at regular intervals. In the event of the screenhouse fire the spare motor can be installed to reestablish the service water system needed to support cold shutdown. The Fire Protection System and Alternate Shutdown System are addressed in Chapter 9 of this Updated FHSR.

GDC 4 requires that equipment important to safety be designed to withstand the effects of environmental conditions for normal operation, maintenance, testing and postulated accidents. Also the equipment should be protected against dynamic effects including internal and external missiles pipe whip, and fluid impingement.

- The SEP reevaluated the various aspects of this criterion when reviewing topics III-12 "Environmental Qualification of Safety-Related Equipment" (USI A-24), III-5.A "Effects of Pipe Breaks Inside Containment," III-5.B "Pipe Breaks Outside Containment," and III-4 "Missile Generation and Protection." These are discussed in Chapter 3 of this Updated FHSR.

- GDC 5 is not applicable for the Big Rock Point Plant because it does not share any equipment with other power units.

7.6.1.2 Listing of Safe Shutdown Systems or Components

Although other systems are available to perform shutdown and cooldown functions as described in this Updated FHSR, based on NRC review of systems available at Big Rock Point to accomplish these functions in accordance with the provisions of BTP RSB 5-1, the NRC determined that the following minimum number of systems is required (Note: the portions within parenthesis identify the Section within this Updated FHSR where these systems or components are described):

1. Reactor Protection and Trip System (Section 7.2)
2. Emergency Condenser (Section 6.8)
3. Fire Protection Water System (Section 9.5)
4. Reactor Depressurization System (Section 6.9)
5. Core Spray Systems (Section 6.3)
6. Post Incident System (Section 6.3)
7. Instrumentation for Shutdown and Cooldown (Table 7.6-1 and Section 9.6)
8. Emergency Power (AC and DC) for the Above Systems and Equipment (Section 8.3 and 8.4)
9. Alternate Shutdown System (Section 9.6)

Table 3.1 in Chapter 3 of this Updated FHSR lists these safe shutdown systems along with a comparison of present design criteria with the criteria to which these systems were designed.

7.6.1.3 Safe Shutdown Instrumentation and Controls

The instrumentation listed in Table 7.6-1 represents those parameters that indicate overall reactor performance (eg., steam drum level, pressure) and those instruments that monitor performance of the systems being used for the shutdown (eg., emergency condenser level). The latter set is included to enable the operator to detect degradation in system performance prior to loss of function. It should be noted that Table 7.6-1 Instruments identified were those selected by the NRC in the review of this SEP Topic. In certain cases, other instruments are utilized which meet Electrical Equipment Qualification Requirements, refer to Section 3.11 of this Updated FHSR.

TABLE 7.6-1

LIST OF SAFE SHUTDOWN INSTRUMENTS

Component/System	Instrument
Reactor System	Steam drum level (LE-1D25 A&B, LI-IA77 and ID59, LT-IA18, ID13)
	Steam drum pressure (PT-IA07B and PR-IA09)
Emergency Condenser	Shell level (LT-3150, LI-3305 and LS-3549)
Fire Water System	Fire System pressure (PI-338)
Core Spray System	Core Spray flow (FT-2162, FI-2335)
Backup Core Spray	Core Spray flow (FT-2163, FI-2336)
Core Spray Recirculation System	Core Spray Recirc pressure (PS-638)
	Containment water level (LS-3562 through 3565)
Emergency AC Power	Emergency Diesel voltage and current indication
Emergency DC Power	125V DC System voltage indication
Alternate Shutdown DC Power	125V DC Alternate Shutdown voltage indication
Alternate Shutdown Instruments	Refer to Section 9.6 of this Updated FHSR

Some of the instrumentation listed would not normally be needed for a shutdown. If the emergency condenser is available, only steam drum level, steam drum or reactor pressure and emergency condenser shell level would be needed. Additional readouts were provided at the alternate shutdown control panel described in Section 9.6 of this Updated FHSR.

If the emergency condenser cannot be used, other instrumentation would be used to monitor RDS, PIS performance, such as containment water level. It would also be desirable to have flow indications for the post-incident cooling system.

7.6.1.4 <u>Safe Shutdown Methods</u>

The emergency condenser provides the most desirable means of decay heat removal in those situations in which the main condenser is not available for cooldown. The tube side of the condenser is designed for primary system pressure. Redundant inlet and outlet flow paths are available. However, the outlet valves are powered by a common DC alternate shutdown bus and would not meet the requirements of IEEE 279 for single failure and separation. Therefore, with an assumed loss of offsite power (shutdown with only onsite power) and a single failure which disables the Alternate Shutdown 125 VDC bus, the emergency condenser DC outlet valves would be inoperable and the emergency condenser could not be used for shutdown. In this case, the RDS, core spray system, and post incident cooling system are operable and provide an acceptable means to depressurize and cool the reactor. Depressurization of the reactor with RDS, coolant injection with the core spray systems, and long term cooling by the post-incident cooling system provide this ability. However, because the RDS discharges to containment, and its use would require an extensive containment cleanup effort, this is not the most desirable cooldown method.

Activation of the RDS and core spray for shutdown with loss of offsite power and an assumed single failure can be done from the control room. However, realignment of the post-incident cooling system for long term cooling requires operator action outside the control room but not inside containment.

Activation of RDS results in a very rapid cooldown. Blowdown with RDS is rapid and the coolant temperature follows at saturation conditions. This is followed by injection of cool water from the core spray (fire water) system and then recirculation using the post incident cooling system core spray heat exchanger.

If DC power is not lost the emergency condenser is used for cooldown. Experience at the plant has shown that the heat removal capacity of the emergency condenser is large enough that it is necessary to take action to limit the cooldown to within Technical Specification limits. Plant experience has also shown that the emergency condenser and a single shutdown cooling system pump and heat exchanger are sufficient to cool the plant to cold shutdown within 36 hours. The following subsections provide an evaluation of the capability of the plant systems to perform this cooldown.

Although the Shutdown Cooling System is normally used to attain cold shutdown conditions during routine shutdown of the plant, it is susceptible to a failure to open of either a single suction or discharge isolation valve located inside the containment sphere. Furthermore, operator entry to containment is necessary to restore power to the valve breakers for remote valve operation. The isolation valves are equipped with handwheels for manual operation in the event of an electrical malfunction. However, the RDS, core spray, and post-incident cooling systems can be used to attain cold shutdown, if required; and these systems are not susceptible to single failures.

7.6.1.5 Residual Heat Removal/Shutdown Cooling System RHR/SCS Controls Evaluations

The Shutdown Cooling System is described in Section 5.4.5 of this Updated FHSR which includes an evaluation of SCS Isolation Controls. The following provides additional analyses and evaluations to supplement the control discussions presented therein.

7.6.1.5.1 SCS Pressure Relief Controls Evaluation

At Big Rock Point, two small relief valves set at 300 psig are installed in the SCS. Relief capacity of each valve is approximately 25 gpm. No significant pressure transients are expected because BWR pressures are determined by saturated steam conditions.

The relief valve discharge drains to the containment enclosure sump and would not impact safety related equipment.

7.6.1.5.2 SCS Pump Protection Controls Evaluation

The Shutdown Cooling System pumps are tripped only on pump overload or by local manual action. There is no protection from overheating, cavitation or loss of pump suction fluid. However, the deviation from this BTP provisions is acceptable because the facility possesses other means to remove core decay heat which are redundant to the Shutdown Cooling System pumps.

7.6.1.5.3 SCS Controls Testing Evaluation

The SCS interlock and auto closure setpoints are checked each refueling and the valves are exercised to assure operability. The licensee has stated that the tests meet the intent of Regulatory Guide 1.22.

7.6.1.6 Procedures For Safe Shutdown and Cooldown Evaluation

Operational procedures for bringing the plant from normal operating power to cold shutdown were reviewed by the NRC as discussed in the September 10, 1982 SER which concluded that the existing procedures for safe shutdown and cooldown were in conformance with Regulatory Guide 1.33.

Subsequent to this SER, plant Emergency Operating Procedures (EOPs) were developed as described in Section 13.5 of this Updated FHSR.

7.6.1.7 Cooling Water Requirements For Safe Shutdown

Appendix "A" of the NRC September 10, 1982 Safety Evaluation Report (SER) provided an evaluation of "Safe Shutdown Water Requirements," which supplements the "Safe Shutdown Systems Report" contained therein. The following provides a summary of the Appendix which has been corrected to reflect current design.

Standard Review Plan (SRP) 5.4.7, "Residual Heat Removal (RHR) System" and Branch Technical Position (BTP) RSB 5-1, Rev. 1, "Design Requirements of the Residual Heat Removal System" and Regulatory Guide 1.139 "Guidance for Residual Heat Removal" are the current criteria used in the Systematic Evaluation Program (SEP) evaluation of systems required for safe shutdown.

The original design criteria for the SEP facilities did not require the ability to achieve cold shutdown conditions. For these plants, and for the majority of operating plants, safe shutdown was defined as hot shutdown. Therefore, the design of the systems used to achieve cold shutdown condition was determined by the reactor plant vendor and was not based on any safety concern.

Safe Shutdown Cooling Water Evaluation

After the reactor trip, the reactor system pressure and temperature increase towards the safety valve pressure setpoint because the main condenser is not operable following an assumed loss of offsite power. The emergency condenser is automatically initiated as described in Section 6.8 of this Updated FHSR. Capacity, makeup water, and operation of the emergency condenser is also described in Section 6.8 and are such that a cooldown to Shutdown Cooling System SCS initiation conditions can be performed in a reasonable time.

As the cooldown progresses, the reactor system fluid contracts and the need for reactor system makeup exists to keep the level of coolant in the steam drum. If the emergency condenser is used to accomplish the depressurization, the shrink will not uncover the core even if no makeup is provided for approximately four hours. The reactor feed system, which is normally used to inject water into the reactor at high pressure is not available because it depends on offsite power. The Control Rod Drive hydraulic system, which can also supply high pressure water, is not considered to be available because it was not designed as a safety system and, therefore, is not included on the safe shutdown system list. Without these high pressure reactor makeup systems, the operator would rely on the Core Spray (CS) system to supply reactor coolant, if needed. The CS system operates using fire system pressure, and therefore, if reactor pressure is not below fire system pressure, the operator must initiate or permit automatic initiation of the Reactor Depressurization System (RDS) to lower the pressure sufficiently for CS flow into the reactor system to occur. In fact, the RDS can be manually initiated at any time during the cooldown sequence following reactor trip, provided the reactor vessel level at RDS initiation is at or below the RDS automatic actuation level; and the CS system will provide adequate core cooling (refer to Section 6.9 of this Updated FHSR for RDS operation). Thus for Safe Shutdown, the RDS and emergency condenser are considered redundant to each other for the function of plant cooldown. The main reasons that the emergency condenser is included on the safe shutdown list are to provide a core cooling method which does not reduce the reactor system coolant inventory since Big Rock Point does not have the high pressure coolant injection capability that most other boiling water reactors have and because use of the RDS would require extensive cleanup of the containment building.

Normally, long term heat removal would be accomplished by the Shutdown Cooling System (SCS). If this system and its auxiliary systems are available, it would be started at a reactor system pressure of ~200 psig. However, since the SCS initiation requires operator action inside containment and its auxiliaries were not designed and constructed with the quality of the plant engineered safety features systems, the RDS, core spray, and containment cooling systems (Post Incident Cooling System) would be relied on for long-term cooling of the plant. The core heat and stored heat in the reactor system materials is transferred to the containment by the core spray and RDS. The containment heat removal systems transfer the heat to the ultimate heat sink.

Safe Shutdown Cooling Water SER Conclusion

Based on the staff's evaluation of safe shutdown water requirements at Big Rock Point, we have concluded that (1) the fire protection water system provides a virtually unlimited supply of makeup water for the emergency condenser, and (2) because of the RDS, Core Spray and Post-Incident Cooling System capabilities, the plant systems permit a cooldown to cold shutdown conditions in accordance with BTP RSB5-1 requirements.

7.6.1.8 Resolution of Safe Shutdown Related SEP Topics

The following provides a discussion of how the Plant meets the safety objectives of associated Safe Shutdown Systematic Evaluation Program Topics.

7.6.1.8.1 Topic V-10.B RHR System Reliability

The safety objective for this topic is to ensure reliable plant shutdown capability using safety-grade equipment subject to the guidelines of SRP 5.4.7 and BTP RSB 5-1. The Big Rock Point systems have been compared with these criteria, and the results of these comparisons are discussed and summarized in 7.6.1 above. Because it does not contain system redundancy (single letdown and return lines), the Shutdown Cooling System, which performs the function of a Residual Heat Removal System, does not satisfy the review guidelines. However, we have concluded that the other systems at Big Rock Point fulfill the safety objective. The staff notes the following:

1. The redundant emergency condenser condensate valves are powered by a single DC bus and so are susceptible to the single failure of this bus, although several sources are available to energize this bus. This single failure in conjunction with loss of offsite power would require the use of RDS and Core Spray for cooldown. Since an alternate method of shutdown exists, albeit one with undesirable operational consequences, and given the demonstrated low frequency of total loss of offsite power, the possible single failure mode for the emergency condenser is considered acceptable.

2. The present plant Technical Specifications for the emergency condenser permit one tube bundle to be inoperable until the next plant outage if a tube leak develops during plant operation. One tube bundle is capable of removing reactor decay heat (refer to Section 6.8 for operation with a leaking outlet valve).

7.6.1.8.2 Topic V-11.A Requirements for Isolation of High and Low Pressure Systems

The safety objective of this topic is to assure adequate measures are taken to protect low pressure systems connected to the primary system from being subjected to excessive pressure which could cause failures and in some cases potentially cause a LOCA outside of containment.

This topic is assessed in this report only with regard to the isolation requirements of the SCS system from the RCS. As discussed in Section 5.4.5 of this Updated FHSR, adequate overpressure protection exists.

7.6.1.8.3 Topic V-11.B RHR Interlock Requirements

The safety objective of this topic is identical to that of Topic V-11.A. The staff conclusion regarding the Big Rock Point valve interlocks, as discussed in Section 5.4.5 of this Updated FHSR, is that adequate interlocks exist.

7.6.1.8.4 Topic VII.3 Systems Required For Safe Shutdown

The Safety objectives of this topic are:

1. To assure the design adequacy of the safe shutdown system to (a) initiate automatically the operation of appropriate systems, including the reactivity control systems, such that specified acceptable fuel design limits are not exceeded as a result of anticipated operational occurrences or postulated accidents, and (b) initiate the operation of systems and components required to bring the plant to a safe shutdown.

2. To assure that the required systems and equipment, including necessary instrumentation and controls to maintain the unit in a safe condition during hot shutdown are located at appropriate locations outside the control room and have a potential capability for subsequent cold shutdown of the reactor through the use of suitable procedures.

3. To assure that only safety grade equipment is required for a plant to bring the reactor coolant system from a high pressure condition to a low pressure cooling condition.

Safety objective 1(a) will be resolved in the SEP Design Basis Event reviews. These reviews will determine the acceptability of the plant response, including automatic initiation of safe shutdown related systems, to various Design Basis Events, ie, accidents and transients (refer to Section 7.6.1 above, and Chapters 2, 3 and 15 of this Updated FHSR).

Objective 1(b) relates to availability in the control room of the control and instrumentation systems needed to initiate the operation of the safe shutdown systems and assures that the control and instrumentation systems in the control room are capable of following the plant shutdown from its initiation to its conclusion at cold shutdown conditions. The ability of the Big Rock Point Plant to fulfill objective 1(b) is discussed in the preceding subsections of Section 7.6. Based on these discussions, we conclude that safety objective 1(b) is met by the safe shutdown systems subject to the findings of related SEP Electrical, Instrumentation, and Control topic reviews (refer to Section 7.6.2 below for resolution).

Safety objective 2 requires the capability to shutdown to both hot shutdown and cold shutdown conditions using systems, instrumentation, and controls located outside the control room.

The fire protection reviews for addressing shutdown following a fire in the control room were completed. An Alternate Shutdown control panel was installed containing vital instrumentation for use during plant shutdown and cooldown. Suitable procedures for reaching both hot and cold shutdown conditions using the Alternate Shutdown System was prepared in accordance with 10 CFR 50, Appendix R, Item III-L, (refer to Section 9.6 of this Updated FHSR).

The adequacy of the safety grade classification of safe shutdown systems at Big Rock Point, to show conformance with safety objective 3, were completed in part under SEP Topic III-1, "Classification of Structures, Components, and Systems (Seismic and Quality)," and in part under the Design Basis Event reviews. Table 3-1 in Chapter 3 of this Updated FHSR provides certain information derived from these SEP Topic reviews.

7.6.2 ELECTRICAL, INSTRUMENTATION, AND CONTROL FEATURES OF SYSTEMS REQUIRED FOR SAFE SHUTDOWN

The NRC revised Safety Evaluation Report (SER) for the Electrical, Instrumentation and Controls (EI&C) Systems identified as being required for safe shutdown was issued under Systematic Evaluation Program (SEP) Topic VII-3, Systems Required for Safe Shutdown, by letter dated December 17, 1982.

The SER was based on information enclosed in NRC letter dated October 29, 1982 and the resolution of Inspection and Enforcement Bulletin IEB 79-27. CPCo response to IEB 79-27 was provided March 19, 1980 and dealt with the "Loss of Nonclass 1-E Instrumentation and Control Power System During Operation."

Evaluation

The systems required to take the reactor from hot shutdown to cold shutdown, assuming only offsite power is available or only onsite power is available and a single EI&C failure are in compliance with current licensing guidelines and the safety objectives of SEP Topic VII-3. Single failures of EI&C equipment cannot render all short and long-term cooling systems inoperable.

The instrumentation available to control room operators to reach and maintain the reactor in cold shutdown conditions does not meet current licensing criteria since a single failure can cause a loss of vital indication such as reactor temperature, pressure and level, as well as process instrumentation for safe shutdown systems.

The capability to shut down and cool down the reactor from outside the control room exists and is in compliance with the safety objectives of SEP Topic VII-3, except that instrumentation to verify shutdown and cooldown conditions from outside the control room is inadequate, (Note: Instrumentation added for Alternate Safe Shutdown has been reviewed and accepted by the NRC subsequent to this NRC Evaluation). Procedures exist to take the plant to cold shutdown from outside the control room to satisfy the safety objectives of SEP Topic VII-3.

Conclusions

The staff has concluded that the present design is an acceptable alternative to current licensing guidelines until Regulatory Guide 1.97 Revision 3 backfit decisions are made. Accordingly, we consider this topic to have been completed acceptably for Big Rock Point.

Setting the 2400/480 V station power banks on the 2280 V (-5%) tap results in excessively high voltages on 440 V motors during base load conditions and cold shutdown conditions (light station power loads) with or without the regulator in service. Setting the main transformer on the 135/13.5 kV tap position results in severe generator Mvar restrictions while operating in the overexcited mode. It was found, however, that the combination of changing the main transformer to the 140/13.5 kV tap and the 2400/480 V transformers to the 2340/480 V tap would alleviate undervoltaged conditions for all Plant operating conditions with the regulator in service and a degraded 138 kV system voltage of 131 kV. Table 8-1 summarizes the undervoltage problems identified in 8.2.3.2 and the resulting problems from tap changes to the No. 11 and No. 22 station power transformers and main transformer.

The tap changes, however, did not completely eliminate the UV condition at the input of the battery chargers or at the input of the I&C power supplies. Additional analysis showed that the minimum voltage at the input of the battery chargers (at bus 2A) in this condition (with the tap changes made) was 430 V, leaving an UV condition of only 0.3% which was considered insignificant. It should be noted that the battery charger manufacturer states that the chargers will provide rated output given input voltages within 10% of its rating.

The UV condition at the input of the I&C power supplies was also determined to be insignificant. The minimum voltage at the input of the power supplies was 103 V after the taps had been changed. To be conservative, additional analysis was performed on the power supply with the highest minimum voltage rating. The analysis was performed on power supply ES-8512B which has a minimum rating 105 V. The additional power supply analysis proved that given an input of 103 V at ES-8512B, the loop transmitter output would be insignificantly affected and would continue to maintain an output current proportional to its pressure input. (Reference 23)

From the above information, it can be seen that there are no significant undervoltages present with the 2400 V voltage regulator out of service.

Changing the main transformer tap to the 140/13.5 kV position does affect turbine generator operation, which now limits the generator to a 40 Mvar net output (overexcited) due to the generator voltage restriction of 14.5 kV. The 40 Mvar net capability should be sufficient during peak system conditions and the present maximum voltage schedule of 143 kV. Generator terminal voltages will be improved in the underexcited mode for the minimum voltage schedule of 140 kV. Final maximum and minimum generator terminal voltages are expected to be 14.5 and 13.1 kV with the lower tap setting.

Table 8-2 summarizes the expected steady-state station power voltages with the tap changes above. Bus voltages are expected to approach 489 volts during cold shutdown conditions without the voltage regulator in service and a maximum 138 kV line voltage of 142 kV. Actual 440 V motor terminal voltages, however, will be below their maximum 110% voltage ratings due to motor feeder cable voltage drops not indicated in Table 8-2.

8.2.3.4 Diesel Generator Operation

Essential station power power loads are maintained by either the 480 V, 250 kVA emergency diesel generator or the recently installed 460 V, 312 kVA standby emergency diesel generator upon loss of offsite power. Sequencing of essential station power loads onto the emergency diesel generator, following loss of offsite power, and are summarized in Table 8-3. Maximum equipment voltages occur during the first 1/2 hour (minimum loading conditions). Minimum equipment voltages occur after all loads are sequenced on line including the 100 hp fire pump (maximum loading conditions).

8.2.3.4.1 Emergency Diesel Generator - Loss of Offsite Power

The 480 V, 250 kVA emergency diesel generator is connected directly to 480 V Bus 2B via 300 feet of 350 kcmil cable. The present range of acceptable operating generator terminal voltages is 480-490 volts. Load flow cases were run at both 480 V and 490 V and minimum loading conditions as summarized in Table 8-4. Overvoltages occur on several 440 V motors with an operating voltage of 490 volts while no overvoltages occur with the 480 V operating voltage. Therefore, the diesel generator voltage during loss of offsite power should be 480 V to avoid overvoltages on 440 V motors during minimum diesel generator loading conditions.

Load flow cases were run at the minimum acceptable 480 V operating voltage and maximum diesel generator loading conditions. Total connected station power loads will approach 314 kVA. Approximately 21.6 kVA, however, is considered intermittent load and is not included in the steady-state continuous loading. These loads include the RDS-UPS supplies, station battery chargers, personnel lock and equipment lock. Thus, the resultant diesel generator load will be 292 kVA. An additional 38 kVA of load can be removed if the loading of the diesel, which is closely monitored during Plant emergency conditions, approaches the maximum 275 kVA rating. Thus, the 250 kVA diesel generator has adequate kVA capacity to maintain the unit in a safe shutdown condition. Table 8-4 summarizes the minimum station power voltages with a maximum diesel generator loading of 260 kVA and a minimum operating voltage of 480 V. As can be seen, all operating voltages are adequate. Surveillance tests include a voltage requirement of 485 V (+0, -10V) for loaded conditions.

8.2.3.4.2 Standby Diesel Generator - Loss of Offsite Power

The 460 V, 312 kVA standby diesel generator is connected to 480 V Bus 2B. The current range of acceptable operating generator terminal voltages is 456-504 volts. Operating at a generator terminal voltage

Three overcurrent relays monitor (Facility Change FC-401) each phase of the generator output. Actuation of two out of three will cause the time delay relay to energize (Facility Change FC-670) which in turn will cause an engine trip and alarm in the control room.

Facility Change FC-434 added an alarm scheme to notify plant operators of conditions that prevent the diesel from starting to an automatic start signal. Loss of 125 VDC control voltage or placement of the selector switch in the "OFF" position actuate the alarm.

Further description of the Emergency Diesel Generator Alarm and Control Circuitry is provided in Section 9.5.6.

8.3.4.4 Diesel Engine Start Time

The start time requirement for the Diesel Generator is 31.2 seconds and is measured from open indication of the tie-breaker until closure of the emergency diesel generator output breaker. This time is based on assumptions made in the derivation of ECCS limits (ie, MAPLHGR and Maximum Bundle of Section 5.2.1 of the Big Rock Point Technical Specifications) for Exxon fuel types.

In performing the ECCS analysis, the Design Basis Accident (DBA) and .375 ft breaks yield peak cladding temperatures closest to the 2200°F limit established by 10 CFR 50, Appendix K. All other break sizes yield lower peak cladding temperatures and would therefore not be as restrictive as to equipment actuation times. The 15 second core spray valve opening time is most important for the .375 ft break where valve actuation is delayed by the attaining of the low reactor pressure condition at 46.5 seconds (low reactor water level occurs within seconds of low drum level for breaks this large). The fire pump start time assumption (45 seconds), on the other hand, is most critical for the largest break (DBA) where rated spray is not assumed until low drum level actuation signal is generated (1.2 seconds) plus the time required for the pump to start and come up to speed (for a total of 46.2 seconds to rated spray).

The emergency diesel generator start time criteria is dictated by DBA requirements. Assuming that rated spray is required at 46.2 seconds as dictated by the diesel fire pumps start time assumption, and assuming that ac core spray valves are effectively full open 15 seconds after the 2B bus is energized, the diesel generator start time is simply the difference between these two values (46.2 seconds - 15 seconds = 31.2 seconds).

8.3.4.5 Testing Requirements

The testing and surveillance requirements for the diesel generator and associated electrical circuits are contained in Section 11.3.5.3 of the Big Rock Point Technical Specifications.

8.4.1.2 Station Battery Load Profile

The Station Battery capacity is sized assuming a large break Loss of Coolant Accident coincident with a Loss of Offsite Power. The battery sizing also includes momentary loads associated with closing of breakers needed to restore station power. Battery sizing is calculated in accordance with IEEE Std 485-1978. The Station Battery Load Profile is shown on Figure 8.1 and the following summarizes these loads per Reference 7.

Constant 2 Hour Loads

Breaker Number	Description	Current
72-1D28	MO-7072 Indication	.035 A
72-1D32	MO-7064 Indication	.132 A
72-22	D.C. Oil Pump Indication	.035 A
72-31	MO-7061 Indication	.068 A
72-32	MO-7051 Indication	.068 A
72-43	MO-7067 Indication	.035 A
72-1D11	Fire System/Access Alarms	.48 A
72-1D13,24	Poison System Valves	.1 A
72-1D14, 31, 33, 1D34, 37, 38	Pan Alarm Annunciators (assume 1/2 or 254 alarms on)	5.08 A
72-1D15	Amplidyne Indication	.035 A
72-1D16	Turbine Controls	.175 A
72-1D17	Deluge Isolation Valve	.07 A
72-1D18	Turbine Trip & Test	.3 A
72-1D20	Steam Bypass Auxiliaries	.15 A
72-1D21	138kV Line Transmitter/Trip	.435 A
72-1D22	RPS Bus 3 Invertor	2.55 A
72-1D26	Rx Building Vent Valves	2.508 A
72-1D29	Rx Building Vent Valves Indication	.665 A
72-1D35	Main Transformer Alarms	.096 A
72-1D36	Hydrogen Panel Alarm	.384 A
72-1D40	Breaker Control Scheme	.42 A
72-1D42	Field Rheostat & Exciter	.07 A
72-1D43	2400V Breaker Control	1.216 A
72-1D44	Stack Lighting	10 A
72-SS-A	7726 OCB Indication	.07 A
72-SS-B	1126 OCB Indication	.162 A
72-SS-D	116 OCB Indication	.132 A
72-SS-E	199 OCB Indication	.298 A
Total	(Two Hour Continuous Loads)	25.77 Amps

Total Load For the 1st Minute:

Continuous Loads	-	25.77 A
Motor Operations	-	300.1 A
Breaker Operations	-	24.0 A
Relay Actuations	-	7.5 A
		357.37 A

Load From 1 Minute To 2 Hours

Continuous Loads	-	25.77 A
D.C. Oil Pump	-	80.0 A
Rod Position M/G Set	-	11.5 A
		117.27 A

Load During Last Minute to Restore Offsite Power

Assuming the 138 kV line is restored at t=2 hours the following actions will occur:

Description	Time	Duration	Amps
Operator trips the 7726 OCB	-	3 cycles	10 A
Operator closes the 199 OCB	-	3 cycles	6 A
Operator closes the 1126 OCB	-	30 cycles	24 A
Cond Pump close 6 sec after 1126 closes	+6 sec	5 cycles	54 A
Circ Pump close 10 sec after 1126 closes	+10 sec	5 cycles	54 A
Operator closes 1136 OCB	-	3 cycles	95 A
Assume one feed pump started	-	3 cycles	58 A

Since those loads are either manual manipulations or automatic reclosures all of short duration, the 95 amp load of the 1136 OCB is used for the one minute duration. This encompasses the demand of the remaining loads.

Total Load For The Final Minute:

Continuous Load	-	25.77 A
Rod Pos M/G Set	-	11.5 A
1136 OCB	-	95.0 A
		132.27 A

Reference 8, Amendment 94 to the Technical Specifications approved the design load profile time interval of two hours which meets the criterion of SEP Topic VIII-3.A. NRC review of load profile, sizing calculations, and assumed two hour scenario concluded consistency with current staff guidance and requirements.

(IEEE Std 450-1975). This review concluded that the surveillance/test requirements including the one hour service period satisfy current licensing requirements. Surveillance requirements are contained in the BRP Technical Specifications.

8.4.3.4 UPS System Bus Monitoring

SEP Topic VIII-3.B (Reference 10) evaluated BRP to assure the design adequacy of the bus voltage monitoring. Control Room monitoring of the UPS consists of a "UPS Abnormal" alarm; local indication consists of battery output current, charger output current and voltage, inverter input current, and inverter output current, voltage, and frequency. Although the control room monitoring does not meet current guidelines, the NRC staff concluded (Reference 12) that additional monitoring of the UPS battery system is not necessary because of the small loads, short load duration, and multiple redundancy provided in the RDS design. The small loads and short load duration make it less likely that a DC system failure that can be masked by battery charger performance will occur.

8.4.4 DIESEL STARTING SYSTEMS

8.4.4.1 Function/Description

Three diesel starting systems using 24V dc battery banks are utilized at Big Rock Point for the following units:

- The Emergency Diesel Generator
- The Standby Diesel Generator
- The Diesel Fire Pump

The emergency diesel control circuit is powered by a battery charger with additional current capacity; via two, six cell, 12 volt (lead acid) series connected batteries providing a combined battery voltage of 24 volts and a current capacity rating of 225 amp hour.

The emergency diesel generator battery charger is capable of providing up to six amperes of current, a nominal float voltage of 26.4 volts dc (2.2 volts per cell) and a high rate (or equalize) voltage of 28.4 volts dc at 77°F. The charger is an automatic two rate charger, cycling to the high rate once every twelve hours and also whenever the engine starter is energized by either manual engine control or the automatic engine controller; thus, the batteries are maintained at full charge. Both the floating and equalizing voltages can be adjusted, if required. The charger operates on 120 v ac powered from Panel 10L.

The standby diesel control circuit is also powered via two, six cell, 12 volt (lead acid) series connected batteries providing a combined battery voltage of 24 volts and a current capacity rating of 225 amp hours. The standby diesel generator batteries are located next to the engine.

Chapter 8 References

1. Letter to AEC dated 6/24/68 - Semi-Annual Report

2. Letter from NRC dated 9/21/81 - SEP Topic VII-6

3. Letter from NRC dated 11/30/81 - Adequacy of Station Electrical Distribution System Voltages

4. Letter from NRC dated 7/8/82 - Adequacy of Station Electrical Distribution System Voltages and Degraded Grid Protection for Class 1E Power Systems and SEP Topic VIII-1.A

5. Letter to NRC dated 5/18/82 - BRP - Station Electrical Distribution System Voltages

6. Letter to CPCo dated 3/8/82 - Technical Specification Amendment 51

7. Big Rock Point Engineering Analyses; EA-E-BRP-86-05 and EA-SC-87-023-1, (Internal Analyses discussed in Reference 8 and the latter was submitted by CPCo letter dated October 26, 1989 - Station Battery Service Test)

8. Letter from NRC dated 2/15/89; Technical Specification Amendment 94

9. Letter from NRC dated 2/27/81; SEP Topic VIII-3.A

10. Letter from NRC dated 2/22/82; SEP Topic VIII-3.B

11. Letter to NRC dated 3/10/83; Response to SEP Topic VIII-3.B

12. NUREG-0828, May 1984; BRP Integrated Plant Safety Assessment

13. Big Rock Point Engineering Analysis; EA-FC-462J-02, (Internal Analysis).

14. BRP O.S.A. No. A-BR-76-35-01 dated 2/2/77, (Internal Analysis).

15. Letter to NRC dated 2/25/80 - ECCS Equipment Timing Requirements

16. Letter from NRC dated 4/7/77

17. Letter from NRC dated 9/2/82 - SEP Topic VIII-2

18. NRC Memorandum and Order to CPCo dated 5/26/76

19. NRC letter to CPCo dated 10/17/77 - Amendment 15

20 Letter to NRC dated 8/3/82 - Response to SEP Topic VIII-2

21. Letter to NRC dated 2/14/83 - Response to SEP Topic VII-10.A

22. Letter to NRC dated 4/25/83 - Response to SEP Topic VIII-4

23. Deviation Report D-NS-82-01 dated 2/23/82

TABLE 9-1

SPENT FUEL POOL STORAGE RACKS

BRP Tag Board Designator	Type of Rack	Rack Cell Array	Center-to-Center Fuel Spacing	Actual Spaces	Type of Storage	Notes
A	"F"	8x13	9"	104	Fuel	
B	"B"	6x12	12"	72	Fuel and Control Blades	(3)
C	"C"	9x10	Non-Fuel	90	Channels	
D	"A_1"	6x8	12"	48	Fuel, Control Blades, and Incores	(1)
E	"A_2"	6x8	12"	48	Fuel, Control Blades, and Incores	(1)
F	"E"	9x9	9"	81	Fuel	(2)
G	"D"	8x11	9"	88	Fuel	

NOTES:

1. Administrative controls have been established for casks other than the fuel transfer cask to ensure that: 1) no cask is moved over stored spent fuel; 2) all cask handling operations are limited to the southwest corner of the spent fuel pool; and 3) no spent fuel is stored in the two existing Type "A" racks adjacent to the cask handling area during cask handling operations. These controls will preclude the dropping or tipping of a cask onto a fuel rack with stored fuel. These racks provide for full core offload capability.

2. Administrative controls have been established to ensure that spent fuel which had a decay time of at least a year or more in the pool will be placed in the outer three rows of the rack adjacent to the south wall of the pool to maintain the dose rates outside the pool within acceptable limits. A prompt investigation of the pool configuration shall be required whenever radiation in the sock tank area exceeds 50 mrem/hr.

3. The storage of materials in the area between the Type "B" rack and the east wall of the spent fuel pool is prohibited. This applies to the area from the pool floor to the top of the fuel rack, to assure that the makeup line flow patterns are not blocked. (In a September 7, 1984 meeting with NRC Region III staff, it was determined that this restriction is not applicable during refueling outages.)

An electric jockey pump and an accumulator are provided to maintain pressure on the fire water system. The fire pumps are arranged to start automatically when the fire loop pressure drops due to a large water demand.

The diesel fire pump driver was replaced via Facility Change FC-607 when parts could no longer be obtained for the original. This change was reported by CPCo letter dated January 9, 1987.

Fire Pumps Single Active Failure Analysis

There are two redundant fire pumps, one electric driven pump and one diesel driven pump. A single failure in either pump, driver, power supply, discharge check or isolation valve will not affect the redundant pump. A failure of a discharge check valve in the open position will bypass flow from the other pump and may require manual closure of the associated isolation valve.

Certain fire operability, surveillance, and bases requirements for operation are addressed under the Fire Suppression System in 9.5.1.2.1 above.

IE Bulletin 79-15: Deep Draft Pump Deficiencies

In letter dated October 17, 1990, the NRC provided a safety evaluation which concluded that safety concerns regarding the two Worthington fire pumps installed at Big Rock Point were resolved. A review of test data collected from the past five (5) years showed no signs of performance degradation in either pump thus providing the basis that the Bulletin 79-15 deficiencies did not adversly impact these pumps.

Diesel Fire Pump Surveillance Requirements

The fire pump diesel starting 24-volt battery bank and charger shall be demonstrated OPERABLE:

a. At least once per 7 days by verifying that:

   1. The electrolyte level of each battery is above the plates, and

   2. The overall battery voltage is $\geq$ 24 volts.

b. At least once per 92 days by verifying that the specific gravity is appropriate for continued service of the battery.

c. At least once per 18 months by verifying that:

   1. The batteries and battery racks show no visual indication of physical damage or abnormal deterioration, and

2. The battery-to-battery and terminal connection are clean, tight, free of corrosion and coated with anti-corrosion material.

9.5.1.2.3 Fire Water Piping System

Both electric and diesel fire pumps feed the underground main loop by a common 8" supply line from the single header. This header was provided with additional supports via Facility Change FC-535 to improve seismic response capability. The seismic capability of certain fire protection equipment and piping are addressed in Table 3-1 found in Chapter 3 of this Updated FHSR. The fire loop supplies the fixed water suppression systems, fire hose stations and exterior fire hydrants.

Sectionalizing valves are provided to allow isolation of various sections of the fire loop. Piping and valving is arranged so that automatic suppression systems and manual fire hose stations can be taken out of service independently for maintenance or repair. A single break in the internal header supplying sprinkler and hose stations could affect both automatic and manual suppression; however, the small size of the plant would permit effective use of hose from exterior hydrants in such an unlikely event.

Fire hydrants are strategically placed around the exterior of the plant. Hydrants are not equipped with auxiliary gate valves but the arrangement of the fire loop and sectionalizing valves is such that any hydrant can be taken out of service for repair or maintenance without shutting off water supply to interior plant suppression systems. Note: Hydrant repair could require isolation of the West Warehouse (stockroom) sprinklers.

A hose house containing 200 feet minimum of 1 1/2 inch coupled fire hose on a reel is provided at each yard hydrant. In addition, a hose cart with 250 feet minimum of 2 1/2 inch coupled fire hose is located in the screen well and pump house.

Single Active Failure Analyses for Fire Pump Supply Lines, Main Distribution Loop and Fire Hydrants

Fire Pump Supply Lines to Underground Main Loop

Both electric and diesel fire pumps feed the underground main loop by a common 8" supply line. A single failure (pipe break) of this supply line to the main loop would result in the loss of immediate supply of fire water to the main. Fire hose connections have been provided on the discharge of the diesel fire pump for supplying water to the main loop should a break occur in the common supply line.

In addition, CPCo has verified by test that a local (offsite) fire department pumper can draft water from the intake bay to provide water if needed.

Main Distribution Loop

A pipe break in the main distribution loop can be isolated by the sectionalizing valves. Fire water supply is then available around the main distribution loop from both directions up to the closed sectionalizing valves.

Fire Hydrant

A pipe break attributed to fire hydrant failure can be isolated with the sectionalizing valves which can be used to isolate the failed fire hydrant. The adjacent fire hydrants and extra hose can then serve the needs of the out-of-service fire hydrant.

Passive Failure of Underground Fire Main Piping

If a passive failure of the underground fire main piping should occur during the long term cooling phase of core spray, the capability exists to bypass the affected portion of piping utilizing a fire hose to ensure the continuation of long term ECCS cooling.

9.5.1.2.4 Fire Spray and/or Sprinkler Systems

The sprinkler systems and hose stations are supplied by a common 6" distribution header which is connected at both ends to the underground main distribution loop.

Automatic wet pipe sprinklers are provided in part of the electrical equipment room (cable spreading area under the control room), auxiliary boiler room, turbine lube oil tank rooms, condenser pipe tunnel area, tool crib, RDS/UPS battery rooms, instrument and electrical shop - storage area, feedwater pumps, generator lube oil line, west warehouse area, and recirculating pump sump area. (For the recirculation pump sump area, the supply valve is normally closed and opened on detector alarm).

Automatic water spray (deluge) is provided on the hydrogen seal oil unit and hydrogen cabinet, and the substation transformer area. (The substation deluge isolation valve CV-4101 closes automatically when any core spray valve is open, Reference Facility Change FC-459.)

Manual water spray (deluge) is provided in the exterior cable penetration area. The substation deluge isolation valve is fitted with a manual T-handle override which may be utilized to protect the substation area during the "recycle" mode of ECCS core spray.

Single Active Failure Analysis of Sprinkler Systems and Hose Stations

The sprinkler systems and hose stations are supplied by a common 6 inch distribution header which is connected at both ends to the underground main distribution loop. A single failure of this distribution header between the isolation valves at either end could result in the loss of fire supply to the sprinkler systems and hose stations in the turbine-generator building only. The small size of the plant would permit effective use of hose from exterior hydrants in such an unlikely event.

In the containment, water is available through a redundant 6" line from the main loop to the core spray heat exchanger and through motor operated valve MO-7072.

Fire Spray and/or Sprinkler Systems Operability Requirements

The spray and/or sprinkler systems located in the following areas are required to be operable at all times when equipment in the area is required:

a. Cable spreading area under the control room.

b. Exterior cable penetration area.

c. Recirculation pump sump area.

Actions Required for Inoperable Spray and/or Sprinkler Systems

With one or more of the spray and/or sprinkler systems required by 9.5.1.2.4 a or b above inoperable, establish a continuous fire watch with backup fire suppression equipment for the unprotected area(s) within one (1) hour; restore the system to operable status within 14 days or, in lieu of any other report required by Technical Specification 6.9.2, prepare and submit a Special Report to the Commission pursuant to Technical Specification 6.9.3 within the next 30 days outlining the action taken, the cause of the inoperability and the plans and schedule for restoring the system to operable status.

With the spray and/or sprinkler system required by 9.5.1.2.4 c above inoperable, stage backup fire suppression equipment for the area within one (1) hour. If the inoperable condition is due to equipment outside the recirculation pump room, restore the system to operable status within 14 days or, in lieu of any other report required by Technical Specification 6.9.2, prepare and submit a Special Report to the Commission pursuant to Technical Specification 6.9.3 within the next 30 days outlining the action to be taken, the cause of the inoperability and the plans and schedule for restoring the system to operable status. If the inoperable condition is due to equipment inside the recirculation pump room, restore the system to operable status before the next start-up from cold shutdown. If the system is not returned to operable status within 14 days, submit, in lieu of any other report required by Technical Specification 6.9.2, a Special Report to the Commission pursuant to Technical Specification 6.9.3 within the next 30 days outlining the cause of the inoperability and the plans and schedule for restoring the system to operable status.

overcurrent, utilizing two independent sensors and coincident logic, while maintaining the engine overspeed trip as is.

Conversations with the emergency diesel generator manufacturer indicate that diesel generator destruction, under loss of oil pressure, would occur rapidly; therefore, the necessity to retain this trip is mandatory. Presently, there are two oil pressure sensing units in use in the diesel control circuitry, the original unit and a redundant scheme added in 1971. By use of auxiliary and spare contacts a coincident and logic scheme will be provided for both of the low oil trip circuitries, and each circuit will utilize two independent sensors.

Because of past problems associated with high emergency diesel generator cooling water temperatures (Reference CPCo letters April 15, 1976 and June 9, 1976), it is prudent to retain this trip function. In order to meet the Branch Technical Position an additional temperature switch will be installed in the diesel cooling water jacket. This switch will be connected in series with the existing temperature switch making it necessary for both elements to sense a high temperature condition prior to diesel generator trip. This scheme meets the dual sensor and coincident and logic criteria.

The final trip that will be maintained is the overcurrent trip. The emergency power system at Big Rock Point is an ungrounded three-phase system. Original design allowed a single overcurrent relay (single-phase fault) to trip the emergency diesel generator. This was modified (via Facility Change FC-401) to require a two-phase fault (phase-to-phase short) for a trip to occur. This would eliminate any trip caused by a single signal, such as a relay failure or single phase-to-ground short, but still prevent major damage should a dual phase fault occur. A time delay relay (installed via Facility Change FC-670) is in series with the overcurrent trip network allowing a bus fault to clear, while maintaining the generator on-line.

Concerning the diesel driven fire pump, the only parameter that could cause a unit trip is engine overspeed which was not utilized on the original fire pump diesel driver and consequently was not connected on the new diesel fire pump driver installed via Facility Change FC-607, (reference Section 9.5.1.2.2 above).

The NRC evaluation and review of the protective trips was documented in Technical Specification Amendment 15 dated October 17, 1977 which concluded:

> Based on our review, the modification to the emergency diesel generator are acceptable because they: (1) satisfy the criteria of BTP EICSB 17, (2) significantly enhance the reliability of the onsite power system, and (3) comply with Section (3)(iii) of the Memorandum and Order, dated May 26, 1976.

It should be noted that further evaluation and review of this issue was accomplished as part of Systematic Evaluation Program (SEP) Topic VIII-2, Onsite Emergency Power Systems - Diesel Generator. A revised Safety Evaluation Report (SER) for this Topic arrived at the same conclusions described above, (reference September 2, 1982 SER).

9.5.6 EMERGENCY DIESEL GENERATOR ALARM AND CONTROL CIRCUITRY

NRC letters dated April 7, 1977 and April 12, 1978 requested information on EDG alarm and control circuitry. The information was provided by letters dated May 24, 1977 and May 11, 1978.

The following conditions render the diesel generator incapable of responding to an automatic emergency start signal:

1. Emergency power auto selector switch (control room) in the "off" position.

2. The power source for 480 V Bus 2B emergency power system open or unavailable (Reactor Depressurization System - Uninterruptable Power Supply - A, 125 Volt DC, Circuit Breaker-12).

3. Emergency diesel generator engine control switch (local) in the "manual" or "off" position.

4. The alarm conditions/trips listed below require resetting at the local control panel or diesel engine housing:

   a. Overspeed - (1 of 1 logic)
   b. Low lube oil pressure - (2 of 2 logic)
   c. High jacket water temperature - (2 of 2 logic)
   d. Generator overcurrent - (2 of 3 logic) (delayed via Facility Change FC-670 - see 9.5.5.)

NOTE: The overspeed trip also requires manual reset at the governor in addition to the common alarm reset.

EDG Control Room Alarm Indications

Conditions 1, 2 and 3 above are alarmed on an annunciator marked "Emergency Generator Start/Control Failure." Condition 4 above is alarmed on an annunciator marked "Emergency Generator Engine Trouble," which is also utilized for the following alarms/trips:

Emergency diesel generator battery undervoltage.

Emergency diesel generator low room air temperature.

Emergency diesel generator high room air temperature.

Emergency diesel generator fuel tank low level.

Emergency diesel generator overcurrent trip.

The emergency diesel generator alarms on overload current in the control room from a different sensor than the overcurrent trip logic above on an annunciator labeled "Emergency Generator Overload."

The EDG does not utilize manual shutdown lockout relays in its control scheme, thus, no alarm for this condition is needed.

9.5.7 EMERGENCY DIESEL GENERATOR COOLING WATER

The EDG cooling water system is shown on Drawing 0740G40123. The cooling water is from the circulating water discharge bay by a self-priming engine driven centrifugal cooling water pump.

Priming water is being supplied continuously to the cooling water pump via the service water system. A backup supply of priming water also exists from the fire water and domestic water systems, thus assuring an adequate supply of priming water. The pump discharges cool water through the diesel engine lube oil cooler and excess priming water is discharged via this same route. Details on the system are contained in a letter to NRC dated May 18, 1973.

On May 8, 1978 the cooling water pump packing and lantern ring were replaced with a mechanical seal, thus eliminating the need for sealing water (Reference SFC-78-006).

The water pump suction inlet is cleaned periodically as a preventative maintenance item.

The cooling water suction line contains an electric heating element, used when freezing weather is a possibility, which is checked for circuit reliability periodically.

control. As the admission valve closes, the pressure in the main steam line starts to rise and increases rapidly if corrective action is not taken in time.

The bypass valve control system attempts to handle the load drop from full to auxiliary load level. An anticipatory valve opening signal (after the 138Kv breaker opens) has been programmed to provide opening proportional to the steam flow to the turbine.

An auxiliary relay and circuitry were installed to provide actuation of the turbine bypass auxiliary when the 138Kv circuit breaker is tripped open manually by the console control switch. This auxiliary relay will provide an opening signal to the bypass valve.

In the past, the opening signal was generated only on the loss of a tone relay signal to the 138Kv circuit breaker between Emmet Substation and Big Rock Point. This change was completed via Facility Change FC-122 and reported to the NRC June 24, 1968.

A condenser vacuum control to override the control system and close the bypass valve if condenser pressure rises to a preset level, is also provided.

Some of the features incorporated in the bypass valve system are the accumulator to provide stable hydraulic power, duplicate hydraulic pumps and servo valves, along with automatic standby pump start on low pressure. The loss of hydraulic power and bypass valve starting open are annunciated in the control room. All the controls for the hv-- , system are located in the control room.

The plant has demonstrated it can accommodate a 138Kv transmission line trip at reactor power up to about 160 Mwt without a reactor scram based upon the automatic opening of the turbine bypass valve. (Reference CPCo letter dated June 2, 1982 for Systematic Evaluation Program - SEP Topic XV-3, Loss of External Load.

A modification was installed in November 1990, to provide an automatic reduction in reactor power in the event of a load rejection. A reliability based recirculation pump trip scheme designed to trip one selected reactor recirculation pump (providing both are in service) upon tripping of the 138 KV transmission line breaker provides this automatic power reduction. Tripping of one reactor recirculation pump will lower reactor power by approximately 40% and place the reactor at a power level near that for which a successful load rejection has been demonstrated. (Reference Section 10.2.4)

10.2.3.2 Turbine Bypass Valve Testing

The turbine bypass valve control system circuitry is tested periodically during normal plant operation. The test will not result in any disturbance in the reactor system. During refueling shutdown, a turbine bypass valve system functional test is performed to test features and associated components.

10.2.3.3 Pressure Regulator Set-Point Changing

Fast changes in the initial pressure regulator set point may cause a pressure and resultant flux transient within the reactor. With a sufficiently rapid change in set point, a flux transient would result, which could be large enough to scram the reactor at 125% of rated power. The rate of change will be limited by operating procedures to a value that will not cause such a flux transient.

Increasing the set point of the initial pressure regulator causes the turbine admission valve to close momentarily; this results in increasing the pressure of the system, and the turbine admission valve then reopens to stabilize the pressure at the new set point.

10.2.3.4 Turbine Bypass Isolation Valve

A direct current motor-operated isolation valve was installed in the bypass line between the main steam line and ahead of the turbine bypass valve. Installation was completed in March of 1968. The turbine bypass isolation valve provides the ability to terminate blowdown caused by inadvertent bypass valve opening and failure to reclose. This valve is one of several valves which provides backup isolation for the main steam isolation valve.

Vacuum interlocks as part of the valve control system close the valve on loss of condenser vacuum.

Valve closure is also automatic on complete loss of Reactor Protection System Motor Generator Power and on Reactor Protection System Containment Isolation from High Containment Pressure or Low Reactor Water Level.

The isolation valve installation and low vacuum closure features were reported in the Eighth Semi-Annual Report dated June 24, 1968.

10.2.3.5 Turbine Bypass Valve Electrohydraulic System

As part of the Integrated Plant Safety Assessment Report (IPSAR) NUREG 0828, Final Report dated May 1984, Section 5.3.3.1, a study of the reliability of the Turbine Bypass Valve Control System electrohydraulic control (EHC) system was proposed. Based upon this study, the servo-amplifier gain for the control system was reduced to provide a slightly overdamped valve signal to eliminate oscillation in valve control. Following valve testing, it was determined that the valve stroke for 0 to 90% opening would occur in equal to or less than 0.2 seconds. This revised gain setting still meets the Technical Specification opening time requirement for maximum speed of full valve stroke of approximately 0.2 seconds.

The Turbine Bypass Valve opening speed is a function of the flow, pressure, and reactor power condition calling for its operation. Original Transient Analyses submitted in General Electric (Atomic Power Equipment Department) APED-4093 in October 1962 calculations assumed a bypass valve opening speed of approximately 0.7 seconds to match the admission valve closure.

Start-up testing reported in General Electric APED-4230, May 1963 reported Bypass Valve stroke rate of approximately 0.5 seconds.

Subsequent modifications to the valve control system and the re-installation of the four inch valve actuator via Facility Change FC-132 to decrease the time response and increase the flow capacity, resulted in an optimum bypass valve opening stroke on full load rejection of approximately 0.2 seconds in order to limit the pressure rise.

10.2.3.6 Turbine Bypass Valve Hydraulic Oil System

The Hydraulic System is designed to operate the by-pass valve with one pump running. The system is designed so that if oil pressure drops, the second pump will start and restore system pressure.

The Hydraulic System also has an accumulator on the high pressure line to the servo valves. The accumulator is designed to full line pressures, and has a capacity which should allow for five complete strokes of the valve. The accumulator is charged with nitrogen and then to full system pressure by the hydraulic pumps. The accumulator will provide pressure in case of power failure to the hydraulic pumps.

The Turbine Bypass Valve Hydraulic Oil System is shown on Drawing 0740G40109.

10.2.4 SECONDARY SYSTEM INSTABILITIES

An evaluation of the effects of load rejection was completed as part of the Systematic Evaluation Program (SEP) Integrated Plant Safety Assessment Report (IPSAR), NUREG 0828, Final Report dated May 1984, Section 5.3.3.2, Secondary System Instabilities was addressed.

This issue stems from the observed phenomena that when the turbine bypass valve opens with the turbine at or near full load, condenser hotwell level can swell sufficiently to cause the condensate reject valve to fully open, such that the reactor feedwater pumps trip on low suction pressure.

An analysis of condenser hotwell/feedwater system characteristics has been completed. As a result of this analysis, a modification was installed in November 1990, to provide an automatic reduction in reactor power in the event of a load rejection. A reliability based recirculation pump trip scheme designed to trip one selected reactor recirculation pump (providing both are in service) upon load rejection provides this automatic power reduction. Tripping of one reactor recirculation pump will lower reactor power by approximately 40% and place the reactor at a power level near that for which a successful load rejection has been demonstrated. Computer modeling of the plant secondary systems indicate that tripping of one recirculation pump has a beneficial effect on keeping feedwater available during such transients.

Automatic tripping of one recirculation pump acts to 1) lower the reactor power and associated steam flow to the turbine/main condenser, 2) lessen the perturbations in the main condenser associated with load rejection and 3) reduce feedwater flow requirements. These three resultant actions tend to eliminate secondary side instabilities inherent to load rejections occurring at higher power levels. This change was completed via Facility Change FC-664.

10.2.5 TURBINE ROTOR DISC INTEGRITY AND OVERSPEED PROTECTION

An evaluation of the turbine-generator was completed as part of the Systematic Evaluation Program (SEP) Topic III-4.B - Turbine Missiles. Results and conclusions in regard to turbine rotor integrity and adequacy of overspeed protection are provided in Section 3.5 of this Updated FHSR along with the turbine rotor surveillance schedule basis.

10.2.6 TURBINE STOP VALVE

The turbine emergency stop valve is an oil operated, spring closed valve controlled from the following devices:

1. Mechanical Low Vacuum Trip
2. Electrical Trips
    a. Turbine Thrust Bearing Failure
    b. Hand Trip in Control Room
    c. Low Vacuum Switch
    d. Reactor Scram Auxiliary
    e. Generator Lockout Relay

?. Emergency Trip Mechanism

A turbine trip circuit was installed to automatically close the turbine stop valve on the occurrence of a reactor scram. This automatic trip was completed via Facility Change FC-108 and reported to the NRC in the sixth Semi-Annual Report May 23, 1967.

The valve is of the quick closing type and functions primarily by being tripped either by hand or by an emergency trip device.

The passage of steam through the stop valve is dependent upon the hydraulic oil pressure forcing the valve open against spring energy. So long as the turbine operates normally, the sustaining hydraulic oil pressure is maintained. However, if an unsafe condition occurs which endangers the machine, the hydraulic oil pressure holding the stop valve open is dumped and spring energy closes the valve.

The turbine stop valve closes in approximately 0.7 seconds.

11.6 DISCHARGE CANAL DREDGING MANAGEMENT

On August 31, 1990 the Commission issued a Safety Evaluation related to Consumers Power Company's application for disposal of dredged discharge canal sediment. The staff found that, pursuant to 10 CFR 20.302, the proposed procedures were acceptable. The dredging will involve relocating between 250 and 500 cubic yards of sediment with an estimated activity of 0.9 μCi from the discharge canal to a confined disposal area above the high watermark (580.8 ft).

Confirmatory measurements of the dredged material will be made by Consumers Power Company after it is land-spread. If the levels of radioactivity measured in the preoperational sediment samples were significant underestimates (greater than 25%) of the actual radioactivity of the dredging spoils, Consumers Power Company will notify the NRC.

Big Rock Point may dredge the canal annually thereafter for a 10 year period. The following commitments, made prior to each dredging, are listed below:

1. Radionuclide concentrations and environmental exposure pathway doses will be evaluated in the same manner as that described in the original application dated December 29, 1989.

2. Compare evaluated doses with the NRC staff guidelines for onsite disposals listed in Section 4.0 of the NRC Safety Evaluation identified above.

3. If the guidelines cannot be met, the disposal of the particular dredging shall be deemed to be outside the scope of the original application, and a reapplication to the NRC shall be made for the dredging in question or alternative disposal method pursued.

13.5.2.3.10 Emergency Operating Procedures

A series of emergency operating procedures have been developed to guide the operator in dealing with emergency situations. These procedures are written in either standard paragraph form and/or flow diagram language. They are symptom based procedures that guide the operator depending on the symptoms that are indicated on the plant instrumentation.

These procedures control and mitigate the consequences of an accident by directing the operator to take control of three major parameters on the reactor, (power, water level and pressure), along with three major parameters on the containment, (pressure, water level and temperature).

On February 14, 1990 the NRC issued a Safety Evaluation Report relating to staff's review of Big Rock Point's Procedure Generation Package (PGP). (The PGP is a requirement of Generic Letter 82-33, Supplement 1 to NUREG-0737.) Based on the CPCo letters, dated December 30, 1986 and January 8, 1987, the staff concluded that Big Rock Point's PGP should be reviewed to address programmatic improvements outlined in Section 2 of the SER.

Augmenting the above SER, a special safety inspection was conducted and described in NRC letter dated May 24, 1990. The inspection team concluded that criteria important to the staff as stated in the letter had been met. Four open items were addressed in a CPCo response dated June 25, 1990. The NRC has required no further action in addition to commitments outlined in the June 25, 1990 response.

Emergency Action Plans for Operating Personnel

Control Room Personnel

Control room personnel will be responsible for the following actions:

a. Assure that the reactor is subcritical.

b. Assure that the containment sphere is isolated and all penetration isolation valves are closed.

c. Notify plant personnel

d. Notify senior member of plant management

e. Assure that cooling of the reactor has been initiated

f. Assure that cooling of the containment vessel is maintained

g. Collect data from radiation monitoring equipment to assure that such data are available for determining subsequent action.

Action By Plant Management

The senior member of plant management present will be responsible for the following actions:

a. Determine extent and severity of the radiological hazard

b. Order partial or complete evacuation of the site as required

c. Formulate and initiate appropriate course of action

d. Notify State and local officials as appropriate

e. Notify off-site Consumers management

f. Notify NRC as required by the operating license or by 10 CFR, Part 20.

13.5.3 Operating Procedural Safeguards

The following procedural safeguards are established to assure the operating safety of the Big Rock Point Plant.

Detailed written procedures for all normal and emergency operations which may involve nuclear safety are prepared and issued prior to startup of the plant.

Instructions for normal operations consist of detailed procedures required for the operation of systems and equipment associated with the plant.

The shift operating personnel are directed to follow the approved procedures unless deviation is required to prevent injury to personnel or damage to equipment or the environment.

Operator aids are posted in appropriate plant locations to assist the operator and administrative controls have been established for these operator aids.

Short term directions from Plant management to the Operators are conveyed via Operations Memos and Daily Orders. Administrative controls have been established for these Memos and Orders.

The emergency procedures are separated into four parts. The first part describes the symptoms, the second the automatic actions, the third the immediate actions which are to be taken to shut the plant down and to place it in a safe condition. The fourth part describes the follow-up actions which are to be taken to maintain the plant in a safe condition. It is recognized that action after placing the plant in a safe condition will be dictated largely by the circumstances existing at the time and that to this extent prepared procedures cannot cover all conditions and thus in all cases will not substitute for the responsible judgment of plant management personnel. In addition to the emergency procedures related to plant operations, procedures and precautions related to emergencies postulated for any industrial plant, such as fire, earthquake, tornado and flood, have been developed. These procedures include specific instructions as to special precautions and procedures which must be followed because of the potential presence of radioactivity.

13.5.4 Measures to Prevent Operating Error

Thorough training of the operating staff and systematically planned operating and maintenance procedures will combine to keep to a minimum the possibility of operator errors.

Each operator will be well acquainted with his specific duties and responsibilities and the action to be taken in the event of off-standard conditions. The following paragraphs discuss the design measures and administrative controls which will promote the safety of plant operation.

13.5.5 Other Procedures

Other procedural requirements for the following categories of procedures are described in the QA Program Description (CPC-2A):

Equipment control procedures.
Plant radiation protection procedures.
Instrument calibration and test procedures.
Chemical-radiochemical control procedures.
Radioactive waste management procedures.
Maintenance and modification procedures.
Material control procedures.
Temporary procedures.
Surveillance test procedures.

Procedural requirements for Security procedures are addressed in the Security Plans discussed in Section 13.6 of this Updated FHSR.

Emergency Preparedness procedures are addressed in the Site Emergency Plan discussed in Section 13.3 of this Updated FHSR.

15.8 ANTICIPATED TRANSIENTS WITHOUT SCRAM

15.8.1 INTRODUCTION

The first analytical evaluation of the response of Big Rock Point to a failure to scram was performed as a part of the original Final Hazards Summary Report published in November 1961 (section 12.5.8), Reference 1. The analysis was performed not so much to include ATWS type events into the design of the plant, but to determine the setpoints for the primary system code safety relief valves. The evaluation is a worst case analysis which assumes that the primary system is instantaneously isolated with the reactor at full power operation. No credit for any mitigating features other than safety valves is taken, such as operation of the emergency condenser or tripping of the reactor recirculating water pumps. As a result of this analysis, allowables are not exceeded during a failure to scram the reactor, regardless of the assumed initiating event or system failures which coincidentally occur.

A subsequent detailed analysis of the response of the plant to ATWS was performed in response to the requirements of WASH-1270 (Technical Report on Anticipated Transients without Scram for Water Cooled Reactors). Submitted in November 1975 (Reference 2), this analysis was directed at determining the response of plant components beyond just the primary system, including containment, and the fuel and fuel cladding. Like the original FHSR analysis, however, this evaluation was worst case in nature, assuming that the primary system was isolated from full power conditions. Credit for emergency condenser operation was taken as was actuation of the liquid poison system, although attainment of hot shutdown was not assumed for ten minutes. Credit for mitigating features such as tripping of the recirculating pumps was not taken in producing the initial results of the analysis reproduced below (taken from General Electric Report NEDE-21065, attached to Reference 2). Examining the results of this evaluation, the primary system remains below code allowable, fuel and fuel cladding perform within proposed guidelines and containment response is close to but slightly greater than assumed membrane yield limits.

WORST REACTOR ISOLATION WITHOUT SCRAM
(BOUNDED BY TURBINE LOAD REJECTION NEGLECTING BYPASS)

Functional Comparison Parameter	General Electric Guide	Value Analysis
Reactor Vessel Pressure (psig)	2700	1587°
Fuel Enthalpy (cal/gm)	280	<165
Cladding Oxidation (%)	17	<1
Containment Pressure (psig)	54	57.7

Still another analysis of plant response to ATWS was undertaken as part of the plant's probabilistic risk assessment. The first part of this evaluation was published in February 1981 in response to a confirmatory order to CP Co to install an automatic recirculating pump trip at Big Rock Point. While demonstrating the relatively small effectiveness of automating recirculating pump trip at Big Rock Point, it also identified unique design features of the plant which had important effects on the manner in which the plant responded to the ATWS event. Unlike the preceding analyses, the recirculating pump trip evaluation was closer to best estimate than worst case in nature. It noted that because of the lack of high pressure injection and the limited nature of feedwater supply, that the extended high pressure operation of the reactor assumed during the vious analyses was not possible at Big Rock Point. The majority of icipated transients, in fact, would not result in either a high pressure condition or safety valve actuation. It was shown that the poison effectiveness in providing reactor shutdown was much faster than previously assumed and that the Reactor Depressurization System, installed subsequent to the previous analyses, played a major role in determining the timing of plant response and operator actions during an ATWS event.

The second part of this analysis was published in October 1986 and addressed the effectiveness of installing the Alternate Rod Injection System as proposed in 10CFR50.62 (which also incorporated the auto recirculating pump trip requirement). The February 1981 analysis principally addresses risks associated with mechanical failures of the control rods as it was assumed that the majority of electrical failures could be overcome by operator action to scram the plant manually. The second part addresses risk associated with electrical failures of the control rod drives to insert (those failures associated with the reactor protection system and the scram solenoid valves). While the reasons for control rod drive insertion failure are different, in general the plant response as presented in February 1981 was used in the October 1986 analysis.

The results of the second analysis showed that while there was some benefit to installing the full alternate rod injection modification, or a simplified version of the modification, more benefit would be realized by addressing the problems associated with the secondary side instabilities during blowdowns to the main condenser. The major contributor to main condenser blowdown occur as a result of load rejections in which the bypass valve opens to reduce steam flow to the turbine.

Analysis of the secondary side instabilities by computer modeling of the load rejection transient, has shown that tripping a recirculating pump in conjunction with the bypass valve opening (based upon the same anticipatory signal) has a positive effect on operation of the secondary side during the transient. This analysis is the basis for the installation of Facility Change FC-664, which provides tripping of a selected recirculation water pump during load rejection transients.

In additions to the anticipatory trip signal to a recirculation pump, circuitry is also provided to trip a recirculation pump should both emergency condenser outlet valves be opened (conditions indicative of a high pressure transient).

15.8.1.1 Plant Design Features Important During ATWS

The primary system of Big Rock Point incorporates the reactor vessel, a steam drum, six external risers and two external recirculation loops. Normal steam flow from the primary system during full power operation is approximately 1E+6 lb/hr whereas normal recirculating water flow is approximately ten times greater at 1E+7 lb/hr. Tripping one of the two recirculating pumps reduces flow to the point that reactor power drops to 60% of its former level while tripping the second pump results in a much more limited drop of only 10% initial power.

Located on the steam drum are six spring loaded code safety valves each rated at over 100 lb/sec steam flow with the primary system at 1870 psia (110% of design). The size and number of safety valves permits the primary system to remain within code allowable limits even if the reactor is isolated a full power, failure of the reactor to scram occurs and no mitigating systems function.

The primary system contains approximately 100,000 lbs of coolant inventory at full power operation, with 35,000 lbs above the low reactor water level setpoint. This setpoint is important from the standpoint that on attaining this reactor water level, Reactor Depressurization System (RDS) actuation can be expected. In newer BWRs, actuation of the auto depressurization system would be precluded by the operation of the high pressure injection system. Big Rock Point has no high volume high pressure injection system other than the motor driven feedwater pumps, and so on loss of feedwater or isolation of the primary system from the main condenser, lowering of the water level to the RDS setpoint can be expected unless reactor shutdown is effected. Actuation of RDS has several effects. First the core is uncovered which has the temporary effect of terminating power operation, and second, the low pressure core spray is permitted to operate providing core cooling. However, mixing of the liquid poison is assumed to be restricted under this configuration and at least limited core damage is expected if the reactor is permitted to return to power on unborated core spray reflood. As a result of the design of RDS, timing of plant response and operator actions to shut the reactor down are largely dependent on the time to reach RDS actuation on low reactor water level.

Big Rock Point is also equipped with an emergency condenser consisting of two independent tube bundles, each capable of removing about 5% of normal reactor power with the primary system near normal operating temperature. During ATWS, operation of the emergency condenser has the beneficial effect of limiting the amount of steam which leaves through the safety valves during high pressure events, thus extending the time to depletion of the primary system to the low reactor level setpoint. The shell of the emergency condenser contains an amount of water equivalent to that required to remove four hours of decay heat. Operation of the emergency condenser is therefore expected to occur in excess of 15 minutes into a high pressure ATWS transient, even without makeup to its shell.

The liquid poison system (LPS) is a relatively fast acting system as compared to those designs requiring charging pumps. The system consists of a tank of sodium pentaborate solution isolated from the reactor by explosive squib valves. On firing the squib valves a siphon is established to the reactor which permits the solution to reach the reactor within 30 seconds of actuation. Depending upon the status of the recirculation pumps the first pass of solution will reach the core within the 15 to 45 additional seconds. Concentration of the first pass is such that hot shutdown will occur. Within five minutes, boron concentration is such that shutdown can be maintained in the cold xenon free condition. For equipment qualification reasons poison injection cannot be assumed after safety valve actuation.

The Big Rock Point containment volume is approximately 1E+6 cubic feet. The relationship of such a large containment volume compared to reactor power level has the effect of extending the time required to raise the pressure and temperature inside containment to design conditions. The plant response analysis from RETRAN suggests that if reactor shutdown is effected prior to RDS actuation then containment design conditions will not be exceeded. Best estimate analyses performed as part of Appendix VII of the PRA suggest that the ultimate strength of containment will not be exceeded until internal pressures exceed 70 psig.

The secondary side of the Big Rock Point Plant is designed with full load rejection capability. The turbine bypass valve and bypass line are sized to accept the steam flow associated with full power operation. The existence of a high pressure condition (Pr + 25) in the steam line to the turbine (or, in the case of a load rejection's loss of offsite power, a tone control relay signal) will result in a signal to open the bypass valve, passing all the steam from the turbine (except that required for house load) directly to the main condenser. The bypass system is designed to prevent a reactor high pressure condition and actuation of relief valves for any ATWS in which the main condenser remains available and the bypass valve remains open. This is significant in that should feedwater remain available, the secondary side of the plant can remove all steam being generated in the reactor, condense it and return it to the primary system maintaining inventory control. The reactor can continue to operate, safety valves will not actuate and primary system inventory will remain constant even though failure to scram has occurred.

Thus, an indefinite amount of time exists for the operator to perform corrective actions to repair the reactor protection system, insert rods by conventional means, or inject liquid poison. However, the ability of the feedwater system to remain in service during events in which a demand on the bypass valve occurs is highly dependent upon reactor power level. Past operating experience indicates that near full power operation with an open bypass valve, reject of hotwell inventory occurs and the feed pumps trip on low suction pressure. With the installation of Facility Change FC-664, which trips a single recirculation pump upon load rejection (effectively lowering power by 40%), the reliability of the feedwater system is expected to be improved for the major contributor to transients involving an open bypass valve.

15.8.2 ANALYSIS

Detailed primary system response to ATWS was evaluated using the RETRAN thermal hydraulic computer code. A Big Rock Point model was developed for analysis of plant response to normal and anticipated transients. Plant control systems and features important to ATWS are incorporated in the model. This includes the turbine bypass, feedwater regulating, pressure relief systems and the recirculating water pumps. The core model is a point kinetics model which includes doppler and void reactivity feedback.

The RETRAN code was developed from the RELAP series of codes by the Electric Power Research Institute. RETRAN is used for the analysis of light water reactor systems during postulated accidents and anticipated transients. The code package includes proven thermal-hydraulic models taken from RELAP plus some additional models which permit "best-estimate" analyses.

RETRAN has been subjected to an extensive verification and qualification program by EPRI, EPRI contractors and utility users. Examples of the verification and qualification program may be found in the RETRAN code manual Volume 4.

In addition to code testing the plant specific model was compared to plant specific test data and previous analyses.

Results of a comparison of the core power response as predicted by the RETRAN model and the BRP simulator model (GROK - Grouped Reactor Operating Kalculations developed for the Big Rock Point Reactor) are summarized below. This comparison indicates very good agreement between the BRP core simulator model and the RETRAN point kinetics model. Core thermal-hydraulic conditions (pressure, subcooling, flow) as predicted by RETRAN at specific points in time were input to the BRP core simulator model. End-of cycle 17 (all rods all out) core conditions were assumed in the core simulator as in the RETRAN model. Initial conditions for the core simulator were selected to duplicate the initial conditions assumed in RETRAN. Xenon was assumed constant throughout the transient.

The time points selected for comparison were 60 seconds after initiation of a loss of feedwater ATWS without recirculating pump trip and 100 seconds after initiation of a loss of feedwater with recirculating pump trip. At these times thermal conditions are changing very slowly and assumed to be at steady-state. The BRP core simulator is a steady-state model and steady-state conditions from RETRAN were needed for comparison.

COMPARISON OF CORE POWER RESPONSE
AS PREDICTED BY RETRAN AND THE BRP CORE SIMULATOR

Case	Subcooling	Flow	Power RETRAN	Power Core Simulator
Initial Condition	24.5 Btu/lbm	100%	100%	100%
Loss of Feedwater ATWS without RPT (t = 60 sec)	3.2	98.1	61.3	61.5
Loss of Feedwater ATWS with RPT (t = 100 sec)	1.1	42.5	28.1	29.5

A second model was developed in order to assess the impact of proposed modifications to fix the secondary side instability problems encountered at Big Rock Point during blowdown to the main condenser. This model includes the primary system (reactor, steam drum and recirculating pumps) and the entire secondary side (turbine/generator, condenser, feedwater heaters, and feedwater pumps). This code was used to show the effects of tripping a recirculating pump in conjunction with the anticipatory signal sent to the bypass valve during load rejection transients. This modification, Facility Change FC-664 performed in November 1990, is expected to reduce the effects of secondary system instabilities for the major contributor to main condenser blowdowns (load rejections).

Tables in Reference 3 and in Appendix VII of the Probabilistic Risk Assessment (PRA)[6] present plant and operators response times for the various ATWS transient categories. This table is reproduced her showing the effects of hotwell and steam drum inventory variations on plant and operator actions (see Table 15.8-1). Effects of hotwell inventory variations are shown in brackets [ ], drum inventory variations in parentheses ( ). Available operator response time to initiate poison injection varies by no more than 8 seconds as a result of drum level uncertainty and 11 seconds as a result of a hotwell level uncertainty.

The risk based evaluations divided the plant response to an ATWS into four different categories: infinite feedwater, low level, high pressure with feedwater, and high pressure without feedwater. The following discussion of the responses is taken from the February 1981 recirculating pump trip analysis and incorporates some references to plant response with automatic recirculating pump trip based upon the requirements of 10CFR50.62 (the primary system level or pressure setpoints for automatic recirculating pump trip).

15.8.3 LOW LEVEL TRANSIENTS

A low level transient may occur as a result of the loss of one or both condensate pumps or reactor feed pumps. It is assumed for this class of ATWS events that the turbine bypass control system functions as designed and maintains primary system pressure at or near normal pressure (1,350 psia). The reactivity coefficients used in the analysis are shown on Table 15.8-2. The coefficients are representative of the End-of-Cycle 17 Big Rock Point core. Initial plant operating conditions assumed in the analysis are listed on Table 15.8-3. Key equipment performance characteristics assumed in the analysis are shown on Table 15.8-4.

Loss of Feedwater Without RPT

The core power transient for the loss of feedwater ATWS event without recirculation pump trip (RPT) is shown on Figure 15.8-1. Power falls following the loss of feed due to the loss of subcooling. Independent calculations with the BRP three-dimensional core simulator predicted that core power would fall to about 60% following loss of subcooling. This compares well with the point kinetics model response. At 27 seconds, low steam drum water level is reached, causing turbine trip. The subsequent pressure rise causes a flux spike to about 122%. The pressure rise also causes the steam dump valve to open and control pressure to approximately 1,350 psia. The steam drum level response is shown on Figure 15.8-2. Without initiation of the liquid poison system (not modeled), water in the system will continue to be depleted to the point of RDS actuation. It was assumed that for RDS to be prevented, no more than 35,000 lbm of liquid could be lost from the primary system prior to reactor shutdown. The remaining liquid would assure a reactor water level at or slightly above the RDS level with the reactor at power and about 2 feet above the RDS level with the reactor shutdown. On this basis, it was estimated that RDS would occur at about 145 seconds after the loss of feedwater for the case without RPT, unless shutdown was achieved prior to that time. Assuming successful shutdown prior to RDS, heat removal via the emergency condenser will prevent further inventory depletion and assure continued core cooling.

The reactor vessel outlet plenum pressure transient for this case is shown on Figure 15.8-3 and recirculation flow through one of the two loops is shown on Figure 15.8-4.

Loss of Feedwater With RPT

The core power transient for the loss of feedwater ATWS with RPT is shown on Figure 15.8-5. RPT is assumed to occur on low steam drum water level at the same level as reactor scram would normally occur

(-8 inches from drum centerline). RPT is actuated at 27 seconds*, and the turbine is also tripped at that time. The resulting pressure rise causes reactor power to spike to approximately 117% and the steam dump valve to open. Primary system liquid inventory (Figure 15.8-6) will continue to fall until the steam drum empties and RDS actuates. This was calculated to occur at about 325 seconds after the loss of feedwater unless reactor shutdown was achieved prior to that time. Assuming that successful shutdown is achieved prior to 325 seconds and that the emergency condenser is placed in operation, inventory depletion will cease and core cooling will be assured in the long term. The operator would have reactor pressure and vessel level instrumentation by which to conduct a controlled cooldown or maintain the plant in a hot condition. Note that the steam drum would likely be empty and thus its level instrumentation unusable. Because system inventory would be low, the operator would probably want to reestablish feedwater and refill the system before conducting a cooldown to prevent an inadvertent RDS actuation as a result of the liquid inventory shrink. The reactor pressure and recirculation flow transients for this case are shown on Figures 15.8-7 and 15.8-8, respectively.

* RPT is not automatic and requires operator action.

15.8.4 HIGH-PRESSURE TRANSIENT WITH LIMITED FEEDWATER

A high-pressure transient may occur as a result of a loss of condenser vacuum, closure of the MSIV, turbine trip or loss of load without bypass. It is assumed for this class of events that the feedwater system remains functional until the condenser hotwell has been drained to the low level condensate pump trip point. Condensate pump trip will cause reactor feed pump trip due to low suction pressure.

Turbine Trip Without Bypass Without RPT

The core power and heat flux response in the turbine trip without bypass ATWS event are shown on Figure 15.8-9. Core power peaks at 219% at 1.3 seconds and fuel heat flux at 156% at 10.5 seconds after turbine trip. Some fuel would likely experience transition boiling in this case. The steam drum safety valves begin to open at about 8 seconds after turbine trip. A peak primary system pressure of 1,670 psia occurs at the pump discharges at about 13 seconds. Note that design pressure is 1,700 psia and code allowable is 1,870 psia. Steam drum water level as a function of time is shown on Figure 15.8-10. The main feedwater system allows drum level to drop slightly to compensate for the feedwater-steam flow mismatch resulting from the turbine trip. Steam drum pressure as a function of time is shown on Figure 15.8-11, and recirculation flow - one of two loops - is shown on Figure 15.8-12. The steam drum safety valves provide more than adequate relieving capacity during all phases of the event. The hotwell which contains about 3,000 gallons (25,000 lbm) of water is predicted to empty at approximately 120 seconds after turbine trip. The transient will then progress in a similar manner to the loss of feedwater ATWS event, except that system pressure is controlled by the safety valves rather than the steam dump system. It was estimated that RDS would occur at about 267 seconds after turbine trip in this case, unless shutdown was achieved prior to that time. Assuming successful shutdown with the liquid poison system prior to RDS, heat removal will be maintained using the main feedwater system to provide makeup from the condensate storage tank and either the safety valves or the main condenser (if it can be reestablished) for steam relief.

Turbine Trip Without Bypass With RPT

The core power and heat flux response for this ATWS case are shown on Figure 15.8-13. The recirculation pumps are assumed to trip on high pressure at 8 seconds*. Core power peaks at 219% at 1.3 seconds after turbine trip as in the case without RPT. Fuel heat flux peaks at 146% at 8.5 seconds after turbine trip. Thus, less fuel may experience transition boiling in this case than in the case without RPT. Steam drum pressure versus time is shown on Figure 15.8-14. The safety valves begin to open at about 8 seconds. A peak primary system pressure of 1,645 psia occurs at the pumps at about 13 seconds after turbine trip. The steam drum water level transient is shown on Figure 15.8-15, and the recirculation flow transient is shown on Figure 15.8-16. The hotwell empties to the point of condensate pump trip at about 240 seconds. This causes the reactor feed pumps to trip as well. The transient then progresses in a similar manner to the loss of feedwater ATWS event following RPT. Primary system liquid inventory is predicted to have fallen by 35,000 lbm at 530 seconds. Thus, for RDS to be prevented, the reactor must be shut down by 530 seconds. Assuming successful reactor shutdown, long-term core cooling can be maintained using the main feedwater system for inventory makeup and either the safety valves or the main condenser as the heat sink. The emergency condenser may also be available.

The containment will respond very similarly in this case (assuming successful shutdown) to the case without RPT. The pressure rise will be more gradual due to the reduced core power level, but the peak pressure will be about the same. If RDS cannot be prevented, containment design pressure will be exceeded just as in the case without RPT.

* RPT is not automatic and requires operator action.

15.8.5 HIGH-PRESSURE TRANSIENTS WITHOUT FEEDWATER

The most likely cause of this type of ATWS event would be a loss of station power (LOSP). This event has not been analyzed using the RETRAN model; however, the sequence of events can be estimated using the results of the other analyses. The loss of station power will cause almost immediate turbine trip, turbine bypass system failure, recirculation pump trip, feedwater pump trip, and loss of condenser vacuum. From the point of view of primary system inventory, the event will progress in a very similar manner to the loss of feedwater ATWS event with RPT. From the points of view of core power, fuel rod heat flux and recirculation flow, the event will look much like the turbine trip without bypass ATWS event with RPT. The power and heat flux transients will not be as severe because of the immediate recirculating pump trip. Therefore, less fuel may experience transition boiling. It has been estimated that RDS will occur in about 300 seconds without reactor shutdown. Assuming successful reactor shutdown with the liquid poison system prior to this time, long-term cooling is uncertain unless the emergency condenser is operable or station power is quickly restored. The emergency condenser is likely to be operable in the short term until shell side inventory is depleted. Makeup will be required to the emergency condenser within several hours.

Because the water in the condenser hotwell is not delivered to the primary system in this case, the containment response prior to reactor shutdown or RDS will be much less severe. The peak containment pressure will be only about 12 psig.

15.8.6 LIQUID POISON SYSTEM

Although not explicitly modeled, the effectiveness of the liquid poison system was evaluated and it was determined that successful shutdown of the reactor could be accomplished within approximately 41 seconds of actuation of the system assuming the recirculation pumps are operable and within 46 seconds with the pumps tripped. This determination was based on the following timing considerations: 30 seconds to establish siphon and purge unborated water from the injection lines, 11 seconds transit time to and through the core in the case with the pumps running (injection is into the suction of each pump), 16 seconds transit time to and through the core with the pumps off (injection is into the vessel lower plenum). A recirculation flow of 40% of normal was assumed in the pumps tripped case. The determination of shutdown time also assumed that the core boron concentration attained on the first sweep of borated water through the core equalled or exceeded that required for hot shutdown. The boron concentration required for hot shutdown was determined to be less than 250 ppm at all times in core life based on calculations using the BRP three-dimensional core simulator and assuming the hot full power rod pattern and full power xenon. The boron concentration of the recirculating water on its first pass through the core can be calculated using the following equation:

$$C_B = W_I \, C_{BI}/(W_R + W_I)$$

Where:

W_I is the rate of poison injection (132 gpm or 18 lbm/sec)

C_{BI} is the boron concentration of the poison solution (19 weight percent $Na_2B_{10}O_{16}$ or 50,700 ppm of boron)

W_R is the recirculation flow rate (nominally 3,389 lbm/sec); (6/W) seconds with pumps tripped, where W is recirculation flow in fraction of rated.

Thus, in the case with the recirculation pumps running, C_B is equal to 268 ppm; and in the case with the pumps tripped, C_B is equal to 664 ppm.

Perfect mixing of the boron in recirculating water has been assumed in these calculations. Perfect mixing is certainly justified for the pumps running case, considering that the injection point is into the suction of each recirculation pump (single-stage centrifugal pumps) and that the borated water must then pass through about 40 feet of 20-inch piping before entering the vessel where it first impinges on a diffuser plate (one over the vessel inlet nozzle), is then distributed radially around the vessel by a flow distribution baffle and finally must flow upward through each of the 84 support tube and channel assemblies.

For the case with the pumps tripped, the poison is injected into the vessel lower plenum below the flow distribution baffle where it will mix with the incoming recirculating water before entering the support tubes. The assumption of perfect mixing may not be completely appropriate for this case, however; if only approximately 40% of the poison solution mixes with the recirculating water, reactor shutdown will still be accomplished on the first pass through the core.

15.8.7 CONTAINMENT RESPONSE TO ATWS EVENTS

The degree to which the containment is pressurized during ATWS sequences as well as the timing of that pressurization relative to any release of radionuclides from the fuel are both important issues in defining the risk from ATWS sequences. To provide a basis for answering these questions, an approach to estimating containment pressurization has been developed which relies on the Big Rock Point containment analysis performed for ATWS-type sequences (Reference NEDE-32065). Table 15.8-5 provides a summary of the peak containment pressures developed in this earlier analysis.

For this analysis, it has been assumed that significant core damage is not inflicted until after actuation of the RDS. Given this assumption, only two general conditions which provide a pressure challenge to containment are of interest: the condition prior to RDS actuation during which primary inventory and feedwater makeup are being exhausted through the safety valves into the containment (of interest for high-pressure ATWS events only) and the condition following RDS actuation during which the containment is being pressurized as a result of the exhausting of vaporized core spray through the RDS valves (of interest for low level and high-pressure events).

Containment Pressurization Prior to RDS Actuation

Because it is desirable to predict the degree of containment pressurization in ATWS events other than those presented in Table 15.8-5, the information in that table has been processed to allow a broader range of ATWS sequences to be evaluated. The procedure employed involved the following assumptions:

(a) The containment pressure achieved during ATWS events prior to RDS actuation is proportional to the amount of steam dumped from the primary system into the containment. The form of this proportionality was not assumed, but rather developed as described below from the computer results presented in Table 15.8-5.

(b) From NEDE-32065, it was estimated that the steam flow to containment prior to RPT and prior to LPS actuation was approximately 110% of the full power steaming rate of 266 lb/sec.

(c) After RPT, the steam addition rate was assumed to decrease instantaneously to 55% of the full power steaming rate.

(d) After LPS actuation, the rate of steam addition to the containment was assumed to decrease linearly from its initial value (either 110% or 55% of full power) to zero during a period of 300 seconds beginning 30 seconds after LPS actuation.

By employing the above assumptions together with the NEDE-32065 computer results presented in Table 15.8-5, a graphical relationship was developed between peak containment pressure and integral steam flow rate into the containment during the event. That relationship is shown in Figure 15.8-17.

Several points should be noted relative to Figure 15.8-17:

(a) The analysis from which the curve was derived was based on an assumption of rapid closure of the MSIV. In reality, the time for closure is approximately one minute, during which time substantial steam can be exhausted to the condenser.

(b) It is clear that heat transfer to structures within the containment and through the containment shell will have an effect on the rate of containment pressurization. However, these effects have been included in the analysis on which Figure 15.8-17 was based; and the consistency of the results in that figure indicates that, for the steam flow rates and the times considered, the correlation developed there is reasonable.

(c) Figure 15.8-17 assumes that the enclosure spray begins after 300 seconds. The effect of this factor on the predicted containment pressure has been assessed, and it has been concluded that the enclosure spray can optimistically remove less than 3% of the heat added to the containment even during the time when it is functioning. Therefore, the assumption that the enclosure spray is functioning is not important to the results.

(d) Figure 15.8-17 was derived based on the total integrated steam flow to containment. The curve is therefore independent of variations in poison injection rates, heat removal rates by the emergency condenser and power levels associated with the transient.

Given the result presented in Figure 15.8-17, the containment pressure achieved at any given time can be assessed under a variety of assumptions on feedwater availability, time at which recirculation pumps are tripped and time when liquid poison is injected.

Containment Pressure Subsequent to RDS Actuation

Actuation of the RDS during an ATWS event at Big Rock Point is being assumed to produce core damage because of the inability to mix liquid poison in the core region for some significant time after its injection. The current best estimate of the phenomena occurring during an ATWS sequence subsequent to RDS actuation (Appendix I of PRA)[6] assumes that the core power will decrease to decay power following RDS actuation; but as the unpoisoned core spray raises the level in the vessel, the core will reattain criticality and increase in power to a level at which a steady state is achieved between the water sprayed on the core and the steam flow from the vessel into the containment through the RDS valves. This power level has been estimated to be approximately 20% of full power.

Because the steam flow rate to the containment with the core at 20% power will be significant, it is necessary to calculate the rate of containment pressurization so that an estimate can be made of the time available prior to containment overpressure failure. This calculation was performed, and the resulting pressure history is shown in Figure 15.8-18. The following assumptions were employed:

(a) The reactor power level following RDS actuation was assumed to be 20% (1.6×10^8 Btu/h).

(b) The enclosure spray was assumed to function at 300 gpm, allowing the removal of 0.2×10^8 Btu/h.

(c) The containment was initially full of air at 80°F.

(d) The containment heat structures were ignored, and the containment shell was assumed to be adiabatic.

(e) The energy input to containment during an RDS actuation was estimated to be 4.5×10^7 Btu.

Because of the above assumptions, the results shown in Figure 15.8-18 are expected to depict an overprediction of the rate of containment pressurization following an RDS actuation in an ATWS event. However, since the steady-state power level after RDS actuation is not well known, the primary purpose of the analysis (that is to estimate the time range during which containment overpressure failure might occur) is adequately satisfied by this analysis.

Figure 15.8-18 shows that the time at which containment overpressure failure might occur for ATWS sequences is between 16 and 49 minutes after RDS actuation, depending upon the pressure at which containment failure is expected. Since our understanding of the processes by which liquid poison mixes within the core following RDS actuation is inadequate to predict nuclear shutdown prior to 50 minutes after RDS actuation, ATWS sequences which lead to RDS actuation are also predicted to produce containment overpressure failure.

15.8.8 REFERENCES

1. Big Rock Point Final Hazards Summary Report dated November 1961 (also refer to General Electric APED-4093 dated October 1962).

2. Letter from R. Sewell (CP Co) to Director NRR, "Docket 50-155 - License DPR-6 - Big Rock Point Plant - Response to WASH-1270" (Genreal Electric Report NEDE-21065 attached) dated November 1975.

3. Letter from G Withrow (CP Co) to D Crutchfield (NRC), "Docket 50-155 - License DPR-6 - Big Rock Point Plant - Probabilistic Risk Assessment Results Relating to the Efficacy of a Recirculation Pump Trip", February 26, 1981.

4. Letter from R. Frisch (CP Co) to director NRR, "Integrated Plan Issue A-112, Alternate Rod Injection Risk Evaluation", October 1986.

5. Letter from T Bordine (CP Co) to D Crutchfield (NRC), "Docket 50-155 - License DPR-6 - Big Rock Point Plant - Response for Additional Information Regarding Probabilistic Risk Assessment Recirculation Pump Trip Analysis", September 10, 1981.

6. Letter from D Hoffman (CP Co) to D Crutchfield (NRC), "Docket 50-155 - License DPR-6 - Big Rock Point Plant - Submittal of the Probabilistic Risk Assessment and Request for Deferral of Requirements Identified as Nonessential by the Probabilistic Risk Assessment", March 31, 1981.

7. Letter from D Bixel (CP Co) to D Ziemann (NRC), "Docket 50-155 - License DPR-6 - Big Rock Point Plant - Forwarding of Description of Reactor Physics Methodology", October 30, 1978.

8. Letter from D Hoffman (CP Co) to D Crutchfield (NRC), "Docket 50-155 - License DPR-6 - Big Rock Point Plant - Systematic Evaluation Program Topic IV-2, Reactivity Control Systems Design and Protection Against Single Failures", May 4, 1981.

TABLE 15.8-1

Plant and Operator Response Time
for ATWS Transient Categories*

Transient	Initial Power Btu/hr x 10^{-6}	Power Prior to RPT Btu/hr x 10^{-6}	Power After RPT Btu/hr x 10^{-6}	Drum Mass at RPT lb	Power after Loss of Feedwater Btu/hr x 10^{-6}	Drum Mass at Loss of Feedwater, lb	Time to RDS Seconds	Time To Mix LPS Seconds	Operator Time To Inject Poison Seconds
Low Level									
No RPT	820	450	-	-	450	24,000(±900)	145(±5)	41	104(±5)
RPT at 80 seconds	820	450	225	5,500(±900)	450	24,000(±900)	268(±8)	75	193(±8)
RPT at 60 seconds	820	450	225	10,100(±900)	450	24,000(±900)	287(±8)	75	212(±8)
RPT at 35 seconds	820	450	225	15,900(±900)	450	24,000(±900)	312(±8)	75	237(±8)
High Pressure With Feedwater									
No RPT	820	738	-	-	406	24,000(±900)	267(±4)[±11]	41	226(±4)[±11]
RPT at 60 seconds	820	738	442	24,000(±900)	243	24,000(±900)	430(±8)[±7]	75	355(±8)[±7]
RPT at 8 seconds	820	738	442	24,000(±900)	243	24,000(±900)	530(±8)[±7]	75	455(±8)[±7]
High Pressure No Feedwater									
RPT at 60 seconds	820	406	243	24,000(±900)	406	24,000(±900)	309(±8)	75	234(±8)
RPT at 0 seconds	820	820	243	24,000(±900)	243	24,000(±900)	350(±8)	75	275(±8)

* RPT is not automatic and requires operator action.
( ) Effect due to uncertainty in steam drum initial water level.
[ ] Effect due to uncertainty in hotwell initial water level.

TABLE 15.8-2

Reactivity Feedback Coefficients

	Value
B_{eff}	5.77×10^{-3}
l^*, sec^{-1}	104.
$\alpha_{Doppler}$, $/°F	-0.0025
α_{Void}, $/%	-0.182

TABLE 15.8-3

Typical Initial Operating Conditions

Parameter	Value
Reactor pressure (psig)	1,350
Core flow (Mlb/h)/ (%)	12.2/100
Vessel diameter (in)	106
Number of fuel bundles	84
Power (MWt)/ (%)	245/102
Steam/Feed flow (lb/sec)/ (%)	276/102
Initial steam drum water level	Center line
Initial vessel inventory (lb)	99,000
Feedwater temperature (°F)	365
Void reactivity coefficient (¢/%)	-18
Doppler coefficient (¢/°F)	-0.25
Sodium pentaborate solution concentration (% by weight)	19
Containment volume (ft^3)	912,000
Initial containment temperature (°F)	100
Condenser hotwell volume (gal)/(minutes of rated steam flow)	3,000/1.9
Core average active void fraction (%)	25

TABLE 15.8-4

Equipment Performance Characteristics

Closure time of MSIV (sec)	45
Safety valve system capacity (% of full power steam flow)/No of valves	200/6
Safety valve set point range (psi)	1,550-1,600
Opening time of turbine bypass valve (sec)	0.2
Boron storage tank volume (gal)	850
Poison system start and transport time (sec)/transport delay inside PCS (sec)	30/11*
Poison system injection rate (gpm)	132
ATWS high-pressure RPT set point (psig)	1,550
ATWS low water level RPT set point (inches from drum center line)	-8

*11 seconds with recirculation pumps running; (6/W) seconds with pumps tripped, where W is recirculation flow in fraction of rated.

TABLE 15.8-5

Summary of Big Rock Point Containment Pressure Analysis
for Various ATWS Events (Source: NEDE-21065)

Condition Description	Case Number														
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
RPT initiation time (min)	None	5	0	None	0	None	0	1	2	3	5	None	None	0	0
LPS injection time (min)	5	5	5	10	10	3	3	5	5	5	5	5	5	5	5
Containment steam flow multiplier	1	1	1	1	1	1	1	1	1	1	1	0.8	1.2	0.8	1.2
Peak containment pressure (psig)	57.7	43.9	25.0	96.2	37.6	42.3	20.5	27.5	31.0	35.1	43.9	43.0	73.0	19.7	30.5

All of the cases described here assume that:

(a) unlimited feedwater is available,
(b) enclosure spray is initiated 5 minutes after the transient begins,
(c) both tube bundles of the emergency condenser are functioning,
(d) transient is full load reject without turbine bypass and
(e) MSIV closes rapidly.

FIGURE 15.8-1

LOSS OF FEEDWATER W/O RPT W/O SCRAM
W/O POISON

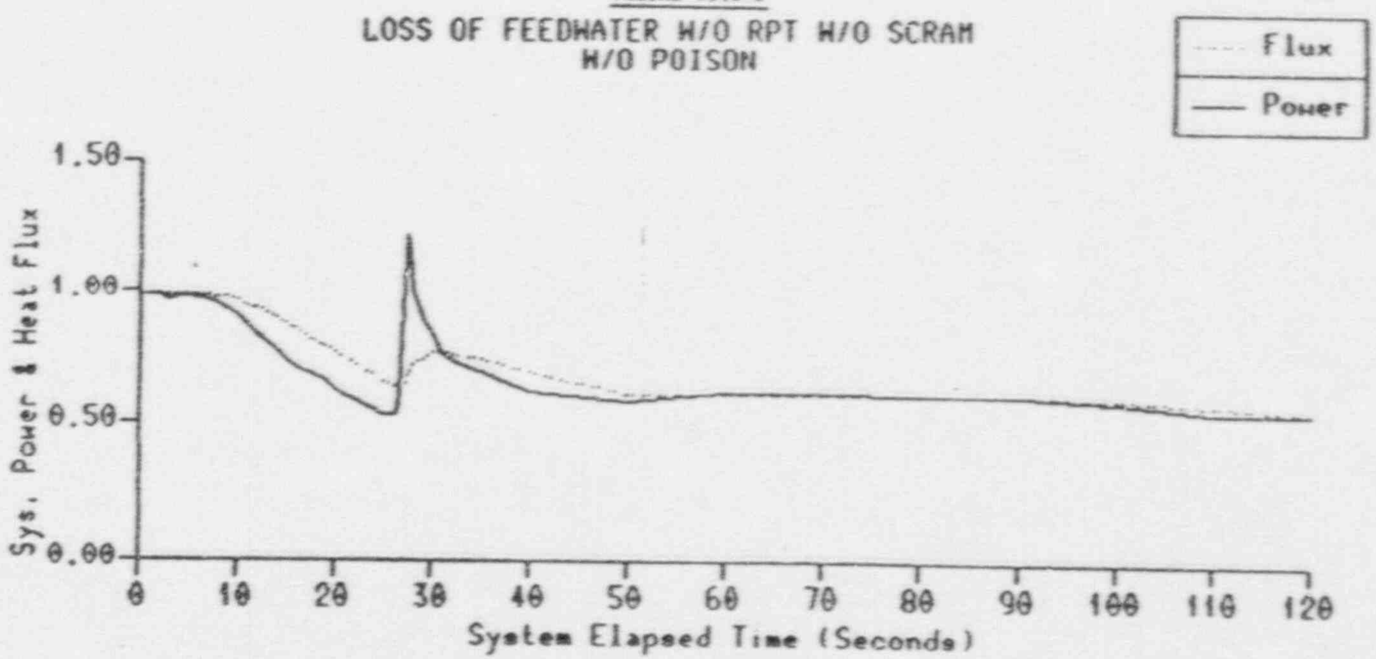


FIGURE 15.8-2

LOSS OF FEEDWATER W/O RPT W/O SCRAM
W/O POISON

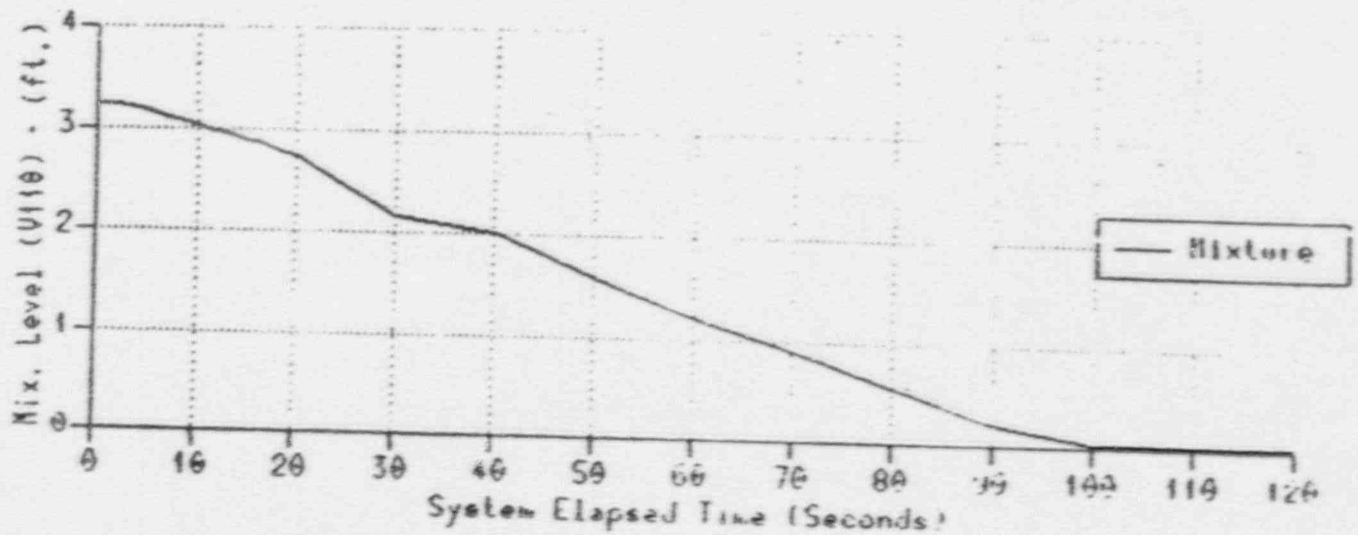


FIGURE 15.8-3

LOSS OF FEEDWATER W/O PPT W/O SCRAM
W/O POISON

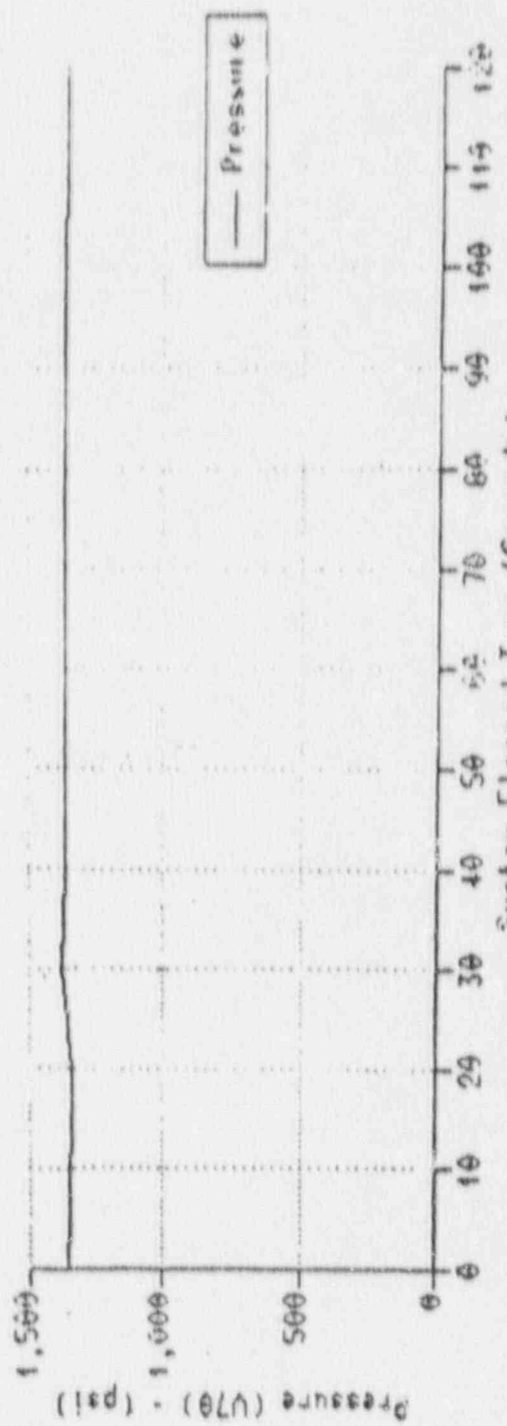


FIGURE 15.2-4

LOSS OF FEEDWATER W/O RPT W/O SCRAM
W/O POISON

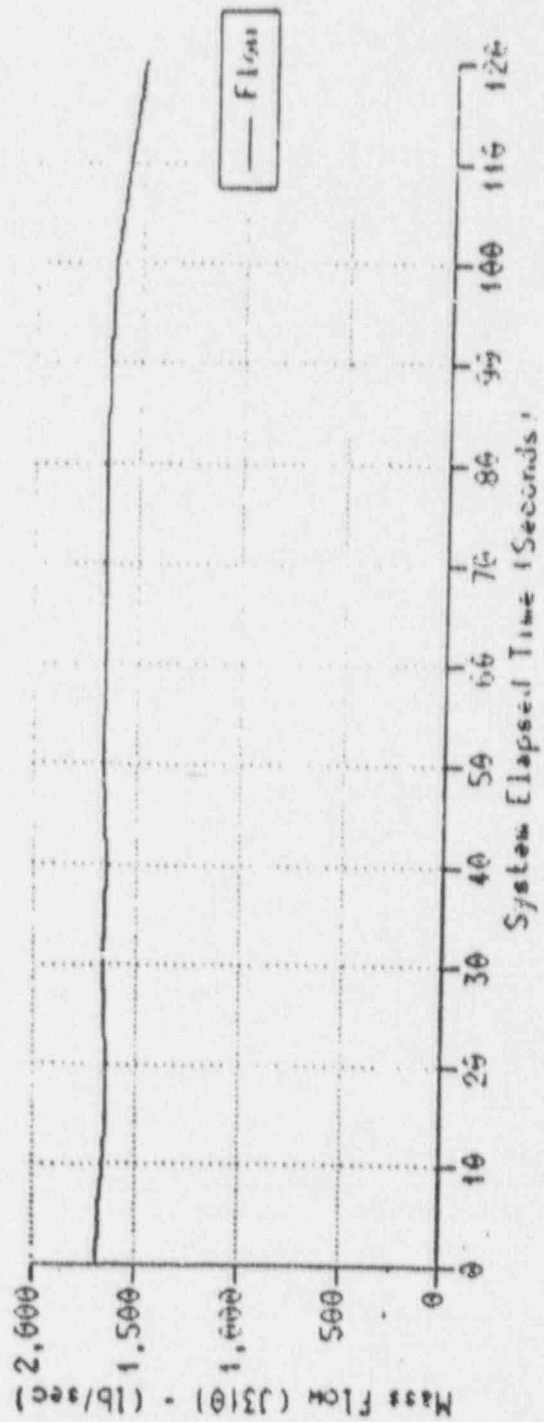


FIGURE 15.8-5
LOSS OF FEEDWATER W/RPT W/O SCRAM
W/O POISON

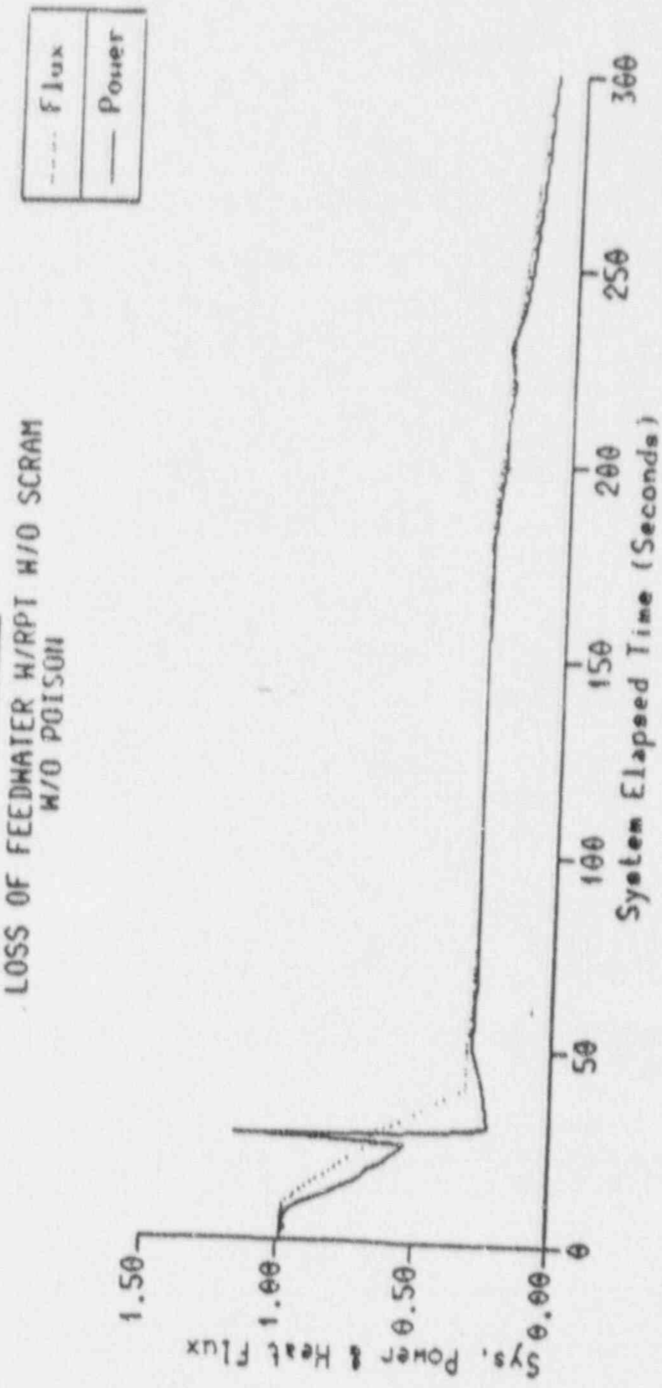


FIGURE 15.8-6

LOSS OF FEEDWATER W/RPT W/O SCRAM W/O POISON

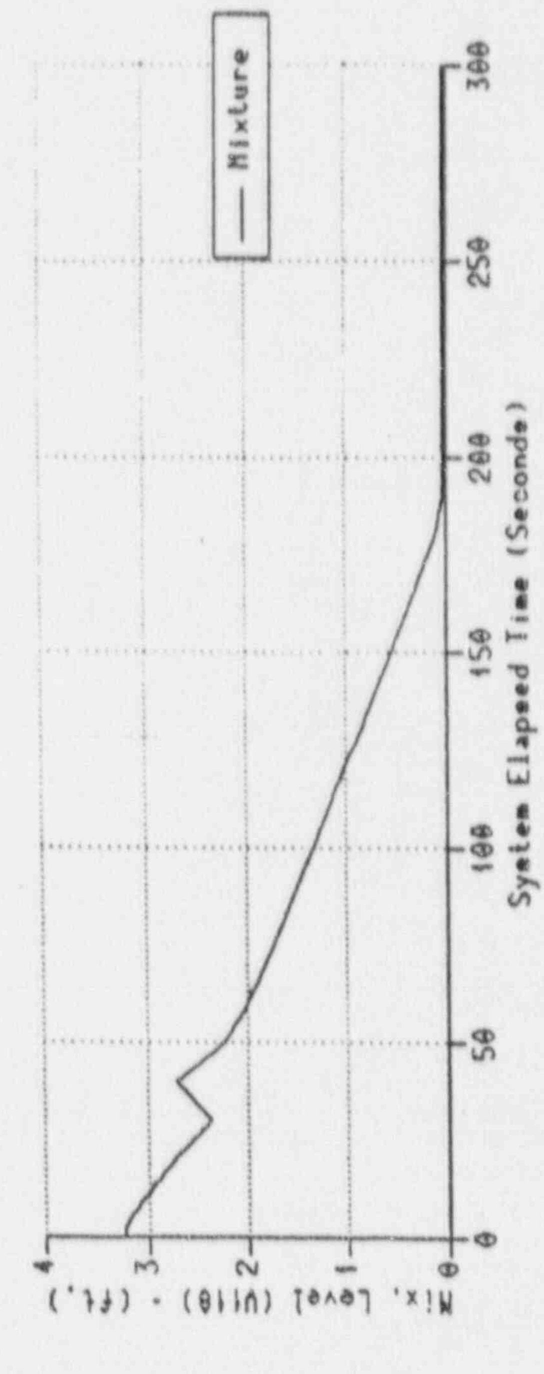


FIGURE 15.8-7

LOSS OF FEEDWATER W/RPT W/O SCRAM W/O POISON

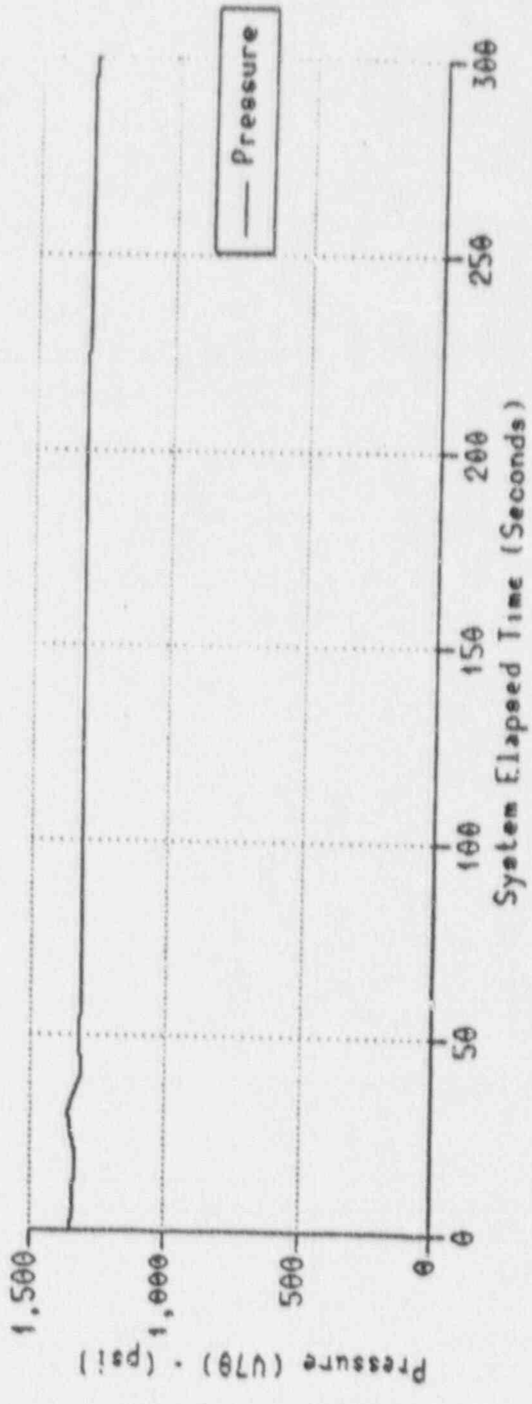


FIGURE 15.8-6

LOSS OF FEEDWATER W/RPT W/O SCRAM W/O POISON

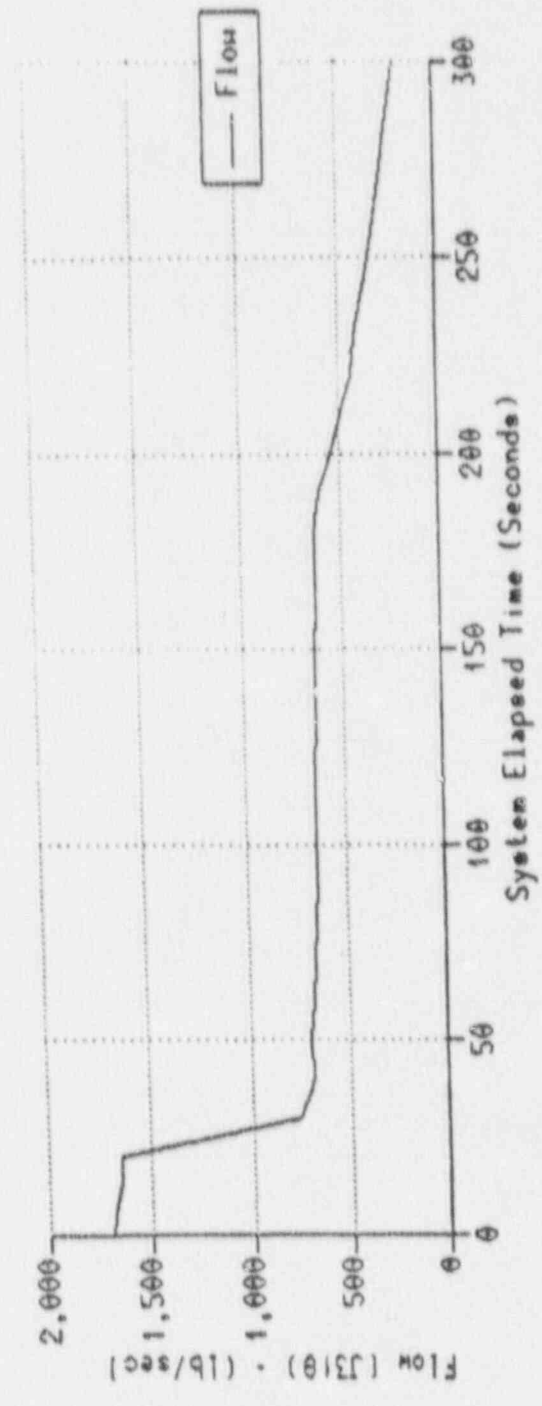


FIGURE 15.8-9

TURBINE TRIP W/O BYPASS W/O SCRAM
W/O PPT W/O POISON

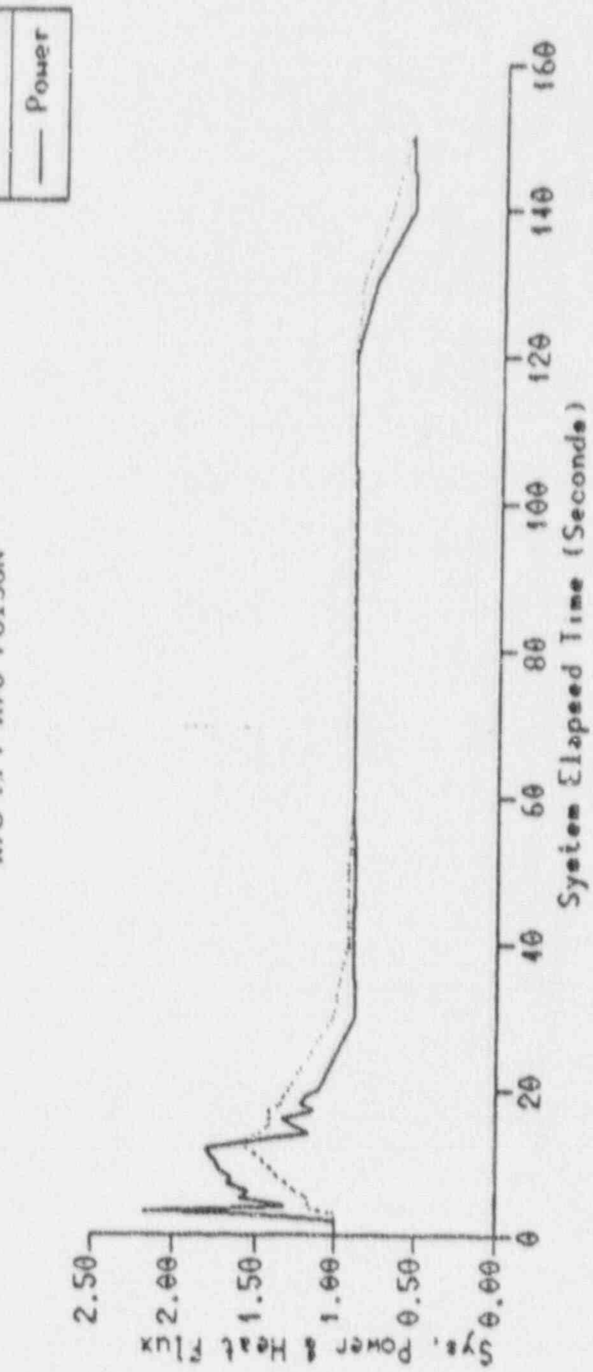


FIGURE 15.8-20

TURBINE TRIP W/O BYPASS W/O SCRAM
W/O RPT W/O POISON

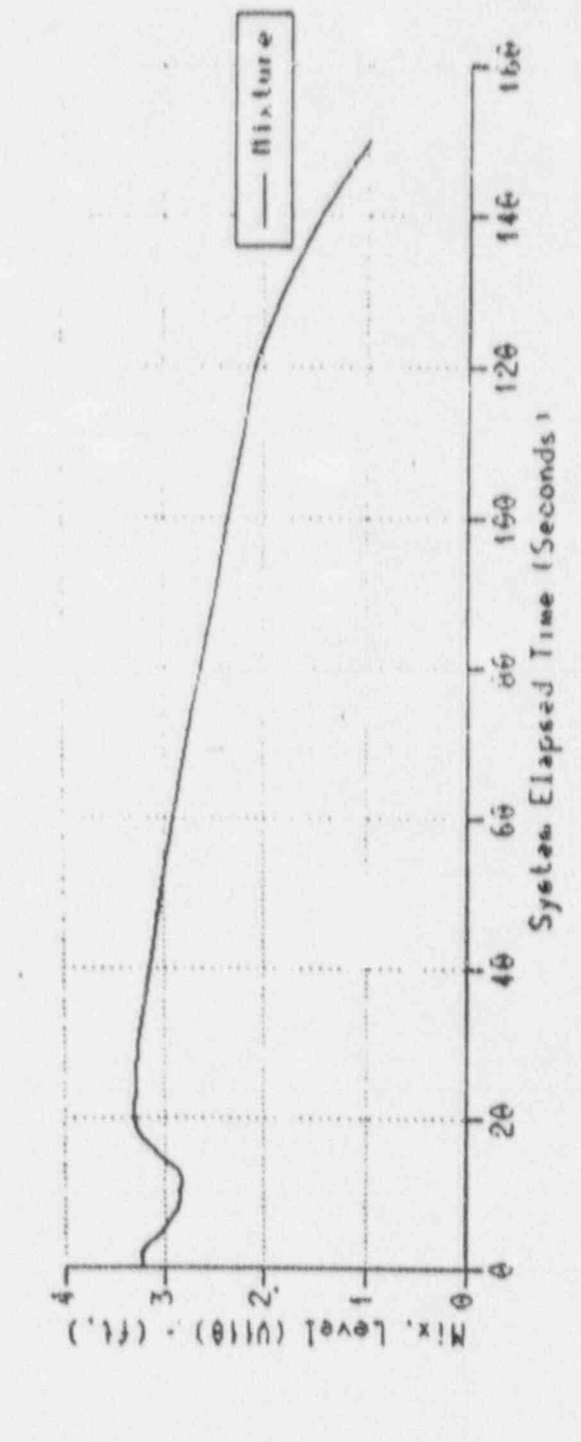


FIGURE 15.8-11

TURBINE TRIP W/O BYPASS W/O SCRAM
W/O RPT W/O POISON

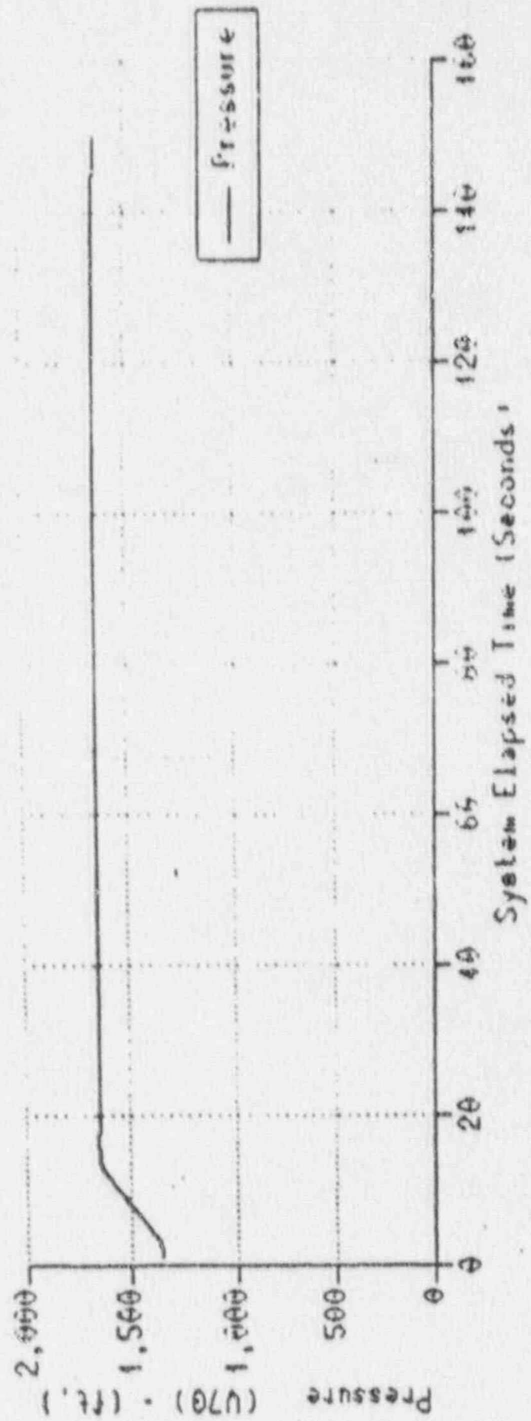


FIGURE 15.8-12

TURBINE TRIP W/O BYPASS W/O SCRAM
W/O RPT W/O POISON

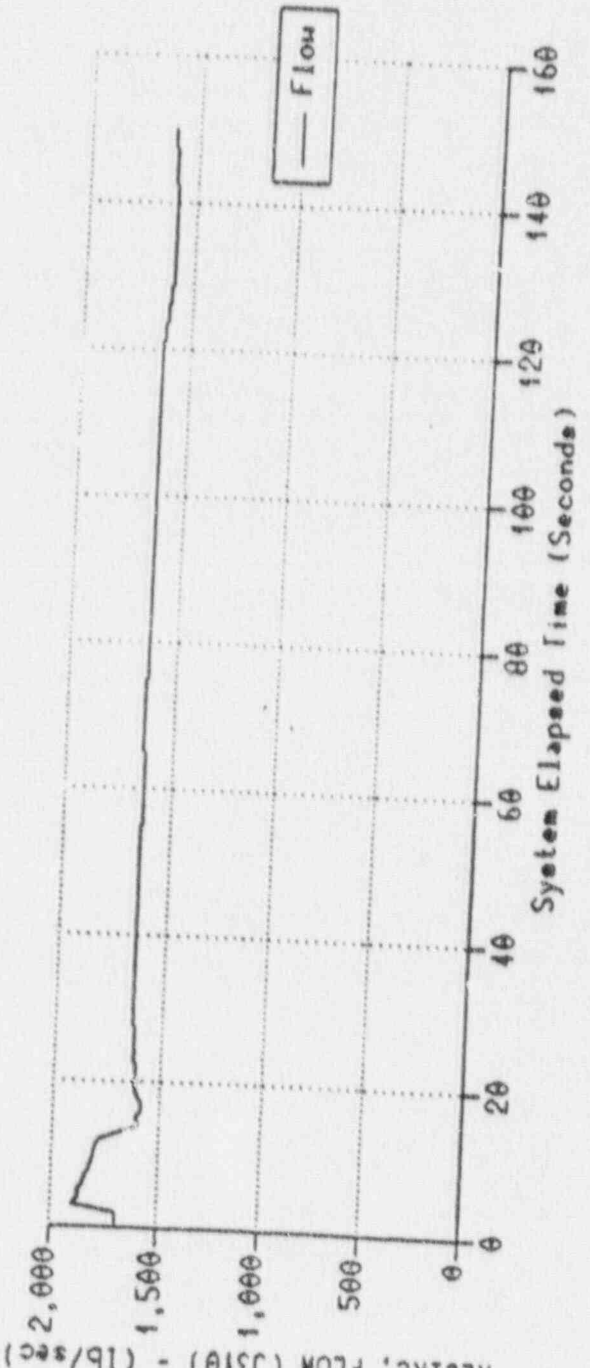


FIGURE 15.8-13

TURBINE TRIP W/O BYPASS W/O SCRAM
W/RPT W/O POISON

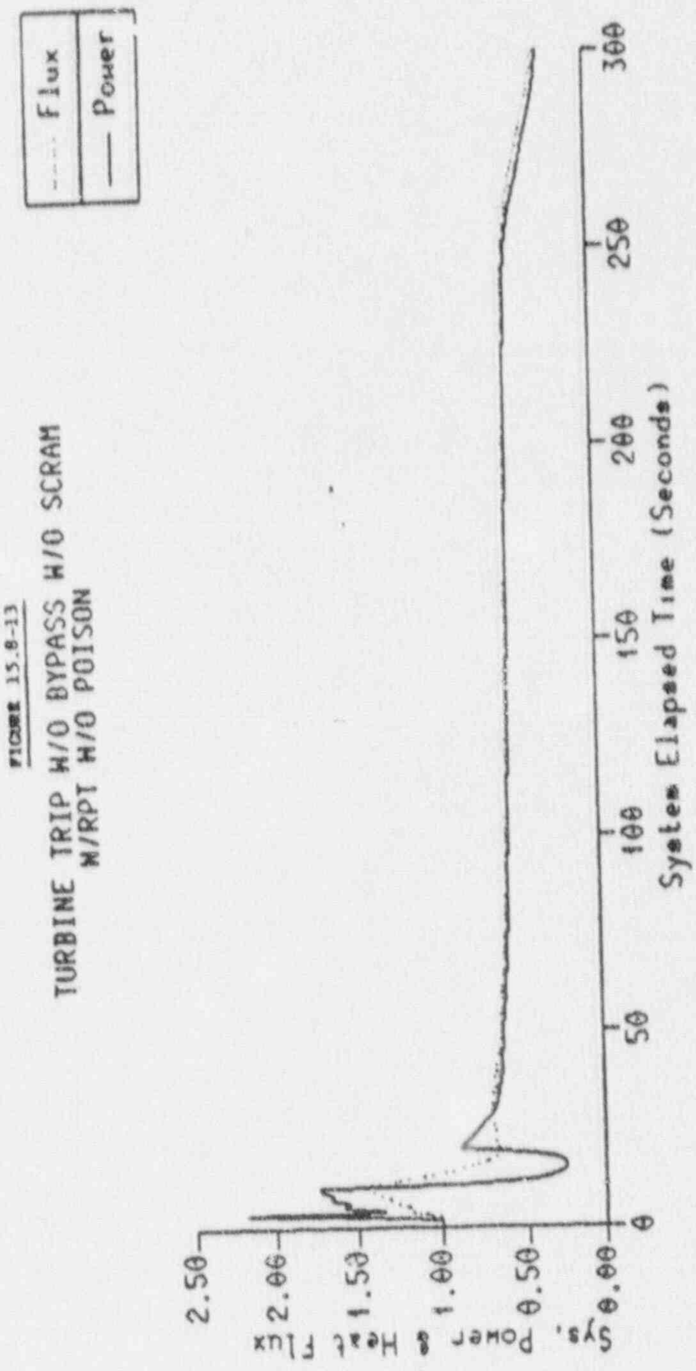


FIGURE 15.8-14

TURBINE TRIP W/O BYPASS W/O SCRAM
W/RPT W/O POISON

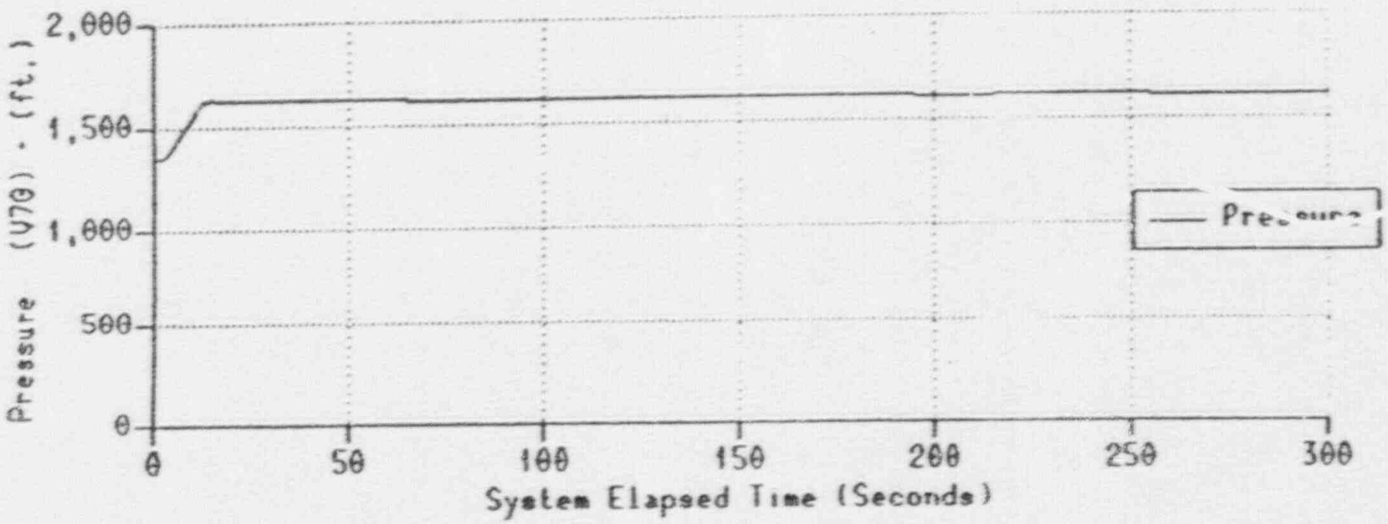


FIGURE 15.8-15

TURBINE TRIP W/O BYPASS W/O SCRAM
W/RPT W/O POISON

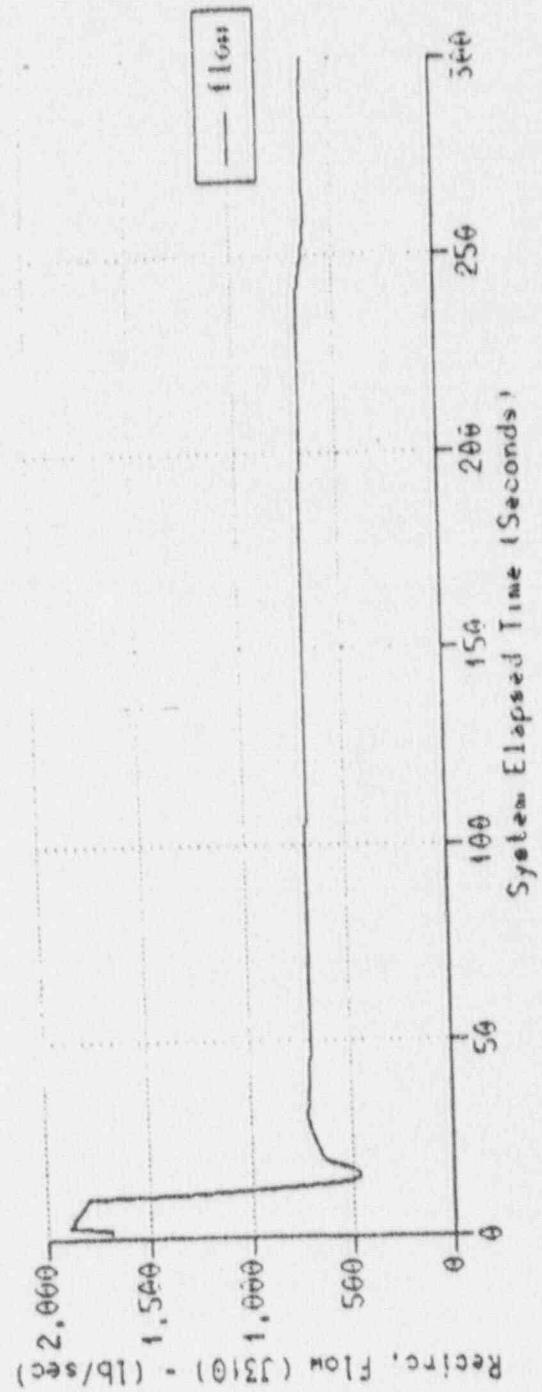
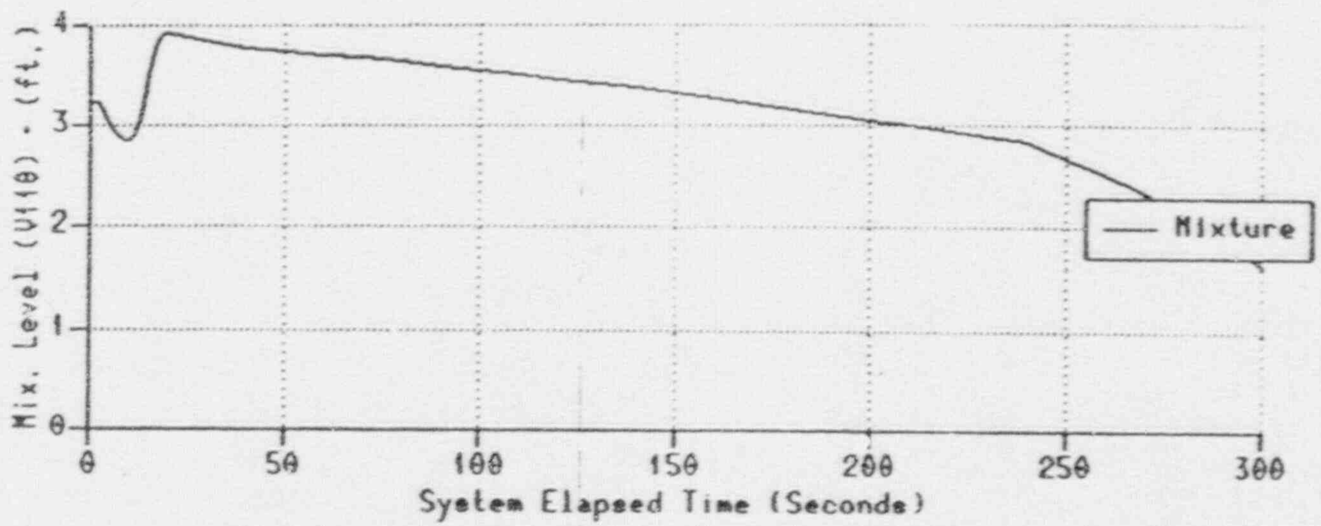


FIGURE 15.8-16

TURBINE TRIP W/O BYPASS W/O SCRAM
W/RPT W/O POISON



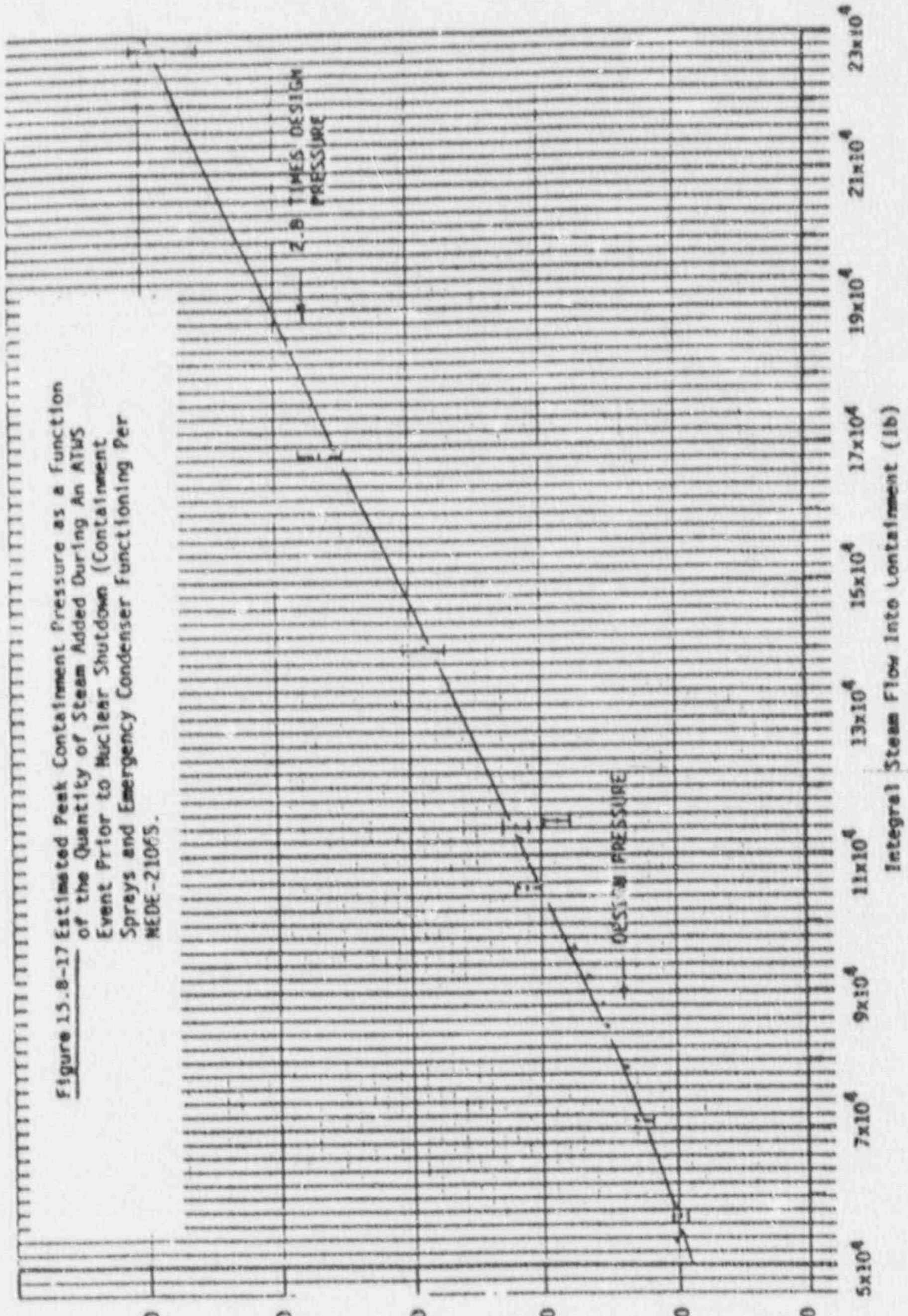


Figure 15.8-17 Estimated Peak Containment Pressure as a Function of the Quantity of Steam Added During An ATWS Event Prior to Nuclear Shutdown (Containment Sprays and Emergency Condenser Functioning Per NEDE-21065.

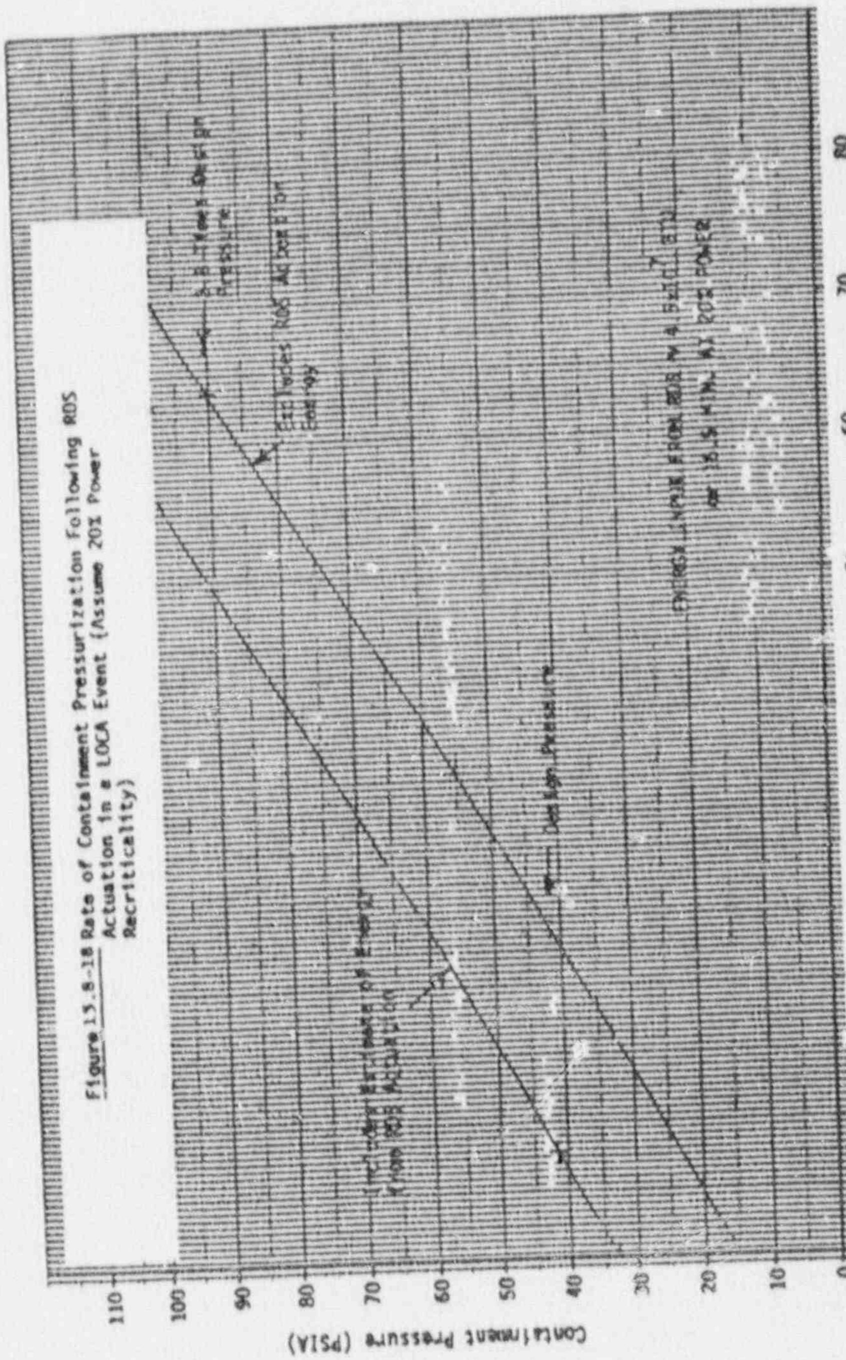


Figure 15.8-18 Rate of Containment Pressurization Following RDS Actuation in a LOCA Event (Assume 20% Power Recriticality)

CRDR SUMMARY REPORT
TABLE OF CONTENTS

NOTE: Supporting documentation for the above Volumes are contained in Volumes IX through XIII C and are available at CPCo.

18.1.3 CRDR RESOLUTION

Based on previously identified documentation and audits, the NRC issued a Safety Evaluation Report (SER) dated July 11, 1990. The staff concluded that the Big Rock Point CRDR program satisfied the nine DCRDR (Detailed Control Room Design Review) requirements of Supplement 1 to NUREG-0737.

Corrective action on all open Human Engineering Deficiencies (HEDs) must be resolved as described in Section 7 of the Program Plan by December 31, 1992.

This completes Big Rock Point's responsibilities associated with the NUREG-0737, Supplement 1 item on conduct of a Detailed Control Room Design Review.

Program verify that identified devices are appropriate with exceptions. Those exceptions are documented in the form of HEDs and will be resolved as a part of the HED process described in Section 18.1.3.

Based on previously identified documentation and audits the NRC issued a Safety Evaluation Report (SER) dated July 11, 1990, and correction dated August 22, 1990. The staff concluded that the Big Rock Point SPDS did provide a concise display of critical plant variables that could be readily perceived and comprehended by all SPDS users following implementation of the BRP recommended changes. These changes included locating back-panel instrumentation (stack gas monitors, high range gamma monitor and containment temperature indication) to the front panel. Critical display instruments were demarcated to assist the SPDS user in determining plant status.

Based upon the Technical Support Center (TSC) being adjacent to the Control Room and the viewing of the CSF devices through the windows being approximately the same as that of an Operator seated at a desk in the Control Room, extension of the critical function display into the TSC is not required.

This completes Big Rock Point's responsibilities associated with NUREG-0737 Supplement 1 item on Safety Parameters Display System evaluation.