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Florida Power CORPORATION

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 970261-EI

In Re: Review of Nuclear Outage at Florida Power Corporation's Crystal River Unit No. 3

DIRECT TESTIMONY AND EXHIBITS OF

PERCY M. BEARD, JR.

For Filing April 14, 1997

FLORIDA POWER CORPORATION
DOCKET NO. 970261-EI

DIRECT TESTIMONY OF
PERCY M. BEARD, JR.

I. <u>BACKGROUND</u>

Q. WHAT IS YOUR NAME, ADDRESS, AND OCCUPATION?

A. My name is Percy M. Beard, Jr. I live at 1630B Royal Palm Drive South, Gulfport, Florida 33707. I am retired from Florida Power Corporation ("Florida Power" or "the Company").

Q. WHAT WAS YOUR POSITION AT FPC?

A. I served as Senior Vice President, Nuclear Operations for Florida Power in charge of the Company's nuclear program and management of the Crystal River Unit 3 nuclear power plant ("CR-3") from December 1989 through my retirement on March 3, 1997. As Senior Vice President, Nuclear Operations, I was responsible for overall management of CR-3 and for assuring, in particular, that all CR-3 activities, including engineering, licensing, operations, and maintenance were performed in accordance with the Facility Operating License issued by the NRC.

Q. WHAT IS YOUR EDUCATION, EXPERIENCE, AND TRAINING?

A. I received my Bachelor of Science Degree in Marine/Electrical Engineering from the U.S. Naval Academy in 1958 and my Doctorate Degree in Nuclear Physics from Duke University in 1964. I served in the U.S. Navy from 1958 through 1981, holding a number of posts, including the command of two nuclear submarines.

In 1981, I joined the Institute of Nuclear Power Operations (sometimes referred to as "INPO"). The Institute of Nuclear Power Operations was formed in 1980 to promote a standard of excellence throughout the commercial nuclear power industry. Between 1981 and 1989, I served at the Institute as an Evaluation Team Manager, Director and Vice President of the Evaluation and Assistance Group, and Vice President of Government Relations. As Vice President of Government Relations, I managed INPO's relationships with the U.S. Nuclear Regulatory Commission ("NRC"), the U.S. Department of Energy, and various industry organizations, including the Nuclear Management and Resource Council (now called the "Nuclear Energy Institute"), the Nuclear Power Oversight Committee, the Edison Electric Institute, and the Electric Power Research Institute.

II. <u>PURPOSE AND SUMMARY OF TESTIMONY</u>

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I describe in my testimony the overall operating performance and safe condition of CR-3 during the years of my tenure leading to the current outage. I also describe a modification that was made during the 1996 refueling outage that provides the immediate background to the current outage, the lube oil pipe failure that precipitated the current outage, and my decision at the beginning of October 1996 to extend the outage in order to permit CR-3 to restore compliance with the conditions of its operating license. Finally, I explain why it was reasonably necessary to incur the costs associated with the current outage.

Q. WOULD YOU PLEASE SUMMARIZE YOUR TESTIMONY?

A. Yes. Over the years, Florida Power has endeavored to avoid extended outages. Since I joined the Company in 1989, the productivity of the plant climbed continually until we commenced this outage in 1996. The plant's capacity factor rose steadily from 53% in 1989 to approximately 100% in 1995. The plant's performance in 1995 placed CR-3 among the top-performing nuclear plants in the world. During the same years, CR-3 enjoyed a steadily declining cost of producing electricity. In 1989, it cost $40.44 per megawatt hour to produce electricity at CR-3; by 1995, the cost was $17.96. Florida Power's ratepayers have enjoyed the benefits of this superior performance over those years.

Florida Power has always operated CR-3 in a safe manner. We continually monitor our safety systems and have succeeded in maintaining our objective over the years in ensuring the availability of emergency equipment and systems. We have consistently observed the safety limits established for the protection of our employees, the public, and the environment.

The Company initiated the current outage in order to repair a ruptured lube oil pipe in the main turbine. The pipe was not observable while the plant was operating and so it's failure was not foreseen. The pipe failed due to stress caused by vibration in the operation of the turbine coupled with latent impurities in the pipe material. We had to shut down the plant to identify the problem with certainty and to make the necessary repairs.

I was compelled to make the decision to place CR-3 in an extended shutdown because we determined by the beginning of October 1996 that we needed to restore compliance with the plant's operating license and that this would require a thorough investigation of alternatives and sufficient time to make any necessary modifications to the plant's Engineered Safeguards system. The modifications we are making grow out of a series of regulatory requirements prompted by the accident at Three Mile Island. On account of these requirements, plants that had been designed and constructed previously had to retrofit their Engineered Safeguards system to meet hypothetical emergency situations that the plants had not been designed to meet.

Over the years, Florida Power has made a number of modifications to CR-3's control systems and procedures and less extensive modifications to the plant's hardware in order to meet applicable licensing requirements. The Company has maintained the plant in safe operating condition while avoiding the need to make extensive modifications requiring lengthy outages.

During the refueling outage that commenced in February 1996, CR-3 engineers added more accurate instrumentation to the meters that plant operators use to manage load on the plant's Emergency Diesel Generators. In the course of analyzing this modification, our engineers detected a potential problem arising out of a modification that had been made years earlier, in 1987, to reduce load on the generators. In 1987, the Company had configured the plant's Emergency Feedwater system so that both of the plant's Emergency Feedwater pumps would be actuated at the same time. Because one of the pumps was driven by steam, the actuation of tnis pump reduced the hydraulic load on the other, electric-powered pump, and thus reduced the electrical load that the electric-powered pump imposed on one of the Emergency Diesel Generators.

During the 1996 refueling outage, CR-3 engineers became concerned based on calculations that they made at that time that simultaneous operation of both Emergency Feedwater pumps -- in a situation involving the loss of the battery that powers the valves to the steam-driven pump -- might cause an excessive flow of feedwater through the pumps potentially leading to pump failure. Up until that time, this hypothetical contingency had not been recognized by the Company, the Architect Engineer (Gilbert Commonwealth, Inc. now Parsons Power) or the nuclear steam supply vendor (Babcock & Wilcox now Framatone Technologies, Inc.). In order to remedy the problem, CR-3 engineers determined to "reverse" the 1987 modification linking the two pumps together.

They were able to do this based on the fact that the Emergency Diesel Generators had been upgraded after the 1987 modification and based on information from the manufacturer of the diesels -- Coltec Industries -- that the diesels could handle the load of the electric-powered pump acting alone. Based on this modification, we were able to restart the plant in May 1996.

In continuing to analyze the Engineered Safeguards system of the plant, however, both Florida Power and the NRC came to question whether the May 1996 modification departed from the documented bases of the plant's Technical Specifications, which are conditions of the operating license. Florida Power and the NRC further determined that the modification gave rise to other concerns about the adequacy of the Emergency Feedwater system. On October 4, 1997, after consulting with CR-3 engineers, I concluded that we had to take steps to restore compliance with the plant's operating license, and that significant time would be required to complete our investigation and to make any necessary modifications.

Even if we had acquired this insight sooner, the same kind of outage would have been required. Because the problem involves complying with the conditions of our license, once we identified the problem we had to shut down the plant in 72 hours, or keep the plant shut down (if it was already out of service), until the problem could be redressed. Further. the modifications that we must make can only be made while the plant is shut down. In addition, we could not have done the extensive work associated with these modifications during any prior outage. Accordingly, this kind of outage was unavoidable.

The Company will benefit from making these modifications at this time because the Company will be able to learn from the trial and error of certain other plants similar to CR-3 that have attempted similar modifications, picking and choosing those solutions that seem best suited to CR-3 and that have proved successful at other nuclear plants.

III. DESCRIPTION OF PLANT PERFORMANCE

Q. PLEASE DESCRIBE GENERALLY CR-3's PERFORMANCE FROM THE TIME YOU ASSUMED YOUR RESPONSIBILITIES AS SENIOR VICE PRESIDENT, NUCLEAR OPERATIONS, UNTIL THE REFUELING OUTAGE THAT COMMENCED IN FEBRUARY 1996.

A. Overall, the plant performed very well during that period of time. Its productivity increased continually from 1989, when I started at Florida Power, through the end of 1995. A good indicator of a power plant's productivity is its capacity factor. The capacity factor is a comparison of a power plant's actual production with its potential production; thus, it represents a measure of how close the plant has come to achieving its full productive potential. I have attached as exhibits to my testimony three tables -- PMB Ex. 1 -- which demonstrate that CR-3's capacity factor rose steadily from 1989 through 1995, culminating in performance that placed CR-3 among the top-performing nuclear plants in the entire world.

Specifically, in 1989, at the end of its first decade of operation, CR-3's lifetime capacity factor was approximately 53%. As of that time, CR-3 was ranked 78th out of 107 nuclear units in terms of net capacity factor. Between 1991 and 1993, CR-3 rose to 41st out of 107 units, and between 1993 and 1995, CR-3 ranked 5th out of 108 units. Comparing the period 1990-1992 to 1993-1995, CR-3 increased its capacity factor by more than twenty percentage points. See PMB Ex. 2. In 1995, CR-3 had a capacity factor of approximately 100%, which was the best capacity factor of all nuclear plants in the country and ranked 5th in the world. Because nuclear fuel is relatively less expensive than alternative sources of fuel, CR-3's exceptional operation during this period of time directly benefited Florida Power ratepayers.

This benefit may be seen more clearly when consideration is given to CR-3's declining costs associated with operations, maintenance, and fuel. Specifically, in 1989, it cost $40.44 per megawatt hour to produce electricity at CR-3. We consistently reduced that cost through 1995. In 1990, we were able to reduce our cost per megawatt hour by more than 25%, to $30.20. By 1995, we had reduced CR-3's cost per megawatt hour to $17.96 -- nearly a 60% decrease since 1989. As a result, CR-3 was able to supply efficient, reliable, and economical energy to Florida Power's ratepayers.

Q. WAS CR-3 SAFE DURING THE TIME THAT YOU SERVED AS SENIOR VICE PRESIDENT, NUCLEAR OPERATIONS?

A. Yes, it was. I placed top priority on the public health and safety during my leadership of the plant, and I would not have allowed the plant to operate if I did not have complete confidence in its safety. We monitored the safety systems and equipment at CR-3 continuously to ensure that they met rigorous standards of availability. We succeeded in meeting our performance indicator targets confirming that the plant's Engineered Safeguards equipment and systems remained in-service and available to respond to emergencies. We continuously monitored and confirmed the reliability of safety equipment to start and function when actuated.

The plant ran well during my tenure and experienced very few "Scrams," or automatic precautionary shut downs. We had a relatively moderate maintenance backlog and succeeded in keeping the plant in sound material condition. CR-3 consistently observed radiological safety limits established to protect employees, the public, and the environment.

Q. ENTERING 1996, DID YOU BELIEVE THAT CR-3 MET ALL CONDITIONS OF ITS LICENSE AND COMPLIED WITH ALL APPLICABLE DESIGN REQUIREMENTS?

A. Yes.

III. SUMMARY OF MODIFICATIONS MADE TO THE CR-3 ENGINEERED SAFEGUARDS SYSTEM DURING THE 1996 REFUEL OUTAGE

Q. DID FLORIDA POWER DETERMINE IN THE COURSE OF THE 1996 REFUELING OUTAGE THAT IT WAS NECESSARY TO MODIFY CR-3's ENGINEERED SAFEGUARDS SYSTEM IN ORDER TO RESTORE COMPLIANCE WITH APPLICABLE DESIGN REQUIREMENTS?

A. Yes, we did.

Q. DID THE COMPANY MODIFY ITS ENGINEERED SAFEGUARDS SYSTEM DURING THE FEBRUARY 1996 REFUELING OUTAGE?

A. Yes, it did.

Q. PLEASE EXPLAIN WHEN, HOW, AND WHY THE COMPANY MADE THESE MODIFICATIONS.

A. At the end of March 1996, wu upgraded the kilowatt meters that are relied upon by operators in applying loads to the Emergency Diesel Generators in the event of an emergency condition requiring the use of the generators. Our engineers had developed a concern that the existing meters lacked reliability at load levels over 200 kW. In the course of analyzing Emergency Diesel Generator loading issues relating to that modification, the engineers examined the assumption that load would be reduced by the concurrent operation of the (electric-powered) "A" Emergency Feedwater pump and the (steam-powered) "B" Emergency Feedwater pump.

As Mr. Paul McKee explains in his testimony at greater length, in order to reduce the load that we would place on the "A" Emergency Diesel Generator during a loss of coolant accident and a concurrent loss of offsite power, the Company modified the Engineered Safeguards system in 1987. The 1987 modification made the "B" Emergency Feedwater pump actuate by opening a valve to the "B" pump, called "ASV-204," anytime the "A" Emergency Feedwater pump was started. Because the "B" pump is steam driven, the Company reasoned that the "B" pump would reduce the burden on the electric-powered "A" pump, in turn reducing the load on the "A" Emergency Diesel Generator.

In re-examining Emergency Diesel Generator loading issues in March 1996, during the most recent refueling outage, CR-3 personnel focused on the plant's reliance on the concurrent operatio,, of the two feedwater pumps and observed that it was possible that the "B" Emergency Feedwater pump might not be available to provide controlled back-up to the "A" Emergency Feedwater pump if a failure occurred in the battery used to power valves on equipment on the "B" side of the Engineered Safeguards system. The valves that control the flow of feedwater through the "B" Emergency Feedwater pump are normally wide open and require power to close. If the battery used to power those valves were to fail, the "B" pump would operate only at its maximum capacity (i.e., with its control valves wide open). This would afford plant operators less control over the operation of the "B" Emergency Feedwater pump in a small break loss of coolant accident.

Further, at that time, CR-3 engineers became concerned that the flow of feedwater through the Emergency Feedwater pumps in the situation just described might result in the loss of sufficient Net Positive Suction Head ("NPSH") needed to maintain the operability of the pumps.

To address this concern, CR-3 engineers from Operations, Licensing, Electrical and Mechanical Design Engineering, and Emergency Operating Procedures determined that it would be appropriate to modify the Engineered Safeguards system so that actuation of the "A" Emergency Feedwater pump would not automatically actuate the "B" Emergency Feedwater pump, thus "reversing" the 1987 modification. This decision was based on several considerations. Since the time of the 1987 modification, the Company had upgraded the Emergency Diesel Generators by adding 150 kW of capacity to them. Also, we had gained greater confidence in our ability to measure load and capacity. During the 1980s Florida Power had based loading determinations on generic information concerning the capacity and performance characteristics of the model

Emergency Diesel Generators used at CR-3. By 1996, however, we had been provided by the manufacturer of these generators -- Coltec Industries -- precise performance curves for the particular Emergency Diesel Generators actually in use at CR-3. Based on this information, our engineers believed that it was not necessary to maintain the linkage established by the 1987 modification between the "A" and "B" Emergency Feedwater pumps.

CR-3 personnel knew that the Emergency Diesel Generators had been assigned ratings by Coltec indicating that the diesels were made to operate continuously at a maximum of 3500 kW for 30 minutes. CR-3 personnel also knew that calculations showed that, if the "A" Emergency Diesel Generator were required to operate the "A" Emergency Feedwater pump without back-up from the "B" pump, load might be expected to spike up to 3700 kW for up to a few seconds at a time. (This knowledge was based on recent state-of-the-art calculations.) But the load was not expected to exceed 3500 kW on a continuous basis. The Electrical Design Engineering Department obtained assurance from Coltec that the Emergency Diesel Generators could in fact handle the transient spikes that might result if we would be required to operate the "A" Emergency Feedwater pump during a loss of coolant accident without concurrent operation of the "B" Emergency Feedwater pump. Accordingly, the decision was made to approve the modification terminating the automatic actuation of the "B" Emergency Feedwater pump upon initiation of the "A" Emergency Feedwater pump. The modification was completed in May

1996. With the completion of this modification, we were able to restart CR-3 on May 17, 1996.

IV. THE CAUSE OF THE SEPTEMBER 2, 1996 OUTAGE

Q. WHY DID FLORIDA POWER SHUT DOWN CR-3 ON SEPTEMBER 2, 1996?

A. The immediate cause of this shutdown was a rupture of a lube oil pipe in the main turbine.

Q. PLEASE EXPLAIN THE CIRCUMSTANCES OF THE LUBE OIL PIPE RUPTURE.

A. Plant operators detected a loss of lube oil pressure in the main turbine on August 30, 1996, which caused an automatic start of the electric back-up bearing oil pump. We commenced an immediate investigation of the problem and contacted the system vendor, Westinghouse, for guidance. Westinghouse suspected that a valve was partially blocked. CR-3 engineers took steps to adjust the valve to correct the problem.

Plant operators monitored the lube oil pressure, and oil pressure continued to fall. On September 2, plant operators detected a substantial drop in the main turbine lube oil reservoir level over the prior 24 hour period. Based upon this problem and the continued loss of lube oil pressure, we decided to take CR-3 off line.

On September 3, our engineers opened several lube oil tank access ports and detected a long pipe crack. Upon further inspection of the system, the engineers identified a four and a half foot crack in a lube oil pipe just inside the top of the tank. In addition, the flange bolts at one end of this pipe had loosened and much of the gasket had blown out. The crack and the condition of the gasket permitted lube oil to leak out of the pipe, explaining the loss of pressure. Our engineers concluded that the crack and the loosening of the flange bolts had been caused by vibration over a period of time that occurs during the operation of the equipment.

Q. BASED ON THE INFORMATION AVAILABLE TO THE COMPANY PRIOR TO THE RUPTURE OF THIS PIPE, DID THE COMPANY ANTICIPATE THAT THIS MIGHT OCCUR?

A. No. The pipe had long been in use, and we had not experienced any problem like this before. The pipe was naturally subject to vibration during the normal operation of the plant. During operation of the plant, the pipe is not observable. We were unaware of the inclusions in the pipe material and of the loosening of the flange bolts since they are both within the oil reservoir. Finally, to our knowledge, there have been no industry advice letters or similar failures at other nuclear units.

Q. WHAT STEPS DID THE COMPANY TAKE TO REPAIR THE PIPE?

A. After shutting the plant down, we continued to investigate the problem, and we commenced repair work. By September 14, we had completed the repairs, cleaned the tank, and refilled it with oil. The lube oil system was restored to service by September 14. Ordinarily, we would have been able to bring CR-3 back on line within about a week of that date, in order to allow for final inspections and verifications and the restart of the unit.

V. <u>THE CAUSE OF THE CURRENT EXTENDED OUTAGE</u>

Q. WHY DID THE COMPANY KEEP THE PLANT OUT OF SERVICE AFTER COMPLETION OF THE REPAIR TO THE LUBE OIL PIPE?

A. I decided to keep the plant shut down after we determined that the Engineered Safeguards system did not comply with CR-3 licensing requirements. We came to this conclusion in the following manner.

After every refueling outage, we re-test our Emergency Diesel Generators. In addition, we provide additional information to the NRC regarding any modification to safety-related equipment. Thus, following the restart of CR-3 in May 1996 both CR-3 personnel and NRC inspectors were conducting an ongoing review of Emergency Diesel Generator loading issues.

Further, the NRC conducted its intensive Integrated Performance Assessment Process ("IPAP") inspection of CR-3 in June and July 1996. This in-depth inspection included a Safety System Functional Inspection ("SSFI") of the decay heat removal function (the process of cooling the core) and supporting systems. In the course of this inspection, representatives of the NRC and the CR-3 plant discussed issues concerning the loading of the Emergency Diesel Generators, which had been addressed by the modification completed before the restart in May. The NRC was aware that Florida Power had determined that in the hypothetical circumstances -- namely, a loss of coolant accident, a loss of offsite power, and a loss of the "B" battery -- that the load placed on the "A" Emergency Diesel Generator would spike above 3500 kW for a few seconds. Florida Power engineers and the NRC inspectors agreed that the

"A" Emergency Diesel Generator had the technical capability of carrying the load that might be placed upon it in this situation.

In September 1996, however, after CR-3 was shut down due to the lube oil pipe rupture, NRC inspectors raised a concern that operating on the assumption that the "A" Emergency Diesel Generator could handle that load in those hypothetical circumstances may raise an "Unreviewed Safety Question" or "USQ." As Mr. McKee explains at greater length in his testimony, an Unreviewed Safety Question arises whenever a licensee has made a modification that results in an affirmative answer to any of the following three questions: (1) could the modification increase the probability of occurrence or consequences of a malfunction of equipment important to safety previously evaluated in the Final Safety Analysis Report? (2) could the modification create a possibility for an accident or malfunction of a different type than any evaluated previously in the Final Safety Analysis Report? or (3) will the modification cause a reduction in the margin of safety as defined in the basis for any of the plant's Technical Specifications? The NRC concluded that the May 1996 modification negating automatic actuation of the "B" Emergency Feedwater pump upon start-up of the "A" Emergency Feedwater pump presented an Unreviewed Safety Question. This was so because the NRC concluded that CR-3's Technical Specifications contemplated that the "A" Emergency Diesel Generator would not be expected to operate at a level above 3500 kW at its maximum 30-minute rating, even on a transient basis.

The NRC further determined that the documented bases of CR-3's Technical Specifications required that the "A" Emergency Diesel Generator be capable of handling a load of 3100 kW in a worst case scenario where all equipment that may be automatically loaded would be required to operate in an emergency. CR-3 engineers had calculated that the load that would actually be placed on the "A" generator at CR-3 in that situation would total 3159 kW. Finally, the NRC expressed concern that the bases of CR-3's Technical Specifications stated that the single largest load from any piece of equipment that might be placed on the Emergency Diesel Generators was 616 kW, attributable to a High Pressure Injection pump. Florida Power's testing revealed that the Makeup Pump & Purification Pump actually imposed the largest load of 690.9 kW on the Emergency Diesel Generators.

CR-3's Technical Specifications prescribe how the Emergency Diesel Generators must perform and how they must be tested. The Technical Specifications themselves do not prohibit, for example, loading the Emergency Diesel Generators above 3500 kW. The Technical Specifications contain a section called "bases," however, which provide the explanation for the actual Technical Specifications. The "bases" portion of CR-3's Technical Specifications set forth the ratings for the generators in the course of explaining the testing procedures.

The NRC's conclusion that the modification made in May 1996 presented Unreviewed Safety Questions was not based on that portion of CR-3's Technical Specifications that prescribes the actual performance and testing criteria for the Emergency Diesel Generators, but on that portion that provides the explanation or "bases" for the Technical Specifications themselves. In fact, Florida Power had actually tested the Emergency Diesel Generators taking into account the actual loads that might be imposed during a small break loss of coolant accident and determined that the generators met the performance criteria of the Technical Specifications and that the generators were capable of performing their safety function for all design basis accidents. Thus, although the intent of the Technical Specifications had been met, the NRC concluded, and we agreed, that there had been a departure from the documented "bases" of the Technical Specifications.

Before this problem was resolved, the NRC further inquired at the end of September 1996, whether an Unreviewed Safety Question existed in connection with CR-3's Emergency Feedwater system. Our engineers initially disagreed with the NRC's interpretation of the circumstances and responded that no such question existed, but we agreed to study the matter. In analyzing this issue, we ultimately concluded that in reversing the 1987 ASV-204 modification, we had inadvertently reduced the reliability of the "B" Emergency Feedwater pump to assist in a loss of coolant accident in certain hypothetical emergency situations and thus had, indeed, created an Unreviewed Safety Question.

This was due in part to the fact that, in 1990, the Company had modified its Engineered Safeguards system to cause the "A" Emergency Feedwater pump to turn off automatically (or "trip" off) whenever the "A" Low Pressure Injection pump was started, based on information from Framatome Technologies Inc. that both pumps would not be needed simultaneously to combat a loss of coolant accident. This modification provided the benefit of reducing load on the "A" Emergency Diesel Generator in certain hypothetical emergency situations. Due to the 1987 ASV-204 modification, the "B" Emergency Feedwater pump would have been actuated when the "A" pump was turned on. The "B" pump would thus be available to supply feedwater between the set point where the Low Pressure Injection pump would be turned on (and the "A" Emergency Feedwater concurrently turned off) -- at 500 pounds per square inch of Reactor Coolant System pressure -- and the time that the Low Pressure Injection pump would actually start to supply water to cool the core -- at approximately 185 pounds per square inch. As a result of the reversal of the 1987 modification, however, a theoretical possibility existed that the "A" pump might be tripped off and the "B" pump would be needed but would no longer be actuated automatically with the initiation of the "A" pump. This resulted in reliance on operator action to initiate an Emergency Feedwater pump, thus arguably increasing the severity of an accident or malfunction.

Because the resulting configuration differed from Technical Specifications that the NRC had previously reviewed and approved, the modification created an Unreviewed Safety Question. Upon examination of this issue, we concluded that we had no apparent means to resolve the concerns about the Engineered Safeguards system without making significant hardware modifications to the plant.

In the circumstances confronting us, we were required under the conditions of our license to restore compliance within 72 hours or to keep the plant shut down. (If the plant had been operating, we would have had 72 hours to rectify non-compliance with our license, or we would have had to shut the plant down). See PMB Ex. 3 (Technical Specifications limiting conditions). Confronted with these facts, I concluded on October 4, 1996 that we could not restart the plant. Accordingly, I directed that the plant remain shut down until we could complete a thorough investigation and implement modifications that would be effective to restore compliance with the conditions of CR-3's operating license.

Q. WHAT MODIFICATIONS IS THE COMPANY MAKING TO MEET THE CONDITIONS OF ITS LICENSE?

A. The principal modifications are (1) upgrading the Emergency Diesel Generators by adding 150 kW of long-term capacity to each and (2) installing cavitating venturis in the Emergency Feedwater pumps to regulate feedwater flow. Given that the plant would be out of service for an extended period of time to accomplish this work, we undertook to make additional modifications that we believe are necessary to maintain design margins in CR-3's Engineered Safeguards system and that will not lengthen the outage. We had planned to perform some of these modifications during future refueling outages, but it will be more economical and more effective to perform this work now while the Engineered Safeguards system can be examined and enhanced as an integrated whole.

Q. HAS THE COMPANY RULED OUT THE POSSIBILITY OF COMPLYING WITH ITS LICENSE BY MAKING LESS EXTENSIVE MODIFICATIONS?

A. Yes. In fact, the Company has been striving ever since regulatory requirements were changed after the Three Mile Island accident to avoid making more extensive modifications to retrofit the plant. We exhausted all practicable alternatives and were left with no reasonable choice but to commence the modifications now underway.

Q. WHY DIDN'T FLORIDA POWER ANTICIPATE THE NEED FOR SIGNIFICANT MODIFICATIONS TO ITS ENGINEERED SAFEGUARDS SYSTEM AND IMPLEMENT THESE GRADUALLY BEFORE NOW?

A. The Company believed that the modifications that it was making all along would be adequate to enable CR-3 to meet the conditions of its license. The modifications that Mr. McKee describes and that I have described were not designed or implemented as temporary fixes, but as the best practicable, permanent alternatives to meeting applicable safety requirements. When it appears possible to meet operating and regulatory requirements with existing equipment, or by means of modifications that do not require extensive shutdowns, it is preferable to pursue that approach. The Company believed that it had the capability to resolve applicable regulatory requirements with its existing equipment and thus felt an obligation to do so.

It must be recognized that the situation that we faced in September and October 1996 was not like running out of gas. We had no gauge that told us this was coming. Rather, what happened was that we suddenly came to recognize that a hypothetical set of circumstances could be supposed to exist where CR-3 would be operating outside its Technical Specifications. We arrived at this determination as the result of improved instrumentation, improved information about the characteristics of our equipment, improved knowledge about the operation of the plant, and sheer analytical insight. Until then, neither plant personnel, the designers of the plant, nor the manufacturers of its equipment spotted this issue.

It is often possible -- particularly with the benefit of hindsight -- to conjure up a "better" solution that costs more and that will require an extensive shutdown to implement, but it is difficult or impossible to know in advance whether these solutions will truly prove better for the ratepayer and the public at large. Until we commenced the current outage and determined that we had to implement the modifications now in progress, we believed that it would be ill-advised to undertake the extensive modifications that we now believe are necessary. We believed that we had other, superior and more cost-effective means available to cope with hypothetical design basis accidents. The Company has tried painstakingly over the years to meet its licensing requirements and to protect the ratepayer against unreasonable costs. We could not conclude that an outage like this one was cost-justified until, as I have described, we concluded in October 1996 that we simply had no choice.

Q. IF THE COMPANY HAD CONCLUDED PRIOR TO OCTOBER 1996 THAT THESE MODIFICATIONS WERE NECESSARY, WOULD THE SAME KIND OF OUTAGE BEEN REQUIRED?

A. Yes. If one supposes that Florida Power had concluded at any time prior to October 1996 that it would be necessary to make the modifications now in progress, one must also suppose that Florida Power knew why these modifications would be necessary: namely, that these modifications are needed to maintain CR-3s compliance with the conditions of its license. If the Company had this recognition earlier, the Company would have had to shut down the plant within 72 hours, under the terms of its license, to implement these modifications. This would have required the same kind of outage as the one we have now.

Q. WHY WASN'T FLORIDA POWER ALERTED TO THE NEED FOR THESE MODIFICATIONS BY THE FACT THAT CERTAIN OTHER UTILITIES WERE MAKING SOME SIMILAR MODIFICATIONS?

A. Although there are many similarities among nuclear plants -- at least those whose reactors were designed by Babcock & Wilcox -- there are also important differences. Each plant must tailor solutions to its own particular configuration and needs. Until now, Florida Power had believed that the most practicable and desirable manner to ensure that its Emergency Feedwater system could meet the requirements of a safety-related system was to implement electrical control solutions (including, for example, the installation of the Emergency Feedwater Initiation and Control system that Mr. McKee describes) rather than extensive hardware modifications that require an extended outage to carry out. In fact, during the time that Florida Power was charting this course, other plants were having difficulty with hardware modifications.

Q. WILL FLORIDA POWER BENEFIT FROM THE FACT THAT OTHER UTILITIES HAVE MADE SIMILAR MODIFICATIONS?

A. Yes. For example, the Davis Besse, Three Mile Island, and Rancho Seco plants (all B&W plants) have installed cavitating venturis to avoid cavitation in their Emergency Feedwater pumps. Florida Power is now able to use state-of-the-art design in making this modification. By contrast, when Arkansas Power first installed cavitating venturis (in its High Pressure Injection system), the devices created excessive vibration and resulting secondary damage, forcing Arkansas Power to modify the devices. The Baltimore Gas & Electric Company has made upgrades to the Emergency Diesel Generators in its Calvert Cliffs nuclear unit similar to the modifications that we are making to CR-3's Emergency Diesel Generators.

Because the Engineered Safeguards system is an integrated system, the Company is making modifications at this time to the Low Pressure Injection system and the High Pressure Injection system. Three Mile Island has made similar modifications to its Low Pressure Injection system, and Oconee, Three Mile Island, and Arkansas Power have made similar modifications to their High Pressure Injection systems. Florida Power will benefit from lessons learned in each of these installations.

Of course, no two plants are exactly alike, and Florida Power must engineer the implementation of these modifications for the particular configuration of CR-3. Nonetheless, the conceptual design work has been verified through operational experience, and the NRC is comfortable with these solutions to the various engineering issues they are designed to address. Florida Power is consulting with the engineers of other Babcock

& Wilcox nuclear units concerning the ongoing modifications at CR-3. As a result, the Company will be able to make these modifications as efficiently and effectively as anyone else in the industry.

Q. COULD THE WORK THAT THE COMPANY IS DOING NOW HAVE BEEN COMPLETED DURING A PRIOR OUTAGE?

A. No. The work now underway is extensive and all consuming. Likewise, during all prior outages during my years at the Company, the Company was fully occupied tending to other important matters. The Company could not have accomplished e· tensive modifications of the kind now being made without lengthening any prior outage by the number of days being consumed in this outage. There is simply no practicable way that this shutdown -- or one just like it -- could have been avoided, given the fact that Florida Power is retrofitting equipment that was not part of the original design for the plant and given the Company's reason for doing it.

Q. WAS IT REASONABLY NECESSARY FOR FLORIDA POWER TO INCUR THE COSTS OF THIS EXTENDED OUTAGE?

A. Yes. For all the reasons I have given, these costs were not reasonably avoidable.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

EXHIBITS TO THE TESTIMONY OF
PERCY M. BEARD, JR.

EXHIBIT NO. ___ (PMB-1)
TABLE I
1989-91 SINGLE-UNIT RANKINGS
1991-93 SINGLE-UNIT RANKINGS
1993-95 SINGLE-UNIT RANKINGS

TABLE I

1989–91 Single-Unit Rankings by DER Net Capacity Factor

Rank	Unit	MWe	Utility	Vendor	A-E	Factor
1.	Prairie Island-1	530	NSP	W	Fluor	87.43
2.	Prairie Island-2	530	NSP	W	Fluor	87.30
3.	Callaway	1171	UEC	W	Bechtel	85.53
4.	San Onofre-3	1080	SCE	C-E	Bechtel	84.97
5.	Oconee-3	886	Duke	B&W	Bechtel*	84.60
6.	Three Mile Island-1	819	GPUN	B&W	Gilbert	84.50
7.	Farley-1	829	SNC	W	Bechtel*	84.27
8.	Point Beach-2	497	Wepco	W	Bechtel	83.86
9.	Vermont Yankee	504	VYAPC	GE	Ebasco	83.57
10.	St. Lucie-2	839	FP&L	C-E	Ebasco	83.53
11.	Oconee-1	886	Duke	B&W	Bechtel*	83.50
12.	Point Beach-1	497	Wepco	W	Bechtel	83.42
13.	North Anna-2	897	VPC	W	S&W	83.09
14.	Maine Yankee	870	MYAPC	C-E	S&W	83.00
15.	Diablo Canyon-1	1086	PG&E	W	(utility)	81.83
16.	Vogtle-1	1101	SNC	W	Bechtel*	81.58
17.	Diablo Canyon-2	1119	PG&E	W	(utility)	81.34
18.	Ginna	470	RG&E	W	Gilbert	81.10
19.	Waterford-3	1104	Entergy	C-E	Ebasco	80.16
20.	Farley-2	829	SNC	W	Bechtel*	80.05
21.	Kewaunee	535	WPS	W	Fluor	80.03
22.	Susquehanna-2	1080	PP&L	GE	Bechtel	80.00
23.	Oconee-2	886	Duke	B&W	Bechtel*	79.82
24.	St. Lucie-1	839	FP&L	C-E	Ebasco	79.80
25.	Hope Creek	1067	PSE&G	GE	Bechtel	79.59
26.	Susquehanna-1	1080	PP&L	GE	Bechtel	78.94
27.	Sequoyah-1	1148	TVA	W	(utility)	78.57
28.	ANO-2	912	Entergy	C-E	Bechtel	78.11
29.	LaSalle-1	1078	CECo	GE	S&L	78.11
30.	Wolf Creek	1170	WCNOC	W	B&SL	76.54
31.	Hatch-2	784	SNC	GE	Bechtel	75.68
32.	Harris	860	CP&L	W	Ebasco	75.65
33.	LaSalle-2	1078	CECo	GE	S&L	75.61
34.	McGuire-2	1180	Duke	W	(utility)	75.45
35.	Byron-1	1120	CECo	W	S&L	75.20
36.	Monticello	545	NSP	GE	Bechtel	75.04
37.	Hatch-1	776	SNC	GE	Bechtel*	74.80
38.	Sequoyah-2	1148	TVA	W	(utility)	74.75
39.	Quad Cities-2	789	CECo	GE	S&L	74.26
40.	Grand Gulf	1190	Entergy	GE	Bechtel	74.15
41.	Arnold	538	IEL&P	GE	Bechtel	73.25
42.	Davis-Besse	906	Centerior	B&W	Bechtel	72.77
43.	North Anna-1	897	VPC	W	S&W	72.60
44.	Cooper	778	NPPD	GE	B&R	72.50
45.	Fort Calhoun	478	OPPD	C-E	G&H	72.34
46.	Salem-2	1115	PSE&G	W	(utility)	71.30
47.	Summer	885	SCE&G	W	Gilbert	71.28
48.	Beaver Valley-2	833	Duquesne	W	S&W	70.90
49.	Byron-2	1120	CECo	W	S&L	70.83
50.	Catawba-1	1145	Duke	W	(utility)	70.73
51.	Cook-1	1020	I&MP	W	(utility)	70.50
52.	Big Rock Point	72	Consumers	GE	Bechtel	70.41
53.	Surry-1	788	VPC	W	S&W	70.18
54.	River Bend	936	GSU	GE	S&W	69.77
55.	San Onofre-2	1070	SCE	C-E	Bechtel	68.60
56.	Limerick-1	1055	PECo	GE	Bechtel	[illegible]
57.	Indian Point-3	965	NYPA	W	UE&C	68.22
58.	Cook-2	1090	I&MP	W	(utility)	68.07
59.	Braidwood-2	1120	CECo	W	S&L	67.99
60.	Yankee	175	YAEC	W	S&W	67.86
61.	Catawba-2	1145	Duke	W	(utility)	67.19
62.	Perry-1	1205	Centerior	GE	Gilbert	66.40
63.	Millstone-1	660	NU	GE	Ebasco	66.33
64.	FitzPatrick	816	NYPA	GE	S&W	65.91
65.	Fermi-2	1080	Detroit	GE	(utility)	64.41
66.	Salem-1	1115	PSE&G	W	(utility)	64.41
67.	Quad Cities-1	789	CECo	GE	S&L	[illegible]
68.	ANO-1	850	Entergy	B&W	Bechtel	63.84
69.	McGuire-1	1180	Duke	W	(utility)	[illegible]
70.	Beaver Valley-1	835	Duquesne	W	S&W	63.35
71.	Millstone-2	870	NU	C-E	[illegible]	63.03
72.	Dresden-2	794	CECo	GE	S&L	61.47
73.	Braidwood-1	1120	CECo	W	S&L	60.74
74.	Millstone-3	1154	NU	W	S&W	59.80
75.	Brunswick-1	821	CP&L	GE	UE&C	59.76
76.	South Texas-1	1251	HL&P	W	Bechtel	59.29
77.	Robinson-2	700	CP&L	W	Ebasco	59.14
78.	Crystal River-3	825	FPC	B&W	Gilbert	57.79
79.	Palo Verde-2	1270	APS	C-E	Bechtel	57.33
80.	Zion-2	1040	CECo	W	S&L	56.61
81.	Dresden-3	794	CECo	GE	S&L	56.54
82.	Oyster Creek	620	GPUN	GE	B&R/GE	56.47
83.	Peach Bottom-2	1065	PECo	GE	Bechtel	55.83
84.	WNP-2	1100	WPPSS	GE	B&R	55.66
85.	Palo Verde-3	1270	APS	C-E	Bechtel	55.30
86.	Brunswick-2	821	CP&L	GE	UE&C	55.04
87.	Indian Point-2	956	ConEd	W	UE&C	54.77
88.	Pilgrim	670	Boston	GE	Bechtel	54.47
89.	Palisades	805	Consumers	C-E	Bechtel	54.46
90.	Nine Mile Point-2	1077	Niagara	GE	S&W	52.85
91.	Surry-2	788	VPC	W	S&W	51.73
92.	Haddam Neck	582	NU	W	S&W	51.09
93.	Clinton	930	IPC	GE	S&L	50.95
94.	Zion-1	1040	CECo	W	S&L	50.15
95.	Palo Verde-1	1270	APS	C-E	Bechtel	47.42
96.	Peach Bottom-3	1065	PECo	GE	Bechtel	45.84
97.	Turkey Point-3	666	FP&L	W	Bechtel	45.37
98.	Trojan	1130	Portland	W	Bechtel	44.60
99.	San Onofre-1	436	SCE	W	Bechtel	41.34
100.	Turkey Point-4	666	FP&L	W	Bechtel	39.91
101.	Calvert Cliffs-1	845	BG&E	C-E	Bechtel	34.73
102.	Nine Mile Point-1	620	Niagara	GE	(utility)	31.21
103.	Calvert Cliffs-2	845	BG&E	C-E	Bechtel	22.09
104.	Browns Ferry-2	1065	TVA	GE	(utility)	13.43
105.	Browns Ferry-1	1065	TVA	GE	(utility)	0.00
106.	Browns Ferry-3	1065	TVA	GE	(utility)	0.00

NOTE: The power ratings shown are effective as of the end of 1991. If the rating changed in the previous three years, the capacity factor is calculated with an appropriate weighting factor. Some of the capacity factor figures above are given as equal to others exactly, but the only tie is for last place, because neither Browns Ferry-1 nor Browns Ferry-3 generated any electricity during 1989–91. Fermi-2, at 64.41331, is listed ahead of Salem-1, at 64.41330.

*Architect-engineering responsibility is considered to be shared by Bechtel and the utility.

TABLE I
1991–93 Single-Unit Rankings by DER Net Capacity Factor

Rank	Unit	Factor	MWe	Utility	Vendor	A-E
1.	Surry-1	87.05	781	VPC	W	S&W
2.	Vogtle-1	86.59	1151	Southern	W	Bechtel*
3.	Vogtle-2	86.47	1151	Southern	W	Bechtel*
4.	Three Mile Island-1	86.15	819	GPUN	B&W	Gilbert
5.	Callaway	85.92	1171	UEC	W	Bechtel
6.	Point Beach-2	85.66	497	Wepco	W	Bechtel
7.	Prairie Island-1	85.05	530	NSP	W	Fluor
8.	North Anna-2	84.81	907	VPC	W	S&W
9.	Ginna	84.66	470	RG&E	W	Gilbert
10.	Point Beach-1	84.41	497	Wepco	W	Bechtel
11.	Oconee-2	84.12	886	Duke	B&W	Bechtel*
12.	St. Lucie-1	84.12	830	FP&L	C-E	Ebasco
13.	Diablo Canyon-2	84.09	1119	PG&E	W	(utility)
14.	Diablo Canyon-1	83.44	1086	PG&E	W	(utility)
15.	Limerick-1	83.27	1055	PECO	GE	Bechtel
16.	Limerick-2	83.23	1055	PECO	GE	Bechtel
17.	Monticello	83.09	545	NSP	GE	Bechtel
18.	Vermont Yankee	82.95	514	VYAPC	GE	Ebasco
19.	Hope Creek	82.91	1067	PSE&G	GE	Bechtel
20.	Waterford-3	82.77	1104	Entergy	C-E	Ebasco
21.	ANO-1	82.71	850	Entergy	B&W	Bechtel
22.	Farley-1	82.36	829	Southern	W	Bechtel*
23.	Davis-Besse	82.15	906	Centerior	B&W	Bechtel
24.	Prairie Island-2	82.08	530	NSP	W	Fluor
25.	Catawba-2	82.04	1145	Duke	W	(utility)
26.	Susquehanna-2	81.66	1050	PP&L	GE	Bechtel
27.	Kewaunee	81.22	535	WPS	W	Fluor
28.	Oconee-1	80.72	886	Duke	B&W	Bechtel*
29.	St. Lucie-2	80.46	830	FP&L	C-E	Ebasco
30.	Summer	80.09	900	SCE&G	W	Gilbert
31.	Beaver Valley-2	80.07	836	Duquesne	W	S&W
32.	Farley-2	79.71	829	Southern	W	Bechtel*
33.	San Onofre-3	79.69	1080	SCE	C-E	Bechtel
34.	Harris	79.45	900	CP&L	W	Ebasco
35.	Byron-2	79.36	1120	CECo	W	S&L
36.	Oconee-3	79.07	886	Duke	B&W	Bechtel*
37.	ANO-2	79.06	912	Entergy	C-E	Bechtel
38.	San Onofre-2	78.88	1070	SCE	C-E	Bechtel
39.	Seabrook	78.53	1148	NU	W	UE&C
40.	Cook-1	78.47	1020	I&MP	W	(utility)
41.	Crystal River-3	77.89	825	FPC	B&W	Gilbert
42.	Hatch-1	77.46	776	Southern	GE	Bechtel
43.	Byron-1	76.89	1120	CECo	W	S&L
44.	Braidwood-2	76.85	1120	CECo	W	S&L
45.	Grand Gulf	76.63	1250	Entergy	GE	Bechtel
46.	Maine Yankee	76.45	870	MYAPC	C-E	S&W
47.	Arnold	76.42	538	IEL&P	GE	Bechtel
48.	Calvert Cliffs-1	76.10	845	BG&E	C-E	Bechtel
49.	Palo Verde-3	75.73	1270	APS	C-E	Bechtel
50.	Fermi-2	75.28	1116	Detroit	GE	(utility)
51.	McGuire-2	74.43	1180	Duke	W	(utility)
52.	Haddam Neck	73.97	582	NU	W	S&W
53.	Susquehanna-1	73.80	1050	PP&L	GE	Bechtel
54.	Pilgrim	73.59	655	Boston	GE	Bechtel
55.	Wolf Creek	73.29	1170	WCNOC	W	Bechtel
56.	LaSalle-1	72.22	1078	CECo	GE	S&L
57.	Surry-2	72.14	781	VPC	W	S&W
58.	Cooper	72.05	778	NPPD	GE	B&R
59.	LaSalle-2	71.72	1078	CECo	GE	S&L
60.	Palo Verde-1	71.66	1270	APS	C-E	Bechtel
61.	Oyster Creek	71.00	650	GPUN	GE	B&R/GE
62.	Hatch-2	70.85	784	Southern	GE	Bechtel*
63.	Robinson-2	70.80	700	CP&L	W	Ebasco
64.	Fort Calhoun	70.69	478	OPPD	C-E	G&H
65.	Braidwood-1	70.67	1120	CECo	W	S&L
66.	Catawba-1	70.65	1145	Duke	W	(utility)
67.	Palo Verde-2	70.33	1270	APS	C-E	Bechtel
68.	North Anna-1	69.91	907	VPC	W	S&W
69.	Clinton	68.71	933	IPC	GE	S&L
70.	Calvert Cliffs-2	68.39	845	BG&E	C-E	Bechtel
71.	Nine Mile Point-1	68.30	613	NiMo	GE	(utility)
72.	Indian Point-2	68.14	956	ConEd	W	UE&C
73.	Nine Mile Point-2	66.87	1062	NiMo	GE	S&W
74.	Peach Bottom-2	66.39	1065	PECO	GE	Bechtel
75.	Peach Bottom-3	65.81	1065	PECO	GE	Bechtel
76.	Beaver Valley-1	65.36	835	Duquesne	W	S&W
77.	Comanche Peak-1	64.33	1150	TU	W	G&H
78.	Perry-1	64.23	1191	Centerior	GE	Gilbert
79.	Browns Ferry-2	63.99	1065	TVA	GE	(utility)
80.	McGuire-1	63.94	1180	Duke	W	(utility)
81.	Big Rock Point	62.79	72	Consumers	GE	Bechtel
82.	Palisades	62.74	805	Consumers	C-E	Bechtel
83.	Sequoyah-2	61.77	1148	TVA	W	(utility)
84.	Quad Cities-1	61.40	789	CECo	GE	S&L
85.	Millstone-1	61.28	660	NU	GE	Ebasco
86.	Salem-1	61.27	1115	PSE&G	W	(utility)
87.	Salem-2	61.10	1115	PSE&G	W	(utility)
88.	Cook-2	59.75	1090	I&MP	W	(utility)
89.	River Bend	59.74	936	GSU	GE	S&W
90.	Quad Cities-2	59.33	789	CECo	GE	S&L
91.	WNP-2	58.60	1120	WPPSS	GE	B&R
92.	Zion-2	57.72	1040	CECo	W	S&L
93.	Turkey Point-3	57.00	693	FP&L	W	Bechtel
94.	Millstone-2	56.57	870	NU	C-E	Bechtel
95.	Zion-1	56.27	1040	CECo	W	S&L
96.	Sequoyah-1	55.86	1148	TVA	W	(utility)
97.	Turkey Point-4	55.85	693	FP&L	W	Bechtel
98.	South Texas-2	55.46	1251	HL&P	W	Bechtel
99.	Millstone-3	53.36	1154	NU	W	S&L
100.	Indian Point-3	52.21	965	NYPA	W	UE&C
101.	Dresden-3	50.74	794	CECo	GE	S&L
102.	Dresden-2	48.86	794	CECo	GE	S&L
103.	South Texas-1	46.99	1251	HL&P	W	Bechtel
104.	Brunswick-2	41.10	821	CP&L	GE	UE&C
105.	FitzPatrick	37.85	816	NYPA	GE	S&W
106.	Brunswick-1	27.78	821	CP&L	GE	UE&C
107.	Browns Ferry-1	0.00	1065	TVA	GE	(utility)
107.	Browns Ferry-3	0.00	1065	TVA	GE	(utility)

The figures above, and elsewhere in this article, are rounded off for convenience. The only actual tie is for 107th place. Oconee-2 (84.12143) is indeed ahead of St. Lucie-1 (84.12126). Some plants' power ratings changed during the three-year period; the figures shown here are the ratings at the end of 1993, but the factors were computed with weighted averages on plants for which ratings changed.

*Architect-engineering responsibility is considered to be shared by Bechtel and the utility.

TABLE I
1993–95 Single-Unit Rankings by DER Net Capacity Factor

Rank	Unit	Factor	MWe	Utility	Vendor	A-E
1.	Prairie Island-1	90.55	530	NSP	W	Fluor
2.	Vogtle-1	89.96	1169	Southern	W	Bechtel*
3.	Limerick-1	89.27	1055	PECO	GE	Bechtel
4.	Vogtle-2	89.16	1169	Southern	W	Bechtel*
5.	Crystal River-3	88.81	825	FPC	B&W	Gilbert
6.	Prairie Island-2	88.07	530	NSP	W	Fluor
7.	Point Beach-1	88.05	497	Wepco	W	Bechtel
8.	Three Mile Island-1	88.00	819	GPUN	B&W	Gilbert
9.	Monticello	87.80	545	NSP	GE	Bechtel
10.	Turkey Point-3	86.76	693	FP&L	W	Bechtel
11.	Catawba-1	86.67	1145	Duke	W	(utility)
12.	Callaway	86.60	1171	UEC	W	Bechtel
13.	Limerick-2	86.57	1115	PECO	GE	Bechtel
14.	ANO-1	86.39	850	Entergy	B&W	Bechtel
15.	Wolf Creek	86.16	1170	WCNOC	W	Bechtel
16.	Peach Bottom-2	86.15	1119	PECO	GE	Bechtel
17.	Byron-2	85.99	1120	ComEd	W	S&L
18.	Calvert Cliffs-1	85.81	845	BG&E	C-E	Bechtel
19.	Farley-1	85.71	829	Southern	W	Bechtel*
20.	Waterford-3	85.60	1104	Entergy	C-E	Ebasco
21.	North Anna-1	85.28	907	VPC	W	S&W
22.	Ginna	85.11	470	RG&E	W	Gilbert
23.	Vermont Yankee	85.04	522	VYAPC	GE	Ebasco
24.	Davis-Besse	84.58	906	Centerior	B&W	Bechtel
25.	Turkey Point-4	84.54	693	FP&L	W	Bechtel
26.	Fort Calhoun	84.27	478	OPPD	C-E	G&H
27.	Nine Mile Point-1	84.27	613	NiMo	GE	(utility)
28.	Point Beach-2	84.05	497	Wepco	W	Bechtel
29.	Oconee-3	83.88	886	Duke	B&W	Bechtel*
30.	San Onofre-3	83.83	1080	SCE	C-E	Bechtel
31.	Kewaunee	83.58	535	WPS	W	Fluor
32.	Diablo Canyon-1	83.55	1086	PG&E	W	(utility)
33.	San Onofre-2	83.34	1070	SCE	C-E	Bechtel
34.	Diablo Canyon-2	83.33	1119	PG&E	W	(utility)
35.	Beaver Valley-2	83.16	836	Duquesne	W	S&W
36.	Oconee-2	83.13	886	Duke	B&W	Bechtel*
37.	Hatch-1	83.00	776	Southern	GE	Bechtel
38.	North Anna-2	82.85	907	VPC	W	S&W
39.	Harris	82.66	900	CP&L	W	Ebasco
40.	Susquehanna-2	82.61	1100	PP&L	GE	Bechtel
41.	ANO-2	82.41	912	Entergy	C-E	Bechtel
42.	Hope Creek	82.08	1067	PSE&G	GE	Bechtel
43.	Oconee-1	81.45	886	Duke	B&W	Bechtel*
44.	Surry-1	81.41	788	VPC	W	S&W
45.	Comanche Peak-1	80.49	1150	TU	W	G&H
46.	Nine Mile Point-2	80.48	1143	NiMo	GE	S&W
47.	Farley-2	80.21	829	Southern	W	Bechtel*
48.	Braidwood-2	79.91	1120	ComEd	W	S&L
49.	Browns Ferry-2	79.74	1065	TVA	GE	(utility)
50.	Peach Bottom-3	79.56	1119	PECO	GE	Bechtel
51.	McGuire-2	79.17	1180	Duke	W	(utility)
52.	Clinton	79.12	933	IPC	GE	S&L
53.	Catawba-2	79.04	1145	Duke	W	(utility)
54.	Oyster Creek	78.95	650	GPUN	GE	B&R/GE
55.	Surry-2	78.81	788	VPC	W	S&W
56.	Millstone-3	78.75	1154	NU	W	S&L
57.	Calvert Cliffs-2	78.63	845	BG&E	C-E	Bechtel
58.	St. Lucie-1	78.48	830	FP&L	C-E	Ebasco
59.	Arnold	78.37	538	IEL&P	GE	Bechtel
60.	Seabrook	78.33	1148	NU	W	UE&C
61.	Palo Verde-1	77.77	1249	APS	C-E	Bechtel
62.	Grand Gulf	77.72	1250	Entergy	GE	Bechtel
63.	Palo Verde-3	77.07	1253	APS	C-E	Bechtel
64.	Braidwood-1	77.05	1120	ComEd	W	S&L
65.	Summer	76.54	900	SCE&G	W	Gilbert
66.	Robinson-2	76.04	700	CP&L	W	Ebasco
67.	Susquehanna-1	75.40	1100	PP&L	GE	Bechtel
68.	Millstone-1	74.47	660	NU	GE	Ebasco
69.	Hatch-2	74.37	784	Southern	GE	Bechtel*
70.	Cook-1	74.30	1020	IMP	W	(utility)
71.	Byron-1	74.22	1120	ComEd	W	S&L
72.	Pilgrim	73.49	655	Boston	GE	Bechtel
73.	River Bend	73.48	936	GSU	GE	S&W
74.	Haddam Neck	73.16	582	NU	W	S&W
75.	LaSalle-1	72.33	1078	ComEd	GE	S&L
76.	St. Lucie-2	71.51	830	FP&L	C-E	Ebasco
77.	Big Rock Point	71.49	72	Consumers	GE	Bechtel
78.	LaSalle-2	71.44	1078	ComEd	GE	S&L
79.	Indian Point-2	71.16	986	ConEd	W	UE&C
80.	WNP-2	70.01	1153	WPPSS	GE	B&R
81.	Beaver Valley-1	69.73	835	Duquesne	W	S&W
82.	Brunswick-2	69.53	821	CP&L	GE	UE&C
83.	Cook-2	68.73	1090	IMP	W	(utility)
84.	McGuire-1	68.53	1180	Duke	W	(utility)
85.	FitzPatrick	67.84	816	NYPA	GE	S&W
86.	Zion-1	64.53	1040	ComEd	W	S&L
87.	Zion-2	63.54	1040	ComEd	W	S&L
88.	Palo Verde-2	62.58	1249	APS	C-E	Bechtel
89.	Palisades	61.05	805	Consumers	C-E	Bechtel
90.	Quad Cities-1	60.76	789	ComEd	GE	S&L
91.	Perry-1	56.48	1191	Centerior	GE	Gilbert
92.	Sequoyah-2	55.64	1148	TVA	W	(utility)
93.	South Texas-1	55.42	1251	HL&P	W	Bechtel
94.	Millstone-2	55.41	870	NU	C-E	Bechtel
95.	Maine Yankee	54.98	870	MYAPC	C-E	S&W
96.	Brunswick-1	54.36	821	CP&L	GE	UE&C
97.	South Texas-2	50.51	1251	HL&P	W	Bechtel
98.	Cooper	49.24	778	NPPD	GE	B&R
99.	Salem-1	48.23	1115	PSE&G	W	(utility)
100.	Dresden-3	48.20	794	ComEd	GE	S&L
101.	Sequoyah-1	46.94	1148	TVA	W	(utility)
102.	Quad Cities-2	46.41	789	ComEd	GE	S&L
103.	Fermi-2	45.73	1116	Detroit	GE	(utility)
104.	Salem-2	44.89	1115	PSE&G	W	(utility)
105.	Dresden-2	43.07	794	ComEd	GE	S&L
106.	Indian Point-3	10.50	965	NYPA	W	UE&C
107.	Browns Ferry-1	2.73	1065	TVA	GE	(utility)
108.	Browns Ferry-3	0.00	1065	TVA	GE	(utility)

These figures, and others in this article, are rounded off. There are no actual ties: Fort Calhoun, in 26th place, has a factor of 84.274923, edging out Nine Mile Point-1's 84.272138. Some units' power ratings changed during the three-year period; the ratings shown here are those in effect at the end of 1995, but the factors were computed with weighted averages in cases where ratings changed.

* Architect-engineering responsibility is considered to be shared by Bechtel and the utility.

EXHIBITS TO THE TESTIMONY OF
PERCY M. BEARD, JR.

EXHIBIT NO. ___ (PMB-2)

TABLE II

CAPACITY FACTOR CHANGE 1993-95 VS. 1990-92

TABLE II
Capacity Factor Change, 1993-95 vs. 1990-92

Rank	Unit	Factor Change, percentage points
1.	Turkey Point-3	+42.35
2.	Calvert Cliffs-1	+36.66
3.	Browns Ferry-2	+36.58
4.	Nine Mile Point-1	+35.33
5.	Calvert Cliffs-2	+32.62
6.	Turkey Point-4	+30.68
7.	FitzPatrick	+30.67
8.	Brunswick-2	+28.09
9.	Nine Mile Point-2	+25.15
10.	Peach Bottom-2	+23.92
11.	Millstone-3	+20.66
12.	Crystal River-3	+20.15
13.	Clinton	+19.71
14.	Fort Calhoun	+19.03
15.	Cook-2	+18.67
16.	Catawba-1	+18.38
17.	Zion-1	+17.67
18.	Limerick-1	+17.26
19.	Haddam Neck	+16.08
20.	WNP-2	+15.87
21.	Zion-2	+15.49
22.	Palo Verde-1	+14.46
23.	Millstone-1	+13.22
24.	Wolf Creek	+13.95
25.	ANO-1	+12.64
26.	River Bend	+12.38
27.	Byron-2	+12.09
28.	Davis-Besse	+10.49
29.	Oyster Creek	+10.05
30.	Robinson-2	+10.00
31.	Hatch-1	+9.85
32.	Prairie Island-1	+9.43
33.	North Anna-1	+8.92
34.	Peach Bottom-3	+8.80
35.	Big Rock Point	+8.72

Rank	Unit	Factor Change, percentage points
36.	Harris	[illegible]
37.	Vogtle-2	+7.30
38.	Braidwood-1	+7.30
39.	Beaver Valley-2	+7.23
40.	McGuire-1	[illegible]
41.	Braidwood-2	[illegible]
42.	Vogtle-1	[illegible]
43.	San Onofre-3	[illegible]
44.	McGuire-2	[illegible]
45.	Point Beach-1	[illegible]
46.	Prairie Island-2	[illegible]
47.	Brunswick-1	[illegible]
48.	Indian Point-2	[illegible]
49.	Oconee-1	[illegible]
50.	Three Mile Island-1	[illegible]
51.	Waterford-3	[illegible]
52.	[illegible]	[illegible]
53.	ANO-2	[illegible]
54.	[illegible]	[illegible]
55.	Farley-1	[illegible]
56.	Millstone-2	[illegible]
57.	Browns Ferry-3	[illegible]
58.	[illegible]	[illegible]
59.	Grand Gulf	[illegible]
60.	San Onofre-2	[illegible]
61.	[illegible]	[illegible]
62.	[illegible]	[illegible]
63.	Hope Creek	[illegible]
64.	Pilgrim	[illegible]
65.	Surry-1	[illegible]
66.	Diablo Canyon-1	[illegible]
67.	Susquehanna-2	[illegible]
68.	Oconee-3	[illegible]
69.	Palisades	+0.85
70.	Ginna	+0.84

Rank	Unit	Factor Change, percentage points
71.	Palo Verde-3	+0.62
72.	Farley-2	+0.43
73.	Surry-2	+0.41
74.	Vermont Yankee	+0.28
75.	Monticello	+0.22
76.	Diablo Canyon-2	+0.02
77.	Browns Ferry-1	0.00
78.	North Anna-2	-0.92
79.	Oconee-2	-1.15
80.	Point Beach-2	-1.22
81.	Byron-1	-1.23
82.	St. Lucie-1	-1.34
83.	LaSalle-2	-1.48
84.	Quad Cities-1	-2.05
85.	Susquehanna-1	-2.99
86.	Dresden-3	-3.35
87.	Summer	-3.56
88.	Hatch-2	-3.89
89.	Beaver Valley-1	-3.89
90.	LaSalle-1	-4.96
91.	South Texas-1	-6.78
92.	Dresden-2	-10.77
93.	Palo Verde-2	-11.09
94.	St. Lucie-2	-11.73
95.	Salem-1	-13.35
96.	Salem-2	-15.75
97.	Perry-1	-16.09
98.	Maine Yankee	-18.45
99.	Quad Cities-2	-18.89
100.	South Texas-2	-22.41
101.	Sequoyah-2	-23.07
102.	Fermi-2	-25.94
103.	Sequoyah-1	-27.41
104.	Cooper	-29.64
105.	Indian Point-3	-86.84

EXHIBITS TO THE TESTIMONY OF
PERCY M. BEARD, JR.

EXHIBIT NO. ___ (PMB-3)
IMPROVED TECHNICAL SPECIFICATION OF CR-3'S
LICENSE, SECTIONS 3.0.4, 3.5.2, 3.7.5 AND 3.8.1

3.0 LIMITING CONDITION FOR OPERATION (LCO) APPLICABILITY

LCO 3.0.1 LCOs shall be met during the MODES or other specified conditions in the Applicability, except as provided in LCO 3.0.2.

LCO 3.0.2 Upon discovery of a failure to meet an LCO, the Required Actions of the associated Conditions shall be met, except as provided in LCO 3.0.5 and 3.0.6.

If the LCO is met or is no longer applicable prior to expiration of the specified Completion Time(s), completion of the Required Action(s) is not required, unless otherwise stated.

LCO 3.0.3 When an LCO is not met, except as provided in the associated ACTIONS, and an associated ACTION is not met or provided, the unit shall be placed in a MODE or other specified condition in which the Specification is not applicable. Action shall be initiated within 1 hour to place the unit, as applicable, in:

a. MODE 3 within 7 hours;

b. MODE 4 within 13 hours; and

c. MODE 5 within 37 hours.

Exceptions to this Specification are stated in the individual Specifications.

Where corrective measures are completed that permit operation in accordance with the LCO or ACTIONS, completion of the actions required by LCO 3.0.3 is not required.

LCO 3.0.3 is only applicable in MODES 1, 2, 3, and 4.

LCO 3.0.4 When an LCO is not met, entry into a MODE or other specified condition in the Applicability shall not be made except when the associated ACTIONS to be entered permit continued

(continued)

3.0 LCO APPLICABILITY

LCO 3.0.4 (continued)

operation in the MODE or other specified condition in the Applicability for an unlimited period of time. This Specification shall not prevent changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS.

Exceptions to this Specification are stated in the individual Specifications. These exceptions allow entry into MODES or other specified conditions in the Applicability when the associated ACTIONS to be entered allow unit operation in the MODE or other specified condition in the Applicability only for a limited period of time.

LCO 3.0.5

Equipment removed from service or declared inoperable to comply with ACTIONS may be returned to service under administrative control solely to perform testing required to demonstrate its OPERABILITY, the OPERABILITY of other equipment, or variables to be within limits. This is an exception to LCO 3.0.2 for the system returned to service under administrative control to perform the required testing.

LCO 3.0.6

When a supported system LCO is not met solely due to a support system LCO not being met, the Conditions and Required Actions associated with this supported system are not required to be entered. Only the support system Specification ACTIONS are required to be entered. This is an exception to LCO 3.0.2 for the supported system. In this event, additional evaluations and limitations may be required in accordance with Specification 5.6.2.16, "Safety Function Determination Program." If a loss of safety function is determined to exist by this program, the appropriate Conditions and Required Actions of the Specification in which the loss of safety function exists are required to be entered.

(continued)

3.5 EMERGENCY CORE COOLING SYSTEMS (E⁚CS)

3.5.2 ECCS—Operating

LCO 3.5.2 Two ECCS trains shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more trains inoperable. AND At least 100% of the ECCS flow equivalent to a single OPERABLE ECCS train available.	A.1 Restor train(s) to OPERABLE status.	72 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 4.	6 hours 12 hours

3.7 PLANT SYSTEMS

3.7.5 Emergency Feedwater (EFW) System

LCO 3.7.5 Two EFW trains shall be OPERABLE.

---------------------------NOTE---------------------------
Only one EFW train, which includes a motor driven pump, is required to be OPERABLE in MODE 3 with steam generator pressure < 200 psig.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One steam supply to the turbine driven EFW pump inoperable.	A.1	Restore steam supply to OPERABLE status.	7 days <u>AND</u> 10 days from discovery of failure to meet the LCO
B. One EFW train inoperable for reasons other than Condition A.	B.1	Restore EFW train to OPERABLE status.	72 hours <u>AND</u> 10 days from discovery of failure to meet the LCO

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. Required Action and associated Completion Time of Condition A or B not met.	C.1	Be in MODE 3.	6 hours
	AND		
	C.2	Be in MODE 4.	12 hours
D. Two EFW trains inoperable.	D.1	Initiate action to restore one EFW train to OPERABLE status.	Immediately

3.8 ELECTRICAL POWER SYSTEMS

3.8.1 AC Sources—Operating

LCO 3.8.1 The following AC electrical power sources shall be OPERABLE:

a. Two qualified circuits between the offsite transmission network and the onsite Class 1E AC Electrical Power Distribution System; and

b. Two emergency diesel generators (EDGs) each capable of supplying one train of the onsite Class 1E AC Electrical Power Distribution System.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One required offsite circuit inoperable.	A.1	Perform SR 3.8.1.1 for OPERABLE required offsite circuit.	1 hour AND Once per 8 hours thereafter
	AND		
	A.2	Declare required feature(s), with no offsite power available, inoperable when its redundant required feature(s) are inoperable.	24 hours from discovery of no offsite power to one train concurrent with inoperability of redundant required feature(s)
	AND		
			(continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. (continued)	A.3	Restore required offsite circuit to OPERABLE status.	72 hours AND 6 days from discovery of failure to meet LCO
B. One EDG inoperable.	B.1	Perform SR 3.8.1.1 for OPERAPLE offsite circuit(s).	1 hour AND Once per 8 hours thereafter
	AND		
	B.2	Declare required feature(s), supported by the inoperable EDG, inoperable when its redundant required feature(s) are inoperable.	4 hours from discovery of Condition B concurrent with inoperability of redundant required feature(s)
	AND		
	B.3.1	Determine OPERABLE EDG is not inoperable due to common cause failure.	24 hours
	OR		
	B.3.2	Perform SR 3.8.1.2 for OPERABLE EDG.	24 hours
	AND		
			(continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. (continued)	B.4	Restore EDG to OPERABLE status.	72 hours AND 6 days from discovery of failure to meet LCO
C. Two required offsite circuits inoperable.	C.1	Declare required feature(s) inoperable when its redundant required feature(s) are inoperable.	12 hours from discovery of Condition C concurrent with inoperability of redundant required feature(s)
	AND		
	C.2	Restore one required offsite circuit to OPERABLE status.	24 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. One required offsite circuit inoperable. AND One EDG inoperable.	------------NOTE------------ Enter applicable Conditions and Required Actions of LCO 3.8.9, "Distribution Systems—Operating," when Condition D is entered with no AC power source to one train. ----------------------------	
	D.1 Restore required offsite circuit to OPERABLE status.	12 hours
	OR	
	D.2 Restore EDG to OPERABLE status.	12 hours
E. Two EDGs inoperable.	E.1 Restore one EDG to OPERABLE status.	2 hours
F. Required Action and associated Completion Time of Condition A, B, C, D, or E not met.	F.1 Be in MODE 3.	12 hours
	AND	
	F.2 Be in MODE 5.	36 hours
G. Three or more required AC sources inoperable.	G.1 Enter LCO 3.0.3.	Immediately