DD-96-21

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION
OFFICE OF NUCLEAR REACTOR REGULATION

Frank J. Miraglia, Acting Director

In the Matter of	)	Docket Nos. 50-282, 50-306, and 72-10
NORTHERN STATES POWER COMPANY	)	
	)	(10 CFR 2.206)
(Prairie Island Nuclear Generating Plant, Units 1 and 2)	)	

DIRECTOR'S DECISION UNDER 10 CFR 2.206

I. INTRODUCTION

On June 5, 1995, the Nuclear Information and Resource Service and the Prairie Island Coalition Against Nuclear Storage (PICANS), now known as the Prairie Island Coalition (Petitioners), filed a Petition pursuant to Section 2.206 of Title 10 of the Code of Federal Regulations (10 CFR 2.206) requesting that the Nuclear Regulatory Commission (NRC) immediately suspend the operating licenses for Prairie Island Nuclear Generating Plant, Units 1 and 2, operated by Northern States Power Company (NSP or Licensee).

II. BACKGROUND

As a basis for their request, Petitioners presented four concerns which are summarized as follows: (1) The Prairie Island steam generators are suffering from tube degradation and may rupture unless proper testing is conducted and corrective actions are taken; (2) the Prairie Island reactor vessel head penetrations (VHPs) have stress-corrosion cracks which, if not found and corrected, may result in a catastrophic accident involving the reactor control rods; (3) plans for loading and unloading of dry cask storage units in an emergency, which include storage of irradiated components in the

fuel transfer canal, were not properly reviewed by NRC and do not satisfy NRC requirements; and, (4) the physical integrity of the Prairie Island crane used to lift the dry cask for Prairie Island's spent fuel requires physical testing and a safety analysis before future crane use following its handling of a heavy load for an extended period of time.

By a letter dated June 19, 1995, the Director of the Office of Nuclear Reactor Regulation (NRR) denied the Petitioners' request for immediate suspension of Prairie Island Units 1 and 2 licenses. The Director stated that the NRC staff's review of the Petition did not identify any safety issues warranting immediate action at the Prairie Island Nuclear Generating Plant. The Director also stated that the NRC staff would issue a Director's Decision addressing Petitioners' concerns within a reasonable time.

PICANS submitted a letter to the Chairman of the NRC dated June 21, 1995, which reiterated the concerns raised in the Petition and requested an evening public hearing within the vicinity of the Prairie Island facility. In a July 12, 1995, response, the NRC staff informed PICANS that an evening public hearing was not warranted at that time but that the request would again be considered at the time of issuance of the Director's Decision.[1] PICANS was further informed that the concerns raised in the June 21, 1995, letter would be addressed in the Director's Decision.

On February 19, 1996, Petitioners filed an addendum to their Petition raising further concerns regarding steam generator tube cracking and requested that Prairie Island, Unit 1 not be allowed to return to operation until certain inspections of steam generator tubes was conducted. In a March 1,

[1] For the reasons set out in the cover letter transmitting this Decision, the NRC staff has again determined that an evening public hearing is not warranted.

1996, response, the Director of NRR denied Petitioners' request for action concluding that no safety issues warranting immediate action had been identified.

On March 13, 1996, Petitioners submitted another addendum to the Petition raising additional concerns regarding steam generator tube cracking at Prairie Island and again requesting that the NRC require that Prairie Island, Units 1 and 2 be placed in mid-cycle outages for the purpose of steam generator tube inspections. Petitioners further requested an informal public hearing if the NRC determined that such testing need not be conducted.

In an August 21, 1996, response, the Director of NRR concluded that the addendum did not raise any safety issues warranting immediate action and that an informal public hearing was not warranted at that time.

Petitioners' concerns are addressed below. In addressing these issues, I have considered the concerns expressed by the Petitioners in the letters of June 21, 1995, February 19, 1996, and March 13, 1996.

III. DISCUSSION

A. Steam Generator Tube Degradation

The steam generators used at pressurized water reactors (PWRs) are large heat exchangers that use the heat from the primary reactor coolant to make steam in the secondary side to drive turbine generators which generate electricity. The primary reactor coolant flows through tubes contained within the steam generator. As the coolant passes through the steam generator tubes, it heats the water (i.e., secondary coolant) on the outside of the tubes and converts it to steam which drives the turbine generators. Steam generator tubes made from mill-annealed alloy 600 have exhibited a wide variety of

degradation mechanisms. Such material has been used in a number of steam generators at commercial nuclear facilities, including the steam generators at Prairie Island Units 1 and 2. These degradation mechanisms include mechanically induced (e.g., fretting wear, fatigue) and corrosion-induced (e.g., pitting, wastage, and cracking) degradation.

Steam generator tubes constitute a significant portion of the reactor coolant pressure boundary. As a result, the structural and leakage integrity of the boundary is important in ensuring the safe operation of the plant. A loss of steam generator tube integrity has potential safety implications, as noted by the Petitioners, namely, (1) the loss of primary coolant which is needed to cool the reactor core and (2) the potential for leakage of radioactive fission products into the secondary system where their isolation from the environment cannot be ensured. As a result of the importance of this portion of the reactor coolant pressure boundary, NRC has regulations on maintaining the structural and leakage integrity of the steam generator tubes. The overall regulatory approach to ensuring that steam generators can be safely operated consists of the following:

(1) Technical specification requirements to ensure that the likelihood of steam generator tube rupture events is minimized, including

(a) periodic inservice inspection of the tubing,

(b) plugging or repair of tubing found by inspection to be defective, and

(c) operational limits on primary-to-secondary leakage beyond which the plant must be shut down.

(2) Analysis of the design-basis steam generator tube rupture event to demonstrate that the radiological consequences meet 10 CFR Part 100 guidelines.

(3) Emergency operating procedures for ensuring that steam generator tube rupture events can be successfully mitigated.

Steam generator tube degradation can be detected through inservice inspection of the steam generator tubes. These inspections are generally required by a plant's Technical Specifications which specify the frequency and scope of the examinations along with the tube repair criteria. In the 1970s, wastage (i.e., general tube wall thinning) and denting (mechanical deformation of the tube) were the dominant degradation mechanisms being observed. These degradation mechanisms were readily detectable with the bobbin coil inspection method and were effectively controlled or eliminated, in part, by improvements in water chemistry. Stress-corrosion cracking (SCC) emerged in the mid-1980s as the dominant degradation mechanism affecting the steam generator tubes. SCC can be oriented axially along the tube or circumferentially around the tube, or can consist of a combination of axial and circumferentially oriented cracks. SCC that has an axial orientation can be detected with a bobbin coil probe. The capabilities of the bobbin coil inspection method at detecting axially oriented cracks depend on such factors as the location of the cracking, interfering signals, and the data analysis procedures.

Circumferentially oriented SCC emerged as a significant problem affecting the industry in the late 1980s. The bobbin coil probe is generally insensitive to such cracking (i.e., circumferential SCC); as a result, locations susceptible to circumferential SCC may need to be examined with techniques other than the bobbin coil. Historically, probes such as the motorized rotating pancake coil (MRPC) probe have been used to detect circumferential SCC at locations susceptible to such degradation. Recently,

more advanced probes (e.g., Zetec Plus-Point probe which contains a plus-point coil) have been used.

Deficiencies have been identified in certain utility inspection programs for detecting SCC, particularly circumferentially oriented SCC. Potential deficiencies include using inappropriate probes for inspecting locations susceptible to circumferential cracking, not optimizing the test methods to minimize electrical noise and signal interference, and not being alert to plant-unique circumstances (e.g., dents, copper deposits) which may necessitate special test procedures found unnecessary at other similarly designed steam generators or not included as part of a generic technique qualification.

Even though deficiencies in eddy-current inspection programs have been identified, operating experience indicates that steam generator tube integrity can be maintained at a plant when appropriate eddy-current data acquisition (including probe selection) and data analysis procedures are used, when the data analysts have been properly trained, when the intervals between inspections are determined based on the inspection findings, and when the operating environment of the steam generator tubes is controlled (e.g., water chemistry control). Adequate tube integrity has historically been achieved at plants through inservice inspections that involved the use of bobbin and MRPC probes. In some instances, operating intervals were shortened between inspections to ensure tube integrity.

Nevertheless, inspection findings at the Maine Yankee Atomic Power Station in 1994 and 1995 raised concerns that large circumferential cracks could develop over the course of an operating interval or that a large number of circumferential cracks may be present if a facility was not using

appropriate inspection techniques. As a result of these inspection findings, the NRC staff issued Generic Letter (GL) 95-03, "Circumferential Cracking of Steam Generator Tubes," on April 28, 1995, which (1) requested affected licensees to evaluate recent experience (including the Maine Yankee experience) concerning the detection and sizing of circumferential cracks and the potential applicability of this experience to their plants; (2) on the basis of the results of this evaluation, including past inspections and the results thereof, and other relevant factors, requested affected licensees to develop a safety assessment justifying continued operation until the next scheduled steam generator tube inspections were performed at their plants; and (3) requested that licensees develop and submit their plans for the next steam generator tube inspection as they pertain to the detection of circumferential cracks.

Subsequent to the issuance of GL 95-03, the Petitioners made the following requests with respect to steam generator tubes at Prairie Island Units 1 and 2: Request (a)-- "That all steam generator tubes in Prairie Island Unit 2 be given a full length inspection utilizing the more comprehensive and proactive battery of tests employed at Maine Yankee during NSP's 1995 outage. Petitioners specifically demand that the Zetec Plus Point Probe and any state of the art, eddy current probe for corrosive cracking be employed at Prairie Island 2 during Outage 17 scheduled to end June 15, 1995." Request (b)-- "That if the Zetec Plus Point Probe and any state of the art probe are not employed during the mid-June 1995 outage, then reactor Unit 2 be taken immediately off-line until such time these specific Zetec Plus Point Probe and any state of the art, eddy current probe for corrosion cracking are completed." Request (c)-- "That Prairie Island Unit 1 immediately be placed

into a mid-cycle outage to perform the NRC requested actions outlined in Generic Letter 95-03. In addition, all Unit 1 steam generator tubes be inspected through the use of the Zetec Plus Point Probe and any state of the art, eddy current probe for corrosion cracking."

NSP submitted its response to the generic letter for Prairie Island Units 1 and 2 by letter dated June 27, 1995. As discussed below, the information submitted provides no indication of an active circumferential crack mechanism at the Prairie Island units, nor does it suggest any significant concern regarding the potential for large, undetected circumferential cracks at these units.

The Prairie Island Unit 2 steam generators were last inspected in June 1995. This inspection included a 100-percent, full-length inspection with the bobbin probe. In addition, a 100-percent inspection was performed with a combined MRPC/Plus-Point probe from the hot-leg tube end to 3 inches above the tubesheet. Most row 1 and 2 U-bends were also inspected with the MRPC/Plus-Point coil. The bobbin probe is appropriate for performing the general-purpose, full-length inspection of the tubing because of its capability to detect flaw geometries exhibiting an axial component (e.g., corrosion thinning and wastage, mechanically induced wear, pitting, and axial cracks). The bobbin inspection was supplemented by inspections with a combined MRPC/Plus-Point probe to provide enhanced sensitivity to detecting cracks. These inspections encompassed the areas of axial crack activity with the bobbin coil probe and, in addition, the locations most vulnerable to circumferential cracking with the MRPC/Plus-Point coil.

NSP reports that the Prairie Island Unit 1 steam generators were last inspected in January 1996. This inspection included a 100-percent full-length

inspection with the bobbin probe, except for rows 1 and 2 U-bends. Rows 1 and 2 U-bends were examined with MRPC/Plus-Point. All hot-leg tubes were examined with rotating probe technology (including Plus-Point) from the tube end to 6 inches above the top of the tubesheet. All sleeves were examined full length with the Plus-Point rotating coil.

In addition, NSP's response to the generic letter addressed, in part, each of five locations at which circumferentially oriented degradation has historically occurred in Westinghouse steam generators. These locations are places where there is significant axial stress associated with variations in tube geometry and include (1) tube expansion transition areas, (2) dented top-of-tubesheet locations in partial roll-expanded tubes (described below), (3) dented tube-to-tube support plate intersections, (4) small-radius U-bends, and (5) sleeve joints. Significant axial stress would contribute to the development of circumferential cracking.

Regarding the first and second categories, the tubes at Prairie Island are roll expanded over only the lower portion of the tubesheet depth (i.e., partial roll expansion). NSP reports that the incidence of circumferential cracks at expansion transitions where the tubes have received a partial-depth expansion has been negligible industry-wide. For Prairie Island Unit 1, the 100-percent MRPC/Plus-Point inspection in the tubesheet regions in January 1996 did not find any circumferential indications in the in-service tubes. Similarly, for Prairie Island Unit 2, the MRPC/Plus-Point inspections in the tubesheet regions did not identify circumferential indications.

With regard to the third category, circumferential SCC at dented tube support plate intersections has only been reported at a limited number of plants. In addition, dented regions have exhibited both axial and

circumferential SCC with axial SCC typically being the more frequently observed degradation mechanism. Axial SCC at dented locations can be detected with the bobbin probe. Although NSP has not reported performing MRPC or Plus-Point examination at the support plates, it has examined 100 percent of these locations using a bobbin probe and has not reported any axial cracking. Not detecting any axial cracking gives confidence that widespread circumferential SCC is not occurring.

Regarding the fourth category, SCC in the small-radius (row 1 and some row 2) U-bends has been extensive in Westinghouse steam generators. This cracking has been predominantly axial, with only isolated instances of non-axial cracks. NSP reports that the small-radius U-bends are routinely inspected with the MRPC. In January 1996, the licensee inspected 100 percent of rows 1 and 2 U-bends on Prairie Island Unit 1 with the MRPC/Plus-Point and found no indications. The June 1995 inspections at Prairie Island Unit 2 with the MRPC/Plus-Point probe looked at the majority of small-radius U-bends, and found one axial and no circumferential indications.

Regarding the fifth category, during the January 1996 inspection in Unit 1, all in-service and new sleeves were examined full length with Plus-Point. Indications were found in the upper sleeve weld region of 61 ABB Combustion Engineering welded tubesheet sleeves. These indications were characterized as single or multiple circumferential indications or volumetric indications. All of these sleeved tubes with circumferential indications were removed from service by sample removal and/or plugging. The volumetric indications were evaluated and indications located within the pressure boundary were plugged. No sleeves are installed in Unit 2. Sleeves were

installed in Unit 1 to address forms of tube degradation (e.g., axial cracking and intergranular attack) other than circumferential cracking.

In response to the large number of indications identified in the upper sleeve welds of ABB Combustion Engineering welded tubesheet sleeves during the January 1996 Unit 1 outage, the NRC staff held discussions and meetings with the Licensee to determine the root cause of the indications. NSP pulled five sleeve/tube samples during the outage to perform metallurgical analysis on and determine the root cause of the indications. Four of the removed tubes contained circumferential indications and one contained a volumetric indication. NSP started up Unit 1 on March 3, 1996, and committed to perform a mid-cycle outage to perform additional inspections unless the results of the metallurgical analyses from the pulled sleeves indicated that additional inspections would not be warranted.

ABB Combustion Engineering performed the metallurgical examinations, with third-party review by the Electric Power Research Institute. The results showed that the sleeve weld indications were not service induced. Instead, they were original fabrication flaws that were the result of faulty cleaning of tube surfaces prior to welding. The examinations of the tube samples revealed the sizes of the flaws were such that the structural integrity of the welds was not compromised. None of the flaws showed any indication of having propagated in service. Since the indications were not service induced, the NRC staff agreed that a mid-cycle outage to perform further inspections was not necessary.

ABB Combustion Engineering is currently revising its topical report on sleeving to incorporate improved cleaning techniques prior to installation of sleeves, in order to prevent such flaws in the future. NSP plans to submit an

amendment to the NRC for review to adopt the revised ABB Combustion Engineering topical report prior to installation of CE sleeves.

After GL 95-03 was issued, additional information from inspections performed at Maine Yankee and the destructive examination of several tubes removed from Maine Yankee became available. This additional information appears in NRC Information Notice 95-40, "Supplemental Information Pertaining to Generic Letter 95-03, 'Circumferential Cracking of Steam Generator Tubes'." This information led to the conclusion that the tubes with the largest indications at Maine Yankee continued to exhibit adequate structural integrity at the time they were found. This was attributable, in part, to the crack morphology as discussed in the Information Notice. As a result, adequate tube structural integrity was ensured for the operating interval between inspections, even though the MRPC probe, rather than the Plus-Point probe, was used during the earlier inspections.

As mentioned above, the safe operation of the steam generators is ensured by performing inspections and repairing defective tubes, limiting the operational leakage through the steam generators, analyzing a design-basis steam generator tube rupture event to demonstrate acceptable radiological consequences, and having appropriate emergency operating procedures in place. As discussed above, the staff believes that the inspection probes used during the May 1994 and June 1995 outages at Prairie Island Units 1 and 2, respectively, were adequate to provide reasonable assurance of tube integrity. In addition, NRC requires an operational leak rate limit to provide reasonable assurance that, should a leak occur during service, it will be detected and the plant will be shut down in a timely manner before rupture occurs and with no undue risk to public health or safety.

Therefore, on the basis of (1) the fact that appropriate steam generator tube inspections have been performed, (2) monitoring of primary-to-secondary leakage is being conducted, and (3) the fact that appropriate emergency operating procedures are in place, the NRC staff has concluded that the Petitioners' request for the shutdown of Prairie Island Units 1 and 2 until full-length tube inspections are completed using the Zetec Plus-Point probe and any state-of-the-art eddy-current probe should be denied.

B. Vessel Head Penetration (VHP) Cracking

The Petitioners contend that the VHP's at Prairie Island Units 1 and 2 are likely to have stress-corrosion cracks which, if not found and corrected, may result in a catastrophic accident involving reactor control rods. The Petitioners also contend that VHPs in PWRs in France, Belgium, Switzerland, and Sweden are cracking and that French data indicate that the cracking mechanism will not necessarily produce a detectable leak prior to a break that would initiate a serious accident. The Petitioners further contend that failure of a VHP could cause the ejection of a control rod drive mechanism (CRDM), resulting in a loss of control of the reactor and/or a serious leak that could not be isolated and thereby could induce a loss-of-coolant accident. The Petitioners request immediate, full inspection of all VHPs in Units 1 and 2 for cracking using state-of-the-art eddy-current testing. The Petitioners also request that NRC immediately suspend the operating licenses of both units until the VHPs are inspected.

This same issue has been the subject of a recent Director's Decision under 10 CFR 2.206 issued by the Director of NRR. See All Pressurized Water Reactors, DD-95-2, 41 NRC 55(1995). There, the NRC staff concluded, after reviewing the information referred to by that Petitioner, that the likelihood

of the formation of circumferential cracks is small, the likelihood of forming small axial cracks is higher, and that leaks would develop before catastrophic failure of a VHP would occur. This would result in the deposition of boric acid crystals on the vessel head and surrounding area that would be detected during surveillance walkdowns. The Petitioners contend that this conclusion is not supportable as French data indicate that the cracking mechanism will not necessarily produce a detectable leak prior to a break that would initiate a serious accident.

The NRC staff's review of the French data does not support the Petitioners' contention that a crack would not be detected due to leakage prior to catastrophic failure. Topical reports submitted to and reviewed by the NRC staff indicate that cracks in the CRDM VHP's would need to grow well above the reactor vessel head before reaching a critical size that would lead to the catastrophic failure of a CRDM VHP. The portion of the crack above the head would leak well before the critical size is reached.

The circumferential crack at the French reactor was very small relative to the size flaw that would jeopardize structural integrity. Furthermore, the circumferential crack initiated from the exterior of the VHP which is more susceptible to circumferential cracking. This situation occurred after a small axial throughwall crack leaked. Thus, it is expected that leakage would be detected long before significant circumferential cracking could occur. Of the numerous VHP inspections in Europe, Japan, and the United States, no additional cases of circumferential cracking have been observed. The members of the Westinghouse, Babcock & Wilcox and Combustion Engineering Owners Groups through Nuclear Energy Institute submitted acceptance criteria for both axial and circumferential cracking to the NRC for review and approval. The

acceptance criteria were partially accepted by the NRC staff. The criteria for axial cracking were accepted as proposed. The criteria for circumferential cracking were rejected. Any circumferential cracks found must be reported to the NRC staff for disposition. If VHP cracking violated the above acceptance criteria, the NRC staff would review the Licensee's plan for monitoring or repair of the crack.

Finally, a foreign reactor developed extensive circumferential cracking in VHPs as a result of two major demineralizer resin ingress events in the early 1980s. The NRC staff issued a request for additional information to NSP on September 25, 1995, to determine if any similar resin ingress events had occurred at Prairie Island. The Licensee responded to the NRC staff on October 24, 1995, that there have been no resin ingress events at Prairie Island.

The NRC staff has closely monitored VHP cracking experience in the U.S. and abroad and has reviewed extensive evaluations of VHP cracking. The evaluations and operating experience indicate that it is highly unlikely that significant circumferential cracks could develop and that there is significant margin between the flaw sizes that would result in detectable leakage and the flaw sizes that would jeopardize structural integrity. Thus, the staff has concluded that VHP cracking is not a safety concern at this time. To assure that VHP cracking continues to be properly monitored and controlled, the NRC is in the process of preparing a Generic Letter requesting addressees to describe their program for ensuring the timely inspection of PWR CRDM VHPs and other VHPs. This letter was issued for public comment on August 1, 1996.

Accordingly, the requests made by the Petitioners for the shutdown of the Prairie Island units and inspection of the VHPs with enhanced inspection

techniques is denied. As explained above, the NRC staff has concluded that no substantial health and safety issues have been raised by the Petitioners.

C. Unloading of Dry Cask Storage Units

Spent fuel discharged from a reactor core is stored on site in a spent fuel pool prior to transfer to the U.S. Department of Energy (DOE) for final deposition. Typically, one-third of a reactor core is discharged every refueling outage (approximately every 18 months in the case of each of the Prairie Island units). The Licensee concluded several years ago that it would reach maximum capacity in its spent fuel pool in 1994, prior to availability of a DOE repository for storage of spent fuel. To support the need for continued storage of spent fuel at the reactor site, the Licensee applied to NRC for a license to store spent fuel in an onsite independent spent fuel storage installation (ISFSI). NRC issued Materials License No. SNM-2506 to NSP on October 19, 1993, for receipt and storage of spent fuel at the ISFSI on the site of the Prairie Island Nuclear Generating Plant. Materials License No. SNM-2506 allows NSP to use the TN-40-type casks for storage at its ISFSI. The TN-40, a metal cask system, is designed to store 40 PWR spent fuel assemblies in each cask. Dimensions of the cask (with protective cover) are 202 inches high with an outside diameter of 103.5 inches. A loaded TN-40 storage cask weighs 109.3 metric tons.

On April 28, 1995, a public meeting was held in Red Wing, Minnesota, to present NRC inspection findings related to dry cask storage activities at the Prairie Island plant. Questions were raised by members of the public as to how the Licensee would unload the spent fuel in a dry storage cask, if it became necessary, i.e., would there be enough empty fuel racks in the spent fuel pool to accommodate unloading of the cask.

In a letter to the NRC dated May 3, 1995, the Licensee submitted a plan for unloading the TN-40 cask in response to the questions raised at the April 28, 1995, meeting. In that letter, the Licensee stated that some of the fuel racks in the spent fuel pool contain nonfuel-bearing components, which could be relocated to a temporary location in the fuel transfer canal. Alternatively, it may be possible for the components to be stored temporarily in the TN-40 cask, should it become necessary to unload a cask. In the latter case, even though the TN-40 cask being returned to the spent fuel pool may no longer be qualified to hold spent fuel, it quite possibly could still safely hold irradiated nonfuel-bearing components.

The Petitioners raised issues concerning compliance with 10 CFR 50.59 and the need to make changes to Technical Specifications in order to use the fuel transfer canal for nonfuel-bearing components under the Licensee's plan. Petitioners also stated that 10 CFR 50.59 requires a safety analysis and amendment to the operating license with a public hearing whenever a change occurs in Technical Specifications for spent fuel pool and reactor transfer canal use. Petitioners further stated that a safety analysis is essential when a Technical Specification change occurs.

The need for a change to the Technical Specifications and the process to be followed under 10 CFR 50.59 are two separate, but related, issues. With regard to the Prairie Island Technical Specifications, the plan proposed by the Licensee in its letter of May 3, 1995, for dealing with the reed to unload a cask, would not involve a change to Technical Specifications because Technical Specifications do not address use of the fuel transfer canal nor do they address movement of nonfuel-bearing components within the spent fuel pool. Prairie Island's Technical Specification 3.8 specifies operating

limitations associated with fuel-handling operations and core alterations only. Further, the fuel transfer canal is not classified as a reactor safety system. The fuel transfer canal provides no protection for the reactor, nor does it mitigate the consequences of a postulated accident to the reactor. The fuel transfer canal is a component of the fuel storage and fuel handling systems, which is considered a plant auxiliary system rather than a reactor safety system. As use of the fuel transfer canal in the Licensee's plan does not involve a change to the Technical Specifications, an amendment for this reason would not be required and the opportunity to request a public hearing with regard to a Technical Specification change would, therefore, not arise.

With regard to Section 50.59 of Title 10 of the Code of Federal Regulations, that provision allows a Licensee to make changes to its facility and procedures as described in the Final Safety Analysis Report (FSAR) without prior approval from NRC, provided a change in Technical Specifications is not involved (which, as described above, is met in this instance) and an unreviewed safety question does not exist. Before moving the nonfuel-bearing components to temporary storage racks in its fuel transfer canal, NSP would need to determine if this use of the transfer canal changes the facility or procedures as described in the FSAR. If NSP determines that a change has been made to the facility or procedures as described in the FSAR, then a safety evaluation pursuant to 10 CFR 50.59 is required to be performed by the Licensee. If a Technical Specification change were needed (not the case as discussed above), or an unreviewed safety question existed, NRC review and approval would be required. Otherwise, the Licensee could make the modifications without prior NRC approval. Licensees submit a list a

modifications that were performed under 10 CFR 50.59 without NRC approval to NRC annually.

The Licensee did not fail to comply with the requirements of 10 CFR 50.59 by presenting a plan for retrieval of fuel from a cask, which included an option to place nonfuel-bearing components in the fuel transfer canal. At the time a cask unloading is deemed necessary, the Licensee can evaluate the specific modifications needed to implement the plan and determine whether 10 CFR 50.59 is applicable.

When applying for the license, NSP performed an accident analysis, in its Safety Analysis Report, as required by NRC regulations.[2] In its Safety Evaluation Report dated July 1993, the NRC staff reviewed the Licensee's accident analysis and determined that "Dose equivalent consequences, from a single cask, to any individual, from direct and indirect radiation and gaseous activity release after postulated accident events, are less than the 50 mSv (5 rem) limit established in 10 CFR 72.106(b)." Additionally, in its Environmental Assessment, dated July 28, 1992, the NRC staff assessed the accident dose at the Prairie Island site boundary as: "a small fraction ... of the criteria specified....", and found that: "These doses are also much less than the Protective Action Guides established by the Environmental Protection Agency (EPA) for individuals exposed to radiation as a result of accidents;..." Because it has been shown that the dose equivalent from a

[2] The Licensee analyzed accidents classified as Design Events III and IV, as described in ANSI/ANS 57.9, "Design Criteria for an Independent Spent Fuel Storage Installation (Dry Storage Type)." Design Event III consists of that set of infrequent events that could reasonably be expected to occur during the lifetime of the ISFSI. Design Event IV consists of the events that are postulated because their consequences may result in the maximum potential impact on the immediate environs. Included among the scenarios considered under Design Event IV was a loss of confinement barrier leading to an immediate release of radioactivity.

single cask to any individual from postulated accident events is not in excess of the levels required for taking protective actions to protect public health, the NRC staff considers that a time-urgent unloading of the TN-40 cask is not a likely event.

Even if such an unlikely accident occurred and the Licensee determines that corrective actions may need to be taken to maintain safe storage conditions, options are available. This may include returning the cask to the auxiliary building and/or the spent fuel pool for repairs. Once the cask is in the spent fuel pool, it does not necessarily have to be unloaded to maintain safe storage conditions. In addition, the Licensee may have other options available to cover this unlikely contingency including temporary storage of spent fuel in a spare storage cask or use of an existing certified transportation cask. The Licensee would have time to consider these, and other available options, in such an unlikely event.

Petitioners also raise an issue concerning the necessity to offload both the entire reactor core and a TN-40 cask simultaneously. NRC has no requirement for licensees to maintain the spent fuel capacity to offload the entire core at once. Prairie Island normally offloads only one-third of the core during refueling outages. If NSP determines the need to offload the entire core during a refueling outage, NSP can install temporary fuel racks in the cask laydown area in the spent fuel pool. Therefore, a cask could not be unloaded for the short time that temporary racks are installed in the cask laydown area. The staff does not view this as a problem for two reasons. First, the probability that a cask would require unloading at the same time a full-core offload is in process is extremely small. Second, in the event it became necessary to unload a cask, fuel could be placed back into the reactor

vessel and the temporary fuel storage racks could be removed. As discussed above, time-urgent unloading of a TN-40 cask is extremely unlikely. The cask could then be unloaded after the cask laydown area was cleared of the temporary fuel storage racks.

In addition to assuring that a TN-40 cask could be unloaded if necessary, the Licensee's plan also provides assurance with regard to spent fuel retrievability. Subpart F of 10 CFR Part 72 provides general design criteria for ISFSIs and monitored retrievable storage installations. Section 72.122 sets overall requirements and 10 CFR 72.122(l) provides for retrievability of the fuel and states: "Storage systems must be designed to allow ready retrieval of spent fuel or high-level radioactive waste for further processing or disposal." The NRC staff concluded in a May 5, 1995, letter to the Licensee that the ability to unload a TN-40 cask if necessary in accordance with the Licensee's plan would satisfy this fuel retrievability provision.

Finally, Petitioners state that the wrong NRC department reviewed and approved NSP's plan for retrievability of irradiated fuel. The Office of Nuclear Material Safety and Safeguards (NMSS) is responsible for licensing and regulating all issues under 10 CFR Part 72, including issues related to the design requirements for ISFSIs. Therefore, NMSS is the correct NRC office to review whether the licensee's plan met 10 CFR 72.122(l). As discussed above, the Licensee's plan does not involve a Technical Specification change. Accordingly, NRR review of such a change would not be required. If, upon implementing its plan, the Licensee determined that a safety evaluation pursuant to 50.59 was required, NRR review and approval would be required only if an unreviewed safety question existed.

With regard to the requests made by the Petitioners, there is no basis for suspending NSP's operating licenses for the Prairie Island units until a safety analysis is completed, reviewed, and approved by NRC, and until NSP's licenses are amended and public hearings have been held. If NSP plans to implement a specific plan to utilize the fuel-transfer canal which changes the facility or procedures as described in the FSAR, then an evaluation pursuant to 10 CFR 50.59 would be required at that time, which would not require prior NRC approval unless an unreviewed safety question exists or a change to Technical Specifications is required.

D. Auxiliary Building Crane

Petitioners contend that a recent incident at Prairie Island on May 13, 1995, involving the crane used to lift the dry cask for Prairie Island's ISFSI, requires physical testing and safety analysis before future crane use. The incident resulted in the crane holding the 123.75-ton cask above the surface of the reactor pool for 16 hours. The Petitioners assert that the incident could have caused metal fatigue within the crane's structure and the cables attached to the crane. Also, Petitioner Prairie Island Coalition asserts in its June 21, 1995, letter to the Chairman of the NRC that the crane, its cable, and its cable mechanisms were not designed to withstand holding nearly a maximum load for 16 hours.

The Prairie Island auxiliary building crane was upgraded in 1992 in accordance with the provisions of Topical Report EDR-1(P), "Ederer Nuclear Safety-Related Extra Safety and Monitoring (X-SAM) Cranes." The crane is designed and tested in accordance with the NRC staff's guidance as outlined in NUREG-0554, "Single-Failure-Proof Cranes for Nuclear Power Plants," and NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants."

The staff evaluated the design of the auxiliary building crane and the lifting device for the cask as part of its review of the dry cask ISFSI. This crane system is designed so that a single failure will not result in the loss of the capability of the system to safely retain the load (this design is known as single-failure proof). The crane is designed to handle a rated load of 125 tons and is capable of raising, lowering, and transporting occasional loads, for testing purposes, of 25-percent higher than the rated load without damage or distortion to any crane part. All parts of the crane that are subjected to dynamic strains, such as gears, shafts, drums, blocks, and other integral parts, have a safety factor of 5 (i.e., they are designed to lift 5 times the design rated load). The hook has a design safety factor of 10 and was subjected to a 200-percent overload test followed by magnetic particle inspection prior to initial operation. Protection against wire rope wear and fatigue damage are ensured by scheduled inspection and maintenance. The special lifting device used for cask movement is designed to support 6 times the weight of the fully loaded cask and was subjected to a 300-percent overload test by the manufacturer. The lifting device undergoes dimensional testing, visual inspection, and nondestructive testing every 12 months (plus or minus 25 percent).

A single-failure-proof crane, such as the crane at Prairie Island, that has become immobilized by failure of components while holding a load, is able to hold the load or set the load down while adjustments or repairs are made. Safety features and emergency devices permit manual operation to accomplish this task. Two separate magnetic brakes are provided as well as an emergency drum band brake. Each magnetic brake provides a braking force of at least 150 percent of rated load. The emergency drum brake assures that the load can be

safely lowered even if power is lost to the crane. Because of the large design margins and the ability to withstand a failure of any single component, the NRC staff does not postulate a load drop from a single-failure-proof crane.

After the incident on May 13, 1995, the Licensee temporarily removed the crane from service for testing. The Licensee and the crane vendor performed testing on the crane to analyze the event and assure the crane was operable. The Licensee's analysis of the May 13, 1995, incident found the problem to be an improperly calibrated load cell (a load cell is a device that measures the load being lifted by the crane and provides input to an overload-sensing device). It was determined that the actual load was less than what was being sensed by the overload-sensing device. The function of the overload-sensing device is to stop the operation of the crane when the load reaches a predetermined value. This prevents loading the crane beyond its rated load by maintaining loads within the design working limit, thereby maintaining safety and the physical integrity of the crane system.

Since the design-rated load of the crane was not exceeded during the incident, there is no reason to assume that the crane cannot continue to operate safely. Even if the rated load had been exceeded, an analysis would be needed to determine how much the rated load was exceeded and if that amount is significant. When cranes are built, manufacturers conduct proof tests at a load above rated load. The proof test for this crane was 25 percent higher than the 125-ton design-rated load for the main hoist (i.e., the proof test was 156.25 tons).

With regard to the Petitioners' comment about metal fatigue, metal fatigue is a condition that results from cyclic stress. Cyclic stress is

produced by repeated loading and unloading. The crane is designed to handle all loading and unloading cycles during the life of the plant, including construction and operating periods. A single static (constant) load such as the load in question, does not produce the cyclic stress that causes metal fatigue. The Petitioners' contention that it was never contemplated that the Prairie Island polar crane hold a load of 123.75 tons inches above the surface of the reactor pool for 16 hours is incorrect. The contemplated failure mechanism of a single-failure proof crane is to hold the load safely at any location until the load can be safely moved. Because of the large design margins, the length of time that a design-rated load (or a load less than design rated) is on the hook of a single-failure-proof crane is inconsequential.

With regard to cable and cable mechanisms (also known as the reeving system and lifting devices), the crane is provided with a balanced dual reeving system with each wire rope capable of supporting the maximum critical load (if a load being held by a crane can be a direct or indirect cause of release of radioactivity, the load is called a critical load). The hydraulic load equalizing system allows transfer of the load to the remaining rope, without overstressing it, in the event of a failure of one rope. Protection against wire rope wear and fatigue damage are ensured by scheduled inspection and maintenance.

In conclusion, NRC agrees with the Licensee in its determination that the cause of the incident was an incorrectly calibrated load cell. This cause was documented in NRC Inspection Report 95-006, issued June 27, 1995. NRC has determined that the Licensee met the design and testing requirements established in industry standards for the control of heavy loads such as a dry

storage cask, that the overload-sensing device worked as designed, and that no safety issue was involved in the Licensee's use of the auxiliary building crane and associated cask handling equipment to move the cask. Therefore, the Petitioners' requests for suspension of NSP's licenses for the Prairie Island units until physical testing and safety analyses can be performed on the crane are denied.

IV. CONCLUSION

Petitioners requested an immediate suspension of NSP's licenses for Prairie Island Units 1 and 2 until corrective actions of potentially hazardous conditions would be taken by NSP and NRC with regard to issues identified in the Petition. The institution of a proceeding in response to a request for action under 10 CFR 2.206 is appropriate only when substantial health and safety issues have been raised. See Consolidated Edison Co. of New York, (Indian Point, Units 1, 2, and 3), CLI-75-8, 2 NRC 173, 176 (1975), and Washington Public Power Supply System (WPPSS Nuclear Project No. 2), DD-84-7, 19 NRC 899, 923 (1984). I have applied this standard to determine if any action is warranted in response to the matters raised by the Petitioners. Each of the claims by the Petitioners has been reviewed. The available information is sufficient to conclude that no substantial safety issue has been raised regarding the operation of Prairie Island Units 1 and 2. Therefore, I conclude that, for the reasons discussed above, no adequate basis exists for granting Petitioners' requests for immediate suspension of NSP's licenses for Prairie Island Units 1 and 2.

A copy of this decision will be filed with the Secretary of the Commission for the Commission to review in accordance with 10 CFR 2.206(c).

As provided by this regulation, this decision will constitute the final action of the Commission 25 days after issuance, unless the Commission, on its own motion, institutes a review of the decision with that time.

Dated at Rockville, Maryland, this 27th day of November, 1996.

FOR THE NUCLEAR REGULATORY COMMISSION

Frank J. Miraglia

Frank J. Miraglia, Acting Director
Office of Nuclear Reactor Regulation

As provided by this regulation, this decision will constitute the final action of the Commission 25 days after issuance, unless the Commission, on its own motion, institutes a review of the decision with that time.

Dated at Rockville, Maryland, this 27th day of November, 1996.

FOR THE NUCLEAR REGULATORY COMMISSION

Orig. signed by

Frank J. Miraglia, Acting Director
Office of Nuclear Reactor Regulation

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