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WILLIAM D. HARRINGTON
SENIOR VICE PRESIDENT
NUCLEAR

August 4, 1983

BECo 83-208

Mr. Darrell G. Eisenhut, Director
Division of Licensing
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

License No. DPR-35
Docket No. 50-293

Reference: NRC Letter dated July 21, 1983 "Inspections of BWR Stainless Steel Piping"

Dear Sir:

As requested in the referenced letter, Boston Edison Company herein provides as an attachment to this letter the subject information.

Boston Edison Company (BECo) has repeatedly demonstrated its commitment to the safe, reliable, and efficient operation of Pilgrim Nuclear Power Station (PNPS).

We are confident that the enclosed information provides adequate justification for the continued operation of Pilgrim Nuclear Power Station until its scheduled January 1, 1984 refueling outage.

Should you require any additional information, or have any questions regarding this information, please do not hesitate to contact us.

Very truly yours,

W.D. Harrington

JMF/mat

Commonwealth of Massachusetts)
County of Suffolk)

Then personally appeared before me W.D. Harrington, who, being duly sworn, did state that he is Senior Vice President - Nuclear of Boston Edison Company, the applicant herein, and that he is duly authorized to execute and file the submittal contained herein in the name and on behalf of Boston Edison Company and that the statements in said submittal are true to the best of his knowledge and belief.

My Commission expires: October 21, 1988

Peter M Kahler
Notary Public

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Attachment

Q-1

A justification for continued operation of your facility prior to completing the inspections described by Exhibit A in view of the increased evidence of cracking since the issuance of IE Bulletin 83-02.

Response

As a part of its commitment to safe operation, BECo has fully supported the EPRI/BWR Owner's Group IGSCC research effort. The results of these intensive efforts were presented in detail to the staff on July 13, 1983 and the Commissioners on July 15, 1983 and will not be repeated in that detail herein. However, it is the technical positions developed as a result of that program in conjunction with our UT inspections performed in 1980 and 1981, the leak before break philosophy, self imposed leak detection limit restrictions and recently performed visual inspections that combine to form the basis for our continued safe operation of PNPS.

BECo concurs with the Industry conclusions that the recent increase in IGSCC indications is due to improved UT technique, operator training and qualification, signal evaluation procedures, and indication reporting requirements and to the increased number of pipe welds now being inspected. The crack initiation and propagation (growth) rates are not increasing.

The extensive industry field data recently compiled is generally consistent with the evaluation of laboratory data and crack growth modeling. IGSCC cracks grow quite rapidly to about 20 percent of the wall thickness, then grow relatively slowly to about 40 percent of the wall. At that point a lead segment of the crack will grow through the wall because it is at a higher stress intensity and will result in leakage. Based upon a very large data base, there is adequate structural margin remaining in the piping at the point of leakage to assure the piping's integrity. Experience with stainless steel piping shows that a complete circumferential crack of about 50 percent of the wall thickness will still meet the required safety margins.

BECo has administratively imposed more restrictive leak rate monitoring criteria which augments its increased attention to leak detection (see response to Question 3). BECo's conservative leak rate criteria and administrative practices provide for early detection of leakage should a crack develop and provide sufficient time to investigate cause of leakage before any significant reduction in the structural capability of the piping occurs.

At the completion of our last refueling outage in April, 1982 BECo performed its 10 year hydrostatic test with no unacceptable leakage. In addition, BECo has recently on three occasions performed visual inspection of the piping within containment, while at pressure, with no leakage observed due to pipe cracking.

During the 1980 and 1981 refueling outages BECo performed UT examination on 22 welds of the recirc. system utilizing a technique which, though preceeding the issuance of IE Bulletin 83-02, essentially satisfied its requirements. The specifics of these examinations are provided in the enclosures to this letter. We believe these examinations show that BECo has been proficient and timely in the application of the improved techniques.

BECo has recently submitted a proposed amendment to its license which addressed the implementation of an integrated Long Term Program. This program was developed to provide a mechanism through which BECo could manage work at its facility in a controlled and safe manner. BECo and the NRC staff have agreed that it is in our best interests to pursue this course of action. Though a key element of our Long Term Program is dynamic scheduling, BECo does not believe that the issue at hand justifies revising our program. Industry experience with crack growth indicates that the approximate 5 months which will elapse between now and our scheduled refueling outage will not, if cracks are present, allow sufficient time for them to propagate to a point that encroaches upon the structural margin of the piping.

BECo is confident that the information summarized above and provided in detail in these enclosures provide adequate justification for the continued operation of Pilgrim Nuclear Power Station until its scheduled January 1, 1984 refueling outage.

Q-2

Identify any weld inspections which appear to satisfy the sensitivity for detection specified by IE Bulletin 83-02. The information provided should include a list of these inspections, the dates of the inspections, the extent and results of those inspections, and a description of the technique or equipment used. If you have concluded that these previous inspections should influence the scope or schedule of the inspections described in Attachment A, please provide the basis for your conclusion. Further, describe any other unique safety related feature, information or action that would justify not accelerating your current test and inspection schedule in accordance with IE Bulletin 83-02.

Response

The ultrasonic examinations of selected pipe welds in the recirculation, RHR and RWCU systems conducted during the January, 1980 and September, 1981/April, 1982 refueling outages satisfy the sensitivity requirements of IE Bulletin 83-02.

The inspection firm that conducted the examinations during both refueling outages has subsequently validated three examination teams in accordance with IE Bulletin 83-02, and one team in accordance with IE Bulletin 82-03.

Prior to the 1980 refueling outage, BECo contacted various consultants, including NRC Region I technical personnel to discuss various volumetric techniques available for the detection of IGSCC in stainless steel pipe welds. Information obtained from these sources led BECo to require specific procedural changes in procedures used by the ISI contractors.

These revisions were incorporated into the inspection procedure prior to the examination of the recirculation system pipe welds and included:

(a) a reduced recording, reporting and evaluation level of 20% DAC (reference level), down from 50% DAC for recording and 100% DAC for reporting and evaluation.

(b) the use of 1.5 MHz dual-element search units, as opposed to the nominal 2.25 MHz single element configuration.

(c) an inspection angle of 60°.

During the period of the 1980 refueling outage the inspection industry concluded that the aforementioned equipment and procedure would provide optimum detection capabilities for IGSCC in stainless steel pipe welds. The results of the 1980 examinations revealed no unacceptable indications.

For the 1981 examinations the same aforementioned procedure was utilized with three additional items:

(a) both a 45° and 60° transducer was used.

(b) prior to the inspection, the Level II ultrasonic technicians utilized in conducting these examinations demonstrated IGSCC detection capabilities on two manufactured cracked pipe samples provided by EPRI.

(c) the requirements, technique and equipment were employed in the examination of stainless steel pipe welds of the recirculation, RHR and RWCU systems.

The procedures used during the 1981 outage were discussed with the NRC staff prior to utilization.

It should also be noted that of the personnel who had validated to either IE Bulletin 83-02 or IE Bulletin 82-03, six took part in the 1980 and 1981 examinations.

As of this time, 22 recirculation system piping welds have been examined during two outages, using the modified equipment, technique and procedure criteria.

It is therefore BECo's position that inspections capable of detecting IGSCC have been performed since 1980. The scope of these inspections was comparable to that required by IE Bulletin 83-02. The 1980 and 1981 examination results revealed no unacceptable indications. The results were reviewed by Region I personnel.

It is also our position that the EPRI crack sizing (characterization) study results will have no bearing on our past examinations because of the absence of any cracks detected by those examinations.

In April, 1982, BECo conducted the ten year hydrostatic pressure test of the Class 1 piping systems in Pilgrim Station. The hydrostatic pressure tests were conducted in accordance with the requirements of ASME Section XI, 1977 edition, winter 1978 addenda. No unacceptable leakage was observed during the hydrostatic pressure test of the Class 1 systems.

In June, 1983, Pilgrim Station was twice voluntarily removed from service to investigate the source of drywell leakage. During these investigations, BECo personnel visually examined the recirculation system for any evidence of leakage. Both investigations determined the source of the leakage to be from mechanical joints.

Pilgrim Station was again removed from service July 30, 1983 and another visual examination of the drywell piping was conducted in conjunction with a maintenance outage. Again, the only leakage was from mechanical joints and the amount correlated, as best as could be estimated by the visual technique, with the data of the on-line monitoring.

Q-3

Describe any special surveillance measures in effect or proposed for primary system leakage in addition to the Current Technical Specification requirements for your facility.

Response

A special order has been written and procedures changed to instruct operating personnel to be in a shutdown condition within 24 hours if an increase in unidentified leakage in excess of 2 gallons per minute occurs within a period of 24 hours or less. This procedure augments our technical specification that unidentified leakage shall not exceed 5 gallons per minute.

In addition, corporate management is apprised of the leak rate each morning by station management. This practice has been followed for the past six months, reflecting the added emphasis BECo has placed on monitoring leakage and relaying any changes to upper management who have directed shutdown based on this daily information and the longer term trend of leak rate data before reaching the limits given to the operator.

As stated earlier in our response to Question 2, Pilgrim has been twice voluntarily removed from service in this manner since June to investigate leakage, and once removed from service to allow other repairs, at which time we conducted additional examinations for leakage. For the last two inspections a documented inspection was performed using the ASME Section XI code for guidance.

To maximize the validity of these visual examinations, personnel conduct the examinations while the reactor is maintained at 5 to 10% power, which gives maximum pressure/temperature characteristics consistent with the physical safety of the inspection personnel.

Three teams of personnel are used to perform inspections. They are performed consistent with ASME Section XI, winter of 1980, IWA 5242. One of the following areas is assigned to a team:

Systems	Elevation
Recirculation	risers 41' to 51' ring header 41' pump suctions/discharge 9'
Residual Heat Removal	tie to recirc. - 41' inlet/outlet - 23'
Reactor Water Cleanup	2" - 23' and 41' 6" - 41'

The following criteria are employed by the teams for conducting the examination:

1) Examine accessible and exposed surfaces and joints of the insulation.

2) Vertical surfaces of insulation need only be examined at the lowest elevation.

3) Horizontal surfaces of insulation shall be examined at each insulated joint.

4) Components whose external insulation surfaces are inaccessible for direct examination, only the examination of surrounding area, including floor areas or equipment surfaces located underneath the components shall be examined.

In the inspections previously discussed, the observed leakage from mechanical joints was directly correlated to the monitored leakage. This quantification effort supported the leakage rates which were indicated by our leakage monitoring program.

Further proposed improvements for primary system leakage detection capabilities are as follows:

Currently, the alarm setpoints on our Drywell Atmosphere Sample Panel (Panel C-19) are set at the full scale value. These setpoints will be lowered to the lowest practical value above spurious actuation. It is also our intention to replace this panel with two redundant systems on the East and West sides of the drywell as well as the replacement of 3 drywell temperature/humidity recorders (Panel C-85). Plans and schedules to effect these changes have been initiated. New platinum RTD's for drywell instrumentation were installed in 1981 and new dew cells will be installed at our next refueling outage.

To allow more dissemination of trending data currently available, a General Work Instruction will be issued to the Shift Technical Advisors to require a review of the drywell environmental status once per shift with the operations personnel. Additional instructions will be provided to all shift operations personnel on the drywell leak detection systems available and the need for operator awareness. A drywell leak detection system training program will be included in the balance of the 1983 operator requalification training and remain in place thereafter.

Q-4

Direct and indirect costs and impact, including effects on other safety related activities, of conducting the inspections described in Attachment A: (a) at a time which you would commit to conduct the inspections consistent with Chairman Palladino's suggestion to the staff and licensees that a realistic schedule for the inspections be developed "with the idea of accelerating the inspection as much as possible," and (b) at the time of your next scheduled refueling outage.

Response

Q-4(a)

The following were taken into consideration consistent with the requirements of our Long Term Program:

Direct Costs

(1) Craft labor to support ISI
(2) NDE contract costs (material & labor)
(3) BECo support
(4) Schedule perturbation of working tasks

Indirect Costs

(1) Replacement Power
(2) Perturbations of task priorities as established in the Long Term Program

Impact

(1) Schedule impact on non-outage activities
(2) Possible schedule slippage on NRC commitments
(3) Long Term Program perturbations
(4) ALARA
(5) Southeastern Massachusetts power grid security

Boston Edison has reviewed each of the above elements with the idea of accelerating the inspection consistent with Chairman Palladino's suggestion to the staff and licensees, and has concluded that the only realistic alternative to our scheduled refueling outage is a December 1, 1983 initiation date.

Q-4(b)

This inspection is already scheduled for the January 1, 1984 refueling outage, and will therefore not effect a penalty on Boston Edison.

Q-5

The direct and indirect costs and impact, including effects on other safety related activities, of suspending operation to initiate the inspection described in Attachment A within each of three possible times: (a) 30 days, (b) 60 days, and (c) 90 days from August 15, 1983.

Response

(a) Cost of Inspection Beginning September 15, 1983

Direct Cost

An appraisal of the estimated direct costs associated with beginning the inspection on or about September 15, 1983 indicates that the direct costs will double to approximately $190,000. This is because insulation removal (craft labor) and support activities (health physics) will need to be duplicated for Refueling Outage #6 if we perform IHSI. In addition, we believe that beginning on September 15, 1983 will create serious perturbations of our Long Term Program, and have a detrimental effect on cost effective implementation of ongoing modifications. Currently, we estimate this cost to be approximately $82,000.

Indirect Cost

A total indirect cost of $6,000,000 will be incurred for the purchase of replacement power. Of this, $4,500,000 will directly burden the customers of Boston Edison, while the remaining $1,500,000 will fall on the customers of NEPOOL.

Impact

As stated above under direct costs, craft and support personnel will be required to repeat activities which will increase their exposure and be adverse to the goals of ALARA. Further, such schedule acceleration could create site work situations, such as overcrowding and inadequate planning, for which the Long Term Program was designed to prevent.

We are preparing an integrated refueling outage plan. Part of that plan is the ultrasonic examination of selected pipe welds in accordance with IE Bulletin 83-02. Contingent upon the results of that examination, we are taking steps to allow us to replace or repair the 12" risers, perform required repairs to the large diameter piping, and do IHSI to piping that would benefit from this technique. We also plan to replace some damaged insulation to reduce the heat losses into the drywell. None of these activities can be done before December 1, 1983 except in an unplanned, inefficient, and scrambling manner.

We have not estimated the direct and indirect costs and other impacts associated with this contingency plan, but are reasonably sure they would be many times more on an accelerated schedule than on the scheduled outage date.

Additionally, we believe that having the inspection in September, 1983 could needlessly imperil the security of the power supply to southeastern Massachusetts because of the recent loss of one of the major generating stations in the system.

(b) Cost of Inspection Beginning October 15, 1983

Direct Cost

Direct costs associated with an October inspection are essentially identical to those described for September, 1983. The additional month does not mitigate direct costs.

Indirect Cost

A total indirect cost of $5,034,000 will be incurred by an October shutdown of Pilgrim. Of this $3,739,000 will be directly borne by those serviced by Boston Edison.

Impact

The impact is the same as for a September inspection, except that at this time we do not believe the southeastern Massachusetts power grid system security will be put at risk.

(c) Cost of Inspection Beginning November 15, 1983

Direct Costs

Direct costs are the same as for September and October.

Indirect Costs

We cannot, at this time, quantify the indirect cost to our customers for a November inspection, but it is estimated to be greater than for October.

Impact

The impact is the same as for October.

Q-6

A discussion of the availability of qualified inspection personnel to perform the inspection described in Attachment A at your facility for the various options in items 4 and 5, above, and the steps you have taken to obtain the services of such personnel.

Response

BECo has made arrangements with an outside inspection agency to conduct the examinations in accordance with the validation requirements and scope of inspections required by IE Bulletin 83-02. Sufficient qualified personnel are expected to be available at BECo's request to perform these inspections assuming reasonable advance notice of the schedule is provided to the contractor.

In assessing the availability of qualified examination personnel to address this question the following criteria were utilized:

1. The inspection contractor utilized a system whereby a Level I technician scans the weld with a remote examination unit which is coupled to a master unit. The results of the examination are being monitored by a Level II examiner. Both the Level II examiner and the Master unit are located outside containment, in order to reduce exposure to the qualified Level II personnel. Only those Level I personnel required to participate in the validation of the entire team will have been validated at the NDE center; all replacement Level I personnel will be trained on-site.

2. The scope of this effort will be confined to examining twenty-nine recirculation and seven RHR circumferential pipe welds. BECo is considering the application of Induction Heat Stress Improvement (IHSI) to 12", 22" and 28" diameter welds found to have either no flaws or flaws less than 30% DAC. The scope of this effort would require the examination of between 90 and 100 pipe welds. Availability of personnel required to conduct these examinations was not considered in determining whether the IE Bulletin 83-02 scope of inspections could be performed on an accelerated schedule. If BECo is directed to perform the IE Bulletin 83-02 scope of inspections on an accelerated schedule, we may be limited on the scope of IHSI which can be performed during the planned refueling outage because of limitations on the availability of qualified inspection personnel.

3. BECo is presently contracting with various agencies to conduct mechanized and remote visual examinations of selected components. These inspections are scheduled to coincide with the 1984 refueling outage activities. If Pilgrim is required to inspect and repair pipe welds prior to the scheduled refueling outage these additional personnel may not be available to BECo when needed.

4. The results of the EPRI flaw characterization studies have not been considered in determining the availability of inspection personnel. The results of these studies will be discussed with the selected contractor

to determine the need for additional training and procedural changes. The completion of this review may dictate that BECo revise its present plans which could impact on the availability of qualified inspection personnel.