ENERGY NORTHWEST

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August 18, 2011
GO2-11-139

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D.C. 20555-0001

Subject: **COLUMBIA GENERATING STATION, DOCKET NO. 50-397 RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION LICENSE RENEWAL APPLICATION**

References: 1) Letter, GO2-10-11, dated January 19, 2010, WS Oxenford (Energy Northwest) to NRC, "License Renewal Application"

2) Letter dated July 19, 2011, NRC to DA Swank (Energy Northwest), "Request for Additional Information for the Review of the Columbia Generating Station, License Renewal Application," (ADAMS Accession No. ML11195A240)

Dear Sir or Madam:

By Reference 1, Energy Northwest requested the renewal of the Columbia Generating Station (Columbia) operating license. Via Reference 2, the Nuclear Regulatory Commission (NRC) requested additional information related to the Energy Northwest submittal.

Transmitted herewith in the Attachment is the Energy Northwest response to the Request for Additional Information (RAI) contained in Reference 2. Enclosure 1 contains Amendment 42 to the Columbia License Renewal Application. One revised commitment is included in this response.

If you have any questions or require additional information, please contact Abbas Mostala at (509) 377-4197.

A143
NRR

I declare under penalty of perjury that the foregoing is true and correct. Executed on the date of this letter.

Respectfully,

DA Swank
Acting Vice President, Engineering

Attachment: Response to Request for Additional Information

Enclosure: License Renewal Application Amendment 42

cc: NRC Region IV Administrator
NRC NRR Project Manager
NRC Senior Resident Inspector/988C
EFSEC Manager
RN Sherman – BPA/1399
WA Horin – Winston & Strawn
AD Cunanan - NRC NRR (w/a)
BE Holian - NRC NRR
RR Cowley – WDOH

RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION

"Request for Additional Information for the Review of the Columbia Generating Station, License Renewal Application,"
(ADAMS Accession No. ML11195A240)

RAI B.2.31-1

Background:

During the Columbia License Renewal Inspection that concluded on November 4, 2010, the U.S. Nuclear Regulatory Commission issued a License Renewal Inspection Report dated December 17, 2010. In the report, the staff noted that Energy Northwest (the applicant) appropriately included the in-scope 115 kV station post insulators into the High-Voltage Porcelain Insulators AMP because they provided power required during a station blackout and would be subject to hard water deposits caused by spray drift from the cooling towers.

Issue:

The inspection team determined that the applicant did not include the in-scope high-voltage station post insulators at the 230 kV ASHE A809 Breaker located in the Ashe Substation in the High-Voltage Porcelain Insulators AMP, even though this breaker provided an alternate path of power during a station blackout. The applicant stated that it did not include these station post insulators because it concluded that the hard water deposits spray drift phenomenon would not occur due to the significant distance between the circulating water system cooling towers and Ashe Substation.

The applicant could not provide any other information to support their conclusions and issued Action Requests 228661 and 228673 to resolve the concern. The applicant indicated that it would either establish appropriate coating or cleaning tasks or develop information that would demonstrate why the phenomenon would not affect the 230 kV switchyard station post insulators.

Request:

Explain why the high-voltage post insulators at the 230kV ASHE A809 Breaker located in the ASHE Substation are not subject to circulating water system cooling tower spray drift and do not require a coating or cleaning aging management program.

Energy Northwest Response:

The reason for not including the high-voltage insulators located at the Ashe substation is that Energy Northwest concluded that the environment required to coat the insulators was not present at the Ashe substation based on:

- there not having been any recorded flashovers at the Ashe substation

- discussions with plant personnel (system engineer and other) associated with the corrective action resolution indicated that the drift studies did not show an adverse effect
- the Ashe substation remains largely unaffected since it is about a quarter mile away from the main plant
- and the discussion below.

A formal root cause analysis performed after the first 500 kV insulator flashover, located in the Columbia transformer yard, (Licensee Event Report (LER) 89-002) resulted in the conclusion that the immediate cause for the failure of the 500 kV insulator was a buildup of conductive film on the surface of the insulator. Chemical analysis showed the film to be composed of chemical residue deposited by the droplets from the Circulating Water System cooling towers. The major constituents of the residue were river water minerals and sulfate compounds generated by sulfuric acid addition used to control the pH of circulating water.

Industry literature identifies two types of droplet emission from cooling towers: Recondensation droplets – those which arise by recondensation during the evaporative process. The recondensation droplets are generally less than 10 microns in diameter and contain negligible quantities of salts. Recondensate emissions are important in the determination of visible plume length.

Drift or "Spray" droplets – those which arise by spraying. The drift droplets are generally larger than 40 microns in diameter and contain salts that are present in the cooling water. Drift emissions are important in the determination of ground deposition rates.

As stated in LER 90-031, the transformer yard is situated in a prevailing, high-speed wind pattern location that results in the insulators being vulnerable to chemical drift deposition from Circulating Water System Cooling Tower drift droplets. As a result of the previous event (LER 89-002), a Cooling Tower Drift Study was performed. The data indicate a significant increase of chemical deposition in the Transformer Yard during the November to January time-frame, relative to the rest of the year. Further meteorological data compiled over five years also indicate that, during August through December 1990, the frequency of high speed (greater than 24 mph) winds from the south-southwest direction exceeded the total from the last five years combined. Winds of that speed and direction would force the Cooling Tower drift droplets into the area of the Transformer Yard.

The meteorologist has determined that 24 mile per hour wind speed is the minimum required to carry the contaminated droplets to the transformer yard with enough turbulence to kick them up on the underskirts of the insulators.

Because of the configuration of the plant, prevailing winds from the south carry contaminant laden drift droplets from the plant's cooling towers towards the station's transformer yard. The Ashe substation remains largely unaffected since it is about a quarter mile north of the main plant. As the drift droplets move northward towards the plant, wind dynamics experienced, as the droplets are carried over the generating station, force much of the droplets down onto the transformer yard, thus making this area the most vulnerable to scintillation. Figure 1 illustrates the effect.

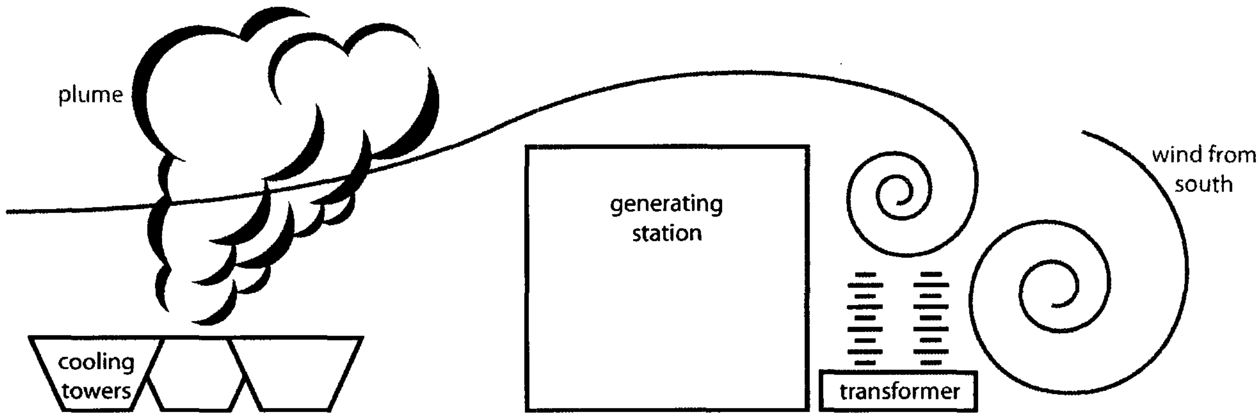

Figure 1: Droplet fallout settling on transformer yard

Under worst-case conditions, the drifting droplets created conditions conducive to arcing in the station's transformer yard. This arcing occurred when a sufficient layer of conductive substances built up on the insulators, became wetted, and formed an electrical track. Columbia Generating Station collects its cooling water from the Columbia River, which it then buffers with various chemicals to temper the water for use in the plant. Thus, the substances found in the drift droplets of the cooling tower are chemical species found naturally in the river, those added to buffer the water, those that form from decomposition of original buffers, and trace minerals and metals from the cooling system. The result is a layer of anions and cations that once settled on the surface of insulators present a prime opportunity for insulator failure.

Based on the above, the 230 kV station post insulators at Ashe were not included in the High-Voltage Porcelain Insulators Aging Management Program.

To substantiate this conclusion, Energy Northwest requested Bonneville Power Administration (BPA), which owns and operates the Ashe substation, to conduct an Equivalent Salt Deposition Density (ESDD) test on a sample of in-scope 230 kV station post insulators located at Ashe. ESDD is an industry standard technique of swiping the surface of an insulator and measuring the amount of contamination found in order to determine its density. The result is expressed in mg/cm^2.

The results of the testing indicate that the contamination levels are well within the acceptance levels established.

Data shows that with current BPA maintenance practices, the highest ESDD value is 0.0383 mg/cm^2 which was located on the underside of the bottom skirt of the A phase of the line drop station post insulator. The highest value for the top surfaces was 0.0086

mg/cm^2. BPA and Energy Northwest have established the action level to be 0.05 mg/cm^2. An industry standard establishes 4 contamination site severity levels. They are Very light (0 – 0.03 mg/cm^2), Light (0.03 – 0.06 mg/cm^2), Average/moderate (0.06 – 0.10 mg/cm^2), and Heavy (>0.10 mg/cm^2). The use of the light level as the acceptance criteria is considered by Energy Northwest as being conservative.

Energy Northwest is revising High-Voltage Porcelain Insulators Aging Management Program to require ESDD testing every eight (8) years and cleaning (if test results indicate the need) of the in-scope 230 kV station post insulators located at Ashe substation. The eight year period is considered acceptable because:

- current BPA maintenance practice is to visually inspect every 7 to 10 years and clean if necessary
- there have not been any recorded flashovers at the Ashe substation
- ESDD test results show that contamination levels are acceptable from any exposure to Circulating Water System Cooling Tower drift.

LICENSE RENEWAL APPLICATION AMENDENT 42

Section Number	Page Number	RAI Number
3.6.2.2.2	3.6-8	RAI B.2.31-1
3.6.2.2.2	3.6-8a	RAI B.2.31-1
Plant Specific Notes, Item 0608	3.6-29	RAI B.2.31-1
A.1.2.31	A-18	RAI B.2.31-1
A.1.2.31	A-18a	RAI B.2.31-1
Table A-1 Line Item 31	A-53	RAI B.2.31-1
B.2.31	B-128	RAI B.2.31-1
B.2.31	B-129	RAI B.2.31-1
B.2.31	B-129a	RAI B.2.31-1
B.2.31	B-130	RAI B.2.31-1
B.2.31	B-130a	RAI B.2.31-1
B.2.31	B-131	RAI B.2.31-1

, for the in-scope high voltage insulators located in the transformer yard,

the 500-kV system. Additional testing was performed, which resulted in developing a coating system that has proven effective in mitigating the flashover when reapplied at least every 10 years.

Due to the operating experience with the 500-kV system, Columbia instituted a program to clean the high voltage insulators on the 115-kV system, identified for license renewal as the plant-specific High-Voltage Porcelain Insulators Aging Management Program, in order to manage the build-up of hard water residue from the cooling tower plume, and thereby mitigate potential degradation of the insulation function. This program allows for the option to either hand clean ~~the in-scope~~ high voltage insulators every two years or to coat the insulators every 10 years and inspect the coating for damage every two years between coatings. The operating experience indicates that this is only an issue with station post insulators located in the transformer yard. There are no station post insulators associated with the 230-kV system in the Columbia transformer yard~~,~~ ~~therefore the 230-kV system is excluded.~~ . Insert A from page 3.6-8a

Loss of material due to mechanical wear is an aging effect for certain strain insulators if they are subject to significant movement. Such movement of the insulators can be caused by wind blowing the supported transmission conductor, causing it to sway from side to side. If this swinging motion occurs frequently enough, it could cause wear on the metallic contact points of the insulator string and between an insulator and the supporting hardware. Although this aging mechanism is possible, industry experience has shown that transmission conductors do not normally swing unless subjected to a substantial wind, and they stop swinging shortly after the wind subsides. Wind loading that can result in conductor sway is considered in the transmission system design. For insulators that are associated with switchyard bus, movement is precluded by the rigid design of the switchyard bus (i.e., the bus is of short length, is rigid itself, and is connected to rigid components). Review of operating experience has identified no concerns related to the occurrence of loss of material due to mechanical wear as a result of wind blowing on transmission conductors and the switchyard high voltage insulators. Therefore, loss of material due to mechanical wear is not an aging effect requiring management for the high voltage insulators at Columbia.

3.6.2.2.3 Loss of Material due to Wind Induced Abrasion and Fatigue, Loss of Conductor Strength due to Corrosion, and Increased Resistance of Connection due to Oxidation or Loss of Pre-Load

The switchyard bus which connects Back-up Transformer E-TR-B to circuit breaker E-CB-TRB and the bus between the 230 kV overhead line and circuit breaker A809 is within the scope of license renewal at Columbia. These are aluminum tube. The switchyard bus is connected to flexible connectors that do not normally vibrate and are supported by insulators and ultimately by structural components such as concrete footings and structural steel. With no connection to moving or vibrating equipment, vibration is therefore not an applicable aging mechanism. The aluminum bus will form a

Insert A for page 3.6-8

However, there are 230 kV station post insulators located at the Ashe sub-station. These insulators will be tested every 8 years for contamination and cleaned if the test indicates unacceptable contamination.

Plant-Specific Notes:	
0608	See Section 3.6.2.2.2 for a description of the surface contamination item affecting the high-voltage insulators ~~in the Columbia transformer yard~~.
0609	The uninsulated ground conductors and connections are included in the license renewal scope because they are required for fire protection (from lightning-induced fires) on certain structures and for facilitating the operation of ground fault detection devices in the event of ground fault or insulation failure on any electrical load or current (see Section 2.5.5.5). There are no aging effects requiring management for the metallic components of the uninsulated ground conductors and connections.
0610	Inaccessible underground power cables (400 V to 2kV) are included in response to recent industry and plant-specific operating experience. In addition, the cable testing frequency will be at least once every 6 years, and the electrical manhole inspection frequency (for water collection) will be performed at least annually. Also, manhole inspections will be performed in response to event-driven occurrences (such as heavy rain or flooding).

minimized by verifying the quality of new fuel oil before it enters the emergency diesel generator storage tanks and by periodic sampling to ensure that both the emergency diesel generator tanks and fire protection tanks are free of water and particulates. The Fuel Oil Chemistry Program is a mitigation program.

The Fuel Oil Chemistry Program is supplemented by the Chemistry Program Effectiveness Inspection, which provides verification of the effectiveness of the program in mitigating the effects of aging.

A.1.2.30 Heat Exchangers Inspection

The Heat Exchangers Inspection detects and characterizes the surface conditions with respect to fouling of heat exchangers and coolers that are in the scope of the inspection and exposed to indoor air or to water with the chemistry controlled by the BWR Water Chemistry Program or the Closed Cooling Water Chemistry Program. The inspection provides direct evidence as to whether, and to what extent, a reduction of heat transfer due to fouling has occurred on the heat transfer surfaces of heat exchangers and coolers.

The Heat Exchangers Inspection is a new one-time inspection that will be implemented prior to the period of extended operation. The inspection activities will be conducted within the 10-year period prior to the period of extended operation.

A.1.2.31 High-Voltage Porcelain Insulators Aging Management Program

The High-Voltage Porcelain Insulators Aging Management Program is an existing program that manages the build-up of contamination (hard water residue) on the surfaces of the 115-kV high-voltage insulators. located in the transformer yard and the 230-kV high voltage insulators located at the Ashe substantion. The program provides for periodic cleaning or recoating of insulators and visual inspection of the coating (if present) on the high-voltage ~~porcelain~~ station post insulators between the 115-kV backup transformer and circuit breaker E-CB-TRB located in the station transformer yard. Insert B page A-18a

The High-Voltage Porcelain Insulators Aging Management Program is a preventive maintenance program consisting of activities to mitigate potential degradation of the insulation function due to hard water deposits. Uncoated insulators located in the transformer yard are inspected and cleaned every two years. Coated insulators Power are visually inspected for damage every two years and are re-coated every 10 years. Insert C page A-18a

A.1.2.32 Inaccessible ~~Medium-Voltage~~ Cables Not Subject to 10 CFR 50.49 EQ Requirements Program

Insert A page A-18a

~~The Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 EQ Requirements Program manages the aging of inaccessible medium-voltage cables that are not environmentally qualified and are within the scope of license renewal. The~~

Section A.1.2.32

Insert A (≥ 400 V) Power

power

The Inaccessible ~~Medium-Voltage~~ Cables Not Subject to 10 CFR 50.49 EQ Requirements Program will manage the aging of in-scope, ~~medium-voltage~~ cables exposed to significant moisture ~~and significant voltage~~. First tests or first inspections for license renewal will be completed before the period ~~of extended~~ operation. These cables will be tested at least once every ~~10~~ years to provide an indication of the condition of the conductor insulation. The specific type of test performed will be determined prior to the initial test, and is to be a proven test for detecting deterioration of the insulation system due to wetting, such as power factor, partial discharge, or polarization index, as described in EPRI TR -103834-P1-~~2~~, or other testing that is state-of-the-art at the time the test is performed. Significant moisture is defined as periodic exposures that last more than a few days (e.g., cable in standing water). Periodic exposures that last less than a few days (e.g., normal rain and drain) are not significant. ~~Significant voltage exposure is defined as being subjected to system voltage for more than 25% of the time. The moisture and voltage exposures described as significant in these definitions are not significant for medium-voltage cables that are designed for these conditions (e.g., continuous wetting and continuous energization are not significant for submarine cables).~~ In addition, inspection for water collection will be performed based on actual plant experience with water accumulation ~~in~~ the manholes. However, the inspection frequency will be at least ~~once every two years~~.

6

(Reference A.1.4-3)

in electrical manholes

annually

Manhole inspections will also be performed periodically, in response to event-driven occurrences (such as heavy rain or flooding).

Insert B:

and testing for contamination, and cleaning if required, of the high voltage station post insulators between the 230-kV overhead line running to Columbia Generating Station and circuit breaker E-CB-TRS.

Insert C:

The program requires enhancement prior to the period of extended operation to have the insulators located in the Ashe substation tested for contamination, and cleaned if required, every 8 years.

Table A-1
Columbia License Renewal Commitments

Item Number	Commitment	FSAR Supplement Location (LRA App. A)	Enhancement or Implementation Schedule
30) Heat Exchangers Inspection	The Heat Exchangers Inspection is a new activity. The Heat Exchangers Inspection detects and characterizes the surface conditions with respect to fouling of heat exchangers and coolers that are in the scope of the inspection and exposed to treated water, closed cooling water, or indoor air. The inspection provides direct evidence as to whether, and to what extent, the relevant effects of aging have occurred.	A.1.2.30	Within the 10-year period prior to the period of extended operation.
31) High-Voltage Porcelain Insulators Aging Management Program	The High-Voltage Porcelain Insulators Aging Management Program is an existing program that will be continued for the period of extended operation~~.~~, with the following enhancement: • For the in-scope station post insulators located at the Ashe substation, add testing for contamination, and cleaning if required, every 8 years.	A.1.2.31	~~Ongoing~~ Enhancement prior to the period of extended operation. Then ongoing.

B.2.31 High-Voltage Porcelain Insulators Aging Management Program

Program Description

and the Ashe substation

The High-Voltage Porcelain Insulators Aging Management Program will manage the build-up of contamination (hard water residue) deposited on the in-scope high-voltage insulators in the transformer yard by the vapor plume from the Circulating Water System cooling towers. This residue, in conjunction with unfavorable weather conditions (moisture from the plume and freezing temperatures), has caused electrical flashovers on the 500-kV bus pedestal insulators in the transformer yard.

The High-Voltage Porcelain Insulators Aging Management Program is a preventive maintenance program consisting of activities to mitigate potential degradation of the insulation function due to hard water deposits.

Note: There are no station post insulators in the 230-kV system located in the transformer yard.

NUREG-1801 Consistency

The High-Voltage Porcelain Insulators Aging Management Program is an existing Columbia program that is plant-specific. There is no corresponding aging management program described in NUREG-1801, therefore, the program elements are compared to the elements listed in Table A.1-1 of NUREG-1800.

The program requires enhancement to include testing, and cleaning if required, of the insulators located in the Ashe substation.

Aging Management Program Elements

The results of an evaluation of each program element are provided below.

- Scope of Program
  The High-Voltage Porcelain Insulators Aging Management Program is credited for managing the build-up of hard water residue on the in-scope high-voltage insulators ~~(located in the transformer yard)~~ deposited by the vapor plume from the Circulating Water System cooling towers.

  The High-Voltage Porcelain Insulators Aging Management Program involves the following equipment:

  - The high-voltage station post insulators between the 115-kV backup transformer (E-TR-B) and circuit breaker E-CB-TRB.

  The 500-kV insulators, which experienced the flashover events in the past, are not within the scope of license renewal.

  - The high-voltage station post insulators between the 230-kV overhead line running to Columbia Generating Station and circuit breaker E-CB-TRS.

- Preventive Actions
The actions of the High-Voltage Porcelain Insulators Aging Management Program are a preventive maintenance activity that mitigates (retards) degradation of the insulation function.

  The High Voltage Porcelain Insulators Aging Management Program provides for either the periodic coating or cleaning of the applicable high-voltage insulators. Cleaning every two years is performed to prevent the build-up of hard water residue on the insulator surface to a point that could cause an electrical flashover. Coating every 10 years prevents the harmful effect of a hard water residue build-up on the insulators. Cleaning is not required if the insulator is coated.

  located in the transformer yard

  Insert A page B-129a

- Parameters Monitored or Inspected
The High-Voltage Porcelain Insulators Aging Management Program visually inspects coated insulators every two years for damage. Uncoated insulators are inspected every two years for any unusual conditions.

  Insert B page B-129a

, for those insulators located in the transformer yard,

- Detection of Aging Effects
The High-Voltage Porcelain Insulators Aging Management Program is a preventative maintenance program that does not have any specific steps to detect hard water residue on the insulators leading to flashover. The program assumes that the residue exists and takes steps to limit its effect (via coating) or to remove it (via cleaning). A visual inspection of the insulator is specified to note any excessive degradation or excessive surface contamination. The in-scope insulators are inspected and cleaned every two years. Cleaning is not required if the insulators are coated. If insulators are coated, the coating is performed every 10 years.

  Insert C page B-129a

- Monitoring and Trending
The High-Voltage Porcelain Insulators Aging Management Program does not include trending actions. The High-Voltage Porcelain Insulators Aging Management Program is a preventive maintenance program that is performed at established intervals to coat or clean the in-scope insulators. If during the inspection of the coating or in preparation for cleaning uncoated high-voltage porcelain insulators, significant or unusual or unexpected hard water residue build-up is noted (i.e., excessive deposits), the inspection results will be evaluated through the corrective action program. The corrective action evaluation may result in analysis or further inspection, and a disposition is generated. This disposition may result in a change in the frequency of inspection.

  Insert D page B-129a

- Acceptance Criteria
The High-Voltage Porcelain Insulators Aging Management Program is a preventive maintenance activity that is periodically performed on specific in-scope equipment. There are no defined acceptance criteria; hard water deposits are assumed to occur and the activity is designed to limit their impact on the insulators. For the visual

<u>Insert A:</u>

The High-Voltage Porcelain Insulators Aging Management Program provides for testing, and cleaning if required, of the applicable high-voltage insulators located in the Ashe substation.

<u>Insert B:</u>

Uncoated insulators located in the Ashe substation are tested for contamination every 8 years.

<u>Insert C:</u>

The High-Voltage Porcelain Insulators Aging Management Program will conduct an Equivalent Salt Deposition Density (ESDD), or other industry recognized test for detecting contamination on a sample of in-scope 230 kV station post insulators located at the Ashe substation at least every 8 years.

<u>Insert D:</u>

The High-Voltage Porcelain Insulators Aging Management Program does include trending actions for those insulators located in the Ashe substation. Test results will be trended to determine if cleaning of the insulators is needed to ensure that contamination levels do not exceed acceptance criteria during the next test period. Trending data will also be used to adjust the testing frequency.

inspection of the insulators, excessive surface contamination that does not wash off (i.e., obvious degradation on the insulator) is unacceptable. Such degradation is not expected to be seen on the porcelain material.

Insert A page B-130a

- Corrective Actions
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Confirmation Process
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Administrative Controls
  This element is common to Columbia programs and activities that are credited with aging management during the period of extended operation and is discussed in Section B.1.3.

- Operating Experience
  The elements that comprise the High-Voltage Porcelain Insulators Aging Management Program are consistent with industry practice and have proven effective in maintaining the high-voltage porcelain insulators free from the adverse effects of hard water residue build-up.

  A review of the most recent operating experience for the high-voltage porcelain insulator inspections reveals that the inspections are performed in accordance with procedure, the results are documented and retrievable, and if any abnormalities are identified during inspection, corrective actions are taken. A review of plant-specific operating experience for the most recent five-year period, through a search of condition reports, revealed that no 115-kV or 230-kV output breakers tripped as a result of high currents created when a porcelain insulator in the transformer yard shorted to ground.

  The incidents which alerted the plant to the hard water deposition on the 500-kV insulators are described in Licensee Event Reports 89-002-00 and 90-031. It is noted that these events occurred almost 20 years ago. There is industry operating experience of similar flashover events occurring at plants on the ocean affected by salt spray (Brunswick, Crystal River 3, and Pilgrim), and also plants affected by heavy fog and contamination deposits on high-voltage insulators (River Bend).

Required Enhancements

~~None.~~

The High-Voltage Porcelain Insulators Aging Management Program will require enhancement to require ESDD testing, and cleaning if required, of the in-scope insulators at the Ashe substation every 8 years.

Insert A:

The High-Voltage Porcelain Insulators Aging Management Program uses industry recognized acceptance criteria for the results of the ESDD testing of not greater than 0.05 mg/cm^2 (within the light contamination level per industry standard). If another industry recognized test is used, then the acceptance criteria will provide reasonable assurance that contamination levels will be maintained at levels that will prevent flashovers due to contamination.

Conclusion

The High-Voltage Porcelain Insulators Aging Management Program will manage the hard water residue build-up on the in-scope high-voltage insulators ~~in the transformer yard~~. The continued implementation of the High-Voltage Porcelain Insulators Aging Management Program provides reasonable assurance that the effects of aging will be managed such that components subject to aging management will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.