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February 28, 2007
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10 CFR 50.46(a)(3)(ii)
10 CFR 50.59(d)(2)
10 CFR 72.48(d)(2)

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

Subject: **COLUMBIA GENERATING STATION, DOCKET NO. 50-397**
INDEPENDENT SPENT FUEL STORAGE INSTALLATION,
DOCKET NO. 72-35
2006 ANNUAL OPERATING REPORT

Dear Sir or Madam:

Enclosed is the annual operating report for Columbia Generating Station for calendar year 2006. This report is submitted pursuant to 10 CFR 50.46, 10 CFR 50.59, 10 CFR 72.48, Regulatory Guide 1.16, Guidelines for Managing NRC Commitment Changes (NEI 99-04), and Licensee Controlled Specification 1.7.8. There are no commitments being made to the NRC by this letter.

If you have any questions or desire additional information pertaining to this report, please contact Mr. GV Cullen at (509) 377-6105.

Respectfully,

Thyrl for D.K. Atkinson

DK Atkinson
Vice President, Nuclear Generation
Mail Drop PE08

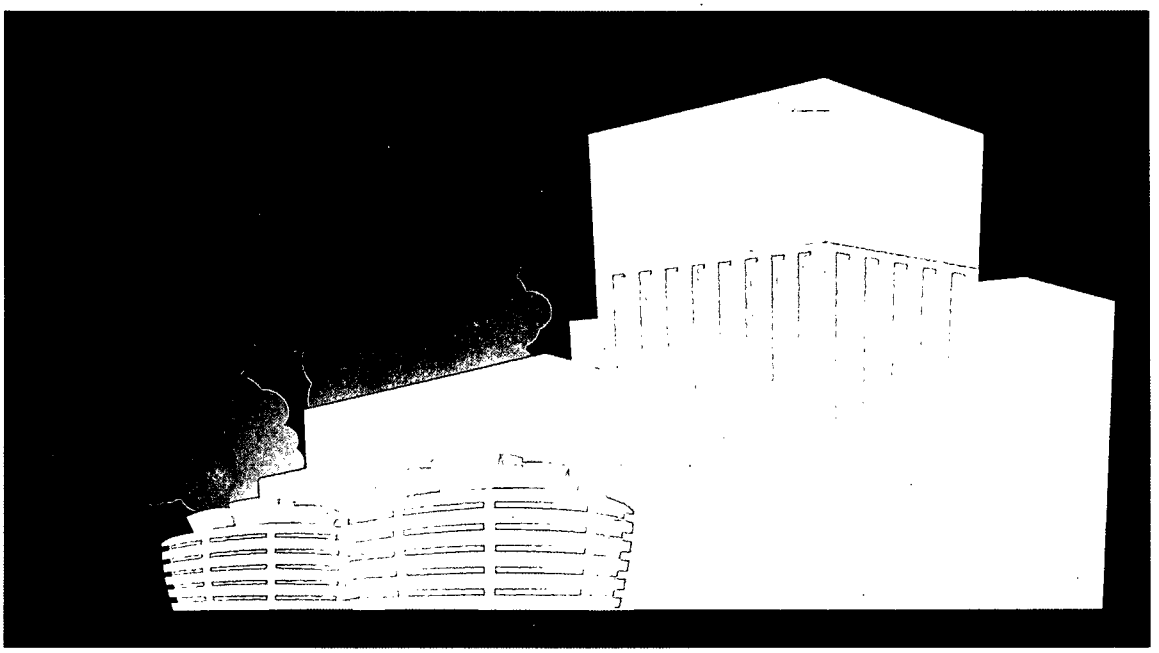
Enclosure: Columbia Generating Station 2006 Annual Operating Report

cc: BS Mallett - NRC RIV
CF Lyon – NRC NRR
Director, SFPO – NRC NMSS
NRC Sr. Resident Inspector – 988C
RN Sherman – BPA/1399
WA Horin - Winston & Strawn

NMSS01

Columbia Generating Station

2006 ANNUAL OPERATING REPORT



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COLUMBIA GENERATING STATION

2006 ANNUAL OPERATING REPORT

DOCKET NO. 50-397

DOCKET NO. 72-35

FACILITY OPERATING LICENSE NO. NPF-21

Energy Northwest
P.O. Box 968
Richland, Washington 99352

Columbia Generating Station
2006 Annual Operating Report

Table of Contents

1.0 Reporting Requirements

The reports in this document are provided pursuant to: 1) the requirements of Licensee Controlled Specification (LCS) 1.7.8, "Sealed Source Contamination;" 2) the requirements of 10 CFR 50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light-Water Nuclear Power Reactors;" 3) the requirements of 10 CFR 50.59, "Changes, Tests, and Experiments;" 4) the requirements of 10 CFR 72.48, "Changes, Tests, and Experiments;" 5) the guidance contained in Regulatory Guide 1.16, "Reporting of Operating Information-Appendix A Technical Specifications," Revision 4, August 1975; and 6) the guidance contained in NEI 99-04, "Guidelines for Managing NRC Commitment Changes," Revision 0, July 1999.

Licensee Controlled Specification 1.7.8 requires a report be submitted to the Commission, on an annual basis, if sealed source or fission detector leakage tests reveal the presence of greater than or equal to 0.005 microcuries of removable contamination.

Regulation 10 CFR 50.46(a)(3)(ii) requires, in part, that for each (non-significant) change to or for each error discovered in an acceptable Emergency Core Cooling System (ECCS) performance evaluation model or in the application of such a model that affects the temperature calculation, the applicant or licensee report the nature of the change or error and the estimated effect on the limiting ECCS analysis to the Commission at least annually as specified in 10 CFR 50.4.

Regulation 10 CFR 50.59(d)(2) requires that licensees submit, as specified in 10 CFR 50.4, a report containing a brief description of any changes, tests, and experiments, including a summary of the evaluation of each. This report must be submitted at intervals not to exceed 24 months.

Regulation 10 CFR 72.48(d)(2) requires that licensees submit, as specified in 10 CFR 72.4, a report containing a brief description of any changes, tests, and experiments, including a summary of the evaluation of each. This report must be submitted at intervals not to exceed 24 months.

Regulatory Guide 1.16 states that routine operating reports covering the operation of the unit during the previous calendar year should be submitted prior to March 1 of each year. Each annual operating report should include:

- A narrative summary of operating experience during the report period relating to safe operation of the facility, including safety-related maintenance not covered elsewhere.

- For each outage or forced reduction in power of over 20 percent of design power level where the reduction extends for more than four hours:

  (a) The proximate cause and the system and major component involved (if the outage or forced reduction in power involved equipment malfunction).

  (b) A brief discussion of (or reference to reports of) any reportable occurrences pertaining to the outage or power reduction.

  (c) Corrective action taken to reduce the probability of recurrence, if appropriate.

  (d) Operating time lost as a result of the outage or power reduction.

  (e) A description of major safety-related corrective maintenance performed during the outage or power reduction, including the system and component involved and identification of the critical path activity dictating the length of the outage or power reduction.

  (f) A report of any single release of radioactivity or single radiation exposure specifically associated with the outage, which accounts for more than ten percent of the allowable annual values.

- A tabulation on an annual basis of the number of station, utility and other personnel (including contractors) receiving exposures greater than 100 mrem/year and their associated man-rem exposure according to work and job functions. (Columbia Generating Station [Columbia] License Amendment 190 eliminated the requirement to report this information.)

- Indications of failed fuel resulting from irradiated fuel examinations, including eddy current tests, ultrasonic tests, or visual examinations completed during the report period.

"Guidelines for Managing NRC Commitment Changes," NEI 99-04, is an NRC-endorsed method for licensees to follow when managing or changing NRC commitments. For commitment changes that meet certain criteria, the guidance specifies that the NRC staff be notified of the changes either annually or along with Final Safety Analyses Report (FSAR) updates required by 10 CFR 50.71(e).

2.0 Summary of Plant Operations

The summary of plant operations is provided in accordance with Regulatory Guide 1.16, Revision 4, Section C.1.b.(1).

The year began with Columbia at 100% power. On July 23, problems with one channel of the adjustable speed drive (ASD) cooling system caused a reactor

recirculation (RRC) pump (RRC-P-1B) speed reduction (runback). Power was subsequently reduced to 70% to recover the affected ASD channel. Repairs were completed and 100% power was reestablished on July 25. On July 27, ASD cooling failures on RRC-P-1A caused the pump to trip and the plant entered single loop operation at 60% power. The plant returned to 100% power on July 29, after the system was repaired. On August 13, power was reduced to 60% due to a hydraulic oil leak on a low pressure turbine intercept valve for the main turbine. The leak was repaired and 100% power was restored on August 15. Columbia entered a forced outage on October 31, due to an automatic reactor scram (LER 2006-001-00) caused by a failed card in the digital electro-hydraulic (DEH) system. The failed DEH card was replaced. During the outage, Energy Northwest disassembled and inspected HPCS-P-2, the service water supply pump for the high pressure core spray (HPCS) system emergency diesel, to address potential common mode failure issues with the shafts on the two other service water (SW) pumps. No damage or failure mechanism indications similar to those on the other pumps were seen on the HPCS pump shaft material. The HPCS-P-2 shafts were replaced and the pump reassembled. During this forced outage, an unplanned loss of shutdown cooling occurred due to an error in a procedure (LER 2006-002-00). Shutdown cooling was restored approximately 46 minutes after the loss occurred. Columbia was returned to the grid on November 8 and restored to 100% on November 9.

Planned power reductions were made routinely during the year for equipment maintenance, surveillance testing, control rod manipulations, and economic dispatch.

3.0 Outages and Forced Reductions in Power

The information about the outages or forced reductions in power is provided in accordance with Regulatory Guide 1.16, Section C.1.b.(2).

July 23 - 25, 2006 (approximately 40 hours at reduced power)
On July 23, problems with a temperature switch tripped one channel of the ASD cooling system. This caused RRC-P-1B motor to runback from the normal 60 hertz to 51 hertz. The temperature switch setpoint that tripped the channel had drifted below the alarm setpoint. The increased load on the remaining channel and the high ambient temperature raised the glycol temperature, starting a standby cooling fan. The additional cooling combined with the reduced load while operating at 51 hertz restored the glycol system temperatures to normal. Power was subsequently reduced to 70% to support repairs and recovery of the affected drive. Repairs were completed and 100% power was reestablished on July 25.

The RRC-P-1B motor runback was caused by the drifting temperature switch setpoint, rather than an actual high temperature. Investigation revealed a

tendency for similar switches on this system to drift low. Therefore, all the temperature switches were replaced with properly calibrated switches. The temperature switches are scheduled for replacement with more reliable equipment during R18 (May – June 2007).

July 27 - 29, 2006 (approximately 56 hours at reduced power)
The RRC system ASD glycol hoses had been replaced during the 2005 refueling outage (R17). On July 20, one of the hoses, on one ASD channel glycol pump, ruptured and the channel was manually tripped. The failed hose was replaced with a hose from the same manufacturer used during R17. On July 27, this hose ruptured and the resulting electrical perturbation tripped RRC-P-1A, forcing the plant into single loop operation at 60% power. All of the ASD glycol hoses were replaced with new hoses from a different manufacturer. Power was lowered to 25% to recover the tripped pump and was subsequently restored to 100% power on July 29.

The hose failed due to a manufacturing defect. The decision to use hose from the same manufacturer used during R17 did not receive the level of review and oversight needed and contributed to the cause of the event. To prevent recurrence of this identified problem, Energy Northwest has improved the gate questions for entry into the operational decision-making process at Columbia.

August 13 - 15, 2006 (approximately 25 hours at reduced power)
On August 13, a low-pressure turbine intercept valve was closed and power was reduced to 60% to repair a leak in the hydraulic oil supply to the valve. Power was restored to 100% on August 15.

The source of the leak was an O-ring failure. The O-ring failed because the solenoid valve had been installed incorrectly in May 2005, during the refueling outage (R17). The solenoid valve was replaced and valves in similar applications were inspected and found satisfactory. The work instructions did not provide adequate guidance to assure correct solenoid valve installation. The model work instructions for this task have been revised to prevent recurrence.

October 31 – November 9, 2006 (approximately 191 generator off-line hours)
On October 31, Columbia entered a forced outage due to an automatic reactor scram **[LER 2006-001-00]** caused by a failed digital input card in the DEH system. The failed DEH card was replaced during the outage. On November 3, an unplanned loss of shutdown cooling occurred due to an error in a procedure **[LER 2006-002-00]**. Shutdown cooling was restored approximately 46 minutes after it was lost. All safety systems were available to perform safety functions during this loss of shutdown cooling. The process for validation and verification has been improved to address the potential for incorporating procedural errors in

the revision process. During the outage, Energy Northwest disassembled and inspected HPCS-P-2, the service water supply pump for the HPCS system emergency diesel, to address common mode failure issues with the other service water pump shafts. No damage or similar failure mechanism indications were detected on the shaft material. The HPCS-P-2 pump shafts were replaced and the pump reassembled. Columbia was returned to the grid on November 8 and restored to 100% power on November 9.

The DEH system contains single point vulnerabilities. The specific failure, in this case, was the output peripheral driver chip. To minimize the potential recurrence of these types of events related to the DEH system, the DEH system is being replaced during R18.

4.0 Sealed Source Contamination

There were no incidents of sealed source contamination during 2006 that required reporting in accordance with LCS 1.7.8.

5.0 Fuel Performance

The fuel integrity information is provided in compliance with Regulatory Guide 1.16, Section C.1.b.(4), and FSAR Section 4.2.4.3, "Post-Irradiation Surveillance."

No fuel failures were identified during calendar year 2006 (Cycle 18). This conclusion was based on readings of offgas radioactivity from the pre-treatment process radiation monitoring system.

The sum-of-six readings have stayed considerably below 300 microCi/sec, the INPO threshold for fuel failures. The values for the Xe-133/Xe-135 and Xe-138/Xe-133 activity ratios have been within the range for an intact core.

Columbia did not experience any fuel defects or gross cladding anomalies during 2006. Accordingly, fuel inspections were not required by FSAR commitments. However, fuel inspections are planned during the R18 outage (following the completion of Cycle 18). The inspections are in response to the Energy Northwest implementation, in recent years, of several new water chemistry programs. The programs include noble metals addition, iron and zinc injection, and hydrogen water chemistry injection.

6.0 10 CFR 50.46 Changes or Errors in ECCS LOCA Analysis Models

The non-significant changes and errors in ECCS cooling performance models are provided in compliance with 10 CFR 50.46. The Westinghouse methodology was used to license SVEA-96 fuel in the Columbia core. No errors were discovered in the Westinghouse ECCS loss of coolant accident (LOCA) analysis model and no revisions were made to the Columbia LOCA Analysis Report during 2006.

The AREVA methodology was used to license ATRIUM-10 fuel in the Columbia core. No errors were discovered in the AREVA ECCS LOCA analysis model and no revisions were made to the Columbia LOCA Analysis Report during 2006.

7.0 10 CFR 50.59 Changes, Tests, and Experiments

This section contains the summary of the evaluations for activities implemented during 2006 that were assessed pursuant to 10 CFR 50.59 requirements.

Energy Northwest evaluated the changes summarized below and determined prior NRC approval was not required.

PLANT DESIGN CHANGE 3006 (Evaluation 5059-05-0003)
Energy Northwest installed components and interconnecting cables for two power system features in accordance with plant design change (PDC) 3006. The PDC provided the capability to cross-connect two of the non-critical 4160 Volt switchgear buses (E-SM-2 to E-SM-1 or E-SM-3) with the HPCS emergency diesel generator (DG-3). The permanently installed, locked open electrical cross connects between the switchgear allow Columbia to power Division 1 or the Division 2 engineered safety feature (ESF) equipment from the ESF Division 3, when plant conditions allow. The installation that will allow the cross connection between the 4160 Volt switchgear is evaluated in Evaluation 5059-05-0011 (below).

The design change also provided an alternative AC power supply to the safety and non-safety related battery chargers. These features are part of risk management actions required by a technical specification (Tech Spec) action statement that supports a 14-day allowable outage time for the Division 1 and the Division 2 emergency diesel generators. These features are designed to mitigate the consequences of a station blackout (SBO) that is beyond the design bases SBO 4 hour coping period.

Evaluation Summary
The battery chargers are not initiators of any accident evaluated previously in the FSAR. No new failure modes are introduced that could initiate an accident or

prevent the charger from charging the battery and carrying the associated safety related loads.

The changes are not associated with a fission product barrier. Hence, these additions do not result in exceeding or altering a design basis limit for a fission product barrier (DBLFPB) described in the FSAR.

Providing electrical continuity to the charger through the transfer switches is a design function and not an FSAR evaluation methodology. Therefore, these additions do not result in a departure from a method of evaluation described in the FSAR used in establishing the design bases or in the safety analyses. The new installation and controls meets the applicable design and licensing requirements. Hence, the increased likelihood of malfunction of a structure, system, or component (SSC) important to safety previously evaluated in the FSAR is minimal.

PLANT DESIGN CHANGE 3671 and FIELD CHANGE REQUEST 4421
(Evaluation 5059-05-0011)
This design change is the completion of the modification initiated with PDC 3006. The change allows for the connection of DG-3 with either 4160 Volt switchgear that provides power to the Division 1 or Division 2 critical switchgear. The change also allows the connection of a non-safety related, trailer-mounted diesel generator (DG-4) to either the Division 1 or the Division 2 battery chargers. Together these changes and applicable operational restrictions provide an emergency power supply to Columbia to mitigate the consequences of an SBO that is beyond the design bases SBO 4 hour coping period.

Evaluation Summary
The off-normal connections designed and evaluated in this design package cannot be used unless Columbia is in a condition that is beyond the design basis analyses. The installed equipment is isolated from the normal electrical distribution system by open, administratively controlled safety related breakers and transfer switches. The equipment does not initiate or increase the frequency of an accident. No new failure mode is introduced by the installation that could initiate an accident.

These new configurations are not an initiator of any accident and no new failure modes are introduced that could create an accident. Hence, the frequency of occurrence of an accident previously evaluated in the FSAR is unchanged.

The new configurations have been analyzed with respect to the voltages at the ECCS pumps, the Main Control Room heat loads and temperature, the vital island room temperatures, electrical system and component load, voltage, short circuit and overcurrent protective devices, available fault current, battery duty cycles, manual transfer switch unavailability, and fire protection and found to be acceptable and within design tolerances. Hence, the increase in the likelihood of

occurrence of a malfunction of an SSC important to safety previously evaluated in the FSAR is minimal.

The switchgear and motor control centers (MCCs) associated with these new configurations are not initiators of any accidents and no new failure modes are introduced. Hence, the consequences of an accident previously evaluated in the FSAR are unchanged.

The consequences of the switchgear and MCCs associated with the new configurations failing to supply their loads in an accident evaluated in the FSAR are not increased since accident dose rates associated with a loss of any of these buses does not increase due to the permitted configurations allowed per this PDC.

The new configurations do not create the possibility of an accident of a different type than any previously evaluated in the FSAR since the associated switchgear and MCCs are not an initiator of any accident and no new failure modes are introduced.

The new configurations do not create a possibility of a malfunction of an SSC important to safety with a different result than any previously evaluated in the FSAR. Failure modes for the switchgear and MCCs associated with these new configurations include short circuit, open circuit, or loss of power source. These failure modes are unchanged by the new configurations allowed by this PDC.

The new configurations do not result in a design basis limit for a fission product as described in the FSAR being exceeded or altered since the switchgear and MCCs associated with these configurations are not associated with a fission product barrier.

The new configurations do not involve a method of evaluation as defined in the FSAR. Power to the critical switchgear and MCCs associated with these configurations is a design function and not FSAR evaluation methodology. Therefore, these new configurations do not result in a departure from a method of evaluation described in the FSAR used in establishing the design basis or in the safety analyses.

8.0 10 CFR 72.48 Changes, Tests, and Experiments

There were no activities implemented during 2006 that required reporting pursuant to 10 CFR 72.48 requirements.

9.0 Regulatory Commitment Changes (NEI 99-04 Process)

This section reports Regulatory Commitment Changes (RCC) pursuant to the NEI Guidelines for Managing NRC Commitment Changes. During 2006, there were no commitment changes that satisfied the NEI criteria for reporting.