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U.S. Nuclear Regulatory Commission
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Washington, D.C. 20555

Subject: **COLUMBIA GENERATING STATION, DOCKET NO. 50-397**
INDEPENDENT SPENT FUEL STORAGE INSTALLATION, DOCKET NO. 72-35
2004 ANNUAL OPERATING REPORT

Dear Sir or Madam:

Enclosed is the annual operating report for calendar year 2004. The enclosure is submitted pursuant to Technical Specification 5.6.1, Licensee Controlled Specification 1.7.8, 10 CFR 50.46, 10 CFR 50.59, 10 CFR 72.48, Regulatory Guide 1.16, and NEI 99-04.

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

Respectfully,

DK Atkinson
Vice President, Nuclear Generation
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Enclosure: Columbia Generating Station 2004 Annual Operating Report

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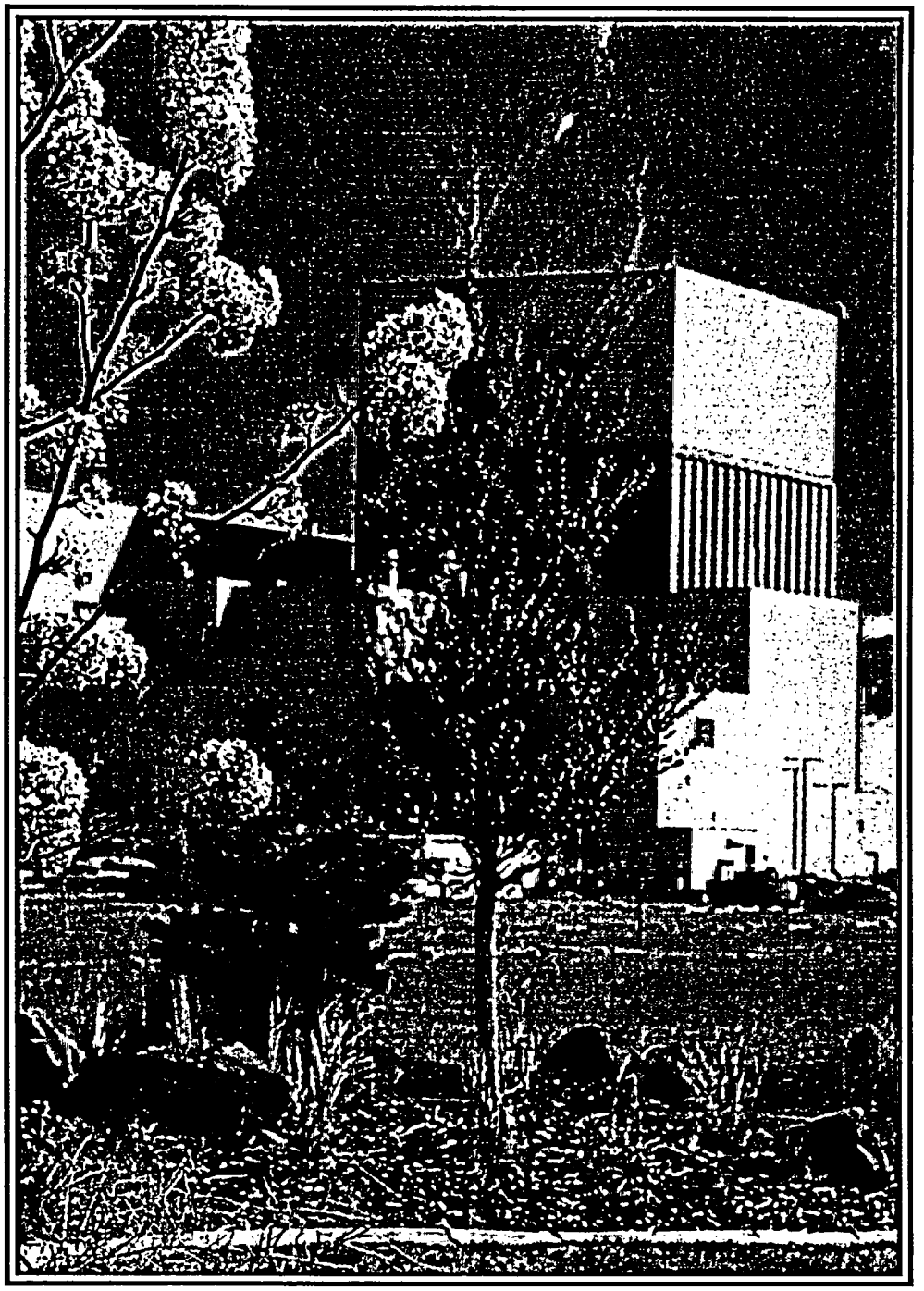
Columbia Generating Station
2004 Annual Operating Report



COLUMBIA GENERATING STATION

2004 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
2004 Annual Operating Report

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1.0 Reporting Requirements

The reports in this document are provided pursuant to: 1) the requirements of Technical Specification 5.6.1, "Occupational Radiation Exposure Report;" 2) the requirements of Licensee Controlled Specification 1.7.8, "Sealed Source Contamination;" 3) the requirements of 10 CFR 50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light-Water Nuclear Power Reactors;" 4) the requirements of 10 CFR 50.59, "Changes, Tests, and Experiments;" 5) the requirements of 10 CFR 72.48, "Changes, Tests, and Experiments;" 6) the guidance contained in Regulatory Guide 1.16, "Reporting of Operating Information-Appendix A Technical Specifications," Revision 4, August 1975; and 7) the guidance contained in NEI 99-04, "Guidelines for Managing NRC Commitment Changes," Revision 0, July 1999.

Technical Specification 5.6.1 requires an occupational radiation exposure report be submitted in accordance with 10 CFR 50.4 by April 30 of each year. The report is required to include a tabulation on an annual basis of the number of station, utility, and other personnel (including contractors) for whom monitoring was performed, receiving an annual deep dose equivalent of greater than 100 mrem and the associated collective deep dose equivalent (reported in man-rem) according to work and job functions (e.g., reactor operations and surveillance, inservice inspection, routine maintenance, special maintenance (describe maintenance), waste processing, and refueling). This tabulation supplements the requirements of 10 CFR 20.2206. The dose assignments to various duty functions may be estimated based on electronic or pocket dosimeter, thermoluminescent dosimeter (TLD), or film badge measurements. Small exposures totaling less than 20 percent of the individual total dose need not be accounted for. In the aggregate, at least 80 percent of the total whole body dose received from external sources should be assigned to specific major work functions.

Licensee Controlled Specification 1.7.8 requires a report to 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, for each (non-significant) change to or 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 shall report the nature of the change or error and its 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.

- 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 FSAR updates required by 10 CFR 50.71(e).

2.0 Summary of Plant Operations

This section contains a narrative summary of the operating experience at Columbia Generating Station (Columbia) during calendar year 2004. The information 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 30, 2004, the station's longest run to date ended when the reactor scrammed automatically on high Reactor Pressure Vessel (RPV) pressure due to a digital electro-hydraulic (DEH) card failure and subsequent closure of main turbine governor valve 1. The reactor was brought to criticality on August 14 and reactor power was increased in preparation for electrical power generation. The reactor was manually scrammed from about 18 percent power on August 15. The scram was in response to a feedwater pump trip that was due to a high water level in the pumped drain tank. The main condenser high water level caused the high level in the drain tank. The reactor was brought to criticality on August 16 and then the reactor was manually scrammed from about 20 percent power on August 17. The reactor was scrammed in response to a feedwater pump trip, which was due to low pump suction pressure induced when feedwater heaters were rapidly filled after repairs. The station returned to full power on August 24 and operated continuously for the remainder of the calendar year.

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

3.0 Outages and Forced Reductions in Power

This section contains information 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 due to an outage (scheduled or forced) or a component failure or other condition that requires that the load on the unit be reduced for corrective action immediately or up to and including the very next weekend (Regulatory Guide 1.16, Section C.1.b.(2)).

January 24 - 28, 2004 (approximately 89 hours at reduced power)
On January 24, 2004, power was reduced to 60% to perform on-line tube plugging in the main condenser. This was in response to increasing condenser tube leakage. On January 27, 2004, the repairs were completed and full power operation was resumed on the morning of January 28, 2004.

May 25 - 26, 2004 (approximately 45 hours at reduced power)
Early in the morning on May 25, 2004, a downpower to plug a leaking main condenser tube(s) commenced. Power was reduced to about 60%. The tube leak was located and plugged, and full power operation was resumed just before midnight on May 26, 2004.

June 10, 2004 (approximately 15 hours at reduced power)
On the morning of June 10, 2004, power was reduced to about 75% in response to an inadvertently mispositioned control rod. The mispositioned rod was fully inserted and the plant was stabilized. Full power operation was resumed late in the evening on June 10, 2004.

The mispositioned control rod was due to a human performance error. Corrective actions for this human performance error included revising Operations individual performance standards and expectations, establishing department trend parameters for human performance and reinforcing error prevention tools. Operations initiated a department performance improvement plan to continue to address creating, communicating, coaching and reinforcing department expectations.

June 27 - 30, 2004 (approximately 81 hours at reduced power)
Early on June 27, 2004, while the plant was at approximately 85% power to recover control rods following preventative maintenance, a first stage low pressure feedwater heater tripped on high level. This in turn tripped a second stage low pressure heater and a third stage low pressure heater. The first and second stage heaters were originally removed from service, as directed by procedure, when power was reduced below 950 MWe. As the first stage heater was being returned to service, following the restoration of the second stage heater, an operator error caused the trip of the three heaters. The tube side relief valve for the first stage heater lifted and would not reseat properly. Power was reduced to about 60% to recover the third stage heater while the work on the relief valve was started. After the relief valve was repaired, the heaters were returned to service following normal operating procedures. Full power operation was resumed late in the morning on June 30, 2004.

The human performance issue was addressed directly with the individual and by reinforcing the need for pre-job briefs and peer checking with the operating crews. The procedure for restoring heaters was also revised.

The problem with relief valves failing to reseat is being addressed as a programmatic issue. The system engineer will work closer with component engineers and Operations to determine if changes can be made to the system or to the way the system is operated to mitigate relief valve lifting.

July 30 - August 17, 2004 (approximately 426 generator off-line hours)
On July 30, 2004, the reactor scrammed automatically on high reactor pressure vessel pressure due to a DEH card failure and subsequent closure of main turbine governor valve 1. **[LER-2004-004-00]** In addition to replacing the failed card, the critical path activities for this forced outage were the disassembly, repair and testing of two main steam isolation valves (MS-V-22D and MS-V-28D). Additional significant safety-related corrective maintenance included replacing a containment isolation valve (MS-V-67D), replacing the position indicating probes for two control rods, and repairing the packing leak inside the containment on the B reactor coolant recirculation (RRC) pump discharge valve. The reactor was brought to criticality on the afternoon of August 14, 2004, and reactor power was increased in preparation for electrical power generation.

Initially, the scope of work for the forced outage was focused on the DEH repairs and previously identified outage activities. However, problems were identified with the MSIVs during the transition to cold shutdown. The unplanned MSIV repair activities extended the critical path for the forced shutdown. To mitigate the impact of valve problems on forced outages, several corrective actions are being implemented to identify potential problems with the MSIVs and to prepare in advance for unplanned MSIV repairs during forced outages. These actions include development of reliability matrices, implementation of preventative maintenance optimization, and establishment of contingency plans.

During power ascension, the reactor was manually scrammed from about 18% power on August 15, 2004. The scram was in response to the operating feedwater pump trip that was due to a high water level in the pumped drain tank. The main condenser high water level caused the high level in the drain tank. **[LER-2004-005-00]** The reactor was brought to criticality on the morning of August 16, 2004, and the generator was connected to the grid early on the morning of August 17, 2004.

The high level in the condenser was attributed to operating the hotwell level controller at the high end of the operating band during the forced outage and the failure to restore the controller for normal operations. The failure to adjust the controller adequately was caused by inadequate interface requirements between normal operating conditions and shutdown waste management strategies. To preclude the recurrence of the high hotwell levels, procedures have been revised regarding normal operating bands for the hotwell and the condensate storage tanks. Guidance has also been developed regarding plant inventory practices.

August 17 - 22, 2004 (approximately 135 generator off-line hours)
On the morning of August 17, 2004, the reactor was manually scrammed from about 20% power. The scram was in response to the operating feedwater pump trip, due to low pump suction pressure, induced when feedwater heaters were rapidly filled after repairs. The cause of the scram was due to a human performance error. **[LER-2004-006-00]** Critical path activities for this portion of the outage were repairing the drive unit for source range monitor C, correcting

the signal cable problem under vessel for two local power range monitors, and replacing the detector for intermediate range monitor F. On the evening of August 22, 2004, the main generator was synchronized to the grid. Full power operation was resumed on the morning of August 24, 2004.

As corrective actions, Operations department pre-job briefs are conducted by a Senior Reactor Operator (SRO) and work order plant impacts are prepared or planned by an SRO and then independently verified by a different SRO. The human performance issues were addressed with individuals directly involved in the event. The procedure for recovering feedwater heaters was revised to include special instructions for this task. An assessment of the corrective actions is scheduled to be performed to ensure the corrective actions were effective in preventing recurrence.

4.0 Radiation Exposure

This section contains the annual work and job function information pertaining to occupational radiation exposure. This information is included pursuant to Technical Specification 5.6.1 and Regulatory Guide 1.16, Section C.1.b.(3).

In 2004, one hundred seventy people received more than 100 mrem. The total dose received, by the 170 people that received more than 100 mrem, was 45.267 rem.

The special maintenance activities discussed in the following table include:

- Repair of main steam isolation valve (MS-V-22D);
- Repair of main steam isolation valve (MS-V-28D);
- Furmanite repair of feed water heater drain tank (HD-TK-3A);
- Main turbine condenser set-up for dewatering of condenser water box in preparation for tube plugging.

The numbers reported in the "Number of Personnel Receiving>100 mrem" are based on the fraction of an individual's total time in the radiologically controlled area that is spent in each of the work categories. These fractions are summed to obtain the results shown in the table.

Reg. Guide 1.16 Work and Job Function Report for CY 2004

Work & Job Function	Number of Personnel Receiving >100 mrem			Total Man-Rem		
	Station Employees	Utility Employees	Contract Workers and Others	Station Employees	Utility Employees	Contract Workers and Others
Reactor Operations & Surveillance						
Maintenance Personnel	3.81	0.24	0.46	1.546	0.068	0.046
Operating Personnel	0.38	0.00	0.00	0.449	0.000	0.000
Health Physics Personnel	0.23	0.04	0.06	0.418	0.033	0.063
Supervisory Personnel	0.00	0.01	0.00	0.000	0.001	0.000
Engineering Personnel	0.24	0.43	0.00	0.031	0.028	0.000
Routine Maintenance						
Maintenance Personnel	54.62	2.64	27.09	12.658	0.914	9.736
Operating Personnel	21.61	0.00	0.00	3.728	0.000	0.000
Health Physics Personnel	36.73	2.91	3.81	8.324	0.478	1.516
Supervisory Personnel	0.00	0.74	0.00	0.000	0.179	0.000
Engineering Personnel	0.66	2.90	3.00	0.441	0.649	1.215
Inservice Inspection						
Maintenance Personnel	0.11	0.00	0.07	0.023	0.000	0.023
Operating Personnel	0.03	0.00	0.00	0.007	0.000	0.000
Health Physics Personnel	0.03	0.00	0.00	0.034	0.000	0.003
Supervisory Personnel	0.00	0.00	0.00	0.000	0.000	0.000
Engineering Personnel	0.06	0.35	0.00	0.023	0.072	0.000
Special Maintenance						
Maintenance Personnel	1.57	0.17	2.38	0.553	0.065	0.709
Operating Personnel	0.00	0.00	0.00	0.000	0.000	0.000
Health Physics Personnel	0.40	0.00	0.12	0.249	0.000	0.098
Supervisory Personnel	0.00	0.25	0.00	0.000	0.065	0.000
Engineering Personnel	0.03	0.32	0.00	0.002	0.038	0.000
Waste Processing						
Maintenance Personnel	0.08	0.15	0.00	0.043	0.056	0.000
Operating Personnel	0.00	0.00	0.00	0.000	0.000	0.000
Health Physics Personnel	1.26	0.04	0.02	0.650	0.020	0.013
Supervisory Personnel	0.00	0.00	0.00	0.000	0.000	0.000
Engineering Personnel	0.00	0.00	0.00	0.000	0.000	0.000
Refueling						
Maintenance Personnel	0.00	0.00	0.00	0.000	0.000	0.000
Operating Personnel	0.00	0.00	0.00	0.000	0.000	0.000
Health Physics Personnel	0.00	0.00	0.00	0.000	0.000	0.000
Supervisory Personnel	0.00	0.00	0.00	0.000	0.000	0.000
Engineering Personnel	0.00	0.00	0.00	0.000	0.000	0.000
TOTAL						
Maintenance Personnel	60.19	3.20	30.00	14.823	1.103	10.514
Operating Personnel	22.02	0.00	0.00	4.184	0.000	0.000
Health Physics Personnel	38.65	2.99	4.01	9.675	0.531	1.693
Supervisory Personnel	0.00	1.00	0.00	0.000	0.245	0.000
Engineering Personnel	0.99	4.00	3.00	0.497	0.787	1.215
Grand Total	**121.85**	**11.19**	**37.01**	**29.179**	**2.666**	**13.422**

Total number of personnel receiving >100 mrem = 170 Total man-rem for personnel receiving > 100 mrem = 45.267 Report produced from electronic dosimeter data

5.0 Sealed Source Contamination

There were no incidents of sealed source contamination during 2004 that required reporting in accordance with Columbia Licensee Controlled Specification 1.7.8.

6.0 Fuel Performance

This section contains information relative to fuel integrity pursuant to Regulatory Guide 1.16, Section C.1.b.(4), and FSAR Section 4.2.4.3, "Post-Irradiation Surveillance."

Fuel Integrity
No fuel failures were identified during calendar year 2004 (Cycle 17). 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 the INPO threshold for fuel failures of 300 microCi/sec. The values for the Xe-133/Xe-135 and Xe-138/Xe-133 activity ratios have been within the range for an intact core.

Fuel Corrosion Update
Columbia did not experience any fuel defects or gross cladding anomalies during 2004. Accordingly, fuel inspections are not required per FSAR commitments. However, both SVEA-96 and ATRIUM-10 fuels are scheduled to be inspected during the May 2005 (R17) outage. These inspections are in response to the Energy Northwest implementation, in recent years, of several new water chemistry programs. These programs include noble metals addition, iron and zinc injection, and hydrogen water chemistry injection.

7.0 10 CFR 50.46 Changes or Errors in ECCS LOCA Analysis Models

This section contains information relative to non-significant changes and errors in Emergency Core Cooling System (ECCS) cooling performance models pursuant to 10 CFR 50.46.

Westinghouse methodology was used to license SVEA-96 fuel in the Columbia core. No errors were discovered in the Westinghouse ECCS LOCA analysis model and no revisions have been made to the Columbia LOCA Analysis Report during 2004.

AREVA Framatome-ANP (FANP) 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 have been made to the Columbia LOCA Analysis Report during 2004.

Below is a correction to a previous report on the changes and errors associated with the ECCS Evaluation Models.

- Section 2.5 of the Columbia Generating Station 2001 Annual Operating Report stated that, "For the SPC fuel, there was an error in the GE ECCS LOCA analysis model which resulted in the accumulated licensing basis upper-bound peak cladding temperature being increased by 5° Fahrenheit..." This statement could be confusing. There is a "licensing basis" peak cladding temperature and an "upper-bound" peak cladding temperature. There is no "licensing basis upper-bound peak cladding temperature". The statement should have read "For the SPC fuel, there was an error in the GE ECCS LOCA analysis model which resulted in the accumulated licensing basis peak cladding temperature being increased by 5° Fahrenheit..." The reported PCT value was correct.

8.0 10 CFR 50.59 Changes, Tests, and Experiments

This section contains the summary of the evaluations for activities implemented during 2004 that were assessed pursuant to 10 CFR 50.59 requirements.

Energy Northwest implemented the revised 10 CFR 50.59 rule in August 2001. Four evaluations were performed for activities implemented in 2004, under the revised rule. One change, implemented in 2004, was evaluated under the old rule, in 2000. Accordingly, the term *unreviewed safety question* still applies to the evaluation that was approved under the old rule.

Each change summarized in the following sections was evaluated and no change required NRC approval, represented an unreviewed safety question, or required a change to the Technical Specifications.

PLANT MODIFICATION RECORD 97-0037-17s (Safety Evaluation 00-0023)
This plant modification provided for the installation of permanent platforms and step ladders in the day tank rooms for each of the emergency diesel generators. In 2004, the platform and step ladder for the high pressure core spray system diesel generator day tank room was installed. The platform replaced temporary scaffolding that was installed to facilitate access to the day tank measuring ports.

Evaluation Summary
The installed platform and step ladder perform a passive function of allowing access to the measuring ports. The platform and step ladder were designed and installed in accordance with seismic requirements to ensure that they would not have any adverse impacts or interactions with important to safety structures, systems, or components (SSC). The evaluation concluded that the plant modification did not represent an *unreviewed safety question.*

PLANT DESIGN CHANGE 0000001749 (50.59-03-0002)
The Hydrogen Water Chemistry (HWC) System was installed to mitigate intergranular stress corrosion cracking (IGSCC) of the stainless steel reactor internals and piping. The HWC is a General Electric designed system to inject hydrogen into the feed water system to recombine with the excess oxygen. The low hydrogen injection rate, which is compatible with the previous noble metals application (Noblechem™), facilitates IGSCC mitigation without the large nitrogen-16 radiation increases associated with higher hydrogen injection rates. The hydrogen injection rate to Electrochemical Potential (ECP) correlation was determined by testing using the ECP probes in the Mitigation Monitoring System. Radiolysis, which produces stoichiometric amounts of hydrogen and oxygen, is reduced by the addition of hydrogen. The resulting off gas stream contains hydrogen in excess of the stoichiometric amounts. Therefore, air is injected into the off gas system for recombination with the hydrogen. Hydrogen injection was initiated in November 2004 and the HWC system was turned over to the plant in January 2005.

Evaluation Summary
The HWC equipment, hydrogen injection to the reactor coolant system, bulk hydrogen storage, the post modification testing, as well as the overall HWC environment and its impact were evaluated. The HWC system will create a reactor coolant environment that will minimize the initiation of IGSCC in reactor components. Improving the resistance to IGSCC will lower the probability of malfunctions or accidents due to the corrosion induced failures. The changes to the off gas system will maintain the system within design parameters causing no increase in the frequency of system failures. The increased in nitrogen 16 levels will not impact the radiological consequences of the design bases accidents.

INSERVICE INSPECTION (ISI) PROGRAM PLAN CHANGE (50.59-03-0001)
Section 6.2.1 of the ISI Program Plan defines the number of augmented piping examinations that are required to be performed in the break exclusion region (BER) piping. The criterion to examine all circumferential butt welds within the BER was changed to the selection of welds for examination using a risk-informed process. The selection process follows the NRC approved methodology in "Extension of the EPRI Risk-Informed Inservice Inspection (RI-ISI) Methodology to Break Exclusion Region (BER) Programs," EPRI Document 1006937, Revision 0-A dated August 2002. The change does not affect the 10CFR50.55a portion of the ISI Program Plan. (The ISI Program Plan is incorporated into the FSAR by reference.)

Evaluation Summary
The proposed activity implements an NRC approved methodology as an alternative to existing requirements in the ISI Program Plan. All items and conditions as stipulated in the NRC issued SER for EPRI Document 1006937 are met by this proposed activity.

LICENSEE CONTROLLED SPECIFICATION (LCS) CHANGE
LDCN-LCS-03-057 (50.59-04-0006)
The interval for the channel calibration of the overcurrent protection relays, pursuant to LCS Surveillance Requirement (SR) 1.8.10.1, was extended from 18 to 24 months to accommodate a 24-month fuel cycle. The relays (primary and backup) protect the primary containment electrical penetrations for the 6.9-kV RRC pumps. The RRC pumps must be de-energized for the primary overcurrent protection relay channel calibration. To schedule the calibration during refueling outages, the interval was changed to 24 months. The backup overcurrent protection relay channel calibration can be performed while the 6.9-kV RRC circuits are energized. However, to maintain consistency with the primary relays, the backup relay interval was also extended.

The design function of these protective relays is to limit the fault current heating experienced by the penetration conductors to levels below the conductor ratings thereby preventing a challenge to primary containment integrity. The periodic channel calibration surveillance requirement for the 6.9-kV overcurrent relays demonstrates the operability of the primary and backup overcurrent protective relays. Although these overcurrent protective devices are not considered to function in any design basis accident or transient, evaluation of the extension of the SR interval was performed using the guidance provided in Generic Letter (GL) 91-04, "Changes in Technical Specification Surveillance Intervals to Accommodate a 24-month Fuel Cycle." The GL 91-04 assigns 3 criteria that must be met in order to extend the SR interval.

Evaluation Summary
Due to the mechanical nature of the design of the relay devices, the calculation methodology that determines the protective relays tap and time dial settings does not consider instrument drift or calibration frequency as an input. This indicates the relay devices are not susceptible to instrument drift over time. For this reason, extension of the calibration interval from 18 to 24 months does not affect performance of the relays within the parameters required to ensure integrity of the penetrations. Therefore, the extension of the SR interval does not affect either the design function or the calculation methodology of the protective relays and therefore does not affect safety.

Surveillance procedures and maintenance records indicate the overcurrent protection devices have performed reliably within expected parameters and needed little or no calibration adjustments over the current 18-month interval, supporting the conclusion that there is no effect on safety presented by the extending the surveillance interval.

The loss of these protective devices is a non-significant risk contributor to core damage frequency and offsite release. The calibration interval is not discussed or specified anywhere else in the license bases, other than the LCS that was changed. Therefore, this proposed change does not invalidate any assumption in the plant licensing basis.

No postulated accidents, transients, or malfunctions are impacted by the increase in the surveillance test interval. Therefore, the change will not increase the frequency or probability of occurrence of an accident or malfunction. The change did not directly or indirectly affect the capability of any important to safety SSC to perform the intended safety functions. The change does not create the potential for a new type of event or adverse impact on the fission product boundaries. The change has no impact on the methodologies used to establish the design bases for the station.

LICENSEE CONTROLLED SPECIFICATION (LCS) CHANGE
LDCN-LCS-04-024 (50.59-04-0007)
Two changes were made to LCS 1.8.11, Motor Operated Valve (MOV) Thermal Overload (TOL) Protection. In the first change, 8 MOVs (MS-V-1, 2, and 20, RHR-V-74A, 74B, 123A, and 123B, and SW-V-90) were removed from the LCS because they are not Class 1E and do not perform any active safety related function. In the second, the surveillance frequency for the TOL was extended from 18 months to 24 months to facilitate better coordination with the two year fuel cycle.

The primary function of TOL devices is to protect the motor windings against excessive heating. However, when the application involves MOVs with an active safety-related function, concerns about motor protection are secondary to the need to ensure that the safety-related function of the valve is completed. The TOLs in such applications are conservatively sized (approximately 140% of motor full load amps) to assure the safety related function of the MOV is completed prior to tripping of the TOL device.

The LCS identifies the station MOVs with TOL protection for which periodic surveillance procedures are performed to check setpoint drift and verify reliability of the TOL devices. Testing the TOLs on the valves deleted from the LCS table has been discontinued.

Section 8.3.1 of the FSAR and NRC Regulatory Guide (RG) 1.106 provide the basis for the scope of the MOVs included in the test population. The scope is limited to active safety-related MOVs classified Class 1E that are equipped with TOL protective devices. Hence, if the MOV performs no active safety related function and is not Class 1E it can be deleted from LCS Table 1.8.11-1. Such is the case for the 8 MOVs deleted from the LCS. Evaluation of the SR interval extension was performed using the guidance provided in Generic Letter (GL) 91-04, "Changes in Technical Specification Surveillance Intervals to Accommodate a 24-month Fuel Cycle." The GL 91-04 assigns 3 criteria that must be met in order to extend the SR interval.

Evaluation Summary

This evaluation was performed to determine if NRC approval is required to delete the 8 valves from the LCS or to extend the surveillance frequency from 18 to 24 months for performing a channel calibration of a representative sample of the MOV TOLs listed in the LCS. Testing MOV TOLs does not cause or prevent failures, but does provide a means of detecting failed TOLs.

Since each of the deleted valves is maintained in its safety related position, failure of the MOV to operate on demand has no impact on the ability of the valve and associated SSCs to perform their safety related function(s). Deletion of these valves from the LCS table is acceptable and can be implemented without NRC approval.

The evaluation also supports the conclusion that interval extension has a minimal potential for increasing the occurrence of MOV failure during a design basis accident due to a failed TOL.

The safety related function of MOV TOLs is not explicitly considered in any design basis accident or transient. They are however, expected to perform their safety related function during any event considered in the safety analysis. The channel calibration verifies the TOLs perform their passive safety related function of maintaining circuit continuity for a sufficient period of time to assure that the safety related function of associated MOVs will be accomplished before the TOL trips. Performance within acceptable parameters ensures, in part, that associated MOVs will remain capable of performing intended safety related function(s) on demand under design basis conditions.

The negative impact of changing the TOL test frequency from 18 months to 24 months was determined to be insignificant. Extending the test frequency may result in delayed detection of a fault. The likelihood of any TOL failure is small. The chances of having a TOL fail due to excessive setpoint drift such that it goes undetected during normal plant operation and surveillance activities, but would prematurely trip during a design basis event has even a smaller likelihood.

Extending the test frequency does not affect the failure rate or likelihood of MOV failure during a design basis event. Since the likelihood of MOV failure is unchanged, there is no change to the probabilities associated with accident initiation or to the ability of the plant to achieve safe shutdown and mitigate the consequences of an accident.

A review of maintenance and surveillance history indicates that the MOV TOL devices are highly reliable. No instances of excessive setpoint drift were noted.

Since the MOV TOL device surveillance interval is not discussed or specified anywhere else in the license bases, this proposed change does not invalidate any assumption in the plant licensing basis.

In conclusion, the deletion of the selected valves from the LCS and the extension of the 18 month surveillance interval to 24 months do not result in more than a minimal increase in the frequency of occurrence of an accident or malfunction or in the consequences of the accident or malfunction. The changes do not create the potential for a new type of event or adverse impact on the fission product barriers. The changes have no impact on the methodologies used to establish the design bases for the station.

9.0 10 CFR 72.48 Changes, Tests, and Experiments

There were no activities implemented during 2004 that required reporting pursuant to 10 CFR 72.48 requirements.

10.0 Regulatory Commitment Changes (NEI 99-04 Process)

This section contains information pertaining to Regulatory Commitment Changes (RCC) and is included pursuant to the NEI Guidelines for Managing NRC Commitment Changes. Included is one commitment change that satisfied the NEI 99-04 criteria for reporting.

Cooling Coil Inspection Requirements (RCC-110797)
The original commitment was that in lieu of thermal performance testing, Energy Northwest would perform annual preventive maintenance inspections on the air side of all the air-to-water service water cooling coils to ensure the coil fins are clean and clear (reference letter GO2-90-017, dated February 5, 1990, GC Sorensen to NRC, Response to Generic Letter 89-13, Service Water System Problems Affecting Safety-Related Equipment).

The commitment was revised to change the frequency from annual to biennial for the service water cooling coil inspections. Based upon a review of the maintenance history of these cooling coils, and the subsequent lack of required cleaning, Energy Northwest concluded that extending the frequency to biennial will not result in any loss of capability or qualification for any of the subject coils. The biennial inspection frequency will be adequate to ensure the air side cleanliness of the service water air-to-water cooling coils.