KEWAUNEE NUCLEAR POWER PLANT

ANNUAL OPERATING REPORT

1993

WISCONSIN PUBLIC SERVICE CORPORATION
WISCONSIN POWER & LIGHT COMPANY
MADISON GAS & ELECTRIC COMPANY

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1.0 INTRODUCTION

The Kewaunee Nuclear Power Plant is a pressurized water reactor licensed at 1650 megawatts thermal (MWt). It is located in Kewaunee County, Wisconsin, along Lake Michigan's northwest shoreline and is jointly owned by Wisconsin Public Service Corporation, Wisconsin Power and Light Company and Madison Gas and Electric Company. The nuclear steam supply system was purchased from Westinghouse Electric Corporation and is rated for a 1721.4 MWt output. The turbine-generator was also purchased from Westinghouse and is rated at 535 megawatts electric (MWe) net. The architect/engineer was Pioneer Service and Engineering (PSE).

The Kewaunee Nuclear Power Plant achieved initial criticality on March 7, 1974. Initial power generation was reached April 8, 1974, and the plant was declared commercial on June 16, 1974. Since being declared commercial, Kewaunee has generated 72,491,953 MW hours of electricity as of December 31, 1993, with a net plant capacity factor of 82.5 using net maximum dependable capacity (MDC).

1.1 Highlights

During 1993, the Kewaunee Nuclear Power Plant was primarily base loaded. The unit was operated at 85.3% capacity factor (using net MDC) with a gross efficiency of 33.4%. The unit and reactor availability were 86.2% and 86.8% respectively. Figure 1.1 provides a histogram of the average daily electrical output of the Kewaunee Plant for 1993.

On March 6, 1993, the unit was removed from service for its eighteenth annual refueling maintenance overhaul. Thirty-six fresh fuel assemblies were loaded for Cycle XIX. The unit was returned to service on April 16, 1993.

As indicated on Figure 1.1, the Kewaunee Nuclear Power Plant experienced an automatic reactor trip on January 28, 1993, due to Bus 1 and 2 undervoltage reactor trip signal. A phase to phase fault in the "B" main feedwater pump motor tripped its supply breaker and caused Bus 1 and 2 undervoltage.

A scheduled outage to repair primary to secondary system leakage in "B" Steam Generator commenced on June 4, 1993, when G-1 was opened. Repairs to a leaking tube plug were successfully completed on June 9, 1993. G-1 was closed on June 12, 1993, and 100% power was reached on June 20, 1993.

KEWAUNEE POWER HISTORY - 1993

AVERAGE DAILY MWE-NET

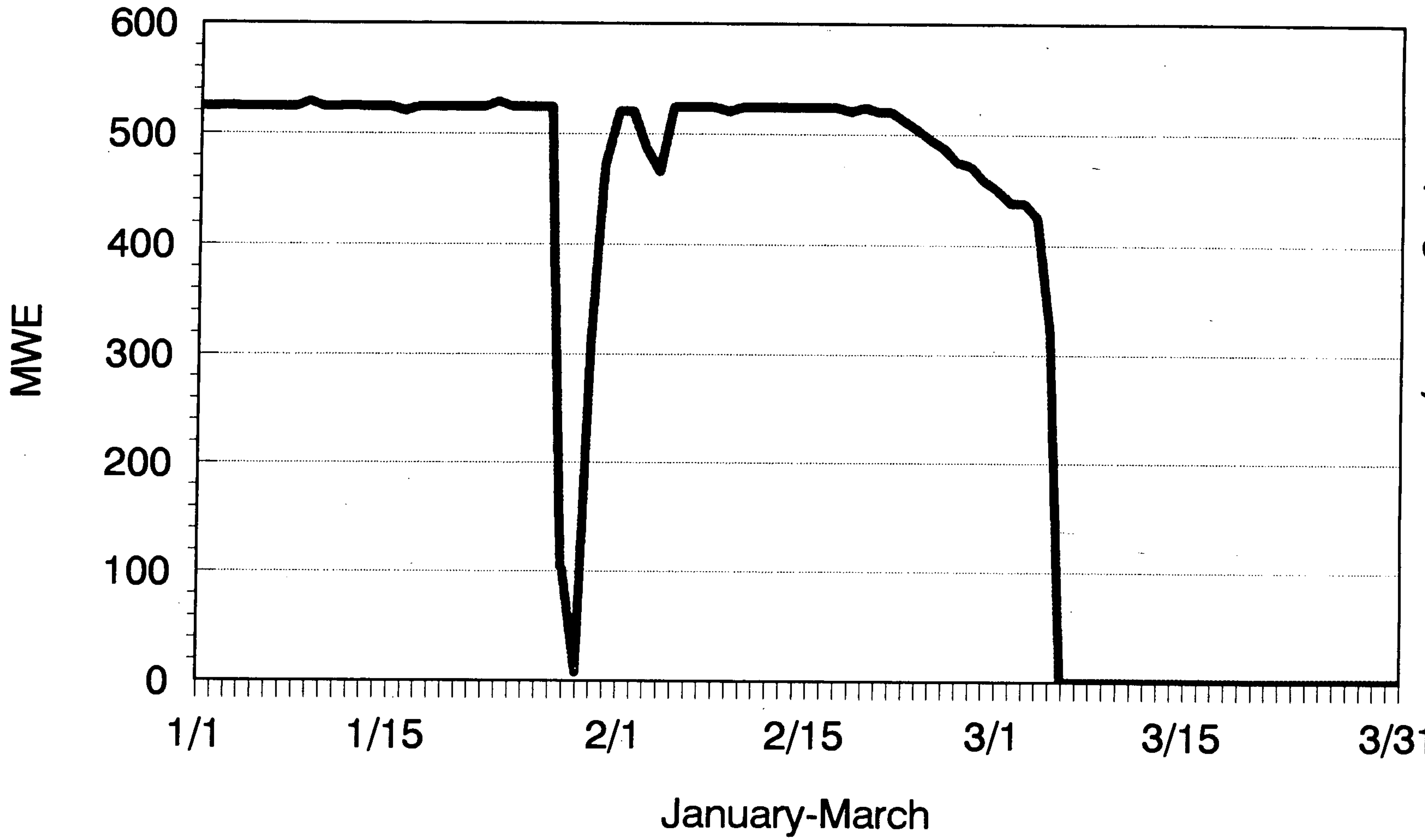

FIGURE 1.1
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KEWAUNEE POWER HISTORY - 1993

AVERAGE DAILY MWE-NET

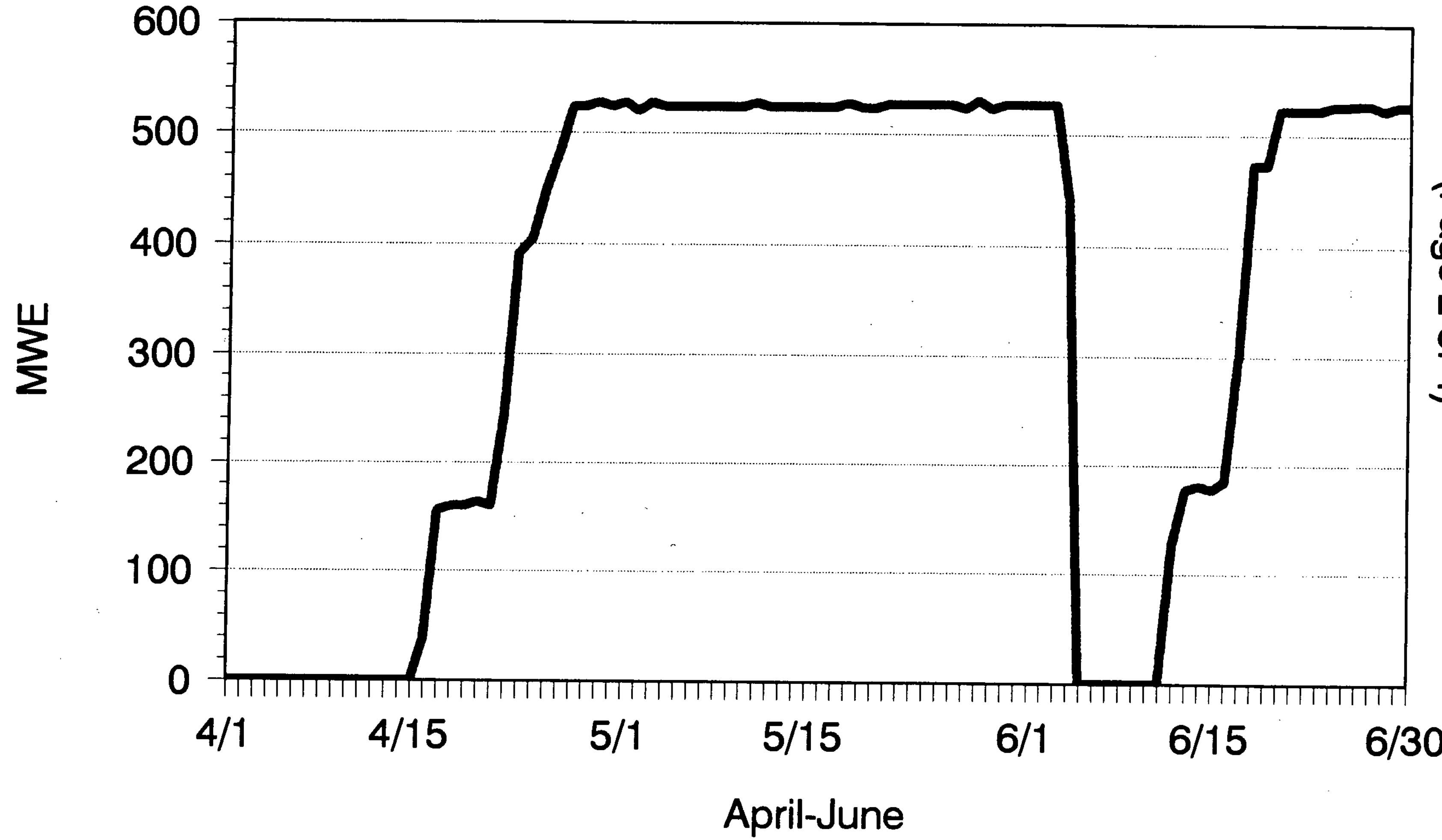

FIGURE 1.1
(Page 2 of 4)

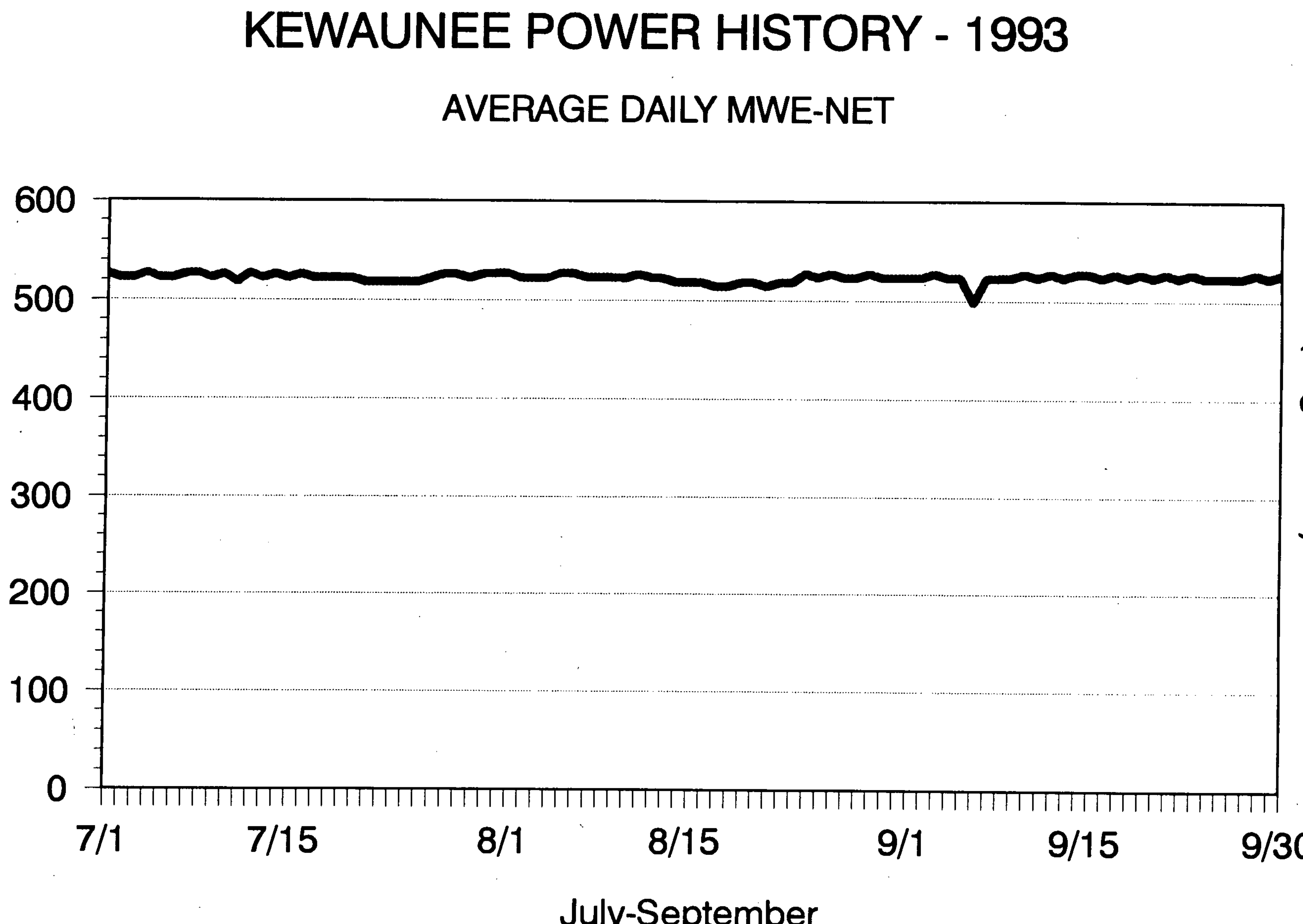

FIGURE 1.1
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KEWAUNEE POWER HISTORY - 1993

AVERAGE DAILY MWE-NET

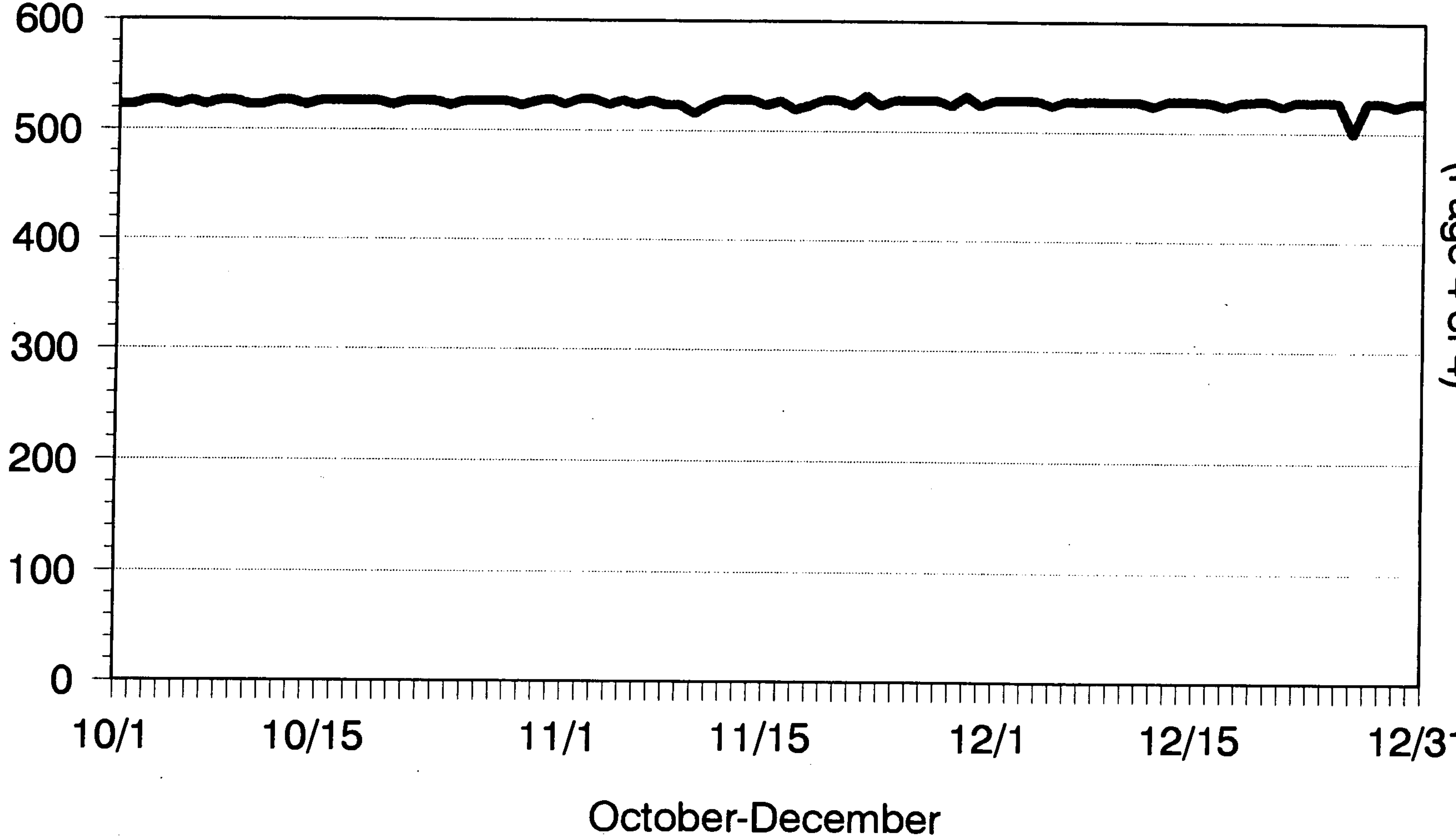

FIGURE 1.1
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2.0 SUMMARY OF OPERATING EXPERIENCE

JANUARY

An automatic reactor trip occurred on January 28, 1993 due to Bus 1 and 2 undervoltage reactor trip signal.

PLANT SHUTDOWNS: A forced outage of 41.3 hours began on January 28, 1993. An automatic reactor trip occurred due to Bus 1 and 2 undervoltage reactor trip signal. Phase to phase fault in "B" main feedwater pump motor tripped its supply breaker and caused Bus 1 and 2 undervoltage.

FEBRUARY

On February 3, 1993, unit load was reduced to 304 MWe to repair an oil leak on "B" Feedwater Pump Motor Outboard Bearing. Repairs were completed the same day; however, xenon oscillations necessitated a further power reduction to 282 MWe. 100% power was reached on February 4, 1993.

PLANT SHUTDOWNS: No shutdowns occurred during the month of February.

MARCH

The unit was shut down on March 6, 1993, to commence the Cycle XVIII - Cycle XIX refueling outage.

PLANT SHUTDOWNS: Scheduled shutdown of 599.8 hours. Commenced Cycle 18-19 refueling outage.

APRIL

The unit was returned to power operation on April 16, 1993, ending the Cycle XVIII - Cycle XIX refueling outage.

PLANT SHUTDOWNS: Scheduled shutdown of 364.3 hours for Cycle 18-19 refueling outage.

A short outage of 6.2 hours was taken to perform the turbine overspeed trip test on April 16, 1993.

MAY

Normal power operation continued through the month of May.

PLANT SHUTDOWNS: No shutdowns or power reductions occurred during the month of May.

JUNE

A scheduled outage occurred in June, 1993.

PLANT SHUTDOWNS: Scheduled shutdown of 174.12 hours to repair primary to secondary system leakage in "B" Steam Generator began on June 4, 1993 when G-1 was opened. Repairs to a leaking tube plug were successfully completed on June 9, 1993. G-1 was closed on June 12, 1993 and 100% power was reached on June 20, 1993.

JULY

Normal power operation continued through the month of July.

PLANT SHUTDOWNS: No shutdowns or power reductions occurred during the month of July.

AUGUST

Normal power operation continued through the month of August.

PLANT SHUTDOWNS: No shutdowns or power reductions occurred during the month of August.

SEPTEMBER

On September 6, 1993, power was reduced to 390 MWG to perform SP 54-086, Turbine Stop Valve Test. 100% power was reached the same day.

PLANT SHUTDOWNS: No shutdowns occurred during the month of September.

OCTOBER

Normal power operation continued through the month of October.

PLANT SHUTDOWNS: No shutdowns or power reductions occurred during the month of October.

NOVEMBER

Normal power operation continued through the month of November.

PLANT SHUTDOWNS: No shutdowns or power reductions occurred during the month of November.

DECEMBER

Normal power operation continued through the month of December.

PLANT SHUTDOWNS: No shutdowns or power reductions occurred during the month of December.

Table 2.1 is a compilation of the monthly summaries of the operating data and Table 2.2 contains the yearly and total summaries of the operating data.

TABLE 2.1
ELECTRICAL POWER GENERATION DATA (1993)

MONTHLY

	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE
Hours RX was Critical	706.3	672.0	120.2	397.7	744.0	550.4
RX Reserve Shutdown Hours	0.0	0.0	0.0	0.0	0.0	0.0
Hours Generator On-Line	702.7	672.0	120.2	348.5	744.0	545.9
Unit Reserve Shutdown Hours	0.0	0.0	0.0	0.0	0.0	0.0
Gross Thermal Energy Generated (MWH)	1136925.0	1085208.0	156579.0	381383.0	1227217.0	754286.0
Gross Electrical Energy Generated (MWH)	379200.0	360200.0	52800.0	125900.0	410500.0	251100.0
Net Electrical Energy Generated (MWH)	361263.0	342848.0	49898.0	117958.0	390753.0	237185.0
RX Service Factor	94.9	100.0	16.2	55.3	100.0	76.4
RX Availability Factor	94.9	100.0	16.2	55.3	100.0	76.4
Unit Service Factor	94.5	100.0	16.2	48.5	100.0	75.8
Unit Availability Factor	94.5	100.0	16.2	48.5	100.0	75.8
Unit Capacity Factor Using maximum dependable capacity (MDC) Net	95.0	99.8	13.1	32.1	102.8	64.5
Unit Capacity Factor (Using design electrical rating (DER) Net	90.8	95.4	12.5	30.7	98.2	61.6
Unit Forced Outage Rate	5.5	0.0	0.0	0.0	0.0	0.0
Hours in Month	744.0	672.0	744.0	719.0	744.0	720.0
Net MDC (MWe)	511.0	511.0	511.0	511.0	511.0	511.0

TABLE 2.1
ELECTRICAL POWER GENERATION DATA (1993)

MONTHLY

	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER
Hours RX was Critical	744.0	744.0	720.0	745.0	720.0	744.0
RX Reserve Shutdown Hours	0.0	0.0	0.0	0.0	0.0	0.0
Hours Generator On-Line	744.0	744.0	720.0	745.0	720.0	744.0
Unit Reserve Shutdown Hours	0.0	0.0	0.0	0.0	0.0	0.0
Gross Thermal Energy Generated (MWH)	1226890.0	1226800.0	1184271.0	1227961.0	1186431.0	1227368.0
Gross Electrical Energy Generated (MWH)	409800.0	408600.0	396500.0	411900.0	397500.0	409400.0
Net Electrical Energy Generated (MWH)	389201.0	388095.0	376951.0	391756.0	379034.0	390410.0
RX Service Factor	100.0	100.0	100.0	100.0	100.0	100.0
RX Availability Factor	100.0	100.0	100.0	100.0	100.0	100.0
Unit Service Factor	100.0	100.0	100.0	100.0	100.0	100.0
Unit Availability Factor	100.0	100.0	100.0	100.0	100.0	100.0
Unit Capacity Factor (Using MDC Net)	102.4	102.1	102.5	102.9	103.0	102.7
Unit Capacity Factor (Using DER Net)	97.8	97.5	97.9	98.3	98.4	98.1
Unit Forced Outage Rate	0.0	0.0	9.2	0.0	0.0	0.0
Hours in Month	744.0	744.0	720.0	745.0	720.0	744.0
Net MDC (MWe)	511.0	511.0	511.0	511.0	511.0	511.0

TABLE 2.2

ELECTRICAL POWER GENERATION DATA

1993

	YEAR	CUMULATIVE
Hours RX was Critical	7607.7	146994.2
RX Reserve Shutdown Hours	0.0	2330.5
Hours Generator On-Line	7550.3	145107.5
Unit Reserve Shutdown Hours	0.0	10.0
Gross Thermal Energy Generated (MWH)	12017408.0	229940146.0
Gross Electrical Energy Generated (MWH)	4015100.0	76161100.0
Net Electrical Energy Generated (MWH)	3816914.0	72491953.0
RX Service Factor	86.8	85.8
RX Availability Factor	86.8	87.2
Unit Service Factor	86.2	84.7
Unit Availability Factor	86.2	84.7
Unit Capacity Factor (Using MDC Net)	85.3	82.5
Unit Capacity Factor (Using DER Net)	81.4	79.1
Unit Forced Outage Rate	0.5	2.2
Hours in Reporting Period	8760.0	171338.0

3.0 PLANT MODIFICATIONS, TESTS AND EXPERIMENTS

10 CFR 50.59(a)(1) allows licensees to make changes in the facility as described in the Updated Safety Analysis Report and conduct tests and experiments not described in the Updated Safety Analysis Report without prior NRC approval, provided the change, test, or experiment does not involve a change in the Technical Specifications or an unreviewed safety question. 10 CFR 50.59(b)(2) requires those changes, tests, and experiments that do not need prior NRC approval be reported to the NRC on an annual basis.

During 1993 there were no modifications, tests, or experiments performed which introduced an unreviewed safety question.

The following summary of modifications and tests includes those 10 CFR 50.59 activities completed during 1993 and not previously reported. Each activity is briefly described, and a summary of the safety evaluation is provided.

CIRCULATING WATER SYSTEM (DCR 2232)

During the original design and construction of the circulating water system intake, splitter and diffuser vanes were installed in the bifurcation passages. The vanes, just upstream of the forebay, are intended to promote uniform flow in the bifurcation passages and the screenhouse bays. The ultimate objective is to have the flow in the circulating water pump suction passages as uniform as possible.

Inspection of the screenhouse forebay revealed detached and/or damaged vanes. This necessitated the removal of the splitter and diffuser vanes.

Summary of the Safety Evaluation

A reliable supply of water will be maintained by removing deteriorated vanes which could block the intake system. The velocity of water in the absence of the vanes is small enough to cause no significant problem in the operation of the circulating water pumps and the related plant systems, therefore, there is no impact on plant safety.

NUCLEAR INSTRUMENTATION SYSTEM (RG 1.97) (DCR 2289)

This modification upgraded the existing source range and intermediate range reactor power detection system to a safety related system in accordance with Regulatory Guide 1.97. The new system is QA Type 1 and Electrical Class 1E. The equipment is environmentally qualified for its respective locations and seismically qualified and mounted.

Summary of the Safety Evaluation

This modification did not change the system setpoints nor protective features, nor did it change system redundancy. The new system is more reliable and technologically more advanced than the previous system. Therefore, there was no effect on plant safety.

CONTROL ROD DRIVE STEP COUNTERS (DCR 2489)

This modification was initiated to replace the control rod step counters of mechanical control console B. Maintenance requirements on the existing units had increased and the original manufacturer could not supply replacement parts. The new step counters have been designed by a different manufacturer to be a one-for-one replacement.

Summary of the Safety Evaluation

The new step counters were designed as a direct replacement for the old step counters. No change in wiring, mounting, or operating voltages AC or DC were required. Therefore, there was no effect on plant safety.

DEGRADED GRID (DCR 2527)

During an internal Safety System Functional Inspection an incorrect assumption was discovered in the degraded grid undervoltage relay setpoint design. The NRC was notified of this in LER 91-02. Due to this error and the subsequent investigation, a number of modifications were made which included the following: 1) Changing tap setting on Station Service Transformers 1-52 and 1-62 to boost their secondary voltage 2-1/2 percent; 2) Raising the degraded grid undervoltage (UV) relay setpoint to 93.6 percent and lowering its time delay to six seconds; 3) Installing interposing relays on QA1 Motor Control Center starter control circuits with excessive voltage drops; 4) Raising the Reserve and Tertiary Auxiliary transformer source available UV relay setpoints to 97.3 percent; 5) Adding a high voltage alarm to the Honeywell Trouble Light Annunciator (TLA) to indicate approach to overvoltage on the 480V safeguard buses; 6) Replacing fire pump control switches and preventing their automatic operation during safety injection. Manual reset is possible using the control room switch; 7) Repowering Fire Pump 1A from its current source, Bus 1-52, to Bus 1-51; and 8) Ensuring Pressurizer Heater Backup Groups 1A and 1B do not operate automatically under safety injection conditions. Manual reset is possible using the control room switch.

Summary of the Safety Evaluation

These modifications will ensure that all safeguards equipment will function properly as required during degraded grid conditions. The changes could increase the probability of a malfunction if the degraded grid UV relay setpoint and/or time delay were incorrect and allowed operation on the offsite power source which disabled safeguards equipment. This should not occur since the computer models used to establish the setpoint conservatively assumed all safety injection loads were running. Additional computer cases were run assuming Unit Trip loads running to verify that the safety injection case was worst case. The UV setpoint was then established above the required voltage to allow for instrument drift between calibrations. The time delay setpoint was calculated so that its delay, plus drift and the time delays associated with the test of the voltage restoring logic up to and including closing of the diesel breaker would not exceed the 10 seconds already assumed in the Updated Safety Analysis Report accident analysis for diesel starting time.

The time delay of the degraded grid UV relays were shown to be short enough to prevent control circuit fuses from blowing during operation between the first level and degraded UV relay setpoints. In addition, the time delay and UV setpoint were shown by testing to be long enough and low enough to ride through "worst case" large motor starting voltage dips with the exception of the reactor coolant pump starts. Since the reactor coolant pump starting time of about 25 seconds exceeds the 6 second time delay of the degraded grid UV relays, they may actuate if initial safeguards bus voltage is less than 95.6 of nominal or 3980V. The Kewaunee substation and safeguards bus voltages are nonnally maintained very near, or above nominal voltage. Starts of reactor coolant pumps are infrequent. Although the probability of starting a reactor coolant pump concurrent with a safeguard bus being at a low voltage is, therefore, extremely unlikely, administrative controls have been implemented cautioning against starting a reactor coolant pump when low voltage exists on a safeguard bus.

Improper setting of the Reserve and Tertiary Auxiliary transformer source available UV relay could also increase the probability of occurrence of a malfunction, allowing unnecessary breaker cycling by allowing transfer of a bus to a source with insufficient voltage to reset the degraded grid relays. This was prevented by setting the Reserve and Tertiary Auxiliary transformer source available UV relays such that at their maximum drift low they will not overlap with the reset setpoint of the degraded grid relays at their maximum drift high.

The Service Station transformer tap changes combined with a higher maximum substation voltage resulted in a computer case under refueling mode conditions showing that 460V rated safeguard motors could be operating at up to 111.3 percent of rated voltage. A high voltage alarm was added from the 480V safeguard buses so that corrective action can be taken. All equipment should continue to operate while corrective action is taken, therefore, this is considered acceptable.

Installing interposing relays on QA1 Motor Control Center starter control circuits with excessive voltage drops provides added assurance that all 480V safeguards equipment contactors operate properly as assumed to mitigate the consequences of an accident as evaluated previously in the Updated Safety Analysis Report. For those contactors requiring the addition of an auxiliary relay, an active component was added to the control circuit. The relay and associated wiring being added is QA1 and its proper post-installation functioning is verified by retest. The addition of the relay will reduce the probability of a contactor malfunction caused by low voltage.

The fire pumps will not be allowed to start during a safety injection sequence to ensure an adequate diesel/generator margin for loading safeguards equipment. The safety injection auto-inhibit can be reset after step 10 of a safety injection sequence, but this is controlled by operator action based on monitoring diesel/generator loading and recommendations from the Independent Plant Emergency Operating Procedures. In addition, the 1A Fire Pump source breaker change from bus 1-52 to 1-51 will not increase the 1-5 bus loading and will not degrade bus 1-51 beyond allowable steady-state limits. During an accident scenario requiring actuation of Engineered Safety Feature components, the fire pump start is not a concern (reference Branch

Technical Position IV A.4, "Postulated fires or fire protection system failures need not be considered concurrent with other plant accidents. . . ."

A written safety evaluation report on the installation of a mechanical latching relay to the pressurizer heater backup group, coincident with a safety injection signal, to ensure that Pressurizer Heater Backup Groups 1A and 1B do not operate automatically under safety injection conditions was provided by Westinghouse and Advanced Nuclear Fuels. Both of these analyses, in addition to the WPSC review of USAR Chapter 14, conclude that this change does not involve an unreviewed safety question as defined in 10 CFR 50.59. This is based on that pressurizer heaters are not modeled for any Loss of Coolant Accident (LOCA) related accidents.

SPARE REACTOR COOLANT PUMP MOTOR (DCR 2586)

This modification replaced the "A" Reactor Coolant Pump Motor with a new upgraded and functionally equivalent motor. The new motor is interchangeable with WPSC's original motor.

Summary of the Safety Evaluation

Several upgrades were implemented in the new Reactor Coolant Pump Motor. The new motor will enhance the reliability and operation of the reactor coolant pump and is functionally equivalent to the existing motor, therefore, safety is not affected.

REACTOR COOLANT PUMP MOTOR REFURBISHMENT (DCR 2609)

This modification refurbished the old "A" reactor coolant pump motor that was removed during the 1992 refueling outage. The motor was refurbished by Westinghouse and was installed on the "B" pump during the 1993 refueling outage. The old "B" reactor coolant pump motor will be stored for several years awaiting future refurbishment.

Summary of the Safety Evaluation

It is Westinghouse's recommendation to refurbish reactor coolant pump motors in order to maintain their high reliability. The refurbished motor enhanced the reliability and operation of the "B" reactor coolant pump, therefore, there was no effect on plant safety.

CONTROL ROOM AIR CONDITIONING (DCR 2656)

The Control Room Air Conditioning Chiller Compressor 1B was replaced with a new compressor. The new compressor was evaluated and found acceptable, based on the motor supplied with the unit being equivalent to the original motor. The new motor had different nameplate voltage (460V versus 480V) and locked rotor current (375 amp versus 320 amp) from the original.

Summary of the Safety Evaluation

The motor's electrical characteristics were evaluated. The replacement motor was shown to be electrically acceptable. The nameplate voltage change is actually an improvement over the old motor as 460 volt rated motors are preferred in order to ensure operation within $\pm 10\%$ of nameplate voltage with KNPP's degraded grid undervoltage relays set to maintain 414 volts or greater at all safeguard Motor Control Centers. The increased locked rotor current of the new motor is shown to not be large enough to cause tripping of the motor's thermal overload or molded case circuit breaker at degraded grid or high voltage conditions. Therefore, this modification did not adversely affect plant safety.

ADDITIONAL MODIFICATIONS

The following design changes did not require a 10 CFR 50.59 safety evaluation (i.e., an unreviewed safety question evaluation); however, are being reported for information only due to their significance.

CONTROL ROOM METERS AND RECORDERS (DCR 1884)

This modification changed the labeling of the scales of meters and recorders in the control room. The meters and recorders are QA-Type 2 or 3. The changes were made to aid the operator by improving readability of the meters and recorders. The changes will help reduce the chances of human error thereby increasing the overall safety of the plant.

TURBINE DRIVEN AUXILIARY FEEDWATER PUMP (DCR 2239)

This design change installed a new steam admission valve and a new Woodward PG-PL governor on the Turbine Driven Auxiliary Feedwater Pump. This arrangement replaced the existing Woodward PG-D Model and a Fisher regulator. The Fisher regulator/PG-D combination was the cause of a high component failure rate. The new PG-PL governor works on the same basic principal as the PG-D except that it has additional start control features and an overspeed trip test feature. The turbine speed is first controlled at a low speed setting (approximately 30% of rated speed), then ramped up to rated speed. Time from turbine start to full rated speed is approximately 40 seconds. The controlled increase to rated speed minimizes the potential for an overspeed condition. Full Auxiliary Feedwater flow is still available within one minute after the signal for pump actuation; therefore, this change does not decrease plant safety.

HEATING STEAM PIPING AND SUPPORTS (DCR 2412)

This design change involved the installation of new pipe supports on the Heating Steam system in Battery Rooms 1A and 1B in order to upgrade the piping seismic design. The piping stress levels including seismic stress are to meet USAR allowables for Class I piping. The subject piping and support walkdowns were performed and designs initiated using NRC Bulletin 79-14 project procedures as a guide. This modification did not change the design, method, or function of the Heating Steam system; therefore, there is no affect on plant safety.

STATION BLACKOUT (DCR 2425)

KNPP's Station Blackout Design provides the Technical Support Center (TSC) diesel generator the capability of being connected to one of the two safeguards train A class 1E 480 volt buses (bus 1-52). The breaker operations for connecting the AAC source to the safety bus is performed by local manual actions. During normal plant operations these manual breakers remain open, thus preventing the TSC diesel generator from being connected to the on site emergency AC power system. The TSC diesel generator is available as an AAC power source to bus 1-52 within one hour of the onset of the SBO event and has sufficient capacity and capability to provide power to the equipment necessary to ensure a safe shutdown of the unit for a 4-hour duration. Kewaunee's method of coping with a Station Blackout was accepted by the NRC in Safety Evaluations dated November 20, 1990, October 1, 1991, and November 19, 1992.

LIMIT SWITCHES (RG 1.97) (DCR 2532)

This design change replaced the non-seismic limit switches on valve NG-302/CV-31298, Pressurizer Relief Tank Nitrogen Supply and Containment Isolation Valve, with seismically qualified limit switches. The safety function of valve NG-302 and its associated position indication were not affected by the limit switch replacement. Containment isolation valve position indication is a Regulatory Guide 1.97 Category 1, Type B, variable. This change upgraded existing limit switches with seismically qualified switches for containment isolation indication; therefore, there was no affect in plant safety.

RCS HOT/COLD LEG TEMPERATURE RANGE (RG 1.97) (DCR 2535)

This modification consisted of a change in the monitored range of the Wide Range Reactor Coolant System (RCS) Hot and Cold Leg temperature indication to meet RG 1.97 commitments for post-accident monitoring. The temperature range was increased from 50-650°F to 50-700°F. This was accomplished by recalibration of the instrument loops. Train A and B cable separation was also accomplished under this modification by rerouting several cables in the relay room. The cable separation and the rescaling of this equipment to monitor temperatures over a wider range will not compromise plant safety.

VEHICLE INSPECTION AREA (DCR 2536)

This design change installed a vehicle inspection area at Kewaunee's north gate to provide controlled access for vehicles and materials for future construction projects and to relieve congestion at the main gate. The intrusion detection system for the north gate was modified to support this change. These changes were made in accordance with 10 CFR 50.54 and do not affect plant safety.

TEMPORARY MODIFICATIONS

RADIATION MONITOR R-15 (TCR 93-10)

This temporary change was made to bypass Radiation Monitor R-15 high alarm function using Weidmueller Blocks while performing radiography to detect pipe wall thinning. Past experience had shown that with simply placing R-15 in "reset", the high alarm still actuated due to its circuitry upon return to service.

Summary of the Safety Evaluation

Kewaunee's Technical Specifications allow R-15 to be out of service, providing grab samples are initiated. The use of Weidmueller Blocks has been used in the past to block the R-15 high alarm functions to allow radiography. R-15 will still be in service for monitoring the air ejector effluent pathway. Functions temporarily bypassed are blowdown and blowdown sample valve isolation (normal alignment), and closing of humidification steam inlet valve to the warehouse annex.

Primary to secondary leakage is monitored during this time by the steam line monitors. If an event were to occur that required blowdown isolation and blowdown sample isolation the operator could take manual action based on elevated steam line readings. The air ejector exhaust is also monitored by the auxiliary building stack monitors giving an additional indication. Therefore, there is no reduction in plant safety.

EQ PLAN REVISION

Revisions made to the EQ Plan in 1993 involved numerous administrative changes. These changes increased the effectiveness of the EQ Plan by either clarifying statements, updating necessary sections, outlining current responsibilities, correcting typographical errors, or updating outdated references. The EQ Plan was also converted to the Word Perfect software now being used by Wisconsin Public Service for word processing. These changes are administrative in nature, and therefore, have no safety significance.

The most significant revision to the EQ plan involved changing the normal and post-accident temperatures for a High Energy Line Break in the Turbine Driven Auxiliary Feedwater (TDAFW) Pump Room from 60-104°F (normal) and 234°F (accident) to 139°F (normal) and 298°F (accident).

Summary of the Safety Evaluation

Previously, the EQ Plan stated that the TDAFW Pump Room shared the same ambient service temperature of 104°F as the remainder of the Class I Aisle (Safeguards Alley). However, the normal ambient service temperature has been calculated to be 139°F. Although the normal ambient temperature in the TDAFW Pump Room was changed from 104°F to 139°F, the electrical equipment in this room is still considered to be classified EQ-Mild. The electrical equipment in the TDAFW Pump Room is classified as EQ-Mild because the environment in the room would at no time be significantly more severe than the environment that would occur during normal plant operation, including anticipated operational occurrences. This classification is consistent with the classification of a mild environment stated in 10CFR50.49. The electrical equipment located in the TDAFW pump room is associated with the operation of the TDAFW pump. Since a steam line break in the room would render the pump inoperable by virtue of loss of steam supply to the turbine, the effect on electrical equipment in the room is not a concern. Therefore, the equipment located in this room would not be needed to mitigate the accident and environmental qualification of this equipment is not needed. These changes do not decrease the level of plant safety.

FIRE PLAN REVISIONS

The Kewaunee Fire Plan was revised during 1993 to address the following:

1. Clarify the original WPSC commitment regarding QA requirements for a fire protection program. The revised wording indicates that WPSC will implement procedures and directives that meet the intent of Branch Technical Position 9.5-1 and Appendix A thereto. The change removes any reference to the OQAP as being the QA program for Fire Protection. Since most of the fire protection system is non-safety related, applying the OQAP to the entire program is not appropriate. It is required however that a QA program that meets BTP 9.5-1 be implemented for fire protection.

2. Remove the automatic NRC reporting requirements regarding inoperable fire protection equipment exceeding 7 and 14 day time clocks and dual fire pump outages (30 day reportable).

3. Provide a 24 hour window to allow for dual fire pump outages required for testing purposes and routine restoration involving minor repairs.

Summary of the Safety Evaluation

The clarification provided by Revision 1 does not change the QA program currently being implemented for the Fire Pretection Program. The current procedures and directives which are controlled by the corporate QA program provide added assurance that the fire protection system is reliable. WPSC will continue to implement a QA program that meets the requirements of BTP 9.5-1. The removal of the reference to the OQAP does not reduce our commitment to meet BTP 9.5-1. The revision clarifies that methods other than the OQAP are acceptable.

The KNPP fire protection program requirements have been removed from the Technical Specifications (TS's) in accordance with NRC Generic Letter 86-10 and 88-12. As specified in the generic letters, the only Fire Protection Program deficiencies required to be reported to the NRC are those which meet the criteria of 10 CFR 50.72 or 10 CFR 50.73. Other conditions which represent deficiencies of the Fire Protection Program and are not encompassed by the 50.72 or 50.73 reporting criteria should be evaluated by the licensee to determine the appropriate corrective action. Since the fire protection requirements are no longer in the TS's, exceeding the allowable out of service times do not meet the reporting requirements of 50.72 or 50.73.

In lieu of reporting all extended outages to the NRC, a KNPP Incident Report will be initiated to outline the actions taken, the cause of the inoperability and the plans and schedule for restoring the equipment to an operable condition. The incident report screening will also ensure that the NRC is notified of any deficiencies which meet the criteria of 10 CFR 50.72 or 10 CFR 50.73.

The proposed changes do not adversely affect the ability to achieve and maintain safe shutdown in the event of a fire.

RG 1.97 PLAN REVISION

Revisions made to the RG 1.97 Plan in 1993 involved changes such as updating references, updating names and titles due to organizational changes, and other minor administrative changes. This revision also incorporated the completion of scheduled 1992 refueling outage modifications. These changes are administrative in nature and have no safety significance.

A significant revision to the RG 1.97 plan involved replacing a previous section entitled "Comparison of RG 1.97 Recommendations versus Kewaunee Nuclear Power Plant (KNPP) Design Basis" with a second entitled "Design and Qualification Criteria for Instrumentation". This new section consists of the design and qualification criteria taken from RG 1.97, revision 3, and has now incorporated Wisconsin Public Service Corporation's (WPSC) commitments along with exceptions and/or deviations to the criteria where applicable. Another significant revision involved revising all of the variable sheets to include updated information or to reformat the information to ensure consistency.

Summary of the Safety Evaluation

These changes have no safety impact. The changes which involve incorporating the "Design and Qualification Criteria for Instrumentation" section strengthen the RG 1.97 plan by listing all of the deviations and exceptions to WPSC's commitment to RG 1.97 (reference letter from WPSC to the Nuclear Regulatory Commission (NRC) dated July 1, 1992.) These deviations and exceptions were reviewed/approved by the NRC and were communicated to WPSC per a safety evaluation dated October 15, 1993. Revising all of the variable sheets has no impact on plant safety. These changes strengthen the plan by listing the correct information for each variable and their current status for RG 1.97.

COMMITMENT CHANGES

NUCLEAR AUXILIARY OPERATOR FACILITY TOURS

Nuclear Auxiliary Operator (NAO) facility tours have been changed from once every four hours to once every six hours. These tours are conducted in order to ensure the status of equipment and areas is known and abnormal conditions are corrected or reported to the shift supervisor.

Summary of the Safety Evaluation

The NRC was notified of this four hour frequency during KNPP Inspection 92-017. The rounds being conducted every four hours appears to have been based on operating experience. WPSC believes that this change does not present a safety concern since no credit is taken for operator facility tours in Kewaunee's Probabilistic Risk Assessment (PRA), security performs plant tours at a minimum frequency of every four hours, and Operations personnel will still perform facility tours every six hours as well as routine operations and inspections. Therefore, the additional two hours between tours does not represent a safety concern.

OVERTIME POLICY

A change was made to allow deviation exceptions from the overtime policy to be approved not only by the Plant Manager, but also by an individual's responsible section manager.

Summary of the Safety Evaluation

Three Mile Island (TMI) Action Plan Item I.A.1.3 "Shift Manning" calls for excessive overtime to be approved by the Plant Manager. This change was evaluated to allow an individual's responsible section manager, who is more involved with the employee's activities, to also approve excessive overtime. The paramount consideration in such authorization will still be the assessment of its impact on the effectiveness of operating personnel.

FIRST AID TRAINING

This evaluation was performed to reduce the number of personnel (from approximately 400 personnel to 125 - 150 personnel) required to be trained in first aid. The requirement to have approximately 400 personnel trained in first aid was overly burdensome and unnecessary. The Updated Safety Analysis Report (USAR) will be changed from "Industrial safety and first aid training are given all WPSC plant personnel, and includes other topics applicable to the nuclear plant." to "Industrial safety training is given to all WPS plant personnel and includes other topics applicable to the nuclear plant. First aid training is given to selcted plant personnel, who are called in the event of an injury."

Summary of the Safety Evaluation

There is no federal requirement requiring that all plant personnel be trained in first aid. There are no safety implications associated with this change, as personnel will still be available who are trained in first aid. This change is administrative in nature and does not affect plant safety.

MISCELLANEOUS

LOW TEMPERATURE OVERPRESSURE PROTECTION

This safety evaluation compared the existing Low Temperature Overpressure Pretection (LTOP) setpoint given in the revised 10 CFR 50 Appendix G pressure-temperature limits of Revision 1 to WPSC's Calculation No. 10557, dated April 27, 1993. This evaluation compares the calculated reactor vessel beltline pressures (including RCS/RHR flow losses) to the revised Appendix G limits. This evaluation demonstrates the existing LTOP setpoint is capable of preventing a design basis LTOP transient from exceeding the 10 CFR 50 Appendix G limits through the end of operating cycle 20 with administrative controls to preclude operation of two reactor coolant pumps when Reactor Coolant System temperature is less than 95°F.

Summary of the Safety Evaluation

The safety evaluation concluded that the LTOP setpoint was capable of preventing a design basis transient from exceeding allowed limits through the end of operating cycle 20 with administrative controls to preclude operation of two reactor coolant pumps when reactor coolant system temperature is less than 95°F.

OPERATING WITH A PRIMARY-TO-SECONDARY LEAK

This safety evaluation justified the addition of Section 1.7, "Heating Boiler Blowdown Operation with Primary-to-Secondary Leak," to the Offsite Dose Calculation Manual (ODCM). This addition was required due to the potential for an unmonitored, uncontrolled release of radioactivity to the environment from heating boiler blowdown when operating secondary plant systems as radioactive systems during a primary-to-secondary leak. This addition adds an unmonitored release path into the ODCM which was not previously described.

Summary of the Safety Evaluation

The amount of radioactivity which could bo released via the heating boiler blowdown is significantly less than the quantity assumed in the various accidents analyzed in the Updated Safety Analysis Report. This is due to the small leakrate from the Reactor Coolant System and the small carryover rate in the steam generators. The effects of these potential releases are minimal and the quantities of radioactivity should be within 10 CFR 20 limits. Therefore, the margin of safety is not significantly reduced.

4.0 LICENSEE EVENT REPORTS

This section is a reprint of the abstracts of the Licensee Event Reports (LER) submitted to the NRC in 1993, in accordance with the requirements of 10 CFR 50.73. None of the events described in the 1993 LERs posed a threat to the health and safety of the public.

LER 93-001-00

On January 28, 1993, at 0443 hours, with the plant operating at 100% power, a large fault on main feedwater pump B motor caused an undervoltage condition on Bus 1 and Bus 2. The bus voltage dropped below the undervoltage reactor trip setpoint and initiated an automatic reactor trip. The voltage on both buses quickly recovered once the fault was isolated.

On January 29, 1993, during the subsequent plant startup, another reactor trip occurred at 1516 hours from 5% power. The narrow range level for steam generator B reached the low-low level reactor trip setpoint of 17% while steam generator level was being manually controlled. Problems with steam dump valve SD-11A1 (to the condenser) contributed to the difficulty in controlling steam generator level.

During both trips, all plant systems responded as designed.

Corrective actions included replacing main feedwater pump B motor with a spare and using the steam generator power operated relief valves during subsequent plant startups until the steam dump valve is repaired. Steam dump valve SD-11A1 was repaired during the 1993 refueling outage.

LER 93-002-00

On January 29, 1993 at 0333 hours, the condenser air ejector radiation monitor (R-15) spiked above its high alarm setpoint. The plant was in the hot shutdown condition. As designed, the high alarm signal closed the steam generator blowdown isolation valves, and the steam generator blowdown sample isolation valves.

The isolation resulted from failure of the Geiger Mueller (GM) tube in the radiation monitoring circuit. A number of probable root causes for the failure were postulated. Engineering staff concluded the probable cause of tube failure was electrical damage resulting from corrosion of the electrical connections for the tube. These connections are located in a high temperature and high humidity environment.

The failed component was replaced and the monitor was returned to service. To prevent recurrence of this failure, the GM tube in the existing installation will be periodically replaced.

A modification to replace the existing radiation monitoring system is under way. The modification, as currently designed, relocates the electrical connections for this detector external to the existing environment.

LER 93-003-00

On March 6, 1993, with the plant in hot shutdown for the 1993 refueling outage, Surveillance Procedure 06-077, Main Steam Safety Valve Test" was performed. During the performance of the procedure it was discovered that the lift pressure of three of the ten main steam (MS) safety valves was out of tolerance, and hence, were declared inoperable.

The three inoperable MS valves were disassembled, rebuilt and tested before exceeding hot shutdown after the 1993 refueling outage. The cause of the safety valve failure was investigated further when the valves were disassembled. A supplement to this LER will be provided to report the results of that investigation.

Sufficient pressure relieving capability existed to ensure the health and safety of the public at all times through a combination of the relieving capability of the MS safety valves and the non-safety related steam relief capabilities of the system.

LER 93-004-00

On March 18, 1993, with the plant in refueling shutdown, eddy current examination of the Steam Generator (SG) tubos was completed for the 1993 refueling outage. The examination found 9 tubes in SG A and 12 tubes in SG B which were considered defective. Since one or more tubes were considered defective in each steam generator, both SGs were categorized as C-2.

The majority of the SG tube degradation at KNPP is probably caused by outside diameter intergranular attack and outside diameter intergranular stress corrosion cracking (IGA/IGSCC). In accordance with KNPP's TS, all defective tubes were plugged. This increased the overall equivalent plugging percentage from 10.06 percent to 10.37 percent for the 1993-1994 operating cycle.

During the 1993 refueling outage, portions of 3 tubes were extracted from the B SG cold leg. These tubes were examined by non-destructive and destructive examination techniques to determine actual tube condition relative to eddy current results.

The secondary side boric acid and Morpholine addition programs will continue during the 1993-1994 operating cycle to reduce the caustic environment and corrosion/erosion on the secondary side.

LER 93-005-00 and LER 93-005-01

On March 8, 1993, with the plant in cold shutdown, the pressurizer pressure transmitters were found out of tolerance (during SP 36-020A) and were subsequently recalibrated. A March 22, 1993, review of the pressure transmitter data determined that Technical Specification 2.3.a.2.A had been exceeded. TS 2.3.a.2.A requires a pressurizer high pressure reactor trip setpoint of less than or equal to 2385 psig. The March 22 review also incorporated the as found calibration data (from February 22 and 23, 1993) for the associated bistables. This review determined that a reactor trip initiation on pressurizer high pressure would not have occurred until 2405 psig. Additionally the Safety Injection block permissive of less than 2000 psig noted in Table TS 3.5-3 would have occurred at 2030 psig.

This event occurred as a result of instrument drift. The cause of the instrument drift may be aging of the transmitters, but the calibration method used is a more probable cause. The calibration is performed at cold shutdown and may indicate instrument drift when in fact at normal plant operating conditions the instruments are within specification.

Pending equipment availability and additional testing, Kewaunee may replace the pressurizer pressure transmitters' during the 1994 refueling outage. In the short term Kewaunee will continue to trend monthly pressurizer pressure transmitter loop currents in order to detect drift in the transmitters outputs. Since May of 1993, no adverse trends have been identified. If an adverse trend develops, appropriate corrective action will be taken which may include calibrating the affected transmitter(s) at power or adjusting the associated bistable setpoints.

LER 93-006-00

On March 22, 1993, at 1100 hours, a potentially non-conservative condition was identified for the Low Temperature Overpressure Protection (LTOP) setpoint development. The plant was in the refueling shutdown condition with the reactor coolant system (RCS) vented. Preliminary evaluation of the LTOP setpoint calculation found the setpoint did not account for flow induced differential pressures or applicable piping losses. The LTOP system was conservatively declared inoperable until a thorough engineering review was completed.

This condition has existed since 1977 as a result of incomplete engineering analysis of the LTOP mitigation system.

The results of the engineering review and calculations were documented in a safety evaluation, which was reviewed and accepted by the Plant Operations Review Committee on April 7, 1993. This evaluation demonstrated the adequacy of the existing LTOP setpoint to prevent RCS pressure from exceeding 10 CFR 50 Appendix G limits during LTOP transients. This safety evaluation, valid through the end of operating cycle 20 (about April 1995), required the imposition of reactor coolant pump operating restrictions.

The operating restrictions were implemented and the LTOP system was returned to operable status.

LER 93-007-00

On March 26, 1993, with the plant in refueling shutdown, the local leak rate test volume associated with the reactor coolant pump A seal injection line could not be pressurized to the required 46 psig. The test volume did not pressurize due to check valve CVC-205A not seating properly. As a result Kewaunee's total "as found" maximum pathway leakage exceeded 0.60La. For Kewaunee, 0.60La is equal to a leakage of 322,800 standard cubic centimeters per minute (sccm). The redundant seal injection line check valve indicated a leakage of 5.6 sccm. The seal injection line is a 2 inch line that supplies water to the reactor coolant pump A seals.

There are no safety implications associated with this event since the redundant valve had a satisfactory leak rate. Excluding CVC-205A leakage, Kewaunee's total "as found" maximum pathway leakage was 42,147.9 sccm. Kewaunee's total "as found" minimum pathway leakage was 15,013 sccm.

On April 7, 1993, with the plant in refueling shutdown, CVC-205A was replaced and a retest indicated an "as left" leakage of 6.8 sccm. As of April 14, 1993, Kewaunee's total "as left" maximum pathway leakage was 8,143.4 sccm. Kewaunee is investigating the future replacement of the other seal injection check valves.

LER 93-008-00

On March 27, 1993, with the plant in refueling shutdown, dynamic testing was completed on valves SI-208 and SI-209, the redundant safety injection to the refueling water storage tank isolation valves. During the testing it was discovered that SI-208 would not close under dynamic conditions whereas SI-209 was found to be operable. The investigation into the failure determined the valve failed to close due to a broken anti-rotational device, an "L" shaped key. Part of the key was found to be rubbing against the valve stem threads, increasing stem resistance.

SI-208 and SI-209 are 2 inch diameter Velan globe valves with Limitorque motor operators. On March 28 an inspection of the other 7 Velan globe valves installed in the plant found 5 of the 7 also had broken keys. An investigation into the failures found three contributing causes. In some cases the key may be bottoming out in the stem keyway when the valve is opened, shearing the key. The key is roughly machined with sharp edges resulting in unnecessary stress risers. The width of the bushing keyway is not uniform. This can overstress the key because it can result in the shorter part of the key assuming the entire load placed on the key.

To correct these problems, new keys were designed, which addressed the three failure mechanisms, and were installed in all 9 valves. The valves were tested and the keys were verified to be intact. The keys will be reinspected during the 1994 refueling outage.

LER 93-009-00

On April 13, 1993 with the plant in the Hot Shutdown mode, a steam exclusion (SE) door was found ajar. With the SE door ajar the plant was in a condition outside of its design basis. A voice activated headset cord was run through a SE door pathway and was found in a position which may have prevented the door from fully closing. The headset cord was run through the doorway in order to perform general maintenance procedure 236-1, "Diagnostic Testing of Limitorque Motor Operated Valves using the Torque Thrust Cell." The SE door was in this condition for approximately five minutes.

The event was caused by the unavailability of voice activated headset connection in the Turbine Driven Auxiliary Feedwater Pump (TDAFWP) room. A contributing factor to this event was determined to be personnel inattention to detail.

An evaluation is being performed to determine the need for installing a voice activated headset connection and a welding receptacle in the TDAFWP room, which would prevent the nced to run cable/cord through the doorway. Additional training was provided on the requirements for opening a SE boundary.

LER 93-010-00

In June 1992, WPSC became aware of the potential for certain multiple transmission line contingencies causing the KNPP generator (GEN) to go unstable and, as a result of the instability, cause all transmission sources into the plant's substation to trip. In order to resolve this issue, WPSC initiated a study to determine whether pre-existing line outages in combination with a transmission line fault could result in credible scenarios by which the KNPP could lose all off-site power.

On April 14, 1993, with the plant in hot shutdown, the results of a stability study of the KNPP were completed. This study confirmed the potential for certain multiple transmission line contingencies causing the KNPP (GEN) to go unstable and, as a result of the instability, cause all transmission sources into the plant's substation to trip.

To ensure the reliability of the transmission sources to the plant's substation, the following interim actions were initiated by WPSC. A WPSC System Operating Procedure was developed requiring the KNPP to be notified when certain transmission lines are out-of-service. This notification along with a KNPP Plant Operations night order, will direct the plant operators to initiate action to plaee the plant in a condition that is within the limits established by the stability study. A summary of the stability study was included as required reading for the plant operators.

LER 93-011-00 and LER 93-011-01

On April 21, 1993, at 1201 hours, with the reactor operating at 35% power, the following significant items were identified during dynamic motor operated valve (MOV) testing of auxiliary feedwater discharge cross connect valve AFW-10A: 1) the as-found setup of the actuator exceeded the manufacturer's recommended limits, and 2) the as-left setup may not fully isolate flow based on test results with similar setups. Valve AFW-10A was being tested in response to Generic Letter 89-10.

It was determined that the actuator is undersized for design basis conditions. The actuator was sized during initial system design using actuator sizing calculations which did not consider current design requirements, such as closure against full pump discharge pressures or weak link ealculations.

Since the operator was undersized for this application, a safety analysis and 10 CFR 50.59 evaluation were initiated to determine the acceptability of modifying plant emergency operating procedures to allow the operators to stop the auxiliary feedwater pump(s) to reduce the high differential pressure across the valve and allow it to close. Danger tags were immediately placed on the valve control switches to address this concern. The procedures have since been revised. Long term corrective actions, including further testing and inspections, have been initiated to determine appropriate resolution for AFW-10A and B coneerns.

LER 93-012-00

On June 5, 1993, at 0310 hours, with the plant at intermediate shutdown, a cooldown to cold shutdown was in progress. During the cooldown, an unplanned automatic letdown isolation occurred when pressurizer level dropped below the low level setpoint of 18.3%. When the cooldown was initiated, pressurizer level was at approximately 37%, two letdown orifice valves were open (allowing a letdown rate of approximately 80 gallons per minute) and both charging pumps were in manual control providing the Reactor Coolant System (RCS) with a total charging/seal injection flow of approximately 86 gallons per minute.

The cause of the letdown isolation was the charging and letdown system not being adequately balanced to account for RCS shrinkage. Contributing factors to the event included letdown flow being maximized for chemistry concerns and the computer alarm setpoint being marginally (0.7%) above the automatic letdown isolation setpoint.

As a corrective action, the computer alarm setpoint for low pressurizer level was raised. This setpoint increase will provide greater reaction time for the operators to respond to changes in pressurizer level. Also, management will be meeting with all nuclear personnel to discuss methods for enhancing human performance.

LER 93-013-00

This report describes an unplanned actuation of the auxiliary feedwater system, which is an engineered safety feature. On June 4, 1993, with the plant in hot shutdown, an automatic actuation of both motor driven auxiliary feedwater pumps occurred. This event occurred while the plant was being shut down for a scheduled outage. Prior to the event, the B main feedwater pump had been secured while the A main feedwater pump remained running. As the demand for feedwater to the steam generators diminished, the main feedwater regulating valves automatically throttled closed. However, the A steam generator level continued to increase with the main feedwater regulating valves indicating fully closed. In order to stop the A steam generator level increase and prevent an automatic trip of the main feedwater pump at 67% steam generator narrow range level, the operator shut off the A feedwater pump. This action caused an automatic start of both motor driven auxiliary feedwater pumps as designed. The circuitry that initiates this automatic auxiliary feedwater pump start is not an engineered safety feature.

The contributing causes of this event were determined to be the failure of the A main feedwater regulating valve to completely isolate feedwater flow and the operator actions taken to isolate the feedwater flow. The main feedwater regulating valve was subsequently repaired and is being monitored. Additionally, the analyses of this event was made required reading for the operations group.

LER 93-014-00

At 0428 hours on June 18, 1993, in accordance with Kewaunee's Technical Specifications, a plant shutdown was initiated when it was determined that the power range nuclear instrumentation could have allowed an overpower condition greater than the 109% technical specification (TS) power limit. Approximately one hour later the shutdown was interrupted to allow the overpower reactor trip bistables to be conservatively reset to 100% power; this would ensure the operability of the overpower trip function. At 0730 hours, with the plant at approximately 88% power, it was determined that, although these trips were within the USAR analyzed condition of 118% of full power, three of the channels had exceeded the TS limit of 109% of full power.

Subsequent review determined that, because of conservatism associated with the calorimetric calculation, only one channel actually exceeded the 109% TS limit; therefore, this report is being submitted to the NRC as a voluntary Licensce Event Report.

The contributing causes to this event were: 1) a gain adjustment (electronic signal correction) at a lower power level that caused an increased deviation at higher power levels, 2) a lack of guidance in the daily calibration surveillance procedure for the performance of gain adjustments, and 3) an unexpected drift of the overpower trip bistables.

Long-term corrective actions include: 1) modifying the plant power range daily calibration surveillance procedure to provide detailed guidance on when to perform gain adjustments, 2) monitoring the overpower trip bistable drift, and 3) making the LER required reading for all operations and reactor engineering personnel.

LER 93-015-00

At approximately 1500 hours on June 18, 1993, with the plant at 87 percent power, a sliding gate to the low level radioactive waste drumming area, which is a High Radiation Area (HRA), was found closed but unsecured and unattended. A Nuclear Auxiliary Operator (NAO) was performing his routine plant rounds when he found the gate (#18) unsecured and unattended. The NAO secured the gate and reported the condition to the Shift Supervisor.

The cause of this event has been determined to be personnel error. A plant electrician finished performing maintenance on equipment in this HRA at approximately 1130 hours. He remembers engaging the lock after exiting the HRA, but does not remember if he routed the chain through the wall-mounted metal tube prior to engaging the lock.

The individual involved with this incident has been counseled on the potential safety consequences of this type of error. This event was also discussed at KNPP safety meetings, which are attended by KNPP personnel (WPSC and Contractors). Additionally, the plant's weekly newsletter, which is distributed for all KNPP personnel, included a message emphasizing the potential impact of this event for KNPP personnel.

LER 93-016-00

At 1014 hours on July 9, 1993, with the plant at 100% power, the steam generator blowdown and blowdown sampling isolation valves closed, as designed, on a high radiation signal from the steam generator blowdown radiation monitor (R-19).

The R-19 high radiation signal prompted operations personnel to closely monitor other parameters which indicated that there was no primary to secondary leak. This indication was supported by a local steam generator blowdown sample and by the results of a primary to secondary leak rate calculation, which both indicated that normal activity levels existed. After determining that there was no primary to secondary leak, R-19 was declared out of service. Additionally, R-19 blowdown isolation signals were bypassed to allow steam generator blowdown to be re-established.

A definitive cause of the high radiation output signal could not be determined. However, a R-19 printed circuit board was found to have an out of specification value for the level calibration and was also fitting loosely in its friction socket connections. The circuit board's condition potentially generated the high radiation signal.

The printed circuit board was replaced. The photomultiplier tube associated with R-19 was also replaced. R-19 was returned to service on July 16, 1993.

LER 93-017-00

At 1437 hours on September 10, 1993, with the plant at 100% power, the steam generator blowdown and blowdown sampling isolation valves closed, as designed, on a high radiation signal from the steam generator blowdown radiation monitor (R-19).

Immediate actions included verifying that all automatic actuations occurred, sampling steam generator blowdown, and monitoring the condenser air ejector gas monitor (R-15). After determining that there was not a primary-to-secondary leak, R-19 was declared out of service, the blowdown isolation signal was bypassed, and steam generator blowdown was reestablished.

The most probable cause of the high radiation output signal was a piece of slightly radioactive sludge breaking free from the detector housing and being detected as it passed by the monitor. The buildup of slightly radioactive sludge on the R-19 detector housing resulted from a previous steam generator primary-to-secondary leak.

The housing of the monitor was wiped free of sludge which lowered background radiation. R-19 was returned to service at 1249 hours on September 16, 1993.

LER 93-018-00

On October 12, 1993, at 0643 hours, with the plant operating at 100% power, an unexpected automatic start of the turbine driven auxiliary feedwater pump (TDAFWP), an Engineered Safety Feature (ESF), occurred. The pump started and reached full speed as designed. The steam generator blowdown isolation valves (BT-2A, BT-2B, BT-3A, and BT-3B) closed as designed. No other alarms occurred concurrent with the automatic start. The TDAFWP was declared out of service, the control switch placed in pullout, and the associated 72 hour Limiting Condition of Operation (LCO) action statement was entered. The inadvertent start occurred as a result of a relay failure.

This event was caused by the failure of a time delay relay (Agastat 2400 series) in the TDAFWP automatic start circuitry. The relay is a normally energized relay; therefore, the coil in the relay has been powered almost continuously since it was installed during original plant construction. The failed relay was replaced with an identical relay from stock. The TDAFWP was returned to service at 1558 hours the same day and the LCO was exited at that time.

The failed relay was replaced with an identical spare. Also, an expedited review of the Nuclear Plant Reliability Data System database and the Kewaunee Operating Experience Assessment database was conducted, which revealed no generic implications associated with the Agastat 2400 series relays. Prior to this event, Kewaunee was performing an engineering evaluation to determine suitable replaeements for the obsolete Agastat 2400 series relays.

This report describes a violation of Kewaunce Technical Specification 3.3.b.2.B, which allows one residual hcat removal (RHR) pump to be inoperable for 72 hours. The 1A RHR pump was declared inoperable at 1841 hours on November 1, 1993, with the plant at 100% power, when a through wall leak was identified on the pump's casing. Since the scheduled repair time would exceed 72 hours, Wisconsin Public Service Corporation requested and received a notice of enforcement discretion from the Nuclear Regulatory Commission prior to exceeding the 72 hour limiting condition of operation action statement.

The flaw, resulting in the leak, originated in a void in the pump casing wall. The void appears to have been caused by non-uniform cooling of the pump casing when it was originally cast. Service induced stresses resulted in crack propagation to the inner and outer diameters of the pump casing.

Corrective actions included visually inspecting the redundant pump and repairing the 1A RHR pump. The pump was repaired and returned to service prior to exceeding the extension provided in the Nuclear Regulatory Commission's notice of enforcement discretion.

5.0 FUEL INSPECTION REPORT

Thirty-six (36) fresh Region X assemblies were loaded for Cycle XIX. Startup physics testing was performed and reported in the Cycle XIX Startup Report.

The irradiated fuel inspection was performed with an underwater TV camera. All peripheral fuel rods were examined using one-half faee scans. Four assemblies were inspected, including one in Region M, one in Region U, and two in Region W. All assemblies exhibited rod slippage to various degrees, and two assemblies have rods in contact with the bottom nozzle. Numerous scrapes to the rodlets, grids, and top and bottom nozzles were noted on all assemblies. However, no damage to the cladding or supporting structures was observed. All assemblies exhibited axially varying crud deposits. Overall condition of the fuel was very good, with no evidenee of fuel cladding degradation on the fuel rods examined. Videotapes were made of all examinations.

6.0 CHALLENGES TO AND FAILURES OF PRESSURIZER SAFETY AND RELIEF VALVES

In response to NUREG-0737, item II.K.3.3, and in accordance with KNPP Technical Specification 6.9.a.2.C, WPSC is committed to reporting challenges to and failures of pressurizer safety and pressurizer power-operated relief valves. There were no challenges to or failures of pressurizer safety or pressurizer power-operated relief valves during 1993.

7.0 SUMMARY OF THE 1993 STEAM GENERATOR EDDY CURRENT EXAMINATION

During the Kewaunee Nuclear Power Plant's 1993 refueling outage, the following steam generator (SG) services were performed.

Eddy Current Inspection (Table 7.1)

The 1993 SG tube eddy current inspection program included:

1) A bobbin coil inspection of 100% of the nonplugged, nonrepaired tubes through their entire length (1998 tubes).

2) A bobbin coil inspection of 100% of the nonplugged, repaired tubes through their entire length.

   Kewaunee has installed sleeves in a large portion of its hot leg tubesheet. The inspection consisted of an examination from the top of the sleeve to the end of the tube on the cold leg side (4282 tubes).

3) An inspection of 10% of the repaired tubes' sleeves (450 sleeves).

4) A motorized rotating pancake coil (MRPC) examination of 100% of the nonplugged tubes row 1 U-bends (67 tubes) and 32% of the nonplugged row 2 U-bends (60 tubes).

5) Motorized rotating pancake coil examinations of all locations with distorted bobbin coil indications.

Table 7.1 is a summary of the 1993 steam generator eddy current inspection.

Mechanical Plugging (Table 7.2)

Table 7.2 summarizes the defect location for which plugging was required.

Steam Generator A

A total of 9 tubes were fitted with mechanical plugs (see Table 7.2). Of the 9 tubes plugged, 7 were plugged for indications at the tube support plates, and 2 were plugged for indications in the hot leg tubesheet crevice. All plugs installed were ABB/CE Inconel 690 mechanical plugs. All installation parameters were met.

Steam Generator B

A total of 9 tubes were fitted with mechanical plugs (see Table 7.2). Of the 9 tubes plugged, 7 were plugged for indications at the tube support plates, and 2 were plugged for indications in the hot leg tubesheet crevice. In addition, a total of 3 tubes were fitted with welded tubesheet plugs. Welded tubesheet plugs were required after tube sections were removed for destructive analysis. All plugs installed were ABB/CE Inconel 690 mechanical and welded tubesheet plugs. All installation parameters were met.

Tube Sample Removal

Portions of 3 tubes in the Steam Generator B cold leg were removed for destructive analysis during the 1993 refueling outage. Portions of 2 tubes were removed below the third tube support plate, and a portion of one tube was removed below the second tube support plate.

As required by Technical Specifications 4.2.b.5.b, Tables 7.3 and 7.4 list the location and percent of wall thickness penetration for each indication of degradation.

Applicable Definitions

Degraded Tube - A tube with a 20% or greater thru-wall indication.

Defective Tube - A tube with a 50% or greater thru-wall indication. If significant tube thinning has occurred in the area of the indication, the defective tube criteria reduces to greater than 40% thru-wall. Defective tube plugging and repair are performed in accordance with approved Technical Specifications.

TABLE 7.1

SUMMARY OF THE 1993 STEAM GENERATOR EDDY CURRENT EXAMINATION

STEAM GENERATOR A

EXTENT OF INSPECTION	NUMBER TESTED
Top of sleeve to TEC[1]	2175
TEC to TEH	971
U-bend	87
Sleeve inspection TEH to STH[2]	225

STEAM GENERATOR B

EXTENT OF INSPECTION	NUMBER TESTED
Top of sleeve to TEC	2107
TEC to TEH	1027
U-bend	40
Sleeve inspection TEH to STH	225

[1] TEC - tube end cold

[2] STH - top of sleeve

TABLE 7.2

LOCATION FOR WHICH MECHANICAL PLUGGING WAS REQUIRED

	SG A	SG B
Hot leg tubesheet	2	2
Hot leg support plates	5	3
Cold leg support plates	2	7
TOTAL:	**9**	**12**

TABLE 7.3

1993 EDDY CURRENT EXAMINATION REPORTABLE INDICATIONS

STEAM GENERATOR A				
ROW	COLUMN	% THRU-WALL PENETRATION	INDICATION LOCATION	SLEEVED/PLUGGED
3	1	22	2H	-
9	2	36	2H	-
17	4	28	2C	-
1	5	32	TSH + 17.45	-
1	5	35	TSC + 17.54	-
18	6	32	1H	-
18	6	20	2C	-
9	7	DSI/SAI	1H	P
16	7	27	AV2	-
18	7	20	AV2	-
13	8	48	1H	-
18	9	24	AV2	-
22	9	44	1H	-
23	9	27	2C	-
12	10	25	1H	-
23	10	47	1H	-
23	10	20	AV2	-
24	10	28	4H	-
27	11	20	6H	-
19	13	24	AV2	-
23	13	24	AV2	-
14	16	46	1H	-
26	16	21	6C	-
31	16	20	1C	-
33	16	29	1H	-
27	17	22	7C	-
27	17	24	6C	-
14	18	21	AV2	-

TABLE 7.3

1993 EDDY CURRENT EXAMINATION REPORTABLE INDICATIONS

STEAM GENERATOR A				
ROW	COLUMN	% THRU-WALL PENETRATION	INDICATION LOCATION	SLEEVED/PLUGGED
14	18	22	AV3	-
26	18	27	7H	-
24	19	23	6C	-
31	19	DCI/SAI	TEH + 7.78	P
37	19	21	AV2	-
1	20	20	1H	-
24	20	27	1H	-
36	22	20	AV2	-
19	23	23	1H	-
26	24	40	6C	-
27	24	25	AV1	-
28	24	21	AV1	-
40	24	DSI/SAI	4H	P
24	25	21	7C	-
5	26	53/MAI	1H	P
40	26	31	1H	-
40	26	20	AV2	-
27	28	23	AV2	-
28	28	22	AV2	-
29	28	20	AV2	-
30	28	24	AV2	-
24	32	22	AV3	-
26	32	24	AV3	-
27	32	23	AV3	-
28	32	22	AV3	-
32	33	20	5C	-
36	33	22	AV2	-
37	33	20	AV2	-

TABLE 7.3

1993 EDDY CURRENT EXAMINATION REPORTABLE INDICATIONS

STEAM GENERATOR A				
ROW	COLUMN	% THRU-WALL PENETRATION	INDICATION LOCATION	SLEEVED/PLUGGED
41	33	22	AV2	-
42	33	21	2H	-
40	36	29	AV3	-
42	36	34	3H	-
42	36	22	AV2	-
44	36	22	AV2	-
32	41	23	AV3	-
33	41	27	AV2	-
29	42	22	AV3	-
43	42	30	7H	-
43	42	23	4C + 31.62	-
44	43	DSI/SAI	1H	P
28	45	25	AV2	-
44	45	20	1H	-
38	49	21	7C	-
46	51	20	AV2	-
11	53	29	1C	-
35	53	34	1H	-
42	53	40	5H	-
12	55	39	2C	-
13	55	23	2C	-
18	55	31	AV2	-
18	55	21	AV3	-
18	57	23	AV2	-
18	57	24	AV3	-
13	58	21	1H	-
18	58	21	AV1	-
18	58	23	AV2	-

TABLE 7.3

1993 EDDY CURRENT EXAMINATION REPORTABLE INDICATIONS

STEAM GENERATOR A				
ROW	COLUMN	% THRU-WALL PENETRATION	INDICATION LOCATION	SLEEVED/PLUGGED
18	58	27	AV3	-
18	58	28	AV4	-
1	61	60/SAI	6C	P
18	62	35	1C	-
34	62	34	7C	-
35	62	DCI/SAI	TEH +3.57	P
6	63	DSI/SAI	1H	P
42	63	23	AV2	-
39	65	20	AV2	-
41	66	53/SAI	6C	P
18	67	34	AV1	-
18	67	42	AV2	-
18	67	35	AV3	-
30	67	22	AV2	-
7	70	23	7C	-
35	71	20	AV2	-
29	74	37	7C	-
32	74	37	7C	-
25	75	20	2C	-
20	76	24	AV3	-
22	76	23	AV4	-
23	76	21	AV3	-
18	77	36	1H	-
36	77	38	3H	-
23	78	23	7C	-
24	78	37	7C	-
24	78	23	6C	-
2	80	22	5C	-

TABLE 7.3

1993 EDDY CURRENT EXAMINATION REPORTABLE INDICATIONS

STEAM GENERATOR A				
ROW	COLUMN	% THRU-WALL PENETRATION	INDICATION LOCATION	SLEEVED/PLUGGED
24	80	22	3C	-
24	80	24	2C	-
28	80	37	1H	-
29	81	21	AV2	-
31	81	21	AV2	-
29	82	20	AV3	-
24	83	38	7C	-
24	84	21	AV2	-
24	84	46	6C	-

AV# - Antivibration bar
DCI - Distorted Crevice Indication
DSI - Distorted Support Plate Indication
#H, #C - Tube support plate hot and cold
MAI - Multiple Axial Indication
P - Plugged
SAI - Siugle Axial Indication
TEH, TEC - Tube end bot and cold
TSH, TSC - Top of tube sbeet hot and cold

Note tbat numbers added to TEH, TSH, etc., are distances in inches above or below tbe indicated reference point.

TABLE 7.4

1993 EDDY CURRENT EXAMINATION REPORTABLE INDICATIONS

STEAM GENERATOR B				
ROW	COLUMN	% THRU-WALL PENETRATION	INDICATION LOCATION	PLUGGED/SLEEVED
9	2	27	TSC + 2.01	-
10	3	24	1H	-
15	3	40	2C	-
11	4	26	2C	-
15	4	45	2C	-
17	4	39	7C	-
17	6	39	6C	-
21	6	46	2C	-
20	7	33	2C	-
3	8	34	1C	-
14	8	21	AV1	-
15	8	26	AV1	-
15	8	20	AV2	-
15	8	21	AV3	-
16	8	21	AV3	-
19	8	21	AV2	-
20	8	22	AV1	-
15	9	23	AV2	-
19	9	23	1C	-
21	9	21	1C	-
13	10	27	TSH + 48.88	-
13	10	25	4C	-
27	10	48	7C	-
5	12	22	1C	-
2	13	36	6C	-
17	13	29	1H + 7.33	-
17	13	36	6C	-
30	15	34	5C	-

TABLE 7.4

1993 EDDY CURRENT EXAMINATION REPORTABLE INDICATIONS

STEAM GENERATOR B				
ROW	COLUMN	% THRU-WALL PENETRATION	INDICATION LOCATION	PLUGGED/SLEEVED
25	16	35	7C	-
25	16	28	5C	-
13	17	24	4C	-
25	18	29	6C	-
25	18	34	3C	-
27	20	DCI/MAI	TEH + 14.35	P
27	20	28	7C	P
9	22	25	1C	-
27	23	38	2C	-
29	23	29	6C	-
20	24	22	AV2	-
27	24	22	AV2	-
28	24	21	AV2	-
39	24	23	4H	-
40	24	34	6C	-
11	25	22	1C + 3.81	-
12	27	20	1C	-
16	28	41	1C	-
34	28	47	7C	-
41	28	21	AV2	-
16	29	32/SAI	1C	P
16	29	<20/SAI	2C	P
8	30	25	AV1	-
16	30	26	2C	-
10	32	39	5C	-
39	33	20	7H	-
17	34	22	2C	-
22	34	29	1C	-

TABLE 7.4

1993 EDDY CURRENT EXAMINATION REPORTABLE INDICATIONS

STEAM GENERATOR B				
ROW	COLUMN	% THRU-WALL PENETRATION	INDICATION LOCATION	PLUGGED/SLEEVED
16	35	22	3C	-
18	35	21	AV2	-
38	35	22	7H	-
38	35	22	3C	-
41	35	25	3H	-
43	35	28	6C	-
38	36	26	4H	-
38	36	23	7H	-
38	36	21	6C	-
38	36	35	5C	-
16	37	29	AV1	-
19	37	29	AV1	-
20	37	23	AV1	-
32	37	27	7H	-
38	37	30	6H	-
38	37	27	7H	-
38	37	23	4C	-
38	37	24	2C	-
44	37	31	3C	-
9	38	33	1C	-
22	38	23	AV3	-
23	38	DSI/SAI	3C	P
38	38	DCI/SAI	TEH + 11.74	P
38	38	23	7H	P
38	38	39	4C	P
40	38	31	6H	-
40	38	35	5C	-
40	38	33	3C	-

TABLE 7.4

1993 EDDY CURRENT EXAMINATION REPORTABLE INDICATIONS

STEAM GENERATOR B				
ROW	COLUMN	% THRU-WALL PENETRATION	INDICATION LOCATION	PLUGGED/SLEEVED
41	38	29	6C	-
32	39	24	AV3	-
13	40	20	1C	-
15	40	20	5C	-
17	40	25	2C	-
18	40	26	AV4	-
20	40	20	AV3	-
22	40	31	AV1	-
41	40	DSI/SAI	6H	P
41	40	40	6C	P
17	41	29	2C	-
30	41	37	1H	-
13	42	25/SAI	2C	P
13	42	35/SAI	1C	P
15	42	40	3C	-
15	42	20	2C	-
16	42	28	4C	P
16	42	30	3C	P
16	42	25/SAI	2C	P
16	42	26/SAI	1C	P
19	42	32	AV1	-
21	42	30	7C	-
38	42	24	5C	-
38	42	31	2C	-
44	42	20	4C	-
41	43	33	4C	-
17	44	29	1C	-
20	44	20	1C	-

TABLE 7.4

1993 EDDY CURRENT EXAMINATION REPORTABLE INDICATIONS

STEAM GENERATOR B				
ROW	COLUMN	% THRU-WALL PENETRATION	INDICATION LOCATION	PLUGGED/SLEEVED
39	44	25	6C	-
39	44	25	5C	-
44	44	29	5H	-
37	45	24	AV1	-
38	45	22	7C	-
25	46	20	7H	-
36	46	31	7C	-
37	46	25	AV1	-
45	46	24	6C	-
13	47	31	1C	-
17	48	31	6C	-
38	48	35	4H	-
38	48	38	6H	-
38	48	36	6C	-
38	48	22	4C	-
43	48	36	7C	-
43	48	28	6C	-
4	49	48	3C	-
13	49	30	2C	-
21	49	37	1C	-
38	49	33	7H	-
38	49	30	7C	-
38	49	32	6C	-
38	49	21	5C	-
17	50	26	1C	-
38	50	40	7C	-
30	51	37	2H	-
38	51	45	7H	-

TABLE 7.4

1993 EDDY CURRENT EXAMINATION REPORTABLE INDICATIONS

STEAM GENERATOR B				
ROW	COLUMN	% THRU-WALL PENETRATION	INDICATION LOCATION	PLUGGED/SLEEVED
38	51	40	7C	-
38	51	35	6C	-
38	51	20	3C	-
24	52	31	6C	-
38	52	33	6C	-
43	52	30	4H	-
43	52	45	7H	-
43	52	29	6C	-
43	52	42	4C	-
38	53	26	7C	-
42	53	20	5H	-
43	53	36	5H	-
43	53	28	7H	-
43	53	49	7C	-
43	53	29	5C	-
45	55	DSI/SAI	2H	P
45	55	39	3H	P
36	56	30	6C	-
41	56	42	6C	-
42	56	30	5H	-
42	57	28	3H	-
17	58	34	7C	-
37	59	29	6C	-
42	59	23	AV3	-
43	59	22	1C	-
32	60	38	7H	-
44	61	23	1H	-
29	62	21	1H	-

TABLE 7.4

1993 EDDY CURRENT EXAMINATION REPORTABLE INDICATIONS

STEAM GENERATOR B				
ROW	COLUMN	% THRU-WALL PENETRATION	INDICATION LOCATION	PLUGGED/SLEEVED
37	62	35	6C	-
39	62	37	7C	-
39	62	29	5C	-
39	62	30	3C	-
31	63	32	1H	-
31	63	33	6C	-
38	63	22	7C	-
43	63	41	1C	-
25	64	31	1H	-
36	64	24	7C	-
37	64	28	AV3	-
37	64	44	AV4	-
37	64	46	6C	-
20	66	21	6C	-
24	66	29	2H	-
35	66	30	6C	-
37	66	33	6C	-
39	66	23	7C	-
17	67	33	6C	-
38	67	31	6C	-
39	67	31	7C	-
39	67	20	2C	-
40	67	25	6C	-
14	68	DSI/SAI	6H	P
14	68	21	5C	P
14	68	22	1C	P
21	68	20	4C	-
40	68	23	AV2	-

TABLE 7.4

1993 EDDY CURRENT EXAMINATION REPORTABLE INDICATIONS

STEAM GENERATOR B				
ROW	COLUMN	% THRU-WALL PENETRATION	INDICATION LOCATION	PLUGGED/SLEEVED
14	69	21	1C	-
36	69	23	7C	-
41	69	37	5H	-
14	70	32	1C	-
35	70	20	6C	-
28	72	33	1H	-
36	72	20	AV2	-
36	72	31	7C	-
36	72	21	3C	-
27	73	22	3H	-
38	73	43	1H	-
4	74	22	1C	-
30	74	28	2H	-
37	74	20	7C	-
37	74	45	5C	-
30	75	31	4C	-
34	75	22	AV2	-
36	75	21	7C	-
36	75	31	6C	-
13	77	27	4C	-
26	78	28	3H	-
31	80	DSI/SAI	6C	P
29	81	29	1H	-
30	82	36	1H	-
30	82	27	2H	-
14	83	34	2C	-
24	83	20	2C	-
24	86	DSI/SAI	6C	P

TABLE 7.4

1993 EDDY CURRENT EXAMINATION REPORTABLE INDICATIONS

STEAM GENERATOR B				
ROW	COLUMN	% THRU-WALL PENETRATION	INDICATION LOCATION	PLUGGED/SLEEVED
14	87	25	6C	-
21	88	24	2C	-
15	89	20	AV3	-
19	89	DSI/SAI	6C	P
19	89	34	1C	P
21	89	25	1C	-
12	90	27	1C	-
6	91	20	1C	-
10	93	22	1C	-
2	94	31	2H	-

AV# - Antivibration bar
DCI - Distorted Crevice Indication
DSI - Distorted Support Plate Indication
#H, #C - Tube support plate bot and cold
MAI - Multiple Axial Indication
P - Plugged
SAI - Single Axial Indication
TEH, TEC - Tube end bot and cold
TSH, TSC - Top of tube sbeet bot and cold

Note that numbers added to TEH, TSH, etc., are distances in incbes above or below the indicated reference point.

8.0 PERSONNEL EXPOSURE AND MONITORING REPORT

Pursuant to 10 CFR 20.407(a)(2) and 20.407(b), a tabulation of the total number of individuals for whom monitoring was provided is shown in Table 8.1. Tables 8.2, 8.3 and 8.4 provide a breakdown of the total number of individuals for whom personnel monitoring was provided.

TABLE 8.1

TOTAL NUMBER OF INDIVIDUALS FOR WHOM PERSONNEL MONITORING WAS PROVIDED IN 1993

RANGE (mR)	NO. OF INDIVIDUALS
No Measurable	374
< 100	183
100 - 249	93
250 - 499	92
500 - 749	44
750 - 999	16
1000 - 1999	8
2000 - 2999	0
3000 - 3999	0
4000 - 4999	0
5000 - 5999	0
6000 - 6999	0
7000 - 7999	0
8000 - 8999	0
9000 - 9999	0
10000 - 10999	0
11000 - 11999	0
> 12000	0
TOTAL	810

TABLE 8.2

TOTAL NUMBER OF CONTRACTORS PROVIDED WITH PERSONAL DOSE MONITORING DEVICES

RANGE (mR)	NO. OF INDIVIDUALS
No Measurable	171
< 100	76
100 - 249	41
250 - 499	58
500 - 749	30
750 - 999	9
1000 - 1999	6
2000 - 2999	0
3000 - 3999	0
4000 - 4999	0
5000 - 5999	0
6000 - 6999	0
7000 - 7999	0
8000 - 8999	0
9000 - 9999	0
10000 - 10999	0
11000 - 11999	0
> 12000	0
TOTAL	**391**

TABLE 8.3

TOTAL NUMBER OF WPSC PLANT STAFF PROVIDED WITH PERSONAL DOSE MONITORING DEVICES

RANGE (mR)	NO. OF INDIVIDUALS
No Measurable	165
< 100	85
100 - 249	45
250 - 499	29
500 - 749	12
750 - 999	5
1000 - 1999	2
2000 - 2999	0
3000 - 3999	0
4000 - 4999	0
5000 - 5999	0
6000 - 6999	0
7000 - 7999	0
8000 - 8999	0
9000 - 9999	0
10000 - 10999	0
11000 - 11999	0
> 12000	0
TOTAL	**343**

TABLE 8.4

TOTAL NUMBER OF PERSONNEL (WPSC NON-PLANT STAFF) PROVIDED WITH PERSONAL DOSE MONITORING DEVICES

RANGE (mR)	NO. OF INDIVIDUALS
No Measurable	38
< 100	22
100 - 249	7
250 - 499	5
500 - 749	2
750 - 999	2
1000 - 1999	0
2000 - 2999	0
3000 - 3999	0
4000 - 4999	0
5000 - 5999	0
6000 - 6999	0
7000 - 7999	0
8000 - 8999	0
9000 - 9999	0
10000 - 10999	0
11000 - 11999	0
> 12000	0
TOTAL	**76**

A tabulation of personnel exposure and person-rem received by work and job function is shown in Table 8.5 in accordance with Section 6.9.a.2 of the Kewaunee Nuclear Power Plant Technical Specifieations. The total actual dose at the Kewaunee Plant for 1993 was 105.683 person-rem.

TABLE 8.5

STANDARD FORMAT FOR REPORTING NUMBER OF PERSONNEL AND MAN-REM BY WORK AND JOB FUNCTION FOR KEWAUNEE - FROM 01/01/93 TO 12/31/93

WORK & JOB FUNCTION	NUMBER OF PERSONNEL (> 100 MREM)			TOTAL MAN-REM		
	STATION EMPLOYEES	UTILITY EMPLOYEES	CONTRACT WORK AND OTHER	STATION EMPLOYEES	UTILITY EMPLOYEES	CONTRACT WORK AND OTHER
REACTOR OPERATIONS						
Surveillance						
Maintenance Personnel	0	0	0	0.013	0.000	0.022
Operating Personnel	3	0	0	1.868	0.000	0.000
Health Physics Personnel	0	0	0	0.000	0.000	0.000
Supervisory Personnel	0	0	0	0.029	0.000	0.000
Engineering Personnel	0	0	0	0.016	0.000	0.000
ROUTINE MAINTENANCE						
Maintenance Personnel	7	4	25	4.083	1.673	9.704
Operating Personnel	2	1	3	0.930	0.141	0.911
Health Physics Personnel	10	0	19	5.186	0.000	5.513
Supervisory Personnel	1	0	0	0.199	0.000	0.000
Engineering Personnel	0	0	1	0.010	0.000	0.278
INSERVICE INSPECTION						
Maintenance Personnel	0	0	12	0.002	0.005	3.330
Operating Personnel	0	0	5	0.000	0.000	2.034
Health Physics Personnel	0	0	0	0.000	0.000	0.000
Supervisory Personnel	0	0	0	0.000	0.000	0.000
Engineering Personnel	1	0	0	0.232	0.000	0.000
SPECIAL MAINTENANCE						
Maintenance personnel	25	4	76	10.130	1.477	38.845
Operating Personnel	1	0	0	0.246	0.000	0.016
Health Physics Personnel	0	0	0	0.259	0.000	0.064
Supervisory Personnel	3	0	0	0.713	0.000	0.000
Engineering Personnel	6	0	1	2.043	0.000	0.118

TABLE 8.5

STANDARD PORMAT POR REPORTING NUMBER OF PERSONNEL AND MAN-REM BY WORK AND JOB FUNCTION FOR KEWAUNEE - FROM 01/01/93 TO 12/31/93

WORK & JOB FUNCTION	NUMBER OF PERSONNEL (> 100 MREM)			TOTAL MAN-REM		
	STATION EMPLOYEES	UTILITY EMPLOYEES	CONTRACT WORK AND OTHER	STATION EMPLOYEES	UTILITY EMPLOYEES	CONTRACT WORK AND OTHER
WASTE PROCESSING						
Maintenance Personnel	0	0	0	0.145	0.000	0.012
Operating Personnel	1	0	0	0.671	0.000	0.000
Health Physics Personnel	0	0	0	0.091	0.000	0.000
Supervisory Personnel	0	0	0	0.000	0.000	0.000
Engineering Personnel	0	0	0	0.000	0.000	0.000
REFUELING						
Maintenance Personnel	7	7	0	4.072	2.619	0.000
Operating Personnel	1	0	0	0.517	0.000	0.000
Health Physics Personnel	0	0	0	0.000	0.000	0.000
Supervisory Personnel	0	0	0	0.177	0.000	0.000
Engineering Personnel	1	0	0	0.329	0.000	0.000
TOTAL						
Maintenance Personnel	39	15	113	18.447	5.774	51.913
Operating Personnel	8	1	8	4.232	0.141	2.961
Health Physics Personnel	10	0	19	5.536	0.000	5.577
Supervisory Personnel	4	0	0	1.118	0.000	0.000
Engineering Personnel	8	0	2	2.630	0.000	0.396
GRAND TOTAL	69	16	142	31.963	5.915	60.847

9.0 CHANGES IN THE EMERGENCY CORE COOLING SYSTEM

The provision of 10 CFR 50.46 requires the reporting of corrections to or changes in the Emergency Core Cooling System (ECCS) evaluation model (EM) that is approved for use in performing the loss-of-coolant accident (LOCA) safety analysis. There were no changes in either the large break LOCA or the small break LOCA EMs during 1993.

10.0 FAILURES OF TURBINE STOP AND CONTROL VALVES

There were no failures to the turbine stop and control valves during 1993.