BWR OWNERS' GROUP

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SUBJECT: *TRANSMITTAL OF BWR OWNERS' GROUP EXTENDED POWER UPRATE (EPU) LESSONS LEARNED AND RECOMMENDATIONS (NEDO-33159)*

Attachment: NEDO-33159, Extended Power Uprate (EPU) Lessons Learned and Recommendations, Revision 0 dated November 2004

This transmittal provides the BWR Owners' Group (BWROG) NEDO-33159 "EPU Lessons Learned and Recommendations" to the NRC staff for information. We are not requesting NRC approval of this document. Since the information contained in this document may be beneficial to the nuclear industry, we have elected to provide this information to NEI, INPO, EPRI, the Westinghouse Owners' Group, and the B&W Owners' Group.

NEDO-33159 provides assistance to BWR plants that are in the evaluation and implementation phases of Extended Power Uprate. The BWROG recommendations are based on operating experiences and evaluations from BWR plants that have previously implemented EPUs and from plants currently performing pre-EPU evaluations.

The BWROG has concluded that implementation of EPU via the approved GE Energy LTR process assures that plant safety is maintained. The BWROG also concludes the majority of the recent problems attributed to EPU are related to plant reliability issues and have not adversely impacted plant safety. However, changes are necessary to the overall implementation strategy of EPU projects to prevent future events. Many issues involve pre-existing plant component conditions, plant margin management, and operating philosophy that are exacerbated by operation at EPU conditions. The majority of the BWROG recommendations involve strategies to reduce the challenges to plant operations during the EPU implementation process and assure plant reliability remains high.

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This letter has been endorsed by a substantial number of the members of the BWR Owners' Group; however, it should not be interpreted as a commitment of any individual member to a specific course of action. Each member must formally endorse the BWROG position in order for that position to become the member's position.

If you desire to discuss this information in more detail, please contact the undersigned.

Very truly yours,

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NEDO-33159
Revision 0
Class I
November 2004

BWR Owners' Group
EPU Committee

Extended Power Uprate (EPU)
Lessons Learned
and
Recommendations

IMPORTANT NOTICE REGARDING THE CONTENTS OF THIS REPORT
Please Read Carefully

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Table of Acronyms

ASME	American Society of Mechanical Engineering
ATWS	Anticipated Transient Without Scram
BOP	Balance of Plant
BWR	Boiling Water Reactor
BWROG	BWR Owners' Group
BWRVIP	BWR Vessel and Internals Project
CS	Core Shroud Heating
CSH	High Pressure Core Spray
DP	Differential Pressure
DT	Differential Temperature
DW	Drywell
ECCS	Emergency Core Cooling System
ECT	Extended Chemical Treatment
EH	Electro Hydraulic
EHC	Electro Hydraulic Control (Turbine Control)
ELTR	Extended Power Uprate Licensing Topical Report
EOC	Extent of Condition
EPRI	Electrical Power Research Institute
EPU	Extended Power Uprate
ERV	Electromatic Relief Valve
FAC	Flow Accelerated Corrosion
FAS	Fluid Actuator Supply
FW	Feedwater
FWLC	Feedwater Level Control
GE	General Electric
GENE	GE Nuclear Energy
GEZIP	GE Zinc Injection Process
HP	High Pressure
HPCI	High Pressure Coolant Injection
HVAC	Heating Ventilation and Air Conditioning
Hz	Hertz (cycles per second)
INPO	Institute of Nuclear Power Operation
IVVI	In Vessel Visual Inspection
LOOP	Loss Of Offsite Power
LPFW	Low Pressure Feedwater
LTR	Licensing Topical Report
MELLLA	Maximum Extended Load Line Limit Analysis
MFRV	Main Feedwater Regulating Valve
MFW	Main Feedwater

MG	Motor Generator
MOV	Motor Operated Valve
MPT	Main Power Transformer
MS	Main Steam
MSIV	Main Steam Isolation Valve
MSL	Main Steam Line
NRC	Nuclear Regulatory Commission
O&M	Operation and Maintenance
OEM	Original Equipment Manufacturer
OPDT	Over Power Delta Temperature
OPRM	Oscillating Power Range Monitor
OLTP	Original Licensed Thermal Power
P	Pressure
PM	Preventive Maintenance
PU	Power Uprate
PWR	Pressurized Water Reactor
R/Hr	REM Per Hour
RAI	Request for Additional Information
RCIC	Reactor Core Isolation Cooling
RFP	Reactor Feed Pump
RFPT	Reactor Feed Pump Turbine
RPV	Reactor Pressure Vessel
RWCU	Reactor Water Cleanup
RWP	Radiation Work Permit
SPR	Sudden Pressure Relay
SG	Steam Generator
SIL	Service Information Letter
SJAE	Steam Jet Air Ejector
SLCS	Standby Liquid Control System
SRV	Safety Relief Valve
T	Temperature
TBCCW	Turbine Building Closed Cooling Water
TCV	Turbine Control Valve
UCLF	Unplanned Capacity Loss Factor

1.0 Executive Summary

The purpose of the BWR Owners' Group (BWROG) EPU Lessons Learned and Recommendations report is to provide assistance to plants that are in the evaluation and implementation phases of Extended Power Uprate. The BWROG recommendations are based on operating experiences and evaluations from BWR plants that have previously implemented EPUs and from plants currently performing EPU evaluations.

The BWROG has concluded that implementation of EPU via the approved LTR processes assures that plant safety is maintained. The BWROG also concludes the majority of the recent problems attributed to EPU are related to plant reliability issues and have not adversely impacted plant safety. However, changes are necessary to the overall implementation strategy of EPU projects to prevent future events. Many issues involve pre-existing plant component conditions, plant margin management, and operating philosophy that are exacerbated by operation at EPU conditions. The majority of the BWROG recommendations involve strategies to reduce the challenges to plant operations during the EPU implementation process and assure plant reliability remains high.

The BWROG concludes that the majority of vibration problems at the Quad Cities plants are an anomaly related to high steam velocities that produce high vibration levels (inside the steam piping). Nevertheless, cracking of components in steam dryers occurs under both pre-EPU and EPU conditions. To address these concerns and reduce the potential for loose parts, steam dryer acoustic load methodologies are being developed which will allow BWR steam dryers to be evaluated for the higher EPU loads and pre-emptive repairs can be made if required. It is recommended that other BWR plants consider the potential for plant-specific acoustic loads, which can adversely impact components susceptible to flow induced vibration.

Key recommendations developed by the BWROG include:

- Prior to EPU implementation, identify plant component condition deficiencies that may be impacted by EPU related changes in operating parameters. Identify mitigating actions or justify the risk of proceeding with the known deficiency.
- Review and disposition issues resulting from the GE/Exelon Extent of Condition review to ensure that increased component wear following implementation of EPU does not adversely impact plant reliability.
- Obtain the recommended pre-EPU baseline data (including vibration data), then compare this baseline data with the post-EPU implementation data and EPU predictions to ensure that unanticipated impacts are not occurring.
- Consider steam dryer acoustic loads and complete appropriate upgrades/modifications prior to implementation of EPU.

- Update operational procedures and preventive maintenance strategies related to systems, equipment, and components when changes may be required as a result of EPU implementation.
- Evaluate instrument setpoint and calibration requirements for all instrumentation when changes may be required as a result of EPU implementation.

In response to the industry lessons learned, GE has revised the EPU analysis process. This includes incorporation of a detailed steam dryer flow induced vibration and structural evaluation. Plants that have completed EPU implementation should review the BWROG recommendations in accordance with plant operating experience programs.

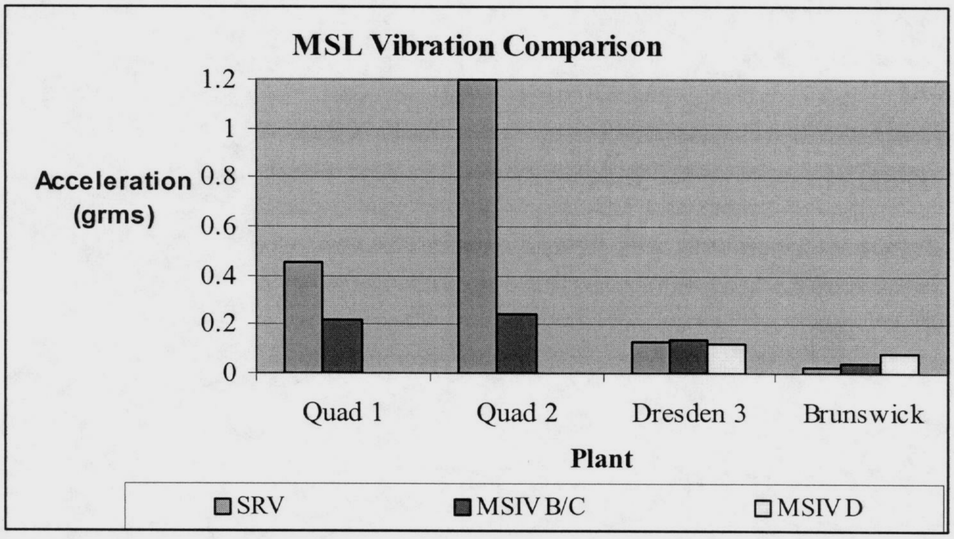
2.0 Introduction

2.1 Background

Extended Power Uprate (EPU) is defined as reactor thermal power in excess of 105% of the original plant licensed power (greater than 105% OLTP). The initial BWR EPUs were implemented approximately 10 years ago, and the early EPU experience was very positive. A 2004 BWROG survey of 13 BWRs showed very few component failures (17 total) that can be attributed to EPU and almost all of these failures are related to flow-induced vibrations in main steam, feedwater, and EHC systems. Approximately 50% of these failures were related to steam dryers at 4 BWR units. Six of the 13 BWR plants surveyed by the BWROG have not experienced a component failure that can be attributed to EPU.

Based on the number of component failures at the Quad Cities plants and the vibration levels in comparison with other BWRs, the BWROG preliminary conclusions are that the vibration problems at the Quad Cities plants are an anomaly related to high steam velocities that produced high vibration levels (inside the steam piping). The BWROG/BWRVIP is following the development of acoustic load methodologies and believes that these methodologies can be employed to verify the uniqueness of the Quad Cities vibration levels.

The following chart supports the BWROG conclusion that the Quad Cities vibration levels are an anomaly. All values are total root mean square acceleration in g's taken at the uprated power level. Note that the SRV vibration levels at Brunswick (120% OLTP) are approximately 60 times lower than at Quad Cites 2 whereas the SRV vibration levels at Dresden 3 are approximately 10 times lower than at Quad Cities 2.



The following table summarizes the operational experience of world-wide BWRs that have implemented EPU. This table demonstrates the extensive operating experience at uprated conditions.

Plant	Licensed Power (%OLTP)	Approx. Maximum Power Achieved (%OLTP)	Approx. Date of Initial Operation at Maximum Power Achieved
KKM	110	110	June 1993
Monticello	106	106	Oct 1998
Hatch 1	115.1	115.1	Nov 1998
Hatch 2	115.1	115.1	Nov 1998
Duane Arnold	120	112.4	Nov 2001
Dresden 2	117	117	Dec 2001
Quad Cities 2	117	117	Mar 2002
Clinton	120	112	May 2002
Brunswick 2	120	116	April 2003
KKL	119.5	119.5	Aug 2002
Dresden 3	117	117	Nov 2002
Quad Cities 1	117	117	Dec 2002
Cofrentes	110	110	Jan 2003
Brunswick 1	120	120	Apr 2004

Following issues that occurred at the Quad Cities and Dresden BWRs in 2003, the BWROG realized the need for industry recommendations. The BWROG agreed to monitor industry activities on EPU issues, prepare and maintain an integrated schedule to help coordinate these activities, and accept the responsibility to be the BWR industry representative on EPU issues.

2.2 INPO Power Uprate and Cycle Extension Database Lessons Learned

The INPO Power Uprate and Cycle Extension Database contain 103 events for the time period from 1992 through January 2004 [reference 1]. This database includes BWRs and PWRs, and power uprates from small measurement uncertainty uprates to extended power uprates. The BWROG screened these events and determined that power uprates directly or indirectly contributed to 52 events, which the BWROG grouped into the following categories:

- 15 due to vibration
- 18 due to instrument calibration problems
- 12 due to operational procedure deficiencies
- 5 due to pre-existing condition, installation errors, defective components, or miscellaneous
- 2 due to erosion / corrosion

A brief summary of the 103 events in this (INPO) database, including the BWROG categorization for these events, is included in Appendix B. The BWROG has determined that none of these events prevented a plant shutdown, prevented a safety system actuation, or complicated the way operations managed any plant transients. However, in the aggregate the events constitute a set of new challenges for the plant staff to manage.

The 17 events that were caused by vibration and erosion / corrosion were considered to have the highest significance due to the resulting component degradation / failure. These events are highlighted in Appendix B and include:

Vibration Events

- BWR-4 socket weld failure on GEZIP skid
- BWR-4 steam dryer damage
- BWR-3 steam dryer damage [4 events]
- BWR-4 recirc pump (vibration and improperly seated testable check valve)
- BWR-3 EHC turbine control valve accumulator leaks
- BWR-4 broken extraction steam line led to feedwater heater tube failures

- BWR-5 feedwater heater tube leaks
- BWR-4 degraded feedwater heater level control valve
- BWR-3 MSL drain line failure
- BWR-4 EHC system leaks
- BWR-4 EHC excessive vibration
- BWR-3 turbine stop valve pressure switches

Erosion / Corrosion Events

- BWR-4 feedwater heater wall thinning and tube support damage
- BWR-4 feedwater heater steam leak

Because of the high percentage of events caused by vibration, a vibration monitoring and evaluation information exchange meeting was held in June 2004. Lessons learned and recommendations derived from this meeting are summarized in Section 3.11 of this EPU Lessons Learned and Recommendations document.

Industry events in the remaining categories, while not desirable or anticipated, are not unique to EPU nor caused by EPU related changes in operating parameters. It is noted that most of the remaining events were caused by inadequate calibrations or revised operational procedures. These issues are considered important lessons learned by the BWROG.

On July 13, 2004 INPO reported at a BWROG General Meeting in Denver, CO that they have evaluated the decreasing performance trend of US power reactors and have determined that EPU has not been a contributing factor. INPO does have concerns with the operational impact of EPUs, the loss of operational margin and the decline in performance indicators of some plants that have implemented EPU.

2.3 BWROG EPU Survey Lessons Learned

The BWROG has evaluated survey responses from 13 BWR plants that have significant operational experience at power levels greater than 105% OLTP [reference 2]. As of February 2004, these plants had accumulated a total of 543 months of operating experience at extended power levels. This experience ranges from a low of 10 months up to a maximum of 130 months at a European BWR. The median operating experience at EPU for these BWR plants is 26 months.

The BWROG survey showed that EPU adversely impacted the unplanned capability loss factor (UCLF) at two BWRs in the period immediately following implementation (steam dryer failures resulted in forced plant shutdowns); whereas, the UCLF improved at two BWRs plants following implementation of EPU. For the other nine BWRs, the UCLF was not significantly affected by implementation of EPU.

The 13 BWRs surveyed reported a total of 17 component failures, most of which were related to flow-induced vibrations in main steam, feedwater, and EHC systems. Eight (8) of these 17 failures involved steam dryer components at 4 BWR plants. Five (5) of the 13 plants reported no component failures that could be attributed to implementation of EPU.

The other failures that were not related to flow-induced vibrations in main steam, feedwater, and EHC systems included:

- Seizure of stator cooling water pump (design issue for replacement larger pump with different coupling and seals)
- Reactor feed pump governor linkage galled not allowing speed feedback to reactor water level control (alternate pump experienced an identical failure pre-EPU)
- Main transformer sudden pressure relay (similar failures have been observed at other plants at pre-EPU conditions in the industry)

A detailed summation of the results from this BWROG survey is included as Appendix A.

Following submittal of the BWROG EPU survey, several noteworthy issues (non-dryer related) occurred at Quad Cities that were associated with the high flow induced vibrations in the main steam system. These issues have been dispositioned by Exelon and are summarized below:

- An electromatic relief valve (ERV) actuator was damaged due to flow induced vibration. The ERV actuators were refurbished and additional laboratory testing was performed to determine the appropriate modifications to resist future degradation. Vibration instrumentation also was installed to monitor future performance and validate testing levels.
- Degradation of a Limitorque operator (limit switch) was noted during a walkdown inspection following the failure of the ERV. The results of Limitorque limit switch vibration testing confirmed minimal wear for simulated one cycle operation. It was determined based on as-found conditions of the limit switch, that there would have been no impact to the valve function.
- During testing, after a full cycle of EPU operation, a Target Rock SRV setpoint was determined to be out of specification. An evaluation revealed that the cause of the setpoint change was due to SRV vibration that wore a groove in the first stage bellows cap. Alternate materials are being evaluated.

Detailed walkdowns were performed at the Dresden and Quad Cities stations. No EPU-related vibration issues were identified as a result of these walkdowns other than the ERVs and the one Limitorque operator at Quad Cities.

The evaluations performed utilizing analysis, testing, and walkdown information concluded that all components are acceptable for full cycle operation at EPU power with the exception of the ERVs, at Quad Cities, and the Target Rock SRVs at both units, that required upgrades to the vulnerable parts. Testing was successfully completed at Wyle Laboratories to confirm the failure modes and to test the proposed modifications. It has been confirmed that the wear mechanism is the result of structural mode excitation of the solenoid plunger assembly for the ERVs, and the first stage pilot bellows cap/spring assembly for the Target Rock SRVs. Vulnerable components within these assemblies are being modified.

RECOMMENDATION: Review main steam and feedwater components for potential vibration and wear related degradation. Evaluate components with known preventive or corrective maintenance due to vibration for potential increased vulnerability.

2.4 GE/Exelon Extent of Condition Evaluation Results and Associated Guidance

In order to better understand the risks associated with EPU implementation and to recommend actions to mitigate failures resulting from these vulnerabilities, GE and Exelon conducted a rigorous Extent of Condition (EOC) review for the Dresden and Quad Cities stations in 2004 [reference 3]. The goal of this comprehensive evaluation is to reduce or eliminate operational challenges as measured by:

- Licensee Event Reports
- Engineered Safety Features Actuations
- Reactor Scrams
- Plant power derates
- Unplanned entries into Technical Specification action statements
- Operator work-around challenges (that increases risk to one of the above events)
- Unexpected accelerated degradation of components (that increases risk to one of the above events)
- Significant loose or lost parts (foreign material exclusion)

For the EOC review, both Power Systems and Safety Systems were evaluated based on potential EPU impact. The Safety System reviews were scenario-based. A total of 43 Balance of Plant Systems and 10 Safety Systems were reviewed in detail. The first step was to determine which systems have the potential to be affected by EPU (flow rates, temperature, pressure, radiation levels, vibration levels). For each system that was potentially affected, P&IDs were employed to identify all system components and instrumentation for further evaluation. Each of these components and associated subcomponents were then evaluated for potential impact due to EPU. Operational data was collected for both pre-EPU and post-EPU operating conditions prior to the system level and component evaluations. The component evaluations involved determining the potential for increased wear or increases in other failure mechanisms that may result from operation under EPU conditions.

GE/Exelon classified the susceptible components and instrumentation into 8 root cause categories. Note that steam dryer issues have been addressed separately (Section 3.5 thru 3.6). The following lists these categories and example components that have been identified for specific evaluations.

(1) Vibration driven

- Reactor recirc system instrumentation sensing lines and other small bore piping
- Main steam lines
- Main steam line instrumentation and small bore piping
- Feedwater system piping, valves, and instrumentation
- Stator cooling water temperature controller
- Turbine/EHC system

(2) Documentation and design basis issues

- Feedwater heater relief valve setpoints
- All other documentation and design basis issues identified are Exelon specific

(3) Accelerated wear and degradation

- Recirc pump motors
- Feedwater pump seals
- Feedwater heaters and drain valves
- Feedwater and condensate AOVs
- Off gas condenser and gland seal valves
- Turbine control valves
- LP turbine inner casing

(4) FW flow requirements

- Flow accelerated corrosion (FAC) of temperature element thermowells
- Impact of FAC on condensate demins
- FAC of heaters and system components
- Impact of increased FAC on pump seals, CRDs, and control rod hydraulic control units
- Erosion of extraction steam piping
- Pumps, pump discharge check valves, minimum bypass valves, and heater valves

(5) Known material condition issues

- Main generator
- Recirc system M-G set
- Feedwater system sample probes
- Condensate demineralizers
- FW heaters, drain coolers, and associated valves
- FW heater shell vents
- Main condenser

(6) Thermal power calculation

- Unique to Exelon specific calculation methods

(7) Reduced operations and analysis margin

- Operator training regarding pressure set adjustments during load drop
- Pressure controller setpoint
- Calibration of main steam flow instrumentation
- Feedwater system pump redundancy
- Feedwater-reactor water level control
- Recovery of safety analysis margin

(8) Reactor internals flow and vibration

- Shroud head and steam separator inspection
- FW sparger end brackets
- Jet pump slip joint bypass leakage and associated vibration
- Jet pump wedge inspections

A detailed summary of these recommendations is included as Appendix C. This appendix can be employed as a checklist to determine requirements for increased inspections following implementation of EPU.

In addition, the following observations were made regarding the effect of EPU on plant equipment:

- Increased feedwater flow can increase the fatigue loading on vessel components, which may require more frequent inspections.
- Increased core differential pressure can change the jet pump flow and consequently the loading on the jet pump support components, which may require more frequent inspections.
- Changed operating conditions (e.g. valve positions) can increase wear, which may require enhanced preventive maintenance.

- Increased feedwater flow, steam flow, and recirculation pump speed can result in increased vibration on system components.
- Elimination of standby feedwater and condensate pumps and operation at non-optimum flow can introduce gradual component degradation.
- Increased flow in extraction steam, moisture separators, and heater drains can increase the effects of Flow Accelerated Corrosion (FAC).
- Known system deficiencies not corrected prior to EPU implementation can result in reduced operating margin.

From the GE/Exelon recommendations, the BWROG compiled specific vulnerabilities and recommendations into the following table. This has resulted in a listing of 18 areas for which the BWR industry should address on a plant-specific basis. Recommendations range from pre-EPU evaluations / system design changes to post-EPU component inspections:

	Issue for BWR Evaluation
1	Shroud head and steam separator
2	Welded access hole covers
3	Feedwater sparger end brackets
4	Recirc system flow sensing lines and other small-bore piping
5	Main steam line differential flow switches
6	Pressure controller setpoints
7	Main generator stator cooling water system temperature controller
8	Condensate and feedwater system pumps, valves, check valves, seals, relays, minimum flow
9	Temperature probes and thermowells, sample probes, hydrogen/oxygen injection quills and sample probes
10	Condensate and feedwater system large and small bore piping
11	Feedwater heaters, drain coolers, drains and associated valves
12	Condensate demineralizers and associated valves
13	Off-gas and gland seal condensers
14	Control rod HCUs and control rod drives
15	Turbine EHC
16	Cross around relief valve setpoints
17	LP turbine inner casing
18	Extraction steam piping

For the Safety Systems, GE and Exelon concluded that the safety functions remain uncompromised. It was also noted that the design inputs for these analyses were generally conservative because of use of a common model that employs the most bounding parameters for Dresden 2, 3 and Quad Cities 1, 2. The analyses results for the Safety

Systems have been adequately implemented at the Exelon plants. Some documentation deficiencies were discovered during the review that are being resolved through the Exelon corrective action program; and the utility has identified systems or analyses with limited post-EPU margin for which actions are being evaluated and implemented to increase the margin as appropriate.

For the Power Systems, no vulnerabilities were identified that could result in an immediate challenge to plant operations. Almost all of the recommendations addressed accelerated equipment degradation due to EPU. Another key recommendation is that the material condition of the plant pre-EPU should be an important factor for future EPU evaluations.

Other key industry recommendations include the identification of and institution of critical preventive maintenance changes for components effected by EPU; and the monitoring and trending of critical operating parameters.

RECOMMENDATION: Review GE/Exelon Extent of Condition recommendations (Appendix C) and assure that applicable issues have been adequately addressed prior to implementation of EPU. Recommendations that involve post-EPU implementation inspections should also be carefully considered and dispositioned.

2.5 Power Ascension Test Program Lessons Learned

Eleven power uprate ascension test reports were examined for common test issue categories and common elements within the issue categories. As a result of this review, only the pressure regulator test was found to be a common test issue category in three of the eleven reports. However, there were no common elements within this issue category (i.e. the specific equipment challenges precipitating the subject issue category differed for all three plants). This observation, in conjunction with the finding that no other common test issues were identified, suggests that testing results are dependent on the unique equipment characteristics of the individual plants.

RECOMMENDATION: Based on GE experience it is recommended that the EPU test director should be a very experienced Senior Reactor Operator and should be experienced in performing control system testing. This is key to successful pressure and feedwater level control testing. Also it is recommended that the EPU procedure writer be a member of the EPU test team to simplify procedural changes when required.

3.0 Plant Evaluation Lessons Learned and Recommendations

3.1 LTR Process Evaluation

The BWR Owners' Group has concluded that implementation of EPU via the approved LTR process assures plant safety is maintained. The BWROG determined that the majority of the recent problems attributed to EPU are in the BOP area and are caused by pre-EPU plant component deficiencies or minimal operating margins. No revisions to the approved GE EPU licensing topical reports are needed to improve the EPU safety evaluation; however, changes to the GE EPU Evaluation process are being made to address these problems (see Section 3.2) [reference 4].

During the early and mid 1990s, GE developed a process for uprating the BWR plant power by about 5%. At that time GE examined the impact of 5% power uprate on plant risk and concluded that the risk increase, as measured by increase in core damage frequency (CDF) and large early release frequency (LERF), was very small and no plant-specific PRA update was recommended.

In subsequent years, GE developed a process for extended power uprate (EPU), which increased the plant power by 15 to 20%. GE recommended and NRC agreed that a plant-specific PRA update was required as part of implementing the EPU. All plants that implemented EPU have performed a PRA for the EPU conditions and have concluded that the CDF increase is not disproportionately high compared to the power increase.

PRA calculates CDF by identifying accident initiators and determines the associated frequencies, and identifies the systems that keep the core covered and evaluates the unavailability of these systems on demand. The combination of initiator frequency and mitigating system unavailability yields the CDF. As part of CDF evaluation, the following areas are considered: initiating events, system analysis, accident sequence development, data analysis, human reliability analysis, dependence analysis, success criteria, structural analysis, thermal-hydraulic analysis and PRA quantification.

In addition to CDF, the PRA calculates large early release frequency (LERF). This is accomplished by modeling the core melt accident sequence progression, core-concrete interaction and containment failure.

NRC has not set a specific acceptance criteria for the CDF and LERF increase associated with EPU. There are, however, criteria in Regulatory Guide (RG) 1.174 which may be considered applicable. RG 1.174 "An Approach for Using Probabilistic Risk Assessments in Risk-Informed Decisions on Plant-specific Changes to Licensing Basis" permits CDF change of less than 1.0E-6 per plant-year and LERF change of 1.0E-7 per plant-year, regardless of pre-EPU PRA results. RG 1.174 also permits CDF changes in the range of 1.0E-6 to 1.0E-5 per plant-year and LERF changes in the range of 1.0E-7 to 1.0E-6 per plant-year provided the pre-EPU CDF and LERF values are less than 1.0E-4 and 1.0E-5 per plant-year, respectively.

The EPU PRAs are generally performed by the individual licensees using the plant-specific PRA model. The results are submitted directly to the NRC by the licensees. The primary impact of EPU on PRAs is attributable to the reduced operator action times resulting from the increased decay heat levels. The reduced time increases the operator error probability.

The impact on initiating event frequency, success criteria and the other parameters is insignificant. The CDF and LERF increase due to an EPU has been about 10% or less over the base CDF. The increase in CDF and LERF values generally meet the RG 1.174 criteria.

3.2 GE Process Changes

Revisions were made to the GENE EPU process as a result of the Exelon/GE Extent of Condition review, which included development of a revised dryer load methodology that considers acoustic load factors, and added a pre-EPU assessment of current plant components that involves evaluation of pre-EPU operating data, trends and interviews of the plant staff [reference 4].

<u>RECOMMENDATION</u>: Perform a comprehensive pre-EPU assessment of the plant that includes:

- **A plant component assessment during the evaluation phase of an EPU project**
- **A review and evaluation of plant operational data, trends, and other operating experience (including interviews with the plant staff)**
- **An evaluation of the current operating margin (as opposed to initial design margin) and an estimate of margin available at EPU conditions.**
- **An evaluation of the potential system and component vulnerabilities due to EPU implementation**
- **Development of recommendations to improve operating margin**

3.3 Plant Condition Evaluation

Recent experience with implementation of EPU has confirmed the importance of evaluating the current maintenance practices prior to implementation of EPU. Preventive maintenance (PM) records should be reviewed to identify components for which a PM has been extended or for which increased PM frequencies have been required. Consideration should be given to scheduling increased maintenance on these components until the impacts of EPU can be quantitatively determined.

RECOMMENDATION: Assure that PMs on system components, which may be impacted by EPU, are adequately evaluated prior to EPU. Consider increasing PM on components that currently require frequent maintenance and/or replacement; and on components for which the required level of maintenance is increasing.

3.4 Operating Margin Assessment

In the design process for upgrading the BWR unit to facilitate increased power production, the impact on plant system and equipment operating margins must be evaluated. The utility must balance the cost of maintaining existing margins (spare pumps, etc) with the risk of lower plant reliability if the existing margins are utilized in the uprated plant design. In some cases it may be cost effective to incorporate the improvement of existing margins in the plant redesign. It is important to conduct a thorough and comprehensive design review for components that have insufficient operating margin at EPU conditions. Plant modifications and upgrades to increase operating margins, where needed, should be made prior to implementation of EPU.

RECOMMENDATION: In the plant evaluation process for EPU, evaluate the impact of EPU on current plant system and equipment margins, and incorporate cost-beneficial design enhancements in the EPU plan to assure that sufficient margin is maintained for reliable plant performance.

3.5 Steam Dryer Loads

In response to industry steam dryer integrity problems, two independent approaches are being developed to assure that steam dryer performance will be safe and reliable in the future. It has recently been demonstrated that acoustic loads can be a significant contributor to the total vibration loads, and these loads can adversely impact steam dryers and other plant components that may be impacted by flow induced vibration. These steam dryer load definition programs are focused on quantification of acoustic loading.

The GE-sponsored steam dryer load definition program includes development of an acoustic analysis model and scale model testing to determine dryer acoustic loads. The steam dryer and piping for a selected plant are replicated in sub-scale and tested in a fixture designed and built for this testing. Acoustic loads measured on the sub-scale fixture will be scaled to full size and combined with other dryer loads determined analytically to arrive at a total loads definition for a given dryer. It is expected that this sub-scale testing will assist in determining the source of significant loads. Note that the sub-scale test results will be benchmarked against full-scale test data taken from the selected operating BWR plant.

The acoustic model will be employed in conjunction with the sub-scale model. The initial objective of the acoustic model is to provide dryer loads for a specific condition for which actual steam piping vibration data is available. It is not expected to be able to predict loads for a steam velocity above which actual plant data is available. Until significant experience has been gained, it is expected that the acoustic model will only be used in conjunction with the sub-scale model.

The Continuum Dynamics Inc. (CDI) steam dryer load definition program employs an acoustic model to predict acoustic loads on the dryer from plant operational vibration data taken on the main steam piping. The calculated steam dryer loads are then verified against available cyclical pressure data taken from instrument taps located close to the steam dryers (reactor water reference leg).

Following determination of the total dryer loads, an evaluation can be made regarding requirements for potential modification or replacement of the steam dryers.

RECOMMENDATION: An evaluation of steam dryer loads for EPU conditions should be made prior to implementation of EPU. Modifications of the dryer or bases for not making modifications should be made based on the results of this evaluation.

3.6 Steam Dryer Inspection and Evaluation

GE SIL 644 revision 1 (November 9, 2004) provides detailed steam dryer inspection recommendations, and recommendations for monitoring the moisture content of the main steam and other reactor system parameters [reference 5]. This SIL is applicable to all BWR steam dryers, not just for BWR plants operating at EPU conditions. The BWROG Steam Dryer Integrity Committee developed the "BWR Moisture Carryover and Operational Response Guidance" that is included in SIL 644 revision 1 as Appendix D.

GE in conjunction with the BWRVIP has developed steam dryer and inspection guidelines [reference 6]. This document discusses the different dryer configurations and the relative risk of failure along with analyses of the failure consequences. This document summarizes previous dryer repair history based on a BWR Steam Dryer Operational Experience survey issued by the BWROG. Dryer inspection guidelines, flaw evaluation methods, and operational guidance are also addressed in the inspection guidelines.

BWRVIP-06 Section 4 has been updated to include recent dryer failures [reference 7]. This document addresses resulting loose parts issues.

RECOMMENDATIONS: Follow the inspection and monitoring recommendations of GE SIL 644 and the BWRVIP steam dryer inspection guidelines. Incorporate the generic loose parts evaluation included in Section 4 of BWRVIP-06 in future plant-specific loose parts evaluations.

3.7 Operating Procedures

The BWROG has determined, based mainly on review of the INPO Power Uprate and Cycle Extension Database (see Appendix B), that inadequate revision of procedures has led to problems during EPU implementation. A thorough review of all procedures that may be impacted by EPU must be completed prior to EPU implementation and the affected procedures must be revised accordingly. Note that this recommendation is applicable for all plant modifications.

RECOMMENDATION: Evaluate plant procedures for all systems and components that may be affected by EPU and revise appropriately prior to implementation of EPU.

3.8 Instrument Calibration and Setpoint Adjustments

Based on review of the INPO Power Uprate and Cycle Extension Database, the BWROG recommends that instrumentation potentially affected by EPU conditions be evaluated for changes in calibration, trip avoidance risk, and necessary setpoint adjustments. Examples of instrumentation that may require adjustments are:

- FW flow and ultrasonic flow meters
- MSL low pressure switches
- MSL high flow trip units
- Turbine first stage pressure switches
- APRMs
- Process Radiation Monitors

RECOMMENDATION: Evaluate industry EPU experience and revise instrumentation calibration and setpoints as appropriate.

3.9 Plant Baseline Data

To provide a reference for historical pre-EPU operation and the effect of EPU modifications, plant baseline data should be obtained prior to implementing the plant modifications needed to support operating at the increased power levels; and immediately after the plant modifications are made prior to operating the plant at EPU conditions. Basic parameters to be measured for all systems and components expected to be impacted by EPU include:

- Steam, feedwater, recirculation system, and core flow rates
- Temperatures
- Pressures

- Radiation levels
- Vibration levels
- MSL moisture content

Vibration monitoring issues are discussed in more detail in Section 3.11.

EPU plant data should be compared with the pre-EPU data. For all unexpected increases or increases greater than projected, increased inspection of potentially affected components should be undertaken.

RECOMMENDATION: Perform baseline measurements for all parameters expected to be impacted by EPU prior to and immediately after making the required plant modifications needed to support operation at the increased power level. EPU data should be compared with baseline data, and for all unexpected increases above baseline plant data, increased inspection of potentially affected components should be undertaken.

3.10 IVVI and FAC Program Changes

The process for the management of FAC in nuclear power plants is summarized in EPRI Report NSAC-202L-R2 "Recommendations for an Effective Flow-Accelerated Corrosion Program" [reference 8]. This process has been accepted by the US NRC and INPO.

One element in the process to control FAC in susceptible piping systems is to model them using the CHECWORKS Steam / Feedwater Application. This computer program predicts FAC on a component-by-component basis. The predictions include the current wear rate, total wear to date, and remaining service life of each modeled component. This allows a plant to identify and inspect the most susceptible locations and repair or replace them as necessary before a failure might occur. It is noted that there are FAC susceptible systems that are not modeled due to unknown conditions such as operating time, actual fluid conditions, etc.

The CHECWORKS model uses an empirical-based algorithm that is based on thousands of points of laboratory and plant data. The algorithm determines the current rate of FAC and damage to date as a function of eight variables (temperature, mass transfer, geometry, steam quality, dissolved oxygen, pH, hydrazine, and alloy composition of the component- namely chrome, copper and molybdenum). The laboratory and plant data that was used in developing the algorithm bound the values typically encountered in nuclear power plant applications.

EPRI has not identified any instances where EPU has resulted in parameters such as temperature or flow rate (related to mass transfer) that are outside of the validation range. It is noted that the changes in FAC due to EPU are small compared to changes when a BWR plant implements Hydrogen Water Chemistry or Noble Metal Chemistry because of the significantly lower concentrations of oxygen in the steam side. Note that the high oxygen in a BWR reduces FAC rates.

In June 2003, Southern Nuclear made a presentation to the CHECWORKS Users Group (CHUG) regarding predictions of FAC rates under EPU operating conditions. Some FAC rates at the Hatch plant went up, while others went down.

RECOMMENDATION: Review IVVI and FAC programs and component status prior to EPU implementation. Increase monitoring requirement on components that are approaching end-of-life.

3.11 Flow Induced Vibration (Exterior and Interior)

Since the majority of EPU-related component failures involve flow induced vibration, the BWROG EPU Committee held a vibration monitoring and evaluation information exchange meeting of industry experts in June 2004. The committee determined that the current process of monitoring large bore piping systems in accordance with the requirements of ASME O&M Part 3 is sufficient to preclude challenges to safe shutdown. Increases in large bore piping vibration levels are a precursor to increased vibration levels in attached small bore piping and components. The following recommendations may be helpful in assessing plant specific EPU.

No.	Vibration Monitoring & Evaluation Recommendations
1.	Obtain pre-EPU baseline data for planned data points prior to implementing uprate modifications that affect main steam and feedwater flow paths.
2.	Review pre-EPU maintenance history and operating experiences for recurring vibration-driven issues with specific evaluation for EPU conditions. Monitor those components found to have been frequently replaced or refurbished. Evaluate preventive maintenance frequencies based upon increased EPU vibration levels of susceptible components. This monitoring may include vibration measurements.
3.	Perform baseline inspections/walkdowns prior to or during EPU outage focusing on configurations identified to be vulnerable to vibration degradation. Determine natural frequencies of potentially susceptible configurations. Verify integrity of piping supports.
4.	Inspect both mechanical and electrical joints to ensure proper torque and locking mechanisms
5.	Monitor components at frequencies greater than 50 Hz. (i.e. 50 Hz. to 200Hz.)
6.	Consider providing capability to obtain all hard-wired vibration data concurrently to facilitate time history evaluations.
7.	Be aware that installation of accelerometers on small bore piping may change frequency response. If so, consideration should be given to retaining the mounting hardware on the piping after test completion (so that the measured data will align with operational performance).
8.	Consider collection of pressure-time history of steam lines pre and post EPU per EPRI specifications.
9.	Consider thermal expansion during installation of accelerometers and associated electronics.
10.	For inaccessible locations, consider the use of redundant sensors.
11.	Avoid reinstallation of insulation over charge converters.
12.	Consider the use of cameras in high dose areas for low frequency/large displacement component vibration detection.

RECOMMENDATION: Perform baseline measurement for all parameters expected to be impacted by EPU prior to and immediately after making the required plant modifications needed to support operation at the increased power level.

For vibration monitoring, consider the above BWROG recommendations that were developed at the vibration monitoring and evaluation information exchange meeting.

4.0 Conclusions

The BWROG has concluded that implementation of EPU via the approved LTR process assures that plant safety is maintained. The BWROG recommendations will reduce the challenges to plant operations during the EPU implementation process and will help assure that plant reliability remains high.

These recommendations will also significantly reduce the potential that safety components will be degraded by loose parts from non-safety systems.

Key recommendations developed by the BWROG include:

- Prior to EPU implementation, identify plant component condition deficiencies that may be impacted by EPU related changes in operating parameters. Identify mitigating actions or justify the risk of proceeding with the known deficiency.
- Review and disposition issues resulting from the GE/Exelon Extent of Condition review to ensure that increased component wear following implementation of EPU does not adversely impact plant reliability.
- Obtain the recommended pre-EPU baseline data (including vibration data), then compare this baseline data with the post-EPU implementation data and EPU predictions to ensure that unanticipated impacts are not occurring.
- Consider steam dryer acoustic loads and complete appropriate upgrades/modifications prior to implementation of EPU.
- Update operational procedures and preventive maintenance strategies related to systems, equipment, and components when changes may be required as a result of EPU implementation.
- Evaluate instrument setpoint and calibration requirements for all instrumentation when changes may be required as a result of EPU implementation.

5.0 References

1. 2004-04 INPO Plant Events Database (Power Uprate and Cycle Extension) Evaluation, revision 2

2. 2004-03 BWROG EPU Survey Compilation, rev 2

3. GE/Exelon Extent of Condition for Dresden and Quad Cities Stations, EDRF 0000-0026-3136 (GE Proprietary)

4. GE'PPL Extended Power Uprate Scoping Study / Project-specific Work Plan, GE-NE-0000-0031-5776 draft R dated September 2004

5. GE SIL 644, Steam Dryer Integrity, Revision 1 dated November 9, 2004

6. BWRVIP Steam Dryer Inspection and Evaluation Guidelines, Revision 0 (to be issued in December 2004)

7. BWRVIP-06, Section 4 revision dated October 20, 2004

8. EPRI Report NSAC-202L-R2 Recommendations for an Effective Flow-Accelerated Corrosion Program

Plant(s)	Max. EPU Operation (%OLTP)	Months at EPU	Component/ Subcomponent Failures	Increased Wear Rates or Parts Replacement	Impact on UCLF due to EPU	Operational Impacts and Other Comments of Interest
Brunswick 1,2	113.5 116	20 10	EHC Accum seals failed a few months after EPU. Failure related to operation at interim powers. EHC drain line fitting at turbine control valve (unit 1 failed in 23 months; unit 2 failed in 8 months). These fittings also experienced failures pre-EPU.	Shorter life for condensate demin filters and deepbed demins (expected) Shorter life expectancy for control rod blades (expected)	No	EHC drain line fittings is not a new failure mode but believed to be driven by EPU, designing mod to install flexible connections Condenser sensing line determined to be located at different points for trip/alarm versus operator indication (mod planned to relocate so that operators valid indication of margin to trip) Downpower dose rates are higher because of increased flow and reduced transport time, RWP changes required because some dose rates exceed 10 R/Hr

Plant(s)	Max. EPU Operation (%OLTP)	Months at EPU	Component/ Subcomponent Failures	Increased Wear Rates or Parts Replacement	Impact on UCLF due to EPU	Operational Impacts and Other Comments of Interest
Duane Arnold	112.4	27	None	Accumulator on EHC FAS lines to each TCV had a recent history prior to EPU of losing their charge, and the frequency increased after EPU Two FW heaters have experienced significant internal shell wastage near extraction steam inlet nozzles	No (increase due to problems with main condenser and DW coolers not related to EPU)	Increased frequency of the EHC accumulators losing their charge due to high gain for the TCV position at the interim power level (not the EPU power level). OEM predicted these swings since the equipment was re-designed for the EPU power level. FW heater shell wastage near the extraction nozzles was occurring prior to EPU. These heaters were previously identified as needing to be replaced due to expected decrease in tube life from increased tube vibration at higher power levels.

Plant(s)	Max. EPU Operation (%OLTP)	Months at EPU	Component/ Subcomponent Failures	Increased Wear Rates or Parts Replacement	Impact on UCLF due to EPU	Operational Impacts and Other Comments of Interest
Dresden 2,3	117 117	26 14	Seven specific steam dryer components	Reactor feed pumps (all 3 pumps operating, no longer a stand-by pump) Condensate and condensate booster pumps (all 4 pumps are operating, no longer a stand-by condensate and condensate booster pump)	"Forced Loss Rate" reduced from 3.4% to 0.8% and UCLF reduced from 4.72% to 1.6% on unit C1 "Forced Loss Rate" reduced from 4.5% to 2.2% and UCLF reduced from 6.12% to 3.8% on unit C2	Not enough operating time at EPU to identify trends on other plant equipment other than failed components

Plant(s)	Max. EPU Operation (%OLTP)	Months at EPU	Component/ Subcomponent Failures	Increased Wear Rates or Parts Replacement	Impact on UCLF due to EPU	Operational Impacts and Other Comments of Interest
Hatch 1,2	115.1 115.1	58 63	None	None	No	During the implementation of the Unit 1 EPU, experienced erroneous high level indication and subsequent level control on the high pressure feedwater heaters. It was later determined that the heater was experiencing a phenomenon known as "wall wetting" due to the additional flow to the HP heaters. The sensing lines for the level transmitters had to be inserted beyond the wall of the heater to negate the additional flow impact. This problem was diagnosed as a condition previously experienced by the heater vendor.

Plant(s)	Max. EPU Operation (%OLTP)	Months at EPU	Component/ Subcomponent Failures	Increased Wear Rates or Parts Replacement	Impact on UCLF due to EPU	**Operational Impacts and Other Comments of Interest**
KKL	119.5	64	None	None	No	As expected, have seen an increase in iron in the condensate system that is indicative of increased erosion in piping due to the increase in steam and condensate flow rates. Possible higher wear rate on shaft seals of FW pumps due to higher speed and/or altered water chemistry. Plant completed extensive surveillance, testing, and analysis program that accompanied the steps of power uprate. Power uprate was implemented in four steps increases over several years.

Plant(s)	Max. EPU Operation (%OLTP)	Months at EPU	Component/ Subcomponent Failures	Increased Wear Rates or Parts Replacement	Impact on UCLF due to EPU	**Operational Impacts and Other Comments of Interest**
Monticello	106.1	64	Stator water cooling pumps seized within 1 month of implementation of EPU, design issue for larger pumps with different couplings and seals	None	No	The feed water nozzle discharge coefficient changes were not translated to the plant process computer correctly causing plant to operate at a slightly higher power level. Turbine component replacements with tighter packings caused higher vibration during startup.

Plant(s)	Max. EPU Operation (%OLTP)	Months at EPU	Component/ Subcomponent Failures	Increased Wear Rates or Parts Replacement	Impact on UCLF due to EPU	Operational Impacts and Other Comments of Interest
Quad Cities 1,2	117.0 117.0	15 24	MSL drain lines Small bore piping failures on feed pump drain lines and suction relief valves Steam dryer	ERV actuators	Increased UCLF due to forced outages	Chattering of MSL low pressure relays due to in appropriate setpoint Increased condensate pump noise EHC leaks caused unplanned load reductions Steam line drains vibrate at higher amplitude RFP TBCCW cooling line cracked Loose nuts on 2C RFP disch. MOV Pinhole leak on 2B RFP discharge drain line High temperature on isophase bus duct system Recirc loop sample line wear

Plant(s)	Max. EPU Operation (%OLTP)	Months at EPU	Component/ Subcomponent Failures	Increased Wear Rates or Parts Replacement	Impact on UCLF due to EPU	**Operational Impacts and Other Comments of Interest**
Quad Cities 1,2 (continued)						MSIV supply line to accumulator leakage MSIV room cooler leakage ERV discharge piping snubber loose HPCI steam bellows cover missing a nut off a capscrew and nut and capscrew in another location RWCU valve cracked limit switch Loose nut on turbine control valve Locknuts and hangers on moisture separators loose Survey also summarized reduced margin issues several of which have been identified after the EPU outages.11

Plant(s)	Max. EPU Operation (%OLTP)	Months at EPU	Component/ Subcomponent Failures	Increased Wear Rates or Parts Replacement	Impact on UCLF due to EPU	Operational Impacts and Other Comments of Interest
Clinton	110	22	Pre-existing crack in steam dryer drain channel observed to exhibit 1.1inch growth.		No Capacity factor slightly higher because operation is not limited by licensed power output.	SJAE exhibited chugging during rapid power ascension at high condensate and lake temperatures. Turbine pressure spikes observed at point where last TCV reached opening point. Partial 3+1 arc admission implemented in conjunction with EPU. Condensate polisher resins changed post-EPU to achieve better chemistry control, which resulted in lower system flow rates. This resulted in a reduction in feedwater pump suction pressure. Additional condensate polisher and improvements to feedwater pump efficiency (pump impeller changeout) are being considered.

Plant(s)	Max. EPU Operation (%OLTP)	Months at EPU	Component/ Subcomponent Failures	Increased Wear Rates or Parts Replacement	Impact on UCLF due to EPU	**Operational Impacts and Other Comments of Interest**
Clinton (continued)						Increased feedwater heater wear predicted by EPU. Plant is performing eddy current testing to quantify changes in heater tube wear rates. Flow accelerated corrosion wear rates in accordance with predictions based on data observed after one operating cycle at EPU.
KKM	110	130 (122 months at 110%)	None	None	No	

INPO Event No.	Event Summary	%Power (time of event)	PU DIRECTLY CAUSED OR INDIRECTLY CONTRIBUTED TO EVENT								Events Only Tangentially Related to PU or Comment
			Vibr.	Erosion / Corrosion	Mod. or Install. Error	Calib. Def.	Amb. Temp. Change	Oper. Proc. Def.	Def. Comp.	Pre-exist. Cond. or Other	Cause of Event
	BWR-3 Increased Moisture Carryover	100	X								
	BWR-3 Automatic Reactor Scram	8						X			
	PWR Flux Anomoly	-									Axial flux, increased crud layer at top of high-powered rods
	PWR Boric Acid Corrosion of valve yokes	0									Increased fuel cycle length

INPO Event No.	Event Summary	%Power (time of event)	PU DIRECTLY CAUSED OR INDIRECTLY CONTRIBUTED TO EVENT								Events Only Tangentially Related to PU or Comment
			Vibr.	Erosion / Corrosion	Mod. or Install. Error	Calib. Def.	Amb. Temp. Change	Oper. Proc. Def.	Def. Comp.	Pre-exist. Cond. or Other	Cause of Event
	Broken Extraction Steam at BWR-4 plate leads to Excessive Tube Failures in FW Heater	0	X								
	BWR-4 Calibration error in CS line break DP instrument	100				X					
	BWR-3 EHC system leaks caused by Pressure Oscillations	-	X								

INPO Event No.	Event Summary	%Power (time of event)	PU DIRECTLY CAUSED OR INDIRECTLY CONTRIBUTED TO EVENT								Events Only Tangentially Related to PU or Comment
			Vibr.	Erosion / Corrosion	Mod. or Install. Error	Calib. Def.	Amb. Temp. Change	Oper. Proc. Def.	Def. Comp.	Pre-exist. Cond. or Other	Cause of Event
	BWR-3 Computer code predicts RCIC' Line may not isolate	-									Concern resolved via analysis
	BWR-6 Condenser Vacuum Loss results 15% power reduction	85						X			
	BWR-6 Criticality couldn't be maintained in 2 reactor startups	0									Procedure Inadequacy

INPO Event No.	Event Summary	%Power (time of event)	PU DIRECTLY CAUSED OR INDIRECTLY CONTRIBUTED TO EVENT								Events Only Tangentially Related to PU or Comment
			Vibr.	Erosion / Corrosion	Mod. or Install. Error	Calib. Def.	Amb. Temp. Change	Oper. Proc. Def.	Def. Comp.	Pre-exist. Cond. or Other	Cause of Event
	BWR-4 Reactor heat balance error during EPU implementation	94						X			
	PWR Discrepancies in vendor calculations	-						X			

INPO Event No.	Event Summary	%Power (time of event)	PU DIRECTLY CAUSED OR INDIRECTLY CONTRIBUTED TO EVENT								Events Only Tangentially Related to PU or Comment
			Vibr.	Erosion / Corrosion	Mod. or Install. Error	Calib. Def.	Amb. Temp. Change	Oper. Proc. Def.	Def. Comp.	Pre-exist. Cond. or Other	Cause of Event
	BWR-3 Nonconservative FW temp. calibrations result in operation at power levels greater than licensed max.	100				X					
	PWR Nonconservative time constants trip channels	100				X					
	PWR Extraction steam line breech	100								X	

INPO Event No.	Event Summary	%Power (time of event)	PU DIRECTLY CAUSED OR INDIRECTLY CONTRIBUTED TO EVENT								Events Only Tangentially Related to PU or Comment
			Vibr.	Erosion / Corrosion	Mod. or Install. Error	Calib. Def.	Amb. Temp. Change	Oper. Proc. Def.	Def. Comp.	Pre-exist. Cond. or Other	Cause of Event
	PWR Oil leaks on new heater drain pump	100									Manufacturing defect
	BWR-3 Leaking seal welds on FW flow elements	-									Manufacturing defect
	BWR-3 MELLLA exceeded during planned load drop	90						X			

INPO Event No.	Event Summary	%Power (time of event)	PU DIRECTLY CAUSED OR INDIRECTLY CONTRIBUTED TO EVENT								Events Only Tangentially Related to PU or Comment
			Vibr.	Erosion / Corrosion	Mod. or Install. Error	Calib. Def.	Amb. Temp. Change	Oper. Proc. Def.	Def. Comp.	Pre-exist. Cond. or Other	Cause of Event
	PWR references between CSH assumptions and current fuel management	-						X			
	BWR-5 Manual Scram Generator Stator Cooling	77						X			
	BWR-5 Multiple FW heater tube leaks	Start-up	X								
	PWR Manual reactor trip in response to MFRV failure	100									Coil failure due to age degradation

INPO Event No.	Event Summary	%Power (time of event)	PU DIRECTLY CAUSED OR INDIRECTLY CONTRIBUTED TO EVENT								Events Only Tangentially Related to PU or Comment
			Vibr.	Erosion / Corrosion	Mod. or Install. Error	Calib. Def.	Amb. Temp. Change	Oper. Proc. Def.	Def. Comp.	Pre-exist. Cond. or Other	Cause of Event
	BWR-4 Degraded FW heater system level control valves	0	X								
	PWR Difficulty in synchronizing main generator to electrical grid	Startup						X			
	BWR-4 Error in generic analysis results in non-conservative OPRM setpoint	100									Error in reload licensing analysis

INPO Event No.	Event Summary	%Power (time of event)	PU DIRECTLY CAUSED OR INDIRECTLY CONTRIBUTED TO EVENT								Events Only Tangentially Related to PU or Comment
			Vibr.	Erosion / Corrosion	Mod. or Install. Error	Calib. Def.	Amb. Temp. Change	Oper. Proc. Def.	Def. Comp.	Pre-exist. Cond. or Other	Cause of Event
	BWR-3 Errors identified in fuel vendors supplemental reload analysis	-									Error in transient analysis
	BWR-3 Excessive EH pipe vibration following PU	100	X								
	BWR-4 Failure of reactor recirc pump "B" discharge valve to close	-									Inadequate maintenance

INPO Event No.	Event Summary	%Power (time of event)	PU DIRECTLY CAUSED OR INDIRECTLY CONTRIBUTED TO EVENT								Events Only Tangentially Related to PU or Comment
			Vibr.	Erosion / Corrosion	Mod. or Install. Error	Calib. Def.	Amb. Temp. Change	Oper. Proc. Def.	Def. Comp.	Pre-exist. Cond. or Other	Cause of Event
	PWR Failure to perform full flow test of turbine auxiliary FW pumps due to personnel error	-									Personnel error
	BWR-4 FW flow indication discrepancy	95				X					
	BWR-4 FW heater wall thinning and tube support damage due to erosion	0		X							

INPO Event No.	Event Summary	%Power (time of event)	PU DIRECTLY CAUSED OR INDIRECTLY CONTRIBUTED TO EVENT								Events Only Tangentially Related to PU or Comment
			Vibr.	Erosion / Corrosion	Mod. or Install. Error	Calib. Def.	Amb. Temp. Change	Oper. Proc. Def.	Def. Comp.	Pre-exist. Cond. or Other	Cause of Event
	PWR FW Oscillations during startup result in Manual Scram	7									AOV problem
	PWR FW transient during MFW pump stop valve testing	100									Apparent valve sticking, operator change after PU
	BWR-5 Forced power reduction due to FW heater steam leak	100		X							

INPO Event No.	Event Summary	%Power (time of event)	PU DIRECTLY CAUSED OR INDIRECTLY CONTRIBUTED TO EVENT								Events Only Tangentially Related to PU or Comment
			Vibr.	Erosion / Corrosion	Mod. or Install. Error	Calib. Def.	Amb. Temp. Change	Oper. Proc. Def.	Def. Comp.	Pre-exist. Cond. or Other	Cause of Event
	PWR Fuel defects	100									One fuel defect
	PWR Heat exchanger biofouling during ECT system outages	-									Biofouling
	BWR-6 High-Pressure turbine horizontal joint leak	100									Inadequate bolt tension
	BWR-4 Hydraulic oil intrusion into primary coolant	100									GEZIP valve issues

INPO Event No.	Event Summary	%Power (time of event)	PU DIRECTLY CAUSED OR INDIRECTLY CONTRIBUTED TO EVENT								Events Only Tangentially Related to PU or Comment
			Vibr.	Erosion / Corrosion	Mod. or Install. Error	Calib. Def.	Amb. Temp. Change	Oper. Proc. Def.	Def. Comp.	Pre-exist. Cond. or Other	Cause of Event
	PWR Incorrect part numbers found in power range channel rate circuit	-									Drawing discrepancy
	PWR Incorrect thermal power calculation caused by software problem	-									Software problem
	PWR Larger axial offset deviation	-									Fuel burnable absorber issue

INPO Event No.	Event Summary	%Power (time of event)	PU DIRECTLY CAUSED OR INDIRECTLY CONTRIBUTED TO EVENT								Events Only Tangentially Related to PU or Comment
			Vibr.	Erosion / Corrosion	Mod. or Install. Error	Calib. Def.	Amb. Temp. Change	Oper. Proc. Def.	Def. Comp.	Pre-exist. Cond. or Other	Cause of Event
	PWR Licensed max power level exceeded	100				X					
	PWR Licensed max power level exceeded	100				X					
	BWR-4 Low condenser vacuum manual scram due to air entrapment	41						X			

INPO Event No.	Event Summary	%Power (time of event)	PU DIRECTLY CAUSED OR INDIRECTLY CONTRIBUTED TO EVENT								Events Only Tangentially Related to PU or Comment
			Vibr.	Erosion / Corrosion	Mod. or Install. Error	Calib. Def.	Amb. Temp. Change	Oper. Proc. Def.	Def. Comp.	Pre-exist. Cond. or Other	Cause of Event
	BWR-4 Main generator causes turbine trip and automatic reactor scram due to manufacturing error	98									Manufacturing error
	PWR Generator lockout/turbine trip and reactor scram	100									gound fault

INPO Event No.	Event Summary	%Power (time of event)	PU DIRECTLY CAUSED OR INDIRECTLY CONTRIBUTED TO EVENT								Events Only Tangentially Related to PU or Comment
			Vibr.	Erosion / Corrosion	Mod. or Install. Error	Calib. Def.	Amb. Temp. Change	Oper. Proc. Def.	Def. Comp.	Pre-exist. Cond. or Other	Cause of Event
	BWR-3 MS isolation signal stop valve testing and steady-state operation after PU	90				X					
	BWR-3 MS piping low point drain line fails due to vibration related to EPU	100	X								

INPO Event No.	Event Summary	%Power (time of event)	PU DIRECTLY CAUSED OR INDIRECTLY CONTRIBUTED TO EVENT								Events Only Tangentially Related to PU or Comment
			Vibr.	Erosion / Corrosion	Mod. or Install. Error	Calib. Def.	Amb. Temp. Change	Oper. Proc. Def.	Def. Comp.	Pre-exist. Cond. or Other	Cause of Event
	BWR-3 MS safety relief valve exceeded setpoint tolerance	100									Corrosion bonding at disc/seat interface
	PWR Main transformer high oil temp.	100					X				
	PWR Main turbine overspeed trip mechanism failure delays unit startup	0									Installation deficiency

INPO Event No.	Event Summary	%Power (time of event)	PU DIRECTLY CAUSED OR INDIRECTLY CONTRIBUTED TO EVENT								Events Only Tangentially Related to PU or Comment
			Vibr.	Erosion / Corrosion	Mod. or Install. Error	Calib. Def.	Amb. Temp. Change	Oper. Proc. Def.	Def. Comp.	Pre-exist. Cond. or Other	Cause of Event
	BWR-3Manual reactor scram due to an EHC oil leak	100									Poor fabrication
	PWR Manual reactor trip in response to MFRV failure	100									Excess current in coil
	BWR-4 New MS line differential pressure switches w/ out-of-specification as-found setpoint	-									Inappropriate assumption regarding setpoint drift

INPO Event No.	Event Summary	%Power (time of event)	PU DIRECTLY CAUSED OR INDIRECTLY CONTRIBUTED TO EVENT								Events Only Tangentially Related to PU or Comment
			Vibr.	Erosion / Corrosion	Mod. or Install. Error	Calib. Def.	Amb. Temp. Change	Oper. Proc. Def.	Def. Comp.	Pre-exist. Cond. or Other	Cause of Event
	BWR-4 Socket weld failure	100	X								
	BWR-4 RFPT control valve oscillations	0									Digital fw control system
	PWR Turbine runback after normalization of loop delta-T	0				X					
	PWR Feed Reg Bypass valve controller cards configured incorrectly	-									Incorrectly configured controller cards

INPO Event No.	Event Summary	%Power (time of event)	PU DIRECTLY CAUSED OR INDIRECTLY CONTRIBUTED TO EVENT								Events Only Tangentially Related to PU or Comment
			Vibr.	Erosion / Corrosion	Mod. or Install. Error	Calib. Def.	Amb. Temp. Change	Oper. Proc. Def.	Def. Comp.	Pre-exist. Cond. or Other	Cause of Event
	BWR-3 Main condenser performance degraded	-									Ineffective cleaning
	BWR-3 Reactor vessel steam dryer structural steel bracing degraded	0	X								
	BWR-6 Licensed thermal power limit exceeded	-				X					
	PWR Blue channel Tavg response	-									Inadequate replacement part

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			Vibr.	Erosion / Corrosion	Mod. or Install. Error	Calib. Def.	Amb. Temp. Change	Oper. Proc. Def.	Def. Comp.	Pre-exist. Cond. or Other	Cause of Event
	PWR Error in temporary change of anomalies surveillance procedure	-									Calculational error
	PWR Brief power excursion to 101%	101									Full arc turbine control system
	PWR Licensed max power level exceeded	100				X					
	BWR-3 Reactor steam dryer damaged	100	X								

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			Vibr.	Erosion / Corrosion	Mod. or Install. Error	Calib. Def.	Amb. Temp. Change	Oper. Proc. Def.	Def. Comp.	Pre-exist. Cond. or Other	Cause of Event
	PWR Unintended effects on secondary plant	-						X			
	PWR Turbine runback due to OPDT	100				X					
	BWR-4 Operation above licensed power due to missed process computer setpoint changes	100				X					

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			Vibr.	Erosion / Corrosion	Mod. or Install. Error	Calib. Def.	Amb. Temp. Change	Oper. Proc. Def.	Def. Comp.	Pre-exist. Cond. or Other	Cause of Event
	PWR Over Power delta temp runback alarms	100								X	
	BWR-6 RFP Sere Inspection	-						X			
	PWR Intermediate range excore channel automatic scram while shutting down	8									Calibration deficiency

INPO Event No.	Event Summary	%Power (time of event)	PU DIRECTLY CAUSED OR INDIRECTLY CONTRIBUTED TO EVENT								Events Only Tangentially Related to PU or Comment
			Vibr.	Erosion / Corrosion	Mod. or Install. Error	Calib. Def.	Amb. Temp. Change	Oper. Proc. Def.	Def. Comp.	Pre-exist. Cond. or Other	Cause of Event
	BWR-3 Plant shutdown due to damaged steam dryer	100	X								
	BWR-6 Plant shutdown to replace defective fuel assemblies	100									Fuel Performance
	BWR-3 POWERPLEX input deck errors	100				X					

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			Vibr.	Erosion / Corrosion	Mod. or Install. Error	Calib. Def.	Amb. Temp. Change	Oper. Proc. Def.	Def. Comp.	Pre-exist. Cond. or Other	Cause of Event
	BWR-3 EPU created increased high frequency vibration of turbine stop valve – component, (pressure switches)		X								
	PWR Reactor coolant system leak greater than 10 GPM	100									Surveillance test deficiency

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			Vibr.	Erosion / Corrosion	Mod. or Install. Error	Calib. Def.	Amb. Temp. Change	Oper. Proc. Def.	Def. Comp.	Pre-exist. Cond. or Other	Cause of Event
	PWR Reactor Core Axial Offset Anomaly	100									Crud burst
	BWR-4 RCIC Automatic Isolation during Surveillance Test	100									Extended cycle surveillance test
	BWR-4 Reactor Scram caused by FW Pump Over-speed Testing	100									Surveillance test inadequacy
	BWR-6 Reactor Scram due to MPT B SPR Actuation	95									Single failure vulnerability, latent defect

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			Vibr.	Erosion / Corrosion	Mod. or Install. Error	Calib. Def.	Amb. Temp. Change	Oper. Proc. Def.	Def. Comp.	Pre-exist. Cond. or Other	Cause of Event
	BWR-4 Reactor scram during main turbine control valve testing	79									Failed seal in pneumatic actuator
	BWR-4 Reactor Trip on High Neutron Flux caused by Reactor Pressure Transient	87									Reactor pressure regulator failure
	BWR-5 Recirc MG Set B Stops Exceeded Tech Spec Limits	95				X					

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			Vibr.	Erosion / Corrosion	Mod. or Install. Error	Calib. Def.	Amb. Temp. Change	Oper. Proc. Def.	Def. Comp.	Pre-exist. Cond. or Other	Cause of Event
	BWR-5 Recirc Pump Vibration following PU Implementation (GE issued SIL 600)	100	X								
	PWR Recurring Axial Offset Anomaly	-									Crud deposition on upper regions of fuel rods
	BWR-6 Scram during EPU Testing (Inadequate maintenance)	86								X	

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			Vibr.	Erosion / Corrosion	Mod. or Install. Error	Calib. Def.	Amb. Temp. Change	Oper. Proc. Def.	Def. Comp.	Pre-exist. Cond. or Other	Cause of Event
	PWR Secondary Calorimetric Inaccuracy resulting from Main FW Mass Flowrate Inconsistencies	100				X					
	BWR-5 Shift Ave. Max. Power Level Exceeded	100				X					
	Core Flow Measurement System Summer Calibrations	-				X					

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			Vibr.	Erosion / Corrosion	Mod. or Install. Error	Calib. Def.	Amb. Temp. Change	Oper. Proc. Def.	Def. Comp.	Pre-exist. Cond. or Other	Cause of Event
	BWR-3 Steam Dryer Failure	-	X								
	BWR-5 SLCS unable to meet requirements of the ATWS Rule for a LOOP/ATWS Event	100									System design inadequacy
	PWR Stator Cooling Water System encountered a fast Rise in the Max DT	100									Decision to not perform chemical cleaning

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			Vibr.	Erosion / Corrosion	Mod. or Install. Error	Calib. Def.	Amb. Temp. Change	Oper. Proc. Def.	Def. Comp.	Pre-exist. Cond. or Other	Cause of Event
	PWR Steam Leaks from High Pressure Turbine Blade Ring	100			X						
	PWR 3rd Point Extraction Steam Expansion Bellows Failure	-									Inadequate evaluation of plant modification
	PWR Tube Leaks in LPFW Heater	100								X	

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			Vibr.	Erosion / Corrosion	Mod. or Install. Error	Calib. Def.	Amb. Temp. Change	Oper. Proc. Def.	Def. Comp.	Pre-exist. Cond. or Other	Cause of Event
	BWR-2 Turbine Anticipatory Scram Bypass Setpoints Nonconservative	99									Setpoint error
	BWR-3 Turbine Control Valve Accumulator Leaks caused Unplanned Shutdown	100	X								
	BWR-3 Turbine Control Valve Oscillations following PU	100				X					

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			Vibr.	Erosion / Corrosion	Mod. or Install. Error	Calib. Def.	Amb. Temp. Change	Oper. Proc. Def.	Def. Comp.	Pre-exist. Cond. or Other	Cause of Event
	BWR-4 Two-Stage Target Rock Safety Relief Valve Pilot Valve Assembly Leakage	0									Manufacturing tolerance problem
	BWR-3 Unexpected Recirculation Pump Runback	32									Operational procedure deficiency
	PWR Unit taken offline to identify/repair 2C SG Leakage	-									Foreign material caused tube degradation

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			Vibr.	Erosion / Corrosion	Mod. or Install. Error	Calib. Def.	Amb. Temp. Change	Oper. Proc. Def.	Def. Comp.	Pre-exist. Cond. or Other	Cause of Event
	PWR Unplanned Power Excursion when Transferring Main Turbine Control from Manual to Automatic	100						X			

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1	Shroud Head & Steam Separator attachment hardware	RX Internals Flow & Vibration	NSSS	Increased flow rate may lead to cracking due to changes in vibration frequency or magnitude	Outage extension due to unexpected failures (derate), loss of should head attachment can result in LER	Increased feedwater flow may excite vibration frequencies that did not previously exist	IVVI can find emergent problems if performed on an appropriate frequency	1. Perform a one-time visual examination of the shroud head bolt locking pin window for wear 2. Perform a one-time visual examination of the shroud head bolt mid-span and top support ring gussets for wear	All	yes	If changes in FIV have occurred post EPU, they will be evident, and the detectability ranking is improved
2	Access hole cover	RX Internals Flow & Vibration	NSSS	Shroud Support increased DP. EPU study addressed bolted design, not original (non-repaired) welded design that is in D3	Outage extension due to unexpected failures (derate)	The original design is more robust than the bolted repair design - the probability of failure is small, both pre and post EPU	IVVI can find emergent problems if performed on an appropriate frequency	Evaluate the original welded D3 Shroud access hole cover to changes in normal (recirculation flow) and accident (EPU modified) design loads	D3	yes	Analysis is expected to show that the original design is more robust than the evaluated bolted repair. The probability of failure will be reduced, although already ranked low
3	Shroud Head & Steam Separator	RX Internals Flow & Vibration	NSSS	Increased flow rate may lead to cracking due to changes in vibration frequency or magnitude	Outage extension due to unexpected failures (derate)	Increased core flow exit quality changes the flow velocity at constant core flow, with the potential to change FIV frequency or magnitude	IVVI can find emergent problems if performed on an appropriate frequency	Perform a one-time sample inspection of the separator standpipe welds to the top of the shroud head for fatigue cracking	All	yes	If changes in FIV have occurred post EPU, they will be evident, and the detectability ranking is improved
4	Feedwater Sparger	RX Internals Flow & Vibration	NSSS	Increased flow rate may lead to cracking due to changes in vibration frequency or magnitude	Outage extension due to unexpected failures (derate), loss of sparger seal to safe end bore can result in LER	Increased feedwater flow may excite vibration frequencies that did not previously exist	IVVI can find emergent problems if performed on an appropriate frequency	Perform a one-time visual inspection of the Feedwater spargers and end brackets for evidence of vibration	All	yes	If changes in FIV have occurred post EPU, they will be evident, and the detectability ranking is improved
5	Jet Pumps	RX Internals Flow & Vibration	NSSS	Increased wear rate on jet pump components including wedges, set screws, and riser braces	Outage extension due to unexpected failures (derate)	Increased core pressure drop (Primarily fuel design driven) drives jet pump m-ratio changes and consequent vibration characteristics	IVVI can find emergent problems if performed on an appropriate frequency	1. Establish the value of the appropriate parameter at which slip joint bypass leakage initiates jet pump vibration 2. Accelerate the BWRVIP-41 recommended inspection of restraint gate wedges (WD-1) to verify that there is no evidence of vibration and wear	all	yes	Identification of flow conditions under which vibration will occur improves both the likelihood of the failure (by elimination of operation at those conditions) and detectability (by requiring IVVI)
6	Recirc Pump motors	EPU Accelerated Wear or Degradation	NSSS	Electrical short or similar	Loss of one Recirc pump will cause derate and probable shutdown	The Recirc pump motor duty is increased due to the smaller flow window available at EPU conditions	No controls are currently in place, failure will only be know at the time of occurrence	Replace Recirc pump motor in accordance with the High Voltage motor maintenance template once every 10 years	all	yes	Motor replacement decreases the probability of occurrence
7	Recirculation pump motor-generator set	Known Material Condition Issues	NSSS	Electrical short or similar, or fluid coupler failure	Loss of one Recirc pump will cause derate and probable shutdown	The MG sets are nearing the end of their useful lives. Fleet wide there are reliability, obsolescence, and parts availability issues	Failure is immediately detectable, but there are minimal precursor signals of impending failure	Adjustable Speed Drives (ASDs) are being considered for installation at Quad Cities Station. This modification should be supported for all 4 units	all	yes	ASDs have greatly improved reliability over the MG sets, and self testing capabilities provide detectability prior to failure

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8	Recir flow sensing lines and other small-bore piping	Acoustic Driven Vibrations	NSSS	Flow induced vibration	Vibration and fatigue to failure of small-bore piping can lead to shutdown or derate	Vibration problems are evident in steam side piping, but small-bore water systems have not been addressed	No controls are currently in place, failure will only be known at the time of occurrence	After Recirc pump speeds are increased to levels not previously attained, inspect the Recirc loop flow sensing lines and other small bore piping in the drywell that are attached to the Recirc system during each of the upcoming outages.	all	yes	If changes in FIV have occurred post EPU, they will be evident, and the detectability ranking is improved
9	Main Steam line DP switches	Acoustic Driven Vibrations	NSSS	Flow induced vibration	Failure of the DP switches can cause derate	This equipment has a history of failure prior to EPU. Increased vibration makes the failure more likely, but high in both cases	No controls are currently in place, failure will only be known at the time of occurrence	Replace MSL flow DP switches with pressure transmitters and digital trip units. Option: replace one switch in each MS line and inspect for signs of degradations, and adjust PM accordingly	all except QC2 (done)	yes	Both the probability of occurrence and detectability are improved with a pressure transmitter and digital trip unit.
10	Operator Training	Reduced Ops & Analysis Margin	NSSS	Operators currently have no guidance for reactor pressure controller setback during load reduction.	Operator Error leading to scram	Existing problem, made worse by EPU	No controls are currently in place, failure will only be known at the time of occurrence	Provide operator guidance for pressure set adjustments during a load drop	all	yes	Severity of consequence and probability are both decreased by improved operator training
11	Pressure Controller Setpoint	Reduced Ops & Analysis Margin	NSSS	The adequacy of the existing septoint under EPU conditions is unknown	Operator Error leading to scram	Existing problem, made worse by EPU	No controls are currently in place, failure will only be known at the time of occurrence	Assess if it is feasible to increase the 30 psid pressure controller setpoint	all	yes	Severity of consequence and probability are both decreased by increasing the setpoint
12	Safety Analysis	Reduced Ops & Analysis Margin	NSSS	The flexibity options currently in place at D/QC may not be consistent with the EPU task evaluations & analyses	Incorrect input may lead to LER or plant shutdown	There is no evidence that this situation actually occurred (this was specifically reviewed during the safety systems review, and no such situation was identified	Failure is immediately detectable upon review of the flexibity options versus safety analysis inputs	Review EPU impacts of flexibility options in place at Dresden and Quad	all	yes	Review of inputs eliminates the possiblity of failure
13	Thermal Power Calculation	Reduced Ops & Analysis Margin	NSSS	Risk of exceeding licensed power rating	Incorrect thermal power calculation leading to LER	The current measurement accuracy is unknown	Without knowledge of loop calibration accuracy, there are no effective controls	Investigate the calibration accuracy of the Main Steam flow instrumentation	all	yes	Knowledge of calibration accuracy increases the detectability and decreased probability of an occurrence
14	Thermal Power Calculation	PDLB Issues	NSSS	Risk of exceeding licensed power rating - the PDLB approach used results in a non-conservative calculation for Dresden because of differences in the RWCU flow.	Incorrect thermal power calculation leading to LER	The extent of the non-conservatism is unknown	Without knowledge of the extent of non-conservatism, there are no effective controls	RE-evaluate the reactor heat balance and Thermo-Kit for Dresden and Quad Cities, focusing on: plant specific parameters, consistency between reactor and turbine heat balances, and acceptability of process computer heat balance input parameter feedwater flow and temperature	all	no	Plant and unit unique thermo kits increase the detectability and decreases the probability of an occurrence
15	Main Generator	Known Material Condition Issues	T/G	Loose stator bars can lead to catastrophic generator failure	Extended shutdown	Stator bars are currently beyond the manufacturer recommended operating range for looseness. The QC 2 generator has high oil in-leakage which accelerates loosening	Inspections can determine the extent of degradation, but the duration between inspections is currently inadequate	Continue implementation and do not delay the Main Generator Material Condition Improvement Plan (MCIP) and the "Long Term Asset management Strategy" for both Dresden and Quad Cities	all	yes	Implementation of the MCIP decreases the probability of failure, and improves the detectability of the condition

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16	Main Generator Stator cooling water system - temperature controller	Acoustic Driven Vibrations	T/G	Flow induced vibration	High stator water outlet temperature leading to generator trip and scram	Failures have occurred (at NMP and D3) and this is the most likely component to fail	This component is addressed by the current PM program, but failure would not be evident until it actually occurs	Perform a one-time inspection of the internals of the Generator Stator Cooling Water Temperature controller for degradation caused by vibration. Adjust PM accordingly	all	yes	Inspections will determine if degradation is actually occurring, and adjustment of PM will decrease the probability of failure.
17	Power supply to Iso Phase Bus (IPB) fan coolers	Documentation Deficiencies	T/G	Upstream 480 V bus may be overloaded under certain loading conditions, causing low system voltage	undervoltage condition requiring operator workaround.	Condition is caused by EPU replacement of existing 50 HP motors with 2 -25 HP motors. Probability of overload is low both pre- and post EPU	Undervoltage condition is immediately detectable	Measure the iso-phase bus cooling fan motor currents, determine the HP, and compare the values to the design values in ELMS. Re-analyze if required	Dres Only	no	Comparison of actual to design numbers will determine if a problem actually exists, reducing the (already low) probability of failure
18	Generator hydrogen cooling system - low pressure setpoint	Documentation Deficiencies	T/G	Inadequate cooling protection and degradation of the generator	Generator overheating leading to short circuit or trip	Misunderstanding of generator MVA curves at uprated conditions can cause condition to occur, however this is unlikely	An alternate monitoring point exists through the process computer	1. Reset the generator hydrogen gas pressure LOW alarm to 58 psig, and update the alarm procedures 2. Upgrade the D & QC operations, maintenance, and other procedures, along with the lesson plan, to state the relationship between the generator MVA capability via the curve, and the specific hydrogen pressure range between 58 and 64 psig.	all	no	Improves both detectability and probability of failure
19	Condensate, Condensate booster, and Feedwater pumps	Reduced Ops & Analysis Margin	BOP	All pumps in the water delivery chain are required for normal operation at EPU thermal power. No standby or spare is available	Loss of any pump leads to power derate	No spare pumping capability and continuous duty leads to high probability of failure	Monitoring and PM program exists	Assess the feasibility of operating at full EPU thermal power with 2 reactor feed pumps and 3 condensate/condensate booster pump combination.	all	yes	Ability to have spare pumping capability improves all three criteria
20	Condensate, Condensate booster, and Feedwater pumps	Feedwater Flow Requirements	BOP	Pumps are running off of their best efficiency points, leading to potential cavitation and impeller wear	Loss of any pump leads to power derate	Cavitation damage has been observed	No controls are currently in place, failure will only be known at the time of occurrence	For current design, perform an analysis and testing to determine the optimum operating conditions at which to start and stop the condensate/condensate booster, and feedwater pumps	all	yes	Running at the best efficiency point will eliminate cavitations, and minimize the probability of failure
21	Condensate pumps	Feedwater Flow Requirements	BOP	Pumps are running off of their best efficiency points, leading to potential cavitation and impeller wear	Loss of any pump leads to power derate	Cavitation damage has been observed	No controls are currently in place, failure will only be known at the time of occurrence	Perform a one-time boroscope examination of all 4 condensate pump impellers during the next outage. Adjust PM accordingly	all	yes	Improves the detectability of failure
22	Condensate and Condensate booster pumps	Feedwater Flow Requirements	BOP	Pumps are running off of their best efficiency points, leading to potential cavitation and impeller wear	Loss of any pump leads to power derate	Cavitation damage has been observed	No controls are currently in place, failure will only be known at the time of occurrence	Install proximity probes of ultrasonic flow measurement device to attain enhanced performance monitoring for condensate and condensate booster pumps	all	yes	Improves the detectability of failure

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23	Feedwater pump discharge check valves	Feedwater Flow Requirements	BOP	Failure of hinge pin can block flow with disc displacement	Loss of pump flow can lead to derate - potential loose parts	Lower flow per pump at EPU conditions probably reduces wear	Monitoring and PM program exists	Inspect one feedwater discharge check valve at the next outage and perform check valve monitoring to manage the potential of accelerated wear on the hinge bushings	all	yes	Improves the detectability of failure
24	Feedwater pump seals	EPU Accelerated Wear or Degradation	BOP	Excessive pump seal leakage from process to environment	Pump out-of-service for seal replacement leads to derate	Increased process temperatures can increase aging of elastomers. Buna-N components specifically identified as vulnerable	Monitoring and PM program exists	Develop a uniform PM template for reactor pump seal replacements	all	yes	Improves the probability of failure
25	Feedwater control relays	Acoustic Driven Vibrations	BOP	Flow induced vibration	Vibration in piping systems can be transmitted to control panels, and can lead to shutdown or derate	Vibration problems are evident in steam side piping, but water systems and closely associated equipment have not been addressed	No controls are currently in place, failure will only be known at the time of occurrence	Perform a one-time inspection of the relays mounted in the feedwater system panels near the feedwater pump room	all	yes	If changes in FIV have occurred post EPU, they will be evident, and the detectability ranking is improved
26	Condensate and Condensate booster minimum flow valves AO 3401	Known Material Condition Issues	BOP	With all pumps in operation at EPU conditions, the minimum flow bypass capacity is inadequate. QC has manual operation of this valve - industry standard is automatic	Pumps seals may be damaged, relief valves may lift (and potentially not reseat), causing internal plant flooding. Derate or shutdown	The current design is inadequate	No controls are currently in place, failure will only be known at the time of occurrence	Incorporate the use of the automatic function AT QC for the condensate/condensate booster minimum flow valve during normal operation	QC Only	no	Change by itself is inadequate to solve the min bypass shortfall at QC. Risk is unchanged. Action is necessary, but not sufficient.
27	Water Delivery systems min bypass valves AO 3401, Mo 3403, MO 3401 ABC, MO3402 ABC,MO 3202 ABCD, MO 3202 ABCD, MO 3204 ABCD, and MO 3202.	Feedwater Flow Requirements	BOP	With all pumps in operation at EPU conditions, the minimum flow bypass capacity is inadequate.	Pumps seals may be damaged, relief valves may lift (and potentially not reseat), causing internal plant flooding. Derate or shutdown	The current design is inadequate	No controls are currently in place, failure will only be known at the time of occurrence	Perform sizing calculation for the Condensate/Condensate Booster min flow valves to verify margin at the new design pressure and temperature. Verify adequate flow capability at the EPU operating conditions with all pumps running	all	yes	Analysis (and resulting modification) will reduce the probability of occurrence to a small value
28	Temperature element thermowells in water delivery systems	Acoustic Driven Vibrations	BOP	Change in flow characteristics may drive matching of vortex shedding frequencies with natural frequencies of these components	Failure of a thermowell can require derate	Failure has been observed at both pre- and post-EPU conditions	No controls are currently in place, failure will only be known at the time of occurrence	Evaluate the temperature element thermowells in the condensate, condensate booster, and feedwater system to eliminate concern with erosion and vortex shedding failure vulnerability	all	yes	Evaluation and design change (if required) reduces the probability of failure to better than pre-EPU values
29	Temperature element thermowells in water delivery systems	Feedwater Flow Requirements	BOP	Change in flow characteristics may accelerate flow accelerated corrosion of these (carbon steel) components	Failure of a thermowell can require derate	Failure has been observed at both pre- and post-EPU conditions	No controls are currently in place, failure will only be known at the time of occurrence	Perform UT for general pipe wall thinning near an installed thermowell on heater string downstream of a "B" or "C" heater. If erosion is occurring, enter the component into the FAC program	all	yes	UT and entry into FAC improves the detectably of the condition, and the probability of occurrence

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30	Sample probes water delivery systems	Known Material Condition Issues	BOP	Failed sample probes in the feedwater, condensate, and condensate booster system require replacement	Failure of a sample probe can lead to a loose part, causing outage extension to look for the part (derate)	Existing condition	No controls are currently in place, failure will only be known at the time of occurrence	Redesign and install the Condensate, condensate booster, and feedwater system sample probes that have failed	all	yes	Evaluation and design change (if required) reduces the probability of failure to better than pre-EPU values
31	Condensate system H2 & O2 injection Quills	Acoustic Driven Vibrations	BOP	Change in flow characteristics may drive matching of vortex shedding frequencies with natural frequencies of these components	Failure of a sample probe can lead to a loose part, causing outage extension to look for the part (derate)	Failure has been observed at both pre- and post-EPU conditions	No controls are currently in place, failure will only be known at the time of occurrence	Evaluate condensate system H2 and O2 injection quills that extend into the flow stream to eliminate concern about breakage caused by increased flow and/or flow induced vibration.	all	yes	Evaluation and design change (if required) reduces the probability of failure to better than pre-EPU values
32	Water Delivery Systems small bore piping	Acoustic Driven Vibrations	BOP	Flow induced vibration	Vibration and fatigue to failure of small-bore piping can lead to shutdown or derate	Vibration problems are evident in steam side piping, but small-bore water systems have not been addressed	No controls are currently in place, failure will only be known at the time of occurrence	Develop, plan, and perform one-time vibration measurements at power levels of 777, 792, 807, 822, 837, 852, 867, 882, and 912 MWe on susceptible small bore piping and instrument taps and the feedwater and compensate booster systems. Assure that the data is characterized in terms of feedwater flow rate, not electrical output	all	yes	Characterization of vibration characteristics will decrease the probability of failure. Identification of problem equipment may decrease the probability of occurrence.
33	Water Delivery Systems large bore piping	Acoustic Driven Vibrations	BOP	Flow induced vibration	Vibration and fatigue to failure of large-bore piping or attached components can lead to shutdown or derate	Vibration problems are evident in steam side piping, but small-bore water systems have not been addressed	No controls are currently in place, failure will only be known at the time of occurrence	Plan and perform a detailed inspection walkdown of the condensate, condensate booster, and feedwater systems similar to the main steam piping walkdown	all	yes	Characterization of vibration characteristics will decrease the probability of failure. Identification of problem equipment may decrease the probability of occurrence.
34	Condensate and condensate booster pump bearing housings, and reactor feed pump seals	Acoustic Driven Vibrations	BOP	Flow induced vibration	Vibration and fatigue to failure of the water supply to these components can lead to shutdown or derate	Vibration problems are evident in steam side piping, but small-bore water systems have not been addressed	No controls are currently in place, failure will only be known at the time of occurrence	Install flex hoses on all 4 TBCCW lines to the condensate and condensate booster pump bearing housings, and the 3 reactor feed pump seal cooling lines.	all	yes	Flex hoses are immune for vibration failure, reducing the probability of failure
35	Feedwater pump min flow valves and operator	Acoustic Driven Vibrations	BOP	Flow induced vibration	Vibration and fatigue to failure of the water supply to these components can lead to shutdown or derate	Vibration problems are evident in steam side piping, but small-bore water systems have not been addressed	No controls are currently in place, failure will only be known at the time of occurrence	Perform a one-time inspection of one of the reactor feed pump min-flow valves and operator/actuator. Adjust PM accordingly.	all	yes	Inspections will determine if degradation is actually occurring, and adjustment of PM will decrease the probability of failure.
36	Feedwater heater isolation valves and operators	Acoustic Driven Vibrations	BOP	Flow induced vibration	Vibration and fatigue to failure of the water supply to these components can lead to shutdown or derate	Vibration problems are evident in steam side piping, but small-bore water systems have not been addressed	No controls are currently in place, failure will only be known at the time of occurrence	Perform a one-time inspection of the HP heater inlet isolation MOV operator/actuator. Adjust PM accordingly.	all	yes	Inspections will determine if degradation is actually occurring, and adjustment of PM will decrease the probability of failure.

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37	Feedwater relief isolation valves operators	Acoustic Driven Vibrations	BOP	Flow induced vibration	Vibration and fatigue to failure of the water supply to these components can lead to shutdown or derate	Vibration problems are evident in steam side piping, but small-bore water systems have not been addressed	No controls are currently in place, failure will only be known at the time of occurrence	Obtain vibration readings and perform a one-time inspection of the FRV Isolation MOV operator/actuator. Adjust PM accordingly.	all	yes	Inspections will determine if degradation is actually occurring, and adjustment of PM will decrease the probability of failure.
38	Feedwater relief isolation valve, low flow regulating valves and operators	Acoustic Driven Vibrations	BOP	Flow induced vibration	Vibration and fatigue to failure of the water supply to these components can lead to shutdown or derate	Vibration problems are evident in steam side piping, but small-bore water systems have not been addressed	No controls are currently in place, failure will only be known at the time of occurrence	Inspect valve internals and operator actuator of one FRV and the Low Flow Regulating Valve per outage	all	yes	Inspections will determine if degradation is actually occurring, and adjustment of PM will decrease the probability of failure.
39	Feedwater LP heater string inlet MOV operator	Acoustic Driven Vibrations	BOP	Flow induced vibration	Vibration and fatigue to failure of the water supply to these components can lead to shutdown or derate	Vibration problems are evident in steam side piping, but small-bore water systems have not been addressed	No controls are currently in place, failure will only be known at the time of occurrence	Perform a one-time inspection of the LP heater string inlet MOV operator/actuator. Adjust Pm accordingly.	all	yes	Inspections will determine if degradation is actually occurring, and adjustment of PM will decrease the probability of failure.
40	Condensate Min flow valve operator	Acoustic Driven Vibrations	BOP	Flow induced vibration	Vibration and fatigue to failure of the water supply to these components can lead to shutdown or derate	Vibration problems are evident in steam side piping, but small-bore water systems have not been addressed	No controls are currently in place, failure will only be known at the time of occurrence	Obtain vibration reading and inspect one Condensate min flow valve operator/actuator	all	yes	Inspections will determine if degradation is actually occurring, and adjustment of PM will decrease the probability of failure.
41	Feedwater Discharge MOV operator	Acoustic Driven Vibrations	BOP	Flow induced vibration	Vibration and fatigue to failure of the water supply to these components can lead to shutdown or derate	Vibration problems are evident in steam side piping, but small-bore water systems have not been addressed	No controls are currently in place, failure will only be known at the time of occurrence	Inspect valve and operator/actuator of one Feedwater Discharge MOV (external torque check and visual)	all	yes	Inspections will determine if degradation is actually occurring, and adjustment of PM will decrease the probability of failure.
42	Feedwater suction relief valves	Acoustic Driven Vibrations	BOP	Flow induced vibration	Vibration and fatigue to failure of the water supply to these components can lead to shutdown or derate	Vibration problems are evident in steam side piping, but small-bore water systems have not been addressed	No controls are currently in place, failure will only be known at the time of occurrence	Perform internal inspection of the Feedwater Suction Relief valves to determine if internal wear is occurring.	all	yes	Inspections will determine if degradation is actually occurring, and adjustment of PM will decrease the probability of failure.
43	Feedwater suction relief valves	Known Material Condition Issues	BOP	Existing problem - lack of weld metal	Failure may require a unit derate to repair	Failure has occurred previously	Monitoring and PM program exists - addition of welds planned at all units	Install 2x1 welds for all feedwater suction relief valves currently without this configuration	all	no	Addition of 2x1 welds reduces the probabilty of failure
44	Feedwater Heaters	EPU Accelerated Wear or Degradation	BOP	Erosion and/or vibration due to increased flow	Feedwater heater out-of-service can lead to derate	The process fluid velocity for Quad Cities at EPU conditions (11 ft/sec) is outside of the heat exchanger institute recommendation of 10 ft/sec. Therefore there is the potential for tube failure due to erosion, vibration, or steam impingement.	Monitoring and PM program exists	Reclassify the feedwater heaters to a category 1 and develop a time directed task for internal inspections (eddy current testing)	QC Only	yes	Timely internal inspections will improve both the detectability and probability of occurrence

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45	HP and LP heater inlet, outlet, and bypass MOVs	Feedwater Flow Requirements	BOP	Flow changes effect the torque requirements for MOV actuators	Failure of the valve to function can allow water induction into the trubine, leading to a turbine failure and scram	The probability of failure is low, both pre- and post EPU, due to the normall torque margins in MOVs	Valve failure can lead to water introduction without warning	Perform torque calculations for the HP and LP heater inlet, outlet, and bypass MOV actuators to verify capability to isolate flow.	all	yes	Performing the sizing calculations will reduce the (already low) probability of failure
46	Dresden C2 FW Heater	Known Material Condition Issues	BOP	Dresden 3 C FW heater is operating with significant tube plugging (17%) well in excess of manufacturers (Yuba) recommendations (10%). Divider plate has been drilled to allow operation at EPU conditions	FW heater out-of-service can lead to derate	Existent condition, and the potential exists for additional tube failures or divider plate failure	Monitoring and PM program exists	Develop a cost-effective solution to reduce the DP across the Dresden 3 C2 FW heater	D3 Only	no	Reducing the DP returns the probability of failure to pre-EPU levels
47	Dresden demins	Known Material Condition Issues	BOP	Excessive pressure difference across demineralizer resin beds can pass resins into the RPV	Presence of resins in the RPV can effect water chemistry, leading to derate, or shutdown	Higher pressure drop increases the probabiltiy of fracture of the resin beads. Ther is perhaps a 10% incrase in the probabiliy after EPU, however the overall proabiltiy is medium in both situations.	Pressure gages and control room alarm	Evaluate need to reduce the pressure drop and alarm setpoint across the demin resin beds during cleaning operations	D3 Only	yes	Evaluation of the current situation does not change any of the risk factors
48	Dresden demins	Known Material Condition Issues	BOP	Failure of demineralizer boot can pass resins into the RPV	Presence of resins in the RPV can effect water chemistry, leading to derate, or shutdown	Boot failure due to temperature and radiation aging of boot elastomer. Has occurred prior to EPU	No controls are currently in place, failure will only be known at the time of occurrence	Institute 4-year preventative maintenance frequency for demineralizer rubber boot	D3 Only	no	Appropriate PM frequency will reduce the probability of failure
49	FW Oxygen Probe	Known Material Condition Issues	BOP	Currently failed oxygen probe quill geometry gives biased O2 readings for feedwater	Correct information required to address high iron content in Feedwater	Current equipment provides biased measurement	None	Replace biased O2 probe in D3 FW piping and obtain more accurate measurements for FW }2	D3 Only	yes	Replacement of failed equipment will provide better O2 data, probability of failure is reduced
50	Condensate demins and FAC program	Feedwater Flow Requirements	BOP	Influent iron concentration has increased ~50% or more in all units. Plant CPI for iron in FW effluent has been exceeded at D3	High iron concentrations in water can lead to fuel failures and/or CRD sticking. Either case will lead to derate.	CPI for effluent iron is currently exceeded in D3	Water chemistry monitoring program is in place	Determine the cause for the higher than expected condensate iron influent in all 4 units. For Dresden 3 only, take action to reduce the effluent level to established guidelines. Potential actions include an increased in O2 levels, coating susceptible iron source locations, or increase prefilter capacity.	all	yes	Reducing the iron effluent to CPI recommendations will reduce the probability of the failure
51	Dresden demins	Feedwater Flow Requirements	BOP	Excessive pressure difference across demineralizer resin beds can pass resins into the RPV	Presence of resins in the RPV can effect water chemistry, leading to derate, or shutdown	Higher pressure drop increases the probabiltiy of fracture of the resin beads. Ther is perhaps a 10% incrase in the probabiliy after EPU, however the overall proabiltiy is medium in both situations.	Pressure gages and control room alarm	Resize and replace orifice in demineralizer 1/7 bypass flow line for D3	D3 Only	no	Increasing the orifice size will reduce the pressure drop, and reduce the probability of failure

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52	FAC program	Feedwater Flow Requirements	BOP	Influent iron concentration has increased ~50% or more in all units. Increased flow velocity may increase FAC in the carbon steel condensate piping	Accelerated FAC can cause wall thinning in piping, leading to shutdown and/or extended outage (derate)	CPI for effluent iron is currently exceeded in D3, but the source of the iron is unknown	Existing FAC program exists, but may not cover all potential locations	Perform Flow Accelerated Corrosion inspections at the condensate booster pump discharge nozzles and downstream of flow element 3441-27. Determine inspection frequency based on results	all	yes	Adding additional locations to the FAC program will improve the detectability and reduce the probability of the failure
53	Condensate and condensate booster pump seals	Feedwater Flow Requirements	BOP	Increased iron loading leading to pump seal leakage or failure	Excessive pump seal leakage can take a pump out-of-service and lead to derate	Increased iron loading increases the probability of failure	Pump seals are visually monitored during startup	Modify the condensate pump seal cooling configuration to take seal cooling water from a point downstream of the demineralizer rather than from the discharge of the condensate pump	all	yes	Reducing the iron loading to the seals will reduce the probability of failure
54	LP heaters, drain coolers, and associated valves and equipment	Known Material Condition Issues	BOP	A design pressure mismatch exists between pump and FW heater tube; potential for overpressurization (if isolation, pumps will operate at 465 psig vs FW heater design pressure of 450 psig)	Opening (and potential lack of reseating) of feedwater relief valves can endanger personnel, and has potential for flooding of plant areas and power reductions	There is currently some evidence of relief valve weeping, indication that the situation has occurred. The pump change causing the overpressure potential was performed prior to EPU	None	Resolve the overpressure condition on LP heaters and drain coolers, consistent with system design and relief valve setpoint conditions	all	yes	Action will reduce the probability of failure to a low value
55	Feedwater and Condensate AOVs	EPU Accelerated Wear or Degradation	BOP	Aging of elastomers due to increased process and/or environmental temperatures	Inability of a valve to change state (i.e. open or close) or be leak tight due to elastomer degradation, sticking, etc. Plant shutdown or power reductions	Process fluid and environmental temperatures have increased post EPU. Small temperature increases past limiting temperatures can have significant effects on thermal aging of elastomer components in AOVs	A PM program exists, however the assumed temperatures may be inconsistent with post EPU operating conditions. Hence, there has been a decrease in detectability.	Ensure that actuator PMs for critical AOVs in the FW and condensate system are based on temperatures consistent with the actual operating conditions.	all	yes	Basing the PM frequency on actual operating conditions improves both the detectability and probability of failure
56	QC demin system AOVs	EPU Accelerated Wear or Degradation	BOP	Aging of elastomers due to increased process and/or environmental temperatures	Inability of a valve to change state (i.e. open or close) or be leak tight due to elastomer degradation, sticking, etc. Plant shutdown or power reductions	Process fluid and environmental temperatures have increased post EPU. Small temperature increases past limiting temperatures can have significant effects on thermal aging of elastomer components in AOVs	A PM program exists, however the assumed temperatures may be inconsistent with post EPU operating conditions. Hence, there has been a decrease in detectability.	Replace Nitrile (Buna-N) elastomers in susceptible valves such as the backwash "W" valves in the Quad Cities demineralizer system	QC Only	yes	Replacement of Buna-N elastomers will decrease the probability of failure
57	Condensate and system piping and components	Documentation Deficiencies	BOP	The pressures and temperatures in this piping have increased post-EPU, but the corresponding specifications have not been updated to reflect these changes	Incorrect information in design documentation can lead to errors in design or procurement, leading to potential failure, derate, or LER	Prior to EPU the specifications were correct, and there probability of occurrence was low.	Good design practice would likely find the specification inconsistencies	Specifications K4080 and R4411should be revised to provide a new piping design temperature of approximately 140F and design pressure of 185 psig for the condensate system piping between the main condenser and the condensate booster pump suction.	all	no	Correction of the specification information reduces the probability of occurrence

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58	Reactor feed pump suction relief valves	Documentation Deficiencies	BOP	There is an apparent discrepancy between the set pressures for these valves at Dresden and QC	Improper set pressure can lead to valve lift, overpressure of components, and power reductions	There is no evidence that valve lift has actually occurred, either pre- or post-EPU	Lift is immediately apparent	Assess the difference between the set points at Dresden and Quad Cities for the reactor feed pump suction relief vavles	all	no	Evaluation of the current situation does not change any of the risk factors, without follow-up changes
59	Feedwater Level control system	Reduced Ops & Analysis Margin	NSSS	The current FWLC system model does not provide adequate simulation of plant transient behavior	Operator training based on incorrect expectations can lead to operator error	Higher transient rates due to increased core power increase the potential for operator error	Actual FW control system performance during recent scrams in inconsistent with expectations, and unanticipated	Develop an analytical model for the FWLC system to better predict the vessel levels, both post transient and scrams	all	yes	Improved modeling improves operator training and decreases the probability of operator errors
60	Feedwater Level control system	Reduced Ops & Analysis Margin	NSSS	The FWLC system is not tuned correctly for off normal (i e. 2 pump) operation	Improper tuning of the FWLCS can result in water level transients, trips, and potential LERs	This situation only occurs if the plant is run in these off-normal conditions, and is not currently done	No controls are currently in place, failure will only be known at the time of occurrence	Evaluate, tune, and test the FWLCS for desired off-rated pump conditions (i e. 2 pumps operation). Incorporate off-normal conditions in the analytical model	all	yes	Improved system tuning decreases the probability a water level transient
61	Offgas condenser flapper valve	EPU Accelerated Wear or Degradation	NSSS	Failure of the offgas flapper valve, most likely in the open position	Other plants have experienced failure of the flapper valve without operational impact	The probability of failure is low, both pre- and post EPU	No controls are currently in place, failure will only be seen during an outage inspection	1. Inspect offgas condenser flapper valve 2. RE-evaluate Task Report 801 recommendation to operate with full offgas condenser condensate flow (procedure change)	all	yes	Inspection will improve detectability
62	Offgas gland seal flapper valve	EPU Accelerated Wear or Degradation	NSSS	Failure of the gland seal flapper valve, most likely in the open position	Other plants have experienced failure of the flapper valve without operational impact	The probability of failure is low, both pre- and post EPU	No controls are currently in place, failure will only seen during an outage inspection	Inspect gland seal condenser flapper valve for evidence of wear	all	yes	Inspection will improve detectability
63	Dresden Main generator iso-phase bus bars	EPU Accelerated Wear or Degradation	T/G	Potential overheating of the iso-phase bus bars due to measurement of duct temperature at locations other that the location of the max expected temperature	Overheating of bus bars can lead to generator trip with subsequent scram	Overheating is unlikely due to improved cooling capability post EPU	Other means of temperature measurement exist - increase in temperature would be recognized, even though the maximum may not be known	Improve the detectability of D3 conductor high temperature by providing readily accessible temperature monitors on the transformer side of the iso-phase bus	D3 Only	no	Modification improves detectability
64	Control Rod Drives	Feedwater Flow Requirements	NSSS	Increased insoluble iron in the reactor water can enter the CRD or control rod guide tube, reducing the operational life of this equipment	Decreased life of CRD/CRGTs can lengthen outages. Severe situations may lead to inability to insert of withdraw control rods, inversely affecting fuel and control rod utilization.	Increased iron loading seen post-EPU increases the probability of failure	PMs included in outage template	Increase the quantity in the outage template of control rod vacuuming if there is evidence of increased iron concentration	all	yes	Increasing the number of CRDs vacuumed reduces the probability of failure

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65	Control Rod Hydraulic Control Units	Feedwater Flow Requirements	NSSS	Increased insoluble iron in the reactor water can enter the CRD or control rod guide tube, then enter the filters in the HCUs. Plugging of filters can slow scram time or effect the ability to move CRs	Additional HCU maintenance can lengthen outages. Severe situations may lead to inability to insert of withdraw control rods, inversely affecting fuel and control rod utilization.	Increased iron loading seen post-EPU increases the probability of failure	PMs included in outage template	During scheduled HCU overhauls, inspect the 135 and 136 filters to determine if they are excessively plugged. Adjust PM based on inspection results.	all	yes	Inspections will determine if degradation is actually occurring, and adjustment of PM will decrease the probability of failure.
66	Turbine Building HVAC	EPU Accelerated Wear or Degradation	BOP	Very little data is available for temperatures in the turbine building, and the impact of any changes in such pre-to-post EPU conditions on TB equipment	NA - with no data available, the FMEA cannot be assessed. Action item is to get data.			Obtain and trend temperature data for areas of the turbine and reactor building that contain equipment affected by increased temperatures under EPU conditions. Compare to the data to projected values from the Task Report	all	no	NA
67	Drywell Ventilation	Known Material Condition Issues	BOP	The Drywell Duravent System at Quad cities represents a single failure vulnerability.	Drywell temperature above Tech Specs can result in derate or shutdown	There is a low probabiliyt of failure, both pre- and post EPU	Drywell temperature is normally monitored and alarmed	Increase either PM or redundancy	QC only	no	Increased PM or addition of redundancy reduces the probability of failure
68	Heater Drain system design	Known Material Condition Issues	BOP	Flashing in the drain system may result in an unexpected or unrealistic change in instrument readings, erratic valve operation due to level oscillations, and potential heater loss.	Loss of a heater results in a derate.	The heater drain system has been inadequate since original operation.	Alarms exist, but are often "sealed in"	Determine the need for de-superheat flow requirements into the moisture separator drains. If required, reactivate the system at Dresden	all	no	Action reduces the probability of failure
69	Heater Drain system design	Known Material Condition Issues	BOP	Flashing in the drain system may result in an unexpected or unrealistic change in instrument readings, erratic valve operation due to level oscillations, and potential heater loss.	Excessive cycling and/or vibration degradation can lead to valve failure and changes in heater level, requiring operation intervention to avoid a trip	The heater drain system has been inadequate since original operation.	Alarms and instrumentation exist to detect and ameliorate the situation	Inspect the valve, actuator, and positioner on normal LCV 3508 or 3509. Document the results in the work package	all	no	Action reduces the probability of failure
70	Heater Drain AOVs	EPU Accelerated Wear or Degradation	BOP	Aging of elastomers due to increased process and/or environmental temperatures	Elastomer degradation can lead to valve failure, causing changes in heater level, requiring operation intervention to avoid a trip	Process fluid and environmental temperatures have increased post EPU. Small temperature increases past limiting temperatures can have significant effects on thermal aging of elastomer components in AOVs	A PM program exists, however the assumed temperatures may be inconsistent with post EPU operating conditions. Hence, there has been a decrease in detectability.	Replace Nitrile (Buna-N) materials in the feedwater heater drain valves, positioners, O-rings, etc with a more temperature resistant material (e g. Viton)	QC Only	yes	Replacement of Buna-N elastomers will decrease the probability of failure

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71	Heater drain piping	Acoustic Driven Vibrations	BOP	Flow induced vibration	Vibration and fatigue to failure of small-bore piping can lead to shutdown or derate	Vibration problems are evident in steam side piping, but small-bore water systems have not been addressed	No controls are currently in place, failure will only be known at the time of occurrence	Develop an inspection plan and perform detailed inspection walkdown of the feedwater heater drain and vent system similar to the main steam system piping walkdown	all	yes	Characterization of vibration characteristics will decrease the probability of failure. Identification of problem equipment may decrease the probability of occurrence.
72	Instruments	EPU Accelerated Wear or Degradation	BOP	Increased operating temperatures may result in set point drift or instrument failure that can cause an unexpected alarm, opening of an emergency valve, main turbine trip or a heater trip resulting in a reduction in final feedwater temperature.	Failure may result in unit scram or derate to repair.	Heater drain temperatures have increased as a result of EPU. This recommendation is a S&W recommendation that was made during EPU and not implemented	Instrument failure would likely be detected by drift, or alarm, prior to failure	Verify sensor temperatures (through thermography, tubing/piping heat dissipation calculations, etc) in level switches and transmitters as noted in S&W EPU report.	all	no	Validation of the instrument temperatures to be within design constraints will lower the probability of failure
73	Heater Drain	Known Material Condition Issues	BOP	Heater performance may degrade or heater may become air bound sometime during normal operation that would result in a unit derate.	Derate	The heater drain system has been inadequate since original operation.	Calculations provide the correct sizing	Perform detailed orifice sizing calculations for the low pressure B and C feedwater heater operating vents.	all	no	Calculation of proper orifice size (and changes in equipment, if required) eliminates the potential for failure
74	Feedwater heater tube side relief valve	Documentation Deficiencies	BOP	Excessive operating pressure can cause lift/leakage, and derate or shutdown to repair	Derate	Pre-EPU modifications to the condensate and condensate booster pumps provided a shutoff head that is marginal for valve operation. Valve lift and heater bay flooding has occurred	System pressure information provides data on potential for valve lifts	Determine appropriate system pressures and low pressure (LP) feedwater heater thermal relief valve set points such that (1) the thermal relief valves do not open under expected operating conditions, and (2) the thermal relief valve set points are such that the tube design pressure of the LP feedwater heaters is not exceeded.	all	yes	Provision of a valve setpoint consistent with pump shutoff head minimizes the probability of occurrence
75	FW heater shells	Feedwater Flow Requirements	BOP	FW heater shell, nozzle or piping failure may result in unit derate or shutdown to repair.	Derate or Shutdown	EPU has increased the extraction flows and temperatures to the FW heaters. Increase in the erosion rate and location are likely given the current flows	Some of the shells have never been inspected since plant startup	Perform Feedwater Heater and Flash Tank NDE inspections at a 3-cycle frequency per the Feedwater Heater PCM template for a category 1 component.	all	yes	Inspections on a 3-cycle frequency reduce the probability of failure and provide better detectability
76	FW heater shells	Known Material Condition Issues	BOP	FW heater shell failure may result in unit shutdown or repair	shutdown	Thinning of the shells, and addition of scab plates is a pre-existing condition. CRs currently exist	The problem is known and understood - UT examinations can find thinning	Replace existing "scab" plates that cover the heater shell thinned areas with replacement shell sections on the B feedwater heaters.	all	no	Replacement of the scab plates with shell sections minimizes the probability of failure
77	Feedwater heater operating vent nozzles	Known Material Condition Issues	BOP	FW heater shell vent nozzle failure may result in unit derate or shutdown to repair	Derate or shutdown	IGSCC cracking was found in these nozzles during the EPU implementation outage. The potential exists that sensitized stainless steel was used in this application in early plants. Increases in the FW heater operating temperatures make the situation worse	Problem may be found by PT or UT	Perform Examinations and inspections on the D, C and B feedwater heater stainless steel operating vent connections for evidence of IGSCC. Repair any indications found.	all	yes	Inspections will increase the probability of detection and decrease the probability of failure

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78	Heater Drain	Known Material Condition Issues	BOP	A marginally designed heater drain system that is intolerant to deviations in any system parameters may result in an unexpected loss of one or more heaters resulting in a loss or reduction in FW heating and a derate due to increased turbine loading.	Derate	The heater drain system has been inadequate since original operation.	Existing instrumentation provides system performance information	Restore original design margin and eliminate abnormal operating condition for the heater drain system	all	yes	System design changes to restore margin decrease the probability of failure
79	Heater Drain system piping and components	Documentation Deficiencies	BOP	The pressures and temperatures in this piping have increased post-EPU, but the corresponding specifications have not been updated to reflect these changes	Incorrect information in design documentation can lead to errors in design or procurement, leading to potential failure, derate, or LER	Prior to EPU the specifications were correct, and there probability of occurrence was low.	Good design practice would likely find the specification inconsistencies	Correct inconsistencies in the maintenance/modification specification documentation for the Feedwater, Condensate, and heater drain system pressures and temperatures (See also item 61)	all	no	Correction of the specification information reduces the probability of occurrence
80	Heater Drain system piping and components	Documentation Deficiencies	BOP	Maximum process pressures and temperatures within Passport do not reflect the actual operating conditions	Non conservative pressures and temperatures can result in a design error or in an unexpected loss in instrument control	This item is a S&W recommended EPU change that was not implemented	This is a known problem	Correct inconsistencies in the controlled passport data instrument parameters' field for the heater drain system pressures and temperatures. Review setpoint calculations and control functionality, as required by the parameter changes.	all	no	Correcting this design control issue reduces the probability of occurrence
81	Heater Drain system piping and components	Documentation Deficiencies	BOP	Improper component classification	Improper component classification or no classification may result in unexpected equipment degradation due to not performing time directed PCM maintenance tasks or inspections.	Existing condition - Dresden has these equipment classifications in Passport - Quad does not	This is a known problem	(Quad Cities Only) update passport to reflect component classification categories and implement PMs per the PCM program templates for Heater Drain System. Align D/Q PCM programs.	QC only	no	Correcting this design control issue reduces the probability of occurrence
82	Turbine/EHC	Acoustic Driven Vibrations	T/G	Flow induced vibration	If failure occurs in the mechanical linkages or electrical connectors that provide TCV position feedback to the EHC system, then control of TCVs is lost, and turbine trip and reactor scram are likely.	Vibration increases are evident in the steam site piping, increasing post-EPU	Components are addressed by current PM system, but failure would not be evident until it actually occurs	Perform a detailed inspection of the electrical connections and mechanical linkages subjected to turbine control valve vibrations. Check for any evidence of looseness or wear. Adjust PM accordingly.	all	yes	Inspections and increased PM will increase the probability of detection and decrease the probability of failure
83	Turbine/EHC	EPU Accelerated Wear or Degradation	T/G	Turbine control valve oscillation leading to valve degradation	Leaking of accumulator seals or loss of accumulator charge can result in erratic performance of TCVs. Erratic performance of TCVs can result in turbine trip and reactor scram.	No current evidence that valve oscillation is actually occurring or driving vibration behavior - prudent action to investigate	Components are addressed by current PM system, but failure would not be evident until it actually occurs	Obtain detailed oscillation data for the turbine control valves to assess impact on piping vibration.	all	yes	Oscillation data can preclude this as an issue. If oscillation is occurring, additional actions can be taken to characterize failure modes, decreasing the failure probability

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84	Cross around Relief Valves - setpoint	Reduced Ops & Analysis Margin	T/G	There is increased potential for valve lift and failure to reseat following turbine transients	Leaking CAR valve, if severe, can lead to loss of condenser vacuum and consequent reactor scram.	Changes in turbine operating conditions have increased the potential for valve list post EPU	This equipment is not normally monitored	Monitor cross-around relief valves for leakage after any pressure transient within the turbine boundary.	all	yes	Post transient monitoring allows detection of a lifted/failed to reseat CAR
85	EHC Accumulators	Reduced Ops & Analysis Margin	T/G	Potential leakage of accumulator seals and/or loss of charge	Leaking of accumulator seals or loss of accumulator charge can result in erratic performance of TCVs. Erratic performance of TCVs can result in turbine trip and reactor scram.	Industry experience has indicated some increase in PM requirements post EPU, but low probability both before and after EPU	Control room alarms indicate that a problem has occurred	Implement PMs based on industry experience related to increased EHC accumulator seal leakage and loss of accumulator charge after EPU implementation.	all	yes	Increased PM decreases the failure probability
86	LP Turbine inner casing	EPU Accelerated Wear or Degradation	T/G	Degraded condition of the turbine inner casing and extraction boxes is judged to be one of the greatest risks to continued successful operation of the main turbine. This vulnerability can cause loss of efficiency, and if inner casing or extraction boxes developed excessive leakage, shutdown for repair would be necessary. In the event of catastrophic failure, consequential damage to the main condenser tubes is possible.	Degradation to shutdown	Known condition, made worse by EPU	Examinations during turbine maintenance are required to find condition	Perform a detailed inspection of a representative LP turbine's inner casing and extraction boxes. Restore the degraded material conditions.	all	yes	Restoration of original condition precludes potential for failure
87	Piping and electrical connection support grommets	Acoustic Driven Vibrations	T/G	Degradation of support leading to loss of connection	unexpected degradation	Existing condition, not EPU related	Problem known to exist, and found in previous inspections	Perform an inspection walk down of the EHC piping and electrical connections and replace degraded support grommets that may be degraded.	all	yes	Restoration of original condition precludes potential for failure
88	Circulating Water Butterfly Valves	Known Material Condition Issues	BOP	Circ water flow limitation to avoid oscillation and valve damage	At Dresden the valves can only be open to 70% before oscillations are detected. Flow limitation can cause derate due to condenser performance limitations	Pre-existing condition	Monitored routinely	(Dresden Only) Modify the design of Circulating Water pump's discharge valves to allow more flow to pass without oscillations.	D only	no	Additional flow capability reduces the probability of a derate

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89	Main Condenser	Known Material Condition Issues	BOP	Condenser tube problems (fouling, debris) can limit turbine performance, and thus power output.	derate	Pre-existing condition	Monitored routinely	1. Perform Main Condenser tube cleaning and waterbox de-sludging if monitoring parameters indicate the presence of scale or debris. 2.(Dresden Only) Assess the effectiveness of the modified chemical treatment plan to prevent Main Condenser scaling 3 (Dresden Only) Implement lessons-learned from the Braidwood lake chemistry problems which caused tube fouling due to calcium carbonate	all	yes	Desluding and improved chemical water treatment decreases the probability of a derate
90	Main Condenser	Known Material Condition Issues	BOP	Excessive number of failed tubes can degrade condenser performance.	derate	Pre-existing condition	Monitored routinely	Perform Eddy Current testing of a sample of unstaked tubes at edge of staked region.	all	yes	Better understanding of the number and trends of condenser tube failures decreases the probability of a derate
91	Extraction Steam	Feedwater Flow Requirements	BOP	Erosion damage	Unexpected degradation	Increased flow rates increase the potential for erosion	May be found by UT inspections	Perform a one time examination of the extraction piping and components for effects of erosion damage. Establish inspection frequency	all	yes	Increased inspections increase the detectability of the situation
92	Safety Analysis	Reduced Ops & Analysis Margin	NSSS	Results of some safety analysis show little margin to regulatory acceptance criteria	Equipment failure or out-of service requirments may lead to unacceptable safety response, shutdown, or LER	Margins have been greatly reduced post EPU, resulting in a much higher probablity of occurrence	Exceeding a regulatory limit would likely not be known until after it happens	Assess areas in which lost margin due to EPU can be recovered.	all	yes	Restoration of original margin to pre-EPU levels