UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION I
2100 RENAISSANCE BOULEVARD, SUITE 100
KING OF PRUSSIA, PENNSYLVANIA 19406-2713

January 21, 2021

EA-20-138

Mr. David P. Rhoades
Senior Vice President
Exelon Generation Company, LLC
President and Chief Nuclear Officer
Exelon Nuclear
4300 Winfield Road
Warrenville, IL 60555

SUBJECT: JAMES A. FITZPATRICK NUCLEAR POWER PLANT – PROBLEM IDENTIFICATION AND RESOLUTION REPORT 05000333/2020012 AND PRELIMINARY WHITE FINDING AND APPARENT VIOLATION

Dear Mr. Rhoades:

On December 14, 2020, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at James A. FitzPatrick Nuclear Power Plant and discussed the results of this inspection with Mr. Pat Navin, Site Vice President and other members of your staff. The results of this inspection are documented in the enclosed report.

Section 71153 of the enclosed report documents a finding with associated apparent violations that the NRC has preliminarily determined to be White with low-to-moderate safety significance. This finding is associated with apparent violations of Title 10 of the *Code of Federal Regulations* (CFR) Part 50, Appendix B, Criterion XV, “Nonconforming Materials, Parts, or Components,” and Criterion VII, “Control of Purchased Material, Equipment, and Services,” because Exelon failed to control defective parts and prevent their use. The subsequent receipt and use of defective parts at FitzPatrick resulted in a failure of the High Pressure Coolant Injection (HPCI) system on April 10, 2020. Consequently, Exelon also violated FitzPatrick Technical Specification (TS) 3.5.1, since the HPCI system was determined to be inoperable for greater than the TS allowed outage time.

The basis for the NRC's preliminary significance determination is described in the enclosed report. We assessed the significance of the finding using the significance determination process (SDP) and readily available information. We are considering escalated enforcement for the apparent violations consistent with our Enforcement Policy, which can be found at http://www.nrc.gov/about-nrc/regulatory/enforcement/enforce-pol.html. Because we have not made a final determination, no Notice of Violation is being issued at this time. Please be aware that further NRC review may prompt us to modify the number and characterization of the apparent violations.

We intend to issue our final significance determination and enforcement decision, in writing, within 90 days from the date of this letter. The NRC’s SDP is designed to encourage an open

dialogue between your staff and the NRC; however, neither the dialogue nor the written information you provide should affect the timeliness of our final determination.

Before we make a final decision on this matter, you may choose to communicate your position on the facts and assumptions used to arrive at the finding and assess its significance by either (1) attending and presenting at a regulatory conference or (2) submitting your position in writing. If you request a regulatory conference, it should be held within 40 days of your receipt of this letter. Please provide information you would like us to consider or discuss with you at least 10 days prior to any scheduled conference. The focus of a regulatory conference is to discuss the significance of the finding and not necessarily the root cause or corrective actions associated with the finding. If you choose to attend a regulatory conference, it will be open for public observation.

If you decide to submit only a written response, it should be sent to the NRC within 40 days of your receipt of this letter. Written responses should reference the inspection report number and enforcement action number associated with this letter in the subject line. Additionally, your response should be sent to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Center, Washington, DC 20555-0001 with a copy to Eric Miller, Acting Branch Chief, U.S. Nuclear Regulatory Commission, Region I, 2100 Renaissance Blvd, King of Prussia, PA 19406.

If you choose not to request a regulatory conference or to submit a written response, the NRC will not entertain an appeal of the NRC's final significance determination. By not doing either, you would fail to meet the appeal requirements stated in the Prerequisite and Limitation sections of Attachment 2 of NRC Inspection Manual Chapter 0609.

Please contact Eric Miller at Eric.Miller@nrc.gov within 10 days from the issue date of this letter to notify the NRC of your intentions. If we have not heard from you within 10 days, we will continue with our significance determination and enforcement decision. This letter, its enclosure, and your response (if any) will be made available for public inspection and copying at http://www.nrc.gov/reading-rm/adams.html and at the NRC Public Document Room in accordance with Title 10 of the *Code of Federal Regulations* 2.390, "Public Inspections, Exemptions, Requests for Withholding."

Sincerely,

X /RA/

Signed by: Daniel S. Collins

Daniel S. Collins
Director
Division of Reactor Projects

Docket No. 05000333
License No. DPR-59

Enclosure:
Inspection Report 05000333/2020012
w/Attachment: Detailed Risk Evaluation

cc w/ encl: Distribution via LISTSERV®

SUBJECT: JAMES A. FITZPATRICK NUCLEAR POWER PLANT – PROBLEM IDENTIFICATION AND RESOLUTION REPORT 05000333/2020012 AND PRELIMINARY WHITE AND APPARENT VIOLATION DATED JANUARY 21, 2021

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U.S. NUCLEAR REGULATORY COMMISSION
Inspection Report

Docket Number:	05000333
License Number:	DPR-59
Report Number:	05000333/2020012
Enterprise Identifier:	I-2020-012-0026
Licensee:	Exelon Generation Company, LLC
Facility:	James A. FitzPatrick Nuclear Power Plant
Location:	Oswego, NY
Inspection Dates:	April 10, 2020 through December 14, 2020
Inspectors:	F. Arner, Senior Reactor Analyst E. Miller, Senior Resident Inspector J. England, Resident Inspector C. Lally, Senior Project Engineer M. McLaughlin, Senior Enforcement Specialist D. Werkheiser, Senior Reactor Analyst
Approved By:	Eric D. Miller, Acting Chief Reactor Projects Branch 1 Division of Reactor Projects

Enclosure

TABLE OF CONTENTS

SUMMARY

The U.S. Nuclear Regulatory Commission (NRC) continued monitoring the licensee's performance by conducting a problem identification and resolution inspection at James A. FitzPatrick Nuclear Power Plant, in accordance with the Reactor Oversight Process. The Reactor Oversight Process is the NRC's program for overseeing the safe operation of commercial nuclear power reactors. Refer to https://www.nrc.gov/reactors/operating/oversight.html for more information.

List of Findings and Violations

Defective Part Results in High Pressure Coolant Injection System Pressure Control Valve Failure			
Cornerstone	Significance	Cross-Cutting Aspect	Report Section
Mitigating Systems	Preliminary White AV 05000333/2020012-01 Open EA-20-138	[H.1] - Resources	71153
The inspectors documented a self-revealed preliminary White finding and apparent violations of Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50, Appendix B, Criterion XV, "Nonconforming Materials, Parts, or Components," and Criterion VII, "Control of Purchased Material, Equipment, and Services," because Exelon did not adhere to requirements to identify and segregate non-conforming parts to prevent the movement, receipt, and use of those parts. Specifically, following General Electric-Hitachi's issuance of a Part 21 notification that affected spare parts in Exelon's inventory system, Exelon staff did not implement required steps following a Part 21 notification to electronically identify a 'hold' in their component tracking database and physically tag and segregate a defective high pressure coolant injection (HPCI) system oil pressure control valve (PCV). Upon receipt at FitzPatrick, Exelon did not ensure that the PCV conformed to all procurement requirements. The lapses in holding/tagging/segregating defective parts and incomplete receipt inspection contributed to Exelon installing the defective PCV at FitzPatrick on December 16, 2017. As a result, the HPCI system was declared inoperable on April 10, 2020, during a planned surveillance test due to the defect identified in the Part 21 notification. This also caused the HPCI system to be inoperable for greater than its technical specification allowed outage time in accordance with NRC reportability guidelines.			

Additional Tracking Items

Type	Issue Number	Title	Report Section	Status
LER	05000333/2020-003-00	LER 2020-003-00 for James A. FitzPatrick Nuclear Power Plant, High Pressure Coolant Injection Inoperable due to Oil Leak	71153	Closed

INSPECTION SCOPES

Inspections were conducted using the appropriate portions of the inspection procedures (IPs) in effect at the beginning of the inspection unless otherwise noted. Currently approved IPs with their attached revision histories are located on the public website at http://www.nrc.gov/reading-rm/doc-collections/insp-manual/inspection-procedure/index.html. Samples were declared complete when the IP requirements most appropriate to the inspection activity were met consistent with Inspection Manual Chapter (IMC) 2515, "Light-Water Reactor Inspection Program - Operations Phase." The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel to assess licensee performance and compliance with Commission rules and regulations, license conditions, site procedures, and standards. Starting on March 20, 2020, in response to the National Emergency declared by the President of the United States on the public health risks of the coronavirus (COVID-19), inspectors were directed to begin telework. In addition, regional baseline inspections were evaluated to determine if all or portion of the objectives and requirements stated in the IP could be performed remotely. If the inspections could be performed remotely, they were conducted per the applicable IP. In some cases, portions of an IP were completed remotely and on site. The inspections documented below met the objectives and requirements for completion of the IP.

OTHER ACTIVITIES – BASELINE

71152 - Problem Identification and Resolution

Annual Follow-up of Selected Issues (IP Section 02.03) (1 Sample)

The inspectors reviewed the licensee's implementation of its corrective action program related to the following issues:

(1) Issue Report (IR) 4334315, HPCI Oil Leak

71153 – Follow-up of Events and Notices of Enforcement Discretion

Event Report (IP Section 03.02) (1 Sample)

The inspectors evaluated the following licensee event reports (LERs):

(1) LER 05000333/2020-003-00, High Pressure Coolant Injection Inoperable Due to Oil Leak (ADAMS Accession No. ML20161A405). The inspection conclusions associated with this LER are documented in this report under Inspection Results Section 71153. This LER is closed.

INSPECTION RESULTS

Defective Part Results in High Pressure Coolant Injection System Pressure Control Valve Failure			
Cornerstone	Significance	Cross-Cutting Aspect	Report Section
Mitigating Systems	Preliminary White AV 05000333/2020012-01 Open EA-20-138	[H.1] - Resources	71153

The inspectors documented a self-revealed preliminary White finding and apparent violations of Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50, Appendix B, Criterion XV, "Nonconforming Materials, Parts, or Components," and Criterion VII, "Control of Purchased Material, Equipment, and Services," because Exelon did not adhere to requirements to identify and segregate non-conforming parts to prevent the movement, receipt, and use of those parts. Specifically, following General Electric-Hitachi's issuance of a Part 21 notification that affected spare parts in Exelon's inventory system, Exelon staff did not implement required steps following a Part 21 notification to electronically identify a 'hold' in their component tracking database and physically tag and segregate a defective high pressure coolant injection (HPCI) system oil pressure control valve (PCV). Upon receipt at FitzPatrick, Exelon did not ensure that the PCV conformed to all procurement requirements. The lapses in holding/tagging/segregating defective parts and incomplete receipt inspection contributed to Exelon installing the defective PCV at FitzPatrick on December 16, 2017. As a result, the HPCI system was declared inoperable on April 10, 2020, during a planned surveillance test due to the defect identified in the Part 21 notification. This also caused the HPCI system to be inoperable for greater than its technical specification allowed outage time in accordance with NRC reportability guidelines.

Description: The HPCI system at FitzPatrick provides an emergency source of water following a transient or accident. This high pressure source of coolant is delivered from two water sources using steam generated from the reactor to drive the associated turbine and pump. The HPCI system pump can deliver up to 4,250 gallons per minute and may be operated across a wide range of reactor pressures. The HPCI system pump and turbine are supported by an oil system designed to lubricate bearings and provide adequate pressure to control the steam turbine stop and control valves.

On November 7, 2017, the NRC issued Order NRC-2017-0177 establishing Exelon Generation, LLC (Exelon) as the owner, operator, and holder of the FitzPatrick Renewed Facility Operating License No. DPR-59. Exelon owns or co-owns and operates 22 nuclear reactors at 13 sites in four states. As stated, in part, in the application dated August 18, 2016 (ML16235A081), and approved by NRC Order NRC-2017-0177, Exelon provided that:

> *"…integration of the operation of FitzPatrick with Exelon Generation's current fleet of nuclear power plants, will allow consolidated operations of FitzPatrick and the other nuclear units operated by Exelon Generation. The seamless integration of FitzPatrick into Exelon Generation's operations will create a single organization with responsibility over all of the plants for which it is the licensed operator."*

Exelon operates a central supply organization that provides support for day-to-day nuclear station (site) operations with a dual reporting relationship to the centralized supply organization and the site organization. Exelon implements a fleet-wide quality assurance

program, along with procurement and warehouse procedures for all its associated nuclear stations to verify, store, and move components between stations using Business Services Company personnel. Once accepted within the Exelon Quality Management System, a component can be installed at the site of receipt, or moved and installed at another facility.

On July 1, 2010, Exelon was notified of a defective part when General Electric-Hitachi issued MFN 10-192 (ML101820160), "Part 21 Reportable Condition Notification: Failure of HPCI Turbine Overspeed Reset Control Valve Diaphragm." The Part 21 identified a vulnerability associated with the HPCI system oil PCV actuator diaphragm due to a manufacturing error. This error resulted in inadequate fabric reinforcement that is critical to ensure durability and reliability of the diaphragm, preventing tearing of the diaphragm when used in the HPCI turbine lube oil system turbine trip and reset valves (PCVs). The failure of the HPCI system PCV's diaphragm results in a loss of HPCI system turbine lubricating and control oil through the failed diaphragm. According to the Part 21 notification, "depending on the amount of oil lost and the system demands, this loss could ultimately result in a failure of the HPCI system." Exelon engineering staff entered IR 1086768 into their corrective action program and assigned actions including one to Business Services Company staff to address the Part 21.

Exelon implemented the requirements of 10 CFR Part 50, Appendix B using the Quality Assurance Topical Manual (NO-AA-10 Revision 84) in 2010. Chapter 1, "Scope," states, "organizational responsibilities are described for assuring that activities affecting quality are prescribed and implemented by documented instructions, procedures, and drawings." It further states that, "the requirements and commitments contained in the quality assurance program are mandatory and must be implemented, enforced, and adhered to by all individuals and organizations." Manual NO-AA-10 Chapter 15, "Non-conforming Material, Parts, and Components," Section 2.2 required non-conforming parts to be identified and Section 2.3 required non-conforming parts to be segregated. Furthermore, Exelon procedure SM-AA-102, "Warehouse Operations," Revision 14, Attachment 3, Section 1.5.2 required, "Items found to be of suspect quality or deficient (e.g., items identified externally via 10 CFR Part 21 defect reporting or items identified internally by maintenance) shall be:

1. Placed on 'Hold' status electronically to prevent allocation and inadvertent issue. In Passport this may require the item to be issued from stock, then returned, moved from QP to QH status.
2. Physically segregated from acceptable items with the same Catalog ID/Stock Code."

Business Services Company staff did not segregate or place an electronic 'hold' on the PCV in their component tracking database to prevent PCV installation with the defective diaphragm as required by internal procedures following the July 1, 2010, Part 21 notification. Business Services Company staff did document the non-conformance in the component tracking database which referenced IR 1086768. However, procedure SM-AA-102 did not include a standard method to document Part 21 deficiencies within the component tracking database. There were several options for documenting a Part 21 notification within this system. Exelon relied on skill of the craft for this process.

On November 19, 2010, SM-AA-102 was revised to require, "conspicuous signage that shows these items are on hold," in addition to the electronic hold and physical separation. Business Services Company staff did not use conspicuous signage on the PCV to prevent movement and installation with the defective diaphragm as required by internal procedures. On December 16, 2017, Business Services Company staff issued purchase order (P.O.)

637326 to move the HPCI system PCV from the Limerick warehouse to FitzPatrick during a planned HPCI system maintenance window. Business Services Company staff at FitzPatrick received the PCV from Limerick's warehouse to address an emergent issue using purchase order 637326. Purchase order 637326 stated, "the requirements of Federal Regulation 10 CFR Part 21 apply to all items identified in this P.O."

Exelon implemented the requirements of 10 CFR Part 50, Appendix B using the Quality Assurance Program Manual (QAPM), Revision 0 in 2017. Section A, "Management," stated, "the requirements and commitments contained in the QAPM are mandatory and must be implemented, enforced, and adhered to by all individuals and organizations." Quality Assurance Program Manual Section 5, "Procurement Verification," required that, "a program is established and implemented to verify the quality of purchased items and services at intervals and to a depth consistent with the item's or service's importance to safety, complexity, and quantity and the frequency of procurement." Procedure SM-AA-102, Revision 23, paragraph 4.5.1.2 required, "the quality receipt inspector to use the purchase order and any inspection clauses, when applicable, for the identification of inspection requirements." Procedure SM-AA-102, Step 4.12.4, "Material Receipt," states in part, "process material receipts in accordance with "Attachment 1, "Receipt of Items." Procedure SM-AA-102, Attachment 1 paragraph 1.3.1 required, "comparing items received to P.O. requirements." Attachment 1 applies to receipt of all components, whether conducted through internal transfer or purchase order.

The inspectors determined that Business Services Company staff did not adequately review the purchase order requirements. As a result, Business Services Company staff failed to identify the open Part 21 during the Quality Receipt Inspection. The required Part 21 information was located in both the Exelon component tracking database and corrective action database. The inspectors reviewed the component tracking database and determined that the IR associated with the Part 21 was reasonable to identify by a qualified procurement engineer. Business Services Company staff did not assess for open 10 CFR Part 21 notifications during receipt inspection. The defective valve was accepted using a Product Quality Certificate dated December 12, 2008. This Product Quality Certificate was invalidated by the July 1, 2010 Part 21 notification. The PCV was subsequently installed in the FitzPatrick HPCI system during the maintenance window on December 16, 2017, and resulted in HPCI being declared inoperable on April 10, 2020.

Business Services Company staff reasonably had access to the 10 CFR Part 21 records through at least three means. First, to receive the part at Fitzpatrick, Business Services Company staff removed a 'hold' due to a shelf life concern. The inspectors reviewed the component tracking database and identified that information on IR 1086768, the IR associated with the 10 CFR Part 21 notification, was present in the database and could reasonably be identified by a qualified procurement engineer when performing a review of available information to address the 'hold'. Second, the Part 21 information was available to the Business Services Company staff through the Exelon corrective action program, as IR 1086768 was noted in the component tracking database. The IR had not been resolved at the time the part was moved to and accepted at FitzPatrick. Finally, the NRC provides a public list of all 10 CFR Part 21 notifications, which was not reviewed by Business Services Company staff.

As a result of the defective part installation, on April 10, 2020, at 1:15 AM, while conducting monthly testing of the HPCI auxiliary oil system operators identified an oil leak on pressure control valve (PCV), 23PCV-12. The auxiliary oil pump was secured and the HPCI system

was still considered operable by Exelon staff. Operators were not able to definitively quantify the initial leak. At 3:00 AM, a second start of the auxiliary oil pump was attempted to quantify the leak. During the second run, operators estimated the leak to be 1.3 gpm. Thus, the HPCI system was declared inoperable and placed the station into a higher licensee-established risk category (Yellow). Exelon notified the NRC of the inoperability per 10 CFR 50.72(b)(3)(v)(D) via Event Notification 54647. The 23PCV-12 valve was replaced and the HPCI system restored to operable status on April 10, 2020, at 8:02 PM.

Corrective Actions: Exelon performed immediate corrective actions to replace the defective HPCI system PCV. Exelon also performed a fleet-wide stand down for procurement staff to conduct additional training. Additionally, Exelon created a separate action for each site to validate that a similar condition does not exist regarding dispositioning Part 21 components with inaccurate codes in their parts tracking database.

Corrective Action References: IR 4334315, IR 4348906

Performance Assessment:

Performance Deficiency: The inspectors determined that Exelon failed to control defective parts and prevent their use as required by 10 CFR Part 50, Appendix B, Criteria XV, "Non-conforming Materials, Parts, and Components," which was within their ability to foresee and prevent.

Exelon implemented the requirements of 10 CFR Part 50, Appendix B using the Quality Assurance Topical Manual (NO-AA-10 Revision 84) in 2010. Chapter 1, "Scope," states, "organizational responsibilities are described for assuring that activities affecting quality are prescribed and implemented by documented instructions, procedures, and drawings." It further states that, "the requirements and commitments contained in the QAPM are mandatory and must be implemented, enforced, and adhered to by all individuals and organizations." Manual NO-AA-10 Chapter 15, "Non-conforming Material, Parts, and Components," Section 2.2 required non-conforming parts to be identified, and Section 2.3 required non-conforming parts to be segregated. Procedure SM-AA-102 implemented the requirements for identification and segregation of non-conforming parts.

Multiple instances of this performance deficiency were identified:

- Following the July 1, 2010, Part 21 report from General Electric-Hitachi, Exelon failed to segregate and tag the affected valve as required by SM-AA-102.
- On November 19, 2010, SM-AA-102 was revised to require, "conspicuous signage that shows these items are on hold," in addition to the previously required electronic hold and physical separation. Exelon failed to use conspicuous signage as required by SM-AA-102.

The inspectors also determined that Exelon failed to control defective parts and prevent their use as required by 10 CFR Part 50, Appendix B, Criteria VII, "Control of Purchased Material, Equipment, and Services," which was within their ability to foresee and prevent.

Exelon implemented the requirements of 10 CFR Part 50, Appendix B using the Quality Assurance Program Manual (QAPM), Revision 0 in 2017. Section A, "Management," stated, "the requirements and commitments contained in the QAPM are mandatory and must be implemented, enforced, and adhered to by all individuals and organizations." Section 5,

"Procurement Verification," required a program to be established and implemented to verify the quality of purchased items and services. Procedure SM-AA-102 implemented these procurement verification requirements.

On December 16, 2017, Exelon failed to verify that the PCV met all purchase order requirements as required by SM-AA-102 and accepted the defective part upon receipt of purchase order 637326 at FitzPatrick. The purchase order included, "the requirements of Federal Regulation 10 CFR 21 apply to all items identified in this P.O." The verification of the PCV did not include a review for Part 21 notifications. The PCV was accepted using a Product Quality Certificate dated December 9, 2008, which had been invalidated by the Part 21 notification issued July 1, 2010.

Screening: The inspectors determined the performance deficiency was more than minor because it was associated with the Equipment Performance attribute of the Mitigating Systems cornerstone and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the HPCI system was unavailable to perform its safety function as a result of the failed PCV.

Significance: The inspectors assessed the significance of the finding using Appendix A, "The Significance Determination Process (SDP) for Findings At-Power." The inspectors reviewed Inspection Manual Chapter (IMC) 0609, Attachment 4, "Initial Characterization of Findings," and determined the finding affects the mitigating system cornerstone. The inspectors evaluated the significance of this finding using Inspection Manual Chapter (IMC) 0609, Appendix A, "The Significance Determination Process (SDP) for Findings at Power," Exhibit 2 – Mitigating Systems Screening Questions. The inspectors determined that the finding represented a loss of the PRA function of a single train, the HPCI system, for greater than its technical specification (TS) allowed outage time and required a detailed risk evaluation (DRE).

A Region I Senior Reactor Analyst (SRA) performed a detailed risk evaluation. The finding was preliminarily determined to be of low to moderate safety significance (White). The risk important core damage sequences were dominated by internal events, primarily loss of condenser heat sink and loss of main feedwater. The dominant core damage sequence is loss of condenser heat sink, failure of high-pressure injection (HPI), and failure to manually depressurize the reactor. See Attachment, "HPCI Oil PCV Failure Detailed Risk Evaluation," for a detailed review of the quantitative and qualitative criteria considered in the preliminary risk determination.

Cross-Cutting Aspect: H.1 - Resources: Leaders ensure that personnel, equipment, procedures, and other resources are available and adequate to support nuclear safety. The cause of the finding was determined to be associated with a cross-cutting aspect of Resources in the Human Performance area because Exelon staff failed to identify and address an open Part 21 during verification of the quality of the HPCI system PCV. Specifically, the inspectors determined there were multiple ways to reasonably determine a Part 21 had not been addressed for the HPCI system PCV, however procurement implementing procedures did not provide adequate guidance to ensure that procedure users would identify and resolve a Part 21 in a consistent manner. Having comprehensive steps within the relevant procedure would have prevented installation of the defective part at FitzPatrick.

Enforcement:

Apparent Violations:

A. Title 10 CFR Part 50, Appendix B, Criterion XV, “Nonconforming Materials, Parts, or Components,” requires that measures shall be established to control materials, parts, or components which do not conform to requirements in order to prevent their inadvertent use or installation. These measures shall include, as appropriate, procedures for identification, documentation, segregation, disposition, and notification to affected organizations. Nonconforming items shall be reviewed and accepted, rejected, repaired, or reworked in accordance with documented procedures.

Exelon procedure SM-AA-102, "Warehouse Operations," Revision 14, in part, specifies required actions to be taken when an applicable 10 CFR Part 21 is identified. Step 5.11.11 requires the licensee to control, handle, and store material in accordance with Attachment 3. Procedure SM-AA-102, Attachment 3, “Control, Handling, and Storage of Material,” Section 1.5.2 states that items found to be of suspect quality or deficient (e.g., items identified externally via 10 CFR Part 21 defect reporting or items identified internally by maintenance) shall be, in part, placed on ‘hold’ status electronically to prevent allocation and inadvertent issue, and physically segregated from acceptable items with the same catalog ID/stock code. Further, upon issuance of SM-AA-102, Revision 15, the use of conspicuous signage is required for items that are on hold.

Contrary to the above, from July 1, 2010 to April 10, 2020, Exelon did not ensure that measures were established to control materials, parts, or components which do not conform to requirements in order to segregate and prevent their inadvertent use or installation, in that a nonconforming item was not reviewed and rejected in accordance with documented procedures. Specifically, Exelon did not take required actions for an applicable 10 CFR Part 21 report issued on July 1, 2010 that identified a material defect in HPCI system turbine overspeed reset control valve diaphragms. Exelon did not place an electronic hold, physically segregate, or use conspicuous signage for a subject defective diaphragm, allowing the defective diaphragm to be installed. As a result, on December 16, 2017, a valve containing the defective diaphragm was installed at FitzPatrick.

B. Title 10 CFR Part 50, Appendix B, Criterion VII, “Control of Purchased Material, Equipment, and Services,” requires, in part, that measures shall be established to assure that purchased material, equipment, and services, whether purchased directly or through contractors and subcontractors conform to procurement documents. Documentary evidence that material and equipment conform to the procurement requirements shall be available at the nuclear power plant or fuel processing plant site and shall be sufficient to identify the specific requirements, such as codes, standards, or specifications, met by the purchased material or equipment.

Exelon Procedure SM-AA-102, Revision 23, Attachment 1 required the Quality Receipt Inspection to verify the documents received met the purchase order requirements. The purchase order required the part to conform with the procurement requirements of 10 CFR Part 21.

FitzPatrick TS 3.5.1, in part, requires the HPCI system to be operable in Modes 1, 2, and 3 with reactor steam dome pressure >150 psig. If the HPCI system is determined to be inoperable, it shall be returned to an operable status within 14 days. If not restored to an operable status, the unit shall be shut down and in Mode 3 within 12 hours.

Contrary to the above, on December 16, 2017, Exelon did not ensure measures were established to assure that purchased material, equipment and services conform to procurement documents. Specifically, Exelon did not perform an adequate quality receipt inspection to ensure that the PCV met the purchase order requirement for compliance with the requirements of 10 CFR Part 21. As a result, on December 16, 2017, the PCV containing the defective diaphragm was accepted and installed for use at FitzPatrick. On April 10, 2020, the HPCI system was declared inoperable during a monthly surveillance test, resulting in a leak and system oil loss that would have prevented the system from performing its safety function. Consequently, the HPCI system was rendered inoperable prior to April 10, 2020, for a period longer than its TS allowed outage time, and the unit was not shut down and placed in Mode 3 within 12 hours in accordance with NRC reportability guidelines.

Enforcement Action: These violations are being treated as apparent violations pending a final significance (enforcement) determination.

EXIT MEETINGS AND DEBRIEFS

The inspectors verified no proprietary information was retained or documented in this report.

On December 14, 2020, the inspectors presented the problem identification and resolution results to Mr. Pat Navin, Site Vice President and other members of the licensee staff.

DOCUMENTS REVIEWED

Inspection Procedure	Type	Designation	Description or Title	Revision or Date
71152	Engineering Changes	631895	JAF Technical Evaluation to Support Availability of HPCI System due to Oil Leak in PCV-12	October 27, 2020
71152	Miscellaneous		Exelon Generation Company, LLC Quality Assurance Program Manual	0
71152	Miscellaneous	Vendor Report 006N1092	HPCI Control Valve Leakage Evaluation, GEH DD233A3600P001	0
71152	Procedures	AOP-10	Loss of Service Water Cooling	16
71152	Procedures	AOP-11	Loss of Reactor Building Closed Loop Cooling	23
71152	Procedures	AOP-18	Loss of 10500 Bus	17
71152	Procedures	AOP-19	Loss of 10600 Bus	17
71152	Procedures	AOP-31	Loss of Condenser Vacuum	25
71152	Procedures	ARP 09-3-3-35	HPCI TURB BRG OIL PRESS LO	3
71152	Procedures	EOP-2	RPV Control	11
71152	Procedures	EP-2	Isolation / Interlock Overrides	9
71152	Procedures	MP-023.15	HPCI Lube Oil Balancing	13
71152	Procedures	MP-101.11	HPCI Turbine and Pump Lubrication System	16
71152	Procedures	NO-AA-10	Quality Assurance Topical Manual	84
71152	Procedures	OP-15	High Pressure Coolant Injection	66A
71152	Procedures	OP-25	Control Rod Drive Hydraulic System	93
71152	Procedures	OP-37	Containment Atmosphere Dilution System	90
71152	Procedures	OP-JF-103-102-1002	Strategies for Successful Transient Mitigation at JAF	2
71152	Procedures	SM-AA-102	Warehouse Operations	14
71152	Procedures	SM-AA-102	Warehouse Operations	15
71152	Procedures	SM-AA-102	Warehouse Operations	23
71152	Procedures	ST-4B	HPCI Monthly Operability Test	62
71152	Procedures	ST-4N	HPCI Quick Start and Flow Rate IST	73
71152	Work Orders	04973475	ST-4N HPCI Quick Start and Flow Rate IST	December 10, 2019
71152	Work Orders	04989094	ST-4N HPCI Quick Start and Flow Rate IST	March 4, 2020

Inspection Procedure	Type	Designation	Description or Title	Revision or Date
71152	Work Orders	04997650	ST-4B HPCI Monthly Operability Test	February 12, 2020
71152	Work Orders	82700213	PM - Replace Valve Operator Diaphragm	November 17, 2017
71153	Calculations	JAF-CALC-PC-03044	Torus Air and Water Volume for EOP Support Calculations	0
71153	Calculations	JAF-CALC-PC-03322	Suppression Pool Temperature during a Small Break Accident	0
71153	Corrective Action Documents	01086768	(Limerick) – Limerick OPEX Review of GE Part 21 SC 10-09	
71153	Corrective Action Documents	04334315	HPCI Oil Leak from 23PCV-12	
71153	Corrective Action Documents	04346516	Proper Controls Were Note implemented on Q1 Cat ID in 2017	
71153	Drawings	FM-18A	Drywell Inerting (CAD) and Purge System System 27	54
71153	Drawings	FM-25	Flow Diagram – HPCI Lube Oil System 23	34
71153	Engineering Evaluations	0284-0063-RPT-001	Independent Review of PCV-12 Oil Leak in JAF HPCI System	0
71153	Miscellaneous	Beck, S.B.M., Bagshaw, N.M and Yates, J.R., Explicit Equations for Leak Rates Through Narrow Cracks, International Journal of Pressure Vessels and Piping, 82(7). pp. 565-570		2005
71153	Miscellaneous	Browns Ferry		

Inspection Procedure	Type	Designation	Description or Title	Revision or Date
		LERs 2009004, 2007001, 2012006		
71153	Miscellaneous	Brunswick LERs 2003-004, 2004-002, 2006-001		
71153	Miscellaneous	Cooper LER 2005001		
71153	Miscellaneous	Duane Arnold LERs 2018003, 2019001		
71153	Miscellaneous	FitzPatrick LERs 2003001, 2005005		
71153	Miscellaneous	Hatch LER 2008004		
71153	Miscellaneous	Hope Creek LER 2004010		
71153	Miscellaneous	JAF Drywell Pressure Plot		January 1, 2019 - January 1, 2020
71153	Miscellaneous	JAF FSAR, Final Safety Analysis Report		7
71153	Miscellaneous	JAF HPCI Oil Leak Presentation		October 23, 2020
71153	Miscellaneous	JAF HPCI Quarterly Run PI Traces		March 4, 2020
71153	Miscellaneous	JAF HPCI Surveillance History (Excel Spreadsheet)		December 16, 2017 - April 10, 2020

Inspection Procedure	Type	Designation	Description or Title	Revision or Date
71153	Miscellaneous	JAF IR Leakage Identification Template, 10/23/2020		
71153	Miscellaneous	JAF Power History Summary		December 2017 - April 2020
71153	Miscellaneous	JAF Reactor Level Instrumentation Setpoint Summary		
71153	Miscellaneous	JAF Suppression Pool Pressure Plot		January 1, 2019 - January 1, 2020
71153	Miscellaneous	JAF TS, Technical Specification		324
71153	Miscellaneous	JAF-RPT-05-00047, Mitigating System Performance Index Basis Document		5
71153	Miscellaneous	JAF-RPT-MISC-02211, JAF Individual Plant Examination of External Events		June 1996
71153	Miscellaneous	JF-PRA-021.11	JF FPRA Summary and Quantification Notebook	2
71153	Miscellaneous	JF-SDP-002	HPCI INOP, dated 11/13/2020	0
71153	Miscellaneous	LaSalle County Station, Unit 2-	LER 2017-003-01	July 3, 2018

Inspection Procedure	Type	Designation	Description or Title	Revision or Date
		Transmittal of the Final LaSalle County Station, Unit 2, Accident Sequence Precursor Report (ML18157A263)		
71153	Miscellaneous	Limerick LERs 2007003, 2013001		
71153	Miscellaneous	MFN 10-192	GE-Hitachi Part 21 Reportable Condition Notification: Failure of HPCI Turbine Overspeed Reset Control Valve Diaphragm	July 1, 2010
71153	Miscellaneous	Mobil DTE-700 Series Oil Specification		2019
71153	Miscellaneous	Monticello LERs 2008005, 2015006		
71153	Miscellaneous	NUREG-1953	Confirmatory Thermal-Hydraulic Analysis to Support Specific Success Criteria in the Standard Plant Analysis Risk Models – Surry and Peach Bottom, including Errata	September 2011
71153	Miscellaneous	NUREG/CR-6883	The SPAR-H Human Reliability Analysis Method	August 2005
71153	Miscellaneous	Perry LERs 2014004, 2014005		
71153	Miscellaneous	PO 00637326, Purchase Order for Valve, Control for HPCI Turbine, with 2-Ply BUNA-N		December 15, 2020
71153	Miscellaneous	Susquehanna LER 2010003		
71153	Miscellaneous	TR-105874 /		November

Inspection Procedure	Type	Designation	Description or Title	Revision or Date
		016909-R1, EPRI Terry Turbine Maintenance Guide, HPCI Application		2002
71153	Miscellaneous	USNRC FitzPatrick SPAR Model		Version 8.59
71153	Procedures	AOP-1	Reactor Scram	49
71153	Procedures	INL/EXT-10-18533	SPAR-H Step-by-Step Guidance	2
71153	Procedures	JF-PRA-004	Human Reliability Analysis (HRA)	1
71153	Procedures	JF-PRA-012	Internal Flooding Analysis Notebook	3
71153	Procedures	JF-PRA-013	PRA Summary Report 13515	0
71153	Procedures	JF-PRA-014	Quantification Notebook 13516	2
71153	Work Orders	04989099	ST-4B HPCI Monthly Operability Test	01/08/2020

ATTACHMENT: HPCI OIL PCV FAILURE DETAILED RISK EVALUATION

CONCLUSION

The total increase in core damage frequency (CDF) for the performance deficiency was estimated to be Preliminary White, a finding of low to moderate safety significance. Based on an initial best estimate considering the effect of the degraded condition on the high pressure coolant injection (HPCI) system, and assumed exposure time, the change in CDF was determined to be a nominal 3E-6/yr. This reflected the lower end of various sensitivity analyses performed for the issue.

SYSTEM BACKGROUND

The HPCI system is a safety-related emergency core cooling system (ECCS) actuated by either a low-low reactor water level (Level 2) or a high drywell (DW) pressure (2.7 psig). Its rated flow capacity is 4,250 gpm. Initially, the system operates in an open loop mode, taking suction from the condensate storage tank (CST), and injecting water into the reactor pressure vessel (RPV) via one of the main feedwater lines. When the level in the CST reaches a low-level setpoint, the HPCI pump suction is aligned to the suppression pool. To maintain reactor pressure vessel level after the initial recovery, the HPCI system can be reduced via automatic flow control or placed in manual control, which involves controlling turbine speed to control level while maintaining turbine minimum revolutions per minute requirements. This could involve cycling the injection motor-operated valve (MOV) with test return valves open, or complete HPCI stop-start cycles. The HPCI system is designed to automatically start and stop to maintain reactor pressure vessel level from low-level actuation (Level 2, 126.5 inches) to High-level trip (Level 8, 222.5 inches). The HPCI system can also be used manually to help control reactor pressure following a transient. In this mode, the turbine-driven pump is operated manually with the injection valve closed and the full-flow test line motor operated valves open. Turbine operation with the injection line isolated and the test line open allows the turbine to draw steam from the reactor pressure vessel, thereby reducing reactor pressure. If suction is from the torus instead of the CST or an initiation signal is present, this full flow test line is interlocked closed and only the injection mode is available. As noted above, operation of the system in the pressure control mode may also occur with intermittent injection of coolant to the reactor pressure vessel. As steam is being drawn off the reactor pressure vessel, the reactor pressure vessel water inventory is reduced, resulting in the need for level restoration. When level restoration is required, the injection valve is opened and the test line MOV is throttled closed. Upon restoration of reactor pressure vessel water inventory, the system is returned to the pressure control line-up. This is also referred as ‘batch-addition’. This cycling between injection and pressure control can be repeated as necessary. FitzPatrick has established their design basis mission time as 10 hours based on CST reserve capacity.

The reactor core isolation cooling (RCIC) system is another high pressure injection system which is actuated, similar to HPCI, on lower reactor water level (Level 2). Its rated flow capacity is 400 gpm. For non loss-of-coolant events it is the preferred system during reactor isolation conditions to maintain reactor pressure vessel level, as HPCI’s capacity is oversized for events simply requiring decay heat and controlled depressurization makeup. For the non-loss of coolant accident events, probabilistic risk assessment standard mission times are 24 hours, and this is consistent with the Fitzpatrick Mitigating Systems Performance Index document. For postulated events requiring injection, the control room operator would manually initiate the system, or the systems would automatically start at the predetermined low-low reactor water

level setpoint. They inject at their design flowrates until operators diagnose the need for injection to maintain adequate level and then take action to control level below a high level (Level 8) trip setpoint.

Control rod drive (CRD) system pumps are also capable of high pressure injection. Normally one pump is operating and the other is in standby. In this evaluation, early control rod drive credit is applied for some events based on the availability of two control rod drive pumps. However, the CST suction source has approximately 122,000 gpm above the control rod drive suction piping which does not support the probabilistic risk assessment mission time. Therefore, there must be a method for makeup to the CST to keep the control rod drive suction requirements satisfied. This was a source of uncertainty because, for the various events, different methods of addition are not available. This credit was not applied to loss of coolant accident (LOCA) events based on reactor decay heat and timing of control rod drive effectiveness. Early control rod drive also was not applied to loss of AC bus and loss of direct current (DC) bus that would affect availably of two control rod drive trains. The base case also did not credit this for loss of offsite power (LOOP) events, or loss of instrument air events where makeup from the demineralized water storage tank could be challenged.

ISSUE BACKGROUND

2010 10 CFR Part 21

On July 1, 2010, Exelon was notified of a defective part when a vendor issued MFN 10-192 (ML101820160), “Part 21 Reportable Condition Notification: Failure of HPCI Turbine Overspeed Reset Control Valve Diaphragm.” The Part 21 identified a vulnerability associated with the HPCI system oil pressure control valve (PCV) actuator diaphragm due to a manufacturing error that resulted in inadequate fabric reinforcement embedded in the diaphragm Buna-N rubber material. The Buna-N rubber material was designed to have two layers of Dacron reinforcement fabric over all pressure bearing surface areas of the diaphragm. Defective diaphragms had either 1-ply or no fabric reinforcement. The fabric reinforcement is critical to ensure durability, reliability, and prevent tearing of the diaphragm when used in the HPCI turbine lube oil system as turbine trip and reset valves. The failure of the HPCI turbine-speed reset control valve’s diaphragm results in a loss of HPCI turbine lube and control oil through the failed diaphragm. Depending on the amount of oil lost and system demands, this oil loss could result in a failure of the HPCI system.

The original defect occurred in the 2009 timeframe and the vendor became aware of this defect after an estimated 0.25-0.5 gpm HPCI diaphragm oil leak was experienced by Browns Ferry Unit 1 and reported to the NRC via Event Notification 45227 on July 24, 2009, and LER 05-259/ 2009-004. The Browns Ferry Unit 1 diaphragm had been installed in the HPCI system PCV for 2 years and 8 months before failure. The vendor reported the aforementioned 10 CFR Part 21 notification on July 1, 2010.

FitzPatrick HPCI PCV (23PCV-12) History

As documented in purchase order 637326 on December 16, 2017, FitzPatrick accepted the HPCI PCV (“Valve, Control, For HPCI Turbine, With 2-Ply BUNA-N Diaphragm”) assembly with a “Q” product quality certification from Limerick Generating Station. The valve assembly had been shelved 9 of its 10 allowed years. The PCV was installed and tested at FitzPatrick on December 17, 2017. There were two instances of HPCI oil leaks (i.e. December 2017 and November 2018, IR 04194946). There was no other history of oil leaking from the PCV until its

diaphragm failure on April 10, 2020. The analyst noted there has been less than 24 hours of HPCI runtime or less than the 24-hour mission time assumed for some events, since installation. The last successful test was on March 4, 2020 (38 days from failure). The previous HPCI turbine test prior to that date was December 10, 2019 (122 days from failure). There was also a previous cycle of the PCV 59 days earlier during a similar monthly HPCI system test using the auxiliary oil pump.

FitzPatrick HPCI Oil Leak on April 10, 2020

Exelon performs a monthly surveillance test, which in part, starts and stops the auxiliary oil pump to evaluate the operation of the HPCI stop valve and control valve motion, without running the turbine. As documented in FitzPatrick issue report 04334315, during performance of ST-4B "HPCI Monthly Operability Test" on April 10, 2020 at 0111, the auxiliary oil pump was started, and during observation of the HPCI stop and control valve motion, a large leak was identified and documented by the field operator from the HPCI trip system PCV (23PCV-12). Operators were not able to definitively quantify the initial leak. During a second run of the auxiliary oil pump, operators estimated the leak to be 1.3 gpm. The pump was secured after approximately a 1-minute runtime based on HOV-1/2 position switch position computer data. Plant operations subsequently re-started the auxiliary oil pump (at 0300) after discussions with shift management to attempt to more accurately quantify the leak rate. During this second auxiliary oil pump start, the leakage was noted to be much larger resulting in the need to secure the pump in approximately 30 seconds. Approximately 2.5 liters of oil were collected. This equates to approximately 1.3 gpm.

The NRC analysts considered the initial leak rate estimate to be highly subjective and a source of high uncertainty. This is based on the unpreparedness for seeing a sizable leak (was documented as a large leak by the operator) with no quantification tools to measure it and limited pump run time to ensure it had even stabilized. Additionally, the analysts noted that this leak was identified with the auxiliary oil pump running which initially controls pressure at a nominal 85 psig. During a normal HPCI turbine start-up, a shaft driven oil pump (SDOP) provides oil pressure once the turbine is up and running. The SDOP provides a design pressure of 110 psig and takes over for the auxiliary oil pump once the HPCI turbine starts running. There is another PCV upstream (PCV-112) which will attempt to respond to this surge in pressure and try to maintain control oil pressure at 38 psig downstream. However, it would be expected that there would be some response time involved such that the initial pressure surge from the shaft driven oil pump or stress on the diaphragm may have been higher as the diaphragm would feel this increased pressure and stress. This simply increases the uncertainty of the quantification of the leak rate due to the potential of additional stress on the diaphragm and effect on the tear during an actual event where the turbine would start. The inspectors determined during interviews that the initial leak rate was estimated by licensee staff from 0.06 gpm to 0.25 gpm. The inspectors also determined that operations staff characterized the leak from "minor" to a "large" leak, further indicative of the uncertainty with the leak rate. Additionally, the analysts concluded the second leak rate may be underestimated due to quantifying it based on timing before pressurization (i.e. takes some time to pressurize the line when the pump is started) and is another source of uncertainty. Factoring in pressurization time may increase the 2nd leak into the 1.7 to 1.8 gpm range.

For all the reasons above, the analysts considered the first leak rate identified to be highly uncertain and subjective, with the second leak rate to be a more accurate representation given it was quantified. FitzPatrick replaced 23PCV-12 and restored HPCI to service at 2015 the same

day (April 10, 2020). This issue was reported to the NRC via Event Notification 54657 on April 10, 2020, and LER 05-333/2020-003.

Licensee Cause Determination

The Initial valve disassembly was conducted by Exelon onsite and identified a damaged Teflon O-ring seal within the valve bonnet. Initial evaluations focused on this area. FitzPatrick and subsequent Exelon Power Labs evaluations focused on this damage concluding that it was the apparent cause of the leakage (Exelon Power Labs report JAF-38488, dated April 28, 2020). The analysts were aware of Exelon's focus on the bonnet, stem, and bellows areas of the valve because there was apparent video evidence of the leak (2nd leak quantification) indicating the fault was in these valve part areas. Exelon requested support from the vendor to aid in the evaluation. The vendor determined that neither the Teflon O-ring nor the bellows assembly was the cause of the leak due to proper inference fit and bellows integrity. The vendor identified the diaphragm on top of the valve to be the next likely source. Subsequently, further vendor evaluation identified a diaphragm tear approximately 1 centimeter (cm) long along the circumferential crest of maximum flexure. The vendor documented the area of the tear lacked any fabric reinforcement, and since it was originally procured in 2008, it was susceptible to the defect in the aforementioned 10 CFR Part 21. The vendor evaluation concluded that the tear in the diaphragm occurred as a result of low-cycle fatigue (exacerbated by the edge of the diaphragm case and valve yoke) from the operation or cycling of the valve. The vendor concluded that significant tear extension with associated leakage growth would not have been expected to occur between cycles if the valve was retained in the open position through the system's operating mission time.

The analysts considered the PCV's integrity and stabilization of the leak rate to be a source of uncertainty considering the diaphragm was a defective non-conforming component and had significantly degraded (> 1.3 gpm leak rate) after one oil pressure cycle. As noted, the leak rates were evaluated under static conditions without potential resonance vibration effects such as turbine speed changes during operational conditions, or the potential for higher stress at turbine startup as the shaft driven oil pump takes over. Most significantly, Exelon's leak rate initially had not considered the effect of actual turbine operation with respect to the heat-up of the oil and increased leakage due to the kinematic viscosity changes.

Analyst Assessment of Leak Rate and Effect on HPCI Operations

A defective component was installed into a safety-related system for over a 2-year period. The analysts considered the PCV's integrity and the licensee's assumption of stabilization of the leak rate to be a source of uncertainty considering the diaphragm was a defective non-conforming component and had significantly degraded (> 1.3 gpm leak rate) after one oil pressure cycle. As discussed, the analysts noted the leak rates were evaluated under static conditions without potential resonance vibration effects such as turbine speed changes during operational conditions, or the potential for slightly higher stress at startup as the SDOP takes over with higher pressure requiring the main oil PCV to respond to maintain a nominal 38 psig. Most significantly, Exelon's evaluation of the leak rate had not considered the effect of actual turbine operation with respect to the heat-up of the oil and increased leakage due to viscosity changes. Additionally, the analysts noted that the defective diaphragm is located in a stagnant area of the oil system and is not continuously cooled by the system lube oil heat exchanger. Therefore, the analysts concluded Exelon's initial documented determination that a 0.1 gpm leak rate would have supported their stated HPCI 10-hour mission time to be technically flawed with high uncertainty.

The analysts also considered that Exelon's operational assumption that once the system is started for all events, it would never be secured for any reason throughout all mission times, was not supported by historical probabilistic data or industry operating experience. Based on prior operating experience, such as review of licensee event reports (LERs) for the industry and the Fitzpatrick station, it is not unreasonable for HPCI to start and stop for at least one cycle after initiation, with the possibility of multiple HPCI start/stop cycles in response to evaluated events. Historical repetitive trips on high level (Level 8) have been addressed through procedure changes to give the ability to defeat this trip as post initiating event operator actions. Notwithstanding this, throughout the industry there have been numerous system trips on failure to control level early in an event, resulting in a trip on initial high level. In at least 50 percent of LERs reviewed since 2003 where HPCI automatically started, HPCI was noted to have been secured either through a trip on high level or because RCIC started successfully and therefore HPCI was secured. The analysts noted in this case once HPCI system would be tripped with this degraded condition of the PCV diaphragm, a severe leak would have developed, allowing only a nominal 20 to 25 minutes of run time before loss of suction to the oil pumps. This would have also resulted in an eventual trip of HPCI from low oil pressure and subsequent stop and control valve closure with the auxiliary oil pump cavitating (operating with no oil suction).

Because the oil leak rate and exposure time of the degraded condition is potentially impacted by the cycles of the system, and in this case one cycle would result in a significant leak rate after temperature affects are considered, a probabilistic assessment with respect to an initial trip of the system was performed. This provided a probabilistic "weighted" estimate of the leak rate for this condition. The highly uncertain initial leak rate was used along with the second quantified leak rate, which represented the rate after the probability that one cycle of PCV operation could occur early. This was used to assess how long the system may be able to run before adversely impacting the shaft driven and auxiliary oil pumps resulting in a failure to support continued operation of the system. This primarily was used to inform an assessment on whether the ability to recover the system should be considered (sensitivity) given the magnitude of leak rate, considering the existing design of the oil system including potential cues relative to the degraded condition. It should be noted there is some non-conservatism with this method, because as noted, the HPCI system could be secured early if RCIC had a successful start. This probability is much higher than a computed probabilistic early trip on high water level. This sometimes would be associated with RCIC failure to run events, which are the dominant contributors to core damage sequences within the NRC SPAR model. However, if RCIC successfully starts and runs for a few minutes or less than an hour, it is typically considered a failure to start on demand per discussions with Idaho National Labs data collection experts.

The analysts calculated a failure probability-weighted effective leak rate bounded by the lower and upper leak rate estimates to gauge the effective time available for HPCI to perform its PRA function. However, the cues to respond to this HPCI leak are identifying the leak while monitoring HPCI oil level at the sight-glass (OP-15, Section E.2) or the main control room annunciator for HPCI turbine bearing low oil pressure (ARP 09-3-3-35). Given the hydraulic design of the system the upstream PCV-112 would likely mask this alarm, responding to even a large leak by opening up to maintain pressure downstream to where this alarm comes off. The spectrum of operator response can be bounded by these cues and upper/lower leak rates. At a low leak rate (~0.3 gpm at 124F) the oil leak may be recognized if an operator walkdown occurs early. Any change in HPCI operation that instigates the large leak rate (~4 gpm at 124F) would not afford any time to mitigate it, and the alarm mentioned above may not alarm due to the design of the hydraulics, giving no timely cue for diagnosis. There is no low oil level alarm associated with the tank at FitzPatrick, and the bearing supply would likely be maintained until

failure of the shaft driven oil pump then auxiliary oil pump to maintain pressure due to total suction loss.

INFLUENTIAL ASSUMPTIONS

This review consisted of determining the best estimate risk increase for the internal and external postulated events for FitzPatrick. This required various key assumptions for this determination including the following:

- The degraded condition of the defective diaphragm and its ability to perform its function under various HPCI system demands and operational modes is a source of high uncertainty. The analysts evaluated the initial assumed leak rate and the subsequent quantified leak rate and determined that temperature effects alone would not support the mission time for events where HPCI is credited. Therefore, an analytical best-estimate probabilistic weighted-average was used due to the high uncertainty with the initial unquantified leak rate to try to provide some approximation of what the original leak rate may be in response to events.

- A failure of the PCV diaphragm can have a significant impact on oil inventory and this would result in required sump level not being maintained. Oil loss that results in a sump level of 8.5” from the top (approximate 63-gallon loss) would result in vortexing, cavitation, and loss of suction to both the SDOP and auxiliary oil pump as noted in the vendor manual. The loss of suction to the oil pumps would result in a trip of the system Stop Valve and Control valves (internal gear pump loses suction pressure). Additionally, the auxiliary oil pump would continue to run with inadequate suction resulting in a pump continuing to run while cavitating as there is no automatic trip to protect this pump. It is uncertain if damage could occur to this pump as well as a system trip. The oil loss condition was modeled as a HPCI failure to run (FTR) with basic event, HCI-TDP-FR-TRAIN, set to TRUE.

- The analytical probabilistic weighted oil leak and time to failure was assessed against system design, such as the lack of oil sump low level alarms, existing makeup procedures and their adequacy to address the size of the calculated oil leak, along with timing considerations, to determine that this condition would not be recoverable. Therefore, basic event, HCI-XHE-XL-FR, fail to recover HPCI failure to run, remained set to TRUE in the SPAR model. However, sensitivity evaluations were performed to assess the effect of HPCI recovery. There would be no alarm cues based on this condition until total loss of pump head and cavitation. The analysts also noted that if the pumps lost suction head, this would also lead to difficulty in even determining where a leak was coming from as no oil pressure would be present in the system for continued leakage out of the PCV with up to 63 gallons of oil present in the skid area.

- Multiple HPCI starts/stops are possible during a 24-hour mission even with operators manually controlling HPCI flow, given certain postulated events and potential scenarios, including where pressure control mode is not available. Certain events could result in high DW pressure and may result in cycling the system on and off to control reactor vessel water level within the emergency operating procedure level band. Therefore, this was evaluated in the condition case for postulated events, along with sensitivity analyses to increase exposure time for this condition, as the assumption is that HPCI start/stop cycles degrade the defective PCV diaphragm. It should be noted, the SPAR model does not credit the HPCI pressure control mode or credit DW cooling for prevention of the loss of the pressure control mode. The Fitzpatrick PRA model also does not credit these functions.

- Early control rod drive high pressure injection credit was determined to be available and credited in the risk assessment, except for LOCA type events, LOOP, loss of instrument air, loss of AC or DC busses and the dominant fire area events. This was modeled by using a surrogate FTR probability for RCIC (3.01E-2/year) and HPCI to represent early control rod drive support for the applicable events. This resulted in an almost order of magnitude reduction in the failure to run events.

Exposure Time Determination

As noted within the assumptions, RASP Handbook Volume I – Internal Events Appendix A gives guidance that the failure duration should be based on the nature of the failure. For this degraded condition, modeling the exposure time as a 24-hour runtime estimate may not be appropriate given the uncertainties with the assumption that the degradation mechanism is directly proportional to the run time of the turbine. Therefore, the conclusion that the number of cycles affects the failure mode was taken into consideration in determining an exposure time which best represents the length of time that the HPCI system would have been unavailable to perform its mitigating function.

The exposure time is a source of uncertainty. The base case exposure time for a few of the postulated events was set to 59 days (February 12 – April 10, 2020, plus repair time). This is based on having a 2-cycle margin for HPCI operation (i.e. HPCI PCV demonstrated two start/stop cycles without leaking or failure during the March test). Some events do not require this margin and were set to 38 days (see Table 3). Several sensitivity evaluations were performed to vary the exposure time. The front-stop exposure time (sensitivity) is determined to be 38 days (since last successful monthly test plus repair time), based on RASP Volume I handbook Section 2.3 since the PCV was a replacement part that passed initial operational tests. However, using Section 2.3 may not be the best representation because it does not account for the number of cycles the PCV may encounter which contribute to the nature of the failure. Section 2.5, 'Exposure Time for Component Run Failures,' is also relevant due to the low-cycle fatigue degradation mechanism. The appropriate exposure time is based on RASP Handbook Volume I, Appendix A as stated above. This states that the failure duration should be based on the nature of the failure, which in this case is the number of cycles the PCV may experience during postulated events. Therefore, this is the appropriate consideration for exposure time and would indicate events where HPCI could be started and stopped more than a few times result in a longer exposure time than 38 days. For events resulting in high DW pressure, the number of cycles of HPCI required to respond to an event would be the influencing factor for the exposure time. Considering the degraded condition and HPCI start/stop cycles anticipated for various events and margin available (based on surveillance test history), a 123-day exposure time (sensitivity) was also assessed. This is based on having a 4-cycle margin for HPCI operation (i.e. HPCI PCV demonstrated four start/stop cycles without leaking or failure). A maximum 1-year exposure time was assessed in a sensitivity review since HPCI had not accumulated 24 hours of runtime (only approximately 10 1/4 hours in the past 12 months) since the PCV installation in 2017. All reasonable sensitivity cases (i.e. less than one year) confirm a preliminary White risk assessment.

For most events this would be from the last time the HPCI test was performed 38 days earlier. However, the analysts noted potential considerations which would support increased exposure time for certain scenarios such as loss of an AC bus or a fire scenario which may render one complete division of DC power unavailable. Factors which would contribute to a higher exposure time for these scenarios were considered in this review. The focus would be on the potential for cycling of the HPCI system and PCVs.

Transient scenarios such as LOOP events, and loss of AC and DC busses would result in elevating DW pressure (due to latent heat effects) from the normal 1.7 - 1.8 psig to 2.7 psig in a relatively quick timeframe. For these scenarios and considering that the degraded condition relative to this performance deficiency appears to be a function of PCV cycles and not just run hours, the analyst considered cases where it would be assumed a nominal 3 or 4 cycles of HPCI may occur before a leak would develop going back to February 2020 and even December of 2019. This time is based on the fact that there was a proven total of 4 PCV cycles from the January 2020 timeframe from testing before the leak rate occurred after the March test. The February 2020 and December 2019 timeframe assumptions were based on obtaining an estimate of plant potential response to this type of event including the following:

- Appendix F from JF-PRA-004, Human Reliability Analyses, Appendix F provides a summary of simulator scenarios to verify plant response, timing of cues, and effect of key actions. Scenario 3, loss of high pressure injection with MSIVs closed indicates that a starting DW pressure of a nominal 1.7 to 1.8 psig could result in reaching the high DW pressure signal of 2.7 psig in a short time after the event. This would result in loss of the pressure control mode for HPCI and the potential for several cycles of the system while controlling within the level band. The associated data plot showed that DW pressure would increase, with the possibility of impacting HPCI pressure control mode availability. For the analyzed fire events, it should be noted that only one RHR pump would be available for torus cooling, limiting the cooling capability for the torus and creating a more challenging condition for controlling DW pressure early.

- An Accident Sequence Precursor Report, (ADAMS Accession No. ML18180A326) for estimating the potential number of cycles for a High Pressure Injection system (HPCS) referenced thermal-hydraulic calculations performed as part of NUREG-1953, “Confirmatory Thermal-Hydraulic Analysis to Support Specific Success Criteria in the SPAR models in part for Peach Bottom,” to use as an input in the number of potential injection valve cycles anticipated during events. This study indicated that HPCI would cycle a nominal 5 times in 7 hours from an initiating event in a batch mode simulated operation if the pressure control mode was not available.

- For the case of a potential high DW pressure condition, the vendor manual instruction states the pump should not be operated below 50 percent of rated flow for sustained periods of time, as operation on minimum flow is intended for startup and shutdown. Severe internal cavitation at high head conditions can result in pump damage. Therefore, a batch mode of starting HPCI to slowly increase level, then securing the pump and restarting on low levels would be consistent with the systems capability and the vendor manual intent for pump operation.

- If the DW pressure reaches 2.7 psig, the test return valves are closed, and pressure control mode would be unavailable. If minimum flow operation would be used, the operators would be pumping CST water (500 to 700 gpm) into the torus while waiting for level to reduce boiloff to inject again. This would increase torus pressure while using the preferred source of CST water and eliminating the suction source for the control rod drive system. It is likely this could result in a batch mode of operation (start and secure system between range of level band) to secure the transfer of CST water into the torus and eliminate severe cavitation of the HPCI pump.

- The NRC SPAR model does not credit DW pressure control or HPCI in the pressure control mode and the Fitzpatrick PRA model also does not formally credit DW cooling or HPCI in pressure control mode.

The above information was used to evaluate events where it is possible that more HPCI PCV cycles may occur, such as the dominant fire scenario for this condition, loss of AC 'A' division and 'A' DC division along with LOOP events. For this scenario, and assuming several system cycles would be required, the exposure time would reasonably be set back to 59 days and as far back as the December 2019 HPCI functional test, and hence a 123-day exposure time sensitivity.

It is noted that HPCI is designed to be cycled automatically in response to events. The causal analysis defined the failure as a function of PCV cyclical stress and movement. After the December 2019 functional test (123 days before the observed failure) if this postulated fire event had occurred the pump could have been started and stopped to maintain level up to 4 times before any leak would have developed. There would be no cue of any kind indicating a problem with the system or this type of operation. As noted above, previous thermal hydraulic studies have shown about 4 or 5 starts would be required to maintain a level band in a nominal 5- to 7-hour timeframe. While this may not meet the number of cycles required in a 24-hour mission time, a cap on the exposure time of 123 days is a reasonable sensitivity given uncertainties with decay heat, the cooldown expected, availability of low pressure systems, and the ability to locally, manually vent containment later in the event.

While 38 days appears to be justified for some of the postulated events, given the potential availability of the pressure control mode of the system or recovery of it, which would eliminate the need of cycling the system, there is still some uncertainty with the conclusion that the degradation mechanism for the diaphragm would not be directly proportional to the run time of the turbine. The causal analysis of steady state pressure on the PCV during operation does not support a 24-hour run time summation. Therefore, the base case is set to 59 days for some events to account for a reasonable number of PCV cycles during the need for potential system cycling. Notwithstanding this, additional sensitivity analysis was provided with different assumptions for exposure times, including up to one year, to reflect the uncertainty with the condition or failure mechanism.

While a strict interpretation that DW cooling or pressure control is not credited, the analysts considered assumptions where batch mode injection would occur with 6 to 7 cycles, but this is not a realistic as-operated estimate and hence limited the estimated exposure time.

LEAKRATE ASSESSMENT AND RECOVERY

Leak Rate Assessment

The leak rates observed on April 10, 2020, as reported from the licensee, have a high level of uncertainty. The initial leak of 0.1 gpm was estimated without actual measurement since the operators had no equipment to measure the leak and it was unexpected. The second start of the auxiliary oil pump to quantify the leak was cut short (only a ~30 second run) based on a much larger leak (>1.3 gpm) that overwhelmed the collection apparatus brought to measure the oil quantity. The PCV leaked on the 1st start and became a very large quantified leak on the 2nd start. This was observed at ambient room temperature. Adjusting for expected HPCI operating temperatures results in a factor of three increase in observed leak rates based on the characteristics of Mobil DTE-732 oil used in this system. Exelon agreed that temperature would

affect the leak rate in subsequent discussions with the analysts. It is not unreasonable to conclude that the HPCI PCV failure could have developed into the larger leak after an initial start of the HPCI turbine, if HPCI was demanded, during dynamic operation. Furthermore, it is not uncommon for the system to either be tripped-off, if RCIC has level under control, or trip-off based on the high level trip being reached considering level swell, RCIC and HPCI addition, and the relatively quick response needed to control level on the initial system initiations.

The analysts considered a number of factors that resulted in using a probabilistic best estimate of what the leak may represent analytically while running and/or system recovery. The factors assessed included the following: 1. a high level of uncertainty estimated in the leak rate and 2. there is an unknown probability that the PCV would not develop into a large leak. This was done by determining a probabilistic weighted average of what the effective leak would analytically be in order to better assess and evaluate HPCI functional run time before failure and the plausibility of recovery actions.

The analysts calculated temperature corrected leak rates based on the oil characteristics and thermal-hydraulic response through cracks (Table 1). The analysts also reviewed NUREG/CR-6928, “Industry-Average Performance for Components and Initiating Events at U.S. Commercial Nuclear Power Plants.” Sections C.2.2 and C.2.3 provide a discussion and industry-average plant data to determine the probability of multiple injection cycles by HPCI and RCIC (MOV-PMINJ). The NUREG provides a HPCI mean value of 1.5E-1 (NUREG/CR-6928, Table C.2.2-4). This is also modeled as a basic event in the NRC SPAR (HCI-MULTIPLE-INJECT = 1.5E-1). The analysts also noted that the industry-average data relevant to probabilities that the RCIC turbine will have to restart (TDP-PRST, NUREG-6928, Table C.2.3-4) after initiation, is the same value used for high pressure coolant valve ‘multiple injection’ data in the SPAR model. This is often due to the initial trip early in an event on high reactor water level. This further supports the basis for using 0.15 as the probability that multiple starts of the HPCI would be necessary.

The analysts reviewed data post-2002, reviewing at least 6 boiling water reactors with HPCI to determine auto starts and how many events resulted in high water level trips or tripping off of HPCI. A Bayesian update analysis for binomial data was performed on the informed prior distribution within the NUREG/CR-6928 for required probability of RCIC restarts using the gathered HPCI data. This analysis resulted in a Jefferies non-informed posterior distribution mean of 0.27. The informed posterior resulted in a mean value of 0.20. This used the events where HPCI auto started and tripped on high level early. This did not account for events where HPCI was secured due to early success of RCIC as LER data indicated HPCI was secured more than 50% of the time. Therefore, the 0.15 probability of restart was considered a reasonable surrogate for an early trip of HPCI only on high level using a Bayes Binomial model approach. This was simply performed to confirm the reasonableness of using a 0.15 value for a best estimated weighted leak rate approach. As stated, this may be slightly nonconservative, given events for sequences involving RCIC fail to run or RCIC fails within the first hour (failed to start) where HPCI is often secured, which in this case, would have resulted in an immediate severe oil leak. The RCIC fail to run are found in the SPAR model dominant cutsets.

As a sensitivity, the analysts performed a SPAR-H evaluation of the human error probability of diagnosing reactor pressure vessel level response and taking action to take early control of HPCI/RCIC to prevent a high-level trip signal (Level 8) after initiation. Failure probability estimate results ranged from 0.105 to 0.21. This was consistent with the actual data provided by the NUREG. The analysts used the data and estimates above to calculate an analytical probability-weighted effective leakage as follows and summarized in Table 1.

- Weighted Leak Rate Estimate = (probability of more than one injection cycle) x (large leak rate observed and quantified after first PCV cycle) + (probability of one injection cycle only, no trip) x (small leak rate only estimated with a larger uncertainty)
- Weighted Leak Rate Estimate = (0.15) x (3.6 gpm) + (0.85) x (0.28 gpm) = 0.79 gpm
- Time estimate loss for suction = 63 gallons lost (8.5" from top of sump) / leak rate (gpm)

Table 1 – Corrected Leak Rate and Weighted Estimate

NRC	data / calculation		**FitzPatrick**	data / calculation	
*gpm at 124F**	*min*	*hours*	*gpm at 120F*	*min*	*hours*
(0.1) / 0.28	225.0	3.75	0.18**	341.1	5.69
(1.3) / 3.65	**17.3**	0.29	3.84***	**16.4**	0.27
LR weighted estimate			LR weighted estimate***		
0.79	80.4	1.34	0.58	109.3	1.82
gpm	*min*	*hours*	*gpm*	*min*	*hours*

* Exelon states steady-state oil temperature will reach less than 124F after 20 minutes.
** Exelon used 0.0625 gpm as their initial leak (based on an operator statement of approximately "1 pint in 2 minutes"; analysts noted HOV1/2 valve position computer data would indicate less run time of about one minute further confirming the uncertainty with this number or non-quantified estimate)
*** Licensee states high-leak rate would preliminarily be limited to 2.8 gpm based on piping and flow restrictions. This value was used in the NRC's assessment of FitzPatrick's data in the leak rate weighted estimate.

The analytical leak rate results assume that the HPCI PCV did not excessively leak on the initial HPCI turbine start cycle. The analysts noted there was large uncertainty with the no-trip leak rate (0.1 gpm) as it was not quantified, and this estimate may not be conservative. From the above data it is noted there is a possible 80 minutes before the oil pumps would lose suction. All estimated times to failure are less than 2 hours. This simply confirms the probabilistic leak rate would not have supported HPCI's function for any event. And as noted, this may be non-conservative given the historical high rate of HPCI tripping off. It should be noted this is relevant to the NRC SDP risk calculation, because the RCIC failure to run events are dominant given their high failure rate over 24 hours. (0.11 nominal)

Recovery Consideration

Considering there may be some time available to identify and recover HPCI before oil pump suction is lost based on the analytical leak rate, a recovery failure probability was estimated for sensitivity. The default value in SPAR is 1.0 (total failure). The analysts reviewed HPCI operating procedure (OP-15) and special procedure section (G.10) that monitors oil level and provides guidance to add oil during turbine operations. Based on this review, the analysts concluded that the oil addition procedure gives appropriate guidance for low volume 'topping-off' to account for some variation in level during HPCI operations. However, it is not written to support rapid high-volume makeup, as there is no direction for local high volume oil pump setup. During subsequent discussions, the licensee provided insights into available resources, operator / crew ingenuity, and skill of the craft to make-up or direct leakage flow back to the sump. However, the analysts noted that neither the severe leak rate or probabilistic analytical leak rates would allow adequate time to identify and respond.

Using information from the spectrum of leak rates and timing cues available, the analysts evaluated the likelihood of operators' failure to diagnose the oil leak, and its impact on HPCI operation, and the action to mitigate the leak through the addition of oil. This was performed to estimate a human error probability for sensitivity evaluations (CASE 3 and 4). The most optimistic case resulted in 0.6 failure probability, however the best estimate resulted in 1.0 (total failure) due to barely adequate available time. A HEP = 0.8 for the sensitivity run was applied based on the 0.6 – 1.0 range.

The analysts reviewed INL/EX-19-54613, "Enhanced Component Performance Study-Turbine Driven Pumps, 2018 Updated," dated September 2019. Section 6.4, 'Engineering Analysis by Failure Modes' states that overall non-recovery probabilities for turbine-driven pumps is 6:1, meaning 6 of every 7 failures were not recovered. This equates to a failure probability of 0.86. This gives baseline data on industry failure data. A further review, which isolated the standby turbine-driven pump data for non-recovery failure to run events (greater than 1 hour), resulted in a nominal 0.95 non-recovery probability. Therefore, the analysts concluded a sensitivity with a HEP = 0.8 is considered reasonable. This also considered that FitzPatrick does not implement a low-level sump alarm. In addition, although there is a pressure switch at the turbine thrust bearing, an upstream PCV within the system would attempt to control pressure at 38 psig. This would prevent this alarm from actuating until complete loss of suction to both of the oil pumps. Even if the alarm did actuate, it would not provide adequate time to respond to the leak. Additionally, for the various postulated events, such as fire, loss of AC and DC busses, and LOCAs the operators would have multiple priorities. Hence, there would be additional challenges to the success probability of identifying the PCV oil leak locally and implementing actions in time to prevent damage and system failure. There would be no initial indications of any problems with HPCI operation, and no operator cue for system priority until oil level loss would impact the oil pumps. Lastly, the auxiliary oil pump would continue to run even after suction is lost, with resultant cavitation and potential for pump damage as there is no automatic pump trip on loss of oil pressure or level. This further provides additional uncertainty regarding any kind of recovery credit for this event.

STANDARDIZED PLANT ANALYSIS RISK (SPAR) MODEL CHANGES AND SENSITIVITY ANALYSES

The analysts used the FitzPatrick NRC SPAR model version 8.59 with Saphire version 8.2.2. This SPAR model already included modifications to include FLEX modifications, which the station had developed in response to NRC Order 12-049, 'Order to Modify Licenses with Regard to Requirements for Mitigation Strategies for Beyond-Design-Basis External Events,' (ML12054A735) and were turned 'ON' via a pre-build changeset. This model was used to assess the internal and seismic events contribution to risk from this degraded condition. For fire and internal flooding risk, since this is not modeled in the FitzPatrick SPAR, the analysts reviewed Exelon's PRA notebooks and IPEEE information.

For early control rod drive credit, the analysts assessed that a surrogate can be used that represents the benefit of early control rod drive mapped to HPCI/RCIC fail to run events. This is logically dominated by the compound basic event (BE) HCI/RCI-TDP-FTR and its compound 'early' and 'late' terms. Adjusting the mission time for the late term (ZT-TDP-FR-L-HCI-RCI) from 23 hours to 5 hours, a surrogate of 3.01E-2/yr FTR is developed. This value is substituted for HPCI and RCIC FTR for the early control rod drive sensitivity base-case and for RCIC FTR for the early control rod drive condition case.

Internal Event Conditional Risk

Internal events are a dominant contributor to risk. Sensitivities were run to explore the impact on exposure time, early control rod drive, and HPCI recovery. The risk contribution from internal events for an exposure of 59 days is estimated at 1.7E-6/yr (ΔCDF) with FLEX and early control rod drive credit applied. The dominant accident sequence cutsets for internal events involve an initiating event of loss of condenser heat sink, failure of high-pressure injection (HPCI/RCIC), and failure to manually depressurize the reactor. Tables 2a and 2b summarizes the internal events ΔCDF. Table 3 summarizes the event and exposure contribution to the total risk since the 59-day and 123-day exposure calculations are hybrid and use 38-day contributions for some events.

Case 2 is considered the best estimate case for this conditional HPCI failure evaluation.

Table 2a - Summary of Internal Events ΔCDF modeled in SPAR (excluding internal flood)

Case and credits	ΔCDF	38 days	**59 days**	123 days	1 year
Case 1 – FLEX	2.04E-5	2.12E-6	**2.37E-6**	3.12E-6	2.04E-5
Case 2 – FLEX, early CRD (BASE)	1.26E-5	**1.46E-6**	**1.71E-6**	**2.47E-6**	**1.29E-5**
Case 3 – FLEX, HPCI Recovery	1.71E-5	1.79E-6	**2.02E-6**	2.71E-6	1.72E-5
Case 4 – FLEX, early CRD, HPCI Recovery	1.11E-5	1.27E-6	**1.50E-6**	2.18E-6	1.13E-5

Table 2b - Summary of Internal Events ΔCDF modeled in SPAR (including internal flood)

Case and credits	ΔCDF	38 days	**59 days**	123 days	1 year
Internal Flooding Estimate	3.86E-7	4.02E-8	**6.24E-8**	1.30E-7	3.86E-7
Case 1 – FLEX	2.04E-5	2.16E-6	**2.43E-6**	3.25E-6	2.08E-5
Case 2 – FLEX, early CRD (BASE)	1.26E-5	**1.50E-6**	**1.77E-6**	**2.60E-6**	**1.33E-5**
Case 3 – FLEX, HPCI Recovery	1.71E-5	1.83E-6	**2.08E-6**	2.84E-6	1.76E-5
Case 4 – FLEX, early CRD, HPCI Recovery	1.11E-5	1.31E-6	**1.56E-6**	2.31E-6	1.17E-5

Table 3 - Summary of Event and Exposure Contribution to 59 / 123-day SPAR Runs

(IE) EVENTs	59-day	123-day
XLOCA	NA	NA
LLOCA	NA	NA
MBLOCA	38	38
SBLOCA	38	38
ISL-RHR	NA	NA
IORV	38	38
LOACB-1	59	123
LOACB-2	59	123
LODCB-1	59	123
LODCB-2	NA	NA

(IE) EVENTs	59-day	123-day	early CRD
LOIAS	38	38	
TRANS	38	38	X
LOMFW	38	38	X
LOCHS	38	38	X
LOOPGR	59	123	
LOOPPC	59	123	
LOOPSC	59	123	
LOOPWR	59	123	
LOSWS	38	38	X
LOUHS	NA	NA	

Nominal Case Information

FitzPatrick SPAR Nominal CDF = 5.85E-6/yr
FitzPatrick SPAR Nominal CDF = 5.47E-6/yr, with FLEX credit (Nominal Case 1)
Change set FLX-XHE-XE-ELAP = 1E-2;
FitzPatrick SPAR Nominal CDF = 2.27E-6/yr with FLEX credit and early CRD (Nominal Case 2)
Change set FLX-XHE-XE-ELAP = 1E-2;
For events where CRD credit is appropriate
HCI-TDP-FR-TRAIN = 3.01E-2; early CRD surrogate
RCI-TDP-FR-TRAIN = 3.01E-2; early CRD surrogate

The ΔCDF for each exposure time was calculated by the summation of the individual event contributions from SAPHIRE multiplied by its exposure fraction for the year (see Table 3). Based on the 38-day contribution to the 59-day and 123-day data, the overall summation for each is less than a simple fractional year calculation.

Events XLOCA, LLOCA, ISL-RHR, LODCB-2, and LOUHS were found not to be impacted by the degraded condition (no ΔCDF) for any of the cases.

CASE 1 – (sensitivity) – HPCI FTR with FLEX credit (default, no early CRD)

Change set used FLX-XHE-XE-ELAP = 1E-2 and HCI-TDP-FR-TRAIN = TRUE.

Nominal Case 1 = 5.47E-6/yr and the conditional case = 2.59E-5/yr; ΔCDF = 2.04E-5/yr

Sensitivity exposure times at 38 days, 122 days, and 1 year were performed, in addition to the 59 days base case exposure:
ΔCDF for 38 days = 2.12E-6/yr
(monthly test on March 4, 2020) and is considered front-stop exposure time.
ΔCDF for **59 days = 2.37E-6/yr**
(monthly test on February 12, 2020), approximately 2 available HPCI start/stop cycles.
ΔCDF for 123 days = 3.12E-6/yr
(quarterly test on December 10, 2019), approximately 4 available HPCI start/stop cycles.
ΔCDF for 1 year = 2.04E-5/yr
(max backstop), approximately 19 available HPCI start/stop cycles.

The dominant core damage sequence is loss of condenser heat sink, failure of high-pressure injection (HPI), and failure to manually depressurize the reactor.

CASE 2 – BASE CASE – HPCI FTR with FLEX credit and early CRD credit

The analysts noted that this case may be slightly non-conservative, because the CST has a nominal 122,000 gallons above the top of the HPCI and RCIC dedicated standpipe suction. The tank level would support 7 or 8 hours assuming HPCI isn't running in a minimum flow mode removing water to the torus. If this would be the case, there would be even less time available before the control rod drive suction would be uncovered. Therefore, makeup to the CST would be required to support a 24-hour mission time for control rod drive. In some cases, the licensee is crediting methods such as firewater to refill the CST, although it is not within the licensee's postulated events' procedures for this issue. The fact that the CST needs to be refilled is not included within the SPAR model and thus has uncertainty involved with this credit.

Change set used FLX-XHE-XE-ELAP = 1E-2, HCI-TDP-FR-TRAIN = TRUE, RCI-TDP-FR-TRAIN = 3.01E-2 (early CRD surrogate).

The integrated nominal case (Nominal Case 1 and Nominal Case 2 based on early CRD) = 3.01E-6/yr. The integrated conditional case = 1.56E-5/yr. The integrated ΔCDF = 1.26E-5/yr

Sensitivity exposure times at 38 days, 122 days, and 1 year were performed, in addition to the 59 days base case exposure:
ΔCDF for 38 days = 1.46E-6/yr;
ΔCDF for **59 days = 1.71E-6/yr;**
ΔCDF for 123 days = 2.47E-6/yr;
ΔCDF for 1 year = 1.29E-5/yr.

The dominant core damage sequence is loss of condenser heat sink, failure of high-pressure injection (HPI), and failure to manually depressurize the reactor.

<u>CASE 3 - (sensitivity) – HPCI FTR with FLEX credit and HPCI Recovery</u>

Change set used FLX-XHE-XE-ELAP = 1E-2, HCI-TDP-FR-TRAIN = TRUE, HCI-XHE-XL-FR (operator fails to recover HPCI failure to run) = 0.8.

Nominal Case 1 = 5.47E-6/yr and the overall conditional case = 2.27E-5/yr; ΔCDF = 1.71E-5/yr.

Sensitivity exposure times at 38 days, 122 days, and 1 year were performed, in addition to the 59 days base case exposure:
ΔCDF for 38 days = 1.79E-6/yr;
ΔCDF for **59 days = 2.02E-6/yr;**
ΔCDF for 123 days = 2.71E-6/yr;
ΔCDF for 1 year = 1.72E-5/yr.

The dominant core damage sequence is loss of condenser heat sink, failure of high-pressure injection (HPI), and failure to manually depressurize the reactor.

<u>CASE 4 - (sensitivity) – HPCI FTR with FLEX, early CRD credit, and HPCI Recovery</u>

Change set used FLX-XHE-XE-ELAP = 1E-2, HCI-TDP-FR-TRAIN = TRUE, RCI-TDP-FR-TRAIN = 3.01E-2 (early CRD surrogate), and HCI-XHE-XL-FR (operator fails to recover HPCI failure to run) = 0.8.

The integrated nominal case = 3.01E-6/yr. The integrated conditional case = 1.41E-5/yr. The integrated ΔCDF = 1.11E-5/yr

Sensitivity exposure times at 38 days, 122 days, and 1 year were performed, in addition to the 59 days base case exposure:
ΔCDF for 38 days = 1.27E-6/yr;
ΔCDF for **59 days = 1.50E-6/yr;**
ΔCDF for 123 days = 2.18E-6/yr;
ΔCDF for 1 year = 1.13E-5/yr.

The dominant core damage sequence is loss of condenser heat sink, failure of high-pressure injection (HPI), and failure to manually depressurize the reactor.

Internal Flooding Risk not included in NRC SPAR model

The Fitzpatrick NRC SPAR model does not include internal flooding risk. FitzPatrick's flooding PRA notebook estimated the overall internal flooding risk base case CDF to be 5.08E-7/yr.

The analyst noted that the baseline dominant risk significant flood area initiator was a service water piping fault in the chiller room within the reactor building. The degraded HPCI condition had no impact on these results as this flood impacts DC power to both HPCI and RCIC in the base case. The analyst estimated that a flood in the 252-foot elevation of the turbine building, %FLD-TB-1, was a bounding condition and the total frequency within the flooding notebook was 5.5E-3/yr for this area. The NRC SPAR model was used with a loss of condenser heat sink as a surrogate event to determine a base case and the conditional case using HPCI fail to run. The CCDP was calculated at 7E-5. Therefore 5.52E-3/yr x 7E-5 = 3.86E-7/yr. For a 59-day exposure this would be a risk increase of 6.24E-8/yr.

A second notable area where HPCI was described to be available for many of the flood area sequences was within the reactor building west crescent area. These floods could result in the loss of RCIC and the A train of RHR and core spray. This contribution was considered bounded by %FLD-TB-1 based on low initiating event frequencies.

Fire External Event Conditional Risk

An initial review of FitzPatrick Fire PRA notebook (JF-PRA-021.11) relative to the degraded condition indicated that this fail to run event was considered a significant risk contributor based on its risk importance measures (i.e. Fussel-Vesely and Birnbaum importance measures). Therefore, the analyst reviewed the notebook, along with the IPEEE to evaluate the condition. To evaluate the as-operated condition, a detailed review of abnormal operating procedure (AOP-28), Operation During Plant Fires, (immediate and subsequent operator actions for specific fire zones) was also performed. The analyst determined that HPCI was part of the safe shutdown equipment for the west inner cable tunnel zone, the west electric bay fire zone, south emergency switchgear room among various other areas. However, it was determined that the most dominant fire areas which would be impacted by this condition were associated with BR-1, the 'A' battery charger room, SW1, Division 1 Switchgear, and TB1E252 turbine building fire resulting in a LOOP event.

It was noted that a HPCI failure event was found in the top 100 cutsets for the base case CDF in the notebook with fire area BR-1 being the applicable event. Therefore, this fire area (BR-1 full zone fire) was assumed to provide the most significant contribution to risk for a HPCI failure. The full zone fire ignition frequency for BR-1 from the notebook was 1.5E-3/yr as referenced in Table B-1 of JF-PRA-021.11 revision 1. A review of the SW1 Switchgear area fires (%F1_SW1_71H03) resulted in an estimated ignition frequency of 1E-3/yr. The ignition frequency for turbine building fires (%F1_TB1E252_FIS_Y) which result in a LOOP event was estimated at 1.89E-3/yr.

<u>'A' Battery Charger Room Fire, BR-1</u>

The analyst noted a fire in this area would have a SPAR model internal event surrogate of a Loss of the 'A' Train DC. This would impact 'A' train equipment including the ability of RCIC to perform its function. The SPAR model initiating event of loss of DC Bus 2A would be the appropriate surrogate to analyze this fire event.

A change set was developed for the base case and conditional case for the SPAR model: Base Case, IE-LODCB-1 (DC Bus 2A Div I) set to 1.0, ADS-XHE-XM-MDEPR set to 2E-3 (SPAR-H, using no diagnosis - only action with all nominal settings other than Stress taken to 'high' – given the fire event, impact on 'A' DC train, and operators in multiple procedures). This base case was run for IE-LODCB-1 with a CCDP of 7.94E-4.

Condition case is simply the above change set with the addition of HCI-TDP-FR-TRAIN set to TRUE. The resultant CCDP is 3.37E-3. Therefore, the delta CCDP is 2.58E-3. Substituting the fire zone BR-1 full zone fire frequency provides for the following: 1.5E-3/yr x delta CCDP (2.58E-3) = 3.9E-6/yr. A minimum of 2 cycles was assumed taking the exposure out to 59 days given the loss of all the equipment and likelihood of early high DW pressure. Additionally, as noted prior, DW pressure control is not credited and it is likely that the high DW pressure setpoint would be exceeded at some point during the event, resulting in the potential need to batch-feed (pressure control mode lost) and start / stop the HPCI system.

The increase in fire risk for this condition was estimated at 3.9E-6/yr x (59/365) = 6.3E-7/yr

<u>Division I Fire Area, SW1</u>

The analyst noted a fire in this area would have a SPAR model internal event surrogate of a Loss of the Division 1 AC Train. This would impact 'A' train equipment including the ability of RCIC to perform its long-term function. The SPAR model initiating event of loss of the 10500 Bus or LOACB-1 would be the surrogate to analyze this fire event.

A change set was developed for the base case and conditional case for the SPAR model: Base Case, IE-LOACB-1 set to 1.0, ADS-XHE-XM-MDEPR set to 2E-3 (SPAR-H, using no diagnosis - only action -with all nominal settings other than Stress taken to 'high' – given the fire event, impact on 'A' AC train, and operators in multiple procedures). This base case was run for IE-LOACB-1 with a CCDP of 4.49E-4.

Condition case is simply the above change set with the addition of HCI-TDP-FR-TRAIN set to TRUE. The resultant CCDP is 2.12E-3. Therefore, the delta CCDP is 1.7E-3. The fire ignition frequencies were estimated to be 1E-3/yr and include high energy arc faults. These were estimated from a review of Table B-1 from JF-PRA-021.11 notebook.

Substituting the fire zone SW1 fire frequencies which contribute to the conditional risk provides for the following: 1E-3/yr x delta CCDP (1.7E-3) = 1.7E-6/yr

The increase in fire risk for this condition was estimated at 1.7E-6/yr x (59/365) = 2.7E-7/yr

<u>Turbine Building Fires resulting in LOOP</u>

The analyst noted a fire in this area would have a SPAR model internal event surrogate of a LOOP event. The SPAR model initiating event of a LOOP event (IE-LOOPPC) would be the appropriate surrogate to analyze this fire event.

A change set was developed for the base case and conditional case for the SPAR model: Base Case, IE-LOOPPC was set to 1.0, ADS-XHE-XM-MDEPR set to 2E-3 (SPAR-H, using no diagnosis - only action -with all nominal settings other than Stress taken to 'high' – given the fire event, and resultant LOOP event, and operators in multiple procedures). This base case was run for IE-LOOPPC with a CCDP of 6.1E-5.

Condition case is simply the above change set with the addition of HCI-TDP-FR-TRAIN set to TRUE. The resultant CCDP is 3.45E-4. Therefore, the delta CCDP is 2.84E-4. Substituting the turbine building fire frequency provides for the following:
1.89E-3/yr x delta CCDP (2.8E-4) = 5.4E-7/yr.

The increase in fire risk for this condition was estimated at 5.4E-7/yr x (59/365) = 8.7E-8yr

The total fire increase in CDF/yr for 59 days is 6.3E-7/yr + 2.7E-7/yr + 8.7E-8/yr = 9.9E-7/yr

Fire Sensitivity Analysis

Considering the degraded condition relative to this performance deficiency appears to be a function of PCV cycles and not just service run hours, the analyst assumed fires, especially with the loss of one division, may result in a high DW pressure condition with a nominal 4 or 5 cycles of HPCI. These cycles are assumed to degrade the PCV such that if these postulated fires were to occur after December of 2019, the PCV may have failed. This was based on the discussion within the exposure time discussion of this DRE.

For the above fires the increase in risk was calculated at 3.9E-6/yr + 1.7E-6/yr + 5.4E-7/yr = 6.1E-6/yr. Therefore, for a sensitivity analyses of a 123-day exposure the increase in CDF/yr would be 6.1E-6/yr x 123/365 days = 2.1E-6/yr.

The analyst noted the above does not consider other areas where HPCI is considered the safe shutdown high pressure system within AOP-28 attachments and assumes there would be insignificant contributions from these areas.

Lastly, the Fitzpatrick baseline fire risk is dominated by fires which result in evacuating the control room and using alternate shutdown strategies. The procedure applicable to this scenario, AOP-43, Plant Shutdown from Outside the Control Room, Revision 43, was reviewed to confirm that this degraded condition had no impact on increased risk because the strategy is to depressurize via the safety relief valves and use low pressure injection systems.

Other External Event Risk Contribution

Other external events were not considered to be significant risk contributors. The seismic risk was calculated using the NRC FitzPatrick SPAR model and the increase in risk was determined to be 9.3E-8/yr. For a 59-day exposure this would be 1.5E-8/yr or insignificant.

The analyst estimated that high winds would also have a negligible impact relative to this degraded condition, due to the low initiating event frequencies.

LARGE EARLY RELEASE FREQUENCY

The analysts reviewed portions of the FitzPatrick's PRA summary notebook relative to the analysis of large early release frequency (LERF). The licensee evaluated a Level 2 methodology analyzing issues such as magnitude and timing of calculated radionuclide releases through level 2 containment event trees. The analysts noted that the licensee had used a LERF multiplier for class IA events (e.g. HPCI FTR) CDF sequences of a nominal 1.12E-1. Other class events also have factors less than 1.0, except containment bypass (Class V). Therefore, this does not increase the LERF importance with respect to risk over or beyond that calculated for the CDF/yr increase.

A bounding result was CASE 1 for the conditional change in ΔCDF = 2.04E-5/yr annualized increase in risk due to a degraded HPCI system. This would result in (2.04E-5/yr x 1.12E-1) x 59 days/365 days = 3.7E-7/yr increase in LERF due to the condition. This bounds any ΔLERF contribution from internal events and therefore the best estimate of risk is represented by the estimated increase in total ΔCDF/yr for the condition.

Also, per Inspection Manual Chapter 0609, Appendix H, Table 5.2, LERF factors of 1.0 and 0.6 are used for high pressure core damage accident sequences with the DW dry or flooded, respectively. These Appendix H LERF factors are considered conservative bounding values. More recent insights from an NRC Office of Research sponsored study by Energy Research, Inc. (ERI/NRC-03-04), November 2003 indicates that without reactor coolant system (RCS) injection during a station blackout (SBO), there is a high probability that the RCS would subsequently depressurize as a result of either temperature-induced creep rupture of the steam lines or a stuck-open safety relief valve (SRV) (due to high temperature cycling). Subsequent State of the Art Reactor Consequence Analysis Project at Peach Bottom Nuclear Power Station (NUREG/CR-7110) have identified that improved modeling and analysis of anticipated types and sizes of reactor coolant ruptures, projected containment heating and fuel-coolant interactions, and operator actions taken to flood containment in accordance with Severe Accident Management Guidelines, significantly reduce the potential for containment breach and the likelihood of a LERF.

The dominant core damage sequences would not significantly contribute to LERF risk due to timing considerations. These sequences involve a failure of HPCI/RCIC and a failure to depressurize the RCS, resulting in the failure of any injection to the RCS (i.e. no low pressure injection from core spray or low pressure coolant injection systems). These sequences are similar to the accident conditions that would be encountered during an SBO event without HPCI availability.

Therefore, the above reports indicate a more benign containment response at the time of vessel breach, in terms of direct containment heating and fuel-coolant interaction-induced containment failure. As a result of the above considerations, the use of a LERF multiple based on a depressurized RCS and a flooded DW floor would be appropriate. The analysts concluded that the risk due to ΔLERF is consistent and bounded by the ΔCDF results, i.e. White.

MODEL COMPARISONS AND LICENSEE RISK PRELIMINARY METHODOLOGY

Exelon's internal and external events analysis of the HPCI PCV failure resulted in a determination of a very low safety significant issue. The result of 3E-7/yr total risk increase, was based on a 38-day exposure, early control rod drive credit for events (nominal 5 hours), and a high success probability to prevent an early HPCI trip on high level. Their evaluation acknowledged HPCI could be tripped off with early RCIC success but concluded it would have a minimal effect. This is because Exelon uses a RCIC failure to run value of approximately 1E-2 per 24 hours, which is an order of magnitude lower than the NRC SPAR model 1.19E-1. The NRC SPAR model dominant cutsets include RCIC fail to run events.

The NRC analysts contacted Idaho National Labs to confirm the appropriateness of the HPCI and RCIC failure to run probabilities and they confirmed the accuracy of them in the SPAR model. This is a significant difference. Additionally, Exelon's SDP evaluation concluded a very high probability to identify and recover from both a small leak (0.18 gpm) and a large leak (2.8 gpm) based on operator skill of the craft. A review of FitzPatrick's SDP indicates an an assumption of success 19 out of 20 times in identifying the leak in order to mitigate the oil loss

until control rod drive can be credited after 5 hours. It is important to note that FitzPatrick's SDP is predicated on an assumption that the leak will remain low, and not degrade with machine operation (no more than the 120°F temperature corrected leak rate of 0.18 gpm). This was based on the 0.06 gpm leak rate that the analysts believe has a very large degree of uncertainty with no evidence for its technical basis. The licensee's methodology using their success probabilities to prevent any large leak with operator actions to control level, reduces the importance of their MBLOCA scenarios. Although DW cooling or HPCI pressure control is not credited in the Fitzpatrick PRA model, Exelon is assuming that they could operate HPCI on minimum flowrate, for up to 5 hours, even with vendor documentation stating severe cavitation would occur due to the nature of the design of the pump curve. This assumes operations would not simply shut the turbine down and then restart it when needed at a lower reactor water level. Exelon is also considering they would perform many skill of the craft actions such as using firewater with no direct procedural direction for the applicable postulated event, to add to the CST to support the control rod drive high pressure mission time even though HPCI and RCIC may be functioning to cool the core while level drops to the standpipe.

Because the Exelon evaluation assumes that HPCI can continue to run for up to 5 hours or greater than 3 hours, they also re-evaluated their human actions for failure to depressurize which is dominant in many core damage cutsets. This increased timing available resulted in some notable revisions to lower the failure probability of this action. The NRC calculated a probabilistic weighted nominal 90 minutes of run time, with a strong likelihood there would be a severe oil leak through the failed PCV diaphragm if RCIC starts successfully with the RCIC failure to run dominant cutsets. Therefore, the fail to depressurize human error probabilities will be different as well.

The licensee also presented a proposed revised calculation for the available oil volume in the HPCI sump that would add an additional 25 gallons, hence extending their proposed low-leak mitigation time. The analysts don't consider this supported by the current data regarding normal oil level and vendor low level requirements to maintain pump suction.

Also, as previously discussed, the analysts do not consider HPCI recovery plausible or feasible and assigns a high failure probability (0.8 for sensitivity, see Case 3 and 4).

Licensee does not consider fire risk significant.

PRELIMINARY CONDITIONAL RISK INCREASE CALCULATION CDF/YR

Total risk is the sum of the internal + external events; CASE 1 is without control rod drive credit or recovery. CASE 2 includes early control rod drive credit for some events and best represents the event assessment. Also, the assessment exposure time is best represented from 38 to 123 days based on the cyclical failure mechanism and not necessarily proportional to the runtime of HPCI. Tables 4a and 4b summarize the estimated total risk:

Table 4a - Summary of Total Risk (ΔCDF) – BASE CASE (early CRD for some events)

Event	ΔCDF	38 days	59 days	123 days
Internal and Flooding – Case 2	1.3E-5/yr	1.5E-6/yr	**1.8E-6/yr**	2.6E-6/yr
Fire	6.1E-6/yr	6.4E-7/yr	**9.9E-7/yr**	2.1E-6/yr
Seismic	9.3E-8/yr	9.7E-9/yr	**1.5E-8/yr**	3.1E-8/yr
Total ΔCDF estimated:		2.1E-6/yr	**2.8E-6/yr**	4.7E-6/yr

Table 4b - Summary of Total Risk (ΔCDF) – DEFAULT CASE (no early CRD)

Event	ΔCDF	38 days	59 days	123 days
Internal and Flooding – Case 1	2.0E-5/yr	2.2E-6/yr	**2.4E-6/yr**	3.3E-6/yr
Fire	6.1E-6/yr	6.4E-7/yr	**9.9E-7/yr**	2.1E-6/yr
Seismic	9.3E-8/yr	9.7E-9/yr	**1.5E-8/yr**	3.1E-8/yr
Total ΔCDF estimated:		2.8E-6/yr	**3.4E-6/yr**	5.4E-6/yr

The total change in core damage frequency (ΔCDF) is the sum of internal and external event ΔCDF risk for a HPCI failure to run and a best estimate is within the range of 2.1E-6/yr to 4.7E-6/yr, (White), Table 4a.

The ΔLERF contribution estimate is consistent with a White risk based on ΔCDF.

The sensitivity evaluations support a White finding.

QUALITATIVE CONSIDERATIONS

Design Service-Life of PCV Diaphragm

An operating experience history review identified that the vendor-specified design service of an original 1-ply BUNA diaphragm is 1000 cycles and the updated (after 1991) 2-ply BUNA diaphragm is rated up to 100,000 cycles, (Hatch LER, 2002-004). The same diaphragm type is installed in other HPCI PCV systems. Based on the FitzPatrick HPCI operating history provided by Exelon since the affected diaphragm (i.e. the defective updated 2-ply) was installed (December 2017), there has been less than 70 estimated PCV cycles.

Estimated Leak Rate

The actual leak rate calculated in this DRE may be underestimated. This is because the actual response of the HPCI system may add up to 10 inches or more of reactor water level compared to how it is modeled in the simulator within the first few minutes, due to setpoint overshoot and the inherent tuning of the system. If the probability of failure were changed to 0.25 (vice the 0.15 used) based on less time for operators to respond per figure 12-4 in NUREG/CR -1278, this would result in a weighted leak rate of 1.2 gpm or 50 minutes before level would render the HPCI auxiliary oil pumps inoperative. If a nominal level of training versus high training level were applied to the operator action for failure to prevent high level trip on level 8, this would suggest using the mean value or 0.5 failure rate from the curve. This would result in a weighted probability average of over a 2 gpm leak with very little HPCI run time before the auxiliary oil pumps would cavitate and continue to run with no suction with potential damage. This further

supports the assumption of no recovery credit. Additionally, there is no warning or cue for a low level in the HPCI oil sump, and the only alarm available for low pressure off the thrust bearing, would likely not alarm due to the main system PCV compensating for the increased leakage.

Early Control Rod Drive credit is appropriate, but Limited due to Available CST Water Volume.

As noted, early control rod drive was credited for events where 2 control rod drive pumps were available and procedures directed a 2nd pump start. However, this would only mitigate loss of HPCI/RCIC once decay heat was low enough for control rod drive to accommodate. This was not in the SPAR model and the analysts incorporated this by using a surrogate change for RCIC and HPCI fail to run events, reducing their failure rate. This takes the SPAR model 0.11 FTR rate for HPCI and RCIC and changes it to 3E-2. It is very uncertain that existing procedures would keep up with the ability to ensure the control rod drive suction is not uncovered given the available volume (122,000 gallons for control rod drive use) with it being depleted as the event initiates and some of the existing makeup methods being affected during certain events.

The CST water volume mean value was stated to be 320,000 gallons within the Fitzpatrick JF-PRA-004, human reliability analysis notebook. This was referenced for a basic event CST-XHE-FO-MINFL. There is 200,000 gallons within the CST that is reserved for HPCI and RCIC operation, therefore 120,000 gallons remains above the standpoint for control rod drive use. It is estimated that this would provide for a nominal 7 hours of control rod drive operation with normal events only requiring for decay heat makeup. Additionally, if Exelon would operate the HPCI system in the minimum flow mode during batch feed operations as portions of their evaluation suggest they would be losing up to 500 to 700 gpm from the CST to the torus, further depleting this available volume. Therefore, using control rod drive credit may not be conservative within this evaluation. The mission time is 24 hours, so there is additional uncertainty with crediting control rod drive early as the CST would require makeup actions. The operators would have to prioritize this action even though HPCI and RCIC would have adequate CST capacity for close to 20 hours.

Exposure Time Uncertainty

It is uncertain what the plant response would be (e.g., containment parameters for many events such as loss of the ‘A’ DC bus or ‘A’ AC bus), where only one RHR loop would be available or one pump for torus cooling. This includes LOOP events and events where it is uncertain how fast DW pressure may increase or if it will increase to 2.7 psig, which would not allow for running HPCI at normal flowrates in pressure control. This creates a challenge as HPCI is oversized for many of the risk impactful events that involve simple high pressure injection. This may result in having to run HPCI on minimum flow, which is not in accordance with vendor guidance due to severe cavitation warnings. It would also pump CST water into the torus, so a batch mode of operation may become necessary. This would require numerous starts and stops of the HPCI pump and would extend the actual exposure time past the 38 days assumed for almost all the evaluated events. Therefore the 38-day exposure time could tend to underestimate the risk of this issue as cycling of the PCV was the causal factor relative to its failure, and the associated failure of the HPCI system.

Lastly, there is uncertainty with the causal evaluation itself. It is not unreasonable to expect that normal HPCI operation would degrade the PCV simply through continued pressurization and increased temperature during operation with resonance vibration from the machine creating stress on the defective component. If this was treated as a degradation proportional to run time, the exposure time would be one year, as the HPCI system has not even run for its mission time

since the defective component was installed. For approximately 2.5 years, there was a defective component in a risk significant system which, thus far, has not run for a total of its mission time.

Operator Response to HPCI Operation vs Simulator Training

Based on review of FitzPatrick HPCI surveillance tests and performance, the analysts questioned the overshoot and recovery of HPCI speed and injection flow (ST-4N). Though these were determined to be within surveillance test acceptance requirements, FitzPatrick had documented instances of speed overshoots during the past 4 HPCI starts (IRs 04323766, 4252625, 4266619, 4302887). Review of HPCI flow traces from the plant computer would indicate about approximately a 1000 gpm overshoot for 40 seconds and recovery to setpoint within 2.5 to 3 minutes. Based on discussions with FitzPatrick staff, this response is not modeled in the plant simulator, further increasing the uncertainty of successful operator control without an early trip of HPCI.

Summary and Conclusion

The result of the evaluation is a best estimate assessment of risk given this condition and considering the uncertainties that surround it. The NRC's evaluation is based on reasonable assumptions and has considered the licensee's perspectives, including CRD credit as appropriate. However, key differences remain such as leak rate assumption and ability to recover the system.

In summary, this defective component had less than seventy cycles in-service and was designed for over thousands of cycles. A severely degraded component was installed in a high safety significant system for over two years. The system had not supported a 24-hour runtime since installation of the defective component. The NRC believes the conclusion that a 3 in 1,000,000 increase in CDF/yr (White) is a reasonable preliminary risk estimate for this issue.