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RS-22-116

10 CFR 50.55a

November 1, 2022

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D.C. 20555-0001

Dresden Nuclear Power Station, Units 2 and 3
Renewed Facility Operating License Nos. DPR-19 and DPR-25
NRC Docket Nos. 50-237 and 50-249

Subject: Submittal of Relief Requests Associated with the Sixth Inservice Testing Interval

In accordance with 10 CFR 50.55a, "Codes and standards," Paragraph (z)(1), Constellation Energy Generation, LLC (CEG), hereby requests NRC approval of the attached relief requests associated with the sixth inservice testing (IST) interval for Dresden Nuclear Power Station (DNPS), Units 2 and 3. The sixth interval of the DNPS, Units 2 and 3, IST Program will comply with the American Society of Mechanical Engineers (ASME) Code for Operation and Maintenance of Nuclear Power Plants (i.e., OM Code), 2017 Edition without addenda as required by 10 CFR 50.55a(f)(4)(ii).

CEG requests approval of the attached requests by November 1, 2023, to support implementation of the sixth 10-year IST interval which is currently scheduled to begin November 1, 2023.

There are no regulatory commitments contained within this letter. Should you have any questions concerning this letter, please contact Mr. Mitchel A. Mathews at (630) 657-2819.

Respectfully,

Patrick R. Simpson
Sr. Manager – Licensing
Constellation Energy Generation, LLC

Attachments:
1. 10 CFR 50.55a Request Number RV-02D
2. 10 CFR 50.55a Request Number RV-03
3. 10 CFR 50.55a Request Number RV-23H

ATTACHMENT 1
10 CFR 50.55a Relief Request RV-02D
Proposed Alternative in Accordance with 10 CFR 50.55a(z)(1)
-Alternative Provides Acceptable Level of Quality and Safety-

1. American Society of Mechanical Engineers (ASME) Code Components Affected

Component Number	System	Code Class	Category
2-0203-3A	Main Steam	1	C
3-0203-3A	Main Steam	1	C

2. Applicable Code Edition and Addenda

ASME OM Code, *Operation and Maintenance of Nuclear Power Plants*, 2017 Edition. without Addenda

3. Applicable Code Requirement

Division 1, Mandatory Appendix I, Inservice Testing of Pressure Relief Devices in Light-Water Reactor Nuclear Power Plants, paragraph I-1320, *Test Frequencies, Class 1 Pressure Relief Valves*, subparagraph (a) *5-Yr Test Interval*, which states:

"Class 1 pressure relief valves shall be tested at least once every 5 yr, starting with initial electric power generation. No maximum limit is specified for the number of valves to be tested within each interval; however, a minimum of 20% of the valves from each valve group shall be tested within any 24-month interval. This 20% shall consist of valves that have not been tested during the current 5-yr interval, if they exist. The test interval for any installed valve shall not exceed 5 yr. The 5-yr test interval shall begin from the date of the as-left set-pressure test for each valve."

4. Reason for Request

Pursuant to 10 CFR 50.55a, *Codes and standards*, paragraph (z)(1), Constellation Energy Generation, LLC (CEG) proposes an alternative to the requirement of ASME OM Code Mandatory Appendix I, subparagraph I-1320(a) for Dresden Nuclear Power Station (DNPS), Units 2 and 3. The basis of this request is that a Main Steam Relief/Safety Valve (MSRV) set pressure performance assessment supports that the proposed alternative would provide an acceptable level of quality and safety.

At DNPS, Units 2 and 3, there is a single Target Rock 3-Stage, Model 67F MSRV installed on each unit's main steam lines inside the Drywell. This valve is classified into the same Inservice Test (IST) program valve group (i.e., group of one on a unit). Per the requirements of ASME OM Code, Mandatory Appendix I, Subparagraph I-1320(a), this valve is assigned a five-year testing interval and is required to be tested every outage in order to comply with the additional requirements that a minimum of 20% of the valves in each group are tested every 24 months. DNPS, Units 2 and 3 are currently operating on 24-month refueling cycles. The DNPS, Units 2 and 3 MSRVs have continued to show reliable set pressure test performance as described in Section 5 below.

A performance assessment of the DNPS Units 2 and 3 Target Rock MSRVs concluded that there is reasonable assurance that each MSRV will retain the set pressure within the required drift tolerances after extending the test interval from the 24-month interval to

4. Reason for Request (Cont.)

a proposed 48-month interval. Extending the MSRV test interval from 24 to 48 months will permit testing the MSRV every other refueling outage and a corresponding reduction in occupational radiological dose incurred during the MSRV removal, testing and re-installation maintenance activities.

5. Proposed Alternative and Basis for Use

CEG proposes that the ASME OM Code, Mandatory Appendix I, subparagraph I-1320(a) minimum testing interval for the group of one MSRVs be extended from 24-months to 48-months.

At DNPS, Units 2 and 3, CEG implemented an SRV Best Practices Maintenance program in 2010 and incorporated several enhancements since implementation that resulted in improved MSRV set point drift performance. Improvements to this program have continued to further increase the MSRV reliability.

The SRV Best Practices Maintenance program is comprised of methods and philosophies concerning maintenance, inspection and techniques which uses the valve manufacturer's recommended maintenance practices and enhancements identified by CEG that have been broadly termed "Best Practices". CEG MSRV Best Practices are developed from the application of the EPRI/NMAC Safety and Relief Valve Testing and Maintenance Guide (Reference 1) and from CEG Operational Experience (OE). The CEG MSRV Best Practices have been implemented through CEG's oversight of the valve vendor's test and rebuild processes. Major program elements include specific performance and inspection criteria and maintenance steps that exceed Original Equipment Manufacturer (OEM) specifications and/or Industry established guidelines. The main program elements include 1) Spring Testing, 2) Lapping Techniques and Tools, 3) Set Pressure Adjustment Methodology Precision, and 4) Average Delay Time (ADT) trending, and 5) Internal Component Condition Variations. Collectively, use of these elements has supported a trend in improved setpoint retention of SRVs in service at DNPS.

An SRV Best Practices Fleet Engineering program document has been established to provide governance over the CEG-approved vendor SRV maintenance procedures, to define the program elements, and to establish performance tracking and trending guidelines. This program document and the CEG-approved vendor procedures are updated to incorporate advances in technology and operating experience from the CEG fleet, the OEM and the industry. Major elements of the program are further described below:

<u>Spring Testing</u>

Spring testing is performed periodically based on valve type. The SRV Best Practices Maintenance program requires the spring characteristics meet physical dimension requirements that are tighter than previous acceptance criteria based on CEG operating experience. This has minimized spring compression rate variations.

5. Proposed Alternative and Basis for Use (Cont.)

Lapping Techniques and Tools

The lapping technique includes multiple lapping passes that develops tighter tolerances using an CEG designed lapping tool based on CEG operating experience. The SRV Best Practices Maintenance program requires this additional lapping to meet the tighter seat leakage tightness criteria. This technique has minimized variation of the seat-to-disk surfaces.

Set Pressure Adjustment Methodology Precision

The SRV set pressure adjustment process includes a spring adjustment factor methodology for the first set pressure adjustment. The SRV Best Practices Maintenance program document includes a calculated spring adjustment factor based on the SRV set pressure adjustment during the pre-certification testing and CEG operating experience. A more accurate set pressure adjustment is obtained with fewer lifts and will minimize introducing variations of the seat-to-disk surfaces.

Average Delay Time Trending

For the Target Rock 3-Stage SRVs, the ADT measures the time between the pilot valve opening and the main disk opening. The SRV Best Practices Maintenance program has trended the ADTs for the Target Rock 3-Stage SRVs for determining if additional maintenance should be performed. The program includes a tighter tolerance than the industry standard criteria for ADT. An SRV with an ADT value outside this criterion is further evaluated for additional maintenance prior to installation.

Internal Component Condition Variations

The SRV inspection and maintenance processes include additional inspections for internal components with criteria that are more restrictive than previous acceptance criteria based on CEG operating experience. Specifically for the Target Rock 3-Stage SRVs, tighter tolerances are applied to the pilot abutment and preload gaps which reduce the likelihood of vibration-induced seat leakage caused by pressure transients.

Moreover, CEG incorporates industry operating experience into our Best Practices Program.

5. Proposed Alternative and Basis for Use (Cont.)

CEG Best Practices guidance is contained in Procedure ER-AA-400-1000, "Safety & Relief Valve (SRV) Testing, Tracking, and Trending." Within this governance the corporate safety relief valve (SRV) Program Engineer is assigned the following responsibilities:

- Develop, implement, and update the SRV program (3.1.1)
- Maintain awareness of industry SRV issues (3.1.2)
- Identify and investigate opportunities for program improvements (3.1.5)
- Interface with Electric Power Research Institute (EPRI), Safety Relief Valve Users Group (SRVUG) and Target Rock Users Group (TRUG) (3.1.6)

Additionally, the procedure recommends the applicable site SRV Owner attend the annual SRVUG and TRUG meetings as a means of staying current with industry experience (3.3.12). These practices ensure that the latest industry experience is identified, evaluated and captured, as appropriate, in the Best Practices Program.

CEG recently performed an assessment pertaining to the performance of the DNPS, Units 2 and 3, Target Rock MSRVs. The MSRV set point drift performance of the DNPS, Units 2 and 3, MSRVs has steadily improved due to this enhanced maintenance program. This assessment concluded that there is reasonable assurance that each MSRV will retain the set pressure within the required drift tolerances after extending the test interval from the 24-month interval to a proposed 48-month interval.

This assessment reviewed As-Left/As-Found set pressure data going back to 1998 and identified: 1) Whether the valves' set pressure drifted up or down, and 2) The absolute set pressure change between tests. Based on the time between the As-Left and As-Found set pressure test of each MSRV, the set pressure drift was then linearly extrapolated to determine whether the MSRV's set pressure would still be within the site's required ± 3.0% tolerance following a 48-month period. An evaluation concluded that use of linear extrapolation provides the best mathematical approach.

When an as-found set-pressure test result failure is discovered, the failure will be documented in the CEG Corrective Action Program (CAP) and the requirements of I-1320(c) will be followed. This guidance states in part: The Owner shall evaluate the cause and effect of valves that fail to comply with the set-pressure acceptance criteria. Based upon this evaluation, the Owner shall determine the need for testing in addition to the minimum Code requirements to address any generic concerns that could apply to valves in the same or other valve groups. Actions determined by the evaluation would be taken to address the failure. Returning the valve to a 24-month test frequency may be optionally implemented based on the failure and evaluation but is not required per the Relief Request.

5. Proposed Alternative and Basis for Use (Cont.)

Since 2014, eight DNPS, Units 2 and 3, valves were removed and as-found tested, and, using the linear extrapolation method, seven of the eight valves were projected to have lift set points within the ± 3.0% set pressure tolerance for more than 48-months. Table RV-02D-1 below summarizes the set pressure test performance, in years of service, predicting when each MSRV would exceed the ± 3.0% set pressure tolerance for MSRVs removed and tested since 2014.

An evaluation of the one valve that did not meet the 48-month set point tolerance criteria was performed and the table note provides a summary identifying the cause for the set point drift, how the CEG SRV Best Practices Maintenance program addresses the cause, and the corrective actions performed.

Today's improved valve performance can be attributed to implementation of the SRV Best Practices Maintenance program which requires that all valves be disassembled and inspected prior to As-Left testing and installation. DNPS will continue to disassemble and inspect each subject MSRV following As-Found set pressure testing to verify that parts are free of defects resulting from time-related degradation or service-induced wear. Each valve shall also be disassembled and inspected prior to As-Left testing and installation in accordance with the SRV Best Practices Maintenance program.

Extending the test interval from 24-months to 48-months is viewed as acceptable based upon past performance and a mathematical evaluation which shows that the DNPS Target Rock MSRVs are capable of maintaining their set point within tolerance over a 48-month period. This proposed alternative to the testing requirements will also contribute to the principals of maintaining radiation dose As Low As Reasonably Achievable (ALARA).

Using recent dose measurements associated with DNPS, Units 2 and 3, MSRVs removal and replacement, the average radiological exposure incurred per valve has been 0.52 Rem. Extending the MSRV testing interval from 24 to 48 months would allow extending the schedule of testing of the MSRV on each unit from every refueling outage to every-other refueling outage, potentially providing a reduction of two MSRVs tested every ten years per unit. This can result in a potential radiological exposure savings of approximately 2 Rem for the station over a ten-year IST interval.

Based on the application of the SRV Best Practices Maintenance program, the past performance of the MSRVs at DNPS and a mathematical evaluation of valve performance, there is reasonable assurance that each MSRV will remain within the set point tolerance over the extended 48-month testing interval. This proposal provides an alternative which would maintain an acceptable level of valve operational readiness,

5. Proposed Alternative and Basis for Use (Cont.)

provides an acceptable level of quality and safety pursuant to 10 CFR 50.55a(z)(1) and provides for reduced occupational radiological exposure.

Table RV-02D-1: MSRV Setpoint Performance Projection

Year As-Found Tested	Setpoint Performance Projection in Years
2014	3.0[1]
2015	9.4
2016	112.0
2017	4.0[1]
2018	4.4
2019	6.0
2020	19.6
2021	11.4

Note:

1. This valve was disassembled, inspected and tested in 2011 before being reinstalled in 2012 and was then removed in 2014 and as-found tested. The 2011 maintenance and testing occurred prior the CEG SRV Maintenance Best Practices in 2014. Consequently, the 2014 as-found test results were out of tolerance high. This same valve was then disassembled, inspected and tested in 2014 before being re-installed in 2015 and was then removed in 2017 and as-found tested. The as-found test results in 2014 for this specific valve showed improvement in the setpoint performance projection to just above the 48-month setpoint performance criteria. Several of the DNPS, Units 2 and 3 Target Rock MSRVs demonstrated relatively low setpoint performance as compared to MSRVs across the CEG fleet. This performance was reviewed as part of CEG's evaluation for DNPS. Efforts are continuing to be made towards reducing the effects of vibrational wear on these components at DNPS. The CEG SRV Maintenance Best Practices were completed during the valve refurbishment in 2014 and 2017, and continued improvement in valve performance is expected.

6. Duration of Proposed Alternative

The proposed alternative will be utilized for the entire sixth 120-month IST Program Interval for DNPS, Units 2 and 3, which is currently scheduled to begin on November 1, 2023, and end on October 31, 2033.

7. Precedent

Letter from N. L. Salgado (U. S. Nuclear Regulatory Commission) to Mr. D. P. Rhoades (Exelon Generation Company, LLC), "Clinton Power Station, Unit No. 1; Dresden Nuclear Power Station, Units 2 and 3; Nine Mile Point Nuclear Station, Unit 2; Peach Bottom Atomic Power Station, Units 2 and 3; and Quad Cities Nuclear Power Station, Units 1 and 2 — Proposed Alternatives to Extend the Safety Relief Valve Testing Interval (EPID L-2020-LLR-0014 through -0018)," Enclosure 2, "Safety Evaluation by the Office of Nuclear Reactor Regulation Proposed Alternative RV-02D Regarding Extension of the Safety Relief Valve Testing Interval Exelon Generation Company, LLC Dresden Nuclear Power Station, Units 2 and 3 Docket Nos. 50-237 and 50-249," dated January 14, 2021 (Accession No. ML21005A061)

8. References

Electric Power Research Institute / Nuclear Maintenance Applications Center (EPRI/NMAC) Safety and Relief Valve Testing and Maintenance Guide, Revision of TR-105872, Technical Report 3002005362, August 2015

1. American Society of Mechanical Engineers (ASME) Code Component(s) Affected

Component Number	Valve Type	CIV, PIV, Both	System	Code Class	Category
2(3)-1501-22A-MO	Gate	Both	LPCI	1	A
2(3)-1501-22B-MO	Gate	Both	LPCI	1	A
2(3)-1501-25A	Check	Both	LPCI	1	A/C
2(3)-1501-25B	Check	Both	LPCI	1	A/C
2(3)-1402-9A	Check	PIV	CS	1	A/C
2(3)-1402-9B	Check	PIV	CS	1	A/C
2(3)-1402-25A-MO	Gate	Both	CS	1	A
2(3)-1402-25B-MO	Gate	Both	CS	1	A

2. Applicable Code Edition and Addenda

ASME OM Code, *Operation and Maintenance of Nuclear Power Plants*, 2017 Edition, without Addenda

3. Applicable Code Requirement

ISTC-3630, Leakage Rate for Other Than Containment Isolation Valves, states "Category A valves with a leakage requirement not based on an Owner's 10 CFR 50, Appendix J program, shall be tested to verify their seat leakages within acceptable limits. Valve closure before seat leakage testing shall be by using the valve operator with no additional closing force applied."

ISTC-3630(a), *Frequency*, states, "Tests shall be conducted at least once every 2 yr."

4. Reason for Request

Pursuant to 10 CFR 50.55a, *Codes and standards*, paragraph (z)(1), an alternative is proposed to the testing requirements of ASME OM Code ISTC-3630(a) for the affected components on the basis that the alternative testing would provide an acceptable level of quality and safety.

ISTC-3630(a) requires that leakage rate testing for Pressure Isolation Valves (PIVs) be performed at least once every 2 years. PIVs are not specifically included in the scope for performance-based testing as provided for in 10 CFR 50, Appendix J, "Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors," Option B, "Performance-Based Requirements" (referred to hereafter as Option B). These motor-operated and check valve PIVs are, in some cases, Containment Isolation Valves (CIVs), but are not within the Appendix J scope since the Low Pressure Coolant Injection (LPCI) valves are considered water-sealed and the Core Spray (CS) system is not exposed to containment atmosphere. Table RV-03-1 below provides additional details regarding current and proposed testing requirements and frequencies.

Table RV-03-1: Current and Proposed Testing Requirements for Affected Valves

Component	Current Testing for 5th Interval		Proposed Testing for 6th Interval	
	Test	**Frequency**	**Test**	**Frequency**
MO 2(3)-1501-22A/B	Exercise Closed	Cold Shutdown	Exercise Closed	Once per fuel cycle IAW ASME OM Code, App. III
	Exercise Open		Exercise Open	
	PIV Seat Leakage	Similar to App J, Option B, NEI 94-01 rev 0 - 24 months up to 60 months with 15-month grace based on performance	PIV Seat Leakage	Similar to App J, Option B, NEI 94-01, Rev 3A – 24 months up to 75 months with nine (9)-month grace based on performance
	OMN-1 Diagnostic Test	IAW OMN-1	Diagnostic Test	IAW ASME OM Code Appendix III
	Position Indication Test (PIT)	PIT will be performed as part of Diagnostic Test per OMN-1	PIT	Performed as part of Diagnostic Test per ASME OM Code, Appendix III
2(3)-1501-25A/B	Exercise Open	Refuel	Exercise Open	Refuel
	Exercise Closed		Exercise Closed	
	PIT	2 Yrs	PIT	2 Yrs
	PIV Seat Leakage	Similar to App J, Option B, NEI 94-01, Rev 0 – 24 months up to 60 months with 15-month grace based on performance	PIV Seat Leakage	Similar to App J, Option B, NEI 94-01, Rev 3A - 24 months up to 75 months with nine (9)-month grace based on performance

Component	Current Testing for 5th Interval		Proposed Testing for 6th Interval	
	Test	Frequency	Test	Frequency
MO 2(3)-1402-25A/B	Stroke Time Open	< 24 months (IAW OMN-1)	Exercise Closed	Once per fuel cycle IAW ASME OM Code, App. III
	Stroke Time Closed		Exercise Open	
	PIV Seat Leakage	Similar to App J, Option B - 24 months up to 60 months with 15-month grace based on performance	PIV Seat Leakage	Similar to App J, Option B, NEI 94-01, Rev 3A – 24 months up to 75 months with nine (9)-month grace based on performance
	OMN-1 Diagnostic Test	IAW OMN-1	Diagnostic Test	IAW ASME OM Code, App. III
	PIT	PIT performed as part of Diagnostic Test IAW OMN-1	PIT	Performed as part of Diagnostic Test per ASME OM Code, Appendix III
2(3)-1402-9A/B	Exercise Open	Cold Shutdown	Exercise Open	IAW Condition Monitoring Plan
	Exercise Closed	IAW Condition Monitoring Plan	Exercise Closed	IAW Condition Monitoring Plan
	PIV Seat Leakage	Similar to App J, Option B - 24 months up to 60 months with 15-month grace based on performance	PIV Seat Leakage	Similar to App J, Option B, NEI 94-01, Rev 3A – 24 months up to 75 months with nine (9)-month grace based on performance

4. Reason for Request (Cont.)

Dresden Nuclear Power Station (DNPS), Units 2 and 3 Technical Specification (TS) 5.5.12, "Primary Containment Leakage Rate Testing Program," states, in part:

> *This program shall establish the leakage testing of the primary containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B, as modified by approved exemptions. This program shall be in accordance with the guidelines contained in NEI 94-01, "Industry Guideline for Implementing Performance-Based Option of 10 CFR 50, Appendix J," Revision 3-A, dated July 2012, and the conditions and limitations specified in NEI 94-01, Revision 2-A, dated October 2008. . . .*

Sections 10.1 and 11.3 of NEI 94-01 allow an extension of up to 25 percent of the test interval (not to exceed 9 months).

The concept behind the Option B alternative for CIVs is that licensees should be allowed to adopt cost effective methods for complying with regulatory requirements. Additionally, NEI 94-01 describes the risk-informed basis for the extended test intervals under Option B. That justification shows that valves, which have demonstrated good performance by the successful completion of two consecutive leak rate tests for two consecutive cycles may increase their test frequencies. Furthermore, it states that if the component does not fail within two operating cycles, further failures appear to be governed by the random failure rate of the component. NEI 94-01 also presents the results of a comprehensive risk analysis, including the statement that "the risk impact associated with increasing [leak rate] test intervals are negligible (less than 0.1 % of total risk)."

The valves identified in this request are installed in water applications. The PIV testing is performed with water pressurized to pressures lower than function maximum pressure differential. However, the observed leakage is adjusted to the function maximum pressure differential value in accordance with ISTC-3630(b), *Differential Test Pressure*, item (4).

This request is intended to provide for performance-based scheduling of PIV tests at DNPS. The reason for proposing this alternative request is dose reduction in keeping with industry As Low As Reasonably Achievable (ALARA) radiation dose principles. Recent historical data was used to identify that PIV testing alone incurs a total dose of approximately 600 millirem each refueling outage. Assuming the affected PIVs continue to remain classified as good performers, the extended test intervals would provide for a savings of approximately 1.2 Rem over a 4-1/2-year period (i.e., a bounding timeframe encompassing two refueling outages). In addition, this request aids the station in the implementation of a division-based outage schedule.

NUREG 0933, "Resolution of Generic Safety Issues," Issue 105, "Interfacing Systems LOCA at LWRs," discussed the need for PIV leak rate testing based primarily on three pre-1980 historical failures of applicable valves industry-wide. These failures all

4. Reason for Request (cont.)

involved human errors in either operations or maintenance. None of these failures involved inservice equipment degradation. The performance of PIV leak rate testing provides assurance of acceptable seat leakage with the valve in a closed condition.

ISTC-3520, "Exercising Requirements." Power-operated valves are routinely full stroke tested in accordance with the ASME OM Code to ensure their functional capabilities.

Typical PIV testing does not identify functional problems, which may inhibit the valve's ability to reposition from open to closed. For check valves, such functional testing is accomplished in accordance with ASME OM Code Paragraphs ISTC-3522, "Category C Check Valves," and

The functional testing of certain PIV check valves is monitored through a Condition Monitoring Plan in accordance with ISTC-5222, "Condition-Monitoring Program," and Mandatory Appendix II, "Check Valve Condition Monitoring Program." Performance of the separate two (2)-year PIV leak rate testing does not contribute any additional assurance of functional capability; it only determines the seat tightness of the closed valves.

The functional capability of check valves 2(3)-1501-25A/B is demonstrated by the opening and closing of the valves each refuel outage using internal magnetic position indication, which is directly coupled to the valve disc and is completely enclosed. This test is separate and distinct from the PIV testing; therefore, there is no need for a Condition Monitoring Plan for these valves.

The functional capability of the 2(3)-1402-9A/B check valves is verified through periodic testing. The valves open function is verified by mechanically exercising the valve open. The frequency is one division each refuel outage in accordance with the Check Valve Condition Monitoring Plan. The close function is verified during the performance of the PIV seat leakage pressure test where valve closure function is verified by the capability to build pressure against the valve disc. The intent of the Condition Monitoring Plan is solely to align the open and close test frequencies to the same frequency as the PIV seat leakage pressure test. It is not intended to extend check valve testing to once every 10 years by means of a Condition Monitoring Plan. By use of a Condition Monitoring Plan, the check valve closure and opening test, based on performance, would be verified concurrently with the PIV seat leakage test.

At DNPS, the functional tests for motor-operated PIVs are performed on a two-year frequency in accordance with Division 1, Mandatory Appendix III, "Preservice and Inservice Testing of Active Electric Motor-Operated Valve Assemblies in Water-Cooled Reactor Nuclear Power Plants."

The above tests provide reasonable assurance of the valves' operational readiness.

5. Proposed Alternative and Basis for Use

DNPS proposes to perform PIV testing at intervals ranging from every refueling outage to every third refueling outage. The specific interval for each valve would be a function of its performance and would be established in a manner consistent with the CIV process under Option B. A conservative control will be established such that if any valve fails its PIV test, the test interval will be reduced consistent with Option B requirements until good performance is re-established.

The primary basis for this proposed alternative is the historically good performance of the PIVs. Tables 1 through 4 in Enclosure RV-03-1 present test data that demonstrate acceptable historical PIV performance for the LPCI and CS systems.

The extension of test frequencies will be consistent with the guidance provided for Appendix J, Type C leak rate tests as detailed in paragraph 10.2.3.2, "Extended Test Interval," of NEI 94-01, which states:

> *Test intervals for Type C valves may be increased based upon completion of two consecutive periodic as-found Type C tests where the result of each test is within a licensee's allowable administrative limits. Elapsed time between the first and last tests in a series of consecutive passing tests used to determine performance shall be 24 months or the nominal test interval (e.g., refueling cycle) for the valve prior to implementing Option B to Appendix J. Intervals for Type C testing may be increased to a specific value in a range of frequencies from 30 months up to a maximum of 75 months. Test intervals for Type C valves should be determined by a licensee in accordance with Section 11.0* [of NEI 94-01].

Note that NEI 94-01 is not the sole basis for this request given NEI 94-01 does not address seat leakage testing with water. This document was cited as an approach similar to the requested alternative method.

5. Proposed Alternative and Basis for Use (Cont.)

Additional basis for this request is provided below:

- Separate functional testing of MOV PIVs and Condition Monitoring of Check Valve PIVs per ASME OM Code.

- Low likelihood of valve mispositioning during power operations (e.g., procedures, interlocks).

- Relief valves in the low pressure (LP) piping – these relief valves may not provide Inner-System Loss of Coolant Accident (ISLOCA) mitigation for inadvertent PIV mispositioning but their relief capacity can accommodate conservative PIV seat leakage rates.

- Alarms that identify high pressure (HP) to LP leakage – Operators are highly trained to recognize symptoms of a present or incipient ISLOCA and to take appropriate actions.

Therefore, the proposed alternative to perform PIV testing at the specified intervals will continue to provide assurance of the PIVs' operational readiness and provides an acceptable level of quality and safety pursuant to 10 CFR 50.55a(z)(1).

6. Duration of Proposed Alternative

The proposed alternative will be utilized for the entire Sixth 120-month IST Program Interval, which is scheduled to begin on November 1, 2023, and end on October 31, 2033.

7. Precedents

1. Letter from R. J. Pascarelli (Nuclear Regulatory Commission) to J. M. Davis (Detroit Edison), "Fermi 2 – Evaluation of In-Service Testing Program Relief Requests VRR-011, VRR-012, and VRR-013 (TAC Nos. ME2558, ME2557, and ME2556)," dated September 28, 2010 (ML102360570).

2. Letter from J. Wiebe (Nuclear Regulatory Commission) to M. J. Pacilio (Exelon Nuclear), "Quad Cities Nuclear Power Station, Units 1 and 2 – Safety Evaluation in Support of Request for Relief Associated with the Fifth 10 Year Interval Inservice Testing Program (TAC Nos. ME7981, ME7982, ME7983, ME7984, ME7985, ME7986, ME7987, ME7988, ME7990, ME7991, ME7992, ME7993, ME7994, and ME7995)," dated February 14, 2013 (ML13042A348)

3. Letter from T. L. Tate (Nuclear Regulatory Commission) to B. Hanson (Exelon Generation, LLC), "Dresden Nuclear Power Station, Units 2 and 3 – Relief Request to Use an Alternative from the American Society of Mechanical Engineers Code Requirements (CAC Nos. MF5089 and MF5090)," dated October 27, 2015 (ML15174A303)

4. Letter from D. A. Broaddus (Nuclear Regulatory Commission) to B. Hanson (Exelon Generation, LLC), "Peach Bottom Atomic Power Station, Units 2 and 3 – Safety Evaluation of Relief Request GVRR-2 Regarding the Fourth 10-Year Interval of the Inservice Testing Program (CAC Nos. MF7630 and MF7631)," dated September 21, 2016 (ML16235A340)

5. Letter from J. G. Danna (Nuclear Regulatory Commission) to B. Hanson (Exelon Generation, LLC), "Nine Mile Point Nuclear Station, Units 1 and 2 – Re: Alternative to the Requirements of the American Society of Mechanical Engineers Code for Operation and Maintenance of Nuclear Power Plants (CAC Nos. MF9073 and MF9074)," dated May 30, 2017 (ML17136A112)

6. Letter from J. G. Danna (Nuclear Regulatory Commission) to B. Hanson (Exelon Generation, LLC), "Limerick Generating Station, Units 1 and 2 – Proposed Relief Request GVRR-8 Regarding Inservice Testing Program Third 10-Year Interval (CAC Nos. MF8787 and MF8788)," dated February 7, 2017 (ML17004A063)

7. Letter from L. M. Regner (Nuclear Regulatory Commission) to B. Hanson (Exelon Generation, LLC), "Lasalle County Station, Units 1 and 2 – Request from the Requirements of the ASME Code Related to Pressure Isolation Valve Testing Frequency (EPID L-2019-LLR-0062)," dated September 10, 2019 (ML19217A306)

8. Letter from J. G. Danna (Nuclear Regulatory Commission) to B. Hanson (Exelon Generation, LLC), "Limerick Generating Station, Units 1 and 2 – Safety Evaluation of Relief Requests GVRR-8, 11-PRR-1, 90-PRR-1 and 47-VRR-2 Regarding the Fourth 10-Year Interval of the Inservice Testing Program (EPID L-2018-LLR-0384, EPID L-2018-LLR-0385, EPID L-2018-LLR-0386, and EPID L-2018-LLR-0387)," dated October 28, 2019 (ML19228A195)

ENCLOSURE RV-03-1 - Leakage History of DNPS, Units 2 and 3 PIVs -

Tables 1 through 4 below summarize the leakage history for the DNPS, Units 2 and 3 LPCI and CS systems PIVs for a minimum of the last 10 years.

Table 1: LPCI Suction PIVs

Valve Number	Test Date	Measured Value (gpm)	Required Action Limit (gpm)	Comments
2-1501-22A-MO	11/18/2009	< 1	5	
2-1501-22A-MO	10/31/2011	< 1	5	
2-1501-22A-MO	11/20/2013	< 1	5	
2-1501-22A-MO	11/8/2015	< 1	5	
2-1501-22A-MO	10/29/2019	< 1	5	
2-1501-22B-MO	11/11/2009	< 1	5	
2-1501-22B-MO	10/31/2011	< 1	5	
2-1501-22B-MO	11/16/2013	< 1	5	
2-1501-22B-MO	11/3/2017	< 1	5	
2-1501-22B-MO	11/11/2021	< 1	5	
3-1501-22A-MO	11/8/2008	< 1	5	
3-1501-22A-MO	11/17/2010	< 1	5	
3-1501-22A-MO	11/26/2012	< 1	5	
3-1501-22A-MO	11/12/2014	< 1	5	
3-1501-22A-MO	11/16/2016	< 1	5	
3-1501-22A-MO	10/27/2020	< 1	5	
3-1501-22B-MO	11/10/2008	< 1	5	
3-1501-22B-MO	11/9/2010	< 1	5	
3-1501-22B-MO	11/12/2012	< 1	5	
3-1501-22B-MO	11/11/2014	< 1	5	
3-1501-22B-MO	11/05/2018	< 1	5	

ENCLOSURE RV-03-1 - Leakage History of DNPS, Units 2 and 3 PIVs -

Table 2: LPCI PIV Check Valves				
Valve Number	Test Date	Measured Value (gpm)	Required Action Limit (gpm)	Comments
2-1501-25A	11/18/2009	< 1	5	
2-1501-25A	11/1/2011	< 1	5	
2-1501-25A	11/27/2013	< 1	5	
2-1501-25A	11/9/2015	< 1	5	
2-1501-25A	10/29/2019	< 1	5	
2-1501-25B	11/11/2009	< 1	5	
2-1501-25B	10/31/2011	< 1	5	
2-1501-25B	11/16/2013	< 1	5	
2-1501-25B	11/5/2017	< 1	5	
2-1501-25B	11/11/2021	< 1	5	
3-1501-25A	11/8/2008	< 1	5	
3-1501-25A	11/17/2010	< 1	5	
3-1501-25A	11/26/2012	< 1	5	
3-1501-25A	11/12/2014	< 1	5	
3-1501-25A	11/05/2016	< 1	5	
3-1501-25A	10/27/2020	< 1	5	
3-1501-25B	11/10/2008	< 1	5	
3-1501-25B	11/9/2010	< 1	5	
3-1501-25B	11/25/2012	< 1	5	
3-1501-25B	11/09/2014	< 1	5	
3-1501-25B	11/05/2018	< 1	5	

ENCLOSURE RV-03-1 - Leakage History of DNPS, Units 2 and 3 PIVs -

Table 3: Core Spray Injection PIVs				
Valve Number	Test Date	Measured Value (gpm)	Required Action Limit (gpm)	Comments
2-1402-25A-MO	11/12/2009	< 1	5	
2-1402-25A-MO	10/26/2011	< 1	5	
2-1402-25A-MO	11/20/2013	< 1	5	
2-1402-25A-MO	11/12/2015	< 1	5	
2-1402-25A-MO	10/28/2019	< 1	5	
2-1402-25B-MO	11/11/2009	< 1	5	
2-1402-25B-MO	10/31/2011	< 1	5	
2-1402-25B-MO	11/16/2013	< 1	5	
2-1402-25B-MO	11/03/2017	< 1	5	
2-1402-25B-MO	11/08/2021	< 1	5	
3-1402-25A-MO	11/11/2008	< 1	5	
3-1402-25A-MO	11/19/2010	< 1	5	
3-1402-25A-MO	11/26/2012	< 1	5	
3-1402-25A-MO	11/07/2014	< 1	5	
3-1402-25A-MO	10/31/2016	< 1	5	
3-1402-25A-MO	10/26/2020	< 1	5	
3-1402-25B-MO	11/10/2008	< 1	5	
3-1402-25B-MO	11/15/2010	< 1	5	
3-1402-25B-MO	11/25/2012	< 1	5	
3-1402-25B-MO	11/04/2014	< 1	5	
3-1402-25B-MO	10/29/2018	< 1	5	

ENCLOSURE RV-03-1 - Leakage History of DNPS, Units 2 and 3 PIVs -

Table 4: Core Spray PIV Check Valves				
Valve Number	**Test Date**	**Measured Value (gpm)**	**Required Action Limit (gpm)**	**Comments**
2-1402-9A	11/10/2009	< 1	5	
2-1402-9A	10/23/2011	< 1	5	
2-1402-9A	11/19/2013	< 1	5	
2-1402-9A*	11/13/2015	< 1	5	
2-1402-9A	10/30/2017	< 1	5	
2-1402-9A	11/19/2019	< 1	5	
2-1402-9B	11/10/2009	< 1	5	
2-1402-9B	10/27/2011	< 1	5	
2-1402-9B	11/14/2013	< 1	5	
2-1402-9B	1103/2017	< 1	5	
2-1402-9B	11/08/2021	< 1	5	
3-1402-9A	11/8/2008	< 1	5	
3-1402-9A	11/20/2010	< 1	5	
3-1402-9A	11/14/2012	< 1	5	
3-1402-9A	11/07/2014	< 1	5	
3-1402-9A	10/31/2016	< 1	5	
3-1402-9A	10/26/2020	< 1	5	
3-1402-9B	11/19/2008	< 1	5	
3-1402-9B	11/12/2010	< 1	5	
3-1402-9B	11/20/2012	< 1	5	
3-1402-9B	11/07/2014	< 1	5	
3-1402-9B	10/29/2018	< 1	5	

* As Left result used - no As Found test performed

ATTACHMENT 3
10 CFR 50.55a Relief Request RV-23H
Proposed Alternative in Accordance with 10 CFR 50.55a(z)(1)
-Alternative Provides an Acceptable Level of Quality and Safety-

1. American Society of Mechanical Engineers (ASME) Code Components Affected

Component Number	System	Code Class	Category
2-2301-32	HPCI	2	B
3-2301-32	HPCI	2	B

2. Applicable Code Edition and Addenda

ASME OM Code, *Operation and Maintenance of Nuclear Power Plants*, 2017 Edition, without Addenda

3. Applicable Code Requirement

ISTC-3300, *Reference Values*, states, in part, "Reference values shall be determined from the results of preservice testing or from the results of inservice testing."

ISTC-3310, *Effects of Valve Repair, Replacement, or Maintenance on Reference Values*, states, in part, "When a valve or its control system has been replaced, repaired, or has undergone maintenance that could affect the valve's performance, a new reference value shall be determined or the previous value reconfirmed ... "

ISTC-3500, "Valve Testing Requirements," states, "Active and passive valves in the categories defined in ISTC- 1300 shall be tested in accordance with the paragraphs specified in Table ISTC-3500- 1 and the applicable requirements of ISTC-5100 and ISTC-5200."

ISTC-3560, *Fail-Safe Valves*, states, in part, "Valves with fail-safe actuators shall be tested by observing the operation of the actuator upon loss of valve actuating power in accordance with the exercising frequency of ISTC-3510."

ISTC-5151, *Valve Stroke Testing*, states, in part:

"*(a)* Active valves shall have their stroke times measured when exercised in accordance with ISTC-3500.

(b) The limiting value(s) of full-stroke time of each valve shall be specified by the Owner.

(c) Stroke time shall be measured to at least the nearest second."

ISTC-5152, *Stroke Test Acceptance Criteria*, states, in part, "Test results shall be compared to reference values established in accordance with para. ISTC-3300, ISTC-3310, or ISTC-3320."

ISTC-5153, *Stroke Test Corrective Action,* subparagraph (b) states, "Valves with measured stroke times that do not meet the acceptance criteria of para. ISTC-5152 shall be immediately retested or declared inoperable. If the valve is retested and the second set of data also does not meet the acceptance criteria, the data shall be analyzed within 96 hours to verify that the new stroke time represents acceptable valve operation, or the valve shall be declared inoperable. If the second set of data meets the acceptance criteria, the cause of the initial deviation shall be analyzed and the results documented in the record of tests."

4. Reason for Request

Pursuant to 10 CFR 50.55a, Codes and standards, paragraph (z)(1), Dresden Nuclear Power Station (DNPS) proposes an alternative to the requirements of the ASME OM Code subsection ISTC-5150 for the subject valves. The basis of this request is that the proposed alternative discussed below provides an adequate level of quality and safety.

These valves function as a backup to the exhaust line drain pot steam trap. During normal operation of the turbine using high quality steam, the drain path from the drain pot to the torus via the steam trap is adequate to remove condensate from the turbine exhaust line. However, during turbine operation with low pressure and low quality steam (which is seen during HPCI surveillance testing during plant startup and as would be expected during HPCI operation during a small break LOCA), condensate collects in the drain pot faster than it can be drained through the trap. Under these conditions, valve 2301-32 opens automatically to drain to the gland seal condenser upon receipt of a signal from a drain pot level switch when the drain pot level reaches the high level alarm setpoint. A high level condition sounds an alarm in the control room.

These valves are equipped with hand switches to enable remote manual operation from the control room; however, they are not equipped with remote position indicating lights, and the valves are totally enclosed, so valve position cannot be verified by direct observation. Valve actuation may be indirectly verified by isolating the HPCI Drain Pot Bypass valve (i.e., 2(3) 2302-32) from the HPCI system, filling the drain pot with water until the high level alarm is received, and observing that the high level alarm clears. The time for the alarm to clear would depend primarily on variables such as the rate of filling and the level of the drain pot when the filling is secured. The steam line drain pot is not equipped with direct level indication; therefore, the time required for the alarm to clear may vary significantly and stroke timing of valve 2301-32 cannot be verified by operation of the hand switch.

Compliance with the quarterly stroke timing and fail-safe requirements of the Code would require either system modifications to replace these valves with ones of testable design, or to purchase non-intrusive test equipment and develop new test methods and procedures.

In order to perform stroke timing of these valves, a design change would have to be implemented. The modification would include: (1) changing the valve design to include position limit switches, (2) routing light indication cabling from the plant through containment boundaries to the control room, and (3) installing position indication lights in the main control room panels. It is estimated that this modification would cost in excess of $300,000 per unit. This remote valve indication would be installed solely for meeting the ASME OM Code requirements and would serve no other operational purpose

Therefore, stroke timing these valves in accordance with Code requirements represents a hardship or unusual difficulty without a compensating increase in the level of quality or safety.

5. Proposed Alternative and Basis for Use

A functional verification test will be conducted on the drain pot level limit switches and the associated control room annunciators at least once every 2 years. Valve actuation will be indirectly verified by removing the HPCI system from service, filling the drain pot with water until the high-level alarm is received, and observing a positive draining of the HPCI drain pot as indicated by a level increase in gland seal condenser and the high-level alarm clearing.

The following provisions of ISTC-5153, *Stroke Test Corrective Action* still apply:

- If a valve fails to exhibit the required change of obturator position, the valve shall be immediately declared inoperable.
- Valves declared inoperable may be repaired, replaced, or the data may be analyzed to determine the cause of the deviation and the valve shown to be operating acceptably.
- Valve operability based upon analysis shall have the results of the analysis recorded in the record of tests (see ISTC-9120).
- Before returning a repaired or replacement valve to service, a test demonstrating satisfactory operation shall be performed.

Additionally, maintenance activities have been instituted to compensate for testing deficiencies. The valves are currently scheduled for replacement every third cycle (six (6) years) in addition to the above testing.

Basis for Use

Failure of these valves to perform their safety function would be indicated by a drain pot high level alarm during operation with low pressure steam. Additionally, condensate entrapped in the steam would cause significant fluctuations in exhaust steam header pressure. These two conditions provide indications that the solenoid valve did not perform as expected in order to prompt investigation and potential corrective actions. Functional tests are conducted on the drain pot level alarm switches at least once each cycle to verify their operability.

These valves will be exercised biennially using the hand switch. They will also be functionally tested biennially. During the test valve 2(3)-2301-32 actuation will be verified by the receipt of the "HPCI TURBINE EXH DRAIN POT HIGH LEVEL" alarm (i.e., water level increase) and reset (i.e., water level decrease due to the open exercise of valves 2(3)-2301-32). During this test, the valve solenoid is also verified to actuate (i.e., valve solenoid is magnetized) by use of a test probe. This testing approach provides reasonable assurance that the valves are functioning as required.

5. Proposed Alternative and Basis for Use (cont.)

If the HPCI Drain Pot Steam Trap (i.e., 2(3) 2301-2) fails, then the HPCI Drain Pot Bypass valve (i.e., 2(3) 2301-32) would receive a signal to open. If both 2(3)-2301-2 and 2(3)-2301-32 fail to open, then the exhaust drain pot could begin to fill, resulting in an exhaust diaphragm rupture and turbine blade and exhaust line check valve damage. Operator actions are currently in place in accordance with DNPS Procedure DAN 902(3)-3 C-11 to trip the HPCI turbine if the HPCI system is being tested. If the alarm occurs during the emergency use of HPCI system, then manual trap bypass valve, 2(3)-2301-50, is opened.

Because exercising of these valves without stroke timing provides no measure of valve degradation, maintenance activities have been instituted to compensate for testing deficiencies. Following discussions with the manufacturer regarding valve design and application, it was decided to replace these valves every third operating cycle.

A review of the Corrective Action Program, work history, and the Inservice Testing (IST) history of these valves did not identify any cases of these valves failing to stroke-open for the past twenty years.

The station currently has a preventive maintenance activity to replace these valves once every six (6) years. This activity was last performed on March 3, 2020, on Unit 2, and March 23, 2015, on Unit 3, and no defects were noted.

Using the provisions of this request (i.e., quarterly exercising and semi-annual functional testing combined with the enhanced maintenance activities) as an alternative to the specific requirements of ISTC-5150 identified above will provide adequate indication of valve performance and continue to provide an acceptable level of quality and safety. Therefore, pursuant to 10 CFR 50.55a(z)(1) Constellation Energy Generation, LLC requests approval of the alternative to the specific ISTC requirements identified in this request.

6. Duration of Proposed Alternative

The proposed alternative will be utilized for the entire sixth 120-month IST Program interval, which is currently scheduled to begin on November 1, 2023, and end on October 31, 2033.

7. Precedent

This relief request (RV-23H) was previously authorized for DNPS, Units 2 and 3 for the fifth 120-month IST interval by NRC Safety Evaluation (SE), dated October 31, 2013. (NRC Accession No. ML13297A515)