This report provides the results the Accident Sequence Precursor Program for 2024. In addition, trends and key insights are provided for the past 10 years (2015 through 2024).

U.S. Nuclear Regulatory Commission Accident Sequence Precursor Program 2024 Annual Report

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1. 2024 ASP RESULTS

There were 165 licensee event reports (LERs) issued in calendar year (CY) 2024. From these LERs, 141 (85%) were screened out in the initial screening process and 24 events were selected and analyzed as potential precursors. Although there was an increase in the overall number of LERs and potential precursors in CY 2024, the numbers remain close to historical lows. Figure 1 provides a breakdown of the number of LERs reviewed by the Accident Sequence Precursor (ASP) Program since the switch was made to review LERs issued on a CY basis in 2016.

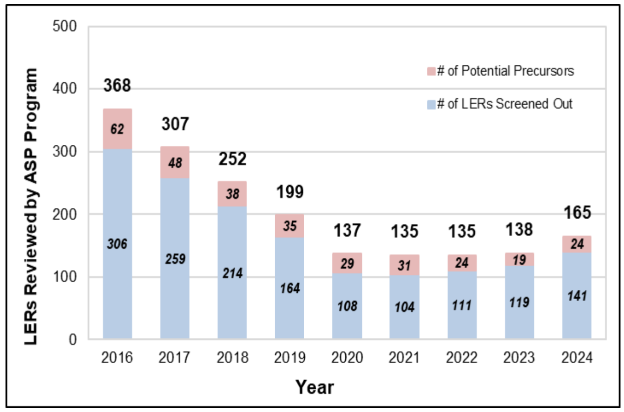

Figure 1. Breakdown of LERs Reviewed by ASP Program Since 2016

Of the 24 potential precursors identified via the LER screening, nine events were determined to exceed the ASP Program threshold and, therefore, are precursors.[1] An additional precursor associated with a Greater-than-*Green* (GTG) inspection finding was identified for a degraded condition where no LER was issued. Eight precursors identified in 2024 were the result of GTG inspection findings, while two precursors were identified via independent ASP analyses.[2] The three 2024 precursors identified at South Texas Project quadrupled the total number of precursors for the site.[3] Table 1 provides a brief description of all precursors identified in 2024.

Table 1. 2024 Precursors

Plant/Description	LER/IR	Event Date	Exposure Time	CCDP/ ΔCDP
Catawba 2, Condition Prohibited by Technical Specifications (TS) and Loss of Safety Function due to Failed Damper Controller for the 2A1 EDG Room Ventilation Fan (ML24234A291)	414-24-001	1/2/24	274 days	*White* Finding
Browns Ferry 2, High-Pressure Coolant Injection (HPCI) Inoperable Due to Rupture Disc Failure and Resulting System Isolation (ML24310A203)	260-24-002	3/19/24	92 days	*White* Finding
Susquehanna 1, EDG B Inoperable due to Failed Excitation System Linear Reactor (ML25016A306)	387-24-002	4/8/24	96 days	*White* Finding
Susquehanna 2, EDG B Inoperable due to Failed Excitation System Linear Reactor (ML25016A306)	387-24-002	4/8/24	96 days	*White* Finding
North Anna 2, Loss of Generator Field for 2J EDG during 2-PT-82.28 (ML24330A016)	339-24-001	4/18/24	93 days	*White* Finding
FitzPatrick, EDG Lube Oil Check Valve Bonnet Cap Leak due to Failed Gasket (ML24299A214)	333-24-001	4/24/24	195 days	*White* Finding

1 The ASP Program defines a degraded condition with an increase in core damage probability (ΔCDP) greater than or equal to 10^{-6} to be a precursor. For initiating events, the ASP Program threshold is the plant-specific conditional core damage probability (CCDP) for a nonrecoverable loss of feedwater and condenser heat sink or 10^{-6}, whichever is greater.

2 An additional GTG inspection finding was identified in 2024 associated with a *White* security-related finding for Millstone Power Station (ML24170A784). This finding was not associated with an increased risk to core damage and, therefore, is out of the scope of the ASP Program.

3 Only one precursor, a concurrent failure of an emergency diesel generator (EDG) and turbine-driven auxiliary feedwater (AFW) pump with another EDG unavailable due to maintenance that occurred in 1993, had been identified at the South Texas Project site prior to 2024.

Plant/Description	LER/IR	Event Date	Exposure Time	CCDP/ ΔCDP
South Texas 2, Automatic Reactor Trip and Actuation of Two of Three EDGs (ML25007A210)	499-24-001	5/12/24	Initiating Event	*White* Finding
South Texas 1, Loss of Offsite Power (LOOP) Resulting in Automatic Reactor Trip and Actuation of EDGs and AFW Pumps (ML25007A210)	498-24-004	7/24/24	Initiating Event	$4{\times}10^{-6}$
Waterford, EDG Failure During 24-Hour Surveillance Test (ML25097A205)	05000382/2025090 (*No LER Issued*)	10/7/24	94 days	**GTG (*Preliminary*)**
South Texas 1, Condition Prohibited by TS and Potential Loss of Safety Function Due to Inoperable Pressurizer Power-Operated Relief Valve	498-24-006	10/22/24	1 year	**$3{\times}10^{-6}$ (*Preliminary*)**

After further analysis, 16 LERs identified by the initial LER screening were determined not to be precursors. Additional information on the LERs determined not to be precursors via an ASP analysis or by acceptance of Significance Determination Process (SDP) results is provided in Appendix A.

2. 2023 ASP RESULTS

The ASP Program 2023 Annual Report (ML24107B130) listed two CY 2023 precursors associated with a preliminary GTG finding for an EDG failure that occurred at Sequoyah Nuclear Power Plant, Unit 1 and Unit 2. A subsequent NRC review of the licensee’s evaluation determined that there was no performance deficiency. However, the NRC concluded that there was a minor violation associated with the licensee’s failure to adequately establish and implement maintenance instructions and practices. This minor violation could not be directly attributed to the failure of the EDG. Since there was no finalized risk evaluation, an independent ASP analysis was performed. The final ASP analysis associated with this degraded condition (ML25023A124) calculated ΔCDPs of $1{\times}10^{-5}$ and $5{\times}10^{-6}$ for Unit 1 and Unit 2, respectively. Therefore, the EDG failure resulted in a precursor for both units.

In addition, an ASP evaluation had not been completed for the degraded condition associated with LER 348-23-002 “Residual Heat Removal Pump Inoperable for Longer Than Allowed by Technical Specifications,” (ML23333A215) at Farley Nuclear Plant, Unit 1. A *Green* finding has been identified for this degraded condition, which will be documented in a forthcoming inspection report. No windowed events were identified and, therefore, the SDP evaluation is accepted as the ASP Program result.[4] Figure 2 provides updated precursor counts for the past 10 years.

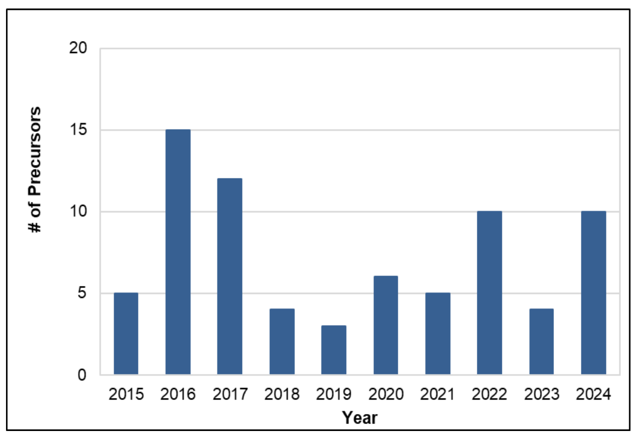

Figure 2. Number of Precursors per CY

3. ASP TRENDS

Trend analyses were performed for the past decade (2015–2024) on the occurrence rate of all precursors and other precursor groups.

4 Windowed events are when multiple structures, systems, and/or components (SSCs) are unable to perform their safety function at the same time. In other words, a windowed event exists when some portion of an exposure period from an SSC unavailability occurs at the same time as an exposure period of another SSC unavailability. These unavailabilities can be due to failure, degradations, or planned maintenance/testing.

Table 2. Precursor Trend Results

Precursor Group	Trend	p-value
All Precursors	No Trend	0.6
Important Precursors (i.e., CCDP/ΔCDP ≥10^{-4})	No Trend	0.6
Precursors with CCDP/ΔCDP ≥10^{-5}	No Trend	0.3
Initiating Events (IEs)	No Trend	0.1
Degraded Conditions (DCs)	No Trend	0.8
LOOPs	No Trend	0.4
EDG Failures	No Trend	0.2
Boiling-Water Reactor (BWR) Precursors	Decreasing	0.05
Pressurized-Water Reactor (PWR) Precursors	No Trend	0.2

Figure 3 provides the occurrence rate of all precursors for the past decade. The occurrence rate and trends (if applicable) of additional precursor subgroups are provided in the Figures 4–7.[5]

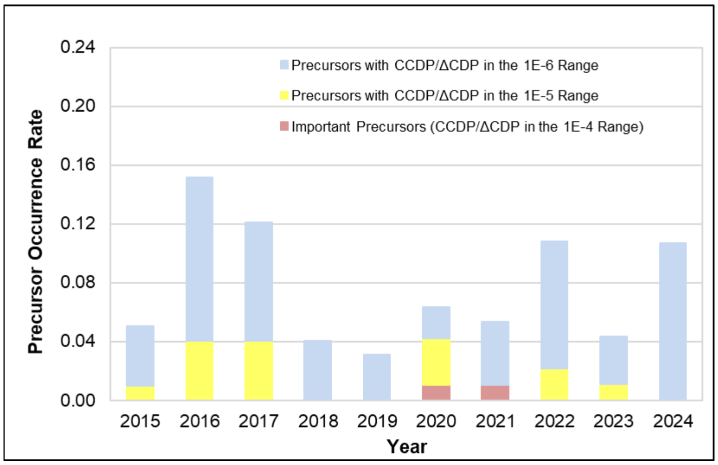

Figure 3. Occurrence Rates of All Precursors

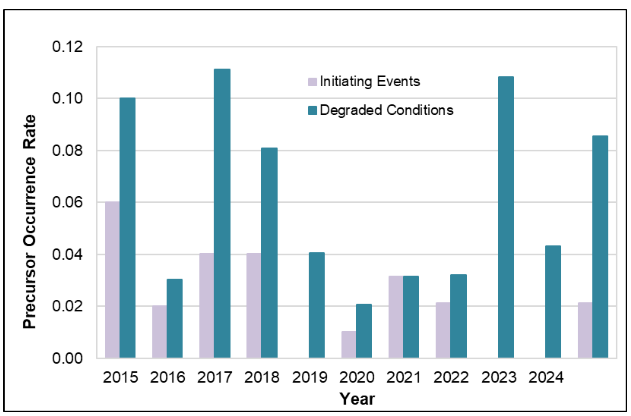

Figure 4. Occurrence Rates of IE / DC Precursors

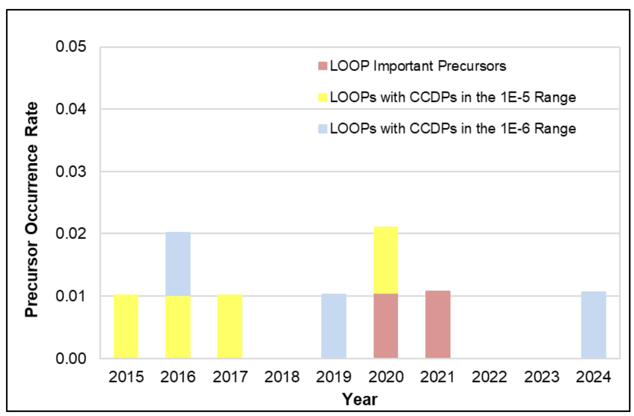

Figure 5. Occurrence Rates of LOOP Precursors

5 A trend line is only shown on figure(s) that have a statistically significant trend (i.e., p-value of ≤ 0.05).

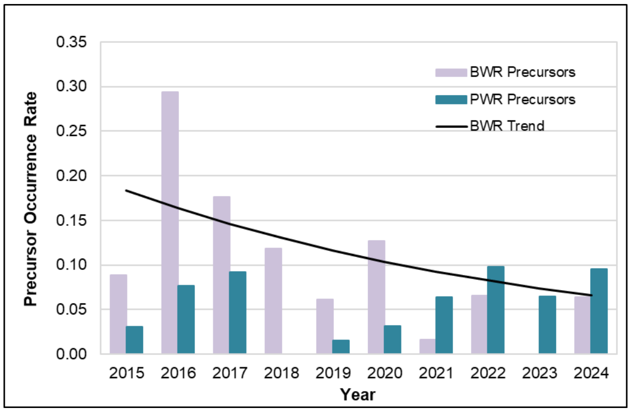

Figure 6. Occurrence Rates of BWR / PWR Precursors

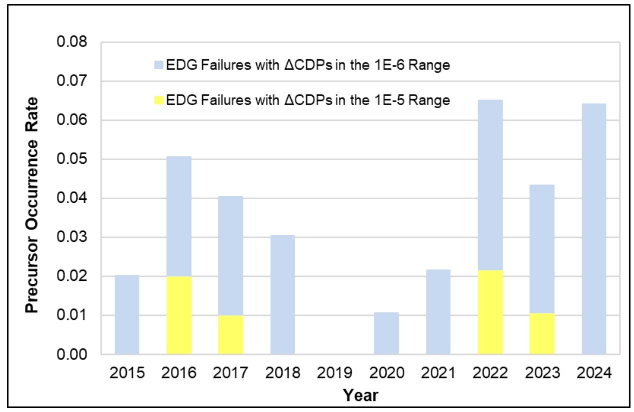

Figure 7. Occurrence Rates of EDG Precursors

4. KEY INSIGHTS

This section provides a few key insights based on the review of the 74 precursors that were identified in the past decade (2015–2024). Note that additional insights can be gathered by using the publicly available ASP Program Dashboard. There were two important precursors identified during this period, both of which were LOOP initiating events.

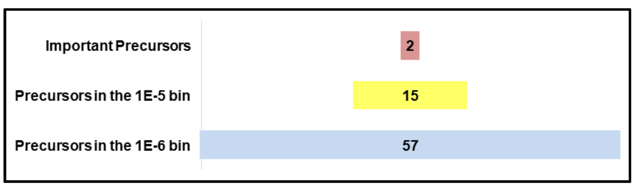

Figure 8. Precursor Breakdown by Risk Bin

The ratio of precursors identified via GTG vs. independent ASP evaluations continues to decrease. In 2016, the 10-year percentage was 69%, but is now 51%.

Natural phenomena caused five precursors, with hurricanes and high winds the most frequent causes.

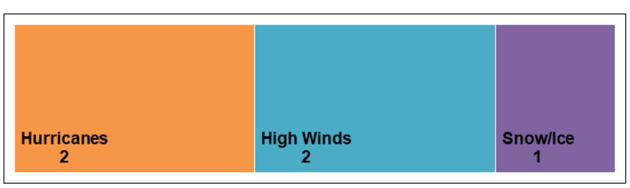

Figure 9. Natural Phenomena Precursors Causes

The most frequent IEs that resulted in precursors were LOOPs and losses of a condenser heat sink.

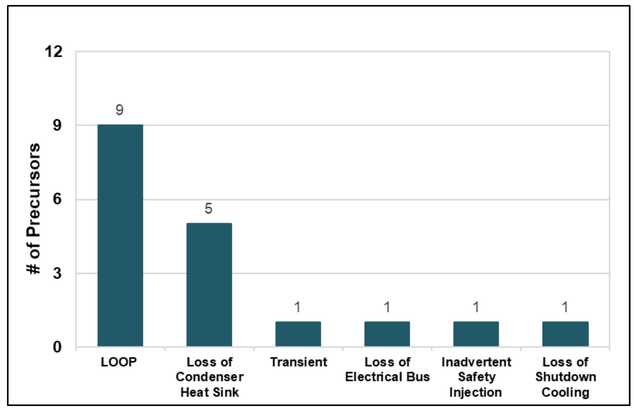

Figure 10. Most Frequent IE Precursor Types

The most frequent SSC failures observed in precursors were associated with EDGs and HPCI failures.

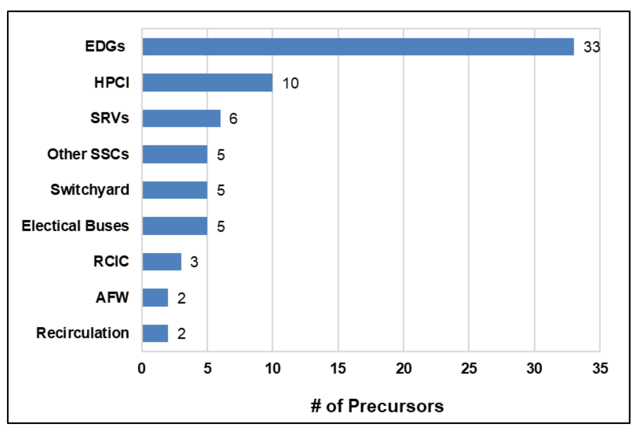

Figure 11. Most Frequent Precursor SSC Failures

A review of the precursors associated with inspection findings that had a significant impact on the risk of the event were most likely due to inadequate procedures and ineffective corrective action programs.

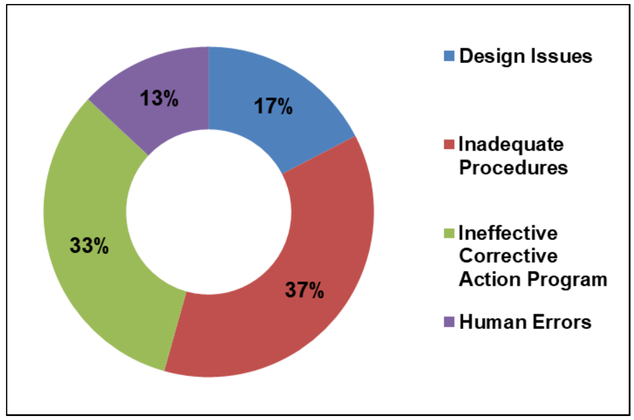

Figure 12. Precursor SSC Failures

5. ASP INDEX

The ASP index shows the cumulative plant average risk from precursors on an annual basis. Unlike the trend analyses performed on various precursor groups that are focused on the occurrence rate of precursors, the ASP index is focused on the total risk due to all precursors that have occurred at a U.S. commercial nuclear power plant. Therefore, the ASP index provides a unique way to evaluate the risk of longer-term DCs over the entire duration of the condition.

The ASP index (shown in Figure 13) does not exhibit a statistically significant trend (*p-value* = 0.7) for the past decade (2015–2024). The total risk associated with precursors (74 total precursors) is dominated by the 2 important precursors, which account for approximately 65% of the total risk due to all precursors. The other 72 precursors account for approximately 35% of the total risk due to all precursors.

A description of how the ASP index is calculated is provided in past annual reports, which can be accessed from the ASP Program Public Webpage.

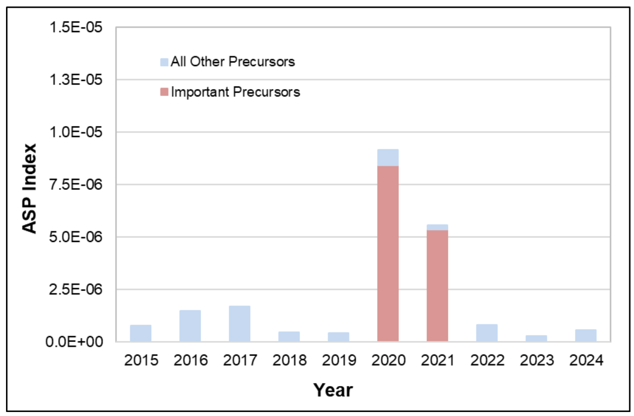

Figure 13. ASP Index

6. OBSERVATIONS

A review of the ASP Program data and trends for the past decade (2015–2024) supports the following observations:

- The number of precursors identified remain at historical low values—the 74 precursors identified in the past decade is the lowest 10-year period total since the ASP Program's inception. The number of LERs and potential precursors identified also remain near historical low values.
- There are no statistically increasing significant trends in the occurrence rate of all precursors and all precursor subgroups, which indicates that licensee risk management initiatives are effective in maintaining a flat or decreasing risk profile for the industry and that current agency oversight programs and licensing activities remain effective.
- Although there is no statistically significant trend for precursors associated with EDG failures,

there has been an increase in these precursors in recent years. Specifically, the 16 EDG precursors identified in the past 3 years is tied for the most in ASP Program history.[6]

- There are no indications of increasing risk due to the potential "cumulative impact" of risk-informed initiatives. In addition, no new component failure modes or mechanisms have been identified, and the likelihood and impacts of accident sequences have not changed.

[6] Sixteen EDG precursors were also identified during the 1990–1992 period.

Appendix A: 2024 ASP Program Screened Analyses

The table in this appendix provides the justification for each LER that was screened out of the ASP Program based on a simplified or bounding analysis or by acceptance of SDP results. Note that the justification reflects the status of the LER (open or closed) at the time of the ASP completion date. While ASP analysts monitor the final SDP evaluation of all findings for including GTG findings as precursors, the screen-out justification is not updated retroactively for events that were initially screened out by an ASP analysis and are later assessed as *Green* (i.e., very low safety significance) in the final SDP evaluation.

<table>
<tr><th>Plant</th><th>LER</th><th>Event Date</th><th>Description</th><th>LER Date</th><th>Screen Date</th><th>Criterion</th><th>Date Assigned</th><th>Date Completed</th><th>Classification</th></tr>
<tr><td>Dresden 2</td><td>237-23-001</td><td>11/20/23</td><td>HCPI Inoperable Due to Air Void Accumulation</td><td>1/19/24</td><td>1/29/24</td><td>3d</td><td>5/22/24</td><td>5/23/24</td><td>Analyst Screen-Out</td></tr>
<tr><td colspan="10">This condition is not discussed in any inspection report (IR) to date; the LER has since been retracted (ML24134A113). On November 20, 2023, a portion of the HPCI system discharge piping was discovered to have an air void during the monthly performance of a nondestructive ultrasonic examination. Upon notification of this discovery, the station entered TS 3.5.1, Condition G, and declared HPCI inoperable. The HPCI system was vented in accordance with station procedures and was restored to operable status after verifying the system was water solid approximately 38 minutes after discovery. A subsequent technical evaluation performed by a licensee contractor determined that amount of air voiding would not have prevented the HPCI system from fulfilling its safety function, and system piping and support structure loads would have been within the design limits upon system actuation. Since the HPCI system was able to fulfil its PRA mission time of 24 hours, there was no loss of safety function and, therefore, this condition is not a precursor, and a review of potential windowed events was not needed.</td></tr>
<tr><td>South Texas 1</td><td>498-24-001</td><td>1/23/24</td><td>Two SG PORVs Inoperable Resulting in a Condition that Could Have Prevented Fulfillment of a Safety Function</td><td>4/1/24</td><td>5/7/24</td><td>3g</td><td>5/22/24</td><td>7/1/24</td><td>Reject</td></tr>
<tr><td colspan="10">A detailed ASP analysis determined that the ΔCDP of the degraded condition and concurrent unavailability due to testing was less than the ASP Program threshold of 1E-6 and, therefore, is not a precursor. The detailed ASP analysis is publicly available (ML24183A224).</td></tr>
<tr><td>Hatch 2</td><td>366-24-001</td><td>12/18/23</td><td>HPCI System Inoperable</td><td>2/14/24</td><td>2/22/24</td><td>3d</td><td>7/1/24</td><td>7/3/24</td><td>Analyst Screen-Out</td></tr>
<tr><td colspan="10">This condition is not discussed in any IR to date; the LER remains open. On December 18, 2023, the HPCI outboard steam isolation valve received a spurious close signal resulting in the HPCI system being isolated and unavailable to automatically start. The plant declared the HPCI system inoperable and entered TS 3.5.1, Condition E. The spurious HPCI isolation was due to electronic noise stemming from a failed reactor core isolation cooling (RCIC) analog transmitter trip system card, which was replaced and HPCI was restored to operable status later on December 18th. The RCIC system and the low-pressure emergency core cooling systems (ECCS) remained operable during this event. The HPCI system was unavailable for approximately 4 hours. A search of LERs did not yield any windowed events. Because the licensee restored HPCI within their TS required action time (14 days) and the exposure time was not longer than the TS allowed outage time for the system, the risk is expected to be low and, therefore, this condition is not a precursor. Calculations to gather additional risk insights were not performed due to very short exposure time (i.e., less than 24 hours).</td></tr>
<tr><td>Cooper</td><td>298-24-002</td><td>8/27/22</td><td>TS Prohibited Condition for Inoperable Service Water Booster Pump</td><td>3/4/24</td><td>3/18/24</td><td>3c</td><td>7/1/24</td><td>7/3/24</td><td>SDP Screen-Out</td></tr>
<tr><td colspan="10">A Green finding was identified in IR 05000298/2024001 (ML24121A143); the LER is closed. On August 27, 2022, residual heat removal service water (RHRSW) booster pump ‘D’ was placed in service to support chemical injection to control zebra mussels within the service water system. Approximately 6 hours later, a high thrust bearing temperature alarm was received in the main control room (MCR). A subsequent licensee investigation identified oil leaks coming from the pump’s inboard radial bearing and outboard thrust bearing. Due to the excessive oil leakage, the plant declared RHRSW booster pump ‘D’ inoperable and entered TS 3.7.1, Condition A, Required Action A.1. Subsequent licensee troubleshooting determined that the thrust bearing lockout nut was overtightened when the pump was replaced on July 29, 2022, which resulted in a degradation of the load bearing surfaces of the bearing and the subsequent overheating. The oil leaks were caused by the improper fabrication of the angled drain slot in the inboard bearing cover labyrinth seal. Repairs were completed on inboard and outboard bearings, and the pump was restored to operable status on September 1st after successful post-maintenance testing. NRC inspectors determined that the licensee failure to implement maintenance that can affect the performance of safety-related equipment without properly preplanning and performing the maintenance in accordance with written procedures, documented instructions, or drawings appropriate to the circumstances was a performance deficiency. Specifically, the work instructions for the rebuilding of RHRSW booster pumps failed to incorporate vendor instructions directing the installation of the outboard thrust bearing. This performance deficiency was determined to be Green (i.e., very low safety significance) using the screening questions provided in Appendix A of Inspection Manual Chapter (IMC) 0609. A search of LERs did not yield any windowed events. Therefore, the SDP risk assessment is accepted as the ASP Program result, in accordance with RIS 2006-024. The risk of this condition is below the ASP Program threshold and, therefore, is not a precursor.</td></tr>
</table>

Plant	LER	Event Date	Description	LER Date	Screen Date	Criterion	Date Assigned	Date Completed	Classification
Waterford	382-24-002	3/21/24	Automatic Reactor Trip Due to Transformer Failure	5/16/24	5/29/24	1d	7/1/24	**7/3/24**	Analyst Screen-Out
			This event is not discussed in any IR to date; the LER remains open. On March 21, 2024, a main transformer ‘B’ failure resulted in a fire and automatic reactor trip. The fire caused extensive damage to the startup transformer (SUT) 'B' preventing a transfer of train 'B' components from unit auxiliary transformer ‘B’. The LOOP to the train 'B' components resulted in safety-related bus ‘B’ being powered by EDG ‘B’. The fire brigade was able to put out the transformer fire in 41 minutes without the assistance of the local fire station. Following the reactor trip, the steam generator (SG) feedwater control system experienced a level deviation resulting in all feedwater regulating valves going to manual control which blocks the valves automatic response to a reactor trip. The MCR operators had to manually perform the reactor trip override function that closes the feedwater regulating valves to a lower flow position. Prior to taking the manual action to lower feedwater flow, a reactor coolant system (RCS) cooldown occurred, due to the high feedwater flow, and RCS pressure lowered to less than 1684 psia resulting in a safety injection (SI) actuation signal and a containment isolation actuation signal. RCS pressure recovered prior to the point of injection from the high-pressure SI pumps. An emergency feedwater (EFW) actuation was also received on the reactor trip due to the SG level shrink. A search of LERs did not reveal any windowed events. A risk analysis was performed for a reactor trip and the failure of SUT ‘B’ resulting in partial LOOP to the safety-related bus ‘B’. This analysis resulted in a mean CCDP of 6E-6, which is below the plant-specific CCDP for a nonrecoverable loss of feedwater and condenser heat sink (1.8E-5) for Waterford. Therefore, the risk of this event is below the ASP Program threshold and, therefore, this event is not a precursor.						
Watts Bar 2	391-24-003	5/13/24	Inoperability of Both Trains of Low Head SI	7/11/24	7/28/24	3d	7/31/24	**8/20/24**	SDP Screen-Out
			A Green finding was identified in IR 05000391/2024002 (ML24219A233); the LER remain open. On May 13, 2024, a MCR operator erroneously rendered residual heat removal (RHR) train ‘B’ inoperable. The inoperability resulted from the operator inappropriately closing the train ‘B’ train RHR heat exchanger’s outlet flow control valve. This manipulation occurred while RHR train ‘A’ train was out of service for preplanned maintenance. RHR train ‘B’ was restored 4 minutes later when the operator reopened the valve. NRC inspectors determined that the licensee failure to follow plant procedures was a performance deficiency. Specifically, an operator inadvertently closed the RHR train ‘B’ heat exchanger outlet flow control valve during a planned RHR train ‘A’ outage resulted in loss of RHR safety function. This performance deficiency was determined to be Green (i.e., very low safety significance) using the screening questions provided in Appendix A of IMC 0609. A search of LERs did not yield any windowed events. Therefore, the SDP risk assessment is accepted as the ASP Program result, in accordance with RIS 2006-024. The risk of this condition is below the ASP Program threshold and, therefore, is not a precursor.						
Hatch 1	321-24-003	5/8/24	RCIC System Inoperable Due to Mispositioned Link	7/3/24	7/24/24	3d	7/31/24	**11/26/24**	SDP Screen-Out
			A Green finding was identified in IR 05000321/2024003 (ML24296B164); the LER is closed. On May 8, 2024, RCIC was undergoing a surveillance test during which an open electrical link was identified. This open electrical link, which should have been in the closed position, defeated the RCIC high reactor water level trip function. The link was closed later on May 8th and therefore, the high reactor water level trip function and RCIC operability was restored. NRC inspectors determined that the licensee failure to restore RCIC operability within the TS allowed outage time was a performance deficiency. Specifically, on May 8th, the RCIC high reactor water level trip function was identified to have been inoperable since March 8, 2024, due to an associated electrical link not being restored in accordance with operating permit instructions. The licensee failed to take the required actions (e.g., verify HPCI was operable) required by TS 3.5.3, Conditions A and B. A detailed SDP risk evaluation was performed by a Region 2 SRA assuming the RCIC high reactor water level trip function was disabled for an exposure time of 62 days. The assessment resulted in a ΔCDF of 4E-7 per year from internal events, internal fires, high winds (including hurricanes and tornadoes), and seismic events. A search of LERs did not yield any windowed events. Therefore, the SDP risk assessment is accepted as the ASP Program result, in accordance with RIS 2006-024. The risk of this condition is below the ASP Program threshold and, therefore, is not a precursor.						
DC Cook 2	316-24-004	9/12/24	2AB EDG Inoperable for longer than allowed by TS	11/11/24	11/27/24	3e	12/3/24	**1/24/25**	SDP Screen-Out
			A Green finding was identified in IR 05000316/2024050 (ML24345A203); the LER remains open. On May 21, 2024, EDG ‘2AB’ failed to reach the required frequency (59.5 to 60.4 Hz) during the slow speed start surveillance test. The failure to reach the required frequency was originally attributed to corroded connections on the minimum speed threshold and slow start control relays. On July 23, 2024, EDG ‘2AB’ again failed to reach the required frequency during a surveillance test. The cause of the failure was determined to be an intermittent failure of the digital reference unit. Due to the similar symptoms between the two failures, it was determined that EDG ‘2AB’ failure on May 21st was also due to the failure of the digital reference unit. Due to the discovery that both failures were a result of the failed digital reference unit, EDG ‘2AB’ was determined to be inoperable from the time the original condition was discovered on May 21st until the time that repairs were completed on July 24th. A licensee evaluation determined that for the frequencies observed during the failed surveillance tests, EDG ‘2AB’ would have been able to meet its PRA success criteria. However, this evaluation concluded that the failed digital reference unit could potentially result in an EDG failure during its mission time. NRC inspectors determined that the licensee failure to identify and correct a condition adverse to quality was a performance deficiency. Specifically, the licensee failed to identify and correct defective equipment, which prevented the EDG from meeting TS 3.8.1.2 during the May 2024 slow speed start surveillance test. A detailed SDP risk evaluation was performed by a Region 3 SRA assuming EDG ‘2AB’ was degraded for an exposure time of 63 days. The assessment resulted in a ΔCDF of less than 1E-6 per year from internal events, internal fires, high winds (including tornadoes), and seismic events. A search of LERs did not yield any windowed events. Therefore, the SDP risk assessment is accepted as the ASP Program result, in accordance with RIS 2006-024. The risk of this condition is below the ASP Program threshold and, therefore, is not a precursor.						

<table>
<tr><th>Plant</th><th>LER</th><th>Event Date</th><th>Description</th><th>LER Date</th><th>Screen Date</th><th>Criterion</th><th>Date Assigned</th><th>Date Completed</th><th>Classification</th></tr>
<tr><td>Calvert Cliffs 1</td><td>317-24-003</td><td>7/8/24</td><td>1A EDG Inoperable Due to Potential Transformer Failure</td><td>9/6/24</td><td>9/16/24</td><td>3e</td><td>11/1/24</td><td>3/19/25</td><td>Analyst Screen-Out</td></tr>
<tr><td colspan="10">This condition is not discussed in any IR to date; the LER remains open. On July 2, 2024, an alarm in the MCR indicated an issue with 4 kV bus ‘17’, which supports the EDG ‘1A’. The initial licensee investigation did not yield an apparent cause of the alarm and concluded that EDG ‘1A’ remained operable. A subsequent investigation identified failure of the potential transformer supporting the protection and synchronizing circuits as the cause of the alarm. On July 8th, a licensee analysis determined that the failed potential transformer would cause an overcurrent trip of the EDG ‘1A’ output breaker during load sequencing. The licensee declared EDG ‘1A’ inoperable, and the Unit 1 entered TS 3.8.1, Condition B. On July 11th the potential transformer was replaced, and EDG ‘1A’ was declared operable after successful post-maintenance testing. The cause of the potential transformer failure was age-related degradation of the winding insulation, which caused turn-to-turn shorts of the primary and secondary windings. A search of LERs did not yield any windowed events. Because the exposure time of 9 days was shorter than the limits of TS 3.8.1, Conditions B and E (14 days), this event is not a precursor. To gain additional risk insights, an evaluation was performed assuming the unavailability of EDG ‘1A’ for an exposure time of 9 days using a TLU Calvert Cliffs Unit 1 SPAR model created on February 25, 2025. This evaluation resulted in a mean ΔCDP of 1E-7 for from internal events, high winds (including hurricanes and tornadoes), and seismic events. Internal flooding and fires scenarios are not included in the Calvert Cliffs Unit 1 SPAR model; however, it is not expected that the risk impact from these hazards would result in any new insights.</td></tr>
<tr><td>Grand Gulf</td><td>416-24-004</td><td>9/24/24</td><td>HPCS Over Frequency Relay Trip</td><td>11/22/24</td><td>1/8/25</td><td>3d</td><td>1/15/25</td><td>TBD</td><td>SDP Screen-Out</td></tr>
<tr><td colspan="10">A Green finding has been identified and will be documented in a forthcoming IR; the LER remains open. On September 24, 2024, while performing a high-pressure core spray (HPCS) LOOP surveillance test, the division III EDG started and loaded the safety bus as expected. However, the HPCS pump breaker immediately tripped resulting in a potential loss of safety function. Licensee troubleshooting revealed that the cause of the trip was determined to be the failure of the over-frequency relay. The HPCS over-frequency relay was replaced. The over-frequency relay was determined to be non-essential, and actions were created to remove the relay from the system. A detailed SDP risk evaluation was performed by a Region 4 SRA assuming the HPCS pump would trip on over-frequency during a postulated LOOP for the maximum exposure time of 1 year. Recovery credit was provided for operators’ ability to restart HPCS given the initial over-frequency trip. This assessment resulted in a ΔCDF of 8E-7 per year from internal events, internal fires, high winds (including hurricanes and tornadoes), and seismic events. A search of LERs did not yield any windowed events. Therefore, the SDP risk assessment is accepted as the ASP Program result, in accordance with RIS 2006-024. The risk of this condition is below the ASP Program threshold and, therefore, is not a precursor.</td></tr>
<tr><td>Monticello</td><td>263-24-002</td><td>6/28/24</td><td>LPCI Inoperable Due to Motor Valve Failure</td><td>8/7/24</td><td>9/11/24</td><td>3d</td><td>10/15/24</td><td>TBD</td><td>SDP Screen-Out</td></tr>
<tr><td colspan="10">A Green finding has been identified and will be documented in a forthcoming IR; the LER remains open. On June 28, 2024, plant personnel were performing OSP-RHR-0556, “RHR Water Fill Verification” surveillance test procedure. As part of this test, MCR operators closed and then attempted to reopen the RHR low-pressure coolant injection (LPCI) division ‘1’ injection outboard valve, but the valve only opened approximately one inch. This valve failure resulted in the inoperability of the LPCI ‘A’ injection path. In addition, due to the plant design of the LPCI loop select logic, this failure rendered both subsystems of LPCI inoperable. Specifically, if the recirculation loop ‘B’ was determined to be broken, the automatic logic would be incapable of opening the path to the LPCI ‘A’ injection path and neither division would automatically inject. NRC inspectors determined that the licensee failure to promptly correct the degradation of the LPCI division ‘1’ injection outboard valve in accordance with the requirements of 10 CFR 50 Appendix B, Criterion XVI, was a performance deficiency. Specifically, on three previous occasions, the licensee identified but failed to promptly correct the inability to declutch and manually operate the LPCI division ‘1’ injection outboard valve. A detailed SDP risk evaluation was performed by a Region 3 SRA assuming the LPCI division ‘1’ injection outboard valve could not be opened for an exposure time of approximately 9 days. This assessment resulted in a ΔCDF of 2E-7 per year from internal events, internal fires, high winds (including tornadoes), and seismic events. A search of LERs did not yield any windowed events. Therefore, the SDP risk assessment is accepted as the ASP Program result, in accordance with RIS 2006-024. The risk of this condition is below the ASP Program threshold and, therefore, is not a precursor.</td></tr>
<tr><td>South Texas 1</td><td>498-23-003</td><td>11/10/23</td><td>Two Essential Chilled Water Trains Inoperable Resulting in a Condition That Could Have Prevented Fulfillment of a Safety Function</td><td>1/9/24</td><td>1/22/24</td><td>3c</td><td>7/5/24</td><td>TBD</td><td>Analyst Screen-Out</td></tr>
<tr><td colspan="10">An initial ASP evaluation was competed on 10/24/24. This initial evaluation and the subsequent reevaluation, including the concurrent failure of pressurizer PORV ‘656A’, will be documented in the ASP analysis report associated with LER 498-24-006.</td></tr>
<tr><td>South Texas 2</td><td>499-23-001</td><td>11/16/23</td><td>Two Essential Chilled Water Trains Inoperable Resulting in a Condition That Could Have Prevented Fulfillment of a Safety Function</td><td>1/15/24</td><td>1/22/24</td><td>4</td><td>8/15/24</td><td>TBD</td><td>Analyst Screen-Out</td></tr>
<tr><td colspan="10">An initial ASP evaluation was competed on 10/24/24. This initial evaluation and the subsequent reevaluation, including the concurrent failure of pressurizer PORV ‘656A’, will be documented in the ASP analysis report associated with LER 498-24-006.</td></tr>
<tr><td>South Texas 1</td><td>498-23-004</td><td>11/27/23</td><td>Condition Prohibited by TS Due to Inoperable Train of Essential Chilled Water</td><td>2/5/24</td><td>2/29/24</td><td>4</td><td>8/15/24</td><td>TBD</td><td>Analyst Screen-Out</td></tr>
<tr><td colspan="10">An initial ASP evaluation was competed on 10/24/24. This initial evaluation and the subsequent reevaluation, including the concurrent failure of pressurizer PORV ‘656A’, will be documented in the ASP analysis report associated with LER 498-24-006.</td></tr>
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Plant	LER	Event Date	Description	LER Date	Screen Date	Criterion	Date Assigned	Date Completed	Classification
South Texas 1	498-24-002	3/10/24	Two Essential Chilled Water Trains Inoperable Resulting in a Condition That Could Have Prevented Fulfillment of a Safety Function	5/9/24	5/21/24	3d	10/1/24	**TBD**	Analyst Screen-Out
An initial ASP evaluation was competed on 10/24/24. This initial evaluation and the subsequent reevaluation, including the concurrent failure of pressurizer PORV '656A', will be documented in the ASP analysis report associated with LER 498-24-006.									
South Texas 1	498-24-003	5/6/24	Condition Prohibited by Technical Specifications and Potential Loss of Safety Function Due to Inoperable Low Head SI Pump	7/1/24	7/25/24	3d	10/1/24	**TBD**	Analyst Screen-Out
An initial ASP evaluation was competed on 10/24/24. This initial evaluation and the subsequent reevaluation, including the concurrent failure of pressurizer PORV '656A', will be documented in the ASP analysis report associated with LER 498-24-006.									