This report provides the results the Accident Sequence Precursor Program for 2023. In addition, trends and key insights are provided for the past 10 years (2014 through 2023).

U.S. Nuclear Regulatory Commission Accident Sequence Precursor Program 2023 Annual Report

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1. 2023 ASP RESULTS

There were 138 licensee event reports (LERs) issued in calendar year (CY) 2023. From these LERs, 119 (86%) were screened out in the initial screening process and 19 events were selected and analyzed as potential precursors. The overall number of LERs and potential precursors continues to decrease 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.

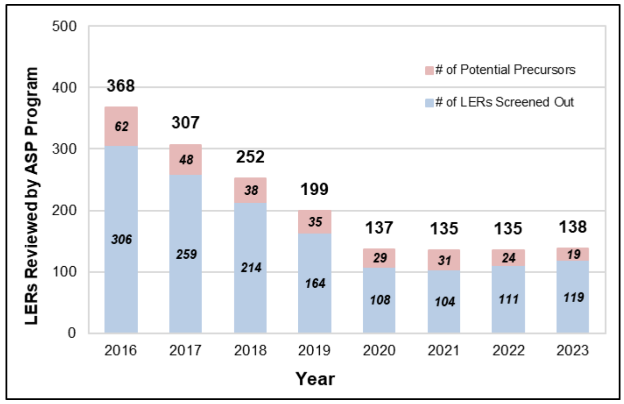

Figure 1. Breakdown of LERs Reviewed by ASP Program Since 2016

Of the 19 potential precursors identified via the LER screening, one event was determined to exceed the ASP Program threshold and, therefore, is a precursor.[1] An additional four precursors were identified for degraded conditions where no LER was issued. All five precursors identified in 2023 were the result of greater-than-*Green* (GTG) inspection findings.[2] Table 1 provides a brief description of all precursors identified in 2023.

Table 1. 2023 Precursors

Plant/Description	LER/IR	Event Date	Exposure Time	CCDP/ ΔCDP
Summer, Failure to Correct a Condition Adverse to Quality Results in an Emergency Diesel Generator (EDG) Failure (ML23342A000)	05000395/2023002 *(No LER issued)*	11/2/22[3]	162 days	*White* Finding
Farley 1, Failure to Identify Nonconforming Work Instructions Results in EDG Lube Oil Leak (ML23263B166)	348-23-001	2/26/23	115 days	*White* Finding
Calvert Cliffs 1, Failure to Establish and Implement Adequate Maintenance Practices Contributes to the Failure of EDG 1A (ML23297A192)	05000395/2023050 *(No LER issued)*	4/24/23	216 days	*White* Finding
Sequoyah 1, Failure to Establish, Implement, and Maintain Adequate Procedures for Maintenance Activities on EDG 1B Results in Failure	05000327/2024090 *(No LER issued)*	9/19/23	246 days	**GTG[4] *(Preliminary)***

[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] Four additional *GTG* inspection findings were identified in 2023. A *White* emergency preparedness finding was identified for River Bend Station (ML23201A132); a *GTG* security-related finding was identified for Shearon Harris Nuclear Plant (ML23249A279); a *White* radiation protection finding was identified for Columbia Generating Station (ML23276B477); and a *GTG* security-related finding was identified for Watts Bar Nuclear Plant, Units 1 and 2 (ML23352A395). These findings were not associated with increased risk to core damage and, therefore, are out of the scope of the ASP Program.

[3] The EDG failure associated with this precursor occurred in CY 2022 and, therefore, will be included in CY 2022 for trending purposes.

[4] Preliminary GTG findings associated with this degraded condition have been identified for both units. A regulatory conference is scheduled for May 2nd. Discussions with Region 3 staff indicate that the risk will likely remain above the precursor threshold.

Plant/Description	LER/IR	Event Date	Exposure Time	CCDP/ ΔCDP
Sequoyah 2, Failure to Establish, Implement, and Maintain Adequate Procedures for Maintenance Activities on EDG 1B Results in Failure	05000327/2024090 *(No LER issued)*	9/19/23	246 days	**GTG[4] (*Preliminary*)**

After further analysis, 17 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. There is an open allegation associated with LER 348-23-002 "Residual Heat Removal Pump Inoperable for Longer Than Allowed by Technical Specifications," (ML23333A215). Initial risk calculations for this degraded condition estimate a ΔCDP in the mid-10^{-7} range. However, this result does not include the risk from internal fire scenarios, which are not included in the Farley Nuclear Power Plant (Unit 1) standardized plant analysis risk (SPAR) model and could significantly impact the whether the final ΔCDP exceeds the ASP Program threshold. An NRC risk evaluation (ASP or SDP) will not be completed until the allegation is closed. Therefore, this degraded condition remains a potential precursor.

An additional evaluation was performed on a degraded condition at Calvert Cliffs Nuclear Plant (Unit 2) for which no LER was issued. A detailed analysis determined that the risk associated with this degraded condition was below ASP Program threshold. This evaluation is publicly available in ADAMS (ML24107A995).

2. ASP TRENDS

Trend analyses were performed for the past decade (2014–2023) on the occurrence rate of all precursors and other precursor groups.

Table 2. Precursor Trend Results

Precursor Group	Trend	p-value
All Precursors	Decreasing	0.01
Important Precursors (i.e., CCDP/ΔCDP $\geq 10^{-4}$)	No Trend	0.3
Precursors with CCDP/ΔCDP $\geq 10^{-5}$	No Trend	0.4
Initiating Events (IEs)	Decreasing	0.004
Degraded Conditions (DCs)	No Trend	0.2
Losses of Offsite Power (LOOPs)	No Trend	0.2
EDG Failures	No Trend	0.4
Boiling-Water Reactor (BWR) Precursors	Decreasing	0.02
Pressurized-Water Reactor (PWR) Precursors	No Trend	0.2

Figure 2 provides the occurrence rate and trend of all precursors for the past decade. Additional precursor trends are provided in the Figures 3–6.

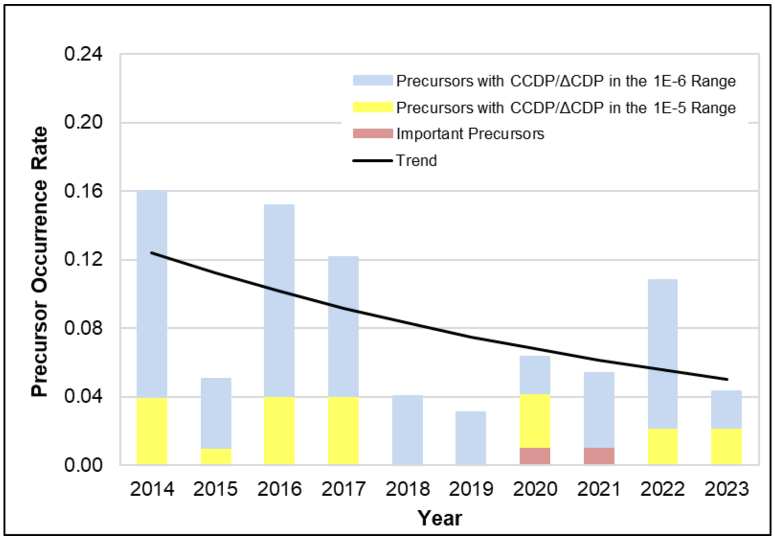

Figure 2. Occurrence Rate of All Precursors

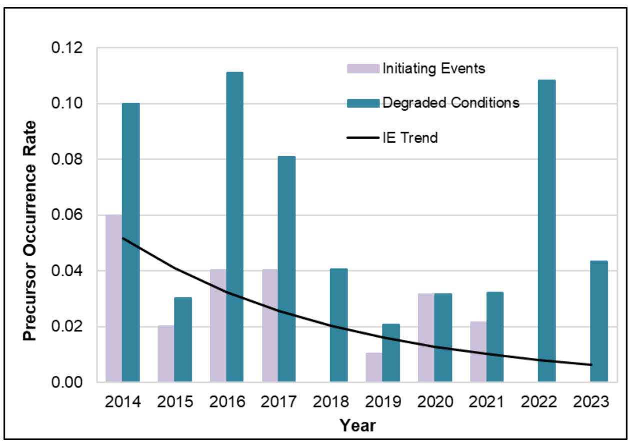

Figure 3. Occurrence Rates of IE / DC Precursors

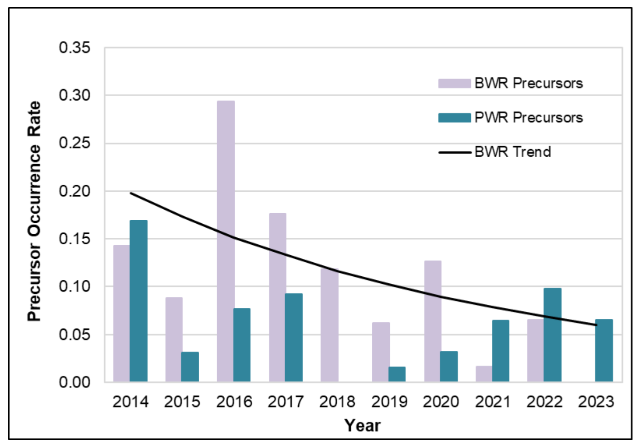

Figure 5. Occurrence Rates of BWR / PWR Precursors

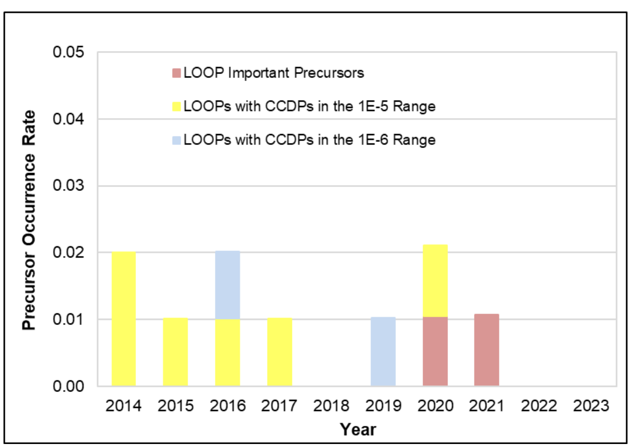

Figure 4. Occurrence Rate of LOOP Precursors

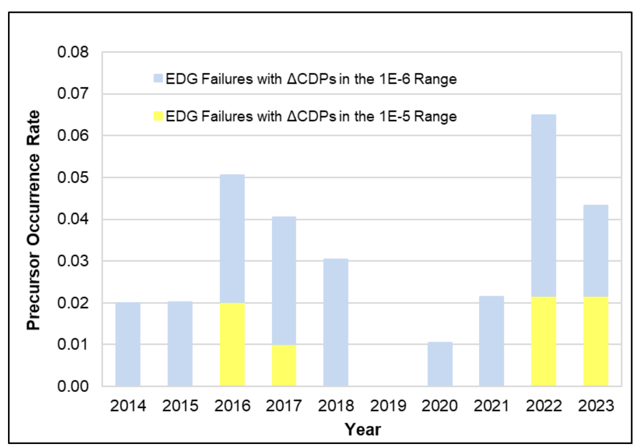

Figure 6. Occurrence Rates of EDG Precursors

KEY INSIGHTS

This section provides a few key insights based on the review of the 80 precursors that were identified in the past decade (2014–2023). 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 of were due to LOOPs.

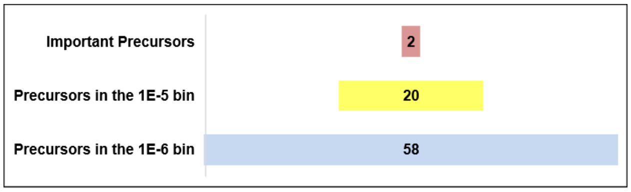

Figure 7. Precursor Breakdown by Risk Bin

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

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

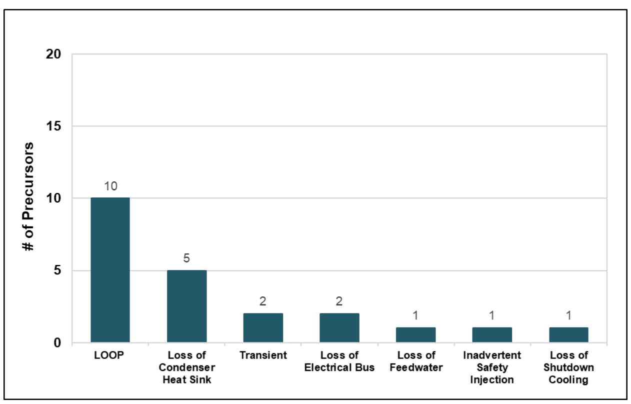

Figure 8. Most Frequent IE Precursor Types

Natural phenomena caused eight precursors, with hurricanes, high winds, and snow/ice the most frequent causes.

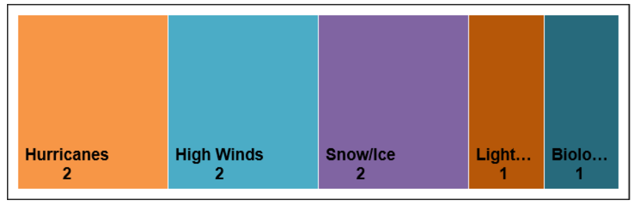

Figure 9. Natural Phenomena Precursors Causes

The most frequent structure, system, and component (SSC) failures observed in precursors were associated with EDGs and high-pressure coolant injection (HPCI) failures.

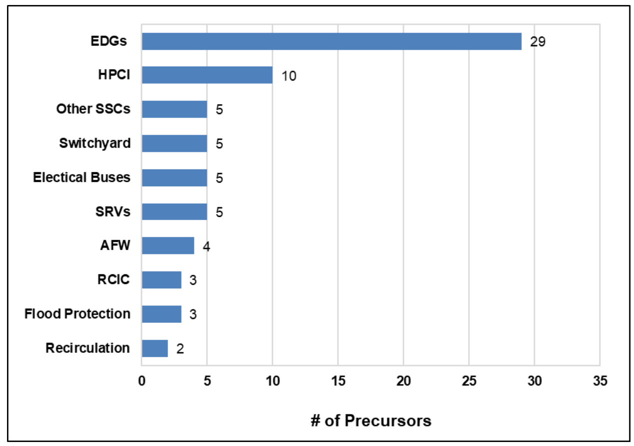

Figure 10. Most Frequent Precursor SSC Failures

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, ineffective corrective action programs, or design issues.

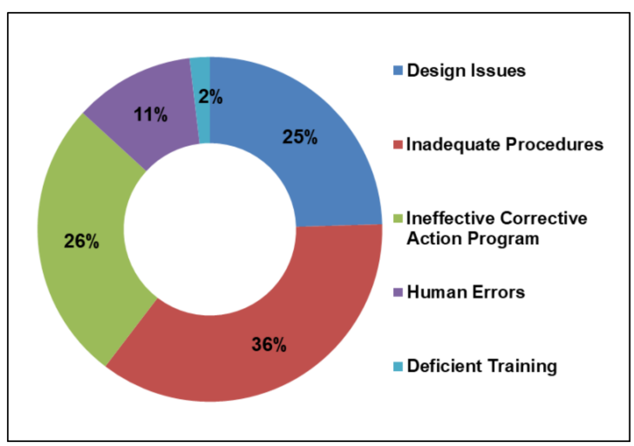

Figure 11. Dominant Precursor SSC Failures

3. 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 12) does not exhibit a statistically significant trend (*p-value* = 0.9) for the past decade (2014–2023). The total risk associated with precursors (80 total precursors) is dominated by the 2 important precursors, which account for approximately 61% of the total risk due to all precursors. The other 78 precursors account for approximately 39% to 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.

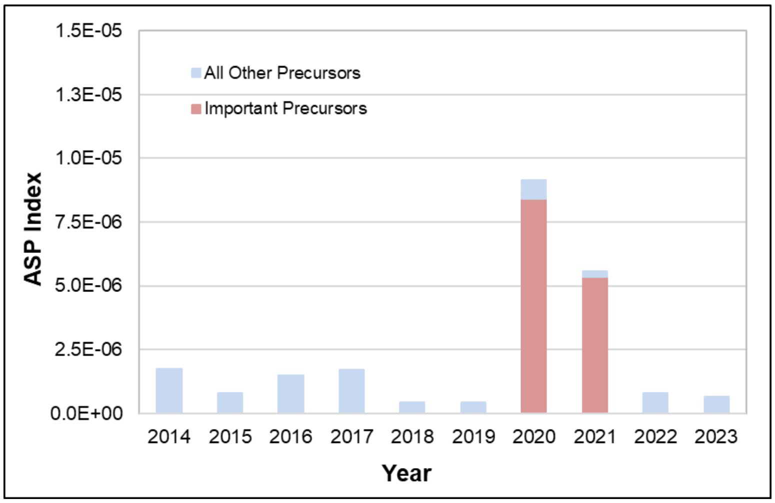

Figure 12. ASP Index

4. OBSERVATIONS

A review of the ASP Program data and trends for the past decade (2014–2023) supports the following observations:

- The number of precursors identified remain at historical low values. The 80 precursors identified in the past decade is the lowest 10-year period total since the ASP Program's inception. In addition, the occurrence rate of all precursors remains decreasing. The number of LERs and potential precursors identified also remain at historical low values.
- Current agency oversight programs and licensing activities remain effective.
- Licensee risk management initiatives are effective in maintaining a flat or decreasing risk profile for the industry.
- There are no indications of increasing risk due to the potential "cumulative impact" of risk-informed initiatives.
- No new component failure modes or mechanisms have been identified, and the likelihood and impacts of accident sequences have not changed.

Appendix A: 2023 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>Browns Ferry 1</td><td>259-23-001</td><td>1/24/23</td><td>High Pressure Coolant Injection System Inoperable Due to a Torn Valve Diaphragm</td><td>3/27/23</td><td>4/12/23</td><td>3d</td><td>4/17/23</td><td>6/22/23</td><td>Analyst Screen-out</td></tr>
<tr><td colspan="10">Analyst Justification. This condition is not discussed in any inspection report (IR) to date, the LER remains open. On January 24, 2023, the high-pressure coolant injection (HPCI) system was declared inoperable because the normally-open HPCI steam line condensate outboard drain valve failed closed due to a failed diaphragm. The reactor core isolation cooling (RCIC) system remained operable, and all automatic depressurization system (ADS) were available during this event to facilitate the use of the low-pressure emergency core cooling systems (ECCS) if needed. The diaphragm was replaced and associated post-maintenance testing was completed on January 25th. The HPCI system was unavailable for approximately 25 hours. A search of LERs did not yield any windowed events. Because the licensee restored HPCI within their technical specification (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. To gather additional risk insights, an evaluation was performed assuming the unavailability of HPCI for the maximum exposure time of 25 hours, which resulted in a mean increase in core damage probability (ΔCDP) of 2E-8 from internal events, high winds (including tornadoes), and seismic events. Internal flooding and fires scenarios are not included in the Browns Ferry SPAR model; however, it is not expected that the risk impact from these hazards would result in any new insights.</td></tr>
<tr><td>River Bend</td><td>458-23-001</td><td>3/24/23</td><td>Ultimate Heat Sink Inoperable due to Boundary Valve Leakage</td><td>5/23/23</td><td>6/28/23</td><td>3f</td><td>7/11/23</td><td>8/11/23</td><td>Analyst Screen-out</td></tr>
<tr><td colspan="10">Analyst Justification. This condition is not discussed in any IR to date, the LER remains open. On March 24, 2023, while in a refueling outage, testing revealed leakage from the standby service water (SSW) system that could have rendered the ultimate heat sink inoperable. Specifically, the testing revealed seat leakage from SWP-MOV57A (service water normal supply header ‘A’ inlet isolation) was approximately 30 gallons per minute (gpm). On May 6, 2023, the seat leakage test performed on the opposite header valve SWP-MOV57B resulted in a leak rate of 15.5 gpm. Licensee design basis calculations allow a leakage rate of 6.9 gpm from these valves. SWP-MOV57A was repaired by replacing the valve seat seals and the closing torque was adjusted on both valves. A licensee risk assessment assuming the worst-case ambient temperature and minimum ultimate heat sink (UHS) initial water level concluded that the UHS would not require replenishment until at least 22 days into an event given the leakage rates from the two valves. Therefore, the UHS was available to perform its safety function for significantly longer than the probabilistic risk assessment (PRA) mission time (i.e., 24 hours) and, therefore, this condition is not a precursor, and a review of potential windowed events was not needed.</td></tr>
<tr><td>Susquehanna 1</td><td>387-23-002</td><td>4/7/23</td><td>Unplanned Inoperability of the HPCI System due Failure of the HPCI Turbine Stop Valve to Fully Close, Most Likely Due to Internal Corrosion and Mechanical Binding of the Valve Hydraulic Drive</td><td>6/6/23</td><td>6/28/23</td><td>3d</td><td>7/11/23</td><td>8/11/23</td><td>Analyst Screen-out</td></tr>
<tr><td colspan="10">Analyst Justification. This condition is not discussed in any IR to date, the LER remains open. On April 7, 2023, the HPCI turbine stop valve failed to stroke fully closed during weekly testing. Upon discovery of the condition, Unit 1 entered TS 3.5.1, "ECCS – Operating," Condition D due to the HPCI system being declared inoperable. The plant exited TS 3.5.1, Condition D on April 8th following valve cleaning/lubrication and satisfactory post-maintenance testing. The valve failure was most likely caused by internal corrosion and mechanical binding of the valve hydraulic drive mechanism due to condensation from a steam leak past the HPCI turbine steam supply valve. The HPCI system was unavailable for a maximum of 8 days. 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. To gather additional risk insights, an evaluation was performed assuming the unavailability of HPCI for the maximum exposure time of 8 days, which resulted in a mean ΔCDP of 9E-8 from internal events, high winds (including tornadoes), and seismic events. Internal flooding and fires scenarios are not included in the Susquehanna SPAR model; however, it is not expected that the risk impact from these hazards would result in any new insights.</td></tr>
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<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>FitzPatrick</td><td>333-23-003</td><td>4/24/23</td><td>Procedure Error in EDG Fuel Oil Supply "B" Subsystem</td><td>6/23/23</td><td>7/14/23</td><td>3e</td><td>7/20/23</td><td>8/11/23</td><td>Analyst Screen-out</td></tr>
<tr><td colspan="10">Analyst Justification. This condition is not discussed in any IR to date, the LER remains open. On April 24, 2023, a licensee investigation revealed that an incorrect 6-day fuel oil supply table was used in place of the 7-day fuel oil supply table in surveillance procedure to determine if additional fuel oil should be ordered for EDG ‘B’. This procedure error resulted in the fuel oil in EDG ‘B’ being less than the required 7-day amount. A subsequent review identified that the 7-day fuel oil supply requirement was not met for EDG ‘B’ between June 20, 2022, to September 12, 2022; November 7, 2022, to December 1, 2022; and March 27, 2023, to April 25, 2023. There was a fuel supply of at least 6 days during these three periods. It was confirmed that the procedure for EDG ‘A’ did not contain the error and its fuel oil quantities met the required 7-day supply. A fuel delivery was made on April 25th, which restored the 7-day required fuel oil quantity to EDG ‘B’. While EDG ‘B’ did not have the required 7-day supply of fuel oil, it remained capable of performing its safety function for significantly longer than the PRA mission time (i.e., 24 hours) and, therefore, this condition is not a precursor, and a review of potential windowed events was not needed.</td></tr>
<tr><td>LaSalle 1</td><td>373-23-001</td><td>4/17/23</td><td>LPCS Inoperable due to Minimum Flow Valve Flow Pressure Switch Failure</td><td>6/16/23</td><td>7/13/23</td><td>3d</td><td>7/20/23</td><td>8/11/23</td><td>Analyst Screen-out</td></tr>
<tr><td colspan="10">Analyst Justification. This condition is not discussed in any IR to date, the LER remains open. On April 17, 2023, the low-pressure core spray (LPCS) pump discharge flow differential pressure switch malfunctioned during surveillance testing. The pressure switch failure prevented the LPCS pump minimum flow valve from opening on a low flow condition. As a result the LPCS pump was declared inoperable according to TS 3.5.1, “ECCS – Operating”. The cause of the differential pressure switch failure was water leakage into the switch electrical housing caused by a failure of the shaft seal. The faulty switch was replaced and the LPCS pump was restored to operable status approximately 15 hours after the observed failure on April 17th. The LPCS pump minimum flow valve had successfully operated after post-maintenance testing completed on April 5th. A search of LERs did not yield any windowed events. A risk analysis was performed assuming LPCS was unable to fulfil its safety function for an exposure time of approximately 13 days, which resulted in a mean ΔCDP of 6E-8 from internal events, high winds (including tornadoes), and seismic events. This estimate is believed to be conservative because the failure of the minimum flow valve would not affect LPCS during a large loss-of-coolant (LOCA), which is the dominant internal event risk contributor. Internal flooding and fires scenarios are not included in the LaSalle SPAR model. The risk impact due to internal floods and fires is likely to be minimal for this degraded condition because there are multiple sources of low-pressure availability mitigate the risk associated with a LPCS unavailability. Therefore, the risk associated with this degraded condition is judged to be below the ASP Program threshold and, therefore, is not a precursor.</td></tr>
<tr><td>Ginna</td><td>244-23-001</td><td>4/11/23</td><td>Vital Bus 17 Failed to Load onto EDG B During Load/Safeguard Sequence Testing; Corroded Breaker Shunt Trip Attachment Plunger Found Which Indicated an Earlier Violation of TS 3.8.1</td><td>6/7/23</td><td>6/28/23</td><td>3e</td><td>7/11/23</td><td>9/21/23</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 (ML23311A186).</td></tr>
<tr><td>Palo Verde 1</td><td>528-23-001</td><td>4/8/23</td><td>Unit 1 Reactor Trip Following a Main Turbine Trip</td><td>6/7/23</td><td>9/25/23</td><td>6a</td><td>9/26/23</td><td>9/29/23</td><td>Analyst Screen-out</td></tr>
<tr><td colspan="10">Analyst Justification. This event is not discussed in any IR to date, the LER remains open. On April 8, 2023, a control oil pump tripped resulting in an automatic start of the alternate control oil pump ‘B’. The running amperage for control oil pump ‘B’ indicated low, and the system pressure continued to degrade until it resulted in a main turbine trip. This resulted in a reactor power cut back, but an automatic reverse power relay actuation did not occur to trip the generator switchyard output breakers. Operators manually opened the generator switchyard output breakers per the applicable procedural guidance. A loss of power to the 13.8 kilovolt (kV) non-class buses (1E-NAN-S01 and 1E-NAN-S02) caused the reactor coolant pumps (RCPs) to trip, which resulted in a reactor protection system (RPS) actuation and a reactor trip. The non-class loads were de-energized due to the loss of power to the non-class 13.8 kV buses, which included condensate pumps. The loss of the condensate pumps caused the main feedwater pumps to trip on low suction pressure. Operators manually started auxiliary feedwater AFW pump ‘B’ to feed both steam generators (SGs). In addition, operators manually initiated a main steam isolation per the Loss of Forced Circulation Emergency Operating Procedure (EOP). Therefore, the SG atmospheric dump valves (ADVs) were used for decay heat removal. Power restoration to the non-class buses was completed approximately 3.5 hours after the reactor trip occurred. A search of LERs did not yield any windowed events. The risk of this event is bounded by a non-recoverable loss of main feedwater and condenser heat sink. Therefore, the risk of this event is below the ASP Program threshold and is not a precursor.</td></tr>
<tr><td>Palo Verde 2</td><td>529-23-001</td><td>6/2/23</td><td>Unit 2 Automatic Reactor Trip on Low Steam Generator Water Level Due to Degraded Feedwater Flow</td><td>8/1/23</td><td>9/21/23</td><td>6a</td><td>9/22/23</td><td>9/29/23</td><td>Analyst Screen-out</td></tr>
<tr><td colspan="10">Analyst Justification. This event is not discussed in any IR to date, the LER remains open. On June 2, 2023, a reduction in the feedwater pump ‘A’ speed led to a reduction in SG level and a subsequent reactor and turbine trips. Following the reactor trip, SG water levels reached the AFW actuation system setpoint resulting in the subsequent start of both class AFW pumps. In addition, both EDGs automatically started, but ran unloaded because safety-related power was supplied via offsite power throughout the event. The 1E-NAN-S02 fast bus transfer did not actuate following the turbine trip resulting in the loss of two RCPs. Both EDGs were secured approximately 4.5 hours after the reactor trip occurred. A search of LERs did not yield any windowed events. The risk of this event is bounded by a non-recoverable loss of main feedwater and condenser heat sink. Therefore, the risk of this event is below the ASP Program threshold and is not a precursor.</td></tr>
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<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>Beaver Valley 2</td><td>412-23-004</td><td>7/12/23</td><td>Condition Prohibited by TS and Loss of Safety Function due to EDG Lube Oil Contamination by Fuel Oil</td><td>9/8/23</td><td>9/5/23</td><td>3e</td><td>9/26/23</td><td>9/29/23</td><td>Analyst Screen-out</td></tr>
<tr><td colspan="10">Analyst Justification. This condition is not discussed in any IR to date, the LER remains open. On July 12, 2023, EDG ‘2-2’ was declared Inoperable due to its rocker arm lube oil system viscosity degrading such that the required 30-day mission time would not be met. The cause to the degraded viscosity was likely due to fuel oil system leakage into the rocker arm lube oil system from a loose fuel oil injection line packing nut. Compensatory measures were implemented to monitor and maintain the lube oil viscosity within the required limit by a proceduralized drain and fill process based on lube oil sample results and EDG run time. EDG ‘2-2’ was declared operable at on July 15th. A licensee calculation based on the calculated leak rate indicated that the EDG ‘2-2’ would have been capable of running for 3.1 days given the maximum allowable dilution rate. Since EDG ‘2-2’ was able to fulfil its PRA mission time of 24 hours, there was not 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>Perry</td><td>440-22-003</td><td>8/10/23</td><td>Plant Trip During Reactor Protection System Power Transfer</td><td>9/28/23</td><td>10/31/23</td><td>2h</td><td>11/6/23</td><td>11/13/23</td><td>Analyst Screen-out</td></tr>
<tr><td colspan="10">Analyst Justification. This event is not discussed in any IR to date, the LER remains open. On August 10, 2023, a reactor scram occurred during the transfer of the RPS power supply ‘B’ from the alternate power supply to the normal power supply. During the transfer, a loss of both RPS buses ‘A’ and ‘B’ occurred, causing the main steam isolation valves (MSIVs) to close and a subsequent reactor scram. The safety relief valves (SRVs) automatically opened to lower and maintain reactor pressure. Water level in the reactor vessel dropped to Level 2 resulting in the automatic starts of the high-pressure core spray (HPCS) and RCIC systems, which was restored reactor water level. A subsequent licensee investigation concluded the loss of both RPS buses resulted from slight overtravel of the RPS power transfer switch from the ALT to the NORM position. The risk of this event is bounded by a non-recoverable loss of main feedwater and condenser heat sink. Therefore, the risk of this event is below the ASP Program threshold and is not a precursor.</td></tr>
<tr><td>South Texas 1</td><td>498-23-001</td><td>3/18/23</td><td>Pressurizer PORV Failed to Open</td><td>6/12/23</td><td>6/28/23</td><td>3i</td><td>7/11/23</td><td>11/13/23</td><td>SDP Screen-out</td></tr>
<tr><td colspan="10">Analyst Justification. A Green finding was identified in IR 05000498/2023003 (ML23310A228); the LER is closed. On March 18, 2023, during a refueling outage, pressurizer power-operated relief valve (PORV) PCV-0656A failed to open when the main control room (MCR) hand switch was taken to open during a surveillance procedure. The surveillance was successfully re-performed later that shift. However, the capability of the PORV to meet its design function to manually control of reactor coolant system (RCS) pressure from November 3, 2021, through March 18, 2023, was not assured and, therefore, PORV PCV-0656A was determined to be inoperable considered. In addition, the other PORV (PCV-0655A) was unavailable due to scheduled maintenance on its power supply on January 4, 2023, for approximately 6.5 hours. A subsequent licensee evaluation determined that following conditions resulted in the failure of PORV PCV-0656A—(a.) an opening orifice was installed in the solenoid operating valve that slowed the opening of the PORV; (b.) the clearance tolerance between the valve plug and cage was out of specification; and (c.) the associated PORV block valve was closed, which resulted in two-phase flow causing a choked condition at the opening orifice . NRC inspectors determined that the licensee failure to establish measures to assure the design basis of PCV-0656A was correctly translated into drawings, procedures, and instructions was a performance deficiency. Specifically, the licensee failed to ensure that instructions or procedures assured that a critical tolerance was within limits before the PORV was returned to service, and failed to ensure that the correct solenoid operator, suitable to the design, was installed during maintenance during refueling outage 1RE23. A detailed SDP risk evaluation was performed by a Region 4 senior reactor analyst (SRA) assuming PORV PCV-0656A was unable to fulfill its safety function for a maximum exposure time of 1 year. The assessment resulted in an increase in core frequency (ΔCDF) of 8E-7 per year from internal events, internal fires, internal floods, 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 event is below the ASP Program threshold and, therefore, this event is a not a precursor.</td></tr>
<tr><td>Fermi</td><td>341-23-001</td><td>3/23/23</td><td>Loss of Mechanical Draft Cooling Tower Fan Brakes during High Speeds Leads to Loss of Safety Function and Inoperability</td><td>5/22/23</td><td>6/28/23</td><td>3f</td><td>7/11/23</td><td>11/13/23</td><td>SDP Screen-out</td></tr>
<tr><td colspan="10">Analyst Justification. A Green finding was identified in IR 05000341/2023002 (ML23304A155), the LER remains open. On March 13, 2023, the division ‘II’ residual heat removal service water (RHRSW) system mechanical draft cooling tower (MDCT) fan ‘D’ brake was declared inoperable due to loss of speed indication at high speeds during an overspeed protection system calibration. The loss of speed indication also affected the fan brake operability during a postulated design basis tornado event. The plant entered TS Limiting Condition for Operation (LCO) 3.0.9, which allows 30 days before declaring the supported system(s) inoperable and the LCO(s) associated with the supported system(s) not met. On March 23rd, the other three MDCT fan brakes were declared inoperable due to the same condition. On March 24th, potentiometers were installed on all four fan brake circuits and the MDCTs were returned to service. A licensee operability review concluded that the speed switches were installed on December 9, 2020, for division ‘I’ and on September 14, 2022, for division ‘II’. Given the maximum exposure time for ASP analyses is 1 year, the exposure time of both divisions of MCDT fans is approximately 192 days and 127 days for the division ‘I MDCT fans alone. NRC inspectors determined that the licensee failure to failed to verify or check the adequacy of design, by the performance design reviews or a suitable testing program, of the operating characteristics of the new mechanical draft cooling tower fan speed switches installed per the engineering design package was a performance deficiency. Specifically, the licensee failed to verify the voltage present at the input to the speed switch aligned with information provided in the design drawings. In addition, the licensee did not verify the fan RPM indicators were reading appropriately after the fans were installed contrary to procedures. A detailed SDP risk evaluation was performed by a Region 3 SRA assuming that all four MDCT fans would fail during a design basis tornado. The maximum exposure time of 1 year was assumed for this evaluation. The assessment resulted in a ΔCDF of less that 1E-7 per year. 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 event is below the ASP Program threshold and, therefore, this event is a not a precursor.</td></tr>
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<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>Limerick 1</td><td>352-23-001</td><td>2/27/23</td><td>Emergency Diesel Generator Lube Oil Pressure Sensing Line Leak Resulting in a Condition Prohibited by Technical Specifications</td><td>6/26/23</td><td>7/13/23</td><td>3e</td><td>1/23/24</td><td>1/25/24</td><td>SDP Screen-out</td></tr>
<tr><td colspan="10">Analyst Justification. A Green finding was identified in IR 05000352/2023003 (ML23310A228); the LER is closed. On February 27, 2023, during planned 24-hour endurance run of the EDG ‘D11’ developed an oil leak at a threaded fitting for an oil pressure indicator instrument line during a planned 24-hour endurance test run. The EDG was secured and declared inoperable according to TS. A subsequent licensee failure analysis identified a crack in a threaded pipe nipple for the affected oil pressure indicator instrument line. Additional forensic analysis of the removed pipe nipple concluded that the pipe nipple showed fatigue fracture that started from one side at the root of the last engaged thread, consistent with unidirectional cyclic bending loads due to vibration. EDG was determined to be inoperable from the last completed surveillance test on January 31, 2023, until restored to operable status following repair of the identified oil leak on February 28th. NRC inspectors determined that the licensee failure to promptly identify and correct conditions adverse to quality associated with EDG ‘D11’ was a performance deficiency. Specifically, the licensee failed to identify certain adverse conditions that caused or contributed to high cycle fatigue fracture of a lubricating oil system pressure instrument fitting on multiple EDGs between 2013 and 2019 but did not take adequate action to promptly identify and correct these adverse conditions on EDG ‘D11’ prior to high cycle fatigue fracture of the same lubricating oil fitting on February 27th. A detailed SDP risk evaluation was performed by a Region 1 SRA assuming EDG ‘D11’ was unable to fulfill its safety function for an exposure time of 144 days. The assessment resulted in a ΔCDF of 9.7E-7 per year from internal events, internal fires, internal floods, 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 event is below the ASP Program threshold and, therefore, this event is a not a precursor.</td></tr>
<tr><td>Susquehanna 1</td><td>387-23-003</td><td>9/12/23</td><td>D Diesel Generator Inoperable due to Clogged Fuel Injectors</td><td>11/9/23</td><td>1/3/24</td><td>3e</td><td>1/23/24</td><td>2/1/24</td><td>Analyst Screen-out</td></tr>
<tr><td colspan="10">Analyst Justification. This condition is not discussed in any IR to date; the LER remains open. On September 12, 2023, EDG ‘D’ failed to reach the required frequency within the acceptance criteria during surveillance testing. Specifically, EDG ‘D’ reached the required frequency in 12.6 seconds, which exceeds the acceptance criteria of 10 seconds specified in Surveillance Requirement 3.8.1.7. Operators declared EDG ‘D’ inoperable, and the plant entered TS LCO 3.8.1, Condition B, for both units. The other three EDGs (‘A’, ‘B’, and ‘C’) were verified to be operable, and operators substituted in EDG ‘E’, which allowed both units to exit LCO 3.8.1, Condition B, later on September 12th. A subsequent licensee investigation determined that the failure of EDG ‘D’ to reach the required frequency within the acceptance criteria was the result of clogged fuel injectors. A licensee evaluation determined that EDG ‘D’ was still able to fulfil its safety function assumed in the applicable safety analyses described in Chapter 15 of the Susquehanna Updated Final Safety Analysis Report. Therefore, this condition is not a precursor, and a review of potential windowed events was not needed.</td></tr>
<tr><td>Grand Gulf</td><td>416-22-003</td><td>12/19/22</td><td>Manual Reactor Scram due to a loss of the Condensate and Feed Water System</td><td>2/16/23</td><td>8/14/23</td><td>1m</td><td>8/14/23</td><td>2/1/24</td><td>Reject</td></tr>
<tr><td colspan="10">A detailed ASP analysis determined that the conditional core damage probability of this event was less than the ASP Program threshold and, therefore, is not a precursor. The detailed ASP analysis is publicly available (ML24033A060).</td></tr>
<tr><td>Millstone 3</td><td>423-23-002</td><td>9/4/23</td><td>Auxiliary Feedwater Control Valve Failure Resulting in a Condition Prohibited by Technical Specifications</td><td>11/30/23</td><td>1/3/24</td><td>3b</td><td>1/23/24</td><td>2/27/24</td><td>SDP Screen-out</td></tr>
<tr><td colspan="10">Analyst Justification. A Green finding was identified in IR 05000423/2023004 (ML24045A114); the LER remains open. On October 1, 2023, turbine-driven AFW control valve for SG ‘A’ (3FWA*HV36A) changed its state to dual position. Coincident with the valve going dual position, the MCR received alarm MB1E “Turbine Driven Auxiliary Feedwater System Bypass Annunciator.” Control valve 3FWA*HV36A went full closed and then returned to the fully open position. The demand from the controller remained at fully open throughout the event. The plant entered the 72-hour shutdown action statements for TS 3.7.1.2 and 3.6.3. A similar occurrence had previously occurred on September 4, 2023. Licensee troubleshooting determined that the failure was caused by a degraded relay logic card. The card was replaced, and the valve was stroked successfully from fully open to 50-percent closed and back to fully open, and the 72-hour shutdown TS action statements were exited on October 3rd. However, 3FWA*HV36A went fully closed and then returned to the full-open position again October 5th. The plant entered the 72-hour shutdown action statements for TS 3.7.1.2 and 3.6.3 again. The licensee replaced card 3FWA*HY36A5. In addition, a temporary engineering change was implemented to install instrumentation to monitor the control circuit for 3FWA*HV36A. An operability determination was developed, and as a compensatory action, fuses were removed to fail 3FWA*HV36A to its full-open position. In the event that 3FWA*HV36A would need to be throttled for AFW flow control or closed for isolation of SG ‘A’, instructions were provided to re-install the fuses to allow operators to control the valve as required by plant conditions. The 72-hour shutdown action statements were exited on October 8th. NRC inspectors determined that the licensee failure to promptly identify and correct a condition adverse to quality associated with the turbine-driven AFW control valve was a performance deficiency. Specifically, the licensee failed to promptly identify and correct a degraded controller/positioner circuit card, which rendered the turbine-driven AFW pump inoperable for longer than its TS allowed outage time. A detailed SDP risk evaluation was performed by a Region 1 SRA assuming 3FWA*HV36A was failed closed for an exposure time of 45 days. The assessment resulted in a ΔCDF of 7E-8 per year from internal events. Because the ΔCDF was below 1E-7, the risk impact due to external events was not evaluated. 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 event is below the ASP Program threshold and, therefore, this event is a not a precursor.</td></tr>
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Plant	LER	Event Date	Description	LER Date	Screen Date	Criterion	Date Assigned	Date Completed	Classification
Braidwood 2	457-23-001	9/22/23	Train B Auxiliary Feedwater Pump was Inoperable due to Degraded Oil in the Crank Case	11/17/23	1/3/24	3b	1/3/24	**4/19/24**	SDP Screen-out

Analyst Justification. A Green finding will be issued in a future IR; the LER remains open. On September 1, 2023, an oil sample from AFW pump '2B' diesel engine indicated that the oil viscosity and fuel percent was in the "fault range". On September 22nd, the resample results confirmed the original analysis, and the AFW pump '2B' was declared inoperable and the plant entered TS LCO 3.7.5, "Auxiliary Feedwater System," Condition A. Maintenance was completed on September 23rd, and AFW pump '2B' operability was restored. NRC inspectors determined that the licensee failure to correct a condition adverse to quality when a May 19, 2023, oil sample result for AFW pump '2B' engine showed viscosity levels in the "alert range" was a performance deficiency. An initial SDP risk evaluation determined that the risk associated with this performance deficiency was GTG. However, subsequent testing contracted by the licensee showed that the AFW pump '2B' diesel engine would have fulfilled its safety function with the contaminated lube oil for the complete PRA mission time except for the approximately 27 hours of repair time. The revised SDP risk evaluation performed by a Region 3 SRA assuming AFW pump '2B' was unable to fulfill its safety function for an exposure time of approximately 27 hours resulted in a mean ΔCDF of 1E-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 event is below the ASP Program threshold and, therefore, this event is a not a precursor.