This report provides the results the Accident Sequence Precursor (ASP) Program for 2021. In addition, trends and key insights are provided for the past 10 years (2012 through 2021).

U.S. Nuclear Regulatory Commission Accident Sequence Precursor (ASP) Program 2021 Annual Report

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Christopher Hunter
(301) 415-1394
christopher.hunter@nrc.gov

Performance and Reliability Branch
Division of Risk Analysis
Office of Nuclear Regulatory Research
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

1. 2021 ASP RESULTS

There were 135 licensee event reports (LERs) issued in calendar year 2021. From these LERs, 104 (approximately 77 percent) were screened out in the initial screening process and 31 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 ASP Program since the switch was made to review LERs issued on a calendar-year basis in 2016. The ASP Program is looking at the potential of other data sources for potential precursors due the decreasing LERs for failures that have been reported historically.

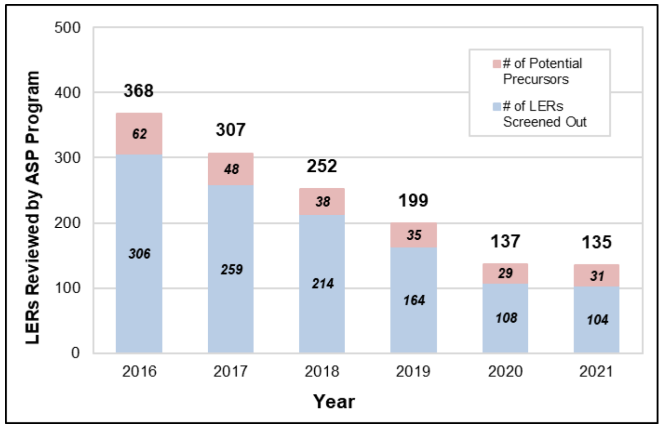

Figure 1. ASP Program LER Review Breakdown

Of the 31 potential precursors, 4 events were determined to exceed the ASP Program threshold and, therefore, are precursors. An independent ASP analysis was performed to determine the risk significance for three of these precursors. One precursor was the result of greater-than-*Green* inspection finding identified in 2021.[1] Table 1 provides a brief description of all precursors identified in 2021. The three precursors identified in 2021 using an independent ASP analysis were compared with results from Management Directive (MD) 8.3, "NRC Incident Investigation Program," (ML18073A200) and Significance Determination Process (SDP). This comparison is provided in Appendix A.

Table 1. 2021 Precursors

Plant/Description	LER/IR	Event Date	Exposure Time	CCDP/ ΔCDP
Davis-Besse, Emergency Diesel Generator (EDG) Speed Switch Failure due to Direct Current System Ground (ML21356A058)	346-21-001	2/12/21	9 days	*White* Finding
Davis-Besse, Field Flash Selector Switch Failure Results in EDG Unavailability (ML22164A812)	05000346/2021050 *(No LER was issued)*	5/27/21	99 days	9×10^{-6}
Davis-Besse, Reactor Trip due to Failed Uninterruptible Power Supply (UPS) and Steam Feedwater Rupture Control System Actuations (ML22125A048)	346-21-003	7/8/21	Initiating Event	3×10^{-6}
Waterford, Loss of Offsite Power (LOOP) during Hurricane Ida (ML22122A190)	382-21-001	8/29/21	Initiating Event	5×10^{-4}

After further analysis, the remaining 27 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 SDP results is provided in Appendix B. The evaluation of other hazards beyond internal events (e.g., internal fires, seismic events) did not result in any additional precursors in 2021.

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[1] Two additional potentially greater-than-*Green* inspection findings, a finalized greater-than-*Green* cybersecurity finding at Davis-Besse Nuclear Station (ML20091L428) and a preliminary *White* radiation protection finding at Columbia Generating Station (ML21347A988), were identified in 2021. However, these findings were not associated with increased risk to core damage and, therefore, are out of the scope of the ASP Program.

2. ASP TRENDS

Table 2. Precursor Trend Results

Precursor Group	Trend	p-value
All Precursors	Decreasing	0.00001
Important Precursors [i.e., conditional core damage probability (CCDP) or increase in core damage probability (ΔCDP) $\geq 10^{-4}$]	No Trend	0.4
Precursors with CCDP/ΔCDP $\geq 10^{-5}$	Decreasing	0.01
Initiating Events	Decreasing	0.002
Degraded Conditions	Decreasing	0.001
LOOPs	Decreasing	0.01
EDG Failures	No Trend	0.9
Boiling-Water Reactor (BWR) Precursors	Decreasing	0.02
Pressurized-Water Reactor (PWR) Precursors	Decreasing	0.0002

These ASP trends, along with the results of the ASP index, indicate that NRC oversight and licensing activities remain effective and that licensee risk management initiatives are not resulting in an increasing risk profile for the industry.

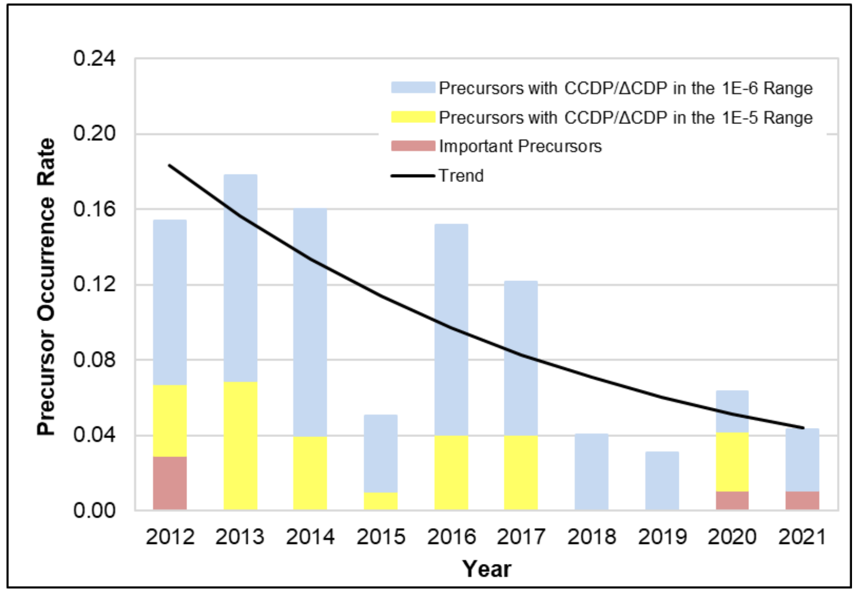

Figure 2. Occurrence Rate of All Precursors

ADDITIONAL PRECURSOR TRENDS

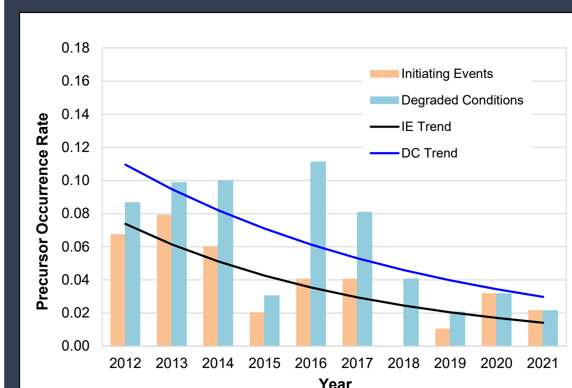

Figure 3. Occurrence Rate of Initiating Event and Degraded Condition Precursors

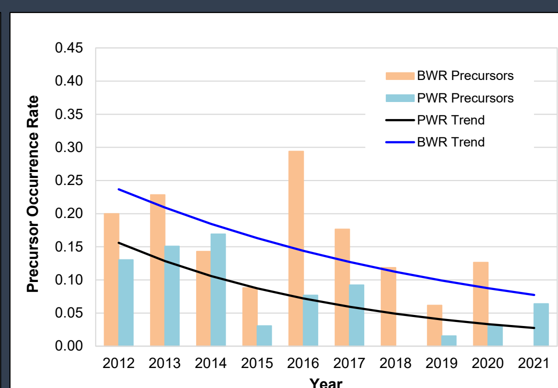

Figure 4. Occurrence Rate of BWR and PWR Precursors

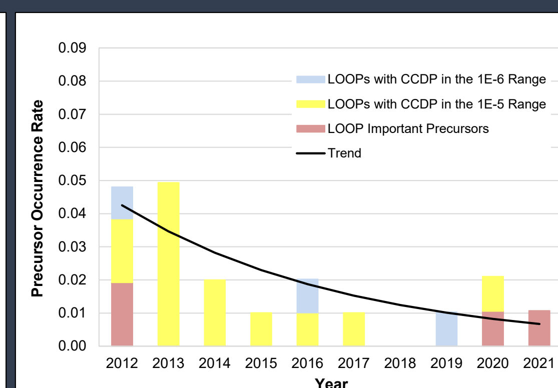

Figure 5. Occurrence Rate of LOOP Precursors

3. KEY INSIGHTS

Key insights based on the review of the 99 precursors that were identified in the past decade (2012–2021) are provided in this section. Note that additional insights can be gathered by using the publicly available ASP Program Dashboard.

There were 5 important precursors identified during this period, all of were due to initiating events (4 LOOPs and a loss of service water).

The ratio of precursors identified via greater-than-*Green* vs. independent ASP evaluations continues to decrease. In 2016, the 10-year percentage was 69 percent, but is currently 54 percent.

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

Natural phenomena caused 11 precursors, with snow/ice and lightning the most frequent causes.

The most frequent structure, system, and component (SSC) failures observed in precursors were associated with EDGs, flood protection, and switchyard.

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 or design issues.

There are no indications of increasing risk due to the potential "cumulative impact" of risk-informed initiatives.

No new component failure modes or mechanisms were identified. In addition, the likelihood and impacts of accident sequences have not changed.

Long duration LOOPs occurring at single-unit site have a high likelihood of resulting in a higher-risk precursors.

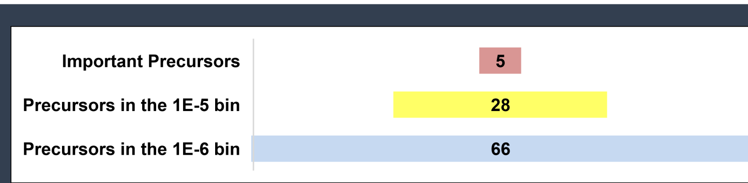

Figure 6. Precursor Breakdown by Risk Bin

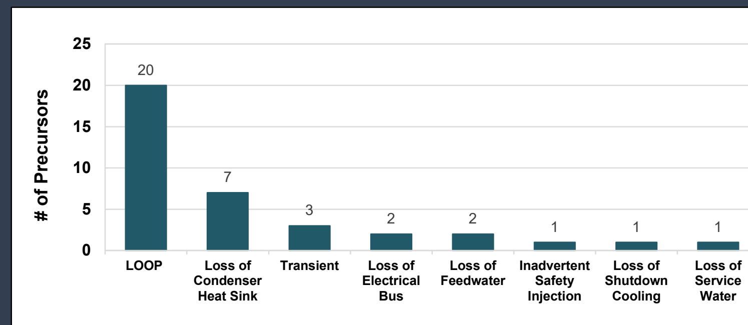

Figure 7. Most Frequent Initiating Event Precursor Types

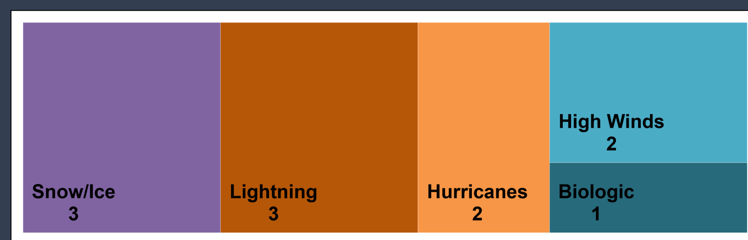

Figure 8. Natural Phenomena Precursors Causes

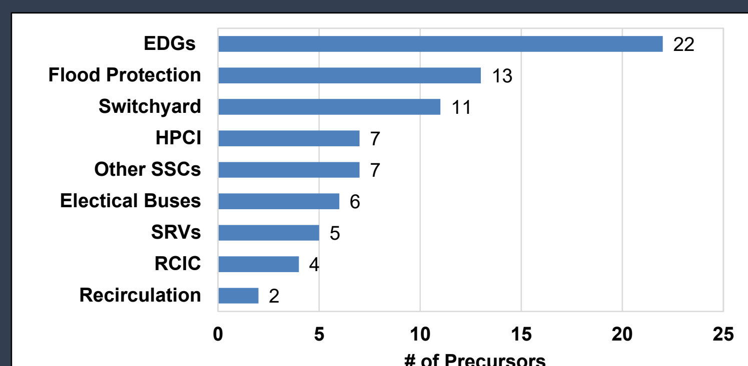

Figure 9. Most Frequent Precursor SSC Failures

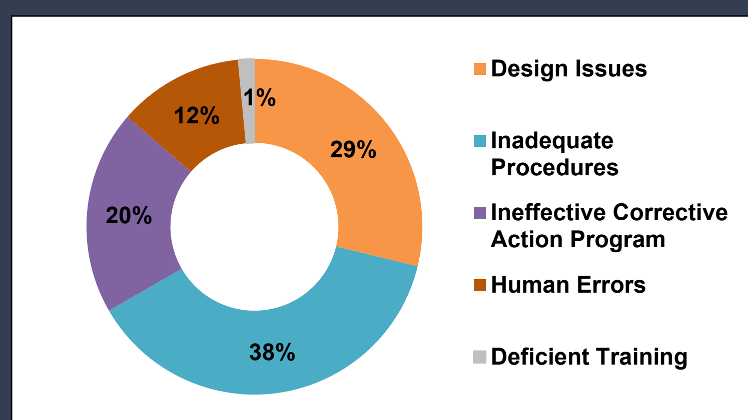

Figure 10. Dominant Precursor SSC Failures

4. 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. Therefore, the ASP index provides a unique way to evaluate the risk of longer-term degraded conditions over the entire duration of the condition.

The ASP index does not exhibit a statistically significant trend (*p-value* = 0.7) for the past decade (2012–2021). The total risk associated with precursors (99 total precursors) is dominated by the 5 important precursors, which account for approximately 60 percent of the total risk due to all precursors. The other 94 precursors account for approximately 47 percent to the total risk due to all precursors.

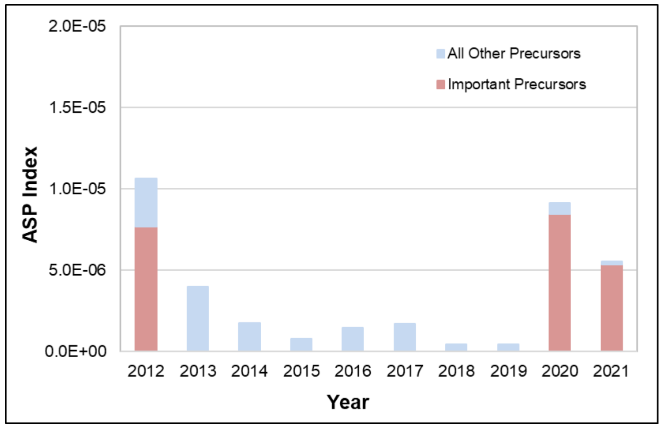

Figure 3. ASP Index

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].

Appendix A: Comparison of 2021 ASP Analyses

The three precursors identified in 2021 using an independent ASP analysis were compared with results from MD 8.3 and SDP analyses, as shown in the following table. Given the three programs have different functions, it is expected that the results are likely to be different.

Event Description	Program Results	SPAR Model/Methodology Improvements and Insights
Davis-Besse, IR 05000346/ 2021050 Field Flash Selector Switch Failure Results in EDG Unavailability	**MD 8.3.** ΔCDP estimated to be in the range of 7×10^{-7} to 5×10^{-6}, which led to a special inspection. See IR 05000346/2021050 (ML21321A365) for additional information. **SDP.** No performance deficiency was identified for this event; therefore, no SDP evaluation was performed. **ASP.** ΔCDP = 9×10^{-6}; EDG unavailable for 99 days. See final ASP analysis (ML22164A812) for additional information.	Credit for FLEX mitigation strategies was provided using with updated reliability data provided by the Pressurized Water Reactor Owners Group (PWROG). Modified FLEX modeling according to review of licensee's final integrated plan.
Davis-Besse, LER 346-21-003 Reactor Trip due to Failed UPS and Steam Feedwater Rupture Control System Actuations	**MD 8.3.** CCDP = 1×10^{-6}, which led to a special inspection. See IR 05000346/2021050 (ML21321A365) for additional information. **SDP.** Three *Green* findings were identified. The first finding was associated with the licensee failure to appropriately classify the digital electro-hydraulic control UPS battery bank as "non-critical" as required by component classification procedures. The second finding was associated with the licensee failing to establish procedural guidance for transferring the gland sealing steam supply from the main steam system to the auxiliary steam system following a reactor trip. The third finding was associated with the licensee failure to have an appropriate procedure for the replacement of main steam isolation valve limit switch. All three findings were screened out (i.e., no detailed risk evaluation was performed). See IR 05000346/2021050 (ML21321A365) for additional information. **ASP.** CCDP = 3×10^{-6}; loss of condenser heat sink and overcooling. See final ASP analysis (ML22125A048) for additional information.	Modified loss of condenser heat sink event tree to account for potential overcooling. Used IDHEAS-ECA for human reliability analysis of critical human failure event.
Waterford, LER 382 21 001 LOOP during Hurricane Ida	**MD 8.3.** No evaluation performed. **SDP.** No performance deficiency was identified for this event; therefore, no SDP evaluation was performed. **ASP.** CCDP = 5×10^{-4}; weather-related LOOP occurred during Hurricane Ida. See final ASP analysis (ML22122A190) for additional information.	Credit for FLEX mitigation strategies was provided using with updated reliability data provided by the PWROG. Modified FLEX modeling according to review of licensee's final integrated plan. Performed MELCOR calculations to support credit for long-term turbine-driven emergency feedwater pump operation. Performed event analyses for other plants that have experienced a LOOP during a hurricane in the past 20 years to develop generic risk insights.

Appendix B: 2021 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 greater-than-*Green* 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>Comanche Peak 1</td><td>445-20-001</td><td>12/16/20</td><td>MFW Pump Failure to Trip</td><td>2/11/21</td><td>2/23/21</td><td>3b</td><td>3/18/21</td><td>4/7/21</td><td>Analyst Screen-Out</td></tr>
<tr><td colspan="10">Analyst Justification. This condition is not discussed in an inspection report (IR) to date; the LER remains open. On October 10, 2020, during a planned shutdown for refueling outage, operators could not manually trip main feedwater (MFW) pump ‘1A’ from the main control room (MCR). Subsequent attempts to trip the pump locally also failed. Operators declared 1 of 2 input signals to engineered safety feature actuation system (ESFAS) instrumentation inoperable for function 6.g of Technical Specification (TS) 3.3.2, which uses a two of two logic to automatically start both motor-driven auxiliary feedwater (MDAFW) pumps when both MFW pumps trip. The manual trip failed because MFW pump ‘1A’ trip oil pressure did not lower when operators attempted to trip the pump from the MCR and locally. Non-licensed operators closed the steam supply valves to the MFW pump ‘1A’ turbine and manually lowered trip oil pressure to activate the ESFAS trip signal. A search of LERs did not yield any windowed events. Although the anticipatory start function of the MDAFW pumps upon a loss of both MFW pumps was lost due to this failure, the other automatic start signals (e.g., low steam generator level) were not affected and remained available. In addition, the operators had the ability to manually start the MDAFW pumps. Given these considerations, the risk of this condition is qualitatively determined to be below the ASP Program threshold and, therefore, is not a precursor.</td></tr>
<tr><td>Shearon Harris</td><td>400-21-002</td><td>12/17/20</td><td>All ECCS Accumulator Isolation Valves Closed in Mode 3 With RCS Pressure Greater than 1000 psig</td><td>2/15/21</td><td>3/2/21</td><td>3d</td><td>3/18/21</td><td>4/7/21</td><td>Analyst Screen-Out</td></tr>
<tr><td colspan="10">Analyst Justification. This condition is not discussed in an IR to date; the LER remains open. On December 17, 2020, with the plant in Mode 3, reactor coolant system (RCS) pressure was being controlled between 900–1000 psig with all three cold leg accumulator discharge valves closed. Operators were manually controlling RCS pressure manual using a pressurizer spray valve with only one reactor coolant pump (RCP) running, which reduced the pressurizer spray effectiveness resulting in an RCS pressure increase. MCR operators took immediate actions to stop the pressure increase by fully opening the pressurizer spray vale, reducing charging flow, and turning off all pressurizer heaters. However, these actions were not performed in time to prevent RCS pressure from exceeding 1000 psig. TS require that the cold leg accumulators be operable in Mode 3 when RCS pressure is greater than 1000 psig. Since all three cold leg accumulator discharge valves were closed, this TS requirement was not met for approximately 15 minutes until operators were able to reduce RCS pressure below 1000 psig. A search of LERs did not yield any windowed events. Because the licensee restored RCS pressure below 1000 psig within 15 minutes, the exposure time was not longer than the TS allowed outage time. Therefore, an evaluation of this condition under the ASP Program to determine whether it is a precursor is not warranted.</td></tr>
<tr><td>Limerick 1</td><td>352-20-002</td><td>11/16/20</td><td>HPCI and RCIC Were Not Aligned for Service During Startup Resulting in TS Violations</td><td>1/26/21</td><td>2/3/21</td><td>3d</td><td>3/29/21</td><td>4/7/21</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 November 16, 2020, Unit 1 was starting up when the reactor steam dome pressure exceeded 150 psig without the reactor core isolation cooling (RCIC) system being aligned for service, which is contrary to TS 3.7.3. Reactor steam dome pressure continued to increase above 200 psig without the high-pressure coolant injection (HPCI) system being aligned for service and, therefore, the plant entered TS 3.5.1. During a shift change the oncoming MCR operating crew recognized HPCI was still isolated and immediately began to warm-up the HPCI system and align HPCI for operation. RCIC and HPCI were aligned for service and declared operable approximately 90 minutes and 2 hours after reactor steam dome pressure exceeded 150 psig and 200 psig, respectively. This condition was caused by the failure of operators to correctly perform the startup procedure. A search of LERs did not yield any windowed events. Because the licensee restored HPCI and RCIC within their TS required action times and the exposure times were not longer than the TS allowed outage times for those systems, an evaluation of this condition under the ASP Program to determine whether it is a precursor is not warranted.</td></tr>
<tr><td>LaSalle 2</td><td>374-21-001</td><td>12/23/20</td><td>HPCS Inoperable due to Water Leg Pump Breaker Cubicle Motor Contactor</td><td>2/18/21</td><td>3/2/21</td><td>3d</td><td>4/16/21</td><td>4/27/21</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 December 23, 2020, the Unit 2 high-pressure core spray (HPCS) water leg pump tripped due to a breaker fault. Operators subsequently declared the HPCS system inoperable according to TS. The RCIC system was verified to be operable. The affected breaker cubicle control power transformer and motor starter contactor were replaced and the HPCS system was declared operable approximately 13 hours after the initial failure. A search of LERs did not yield any windowed events. Since the HPCS system was unavailable for less than the limits of TS Limiting Condition of Operation (LCO) 3.5.1, Condition B (14 days), this condition is screened out and is not considered 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>Susquehanna 1</td><td>387-21-001</td><td>3/9/21</td><td>Unplanned Inoperability of the HPCI System due to a PCIV Failure to Stroke Full Closed On-Demand due to an Intermittent Break in the Close Control Circuitry</td><td>5/6/21</td><td>5/13/21</td><td>3d</td><td>5/27/21</td><td>6/9/21</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 9, 2021, during performance of quarterly HPCI system valve exercising, the HPCI turbine exhaust vacuum breaker inboard isolation valve (HV155F079) failed to stroke fully closed. The closure function of this valve supports primary containment isolation; however, this function was maintained given the outboard containment isolation valve (HV155F075) successfully stroked closed. The direct cause of the condition was an intermittent break in the valve’s close control circuitry likely due to dirty contacts on the HPCI turbine exhaust vacuum breaker inboard isolation valve hand switch. Key corrective actions include planned replacement of the hand switch. After the initial failure, operators successfully stroked HV155F079 open and closed within acceptance times. Although the HPCI system was TS inoperable for approximately 39 hours, operators could manually open HV155F079 to restore HPCI availability. A search of LERs did not yield any windowed events. Because the licensee restored HPCI within their TS required action time and the exposure time was not longer than the TS allowed outage time, an evaluation of this condition under the ASP Program to determine whether it is a precursor is not warranted.</td></tr>
<tr><td>Palo Verde 2</td><td>529-21-002</td><td>5/19/21</td><td>Reactor Trip during Plant Protection System Surveillance Testing</td><td>7/16/21</td><td>8/5/21</td><td>1d/2h</td><td>8/6/21</td><td>8/12/21</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 May 19, 2021, an invalid actuation of the safety injection (SI), containment isolation, and main steam isolation signals occurred resulting in an automatic reactor trip due to high pressurizer pressure caused by the closure of the main steam isolation valves (MSIVs). The essential AFW pumps automatically started due to low steam generator (SG) level. Both trains of the high-pressure safety injection (HPSI) and low-pressure safety injection (LPSI), containment spray, and essential spray pond pumps automatically started due to the SI actuation signal. RCS pressure remained above the HPSI pump head and, therefore, no injection into the RCS occurred during this event. In addition, the emergency diesel generators (EDGs) automatically started; however, the EDGs did not load onto their respective buses because they remained supplied by offsite power. Operators reset SI actuation signal, closed the HPSI and LPSI injection valves, and stopped all HPSI, LPSI, and containment spray pumps as directed by the emergency operating procedures (EOPs). Although the steam supply to the MFW pumps was interrupted by the closure of the MSIVs, the condensate system continued to operate, and condenser vacuum remained intact. MFW was potentially recoverable using existing plant procedures in approximately 30 minutes. This event was caused by invalid trip signal that occurred during plant protection system functional testing. 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/or condenser heat sink. Therefore, the risk of this event is below the ASP Program threshold and is not a precursor.</td></tr>
<tr><td>Peach Bottom 2</td><td>277-21-001</td><td>4/29/21</td><td>HPCI System Declared Inoperable Due to Instrument Power Inverter Failure</td><td>6/24/21</td><td>7/22/21</td><td>3d</td><td>8/6/21</td><td>8/12/12</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 29, 2021, the HPCI system inverter circuit failure alarm was received the MCR. Operators immediately noticed erratic performance of HPCI system pressure instruments and a loss of the expected status display on the HPCI flow controller. Examination of the HPCI rack-mounted inverter revealed that the power indicator light was cycling on and off. Further inspection of the HPCI back panel revealed that the logic bus power monitoring relay was chattering. In the event of a valid HPCI initiation signal, the erratic power supply to the HPCI flow controller would have resulted in a loss of HPCI safety function. On April 30th, the inverter replacement was completed, and HPCI function was restored after satisfactorily testing was completed. The exposure time for the failed HPCI inverter was approximately 15 hours. A search of LERs identified LER 277-21-002 as a potential windowed event. The “windowed” aspect of these two events will be evaluated as part of the ASP evaluation of LER 277-21-002. 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, an evaluation of this condition under the ASP Program to determine whether it is a precursor is not warranted.</td></tr>
<tr><td>Braidwood 1</td><td>456-21-001</td><td>4/23/21</td><td>Train A and B Source Range Neutron Flux Trip Functions Bypassed During Plant Startup</td><td>6/21/21</td><td>7/8/21</td><td>3a</td><td>7/19/21</td><td>8/25/21</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 23, 2021, during reactor startup activities with the plant in Mode 2, operators identified that both trains ‘A’ and ‘B’ source range neutron flux reactor trip functions were bypassed. Operators immediately took the bypass switches to normal in accordance with TS. The incorrect position of the source range neutron flux reactor trip functions existed since April 21st while the plant was in Mode 5 operation. A licensee review determined that on April 21st, with the plant in Mode 5, both source range neutron flux trips were placed in bypass per procedure in support of switchyard activities. After the switchyard activities were completed, operators failed to restore the source range neutron flux trips per procedure. A search of LERs did not yield any windowed events. The source range neutron flux trips provide protection during postulated uncontrolled rod withdrawal events. The source range detectors provide indication of an RCS boron dilution event. However, there are diverse trip and indications for both of these events (e.g., power range high neutron flux trip, volume control tank level alarm, etc.). Given the availability of the redundant, but diverse systems and the short exposure time of less than 3 days, the risk of this condition is qualitatively determined to be below the ASP Program threshold and, therefore, 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>Peach Bottom 2</td><td>277-21-002</td><td>5/18/21</td><td>SRV Inoperability Due to Nitrogen Leakage from Braided Hose Wear</td><td>7/16/21</td><td>8/5/21</td><td>3d</td><td>7/29/21</td><td>8/25/21</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 21, 2021, operators noted that the instrument nitrogen compressors were increasing in run hours, with all other related parameters steady. The condition was monitored and trended, and investigation determined the most likely cause to be nitrogen leakage within primary containment. A second step increase in nitrogen leakage occurred in May, which led to the decision to decrease reactor power to allow for entry into primary containment and investigate the source of leakage. On May 18th, the licensee identified that the nitrogen supply to safety relief valve (SRV) RV-2-02-071K was the source of the leak. Specifically, the stainless-steel braided hoses that supply and return nitrogen from the actuating solenoid valve had failed. This valve is one of five automatic depressurization system (ADS) valves and, therefore, the ADS function was declared inoperable according to TS 3.5.1. The failure of the braided hoses did not affect the overpressure function of SRV RV-2-02-071K. Note that the other four ADS valves use hard pipe for the instrument nitrogen supplies and returns. The hoses were replaced on May 18th and the unit was returned to full power. A search of LERs identified LER 277-21-001 as a potential windowed event. A risk assessment was performed assuming the unavailability of ADS valve 71K to open for its depressurization function. A potentially conservative exposure time of 75 days (March 5th to May 18th) was used. This analysis resulted in a ΔCDP of 4E-9 from internal events, internal fires, internal floods, seismic hazards, high winds, and tornados. A sensitivity analysis assuming the concurrent unavailability of the HPCI system for an exposure time of 15 hours (from LER 277-21-001) results in a ΔCDP of 4E-7, which is dominated by the risk of the HPCI failure during postulated internal fires scenarios. The risk of this condition, including the “windowed” aspects of LER 277-21-001, is below the ASP Program threshold and is not a precursor.</td></tr>
<tr><td>Palisades</td><td>255-21-001</td><td>6/16/21</td><td>Atmospheric Steam Dump Valves Inoperable Due to Relay Failure</td><td>8/13/21</td><td>8/30/21</td><td>3i</td><td>8/30/21</td><td>9/8/21</td><td>Analyst Screen-Out</td></tr>
<tr><td colspan="10">Analyst Justification. This condition is briefly mentioned in IR 05000255/2021002 (ML21222A118); the LER remains open. On June 16, 2021, operators smelled an acrid odor in the MCR. A subsequent investigation revealed that the steam dump control relay failed as result of a short circuit in the coil, which rendered all four atmospheric dump valves (ADVs) inoperable. The total relief capacity of the ADVs is a steam flow of 30% with the reactor at full power and their operation prevents lifting the main steam safety valves following a turbine trip. The failed relay coil resulted in an overcurrent condition causing the supply fuse to open disabling both the ADVs automatic fast-open function and manual operation. The relay failure was due to age being beyond the vendor recommended life for a normally energized relay because the licensee had improperly classified it as a low-duty cycle instead of a high-duty cycle. The fuse and relay were replaced and the ADVs were returned to service approximately 12 hours later. A search of LERs did not yield any windowed events. Because the licensee restored the ADVs within their TS required action time (24 hours) and the exposure time was not longer than the TS allowed outage time for the system, an evaluation of this condition under the ASP Program to determine whether it is a precursor is not warranted.</td></tr>
<tr><td>Hope Creek</td><td>354-21-001</td><td>6/14/21</td><td>SRV As-Found Setpoint Failures</td><td>8/13/21</td><td>8/27/21</td><td>3i</td><td>8/30/21</td><td>9/15/21</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 June 14, 2021, tests of the pilot stage assemblies of SRVs ‘A’ and ‘J’ exceeded the lift setting tolerance of the nominal setpoint values prescribed in TS. In addition, SRV ‘R’ failed to lift when tested. Hope Creek has 14 safety-related main steam SRVs that provide reactor pressure vessel overpressure protection and an automatic/manual depressurization function. The setpoint exceedance for SRVs ‘A’ and ‘J’ was attributed to corrosion bonding between the pilot discs and seating surfaces. The cause of SRV ‘R’ not lifting was main disc and piston thread wear. SRV ‘R’ was replaced, and the seven two-stage SRVs (including SRVs ‘A’ and ‘J’) were replaced with three-stage models. A search of LERs did not yield any windowed events. Although SRVs ‘A’ and ‘J’ exceeded their lift setpoints by slightly greater than 3%, the licensee determined that both SRVs would have remained available to prevent overpressure of the reactor pressure vessel according to the margins of the plant’s design analysis. In addition, TS only requires 13 of 14 SRVs to be operable and, therefore, the failure of SRV ‘R’ did not affect the availability of overpressure protection of the reactor pressure vessel. Given these considerations, an evaluation of this condition under the ASP Program to determine whether it is a precursor is not warranted.</td></tr>
<tr><td>Fermi</td><td>341-21-001</td><td>5/3/21</td><td>Unrecognized Impact of Opening of Barrier Doors on HELB Analysis</td><td>7/1/21</td><td>7/22/21</td><td>3d</td><td>7/23/21</td><td>9/15/21</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 May 3, 2021, the licensee determined that the reactor building steam tunnel door had been open on several occasions for longer than was required for personnel ingress/egress. If a postulated high-energy line break (HELB) had occurred while the door was open, equipment outside the reactor building steam tunnel could have been adversely impacted by the post-HELB conditions. The maximum time the door was open over any 1-year period was approximately 12 hours. A search of LERs did not yield any windowed events. A risk assessment was performed assuming that the reactor building steam tunnel door was open for an exposure time of 12 hours using the Fermi SPAR model that was modified by Idaho National Laboratory (INL) to include a main steam line break (MSLB) event tree. This risk assessment conservatively assumed that HPCI, RCIC, residual heat removal (RHR), and low-pressure core spray (LPCS) would fail as the result of post-HELB conditions during a postulated MSLB in the reactor building steam tunnel with the door open. The MLSB initiating event frequency is considered bounding because not all steam line breaks would occur in the reactor building steam tunnel. This analysis resulted in a ΔCDP of 2E-10. The risk of this degraded condition is below the ASP Program threshold and, therefore, is not a precursor.</td></tr>
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<tr><td>Susquehanna 2</td><td>388-21-001</td><td>7/6/21</td><td>Condition Prohibited by TS Due to Drift of Reactor Pressure Switch</td><td>9/1/21</td><td>9/3/21</td><td>3d</td><td>9/7/21</td><td>10/14/21</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 6, 2021, the channel ‘D’ of reactor steam dome pressure low permissive pressure switch dropped below TS allowable value, which is intended to ensure that the emergency core cooling system (ECCS) injection prevents the fuel peak cladding temperature from exceeding regulatory limits. In addition, channel ‘C’ was under surveillance test when operator found the instrument drift on channel ‘D’ and, therefore, two channels were inoperable at the same time. Although the drift of channel ‘D’ was below the TS allowable value, the as-found set point remained above the limit assumed in the accident analysis and, therefore, the licensee determined that ECCS remained available. Since ECCS remained available, this condition is not a precursor, and a review of potential windowed events was not needed.</td></tr>
<tr><td>Hatch 1</td><td>321-21-003</td><td>9/8/21</td><td>HPCI System Discharge Valve Failure to Open</td><td>11/1/21</td><td>11/18/21</td><td>3d</td><td>11/19/21</td><td>11/30/21</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 8, 2021, the HPCI pump discharge isolation valve was stroked closed as a part of surveillance testing. Subsequent attempts by operators to reopen the valve failed. HPCI was declared inoperable in accordance with TS. Licensee troubleshooting determined that the pinion gear key in the valve actuator had not been properly staked during maintenance activities completed in 2006, which resulted in the key moving and the pinion gear disengaging from the actuator motor shaft. This issue was corrected on September 9th and HPCI was returned to operable status. The HPCI pump discharge isolation valve is normally open valve and does not change position during HPCI operations. Therefore, the exposure time of the loss of HPCI system function was limited to the 2 days when the valve was closed on September 8th and 9th. A search of LERs did not yield any windowed events. Since the HPCI system was unavailable for less than the limits of TS, this condition is screened out and is not considered a precursor.</td></tr>
<tr><td>Point Beach 1</td><td>266-21-001</td><td>7/31/21</td><td>MFW Pump Trip Results in Manual Reactor Trip</td><td>9/28/21</td><td>10/19/21</td><td>2h</td><td>10/20/21</td><td>12/6/21</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 July 31, 2021, operators manually tripped the reactor due to the failure of the MFW pump ‘B’ motor. After the reactor trip, the AFW pumps started and restored SG inventory levels. During the trip response, a condenser steam dump valve cycled but did not fully close, requiring operators to locally close the valve to prevent additional reactor cooldown. In addition, the crossover steam dump valves did not close resulting in deteriorating vacuum in the main condenser. Operators subsequently closed the valves resulting in the unavailability of the main condenser. The SG ADVs were used for decay heat removal. During the feedwater transition, the MFW regulating bypass valve ‘B’ did not maintain proper control of SG levels in automatic requiring operators to take manual control of the valve. MFW pump ‘A’ remained available throughout the event; however, reactor power was too high to support the loss of one of the two MFW pumps without requiring a reactor trip. 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/or condenser heat sink. Therefore, the risk of this event is below the ASP Program threshold and is not a precursor.</td></tr>
<tr><td>Perry</td><td>440-21-001</td><td>6/1/21</td><td>Division 3 EDG Inoperability Resulting in an Operation or Condition Prohibited by TS</td><td>7/28/21</td><td>8/19/21</td><td>3d</td><td>8/20/21</td><td>12/6/21</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 June 1, 2021, erratic output voltage was observed on the division ‘3’ EDG approximately 45 seconds after starting during monthly surveillance testing. The operators initially believed that the EDG was still operable; however, a subsequent evaluation did not support continued operability and the division ‘3’ EDG was later declared inoperable on June 3rd according to TS. On June 4th, voltage regulator was replaced and was tested satisfactory, thus restoring the division ‘3’ EDG to operable status. Discussions with NRC inspectors indicate that although the voltage fluctuation exceeded the TS limit, the voltages and frequencies experienced during the surveillance test were sufficient to support successful operation of the division ‘3’ EDG. Since the division ‘3’ EDG remained available, this condition is not a precursor, and a review of potential windowed events was not needed.</td></tr>
<tr><td>Nine Mile Point 1</td><td>220-21-002</td><td>9/25/21</td><td>Isolation of both Emergency Condensers due to loss of UPS 162A</td><td>11/19/21</td><td>12/3/21</td><td>3d</td><td>12/6/21</td><td>12/7/21</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 25, 2021, the MCR operators received multiple annunciators due to the loss of power to reactor protection system (RPS) bus ‘11’ caused by the failure of the uninterruptible power supply (UPS) ‘162A’. The loss of power to RPS bus ‘11’ resulted in a half scram, isolation of the reactor water cleanup system, and isolation of both emergency condensers. Operators subsequently declared the emergency condenser system inoperable according to TS, which requires operators to manually shutdown that plant within 1 hour. Operators reenergized RPS bus ‘11’ from instrumentation bus ‘130A’ in approximately 24 minutes. Both emergency condensers were restored to standby in approximately 39 minutes and 48 minutes respectively and, therefore, the reactor shutdown was no longer required. A search of LERs did not yield any windowed events. A risk assessment was performed assuming the unavailability of both emergency condensers for 1 hour, which is the minimum exposure time allowed by SAPHIRE. This analysis resulted in a ΔCDP of 1E-8 from internal events, seismic hazards, and high winds (including tornados). Internal flooding and fire scenarios are not included in the Nine Mile Point 1 SPAR model; however, the risk impact associated with these hazards is expected to be minimal due to the very short exposure time of this condition. The risk of this degraded condition is below the ASP Program threshold and, therefore, is not a precursor.</td></tr>
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<tr><td>Limerick 1</td><td>352-21-001</td><td>9/23/21</td><td>HPCI Inoperable Due to Remote Shutdown Panel Switch Failure</td><td>11/22/21</td><td>12/3/21</td><td>3d</td><td>12/6/21</td><td>12/15/21</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 23, 2021, the licensee was scheduled to perform the HPCI logic system functional isolation logic test and the HPCI pump valve and flow test. The HPCI logic system function isolation test was completed successfully. However, during the initial start of the turbine during the HPCI pump valve and flow test the indicated turbine speed on the plant computer point and MCR tachometer was downscale. The test was subsequently aborted when the HPCI pump was not able to meet the TS requirements for rated flow and discharge pressure. Licensee troubleshooting determined a high contact resistance existed in the HPCI emergency shutdown switch located on the remote shutdown panel. The purpose of this switch is to terminate or prevent HPCI injection from the remote shutdown panel under various fire safe shutdown events. The HPCI emergency shutdown switch high resistance was attributed to mechanical switch degradation that was introduced by cycling the switch during the HPCI logic system functional isolation logic test, which was performed 1 hour and 32 minutes prior to the HPCI pump valve and flow surveillance test. A search of LERs did not yield any windowed events. The HPCI system was unavailable for less than TS allowed outage time of 14 days. In addition, the failure of the HPCI emergency shutdown switch was in the safe direction (i.e., the high contact resistance would have terminated HPCI injection if manipulated during a MCR abandonment scenario). Given these considerations, the risk of this condition is qualitatively determined to be below the ASP Program threshold and, therefore, is not a precursor.</td></tr>
<tr><td>Vogtle 1</td><td>424-21-001</td><td>9/16/21</td><td>Train ‘A’ SI Pump Inoperability Causes the Unit to operate in a Condition Prohibited by TS</td><td>11/15/21</td><td>11/18/21</td><td>3d</td><td>11/19/21</td><td>12/15/21</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. During the refueling outage on September 16, 2021, plant operators conducted a surveillance test of SI pump ‘1A’. During the test, pump bearing temperatures rose rapidly requiring operators to secure the pump. A subsequent licensee investigation found a piece of plastic tubing between the gears of the lube oil pump, which resulted in lack of oil to the two bearings causing their failure. The pump was returned to operable status on September 29th after the bearing were replaced and the system was flushed . Improper oil sampling of SI pump ‘1A’ performed on September 6, 2021, introduced the foreign material into the pump's oil system. The plant entered into Mode 4 on September 12th as part a refueling outage. A search of LERs did not yield any windowed events. A risk assessment was performed assuming the SI pump ‘1A’ was failed for an exposure time of 138 hours (September 6th through September 12th). This analysis resulted in a mean ΔCDP 2E-8 from internal events, internal fires, internal floods, seismic hazards, and high winds (including tornados). The risk of this degraded condition is below the ASP Program threshold and, therefore, is not a precursor.</td></tr>
<tr><td>Browns Ferry 1 and 2</td><td>259-21-001</td><td>3/3/21</td><td>480V Load Shed Logic Inoperable Longer than Allowed by TS due to Failed Relay</td><td>11/22/21</td><td>12/3/21</td><td>3e</td><td>12/6/21</td><td>1/10/22</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 23, 2021, the division ‘I’ 480V load shed logic for Units 1 and 2 was declared inoperable during the performance of surveillance testing. During the test, relay 0-RLY-231-00A7 failed to energize due to an open circuit in the coil. The division ‘I’ 480V was declared inoperable according to TS. The relay was replaced and the division ‘I’ 480V load shed logic was declared operable on September 25th. A subsequent engineering evaluation determined that relay 0-RLY-231-00A7 was likely failed since the last time it was energized during testing on March 3, 2021. During this period, the division ‘II’ 480V load shed logic was out of service twice to support testing on March 4th and May 19th for a total of 78 hours. A search of LERs did not yield any windowed events. The loss of both divisions of the load shed logic would result in the failure of all four shared EDGs between Units 1 and 2 given a concurrent loss offsite power (LOOP) and loss-of-coolant accident (LOCA) event. The SPAR models include the load shed logic as part of the EDG sequencer component boundary, which does not allow the modeling of this degraded condition. Model changes were made to include the failure of both divisions of load shed logic given a concurrent LOOP and LOCA would result in the failure of all four Unit 1 and 2 EDGs. A risk assessment was performed assuming (a.) the unavailability of the division ‘I’ load shed logic from March 3, 2021, until September 25, 2021 (i.e., an exposure time of 207 days) and (b.) the unavailability of both EDG sequencers for an exposure time of 78 hours. These assessments result in a mean ΔCDP of 8E-10 and 5E-9 from internal events, seismic hazards, and high winds (including tornados), respectively. These results are conservative because the FLEX mitigation strategies were not credited. The risk impact is dominated by seismic scenarios that result in concurrent LOOP and LOCA. Internal flooding and fire scenarios are not included in the Browns Ferry SPAR model; however, the risk impact associated with these hazards is expected to be small for this condition because these hazards are unlikely to lead to concurrent LOOP and LOCA. The risk of this degraded condition is below the ASP Program threshold and, therefore, is not a precursor.</td></tr>
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<tr><td>Diablo Canyon 2</td><td>323-21-001</td><td>7/22/21</td><td>EDG Declared Inoperable due to Low Frequency Condition Discovery during Routine Surveillance</td><td>9/20/21</td><td>9/29/21</td><td>3e</td><td>9/30/21</td><td>1/10/22</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 21, 2021, EDG ‘2-3’ was started on a simulated under-voltage signal for routine surveillance testing. With the mode select switch in the “AUTO” position, the frequency indicated 58.9 Hz, which is below the TS required minimum of 59.5 Hz. Operators placed the EDG ‘2-3’ mode select switch in “MANUAL” and the frequency and speed were adjusted into their proper band and the test was completed meeting the acceptance criteria. The cause of the EDG ‘2-3’ low frequency condition was due to an inadequately performed post-maintenance testing on June 30, 2021. Specifically, the testing sequence did not fully consider the need for revalidation of frequency following setting of the EDG governor following maintenance activities. The Diablo Canyon USAR Section 8.3.1.1.6.1.13, “Selection of Diesel Generator Set Capacity for Standby Power Supplies,” refers to Safety Guide 9, March 1971, “Selection of DG Capacity for Standby Power Supplies,” (ML12305A251). The safety guide allows frequency to decrease by 2% during recovery from transients (i.e., approximately 1.2 Hz). Since the frequency only decreased by 1.1 Hz, the EDG remained functional within the limits of the safety guide capacity. Since EDG ‘2-3’ remained available, this condition is not a precursor, and a review of potential windowed events was not needed.</td></tr>
<tr><td>Grand Gulf</td><td>416-21-003</td><td>9/9/21</td><td>HPCS Declared Inoperable</td><td>11/4/21</td><td>11/18/21</td><td>3d</td><td>11/19/21</td><td>1/11/22</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 9, 2021, the MCR received an alarm for HPCS out of service along with HPCS motor operated valve/overload power loss status light. In addition, the HPCS minimum flow to suppression pool light indication was lost. Licensee troubleshooting revealed that this condition was caused by the failure of the alarm relay associated with HPCS minimum flow to suppression pool breaker due to the shorting of its coil. This failed relay subsequently caused the control circuit fuse to blow resulting in the inability to open the HPCS minimum flow valve to the suppression pool. The licensee took immediate action and replaced the damaged relay and associated control fuse. A search of LERs did not yield any windowed events. Because the licensee restored the HPCS within their TS required action time (14 days) and the exposure time was not longer than the TS allowed outage time for the system, an evaluation of this condition under the ASP Program to determine whether it is a precursor is not warranted.</td></tr>
<tr><td>Susquehanna 1</td><td>387-21-004</td><td>10/7/21</td><td>Loss of 1B RHRSW Pump due to Cable Damage During Excavation Activities</td><td>12/1/21</td><td>1/3/22</td><td>3d</td><td>1/4/21</td><td>1/20/22</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 October 7, 2021, operators observed current oscillations during a run of residual heat removal service water (RHRSW) pump ‘1B’. Operators secured the pump and entered TS 3.7.1, Condition B for an inoperable RHRSW subsystem. Licensee troubleshooting identified the cause of the current oscillations to be a ground on the B-phase power cable for the pump that was likely damaged during excavation activities on September 23, 2021. The power cable was replaced and the RHRSW system was declared operable on October 11th. On September 19, 2021, the RHRSW train ‘A’ subsystem was declared inoperable due to ultimate heat sink spray array and bypass valve alignments to support spray array inspection and nozzle cleaning. However, the licensee determined that the RHRSW train ‘A’ subsystem remained available. A search of LERs did not yield any windowed events. A risk assessment was performed assuming the RHRSW pump ‘1B’ was failed from September 23rd until October 11th (i.e., an exposure time of 19 days). This analysis resulted in a ΔCDP of 2E-7 from internal events, seismic hazards, and high winds (including tornados). A review of these results indicates that this result is likely very conservative (i.e., by at least an order of magnitude) because cross-unit common-cause failure (CCF) of the RHRSW pumps is the dominant failure and the existing CCF data does not currently support this application. In addition, the human error probability for containment venting appears to be very conservative for loss of instrument air and applicable LOOP scenarios. Internal flooding and fire scenarios are not included in the Susquehanna Unit 1 SPAR model. Licensee risk information for these hazards is available; however, specific scenario information for this condition is not available at this time. The risk impact from internal flooding scenarios is expected to be minimal for this condition. The risk from internal fires for this scenario could be dominant this condition; however, it is unlikely to result in exceeding the precursor threshold by itself. Given these considerations, the risk of this degraded condition is judged to be below the ASP Program threshold and, therefore, is not a precursor.</td></tr>
<tr><td>Fermi</td><td>341-21-003</td><td>6/3/21</td><td>HPCI Inoperable due to Contact Oxidation</td><td>12/29/21</td><td>1/10/22</td><td>3d</td><td>1/10/22</td><td>1/21/22</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 June 3,2021, the licensee was performing the HPCI condensate storage tank (CST) level channel functional test and the HPCI pump suction isolation valve from the suppression pool took approximately 5 minutes to open on the simulated low CST level signal. This condition resulted in the plant entering TS 3.3.5.1, Actions D.2.1 and D.2.2, which allows 24 hours to place the channel in trip or to align HPCI pump suction to the suppression pool. The licensee HPCI suction was transferred to the suppression pool later on June 3rd. Licensee troubleshooting of the condition identified an oxidated relay contact was the cause of the slow opening of the suction isolation valve. The licensee later determined that this condition affected both channels and, therefore, the licensee should have declared the HPCI system inoperable according to TS 3.3.5.1, Action D.1. After repair of the relay was completed and reperforming the HPCI CST level channel functional test, the licensee declared the HPCI system operable on June 4th. A licensee evaluation determined that HPCI would operate as designed for most of the 5 minutes it would take to automatically transfer suction from the CST to the suppression pool. However, CST level would have lowered to a level where air entrainment would have occurred and, therefore, HPCI would have tripped on a low suction pressure signal without operator action. Upon completion of the late suction transfer, suction pressure would be restored, and HPCI would automatically restart if demanded and continue to inject. In addition, procedures direct operators to complete any incomplete automatic actions manually, which means there was a high likelihood that operators would complete the HPCI suction transfer prior to HPCI tripping on low suction pressure given this condition. Because the HPCI would have restarted automatically if the slow transfer resulted in a low suction trip, HPCI remained available and, therefore, this condition is not a precursor, and a review of potential windowed events was not needed.</td></tr>
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<tr><td>Calvert Cliffs 2</td><td>318-21-003</td><td>8/10/21</td><td>AFW Pump Inoperable Due to Improper Reset of Trip Throttle Valve</td><td>9/23/21</td><td>9/29/21</td><td>3b</td><td>9/30/21</td><td>2/2/21</td><td>Analyst Screen-Out</td></tr>
<tr><td colspan="10">Analyst Justification. A Green finding was identified in IR 05000318/2021002 (ML21222A039); the LER remains open. On August 10, 2021, the licensee received an inspection report documenting the NRC’s position that the turbine-driven auxiliary feedwater (TDAFW) pump ‘22’ was considered inoperable from March 20, 2021, until March 26, 2021, because its trip throttle valve was not reset properly. Specifically, the trip throttle valve, which is part of the pump overspeed trip mechanism, did not appear to be aligned properly such that the trip hook and latch-up lever were not fully engaged. The licensee later determined that the post-maintenance procedure had inadequate instructions regarding the verification that trip hook and latch-up lever were fully engaged. NRC inspectors determined that the licensee failure to properly reset the TDAFW pump ‘22’ trip throttle in accordance with the surveillance test procedure was a performance deficiency. The inspectors determined that the performance deficiency was more than minor; however, the degraded condition did not represent a loss of safety function of one train of a multi-train system for greater than its TS allowed outage time. Therefore, the performance deficiency was determined to be Green (i.e., very low safety significance). A search for windowed events identified LER 318-2021-002 associated with a failed main feedwater regulating valve on March 21st, which resulted in a subsequent manual reactor trip. A risk assessment was performed assuming a reactor trip with the failure of the TDAFW pump ‘22’ to evaluate this windowed event. Recovery of TDAWF pump ‘22’ was not considered, which is potentially conservative. This analysis resulted in a CCDP of 1.5E-6, which is below the plant-specific CCDP for a nonrecoverable loss of feedwater and condenser heat sink of 2.8E-6 for Calvert Cliffs Unit 2. The risk of this condition, along with the “windowed” March 21st reactor trip, is below the ASP Program threshold and, therefore, is not a precursor.</td></tr>
<tr><td>Susquehanna 2</td><td>346-21-003</td><td>10/11/21</td><td>Automatic Reactor Scram due to Main Turbine Trip</td><td>12/9/21</td><td>2/28/22</td><td>2h</td><td>2/28/22</td><td>3/8/22</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 October 11, 2021, the Unit 2 reactor automatically scrammed due to a main turbine trip. The MCR received indication of a main turbine trip with both divisions of the RPS actuated and all control rods inserted. The turbine bypass valves (TBVs) opened automatically to control reactor pressure but failed to reclose causing the reactor to depressurize. Operators closed the MSIVs to stop reactor depressurization and manually initiated HPCI and RCIC to control reactor water level. Subsequently, operators maintained reactor water level in the normal operating band using RCIC and controlled reactor pressure using HPCI and the main steam line drains. The reactor recirculation pumps tripped on end-of-cycle trip. The licensee is still investigating the cause of the main turbine trip. A preliminary licensee investigation identified that a failed pressure transmitter resulted in the TBVs to close. 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/or condenser heat sink. Therefore, the risk of this event is below the ASP Program threshold and is not a precursor.</td></tr>
<tr><td>Nine Mile Point 1</td><td>220-21-001</td><td>9/25/21</td><td>Isolation of Both Emergency Condensers due to Loss of UPS 162A</td><td>11/19/21</td><td>3/7/22</td><td>3a</td><td>3/8/22</td><td>3/17/22</td><td>SDP Screen-Out</td></tr>
<tr><td colspan="10">A Green finding was identified in IR 05000220/2021004 (ML22026A350); the LER is closed. On September 25, 2021, the MCR received multiple annunciators concurrent with a loss and subsequent restoration of RPS bus ‘11’ on UPS ‘162A’. This resulted in a half scram, reactor water cleanup isolation, and isolation of both emergency condensers. The emergency condenser system was declared inoperable and TS 3.1.3, LCO E was entered. Operators restored power to RPS bus ‘11’ in 24 minutes using an alternative source. Both emergency condensers were restored to standby within 48 minutes. NRC inspectors determined that the licensee failure to ensure that an identified deviation from the normal operating frequency of UPS ‘162A’ was promptly identified and corrected was a performance deficiency. 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 0609. A search of LERs did not yield any windowed events. The SDP risk assessment is accepted as the ASP Program result, in accordance with RIS 2006-024, because there was no reactor trip nor windowed event. The risk of this condition is below the ASP Program threshold and, therefore, is not a precursor.</td></tr>
<tr><td>Fermi</td><td>341-21-002</td><td>8/22/21</td><td>Unplanned Inoperability of HPCI System Due to an Inverter Circuit Failure</td><td>10/21/21</td><td>11/5/21</td><td>3d</td><td>11/8/21</td><td>6/7/22</td><td>Reject</td></tr>
<tr><td colspan="10">A detailed ASP analysis determined that the ΔCDP of the concurrent degraded conditions identified in the LER was less than the ASP Program threshold of 10^{-6} and, therefore, is not a precursor. The detailed ASP analysis is publicly available (ML22158A092).</td></tr>
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