U.S. Nuclear Regulatory Commission
Accident Sequence Precursor Program
2019 Annual Report

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Summary of ASP Program Results

2019 Results. Based on the review of all licensee event reports (LERs) issued during calendar year 2019 and the results from the Significance Determination Process (SDP), two events were determined to be precursors. Both precursors were evaluated via an independent Accident Sequence Precursor (ASP) analysis. There were no greater than *Green* inspection findings with risk impacts to core damage identified in 2019.

The annual count of two precursors is a historic low. In addition, the number of LERs issued and those identified as potential precursors are at historically low levels. For the second year in a row, no higher-risk precursors (i.e., a conditional core damage probability (CCDP) or increase in core damage probability (ΔCDP) greater than or equal to 10^{-5}) were identified.

ASP Trends. Trend analyses of precursor data are performed on a rolling 10-year period (i.e., 2010–2019 for this report). The following table provides the updated results of these analyses:[1]

Precursor Category	Trend
All Precursors	↓
Higher-Risk Precursors	↓
Initiating Events	↓
Degraded Conditions	↓
Emergency Diesel Generator (EDG) Failures	↔
Loss of Offsite Power (LOOP) Events	↓
Boiling-Water Reactors (BWRs)	↔
Pressurized-Water Reactors (PWRs)	↓

Key Insights. The following are some key ASP Program insights for the past decade:

- A total of 118 precursors have been identified. Precursors involving degraded conditions (74 precursors) outnumbered initiating events (44 precursors) by a factor of two.
- The 44 precursors due to initiating events make up approximately 64 percent of all higher-risk precursors. Three-quarters of these precursors are due to LOOP initiating events.
- 34 percent of initiating event precursors resulted from natural phenomena (e.g., severe weather, seismic, etc.).
- EDG failures remain the most frequent (36 percent) cause of degraded condition precursors. However, no precursors associated with EDG failures were identified in 2019 (for the first time in 20 years).
- Of the 74 precursors involving degraded conditions, 24 percent existed for at least 10 years.
- Of the 35 precursors involving degraded conditions at BWRs, most were caused by failures in emergency core cooling systems (40 percent), others were caused by failures of EDGs (37 percent), and safety-relief valves (11 percent).
- Of the 39 precursors involving degraded conditions at PWRs, most were caused by failures of EDGs (36 percent), others were caused by failures in the auxiliary feedwater system (31 percent), emergency core cooling systems (18 percent), or safety-related cooling water systems (13 percent).

1 Horizontal arrows indicate that no increasing or decreasing trend exists. Up and down arrows indicated that there is a statistically significant increasing or decreasing trend, respectively.

- The total risk associated with precursors is dominated by 7 important precursors (i.e., CCDP or ΔCDP greater than or equal to 10^{-4}), which account for approximately 51 percent of the total risk due to all precursors. The other 111 precursors account for approximately 49 percent to the total risk due to all precursors.

Conclusions. A review of the ASP Program data and trends for the past decade indicates that:

- Current agency oversight programs and licensing activities remain effective as shown by decreasing 10-year trends in the occurrence rate of all precursors (and most precursor subgroups) and the decreasing overall risk from precursors as shown in the integrated ASP index. In addition, the number of LERs and potential precursor identified continues to decrease to historical lows.
- 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.

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1. INTRODUCTION

This report provides the ASP Program results for all LERs issued in 2019. In addition, updated precursor trends and insights are also included.

2. 2019 ASP RESULTS

There were 218 LERs issued in calendar year 2019. From these LERs, 183 (approximately 84 percent) were screened out in the initial screening process and 34 events were selected and analyzed as potential precursors. Of the 35 potential precursors, 2 events were determined to exceed the ASP Program threshold and, therefore, are precursors. An independent ASP analysis was performed to determine the risk significance of both precursors. There were no precursors due to greater than *Green* inspection findings in 2019.[2] Table 1 provides a brief description of all precursors identified in 2019.

Table 1. 2019 precursors

Plant/Description	LER	Event Date	Exposure Period	CCDP/ ΔCDP	ADAMS Accession No.
Browns Ferry 3, Automatic Reactor Scram Due to Turbine Load Reject	296-19-001-01	3/9/2019	Initiating Event	3×10^{-6}	ML19288A331
Pilgrim, Reactor Core Isolation Cooling (RCIC) System Declared Inoperable During Surveillance Testing	293-19-001	1/8/2019	51 days	3×10^{-6}	ML19169A279

After further analysis, the remaining 33 LERs identified by the initial LER screening were determined not to be precursors. These events were evaluated not to be precursors by acceptance of SDP results (4 events), completion of a simplified/bounding analysis (27 events), or a detailed ASP analysis (1 event). A detailed ASP analysis for an event determined not to be precursor was performed for a reactor scram due to a turbine bypass valve drifting open at Grand Gulf.[3] See Agencywide Documents Access and Management System (ADAMS) Accession No. ML19198A335 for additional information on this analysis. Additional information

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2 There were two greater than *Green* inspection findings issued in 2019. In addition, a preliminary *White* finding was identified, but has not been finalized. The first *White* finding was issued for Clinton Power Station on April 1, 2019 in Inspection Report (IR) 05000461/2018092 (ADAMS Accession No. ML19092A212). This event has already been counted as a precursor in 2018 due to its event date. The second *White* finding was issued for Watts Bar Nuclear Plant on April 15, 2019 in IR 05000390/2019090 (ADAMS Accession No. ML19105B198). This event also corresponds to a 2018 event due to its event date. However, this event was not considered a precursor because there was no risk impact to core damage because it involved the licensee failure to maintain an effective emergency plan. The preliminary *White* finding was identified for Vogtle Electric Generating Plant on December 26, 2019 in IR 05000424/2019090 (ADAMS Accession No. ML19361A059). This event corresponds to calendar year 2019; however, this event will not be considered a precursor regardless of the result, because there was no risk impact to core damage. This event involved the licensee failure to correctly calibrate radiation monitors that are relied on to provide data for the assessment of a radiological release during an accident.

3 A detailed ASP analysis was also performed for a reactor coolant system leak at Brunswick Steam Electric Plant (Unit 1) as documented in LER 325-2019-002. This event did not screen into the ASP Program because it did not result in an initiating event (i.e., a controlled reactor shutdown occurred) and did not involve a loss of safety function of any equipment. However, due to attention this event was getting in the operating experience community and the rarity of the complete reference line failures, a detailed ASP analysis of this event was performed for training purposes. See ADAMS Accession No. ML20050R568 for additional information on this analysis. Note that the estimated CCDP of this event is 1.37×10^{-5}; however, this event is not a precursor because the ASP Program threshold for initiating events is the plant-specific CCDP equivalent for a non-recoverable loss of condenser heat sink (1.42×10^{-5} for Brunswick Unit 1).

on the LERs determined not to be precursors via a simplified/bounding analysis or by acceptance of SDP results is provided in Appendix A.

- *Decreasing LERs and Potential Precursors.* The overall number of LERs and potential precursors continues to decrease to historical lows. Table 2 provided the total of number of LERs reviewed and screened by the ASP Program since 2016 (i.e., when the ASP Program switched to reviewing LERs issued on a calendar-year basis.

Table 2. LERs reviewed and screened by the ASP Program since 2016

Calendar Year	Number of LERs Reviewed	Number of LERs Screened-Out	Percentage of LERs Screened-Out	# of Potential Precursors from LERs
2016	352	289	82%	62
2017	323	273	85%	48
2018	253	215	86%	38
2019	218	183	84%	35

3. ASP TRENDS AND INSIGHTS

This section provides the results of trending analyses performed for several different precursor categories and discusses any insights identified. The purpose of the trending analysis is to determine if a statistically significant trend exists for the precursor group of interest during a specified period. A statistically significant trend is defined in terms of the *p-value*. A *p-value* is a probability indicating whether to reject the null hypothesis that no trend exists in the data. A *p-value* less than or equal to 0.05 indicates that there is 95 percent confidence that a trend exists in the data (i.e., leading to a rejection of the null hypothesis that there is no trend). The data period for ASP trending analyses and insights provided in this report is a rolling 10-year period (i.e., 2010–2019 for this report). Note that the figures in this report only include a trend line if a statistically significant increasing or decreases trend was observed.[4]

3.1. All Precursors

Trending of all precursor analyses provides insights as part of the agency's long-term operating experience program.

- *Trend.* Over the past decade (2010–2019), the mean occurrence rate of all precursors exhibits a statistically significant decreasing trend (*p-value* = 0.0003).[5] See Figure 1 for additional information. A figure containing the historical precursor occurrence rates is provided in Appendix B of the ASP Program Summary Description (ADAMS Accession No. ML20049G020).

[4] For figures with statistically significant trends, the solid line is the fitted occurrence rate of precursor using a Poisson process model. The dashed lines represent the 90-percent confidence band for the fitted occurrence rate.

[5] The occurrence rate is calculated by dividing the number of precursors by the number of reactor years.

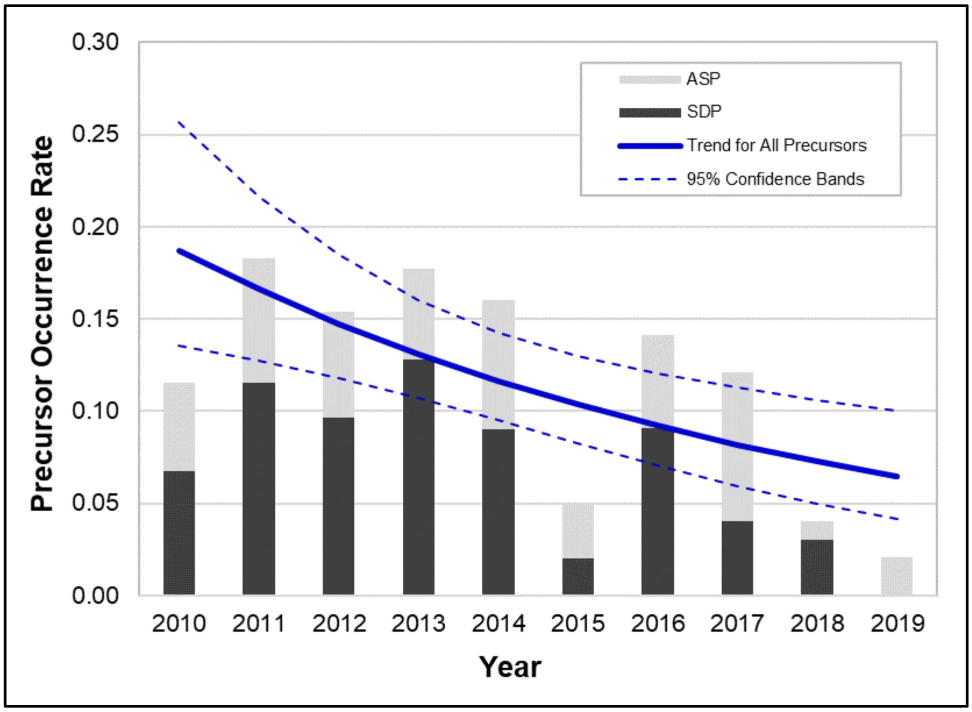

Figure 1. Occurrence rate of all precursors

- *Use of SDP Results.* Approximately 58 percent of all precursors used SDP evaluation results for the ASP Program purposes. These precursors typically involve a single unavailability or degradation in which no initiating event occurred. However, in a few cases the SDP condition assessment risk exceeded the ASP initiating event risk and, therefore, was used as the final ASP Program result.

3.2. Significant Precursors

The NRC's Congressional Budget Justification (NUREG-1100) uses performance indicators to measure and evaluate performance as part of the NRC's planning, budget, and performance management process. The number of *significant* precursors identified by the ASP program is one of several inputs to a safety performance indicator used to monitor the agency's Safety Performance Goal 4. No *significant* precursors were identified in 2019. The last *significant* precursor was identified in 2002, which involved concurrent, multiple degraded conditions at the Davis-Besse nuclear power plant. Additional information on all *significant* precursors identified since 1969 is provided in Appendix A of the ASP Program Summary Description (ADAMS Accession No. ML20049G020).

3.3. Higher-Risk Precursors

Precursors with a CCDP or ΔCDP greater than or equal to 10^{-4} are called *important* because they generally have a CCDP higher than the annual CDF estimated by most plant-specific PRAs. The staff did not identify any *important* precursors in 2019. No *important* precursors have been identified since 2012. See Table 2 of the ASP Program 2018 Annual Report (ADAMS Accession No. ML19119A276) for additional information on *important* precursors that have occurred since 2003. In addition, the staff did not identify any precursors with a CCDP or ΔCDP greater than or equal to 10^{-5} in 2019. This is the second year in a row that no such precursors were identified in the ASP Program.

- *Trends*. Over the past decade (2010–2019), the mean occurrence rate of precursors with a CCDP or ΔCDP greater than or equal to 10^{-5} exhibits a statistically significant decreasing trend (*p-value* = 0.00006). See Figure 2 for additional information. In addition, the mean occurrence rate of *important* precursors exhibits a statistically significant decreasing trend (*p-value* = 0.0008).

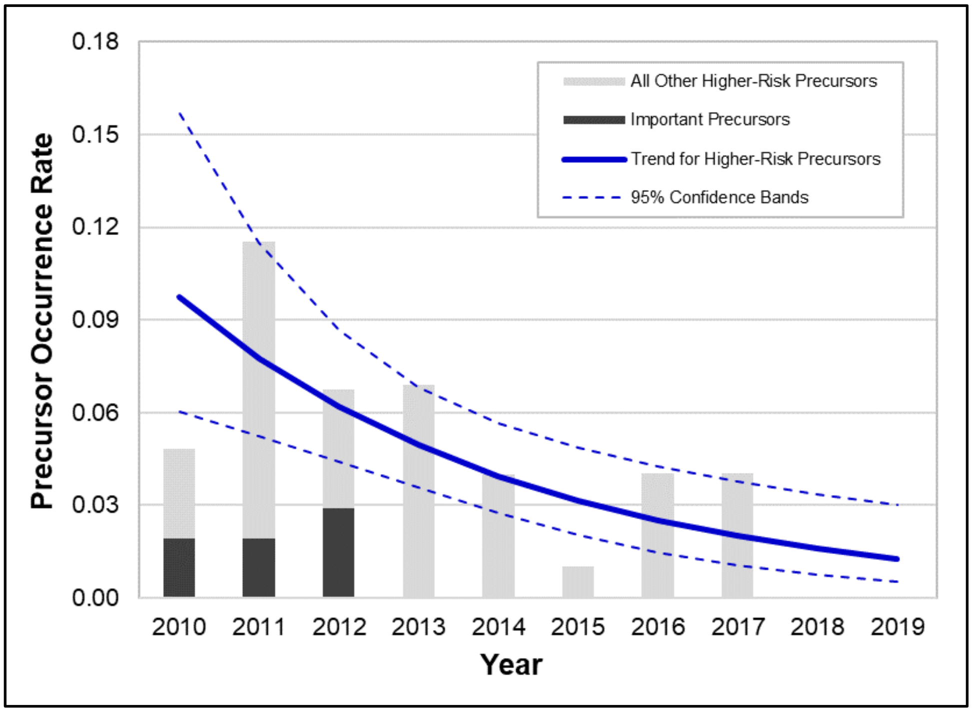

Figure 2. Occurrence rate of all higher-risk precursors

- *Initiating Event Impact.* Precursors due to initiating events make up approximately 64 percent of all precursors with a CCDP or ΔCDP greater than or equal to 10^{-5}, which is near the historical average. Three-quarters of these precursors are due to LOOP initiating events.

3.4. Precursors Involving Initiating Events and Degraded Conditions

Both initiating events and degraded conditions have the potential to be precursors. An initiating event can (by itself) result in a CCDP that exceeds the ASP Program threshold (e.g., LOOP, loss-of-coolant accident, etc.). In addition, a reactor trip concurrent with a structure, system, or component (SSC) unavailability can result in a precursor. Degraded conditions that exceed the ASP Program threshold can be associated with a single or multiple (i.e., "windowed") unavailabilities.

3.4.1. Initiating Events

- *Trend*. Over the past decade (2010–2019), the mean occurrence rates of precursors involving initiating events exhibits a statistically significant decreasing trend (*p-value* = 0.002). See Figure 3 for additional information.

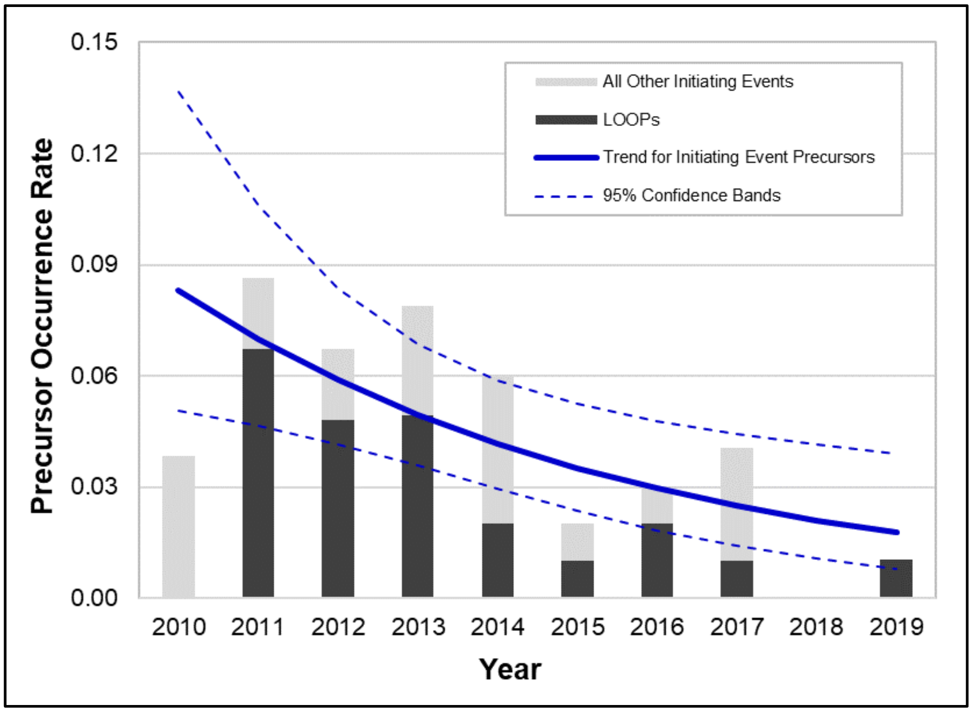

Figure 3. Occurrence rate of precursors involving an initiating event

- *Initiating Event Precursor Breakdown*. Of the 44 precursors involving initiating events, 24 precursors (55 percent) were LOOP events and 20 precursors (45 percent) were complicated reactor trips.[6] One of the LOOP initiating events occurred while the affected plant was shut down. Typically, the CCDP estimates for LOOPs are higher than for complicated trips.

- *LOOP Trend*. The mean occurrence rate of precursors involving LOOP events exhibits a statistically significant decreasing trend (*p-value* = 0.02).

- *LOOP with Concurrent EDG Unavailability*. Of the 24 LOOP precursors, two events involved a concurrent unavailability of an EDG. One precursor involved an EDG failure to run due to a leak in the coolant system and the other precursor involved an EDG out of service due to maintenance.

- *LOOPs at Multi-Unit Sites*. Of the 24 LOOP precursors, 11 precursors occurred at all units at a multi-unit nuclear power plant (NPP) site, 7 precursors occurred at a single unit on a multi-unit site, and 6 precursors occurred at a single-unit site.

- *Initiating Events due to Natural Phenomena.* Of the 44 precursors involving initiating events, 15 precursors (34 percent) resulted from natural phenomena (e.g., severe weather, seismic, etc.). Of these 15 precursors, 11 (73 percent) were the result of LOOP initiating events caused by tornadoes (5 precursors), the 2011 Virginia earthquake (2 precursors), other weather-related events (4 precursors). All units at the five multi-unit NPP sites involved in these events were affected.

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6 A complicated reactor trip includes a concurrent loss of mitigating equipment.

3.4.2. Degraded Conditions

- *Trend*. The mean occurrence rates of precursors involving degraded condition(s) exhibits a statistically significant decreasing trend (*p-value* = 0.03). See Figure 4 for additional information.

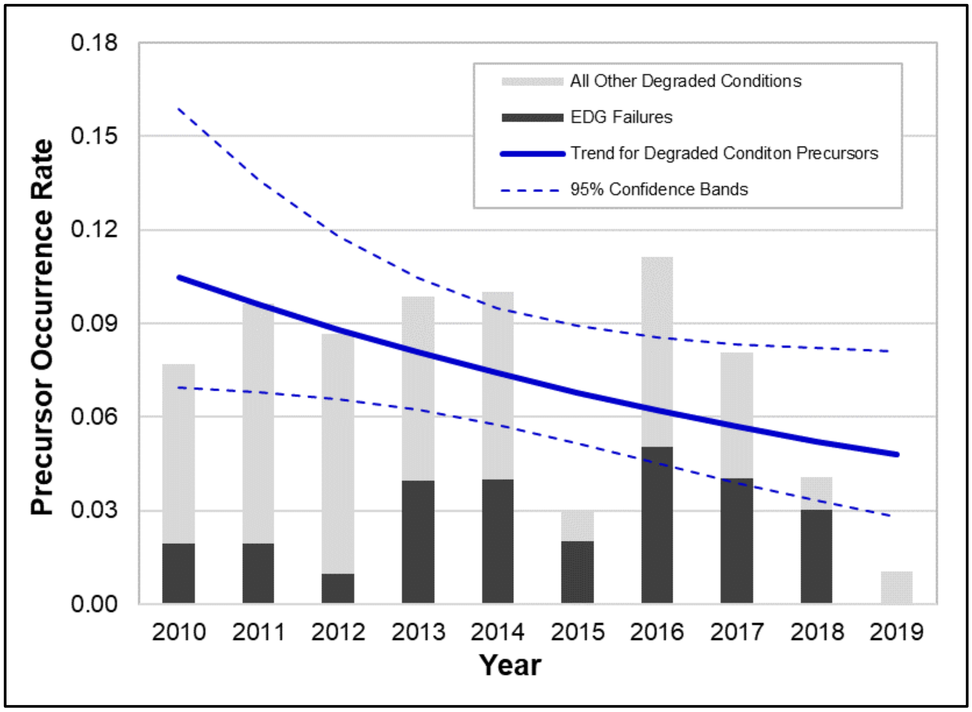

Figure 4. Occurrence rate of precursors involving degraded condition(s)

- *Degraded Conditions vs. Initiating Events*. Precursors involving degraded conditions (74 precursors) outnumbered initiating events (44 precursors) by a factor of approximately two.

- *EDG Failure Trends*. The mean occurrence rate of precursors involving EDG failures does not exhibit a statistically significant trend (*p-value* = 0.8).[7]

- *Degraded Conditions due to External Hazards.*[8] Of the 74 precursors involving degraded conditions, 18 precursors (24 percent) were associated with postulated external hazards (fire, flood, etc.). Of these 18 precursors, 15 precursors were associated with degradations related to floods, 2 precursors were associated with degradations related to fires, and 1 precursor was associated with a degradation related to tornadoes.

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[7] The past three ASP Program annual reports reported an increasing trend for precursors due to EDG failures for a 20-year period. However, updated analyses for the past 20 years (2000–2019) shows that no statistically significant trend (p-value = 0.3) exists for the mean occurrence rate of these precursors.

[8] External hazards often include hazards other than internal events that also occur within the plant boundary such as internal fires.

- *Degraded Condition Causes.*[9] Of the 74 precursors involving degraded conditions, 23 precursors (31 percent) were due to inadequate procedures, 21 precursors (28 percent) were due to design deficiencies, and 18 precursors (24 percent) were due to an ineffective corrective action program.

- *Long-Term Degraded Conditions*. Of the 74 precursors involving degraded conditions, 18 precursors (24 percent) involved degraded conditions existing for a decade or longer.[10] Of these 19 precursors, 7 precursors involved degraded conditions dating back to initial plant construction.

3.5. Precursors at BWRs and PWRs

Some events (e.g., LOOP initiators, EDG unavailabilities) are not typically influenced by different reactor technologies and can lead to significantly increased risk regardless of whether the affected NPP is a BWR or PWR. However, given the substantial differences in plant design and operating conditions, it is valuable to investigate whether design differences result in proportional precursor occurrence rates between the two reactor technologies currently used in the U.S.[11]

- *Trends*. The mean occurrence rates of precursors that occurred at BWRs does not exhibit a statistically significant trend (*p-value* = 0.5).[12] However, there is a statistically significant decreasing trend (*p-value* = 0.0002) for the mean occurrence rate of precursors that occurred at PWRs. See Figure 5 for additional information. *LOOPs by Plant Type*. Of the 19 precursors involving initiating events at BWRs, 12 precursors (63 percent) were complete LOOP events. Of the 25 precursors involving initiating events at PWRs, 12 precursors (48 percent) were complete LOOP events.

- *BWR Degraded Condition Breakdown*. Of the 35 precursors involving degraded condition(s) at BWRs, most were caused by failures in emergency core cooling systems (14 precursors or 40 percent), others were caused by failures of EDGs (13 precursors or 37 percent), and safety-relief valves (4 precursors or 11 percent).

- *PWR Degraded Condition Breakdown*. Of the 39 precursors involving degraded condition(s) at PWRs, most were caused by failures of EDGs (14 precursors or 36 percent), others were caused by failures in the auxiliary feedwater system (12 precursors or 31 percent), emergency core cooling systems (7 precursors or 18 percent), safety-related cooling water systems (5 precursors or 13 percent), or electrical distribution system (3 precursors or 8 percent).

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9 These causes were determined by a review of inspections findings associated with the applicable precursor events. Typically, these causes were associated with greater-than-*Green* findings. However, causes associated with *Green* findings (i.e., very low safety significance) were considered for events with "windowed" effects that resulted in the event exceeding the precursor threshold.

10 Risk analyses performed as part of the ASP Program and the SDP limit the exposure period to 1 year.

11 Approximately two-thirds of U.S. NPPs are PWRs; therefore, we may expect PWR precursor counts to be about twice as common as the BWR precursor counts.

12 The past three ASP Program annual reports reported an increasing trend for precursors that occurred at BWRs for a 20-year period. However, updated analyses for the past 20 years (2000–2019) shows that no statistically significant trend (p-value = 0.4) exists for the mean occurrence rate of these precursors.

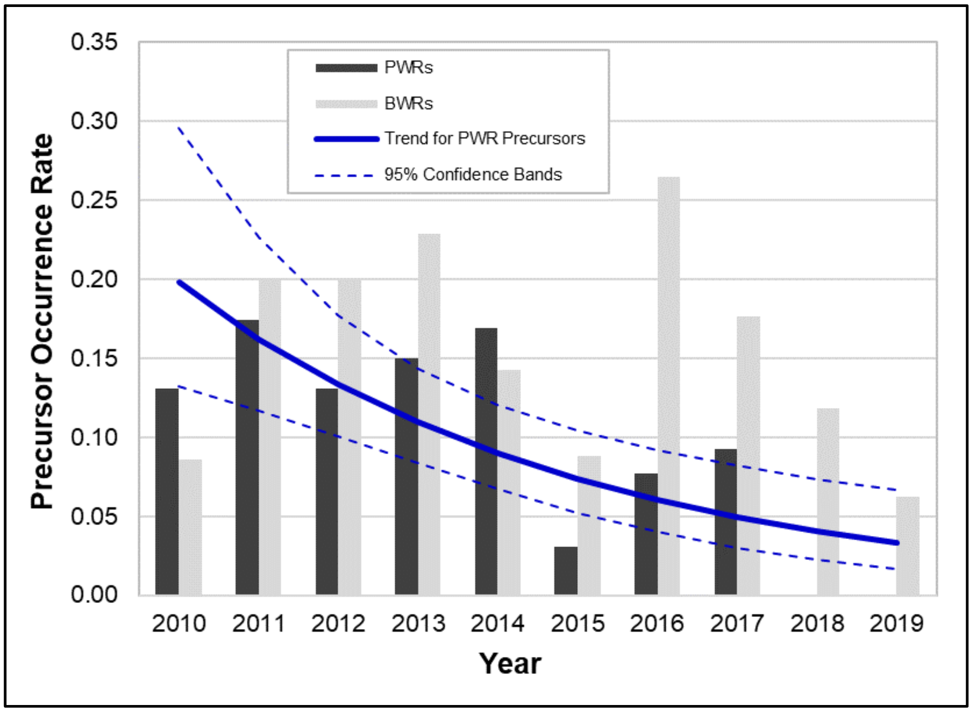

Figure 5. Occurrence rates of precursors at BWRs and PWRs

- *Degraded AFW systems*. Of the 12 precursors involving failures of the auxiliary feedwater system, 4 precursors (33 percent) were specific to the turbine-driven pump train.

- *PWR Sump Recirculation*. Of the 7 precursors involving failures in the emergency core cooling systems, 2 precursors (29 percent) were because of conditions affecting sump recirculation during postulated loss-of-coolant accidents of varying break sizes.

4. ASP INDEX

The integrated ASP index shows the cumulative plant average risk from precursors on an annual basis. The integrated ASP index is calculated using the sum of CCDPs/ΔCDPs from precursors identified in a given year and is then normalized by dividing the total reactor-operating years for all NPPs in that year. In addition, the integrated ASP index includes the risk contribution of a precursor for the entire duration of the degraded condition (i.e., the risk contribution is included in each fiscal year that the condition existed). For example, a precursor involving a degraded condition is identified in June 2015 and has a ΔCDP of 5×10^{-6}. A review of the LER or IR reveals that the degraded condition has existed since a design modification that was completed in February 2011. In the integrated ASP index, the ΔCDP of 5×10^{-6} is included in the years 2011–2015 (i.e., the year it was identified and any year that the deficiency existed). The risk contributions from precursors involving initiating events are included in the year that the event occurred.

- *Trends.* The integrated ASP index exhibits a statistically significant decreasing trend (*p-value* = 0.0001).[13] This trend is largely influenced by the seven precursors with CCDP or ΔCDP greater than or equal to 10^{-4} that occurred in the 2010–2012 period. See Figure 6 for

13 A log-linear regression was used for the trend analysis of the integrated ASP index.

additional information.

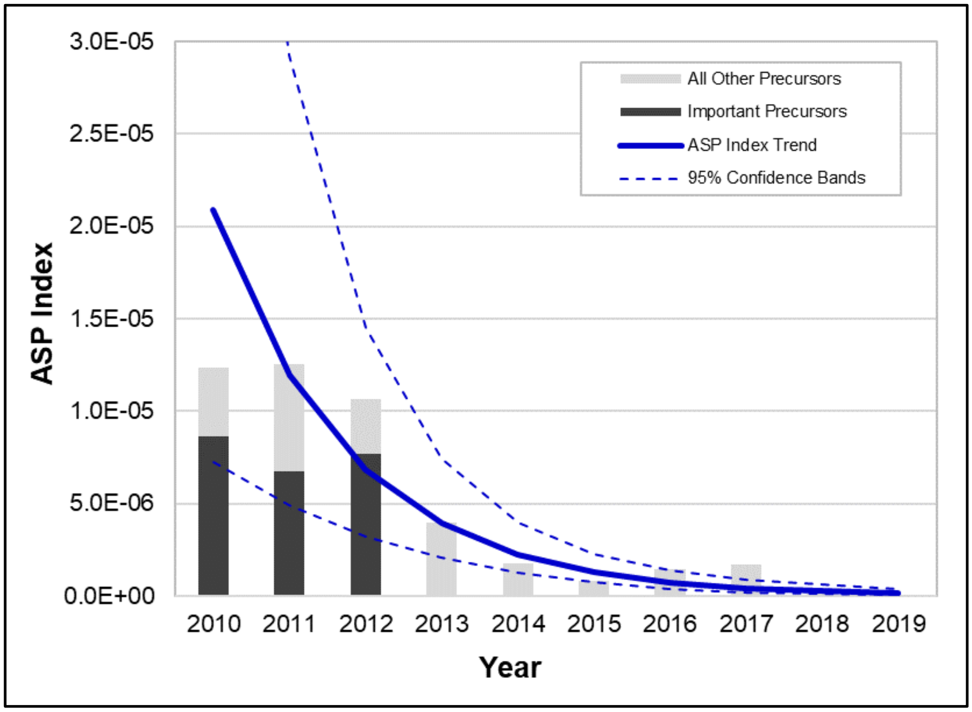

Figure 6. Integrated ASP index

- *Insights.* The total risk associated with precursors (118 total precursors) is dominated by 7 important precursors, which account for approximately 51 percent of the total risk due to all precursors. The other 111 precursors account for approximately 49 percent to the total risk due to all precursors.

- *Limitations.* Unlike the trend analyses performed on various precursor groups that are focused on the occurrence rate of precursors, the integrated ASP index is focused on the total risk due to all precursors. It is important to note that precursors evaluated by an independent ASP analysis or an SDP evaluation are limited to a 1-year exposure period. Therefore, the integrated ASP index provides a unique way to evaluate the total risk effect of longer-term degraded conditions that is not fully captured in the individual analyses.

5. COMPARISON OF RECENT PROGRAM PESULTS

The two precursors identified in 2019 using an independent ASP analysis were compared with results from Management Directive (MD) 8.3, "NRC Incident Investigation Program," (ADAMS Accession No. ML18073A200) and SDP analyses, as shown in Table 3. Given the three programs have different functions, it is expected that the results are likely to be different.

Table 3. 2019 independent ASP analysis comparison

<table>
<tr><th>Event Description</th><th>Evaluation Results of NRC's Three Risk Analysis Programs</th><th>SPAR Model/Methodology Improvements and Insights</th></tr>
<tr><td rowspan="3">Browns Ferry 3, LER 296-19-001-01, 3/9/2019. Automatic reactor scram due to turbine load reject.</td><td>MD 8.3. CCDP estimated to be 2.6×10^{-6}, baseline inspection performed (ADAMS Accession No. ML19086A144).</td><td rowspan="3">Credit for new electric-driven, high-pressure makeup pump was added to the SPAR model. This pump was installed at the plant to address issues associated with plant's adoption of National Fire Protection Association 805.

FLEX strategies were credited in ASP analysis using screening values to represent uncertainties associated with unknown human and equipment reliability."</td></tr>
<tr><td>SDP. Green finding associated with the licensee failure to properly operate the Unit 3 automatic voltage regulator while adjusting the reactive load on the main generator to lower grid voltage. No risk evaluation was performed (screened in Phase 1). See IR 05000296/2019002 (ADAMS Accession No. ML19224B824) for additional information.</td></tr>
<tr><td>ASP. CCDP = 3×10^{-6}; a plant-centered LOOP occurred (ADAMS Accession No. ML19288A331).</td></tr>
<tr><td rowspan="3">Pilgrim, LER 293-19-001 1/8/2019. RCIC system declared inoperable during surveillance testing.</td><td>MD 8.3. No MD 8.3 evaluation was performed.</td><td rowspan="3">The preliminary ASP results were reviewed to determine if FLEX strategies would affect the risk of this event. For FLEX strategies to be successful at Pilgrim, either RCIC or high-pressure coolant injection (HPCI) must be available. The dominant sequences for this event involved both RCIC and HPCI failing. Without either, FLEX cannot be successfully deployed and, therefore, were not considered in the final ASP analysis.</td></tr>
<tr><td>SDP. No performance deficiency has been identified for this event; therefore, no SDP evaluation was performed.</td></tr>
<tr><td>ASP. ΔCDP = 3×10^{-6}; RCIC unavailability for approximately 50 days (ADAMS Accession No. ML19169A279).</td></tr>
</table>

6. LER SCREENING QUALITY ASSURANCE REVIEW

The ASP Program leverages current activities to provide the quality assurance review of the LER screening. The primary activity for this is the participation in the Operating Experience Clearinghouse meetings, which is held up to three times per week. This meeting reviews all event notifications, LERs, regional phone call items, greater-than-*Green* regulatory findings, NRC communications, and Part 21 notifications and distributes them to the relevant internal technical review groups. When LERs are reviewed by the clearinghouse, the ASP Program manager determines whether the events described meet one or more candidate ASP criteria. If so, the ASP Program manager then ensures that the applicable LER was determined to be a potential precursor via the INL screening process.

A secondary activity is the search for “windowed” LERs for events that were identified by INL to be potential precursors. As part of the detailed evaluation for LERs corresponding to potential precursors, ASP analysts are required to review other LERs from the applicable plant that may have resulted in initiating events and/or SSC unavailabilities during the same period identified in the LER undergoing the ASP evaluation. As part of these reviews, ASP analysts can identify LERs that were inappropriately screened-out in the initial LER screening.

These two activities resulted in the identification of two LERs, initially screened out of the ASP Program, as potential precursors. In subsequent discussions with INL, these LERs were inappropriately screened-out due to a misinterpretation of information provided in the LER and a documentation error, respectively. Note that one these LERs, LER 296-19-001-01 (ADAMS Accession No. ML19189A125), was determined to be a precursor after the detailed evaluation was performed.

Appendix A: 2019 ASP Program Screened Analyses

The table in this appendix provides the justification for each licensee event report (LER) that was screened out of the Accident Sequence Precursor (ASP) Program based on a simplified or bounding analysis or by acceptance of Significance Determination Process (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>LER Date</th><th>Screening Date</th><th>cASP Criterion</th><th>Evaluation Completed</th><th>Classification</th></tr>
<tr><td>Peach Bottom 2</td><td>277-19-001</td><td>2/11/19</td><td>4/11/19</td><td>5/20/19</td><td>3d</td><td>6/11/19</td><td>Analyst Screen-Out</td></tr>
<tr><td colspan="8">Analyst Justification. This event is not discussed in any inspection report (IR) to date; the LER remains open. At 10:32 p.m., on February 11, 2019, the 220-08 offsite power line was lost due to a malfunction of a lightning arrestor at an associated substation. The loss of the 220-08 line caused all 4 kilovolt (kV) emergency buses to fast transfer to the alternate emergency auxiliary transformer, which is fed by the 220-34 offsite power line. The plant responded per design and the operators correctly responded to applicable procedures. However, the breaker that supplies 480-volt (V) load center 'E434' via the unit 3 4 kV emergency bus ‘E43’ failed to reclose after the successful fast transfer. This 480 V load center supplies support systems for emergency diesel generator (EDG) ‘E4’ operation. Note that the unit 3 core spray loop ‘A’ was unavailable due to planned maintenance at the time of the event. The operators manually closed the affected breaker in approximately 18 minutes, thus reenergizing 480 V load center 'E434'. On February 12th, the core spray loop 'A' was returned to an operable status at 6:16 a.m. and repairs on the failed 'E434' breaker were completed at 3:59 p.m., respectively. A search of LERs did not reveal any windowed events. The risk associated from this event is due to the following: (a.) the 18-minute period when 480 V load center breaker was open resulting in EDG '4' and core spray loop 'B' to be unable to fulfil their safety function and (b.) the unknown time period for which the 480V breaker was closed but would be required to open and reclose given a postulated loss of offsite power (LOOP). A risk assessment was performed for the 18-minute period where both loops of the core spray and EDG 'E4' were unable to fulfil their safety function. This analysis results in an increase in core damage probability (ΔCDP) of 10^{-11}. An additional risk assessment was performed assuming a bounding 1-year exposure period where the automatic closure feature of the 480 V breaker was failed. This analysis assumed a conservative 0.1 recovery probability for operators to manually shut the breaker during applicable scenarios (i.e., LOOPs). This second analysis results in a ΔCDP of 5×10^{-9}. The seismic impact for this event is 6×10^{-9}. These analyses show that the risk of this event is below the ASP Program threshold and, therefore, this event is not a precursor. A search of LERs did not identify any windowed events.</td></tr>
<tr><td>Duane Arnold</td><td>331-19-001</td><td>4/20/19</td><td>6/17/19</td><td>7/24/19</td><td>2h</td><td>8/5/19</td><td>Analyst Screen-Out</td></tr>
<tr><td colspan="8">Analyst Justification. This event is not discussed in any IR to date; the LER remains open. On April 20, 2019, both reactor feedwater pumps tripped due to a low suction pressure condition caused by the condensate filter effluent valves closing on a loss of instrument air to the condensate filter demineralizer control panel. The cause of the loss of instrument air pressure was the failure of the inline air filter bowl located upstream of PCV-80, which is located inside the condensate filter demineralizer control panel. Due to the loss of all feedwater, operators manually scrammed the reactor and all control rods inserted. High-pressure coolant injection (HPCI) and reactor core isolation cooling (RCIC) automatically started and provided inventory makeup to the reactor. During the recovery of reactor water level, operators tripped HPCI and closed the main steam isolation valves to reduce the cooldown rate. Reactor water level continued to rise and RCIC eventually tripped on high level. Operators manually restarted RCIC to control reactor pressure and maintain reactor water level. A risk assessment was performed assuming a recoverable loss of condenser heat sink with high level trip of RCIC. A screening value of 0.1 was used for the recovery of the condenser. The requirement for a restart of RCIC, due to the high-level trip, used existing SPAR model fault tree logic. The conditional core damage probability (CCDP) was calculated to be 9.6×10^{-7}, which is below the ASP Program threshold and, therefore, this event is not a precursor. A search of LERs did not identify any windowed events.</td></tr>
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Plant	LER	Event Date	LER Date	Screening Date	cASP Criterion	Evaluation Completed	Classification
Hatch 2	366-19-002	3/19/19	5/16/19	5/23/19	3d	8/16/19	Analyst Screen-Out
Analyst Justification. This event is briefly discussed in IR 05000366/2019002 (ADAMS Accession No. ML19219A494); the LER is closed. On March 19, 2019, while starting up from a refueling outage, the HPCI main stop valve did not open during testing due to the failure of its associated auxiliary oil pump. The HPCI auxiliary oil pump failed to start due to motor control center breaker secondary connection stabs not making adequate contact. HPCI was declared inoperable, repaired, and returned to service approximately 14 hours later. The licensee determined that the affected breaker connection stabs had been widened during the maintenance evolution performed during the outage, which resulted in the inadequate contact. Per plant technical specifications (TS), HPCI is not required to be operable until the plant is in Mode 2 with reactor steam dome pressure greater than 150 psig. When the reactor steam dome pressure increased over 150 psig on March 19th, the licensee performed functional testing HPCI that resulted in the failure. Therefore, HPCI was only inoperable for a short period prior to the failure (less than 2 hours) and for approximately 14 hours during repairs. Since the HPCI system was unavailable for less than the limits of TS limiting condition for operation (LCO) 3.5.1, Condition C (14 days), this event is screened out and is not considered a precursor. A search of windowed events revealed LER 366-2019-003, which documents a relay failure that prevented the fast transfer of electrical power to the nonsafety-related buses after a turbine trip. This relay was likely degraded during this short period where HPCI was unable to fulfill its safety function. The windowed effects of these two events will evaluated as part of the ASP evaluation of LER 366-2019-003).							
Palo Verde 1 & 2	528-17-002	11/13/17	7/3/19	8/22/19	3e	8/26/19	Analyst Screen-Out
Analyst Justification. This event is briefly discussed in IR 05000528/2019002; the LER remains open. On two separate occasions, November 2017 (Unit 1) and February 2019 (Unit 3), one of the unit's EDGs was declared inoperable due to the failure of the associated diesel fuel oil transfer pump. In response to these failures, the licensee performed testing of the unit's opposite train EDG to ensure that no common-cause failure (CCF) occurred, in accordance to TS requirements. In May 2019, the licensee determined that the testing procedure used during these two occurrences rendered the EDG being tested inoperable. Specifically, the EDG day tank level gauges are not seismically qualified. In addition, the day tank drain valves are required to be closed to maintain EDG operability. The day tank level gauges are place in service and the drain valves are cycled open and closed during this testing and, therefore, render the applicable EDG inoperable. The failure of the diesel fuel oil pumps and subsequent testing led to both Unit 1 and Unit 3 EDGs being inoperable for periods of 30–90 minutes in November 2017 (Unit 1) and February 2019 (Unit 3). Although the EDGs were inoperable due to TS, operators were stationed locally during the testing and could have isolated the day tank level gauges quickly during a postulated seismic event to prevent any loss of safety function. In addition, operators had the ability to quickly close the day tank drain valve to restore EDG operability. Since both unit EDGs were unavailable for less than the limits of TS LCO 3.8.1, Condition E (2 hours) during these two occurrences, this event is screened out and is not considered a precursor. A search of LERs did not identify any windowed events that would significantly impact the risk of this event.							

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<tr><th>Plant</th><th>LER</th><th>Event Date</th><th>LER Date</th><th>Screening Date</th><th>cASP Criterion</th><th>Evaluation Completed</th><th>Classification</th></tr>
<tr><td>Brunswick 2</td><td>324-19-003</td><td>6/12/19</td><td>7/31/19</td><td>8/26/19</td><td>3d</td><td>8/27/19</td><td>Analyst Screen-Out</td></tr>
<tr><td colspan="8">Analyst Justification. This event is not discussed in any IR to date; the LER remains open. On June 12, 2019, the HPCI turbine experienced an overspeed trip during routine testing. The turbine subsequently coasted down, reset, and restarted to rated conditions per design. Due to the overspeed trip, the HPCI response time exceeded the 60-second acceptance criteria for the surveillance test and, therefore, was declared inoperable. The overspeed trip was caused by the momentary failure of the electric governor remote to control HPCI turbine speed during the initial turbine roll. The failed electric governor remote was replaced on June 15th. Post-maintenance testing was completed successfully and HPCI was declared operable. Although HPCI was declared inoperable due to the slow response time cause by the electric governor remote (according to TS), HPCI remained available to perform its safety function (i.e., it was capable of injecting to the reactor at a sufficient flow rate). Since no loss of safety function was experienced, this event is screened out and is not considered a precursor. A review of potential windowed events was not needed because there was no loss of safety function.</td></tr>
<tr><td>Limerick 2</td><td>353-19-002</td><td>7/22/19</td><td>9/20/19</td><td>10/7/19</td><td>3e</td><td>10/17/19</td><td>Analyst Screen-Out</td></tr>
<tr><td colspan="8">Analyst Justification. This event is not discussed in any IR to date; the LER remains open. During surveillance testing on July 22, 2019, an instrumentation line threaded pipe connection for an EDG 24 pressure indicator was found to be sheared. This one-quarter inch instrumentation line connection connects to the 4-inch main lube oil piping near the discharge of the engine driven lube oil pump. Prior to the test, there was no indication of a lube oil leak. This threaded pipe has experienced several leaks in the past and was most recently replaced on January 21, 2019. The leaks and failure associated with this threaded pipe connection was attributed to high-cyclic fatigue. Operators declared EDG 24 inoperable. Repairs were completed on July 25th and EDG 24 was declared operable after successful testing. EDG 24 was last successfully run on June 18th and had completed its 24-hour endurance run on March 20th. A risk analysis was performed using a test/limited use SPAR model for Limerick 2. The analysis conservatively assumed that EDG 24 was unable to fulfil its safety function for the complete 24-hour PRA mission time for approximately 127 days (March 20th through July 25th). The analysis assumed credit for cross-tie ability of any of the Unit 1 EDGs to any 4.16 kV safety bus for Unit 2. The credit for operators to crosstie the EDGs was given a potentially conservative human error probability of 0.1. Credit for FLEX mitigation strategies was not provided, which is conservative. This analysis resulted in a ΔCDP of 3×10^{-7}. The seismic impact of this analysis is 2×10^{-8}. The risk of this event is below ASP Program threshold and, therefore, this event is not a precursor. A search of LERs did not identify any windowed events.</td></tr>
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Plant	LER	Event Date	LER Date	Screening Date	cASP Criterion	Evaluation Completed	Classification
Catawba 1	413-19-001	3/21/19	5/20/19	7/8/19	3e	10/29/19	SDP Screen-Out
Analyst Justification. A *Green* finding was identified in IR 05000413/2019002 (ADAMS Accession No. ML19226A096), the LER is closed. On March 21, 2019, main control room (MCR) operators observed that there was no nuclear service water flow to the EDG '1A' jacket water heat exchanger approximately 3 minutes after the EDG had been started for monthly surveillance testing. The operators subsequently secured EDG '1A' and declared it inoperable according TS 3.8.1, Condition B. In addition, the plant entered TS 3.7.8, Condition A, due to an inoperable nuclear service water component with the plant in single pond return header operation. Single pond return header operation is an alignment that isolates one of the two below ground nuclear service water pond return headers between the auxiliary building and the standby nuclear service water pond. In this alignment, cooling water flow is directed from essential components (e.g., EDGs) to the remaining in-service pond return header. A licensee investigation revealed valve 1RN-P09 was in the closed position due to a separation of actuator coupling. This valve is part of the return header flow path while in an alternative alignment of single pond return header operation. This manual valve was locked open on March 11, 2019. However, the actual position of valve was closed due to the valve actuator failure. Valve 1RN-P09 was repaired and the applicable TS conditions were exited on March 22nd. A detailed risk evaluation was performed as part of the SDP. Nuclear service water was assumed to be unavailable to EDG '1A' for a 268-hour exposure period. Limited credit for recovery of nuclear service water to EDG '1A' via opening an alternate service water valve from the main control room was provided. However, credit for FLEX equipment was not provided, which is conservative. The analysis revealed an increase in core damage frequency (ΔCDF) of less than 10^{-6} per year. The SDP finding was determined to be *Green* (i.e., very low safety significance). In addition, a search of LERs identified a potential windowed event associated with LER 413-2019-002. This LER identified an unavailability of motor-driven auxiliary feedwater (AFW) pump 'B' due to the failure of its associated sump pump during a postulated feedwater rupture and concurrent LOOP. The exposure period of the failed sump pump is not provided in the LER; however, an evaluation assuming the sump pump was failed during the complete 268-hour exposure time for EDG '1A' resulted in a negligible risk impact. The risk of this event is below the ASP Program threshold and, therefore, this event is not a precursor.							
Nine Mile Point 1	220-19-004	8/4/19	10/3/19	10/16/19	3a	10/29/19	Analyst Screen-Out
Analyst Justification. This event is not discussed in any IR to date; the LER remains open. On August 4, 2019, with the plant at 100 percent reactor power, recirculation pump 11 tripped due a degraded tachometer generator on the its associated motor generator set. Subsequently, reverse flow through the tripped recirculation pump caused plant operators to declare the average power range monitors (APRMs) inoperable. A reverse flow condition results in an unconservative total flow input used in the APRM flow-biased trip set point (i.e., set point is higher than allowed by TS). Operability of the APRMs was restored in approximately 13 minutes by closing the discharge block valve for the tripped recirculation pump. When the APRMs are inoperable, operators are required to use procedures, in conjunction with the exclusion/restricted regions on the power-to-flow map, to protect the safety limit minimum critical power ratio. For the power-to-flow conditions following the recirculation pump trip, the licensee determined that reactor oscillations would not be a concern unless there was an additional reduction in reactor recirculation flow. The licensee evaluation also determined that high neutron flux trip was still available at 122 percent rated thermal power and that other direct reactor scram signals were available for cycle-specific transients. Given the results of the licensee evaluation and the short period that the APRM flow-biased trip set point was affected, this event is screened out and is not considered a precursor. A search of LERs did not yield any windowed events.							

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<tr><td>Perry</td><td>440-19-004</td><td>8/6/19</td><td>10/4/19</td><td>10/16/19</td><td>3a</td><td>10/29/19</td><td>Analyst Screen-Out</td></tr>
<tr><td colspan="8">Analyst Justification. This event is not discussed in any IR to date; the LER remains open. On August 6, 2019, at 1:35 p.m., with the plant at approximately 65 percent power, a partial loss of high-pressure feedwater heating occurred. Specifically, feedwater heaters 5A and 6A isolated on high-high level during the transfer of the heater 5A level control from startup to normal mode. The isolation of heaters 5A and 6A resulted in a decrease in feedwater temperature of approximately 38°F, which impacted certain reactor protection system, end-of-cycle recirculation pump trip, and control rod block instrumentation setpoints that are derived from the main turbine first stage pressure. With turbine first-stage pressure lowered due to abnormal feedwater temperature, the relation of the main turbine first-stage pressure to reactor power was incorrect and, therefore, the setpoint for which these functions are bypassed (38 percent rated thermal power) were also incorrect. At 2:22 p.m., the four trip units were removed to disable the bypass function and obtain compliance with applicable TS LCOs. Operators successfully restored feedwater heaters 5A and 6A at 4:31 p.m. At 7:15 p.m., the trip units were reinstalled to reenable the bypass functions. The incorrect bypass setpoints for the applicable instrumentation functions were disabled within 1 hour. Since all functions were restored to operability prior to the applicable TS LCOs, this event is screened out and is not considered a precursor. A search of LERs did not yield any windowed events.</td></tr>
<tr><td>Fermi</td><td>341-19-004</td><td>7/30/19</td><td>9/30/19</td><td>10/16/19</td><td>3d</td><td>11/6/19</td><td>Analyst Screen-Out</td></tr>
<tr><td colspan="8">Analyst Justification. This event is not discussed in any IR to date; the LER remains open. On July 30, 2019, the division 2 mechanical draft cooling tower (MDCT) fan 'D' tripped during monthly surveillance testing when operators shifted the fan to high speed. The MDCT fans are required for the ultimate heat sink, which supports operability of the division 2 of the emergency equipment cooling water (EECW) system. Division 2 of the EECW system cools various safety related components, including the HPCI room cooler. The licensee determined that the fan failure was caused by a blown speed breaker control power fuse. The failed fuse was replaced in approximately 4 hours, the MDCT fan 'D' was tested satisfactorily, and declared operable on July 30th. A licensee evaluation determined that one MDCT fan (per division) was sufficient for at least 24 hours, which is likely conservative because the evaluation assumed that fan 'D' was failed, and it could still have run in slow speed. In addition, the plant FSAR indicates that at least 6 hours would be available to operators to restore fan capability given a postulated loss of all four MDCT fans. The Fermi SPAR model does not distinguish between the slow and fast speeds of the MDCT fans. Therefore, a risk analysis was performed using the bounding assumption that MDCT fan 'D' was completed failed. A 30-day exposure time was used, which corresponds to the last successful test of MDCT fan 'D' in fast speed. This analysis results in an increase in core damage probability (ΔCDP) of 3.7×10^{-6}, which is dominated by potential CCF of all four MDCT fans. However, this conditional CCF probability is conservative because it assumes that all four fans are failed completely; whereas, the most likely potential CCF is that the other three fans would fail in slow speed given the observed fast speed failure of MDCT fan 'D'. Given the likelihood that all four fans are available in at least slow speed and based on the licensee evaluation in the FSAR, it is probable that the safety function of the ultimate heat sink will be maintained for at least 24 hours. Even if the safety function was lost prior to the plant reaching a safe/stable end state, there would be significant time available to operators to repair the fast speed function of at least one fan. Given these considerations, the risk impact is determined to be minimal and, therefore, this event is qualitatively screened out of the ASP Program. A search of LERs did not yield any windowed events.</td></tr>
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Plant	LER	Event Date	LER Date	Screening Date	cASP Criterion	Evaluation Completed	Classification
Grand Gulf	416-19-004	8/28/19	10/24/19	11/4/19	3d	11/8/19	Analyst Screen-Out
Analyst Justification. This event is not discussed in any IR to date; the LER remains open. On August 28, 2019, the MCR received a high-pressure core spray (HPCS) out-of-service alarm and power status lights (e.g., logic power failure). Operators subsequently declared HPCS inoperable according to TS 3.5.1, Condition B. Instrument and control technicians determined that the HPCS instrument inverter, which converts 125 VDC to 120 VAC, had failed. Due to the loss of instrument inverter power, the HPCS suction minimum flow valve opened as designed and, therefore, operators also entered TS 3.6.1.3, Condition A, for an open primary containment isolation valve. Operators opened the associated breaker, and the minimum flow valve was manually closed per the required actions in TS 3.6.1.3, Condition A.1. HPCS was declared operable approximately 10 hours later on August 28th, when the inverter was replaced. Since the HPCS system was unavailable for less than the limits of TS LCO 3.5.1, Condition B (14 days), this event is screened out and is not considered a precursor. A search of LERs did not yield any windowed events.							
South Texas	498-19-002	7/30/19	9/30/19	10/16/19	3d	11/8/19	Analyst Screen-Out
Analyst Justification. This event is not discussed in any IR to date; the LER remains open. On December 31, 2018, reactor head vent throttle valve (RHVTV) 'A' unexpectedly auto transferred to the auxiliary shutdown panel. An investigation of the auxiliary shutdown panel showed indication for RHVTV 'A' in the MCR position. Operators subsequently declared RHVTV 'A' inoperable according to TS. On March 7, 2019, a 10 CFR Part 21 report notification was received by the licensee that was associated with a defect for Target Rock modulating valve positioners. Licensee engineers performed an evaluation and concluded that the positioners for the RHVTVs in Unit 1 were degraded and needed to be replaced at the next available opportunity. On July 30, 2019, during a training demonstration, an instructor identified a bad computer reading associated with the position of RHVTV 'B'. Based on the instructor's knowledge, the erroneous indication was likely caused by a blown fuse in the RHVTV 'B' control unit and immediately notified the MCR. Operators declared the RHVTV 'B' inoperable; however, a reportability review was not requested as required by procedure when two or more trains of a component or system are inoperable. Further evaluation by the licensee determined that the fuse associated with RHVTV 'B' likely failed on June 24, 2019. Therefore, both RHVTVs were inoperable for longer than the associated 30-day TS action statement and the required shutdown TS action requirements were not met. RHVTVs 'B' and 'A' were declared operable on August 1st and August 15th, respectively. The reactor vessel head vent system is designed to mitigate a possible condition of inadequate core cooling or impaired natural circulation resulting from the accumulation of non-condensable gases in the reactor coolant system. The depressurization function of this system is not typically included in the SPAR models because venting of the reactor head typically would occur after a complete loss of core cooling and the onset of accident conditions (i.e., does not prevent initial core damage). Since this event has no impact on the risk of core damage, it is screened out and is not considered a precursor. A search for windowed events is not required.							

Plant	LER	Event Date	LER Date	Screening Date	cASP Criterion	Evaluation Completed	Classification
Davis-Besse	346-19-002	8/19/19	10/18/19	11/12/19	3b	11/15/19	Analyst Screen-Out
Analyst Justification. This event is not discussed in any IR to date; the LER remains open. On August 19, 2019, the licensee initiated preventive maintenance activities to remove piping insulation and perform ultrasonic testing and inspection of service water piping to AFW train 1 piping. Security personnel opened door 363 to the AFW pump 2 room to support the maintenance. After maintenance workers entered, door 363 was latched open. The workers and security officer subsequently entered door 215, which is a watertight door that provides normal access to AFW pump 1 room. This door was left open after workers passed through. This door serves as a fire, flood, tornado, security, and high energy line break barrier. The central alarm station received an expected alarm when door 215 was opened at 8:11 a.m. Note that the associated card reader does not control access of door 215 (i.e., it alarms when the door is opened and resets when closed). Following piping insulation removal, maintenance workers returned to their shop to wait for the quality control workers to complete their inspections before reinstalling the insulation. A subsequent patrol by a security officer observed one of the quality control workers going between the two AFW pump rooms with door 215 open. The security officer called the central alarm station officer and reported the door check was complete and left the area at 9:00 a.m. Approximately 22 minutes later, an additional quality worker also left the area with door 215 remaining open. At 9:24 a.m., a plant operator performing a zone tour swiped their badge at door 363 and noted that door 215 was open and unattended. The operator contacted the shift manager, who directed the operator to close door 215. Door 215 was subsequently closed, and a reset alarm was received at the central alarm station at 9:26 a.m. Because door 215 was left open for approximately 87 minutes, operators declared the two associated AFW pump trains inoperable due to the loss of train separation per TS 3.7.5, Condition D. This requires the plant be placed in Mode 3 within 6 hours and Mode 4 within 12 hours. Since the two AFW pumps were inoperable for less than the limits of TS, this event is screened out and is not considered a precursor. A search of LERs did not yield any windowed events.							
Hatch 2	366-19-004	8/22/19	10/16/19	11/12/19	3d	11/15/19	Analyst Screen-Out
Analyst Justification. This event is not discussed in any IR to date; the LER remains open. On August 22, 2019, the HPCI system inverter circuit failure alarm was received in the MCR. Operators immediately noticed the loss of indication on several digital recorders and on the HPCI flow controller. After approximately 2 minutes, the alarm cleared, and all digital indications returned to normal. Operators subsequently declared HPCI inoperable due to the failure of a ceramic capacitor inside of the HPCI turbine speed control power supply. The failed capacitor caused a short-circuit that momentarily depressed power on the HPCI inverter and resulted in a loss of function to the HPCI flow controller. The HPCI turbine speed control power supply was replaced and was tested satisfactorily. Since the HPCI system was unavailable for less than the limits of TS LCO 3.5.1, Condition C (14 days), this event is screened out and is not considered a precursor. A search of LERs did not yield any windowed events.							

Plant	LER	Event Date	LER Date	Screening Date	cASP Criterion	Evaluation Completed	Classification
Wolf Creek	482-19-002	8/9/19	10/14/19	11/12/19	3e	11/21/19	Analyst Screen-Out
Analyst Justification. This event is not discussed in any IR to date; the LER remains open. On August 19, 2019, EDG 'A' was declared inoperable during its monthly surveillance test due to high intercooler water temperature. As a result, the plant entered TS LCO 3.8.1, Condition B. Subsequent licensee investigation revealed the cause for the high intercooler water temperature was the failure of the thermostatic "power pills" in the intercooler heat exchanger temperature control valve. These "power pills" are devices that contain a temperature sensitive metal/wax solution that expands with increasing temperature, which provides the motive force to lift the controlling valve element off its seat. The failed "power pills" caused the valve to fail in the bypass position, thereby reducing cooling flow through the intercooler heat exchanger. The licensee determined that the power pills most likely failed prematurely due to accelerated aging caused by annual shelf life testing. Due to the probable cause of failure, the condition is believed to have existed since the completion of the previous successful monthly test of EDG 'A' on July 15th. In addition, EDG 'B' was out of service for maintenance for approximately 2 days during this period. The failed "power pills" were replaced and EDG 'A' was returned to service on August 20th and TS LCO 3.8.1, Condition B was exited. A risk analysis was performed assuming two exposure periods: (a.) approximately 2 days that both EDGs were unavailable to perform their safety function and (b.) the remaining 34 days that EDG 'A' was unable to fulfil its safety function. In addition, two cases for each of these exposure periods were performed that credited and omitted FLEX mitigation strategies, respectively. The ΔCDPs for the first exposure period (i.e., both EDGs unavailable for 2 days) are 8.6×10^{-8} and 5.4×10^{-7} with and without credit for FLEX, respectively. The ΔCDPs for the second exposure period (i.e., EDGs 'A' failed for 34 days) are 9.9×10^{-8} and 6.4×10^{-7} with and without credit for FLEX, respectively. Therefore, the total ΔCDPs are 1.9×10^{-7} and 1.2×10^{-6} with and without credit for FLEX, respectively. Although there are significant uncertainties associated with the modeling of the FLEX mitigations strategies (e.g., human and equipment reliability), the analysis results show that very little FLEX credit is needed to reduce the risk of this event below the precursor threshold of 10^{-6}. The total seismic risk contribution for this event is negligible. Therefore, even with very conservative FLEX reliability considerations, the risk associated with this event is below 10^{-6} and, therefore, this event is screened out and is not considered a precursor. A search of LERs did not reveal any windowed events.							
Browns Ferry 1	259-19-001-01	7/12/19	9/6/19	9/20/19	3d	11/26/19	Analyst Screen-Out
Analyst Justification. This event is not discussed in any IR to date; the LER remains open. On July 12, 2019, the HPCI system unexpectedly received a group 4 primary containment isolation system (PCIS) signal, which closed the HPCI inboard and outboard steam supply valves. Operators declared HPCI inoperable and entered TS 3.5.1, Condition C, and subsequently verified that RCIC was operable as required. In response to the group 4 PCIS actuation, operators entered Abnormal Operating Instruction 1-AOI-64-2b, "Group 4 High Pressure Coolant Injection Isolation." A licensee investigation determined that electrical maintenance personnel were performing procedure EPI-0-075-RLY001, "Functional Test of Pressure Suppression Chamber Head Tank Pump Suction Valve Interlock Relays," at the time of this event. Terminal points were tested in the incorrect panel, which resulted in completing the circuitry for the group 4 PCIS actuation. HPCI was returned to operability in approximately 4.5 hours after the group 4 PCIS actuation and, therefore, operators exited TS 3.5.1, Condition C. Since the HPCS system was unavailable for less than the limits of TS LCO 3.5.1, Condition C (14 days), this event is screened out and is not considered a precursor. A search of LERs did not yield any windowed events.							

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<tr><th>Plant</th><th>LER</th><th>Event Date</th><th>LER Date</th><th>Screening Date</th><th>cASP Criterion</th><th>Evaluation Completed</th><th>Classification</th></tr>
<tr><td>St. Lucie 1</td><td>335-19-003</td><td>8/30/19</td><td>10/28/19</td><td>11/13/19</td><td>3e</td><td>11/26/19</td><td>Analyst Screen-Out</td></tr>
<tr><td colspan="8">Analyst Justification. This event is not discussed in any IR to date; the LER remains open. On July 15, 2019, EDG '1B' was started for monthly surveillance testing. After approximately 40 minutes of run time, the EDG tripped due to high jacket water temperature. A subsequent licensee investigation revealed that a radiator fan on the EDG was not rotating and that the fan's associated crankshaft connection was sheared. Repairs were completed and EDG '1B' was returned to service on July 28th. Forensics determined that approximately 10 percent of the radiator-to-crankshaft connection remained after the previous monthly surveillance test that was completed on June 17th. EDG '1B' had successfully completed its 24-hour endurance test on May 22, 2019. Given that the plant was in Mode 5 until June 8th and the forensic data, it was determined that EDG '1B' was unable to fulfil its safety function for approximately 50 days (i.e., June 8th through July 28th). An analysis was performed assuming EDG '1B' failure to run for an exposure period of 50 days. Two cases were performed, one with credit of FLEX mitigation strategies and one without, which resulted in ΔCDPs of 5.3×10^{-7} and 2.1×10^{-6}, respectively. The total seismic risk contribution is negligible for this event. Although there are significant uncertainties associated with the modeling of the FLEX mitigations strategies (e.g., human and equipment reliability), a sensitivity analysis with more conservative human error probabilities associated with implementation of FLEX strategies result in ΔCDP below the precursor threshold of 10^{-6}. Given these analyses results, this event is screened out and is not considered a precursor. A search of LERs did not reveal any windowed events. However, discussions with a Region 2 SRA identified that EDG '1A' was inoperable for approximately 4 hours (for monthly surveillance testing) during the EDG '1B' 50-day exposure period. Although inoperable due to TS, the safety function for EDG '1A' could be readily restored and, therefore, this windowed condition is not expected to affect the risk associated with the failure of EDG '1B'.</td></tr>
<tr><td>Palo Verde 2</td><td>529-19-001</td><td>8/16/19</td><td>10/11/19</td><td>11/11/19</td><td>2h</td><td>12/3/19</td><td>Analyst Screen-Out</td></tr>
<tr><td colspan="8">Analyst Justification. This event is not discussed in any IR to date; the LER remains open. On August 16, 2019, a Unit 2 main turbine trip occurred followed by an automatic reactor trip due to low departure from nucleate boiling ratio and high local power density due to the loss of power to all four reactor coolant pumps (RCPs). All reactor control rods fully inserted into the reactor core. The main turbine trip was due to the opening of the salt river project (SRP) main generator output switchyard breakers. These breakers received an invalid generator trip output signal. The opening of the main generator output breakers does not provide the electrical circuit logic needed to initiate a fast bus transfer of the nonsafety-related 13.8 kV loads. The transfer of these loads is needed to supply and maintain power to the RCPs and other secondary systems powered by nonsafety-related buses. The loss of the nonsafety-related buses resulted in a loss of reactor coolant flow, main feedwater, plant cooling water, turbine cooling water, nuclear cooling water, normal chill water, instrument air, circulating water, and condenser vacuum. MCR operators entered emergency operating procedure 40EP-9E007, "Loss of Offsite Power / Loss of Forced Circulation," and manually actuated a main steam isolation signal in response to the loss of circulating water flow to the main condenser. Operators verified natural circulation with steam generator level control being provided by manually starting an AFW pump and a spray pond pump. Decay heat removal was provided via the steam generator atmospheric dump valves. All safety-related buses remained powered from offsite power throughout the event. This event is bounded by a nonrecoverable loss of condenser heat sink and, therefore, is not a precursor. A search of LERs did not identify any windowed events.</td></tr>
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Plant	LER	Event Date	LER Date	Screening Date	cASP Criterion	Evaluation Completed	Classification
Hatch 2	366-19-003	3/24/19	5/22/19	7/1/19	2h	12/10/19	Analyst Screen-Out

Analyst Justification. This event is discussed in IR 05000366/2019002 (ADAMS Accession No. ML19219A494); the LER was closed with no performance deficiency identified. On March 24, 2019 while starting up in Mode 1 at 25 percent power, the main condenser was losing vacuum due to a throttled valve supplying condensate flow to the steam jet air ejector '2B', which was not fully open as required. The operators lowered reactor power and initiated a manual reactor scram. Subsequently the nonsafety-related 4.16 kV buses failed to fast transfer to the alternate power supply resulting in the loss of all nonsafety-related loads such as condensate and feedwater. Reactor water level and pressure were maintained by RCIC and HPCI throughout the event. The failure of the fast transfer of the nonsafety-related buses was caused by a faulted relay, which was designed to actuate when the main generator output breakers open to automatically transfer nonsafety-related 4.16 kV buses from their normal power supplies to the alternate supplies. The loss of condenser vacuum was caused by the failure to return the condensate throttle valve to its required position prior to plant startup. A test and limited use Hatch SPAR model was used to perform a risk assessment of this event, which incorporated modeling improvements for the nonsafety-related buses automatic transfer function. Two cases were evaluated for this event. The first case evaluated a loss of condenser heat sink initiating event with a failure of fast transfer of the nonsafety-related buses to their alternate power supply. The second case involved a condition assessment of the unavailability of the fast transfer of the nonsafety-related buses for 1 year. The 1-year exposure period was selected because the last time the fast transfer successfully operated was several years prior and, therefore, the maximum of 1 year was selected. Note that manual action to transfer the power supplies of the nonsafety-related 4.16 kV buses to their alternate power supplies is already accounted for in the SPAR model. The risk of the initiating event was bounded by the plant-specific CCDP of a non-recoverable loss of condenser heat sink (i.e., the failure of the fast transfer did not add any risk impact to the loss of condenser heat sink initiating event that occurred on March 24th). For the condition assessment, basic events ACP-ABT-FC-SUTC and ACP-ABT-FC-SUTD were set to TRUE to represent the failure of the fast transfer for the nonsafety-related 4.16 kV buses to their alternate power supplies. The result of this condition assessment is a ΔCDP of 5.2×10^{-7}. A search of Hatch LERs revealed that LER 2019-366-002 reported a HPCI inoperability for approximately 14 hours due to the failure of the HPCI auxiliary oil pump caused by inadequate contact of the motor control center pan assembly secondary connection stabs (LER 2019-366-002). This 14-hour HPCI unavailability occurred during the 1-year exposure period of the failed fast transfer. Therefore, a condition assessment assuming the concurrent failures of HPCI and the fast transfer for 14 hours was performed, which resulted in a ΔCDP of 6.1×10^{-8}. This risk impact from these two windowed events does not significantly impact the risk from the 1-year condition assessment for the failure of the fast transfer alone. The seismic risk impact of the event is negligible. The risk for this event is below the ASP Program threshold and, therefore, this event is not a precursor.

Plant	LER	Event Date	LER Date	Screening Date	cASP Criterion	Evaluation Completed	Classification
Susquehanna 1 and 2	387-19-002	8/28/19	10/28/19	11/13/19	3c	12/10/19	Analyst Screen-Out
Analyst Justification. This event is not discussed in any IR to date; the LER remains open. On August 28, 2019, during inservice testing of loop 'A' of the emergency service water (ESW) system, the differential pressure for ESW pump 'C' was found to be 88.875 psid. This differential pressure is below the established acceptance criteria. Specifically, ESW pump 'C' was in the inservice testing required action range, which requires the pump to be declared inoperable. At the time of discovery of this condition, both units were in TS 3.7.2, Condition C in support of inservice testing activities on ESW loop 'A'. On August 29th, the pump lift setting was adjusted and ESW pump 'C' was retested. The retest resulted in an acceptable differential pressure of 91.9 psid, which was in the alert range and no longer in the required action range. TS 3.7.2, Condition C was exited later on August 29th. On October 4th, Susquehanna completed replacement of ESW pump 'C'. The removed pump had notable degradation and, therefore, the licensee determined that degraded condition existed for longer than allowed by TS 3.7.2. Although inoperable due to TS, ESW pump 'C' would be expected to fulfil its safety functions for internal hazards; however, seismic hazards may result in failure due to the deterioration the pump. A risk assessment was performed conservatively assuming that ESW pump 'C' would fail during any seismic event for the maximum exposure period of 1 year. This analysis results in a ΔCDP of 10^{-8}, which is below the ASP threshold and, therefore, this event is not a precursor. A search of LERs did not identify any windowed events.							
Quad Cities 1	254-19-001	2/5/19	4/5/19	4/30/19	3d	12/10/19	Analyst Screen-Out
Analyst Justification. This event is discussed in IR 05000254/2019002 (ADAMS Accession No. ML19214A115); the LER was closed with no performance deficiency identified. On February 5, 2019, a fuse failed in the logic for the motor speed changer for the HPCI turbine during operability testing. The failed fuse disabled both the manual and automatic injection functions of HPCI. The system had been out of service for planned maintenance, but no maintenance activities took place on equipment protected by this fuse. The last successful test for HPCI occurred on November 8, 2018. Licensee troubleshooting identified that the motor speed changer motor and gearbox were mechanically bound. The licensee also determined that intermittent failure of the low speed stop limit switch caused intermittent operation of the associated relay. The limit switch failure was due to high resistance contacts attributed to deposits and pitting caused by age related degradation. All failed components were replaced, testing completed satisfactorily, and HPCI was declared operable on February 8th. A risk assessment was performed assuming the failure of HPCI for an exposure period of 92 days (i.e., November 8th through February 8th). This analysis results in a ΔCDP of 5×10^{-7}. The seismic impact for this event is negligible. This analysis result is below the ASP threshold of 10^{-6} and, therefore, this event is not a precursor. A search of LERs did not identify any windowed events.							

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<tr><th>Plant</th><th>LER</th><th>Event Date</th><th>LER Date</th><th>Screening Date</th><th>cASP Criterion</th><th>Evaluation Completed</th><th>Classification</th></tr>
<tr><td>Catawba 1</td><td>414-19-003</td><td>7/6/19</td><td>9/4/19</td><td>9/20/19</td><td>3c</td><td>12/11/19</td><td>SDP Screen-Out</td></tr>
<tr><td colspan="8">Analyst Justification. A Green finding was identified in IR 05000414/2019003 (ADAMS Accession No. ML19311C629), the LER is closed. On July 5, 2019, the discharge check valve for component cooling water (CCW) pump '2A1' failed to close after the pump was secured. The condition resulted in an unplanned entry into a 72-hour TS action statement for one CCW train inoperable. On July 6, 2019, during the repair of failed check valve, the isolation boundary was expanded, which resulted in the plant to implement an existing procedure that defeated the interlocks for the non-essential reactor building supply and return header valves to close on an engineered safeguards actuation signal. Operators were unaware that defeating the interlocks would cause a failure to meet a TS surveillance requirement, which should have resulted in the declaration of CCW Train '2B' as inoperable. NRC inspectors determined that the licensee failure to take required TS actions for the inoperability of both CCW trains was a performance deficiency. A detailed risk assessment was performed assuming the defeated interlocks would result in a loss of all CCW due to an engineered safeguards actuation signal (i.e., loss-of-coolant accident). The exposure period of the defeated interlocks was determined to be approximately 14 hours. This analysis resulted in a ΔCDF of less than 10^{-6}, which is below the ASP threshold and, therefore, this event is not a precursor. A search of LERs did not identify any windowed events.</td></tr>
<tr><td>Catawba 1</td><td>413-19-002-01</td><td>4/11/19</td><td>9/11/19</td><td>10/3/19</td><td>3b</td><td>12/20/19</td><td>SDP Screen-Out</td></tr>
<tr><td colspan="8">Analyst Justification. A Green finding was identified in IR 05000413/2019003 (ADAMS Accession No. ML19311C629); the LER is closed. On April 11, 2019, the sump pump associated with the ‘1B’ motor-driven (MD) AFW failed to start due to a seized impeller. The sump pump was repaired and returned to service on May 1st. The ‘1B’ MDAFW pump was not declared inoperable due to the sump pump failure. However, a revised auxiliary building flooding calculation subsequently revealed that a postulated feedwater line break in the interior doghouse coincident with a LOOP would result in the failure of the MDAFW pumps if their associated sump pumps were not functional. Therefore, the ‘1B’ MDAFW pump should have been declared inoperable, according to TS, for the failure that occurred on April 11th. In addition, the licensee determined other instances when the MDAFW pumps should have been declared inoperable when the sump pumps were rendered unavailable. NRC inspectors determined that the failure to declare the MDAFW pumps inoperable when a necessary support system was unavailable to perform its related support function was a performance deficiency and a violation of TS 3.7.5. The detailed risk analysis performed by the Region 2 SRA assumed that the risk associated with the unavailability of the sump pump(s) for the MDAFW pumps was limited to a postulated feedwater rupture in the interior doghouse. A total flood frequency of 6.6×10^{-3} per year was used in the analysis. No credit was provided for the nonsafety-related floor drain sumps that would be available for non-LOOP events, which is conservative. The analysis resulted in an ΔCDF of 5.5×10^{-8} per year. The performance deficiency was determined to be Green (i.e., very low safety significance). This analysis was reviewed and determined to be appropriate for ASP Program needs. The calculated risk is below the ASP Program threshold; therefore, this event is not a precursor. A search of LERs did not yield any windowed events.</td></tr>
<tr><td>Columbia</td><td>397-19-001</td><td>9/24/19</td><td>11/25/19</td><td>12/16/19</td><td>3d</td><td>12/20/19</td><td>Analyst Screen-Out</td></tr>
<tr><td colspan="8">Analyst Justification. This event is not discussed in any IR to date; the LER remains open. On September 24, 2019, during maintenance to drain an air receiver in the HPCS diesel starting air system, a pressure control valve (PCV) vented due to a leaking isolation valve, resulting in the in-service air receiver pressure to drop below the minimum value required by TS. Operators declared the HPCS diesel generator, HPCS service water, and the HPCS system inoperable. The leak was isolated, and the in-service air receiver pressure was restored on September 25, 2019, and all associated TS were exited. The total time of the degraded air pressure was 1 hour and 26 minutes. Since the HPCS system was unavailable for less than the limits of TS LCO 3.5.1, Condition B (14 days), this event is screened out and is not considered a precursor. A search of LERs did not yield any windowed events.</td></tr>
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Plant	LER	Event Date	LER Date	Screening Date	cASP Criterion	Evaluation Completed	Classification
Perry	440-19-002	5/24/19	7/18/19	8/23/19	3d	12/20/19	SDP Screen-Out
Analyst Justification. A *Green* finding was identified in IR 05000440/2019003 (ADAMS Accession No. ML19318F401); the LER remains open. On May 24, 2019, unexpected alarms were received for residual heat removal train 'A' and the division I EDG out-of-service, following the start of ESW pump 'A' for pump packing adjustment. Indications in the MCR were also illuminated for ESW pump 'A' Breaker Out/Power Loss/Overload. ESW pump 'A' pump remained running during this time. The licensee subsequently discovered that the closing control power fuses for the pump breaker were not seated properly, which resulted in the inoperability of ESW train 'A' and several safety-related systems it supports (e.g., low-pressure core spray). The control power fuse block for the ESW pump 'A' breaker was fully seated by the initial responder on May 24th. The fuse block had no issue staying properly in place and with adequate tightness, which demonstrated that the closing power fuse block was not loose and was not jarred out of the seated position during breaker operation. ESW pump 'A' was stopped and restarted successfully, and the pump was declared operable on May 24th (approximately 7.5 hours after the alarms were received in the MCR). NRC inspectors determined that the licensee failed to properly install the ESW pump 'A' control power fuses in accordance with SOI-R22, "Metal Clad Switchgear 5–15 kV," was a performance deficiency. It was determined that control power fuses for ESW pump 'A' were last manipulated on April 25, 2019. During this 30-day exposure period, the pump ran successfully several times. Therefore, the detailed risk analysis, performed by the Region III SRA, assumed that the risk associated with this event would only be from postulated seismic events that could challenge the operation of the pump in the degraded condition. This analysis resulted in an ΔCDF less than 10^{-7} per year, which is a finding of very low safety significance. This analysis was reviewed and determined to be appropriate for ASP Program needs. The risk of this event is below the ASP Program threshold; therefore, this event is not a precursor. A search of LERs did not yield any windowed events.							
Oconee 1	269-19-002	7/24/19	9/19/19	10/7/19	3d	12/27/19	Analyst Screen-Out
Analyst Justification. This event is discussed in IR 05000269/2019003; the LER remains open. On July 24, 2019, operators began to vent the '1A' core flood tank (CFT) due to a rise in pressure resulting from increased seasonal temperatures by remotely opening isolation valve 1CF-5. When pressure for the '1A' CFT lowered to an acceptable value, the licensee attempted to close 1CF-5 to stop the venting. However, 1CF-5 failed to fully close and the depressurization of the '1A' CFT continued until pressure dropped below the TS allowed minimum. Additional operators were dispatched to align a makeup supply of nitrogen while the venting continued through 1CF-5. Approximately 4 hours later, operators terminated the venting of the '1A' CFT by closing a downstream manual isolation valve and, therefore, restoring TS operability. Since the '1A' CFT was unavailable for less than the limits of TS LCO 3.5.1, Condition C (12 hours), this event is screened out and is not considered a precursor. A confirmatory condition assessment was performed assuming the failure of the '1A' CFT for 4 hours indicated a negligible risk impact. A search of LERs did not yield any windowed events.							

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<tr><td>Sequoyah 2</td><td>328-19-001</td><td>6/17/19</td><td>11/15/19</td><td>11/26/19</td><td>3c</td><td>12/27/19</td><td>Analyst Screen-Out</td></tr>
<tr><td colspan="8">Analyst Justification. This event is not discussed in any IR to date; the LER remains open. On August 24, 2019, during the flush of a CCW heat exchanger, an essential raw cooling water (ERCW) manual valve (2-VLV-67-551) was placed in a throttled position that was determined as part of a temporary modification implemented on June 17, 2019. Shortly after beginning the flush, CCW alarms were received in the MCR which caused operators to terminate the flush and restore ERCW flows. The licensee subsequently evaluated flow test data and identified the throttle positions implemented by the temporary modification did not allow the required flow. On August 28th, a flow balance was conducted, and the correct throttle positions were determined. A licensee evaluation concluded that had a Unit 2 loss-of-coolant accident (LOCA) occurred (or any transient requiring safety injection), the ERCW System and CCW would have been able to perform their required functions of core cooling and containment vessel protection. In addition, the ERCW and CCW systems would have been able to provide the required equipment cooling functions for Unit 1. However, this evaluation also determined that had a Unit 1 LOCA occurred (or any transient requiring a safety injection), the Unit 2 CCW train 'A' would not have been able to perform its required equipment cooling function for Unit 2 without operator intervention. Based on this determination, the Unit 2 CCW Train 'A' was declared inoperable from June 17th to August 28th. A risk assessment was performed assuming that any initiating event on Unit 2 during a LOCA on Unit 1 would result in a loss of the Unit 2 CCW train 'A'. This is potentially conservative because operators could restore full CCW flow given that alarms would be present (as they were during the event). This analysis assumed a 73-day exposure time. The total LOCA frequency for Unit 1 was calculated using the SPAR model by summing all LOCA frequencies (e.g., large, medium, small, steam generator tube rupture, stuck-open relief valve, etc.). This total frequency was estimated to be 3×10^{-3} per year. Since this frequency is used in the CCW train 'A' fault tree logic, it was converted to a probability of 6×10^{-4} by multiplying the frequency by (73 days/1 year). The result of this condition assessment was a ΔCDP of 6×10^{-9} for internal hazards. The seismic impact for this event is a ΔCDP of 3×10^{-10}. This analysis result is below the ASP Program threshold and, therefore, this event is not a precursor. A search of LERs did not identify any windowed events.</td></tr>
<tr><td>River Bend</td><td>458-19-004</td><td>10/24/19</td><td>12/23/19</td><td>1/10/20</td><td>3d</td><td>1/13/20</td><td>Analyst Screen-Out</td></tr>
<tr><td colspan="8">Analyst Justification. This event is not discussed in any IR to date; the LER remains open. On October 24, 2019, the automatic depressurization system (ADS) air supply header pressure began to lower. This header provides air for the automatic or manual operation of the safety relief valves (SRVs) from the MCR. A loss of header air pressure was caused by leaking air-operated valves (AOVs) on the ADS train 'B' dryer, which was undergoing maintenance at the time of the event. When a tagout was removed on the ADS train 'B' AOVs, header pressure began to subsequently lower. The ADS train 'A' safety vent valve compressor attempted to maintain header pressure but tripped on a thermal overload caused by excessive start/stops due to the leaking AOVs. At this time, the train 'B' compressor was still tagged out for maintenance. The tagout was removed and the compressor started; however, header pressure continued to lower. The train 'A' compressor was subsequently reset and started, which restored ADS header pressure to its normal operating pressure. The seven SRVs were inoperable for approximately 40 minutes due to ADS header pressure lowering below the TS limit of 131 psig. Since ADS was unavailable for less than the limits of TS LCO 3.5.1, Condition G (12 hours), this event is screened out and is not considered a precursor. A search of LERs did not yield any windowed events.</td></tr>
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Plant	LER	Event Date	LER Date	Screening Date	cASP Criterion	Evaluation Completed	Classification
Beaver Valley 1	334-19-001	11/2/19	12/30/19	1/10/20	3d	1/13/20	Analyst Screen-Out
Analyst Justification. This event is not discussed in any IR to date; the LER remains open. On November 2, 2019, surveillance test 1OST-11.1, "Safety Injection Pump Test," was performed on low-head safety injection pump 'A' during the refueling outage. This quarterly test verifies that the pump starts and delivers sufficient recirculation flow. During the surveillance test, the refueling water storage tank (RWST) level began to drop resulting in a low-level alarm. The RWST was subsequently declared inoperable according to TS due to insufficient inventory. The licensee later determined that approximately 850 gallons of water from the RWST was transferred to the safeguards building sump. Low-head safety injection pump 'A' was secured and the RWST level stopped decreasing. The plant also entered TS 3.5.2 for two trains of low-head safety injection being inoperable. In addition, the leakage coincident with the transfer to recirculation following a design basis large LOCA would result in exceeding the dose analysis in the MCR. Therefore, the MCR envelope was declared inoperable (TS 3.7.10) for both units due to the shared MCR. Licensee troubleshooting determined that the discharge relief valve for low-head safety injection pump 'A' was lifting due to having a set point below the high-peak pump start pressure and the relief valve failing to reseat when system pressure dropped below the expected design blowdown pressure. The failure of the relief valve to reclose was caused by station personnel failing to verify that the guide ring was properly set when the relief valve was replaced during the refueling outage. The leaking discharge relief valve was isolated, and a temporary gag was placed on the valve that will be removed during the next refueling outage. A licensee evaluation determined that the surveillance test pump flow acceptance criteria was met for low-head safety injection pump 'A', which assures that the pump will deliver sufficient flow upon a safety injection recirculation signal. Therefore, there is reasonable assurance that the leakage was small enough such that no loss of safety function occurred. Since no loss of safety function was experienced, this event is screened out and is not considered a precursor. A review of potential windowed events was not needed because there was no loss of safety function.							
Clinton	461-19-004	10/2/19	11/29/19	1/14/20	3d	1/29/20	Analyst Screen-Out
Analyst Justification. On October 2, 2019, the licensee was performing SRV testing during a refueling outage, when SRV 1B21-F041B failed to open upon demand from its MCR switch. Subsequent investigation identified that the division 1 MCR switch for SRV 1B21-F041B opened SRV 1B21-F051B and the switch for SRV 1B21-F051B opened SRV 1B21-F041B. The issue was determined to be caused by a wiring error that occurred during the previous refueling outage completed in May 2017. The wiring was corrected, and a post-maintenance test completed. Both SRVs maintained their safety relief functions; however, the ADS function for SRV 1B21-F041B was determined to be inoperable according to TS since May 2017. A risk assessment was performed assuming the failure of SRV to open for its ADS function for the maximum exposure period of 1 year. This analysis results in a ΔCDP of 5×10^{-7}. The seismic impact for this event is ΔCDP of 7×10^{-8}. This analysis result is below the ASP Program threshold and, therefore, this event is not a precursor. A search of LERs did not identify any windowed events.							

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<tr><td>Waterford</td><td>382-19-007</td><td>7/31/19</td><td>9/26/19</td><td>10/16/19</td><td>3d</td><td>1/30/20</td><td>Analyst Screen-Out</td></tr>
<tr><td colspan="8">Analyst Justification. This event is not discussed in any IR to date; the LER remains open. On June 30, 2019, licensee personnel identified a 0.24 gpm leak in the chemical volume control (CVC) system drain line upstream valve CVC-186. CVC-186 provides a drain path from the volume control tank and charging pump suction header to the equipment drain tank. This drain line is on the suction path to all three charging pumps and is part of the emergency boration flow path. Radiography was performed and determined that the line had a 1.162-inch circumferential flaw. Analysis was performed and determined that the maximum allowable flaw size for the piping configuration was 1.7 inches. Daily monitoring of the piping flaw was established. On July 31st, the flaw size increased to 1.75 inches, which resulted in all three charging pumps and the associated emergency boration flow path being declared inoperable according to TS. Operators entered TS 3.0.3 and commenced a plant shutdown. Repairs were attempted while the plant was in Mode 3 but were unsuccessful. The plant entered Mode 5 on August 1st and the damaged section of pipe was replaced. After repairs were completed, the system was successfully returned to service on August 3rd. The risk impact of this event was the potential loss of emergency boration capability using the charging pumps. A risk assessment was performed assuming the unavailability of emergency boration via the charging pumps for an exposure period of 32 days, which is potentially conservative. This analysis resulted in a ΔCDP 2×10^{-7} for internal hazards. The seismic risk contribution was 2×10^{-9}. This analysis result is below the ASP Program threshold and, therefore, this event is not a precursor. A search of LERs did not yield any windowed events.</td></tr>
<tr><td>Nine Mile Point 2</td><td>410-19-001</td><td>11/1/19</td><td>12/31/19</td><td>2/24/20</td><td>3d</td><td>2/26/20</td><td>Analyst Screen-Out</td></tr>
<tr><td colspan="8">Analyst Justification. This event is not discussed in any IR to date; the LER remains open. On November 1, 2019, annunciators HPCS System Inoperable and inoperable status light Indication for Trip Units Out of File/Power Fail were received in the MCR. Operators attempted to close the HPCS Minimum Flow Valve to secure draining condensate storage tanks (CSTs) to the suppression pool; however, the valve immediately reopened. Operators subsequently realigned the HPCS pump suction CSTs to suppression pool per procedure and declared the HPCS system inoperable according to TS. The RCIC system was verified to be operable. Licensee troubleshooting identified 24V DC power supply E22A-PS1 was failed. The failed power supply was replaced approximately 10 hours after its failure. The plant exited all applicable TS LCOs when HPCS operability was restored after post-maintenance testing was successfully completed. Since the HPCS system was unavailable for less than the limits of TS LCO 3.5.1, Condition B (14 days), this event is screened out and is not considered a precursor. A search of LERs did not yield any windowed events.</td></tr>
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