U.S. Nuclear Regulatory Commission

Accident Sequence Precursor Program

2017 Annual Report

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Contacts:
Ian Gifford, (301) 415-3256 (ian.gifford@nrc.gov)
Christopher Hunter, (301) 415-1394 (christopher.hunter@nrc.gov)
Anders Gilbertson[1], (301) 415-1541 (anders.gilbertson@nrc.gov)

[1] Acting Chief, Performance and Reliability Branch

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

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Summary of ASP Program Results

2017 Results. Based on the review of all licensee event reports (LERs) issued during calendar year 2017 and the results from the Significance Determination Process (SDP), 13 events were determined to be precursors. An independent Accident Sequence Precursor (ASP) analysis was performed to determine the risk significance of eight precursors, while SDP results were used for the other five precursors.

ASP Trends. Trend analyses of precursor data are performed on a rolling 10-year period (i.e., 2008–2017 for this report). In addition, trend analyses are performed on a rolling 20-year period (i.e., 1998–2017 for this report) to provide a historical perspective. The following table provides the updated results of these analyses[1]:

Precursor Category	10-Year Trend	20-Year Trend
All Precursors	↓	↔
Precursors with a CCDP/ΔCDP $\geq 10^{-4}$	↔	↓
Precursors with a CCDP/ΔCDP $\geq 10^{-5}$	↔	↔
Initiating Events	↔	↔
Degraded Conditions	↓	↔
Emergency Diesel Generator (EDG) Unavailabilities	↔	↑
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:

- The ASP Program has documented 149 precursors.
- 65 percent of all precursors used SDP evaluation results for the ASP Program purposes.
- The last significant precursor (i.e., conditional core damage probability (CCDP) or change in core damage probability (ΔCDP) greater than or equal to 1×10^{-3}) was identified in 2002, which involved concurrent degraded conditions at the Davis Besse nuclear power plant.
- Seven precursors with a CCDP or ΔCDP greater than or equal to 1×10^{-4} were identified in 2010–2012; however, none have been identified since.
- 58 percent of the precursors with a CCDP or ΔCDP greater than or equal to 1×10^{-5} are due to initiating events (with the remaining from degraded conditions). Of these, almost three-quarters were the result of a LOOP.
- Precursors involving degraded conditions (99 precursors) outnumbered initiating events (50 precursors).
- 34 percent of initiating event precursors resulted from natural phenomena (e.g., severe weather, seismic, etc.).
- Of the 99 degraded condition precursors, 24 percent existed for at least 10 years.
- Of the 42 precursors involving a degraded condition(s) at boiling-water reactors (BWRs), most were caused by failures in the emergency power system (38 percent), others were caused by failures in emergency core cooling systems (14 percent), and safety-relief valves (10 percent).
- Of the 57 precursors involving a degraded condition(s) at pressurized-water reactors (PWRs), most were caused by failures in the emergency power system (32 percent), others were caused by failures in the auxiliary feedwater system (26 percent), safety-related cooling water systems (11 percent), electrical

[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.

distribution system (11 percent), or emergency core cooling systems (11 percent).

- The following table provides notable observations about the number of precursors identified at various plants:

No Precursors Since Plant Startup
Comanche Peak 2; South Texas 2; Watts Bar 2
No Precursors in the Past 20 Years
Beaver Valley 1 & 2; Limerick 1, Peach Bottom 2; Salem 1; South Texas 2; Susquehanna 2; Vogtle 1
No Precursors in the Past 10 Years
Byron 1; Callaway; Calvert Cliffs 2; Comanche Peak 1 & 2; D.C. Cook 2; Diablo Canyon 1; Fermi; Fitzpatrick; Grand Gulf; Indian Point 2 & 3; McGuire 1 and 2; Nine Mile Point 1& 2; Palo Verde 1 & 2; Peach Bottom 3; Quad Cities 1 and 2; Salem 2; St. Lucie 2; Summer; Turkey Point 4
Four or More Precursors in the Past 10 Years
Arkansas Nuclear One Unit 2; Browns Ferry 1, 2, and 3; Dresden 3; Duane Arnold; Oconee 1; Oyster Creek; Pilgrim; Robinson; Waterford
Eight or More Precursors in the Past 20 Years
Oconee 1, 2, and 3; Oyster Creek
15 or More Precursors Since Plant Startup
Arkansas Nuclear One Unit 1; Davis Besse; Hatch 1; Oconee 1, 2, and 3; Oyster Creek; Palisades; Pilgrim

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 trends in the occurrence rate of all precursors and integrated ASP index.
- 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. BACKGROUND

The U.S. Nuclear Regulatory Commission (NRC) formed the Risk Assessment Review Group (commonly referred to as the Lewis Committee) to perform an independent evaluation of WASH-1400, "The Reactor Safety Study". That committee made a number of recommendations in 1978, including that more use be made of operational data to assess the risk from commercial nuclear power plants (NPPs). Specifically, NUREG/CR-0400, "Risk Assessment Review Group Report" (also known as the Lewis Report) stated:

> *It is important, in our view, that potentially significant sequences and precursors, as they appear, be subjected to the kind of analysis contained in WASH-1400, in such a way that the analyses are subjected to peer review.*

After the accident at Three Mile Island (Unit 2), the NRC instituted a special inquiry to review and report on the accident. The principal objectives of the inquiry were to:

- Determine what happened and why;
- Assess the actions of utility and NRC personnel before and during the accident; and
- Identify deficiencies in the system and areas where further investigation might be warranted.

This inquiry, as documented in NUREG/CR-1250, "Three Mile Island; A Report to the Commissioners and to the Public" (also known as the Rogovin Report) concluded, in part, that:

> *…the systematic evaluation of operating experience must be undertaken on an industrywide basis, both by the utility industry, which has the greatest direct stake in safe operations, and by the NRC.*

In response to these insights and recommendations, the NRC established the Accident Sequence Precursor (ASP) Program as part of the Office of Analysis and Evaluation of Operational Data (AEOD). In 1998, the Commission issued a Staff Requirements Memorandum, "SECY-98-228, Proposed Streamlining and Consolidation of AEOD Functions and Responsibilities", which approved the transfer of the ASP Program to the Office of Nuclear Regulatory Research (RES). The Commission stated that:

> *The lessons learned from the independent assessment of operational events must continue to be shared with the nuclear industry in an effort to improve the safety of licensed operations and to assess the effectiveness of agency wide programs. It is important that these functions continue with a degree of independence and, in particular, remain independent of licensing functions. The Office of Research should provide focused analysis of the operational data and not expend scarce resources on those operational incidents that are not risk significant.*

2. PROGRAM OBJECTIVES

The ASP Program has the following primary objectives:

- Assists in ensuring that the agency meets Safety Objective 1 (see NRC Strategic Plan)—to prevent, mitigate, and respond to accidents and ensure radiation safety.
- Contributes to Safety Strategy 1 (see NRC Strategic Plan) to evaluate domestic and international operating events and trends and advances in science and technology for safety

implications and enhance the regulatory framework as warranted.[2]

- Assists in fulfillment of agency Safety Performance Goal 4 (see NRC Congressional Budget Justification)—to prevent accident precursors and reductions of safety margins at commercial nuclear power plants (operating or under construction) that are of high safety significance.[3]
- Assesses the efficacy of existing agency programs (Appendix B in the NRC Strategic Plan) and helps shape the agency's objectives and strategies for reactors.[4]
- Reviews and evaluates operating experience to identify precursors to potential core damage in accordance with Management Directive (MD) 8.7, "Reactor Operating Experience Program."

Additional ASP Program objectives include:

- Providing feedback to improve NRC Standardized Plant Analysis Risk (SPAR) models.
  - Examples include: common-cause interactions and events; operator recovery actions; inclusion of support systems; alternate success paths.
  - Models are used in a different manner and reviews of model results allow for model improvements that aid other NRC programs (e.g., SDP, MD 8.3).
  - Assists in fulfillment of the MD 8.7 requirement to provide feedback to agency risk models based on operating experience lessons learned from the application of these tools and models.
- Providing analyses to licensees for incorporation into their operating experience programs.
- Increasing NRC and licensee staff knowledge and increasing better harmonization of the PRA models by discussing and reviewing key modeling issues and assumptions with licensees. In addition, the ASP Program can provide insights into the adequacy of current PRA standards and guidance.
- Communicating risk-significant insights not associated with licensee performance to enable consideration of corrective actions or plant improvements, as appropriate.

3. PROGRAM SCOPE

The ASP Program is one of three agency programs that assess the risk significance of events at operating NPPs. The other two programs are the Significance Determination Process (SDP), as defined in Inspection Manual Chapter (IMC) 0609, and the event-response evaluation process, as defined in MD 8.3, "NRC Incident Investigation Program". The SDP evaluates the risk significance of a single licensee performance deficiency, while the risk assessments performed under MD 8.3 are used to determine, in part, the appropriate level of reactive inspection in response to an event. An SDP assessment has the benefit of information obtained from the inspection, whereas the MD 8.3 assessment is expected to be performed within several days of the event notification.

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2 The ASP Program scope is limited to domestic operating events and trends.

3 The ASP Program defines a significant precursor as an event with a conditional core damage probability (CCDP) or change in core damage probability (ΔCDP) greater than or equal to 10^{-3}. Significant precursors are an input into the annual Abnormal Occurrence (AO), Congressional Budget Justification, and Performance and Accountability reports to Congress.

4 There are two other program that provide this function: the Reactor Oversight Process (ROP) and AO Report.

In contrast to the other two programs, a comprehensive and integrated risk analysis under the ASP Program includes all anomalies observed at the time of the event or discovered after the event. These anomalies may include unavailable and degraded plant structures, systems, and components (SSCs); human errors; and an initiating event (reactor trip). In addition, an unavailable or degraded SSC does not have to be attributed to a performance deficiency (e.g., SSCs out for test and maintenance) or an analyzed condition in the plant design basis. The ASP Program has the benefit of time to complete the analysis of complex issues and thus produces a more refined estimate of risk. The ASP Program analysis schedules provide time so that NRC or licensee engineering evaluations can be made available for review. State-of-the-art methods can be developed or current techniques can be refined for unique conditions when necessary. In addition, the SPAR models can be modified for special considerations (e.g., hazards such as seismic, internal fires, and flooding). The discussion of these differences is meant to highlight the programmatic differences and how they impact the results of risk assessments. Each program has been designed to achieve their respective objectives in an efficient manner.

There are similarities in the risk assessments conducted by the three programs. All three programs use SPAR models, the same documented methods and guidance in the Risk Assessment Standardization Project (RASP) manual, and similar analysis assumptions. Differences arise where the programs' objectives deviate from one another. ASP and SDP analyses assumptions are typically the same when the event is driven by a single performance deficiency. Because of this specific similarity, since 2006, in accordance with Regulatory Issue Summary (RIS) 2006-24, "Revised Review and Transmittal Process for Accident Sequence Precursor Analyses," SDP results have been used in lieu of ASP analyses in specific instances where the SDP analyses considered all concurrent degraded conditions or equipment unavailabilities that existed during the time period of the condition. For initiating events, many of the modeling assumptions made for MD 8.3 analyses can be adopted by ASP analyses. However, it often becomes necessary to revise some modeling assumptions as more detailed information about the event becomes available upon completion of inspection activities. In addition, there are program differences on how certain modeling aspects are incorporated (e.g., SSCs unavailable due to testing or maintenance). These key similarities provide opportunities for significant ASP Program efficiencies. For a potential significant precursor, analysts from the three programs work together to provide a timely determination of plant risk. As such, duplication between the programs is minimized to the extent practicable within the program objectives.

4. ASP PROCESS

To identify potential precursors, the staff reviews operational events from all licensee event reports (LERs) submitted to the NRC per Title 10 of the *Code of Federal Regulations* (10 CFR) Section 50.73. In recent years, there are approximately 300 to 400 LERs issued each year. Idaho National Laboratory (INL) performs this initial LER screening as part of their LER review activities that support other NRC data collection activities (e.g., initiating event and system studies). Each LER is evaluated (on a plant unit basis) against qualitative screening criteria to identify events that warrant further analysis as potential precursors. If an LER describes an event that does not meet one of the following candidate ASP (cASP) criteria, then the LER is screened out of the ASP Program:

Criterion 1—Unplanned Scrams with Complications. Did the event involve an unplanned scram with a complication that results in a yes to any question per Nuclear Energy Institute

(NEI) 99-02, “Regulatory Assessment Performance Indicator Guideline”? Examples of complications include:

Pressurized-Water Reactors (PWRs)

a. Failure of two or more control rods to insert,
b. Failure of turbine to trip,
c. Loss of power to safety-related electrical bus,
d. Safety injection signal,
e. Non-recoverable loss of main feedwater (MFW), or
f. Operators needed to enter emergency procedures other than scram procedure.

Boiling-Water Reactors (BWRs)

g. Failure of reactor protection system to indicate or establish a shutdown rod pattern for a cold clean core,
h. Pressure control unavailable following initial transient,
i. Loss of power to safety-related electrical bus,
j. Level 1 Injection signal,
k. Non-recoverable loss of MFW, or
l. Reactor pressure/level and drywell pressure meet the entry conditions for emergency operating procedures.

Criterion 2—Core Damage Initiators. Did the reactor scram due to either an initial plant fault or a functional impact in one of the following categories from NUREG/CR-5750, “Rates of Initiating Events at U.S. Nuclear Power Plants: 1987–1995”?

a. Loss of offsite power (LOOP), including partial LOOP events,
b. Loss of safety-related electrical bus,
c. Loss of instrument air,
d. Loss of safety-related cooling water (e.g., service water),
e. Steam generator tube rupture,
f. Loss-of-coolant accidents (LOCAs),
g. High-energy line break,
h. Loss of condenser heat sink, or
i. Loss of MFW.

Criterion 3—Safety System Functional Failures. Events which qualify as safety system functional failure per NEI 99-02 and 10 CFR 50.73(a)(2)(v) for the listed systems. Examples include:

a. Reactor protection system,
b. Auxiliary/emergency feedwater,
c. Safety-related service water,
d. Emergency core cooling systems (ECCS),[5]
e. Safety-related electrical power systems,
f. Ultimate heat sink,

[5] Inoperability of containment isolation, secondary containment, control room ventilation, hydrogen control, containment spray or containment fan coolers are typically not evaluated in the ASP Program. ASP analyses are focused on the risk associated with core damage.

g. Other systems with safety-related SSCs required by technical specifications to be operable that are intended to mitigate the consequences of an accident as discussed in Chapters 6 and 15 of the final safety analysis report,
h. Any event where safety-related components were not available or failed to function as required which may or may not have failed the train or system, and
i. Primary safety relief valve(s) or pressurizer power-operated relief valve(s).

Criterion 4—Risk Significant Events Based on a Probabilistic Risk Assessment (PRA). Events in which the licensee indicates the CCDP or ΔCDP was greater than or equal to 10^{-8}.

Criterion 5—Other Risk-Significant Events. Any event that, based on the reviewers' experience, could have resulted in potential core damage.

Typically, 70 to 85 percent of all LERs are screened out of the ASP Program in this initial process. This initial screening supports agency efficiency goals by focusing risk analyst resources on events of higher risk significance. In 2018, these screening criteria will be reviewed to determine if additional efficiencies can be gained (i.e., a greater percentage of LERs can be screened out). For LERs that are determined to be potential precursors, the staff uses risk evaluations performed as part of the SDP for degraded conditions in accordance with RIS 2006-24, when possible. However, if potential precursors associated with LERs involve an initiating event (e.g., loss of condenser heat sink, loss of offsite power), are "windowed" (i.e., are concurrent with other degraded condition(s)), or were not evaluated by the SDP (e.g., no performance deficiency was identified), then an independent ASP analysis is performed. Independent ASP analyses are conducted using the NRC's SPAR models and the Systems Analysis Programs for Hands on Integrated Reliability Evaluations (SAPHIRE) software. Additional details on the ASP process are provided in Figure 1.

5. ANALYSIS TYPES AND PROGRAM THRESHOLDS

An operational event can be one of two types: (1) a degraded plant condition characterized by the unavailability or degradation of equipment without the occurrence of an initiating event, or (2) the occurrence of an initiating event, such as a reactor trip or a loss of offsite power, with or without any subsequent equipment unavailability or degradation.

For the first type of event, the staff calculates a ΔCDP. This metric represents the increase in core damage probability for the time period during which a component, or multiple components, were deemed unavailable or degraded. The ASP Program defines a degraded condition with a ΔCDP greater than or equal to 10^{-6} to be a precursor.

For the second type of event, the staff calculates a CCDP. This metric represents a conditional probability that a core damage state is reached given the occurrence of the observed initiating event (and any subsequent equipment failure or degradation). When the value of the plant-specific CCDP for a non-recoverable loss of feedwater and condenser heat sink is greater than 10^{-6}, the value of the plant-specific CCDP is used as the threshold for an initiating event precursor. This ensures the more safety-significant events are analyzed. Since 1988, this initiating-event precursor threshold has screened out uncomplicated trips (i.e., reactor trips with no losses of safety-related equipment) from being precursors because of their relatively low risk significance.

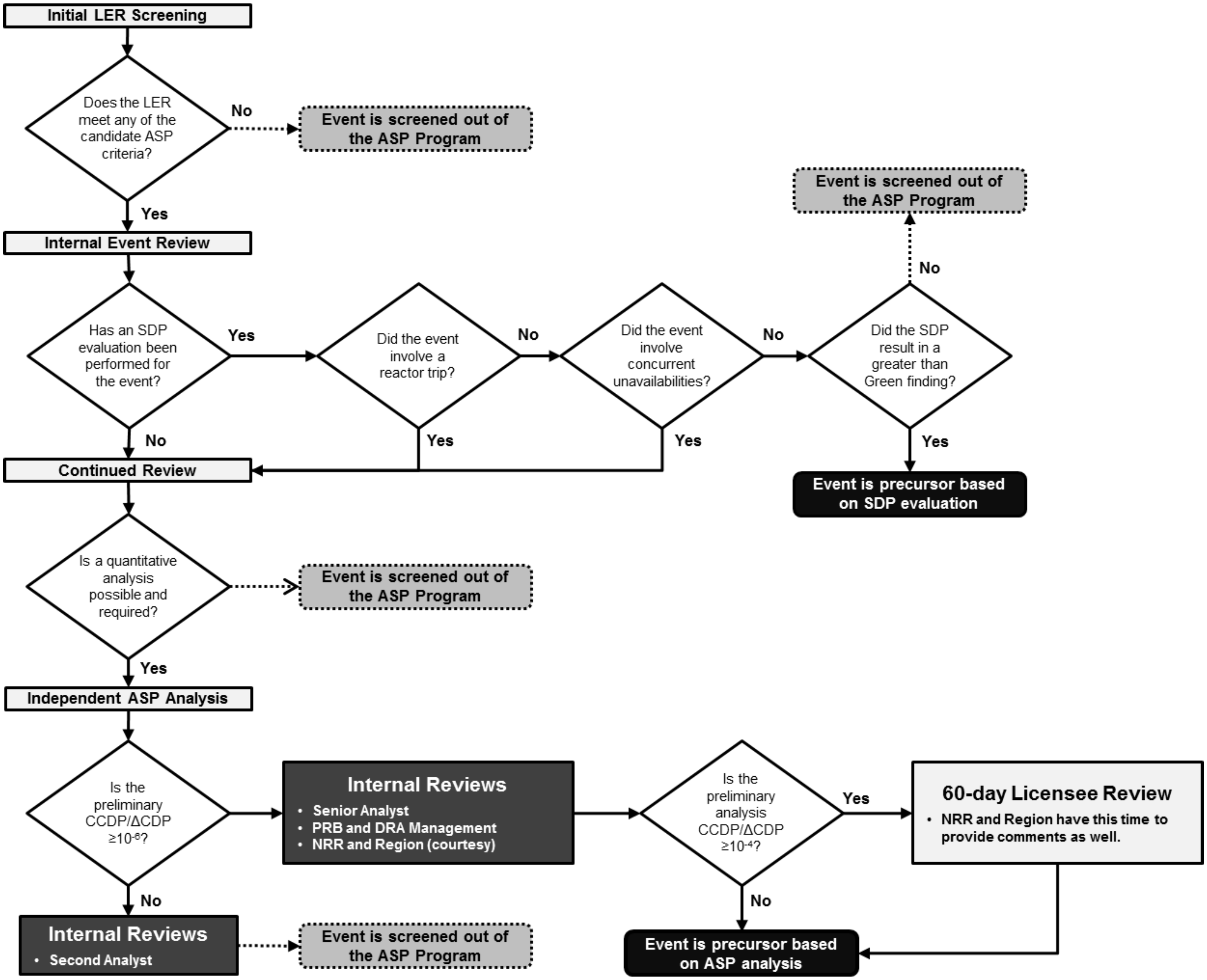

Figure 1. ASP Process Diagram.

The ASP Program defines a significant precursor as an event with a CCDP or ΔCDP greater than or equal to 10^{-3}. Significant precursors are included in the annual AO (Criterion II.C) and Performance and Accountability (Safety Performance Goal 4) reports to Congress.

Note that when risk evaluations performed as part of the SDP are used for ASP program purposes, the SDP color representing the significance of the inspection finding is used as the official ASP Program result. The associated risk of the four SDP colors is as follows:

- *Red* (*High Safety Significance*), which corresponds to an event with a CCDP/ΔCDP greater than or equal to 10^{-4};
- *Yellow* (*Substantial Safety Significance*), which corresponds to an event with a CCDP/ΔCDP greater than or equal to 10^{-5}, but less than 10^{-4};
- *White* (*Low to Moderate Safety Significance*), which corresponds to an event with a CCDP/ΔCDP greater than or equal to 10^{-6}, but less than 10^{-5}; and
- *Green* (*Very Low Safety Significance*), which corresponds to an event with a CCDP/ΔCDP less than 10^{-6}.

6. 2016 ASP RESULTS

The 2016 Annual ASP Report referenced two events reported in 2016 that were still pending a final risk assessment at the time the report was issued in May 2017. The first event, LER 440-16-003, involved an unresolved issue (URI) at Perry concerning the installed design of the safety-related 4.16 kilovolt (kV) under-voltage protection scheme (see IR 05000440/2016008 for additional information). This URI remains in the Technical Interface Agreement (TIA) process to determine if the concern is a potential licensee performance deficiency or should be considered in a back-fit evaluation. No decision has been finalized to-date. In the interim, the ASP Program initiated an independent analysis, and preliminary results indicate this event is likely a precursor.

The second event, LER 293-16-008, involved a preliminary finding at Pilgrim concerning unavailability of an emergency diesel generator (EDG) due to low gearbox oil caused by a leaking relief valve. The SDP completed its risk assessment on August 9, 2017, and determined the significance to be *Green* (i.e., very low safety significance). See IR 05000293/2017008 for additional information. The ASP Program used the SDP result per the established process. Since the EDG was determined to be able to fulfill its safety function, no search of "windowed" events was required.

7. 2017 ASP RESULTS

There were 323 LERs reviewed during calendar year 2017. From these LERs, 273 (approximately 85 percent) were screened out in the initial screening process and 50 events were selected and analyzed as potential precursors.[6] Of the 50 potential precursors, 11 events were determined to exceed the ASP Program threshold and, therefore, are precursors. For three of these precursors, the performance deficiency identified under the SDP documented the risk-significant aspects of the event completely. In these cases, the SDP significance category (i.e., the "color" of the finding) is reported as the ASP Program result. An independent ASP analysis was performed to determine the risk significance of the other eight precursors. Table 1

[6] Two additional precursors were identified by the inspection process for which no LER was issued. The events occurred at Perry and Catawba, Unit 2, and both related to EDG diode failures.

provides a brief description of all precursors identified in 2017, including the two precursors that were not reported in an LER. Three of thirteen precursors identified in 2017 had late-2016 event dates and, therefore, are included in the 2016 precursor counts for trending purposes.

Table 1. 2017 Precursors.

Plant	LER	Event Date	Exposure Period	Description	CCDP/ΔCDP SDP Color	ADAMS Accession #
Davis-Besse	346-17-002	9/13/17	87 days	Auxiliary feed water (AFW) pump turbine bearing damaged due to improperly marked lubricating oil sight glass	White	ML18103A208
Waterford	382-17-002	7/17/17	Initiating Event	Automatic reactor scram due to the failure of fast bus transfer relays to automatically transfer station loads to offsite power on a main generator trip	2×10^{-5}	ML18066A196
Clinton	461-17-008	6/15/17	92 days	Division 3 shutdown service water pump start failure	White	ML18058B796
Arkansas 1	313-17-001	4/26/17	Initiating Event	Automatic start of an emergency diesel generator (EDG) due to the loss of offsite power due to severe weather	1×10^{-5}	ML17319B035
Catawba 2	N/A	4/11/17	184 days	Failure to adequately establish and adjust preventative maintenance for EDG excitation system diodes	White	ML17289A300
Turkey Point 3	250-17-001	3/18/17	Initiating Event	Loss of 3A 4 kV vital bus results in reactor trip, safety system actuations and loss of safety injection function	3×10^{-6}	ML18038B063
Clinton	461-17-002	3/9/17	10 months	Failure of the division 1 diesel generator ventilation fan load sequence relay circuit during concurrent maintenance of residual heat removal (RHR) division 2 results in an unanalyzed condition	White	ML17331B161
Vogtle 2	425-17-001	3/9/17	49 days	Power supply failure results in operation in a condition prohibited by technical specifications	8×10^{-5}	ML17250B343
LaSalle 2	374-17-003	2/11/17	3 years	High-pressure core spray (HPCS) system inoperable due to injection valve stem-disc separation	2×10^{-5}	ML18072A326
Cooper	298-17-001	2/5/17	83 days	Concurrent unavailabilities—RHR loop A, reactor core isolation cooling (RCIC), and emergency station service transformer	6×10^{-6}	ML18068A724
Columbia	397-16-004	12/18/16	Initiating Event	Automatic scram due to offsite load reject	1×10^{-5}	ML17249A968
Palo Verde 3	530-16-002	12/15/16	176 days	Emergency diesel generator failure resulting in a condition prohibited by technical specifications	2×10^{-5}	ML17313B159
Perry	N/A	11/8/16	18 months	Division 2 diesel generator failure to start due to a failed diode in the 125 VDC control power circuit	White	ML17236A187

After further analysis, the remaining 39 LERs identified by the initial LER screening (as described in Section 4) were determined not to be precursors. These events were evaluated not to be precursors by acceptance of SDP results (9 events), completion of a simplified/bounding analysis (29 events), or a detailed ASP analysis (1 event). The detailed ASP analysis was performed for a loss of both Keowee hydroelectric units at Oconee (Unit 1) that occurred on June 16, 2017 (see ML18033A619 for additional information). Additional information on the LERs determined to not be precursors via a simplified/bounding analysis or by acceptance of SDP results is provided in Appendix A.

8. 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 time period. A statistically significant trend is defined in terms of the *p-value*. A *p-value* is a probability indicating whether to accept or reject the null hypothesis that no trend exists in the data.[7] 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 is a rolling 10-year period (i.e., 2008–2017 for this report). In addition, data and trending information for the past 20 years (i.e., 1998–2017 for this report) is provided for historical perspective. Note that the figures in this report only include a trend line if a statistically significant increasing or decreases trend was observed.[8]

8.1. 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 (2008–2017), the mean occurrence rate of all precursors exhibits a statistically significant decreasing trend (*p-value* = 0.04).[9] See Figure 2 for additional information.
- *Long-Term Trend.* There is no statistically significant trend (*p-value* = 0.81) for the mean occurrence rate of all precursors over the past 20 years (1998–2017).
- *Use of SDP Results.* Over the past decade, 65 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. For example, the 2011 Fort Calhoun *Red* finding involving fire vulnerability of multiple breakers within different systems had a higher risk result from the SDP condition assessment than the ASP analysis of the loss of shutdown cooling initiating event that occurred.

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7 For the purposes of this analysis, the null hypothesis is based on a constant-rate Poisson process producing the observed data set. A lower p-value indicates a lower likelihood that the observed data could be produced by this constant-rate process.

8 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.

9 The occurrence rate is calculated by dividing the number of precursors by the number of reactor years.

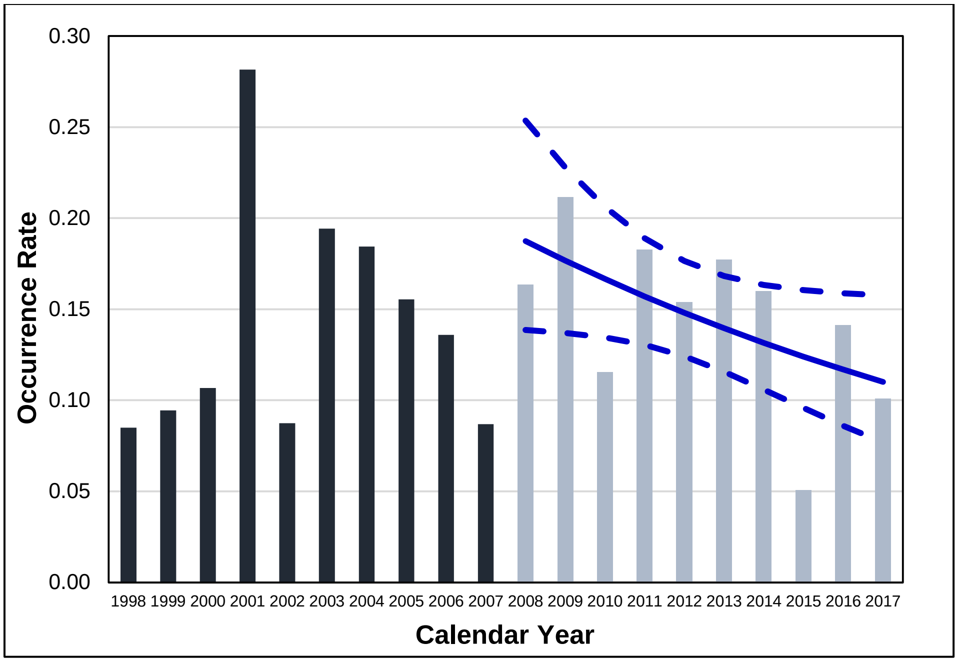

Figure 2. Occurrence rate of all precursors.

8.2. 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 2017. The last significant precursor was identified in 2002, which involved concurrent, multiple degraded conditions at the Davis-Besse nuclear power plant. Appendix B provides additional information on the significant precursors identified since 1969.

8.3. Precursors with a CCDP or ΔCDP ≥ 1×10^{-4}

Precursors with a CCDP or ΔCDP ≥ 1×10^{-4} are important in the ASP Program because they generally have a CCDP higher than the annual CDP estimated by most plant-specific PRAs. The staff did not identify any precursors with a CCDP or ΔCDP greater than or equal to 1×10^{-4} in 2017.

- *Trend*. Over the past decade (2008–2017), the mean occurrence rate of precursors with a CCDP or ΔCDP greater than or equal to 1×10^{-4} does not exhibit a statistically significant trend (*p-value* = 0.23). See Figure 3 for additional information.
- *Long-Term Trend.* There is a statistically significant decreasing trend (*p-value* = 0.01) for the mean occurrence rate for precursors with a CCDP or ΔCDP greater than or equal to 1×10^{-4} over the past 20 years (1998–2017).

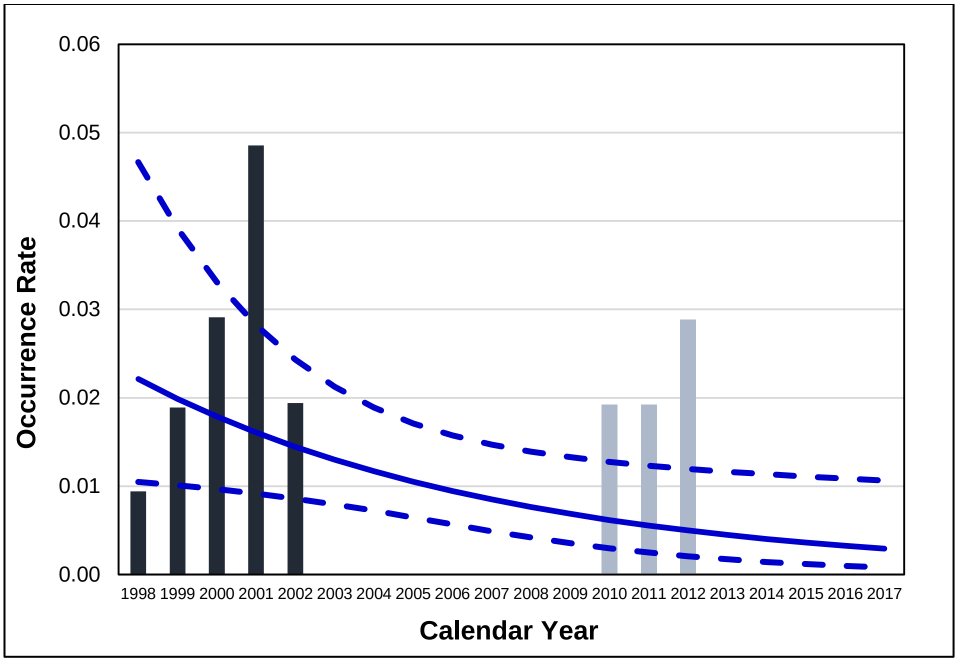

Figure 3. Occurrence rate of precursors with a CCDP or ΔCDP ≥ 1×10^{-4}.

- *Past Trends*. In 2012 and 2013, statistically significant increasing trends were observed in each respective 10-year period. However, with no additional precursors with a CCDP or ΔCDP greater than or equal to 1×10^{-4} observed in FYs 2013–2017, a statistically significant trend no longer exists. In 2014, and based in part on the observed increases in electrical-related precursors over the past few years, the staff initiated a detailed study to better understand the risk contributions of electrical system and associated component failures at NPPs.[10]
- *Precursor Counts*. Over the past decade, seven precursors with a CCDP or ΔCDP greater than or equal to 1×10^{-4} were identified, with all of these precursors occurring from 2010 to 2012. See Table 2 for additional information on these seven precursors. Six of the seven precursors involved events in electrical distribution systems.

Table 2. Recent Precursors with a CCDP or ΔCDP ≥ 1×10^{-4}.

Date	Plant (Risk Measure)	Description	Risk Insights
5/24/12	River Bend **CCDP = 3×10^{-4}**	***LER 458-12-003,*** Loss of normal service water, circulating water, and feedwater due to electrical fault.	Initiating event coupled with postulated loss of safety-related service water would lead to complete loss of heat sink. ML13322A833
1/30/12	Byron 2 **CCDP = 1×10^{-4}**	***LER 454-12-001,*** Transformer and breaker failures cause loss of offsite power, reactor trip, and de-energized safety buses.	The key issue for this event is the potential for operators to fail to recognize this scenario. Operator errors could lead to station blackout (SBO) -like sequences. See NRC Information Notice (IN) 2012-3, "Design Vulnerability in Electric Power System" and NRC Bulletin 2012-01, "Design Vulnerability in Electric Power System," for additional information. ML13059A525

10 This study was originally scheduled for completion in 2017; however, resources were shifted to other work as part of Project Aim. Completion is now expected in 2019. Additional information on Project Aim can be found on the NRC public Web page https://www.nrc.gov/about-nrc/plans-performance/project-aim-2020.html.

Date	Plant (Risk Measure)	Description	Risk Insights
1/13/12	Wolf Creek **CCDP = 5×10^{-4}**	***LER 482-12-001,*** Multiple switchyard faults cause reactor trip and subsequent loss of offsite power.	This event involved a moderate length LOOP (2–3 hours) caused by equipment failures in the switchyard. Risk was dominated by SBO sequences. The ASP analysis looked at the LOOP initiating event while the SDP analysis performed a condition assessment on the loss of the startup transformer resulting in a *Yellow* finding associated with the a licensee performance deficiency for the failure to identify that electrical maintenance contractors had not installed insulating sleeves on wires that affected the differential current protection circuit, contrary to work order instructions. ML13115A190
8/23/11	North Anna 1 **CCDP = 3×10^{-4}**	***LER 338-11-003,*** Dual unit loss of offsite power caused by earthquake that coincided with the Unit 1 turbine-driven auxiliary feedwater (AFW) pump being out-of-service because of testing and the subsequent failure of a Unit 2 emergency diesel generator (EDG).	This event involved an earthquake coupled with routine maintenance on the AFW pump and an unrelated failure of an EDG. Risk was dominated by SBO sequences. The SDP assessment resulted in a *White* finding associated with the licensee performance deficiency for the failure to establish and maintain maintenance procedures appropriate to the circumstances for the safety-related EDGs. See NRC IN 2012-01, "Seismic Considerations – Principally Issues Involving Tanks," and IN 2012-25, "Performance Issues with Seismic Instrumentation and Associated Systems for Operating Reactors," for additional information. ML12278A188
6/7/11	Fort Calhoun ***Red* Finding**	***EA-12-023,*** Fire in safety-related 480-volt electrical breaker because of deficient design controls during breaker modifications. Eight other breakers were susceptible to similar fires.	The plant operated with a poorly designed modification to nine breakers, all of which had a potential for a fire, especially in a relatively minor seismic event. Risk comes from a very wide variety of sequences. ML12101A193
10/23/10	Browns Ferry 1 ***Red* Finding**	***EA-11-018,*** Failure to establish adequate design control and perform adequate maintenance causes valve failure that led to a residual heat removal loop being unavailable.	A valve failure coupled with a postulated fire that required execution of self-induced SBO procedures could have resulted in a loss of recirculation capability. The self-induced SBO procedures added one to two orders of magnitude to the risk of this event. See NRC IN 2012-14, "Motor-Operated Valve Inoperable due to Stem-Disc Separation," for additional information. ML111290482
3/28/10	Robinson **CCDP = 4×10^{-4}**	***LER 261-10-002,*** Fire causes loss of non-vital buses along with a partial loss of offsite power with reactor coolant pump (RCP) seal cooling challenges.	Neither the fire nor the minor equipment failures individually should have led to a high risk event. However, poor operator performance created a much higher risk scenario. Risk was dominated by transient-induced RCP seal LOCA. The SDP assessment resulted in two *White* findings (one performance deficiency was for failure to adequately implement the requirements contained in OPS-NGGC-1000, "Fleet Conduct of Operations," and the other performance deficiency was for improper implementation of the Commission-approved requalification program). See NRC IN 2010-09, "Importance of Understanding Circuit Breaker Control Power Indications," for additional information. ML112411359

8.4. *Precursors with a CCDP or ΔCDP ≥ 1×10^{-5}*

The staff identified six precursors with a CCDP or ΔCDP greater than or equal to 1×10^{-5} for LERs issued in 2017.[11] All six of these precursors were identified by an independent ASP analysis. The first of these precursors occurred at Waterford involving a plant-centered LOOP due to a failure of the electrical buses to fast transfer to the alternate transformer after the reactor trip (CCDP = 2×10^{-5}). The second precursor occurred at Arkansas Nuclear One (Unit 1) involving a reactor trip and subsequent partial LOOP caused by severe weather (CCDP = 1×10^{-5}). The third precursor occurred at Vogtle (Unit 2) involving the failure of redundant power supplies resulting in the unavailability of an EDG for 49 days (ΔCDP = 8×10^{-5}). The fourth precursor occurred at LaSalle (Unit 2) involving a HPCS unavailability for 1 year due to a stem-disc separation failure of an injection valve. The fifth precursor occurred at Columbia involving an automatic scram due to offsite load reject. The sixth precursor occurred at Palo Verde (Unit 3) involving an EDG unavailability for 176 days due to the failure of multiple internal components.

- *Trend*. Over the past decade (2008–2017), the mean occurrence rate of precursors with a CCDP or ΔCDP greater than or equal to 1×10^{-5} does not exhibit a statistically significant trend (*p-value* = 0.33). See Figure 4 for additional information.

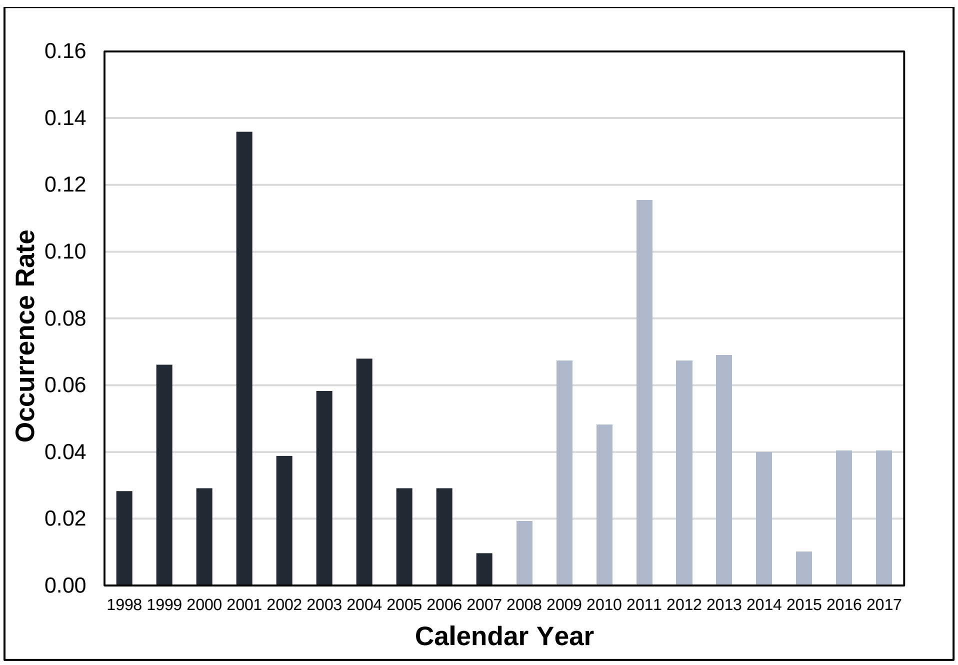

Figure 4. Precursors with a CCDP or ΔCDP ≥ 1×10^{-5}.

- *Long-Term Trend.* There is no statistically significant trend (*p-value* = 0.52) for the mean occurrence rate for precursors with a CCDP or ΔCDP greater than or equal to 1×10^{-5} over the past 20 years (1998–2017).

- *Initiating Event Impact.* Historically, precursors due to initiating events make up approximately 65 percent of all precursors with a CCDP or ΔCDP greater than or equal to 1×10^{-5}. Over the past decade (2008–2017), the percentage is approximately 58 percent. The majority of these precursors (i.e., 74 percent) are due to LOOP initiating events.

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[11] Two of these six precursors (Columbia and Palo Verde, Unit 3) occurred in 2016 and, therefore, are considered as 2016 precursors for trending purposes.

8.5. *Precursors Involving Initiating Events and Degraded Conditions*

Both initiating events and degraded conditions have the potential to be precursors (as described in Section 5). An initiating event can (by itself) result in a CCDP that exceeds the ASP Program threshold (e.g., LOOP, LOCA, etc.). In addition, a reactor trip concurrent with an 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. Historically, precursors associated with degraded conditions have outnumbered those due to the occurrence of an initiating event.

- *Trends*. The mean occurrence rates of precursors involving initiating events does not exhibit a statistically significant trend (*p-value* = 0.52) during the past decade (2008–2017). During this same period, there is a statistically significant decreasing trend (*p-value* = 0.04) for the mean occurrence rate of precursors due to degraded conditions. See Figure 5 and Figure 6, respectively, for additional information.

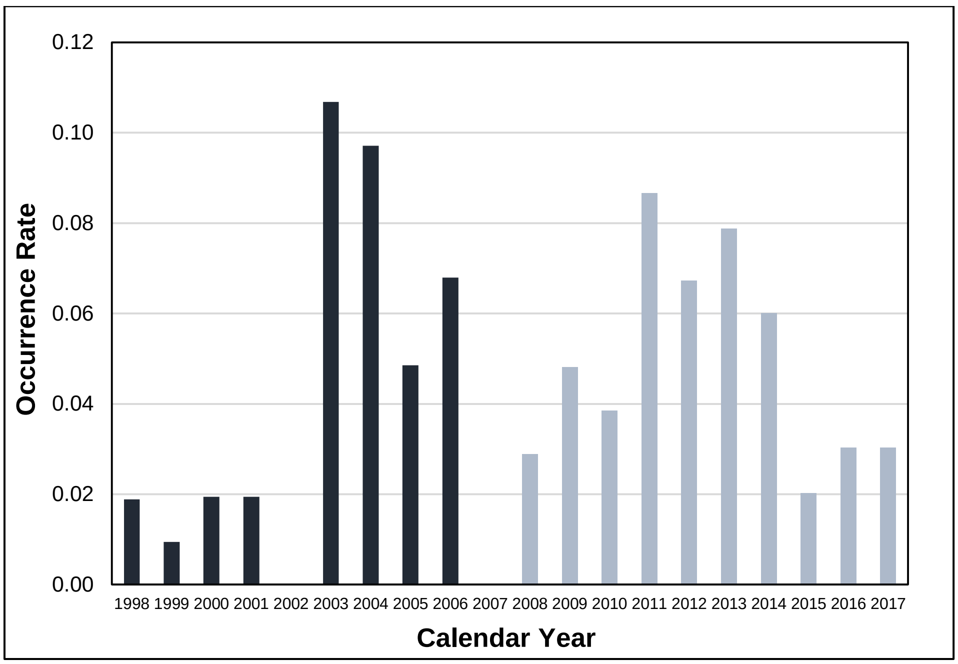

Figure 5. Occurrence rate of precursors involving an initiating event.

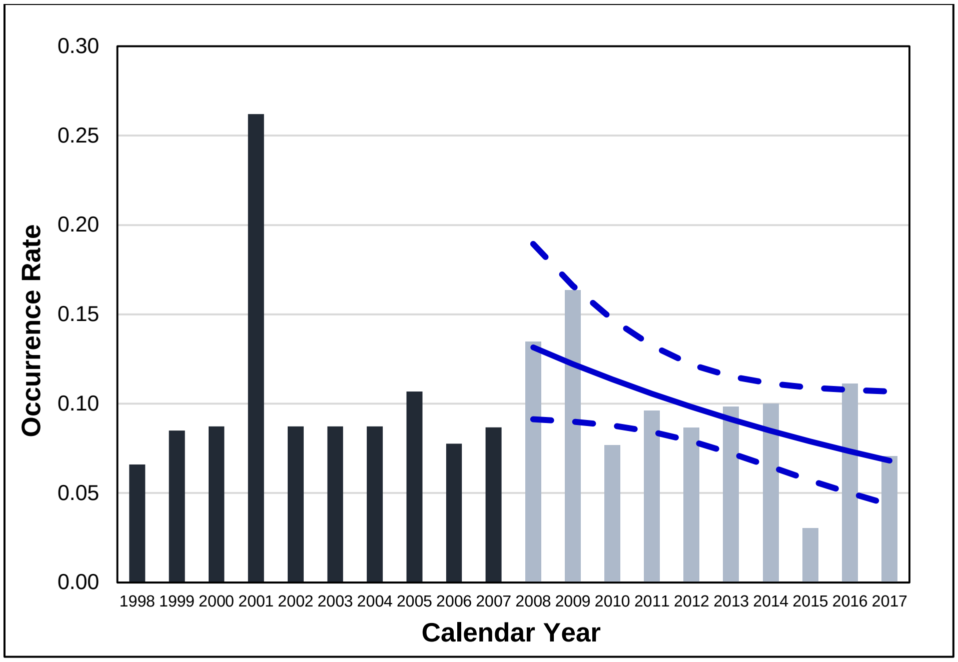

Figure 6. Occurrence rate of precursors due to degraded condition(s).

- *Long-Term Trend.* The mean occurrence rates of precursors involving initiating events and degraded conditions do not exhibit statistically significant trends (*p-values* = 0.15 and 0.21, respectively) during the past 20 years (1998–2017).

A review of the data for the past decade (2008–2017) reveals the following insights:

- *Precursor Counts*. Precursors involving degraded conditions (99 precursors) outnumbered initiating events (50 precursors) by a factor of approximately two.
- *Initiating Event Precursor Breakdown*. Of the 50 precursors involving initiating events, 26 precursors (52 percent) were LOOP events and 22 precursors (44 percent) were complicated trips.[12] Three initiating events occurred while the affected plant was shut down. Typically, the CCDP estimates for LOOPs are higher than for complicated trips.
- *Initiating Events due to Natural Phenomena.* Of the 50 precursors involving initiating events, 17 precursors (34 percent) resulted from natural phenomena (e.g., severe weather, seismic, etc.).
- *EDG Failure Trends*. The mean occurrence rate of precursors involving degraded conditions due to EDG failures reveals a statistically significant increasing trend (*p-value* = 0.01) over the past 20 years (1998–2017). This increasing trend was first noted in the 2016 annual ASP report and is largely influenced by the very small number of EDG precursors in the late 1990s and early 2000s. Over the past decade (2008–2017), no statistically significant trend (*p-value* = 0.63) exists for this precursor group.
- *Degraded Conditions due to External Hazards.*[13] Of the 99 precursors involving degraded conditions, 28 precursors (28 percent) were associated with postulated external hazards

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12 A complicated trip is a reactor trip with a concurrent loss of safety-related equipment.

13 The term external hazards often includes hazards other than internal events that also occur within the plant boundary such as internal fires.

(fire, flood, etc.). Of these 28 precursors, 19 precursors were associated with degradations related to floods, 8 precursors were associated with degradations related to fires, and 1 precursor was associated with a degradation related to tornadoes.

- *Degraded Condition Causes.*[14] Of the 99 precursors involving degraded conditions, 34 precursors (34 percent) were due to inadequate procedures, 30 precursors (30 percent) were due to design deficiencies, and 23 precursors (23 percent) were due to an ineffective corrective action program.
- *Long-Term Degraded Conditions*. Of the 99 precursors involving degraded conditions, 24 precursors (24 percent) involved degraded conditions existing for a decade or longer.[15] Of these 24 precursors, 10 precursors involved degraded conditions dating back to initial plant construction.

8.6. Precursors Involving a LOOP Initiating Event

A LOOP initiating event involves a reactor trip and the simultaneous loss of electrical power to all unit safety-related buses (also referred to as emergency buses, Class 1E buses, and/or vital buses) requiring all EDGs to start and supply power to the safety buses. An initiating event that involves the loss of offsite power to all electrical buses is considered a complete LOOP. Typically, all complete LOOP initiating events (i.e., loss of offsite power to all electrical buses) meet the precursor threshold. However, if the nonsafety-related buses remain energized during a LOOP initiating event, the CCDP may not exceed the precursor threshold. The only LOOP initiating event that occurred in 2017 was a plant-centered LOOP at Waterford due to a failure of the electrical buses to fast transfer to the alternate transformer after the reactor trip.

- *Trend*. Over the past decade (2008–2017), the mean occurrence rate of precursors involving LOOP precursor events does not exhibit a statistically significant trend (*p-value* = 0.87). See Figure 7 for additional information.
- *Long-Term Trend.* There is no statistically significant trend (*p-value* = 0.61) for the mean occurrence rate of precursors involving a LOOP over the past 20 years (1998–2017).

A review of the data for the past decade (2008–2017) reveals the following insights:

- *Precursor Counts.* Of the 149 precursors that occurred during the past decade, 26 precursors (17 percent) were LOOP events that occurred at 20 nuclear power plant (NPP) sites. Of the 26 LOOP precursor events, 17 precursors occurred in between 2011–2013.
- *Concurrent Unavailability of an Emergency Power Train*. Of the 26 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.
- *Natural Phenomena.* Of the 26 LOOP precursors, 13 (50 percent) precursors resulted from natural phenomena, including: two tornadoes (5 precursors), Hurricane Katrina (1 precursor), 4 other weather-related events (54 precursors), and the 2011 Virginia

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14 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.

15 Note that although these degraded conditions lasted for many years, ASP and SDP analyses limit the exposure period to 1 year.

earthquake (2 precursors). All units at the five multi-unit NPP sites involved in these events were affected.

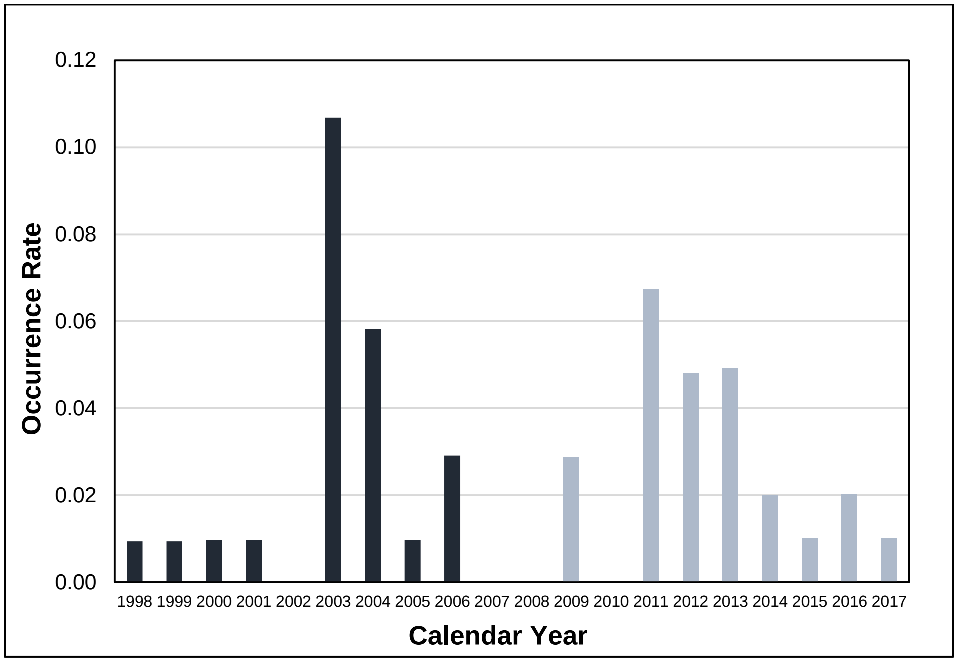

Figure 7. Occurrence Rate of Precursors Involving a LOOP.

- *Grid-Related LOOPs*. Of the 26 LOOP precursors, 5 (19 percent) precursors resulted from an electrical fault either in the plant switchyard or offsite power transmission line to the switchyard.
- *Multi-unit NPP Sites*. Of the 26 LOOP precursors, 11 precursors occurred at all units at a multi-unit NPP site, 7 precursors occurred at a single unit on a multi-unit site, and 8 precursors occurred at a single-unit site.

8.7. 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.[16]

- *Trends*. Over the past decade (2008–2017), the mean occurrence rates of precursors that occurred at BWRs does not exhibit a statistically significant trend (*p-value* = 0.50). During this same period, there is a statistically significant decreasing trend (*p-value* = 0.03) for the mean occurrence rate of precursors that occurred at PWRs. See Figure 8 and Figure 9 for additional information.
- *Long-Term Trends.* The mean occurrence rate of precursors at BWRs exhibits a statistically significant increasing trend (*p value* = 0.004) over the past 20 years (1998–2017). During the same period, the mean occurrence rate for precursors at PWRs exhibits a statistically

[16] 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.

significant decreasing trend (*p-value* = 0.02).

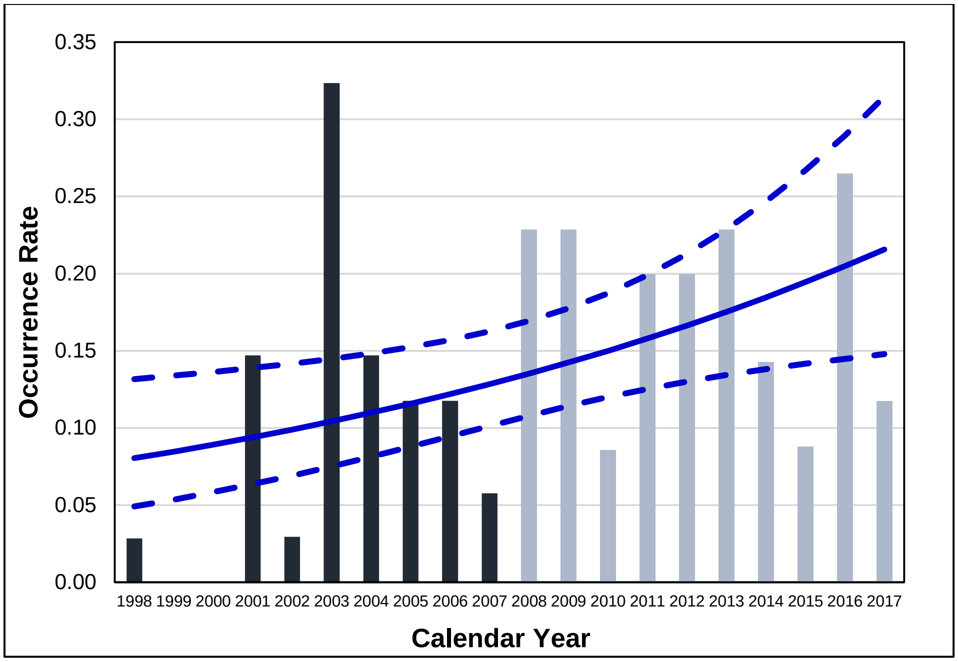

Figure 8. Precursors at BWRs.

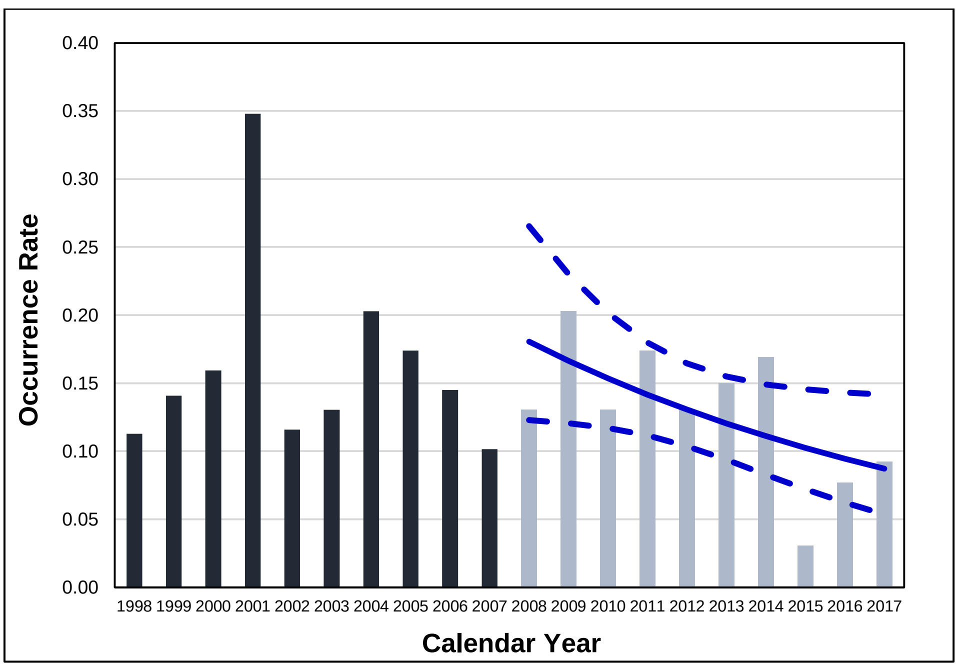

Figure 9. Precursors at PWRs.

A review of the data for the past decade (2008–2017) reveals the following insights:

- *LOOPs by Plant Type*. Of the 20 precursors involving initiating events at BWRs, 12 precursors (60 percent) were complete LOOP events. Of the 30 precursors involving initiating events at PWRs, 14 precursors (47 percent) were complete LOOP events.
- *BWR Degraded Condition Breakdown*. Of the 42 precursors involving degraded condition(s)

at BWRs, most were caused by failures of EDGs (16 precursors or 38 percent), others were caused by failures in emergency core cooling systems (14 precursors or 33 percent), and safety-relief valves (4 precursors or 10 percent).

- *PWR Degraded Condition Breakdown*. Of the 57 precursors involving degraded condition(s) at PWRs, most were caused by failures of EDGs (18 precursors or 32 percent), others were caused by failures in the auxiliary feedwater system (15 precursors or 26 percent), safety-related cooling water systems (6 precursors or 11 percent), electrical distribution system (6 precursors or 11 percent), or emergency core cooling systems (6 precursors or 11 percent).
- *PWR Sump Recirculation*. Of the six precursors involving failures in the emergency core cooling systems, three precursors (50 percent) were because of conditions affecting sump recirculation during postulated loss-of-cooling accidents of varying break sizes.
- *Degraded AFW systems*. Of the 15 precursors involving failures of the auxiliary feedwater system, 7 precursors (47 percent) were specific to the turbine-driven pump train.

9. ASP INDEX

The integrated ASP index shows the cumulative plant average risk of 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 2011 and has a ΔCDP of 5×10^{-6}. A review of the LER or inspection report (IR) reveals that the degraded condition has existed since a design modification that was performed in September 2007. In the integrated ASP index, the ΔCDP of 5×10^{-6} is included in the years 2008–2011 (i.e., the year it was identified and any full year that the deficiency existed). The risk contributions from precursors involving initiating events are included in the year that the event occurred. Figure 10 depicts the integrated ASP indices for 1998 to 2017.

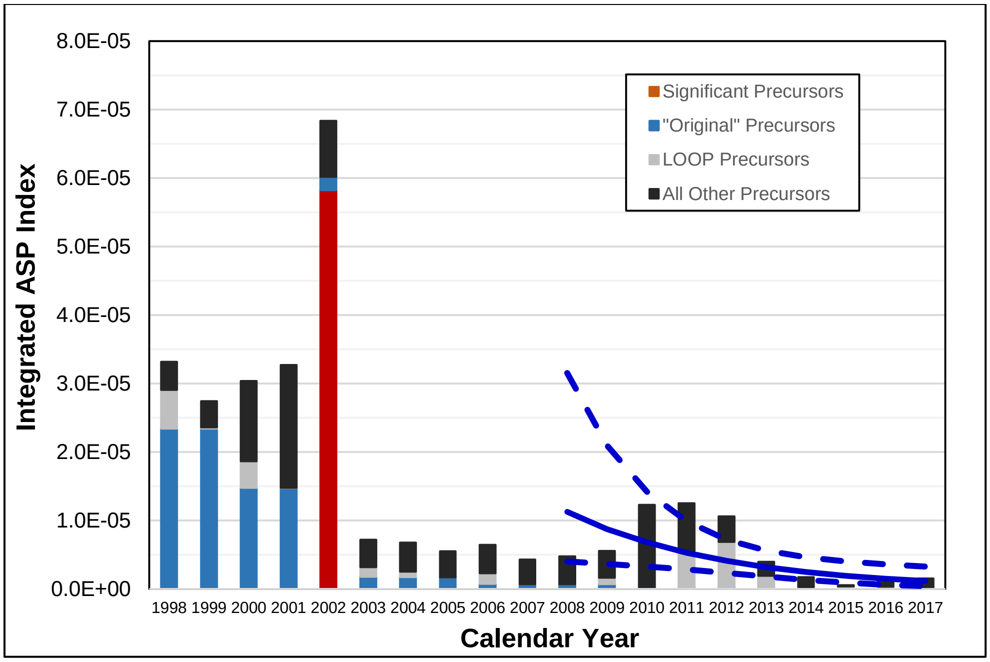

Figure 10. Integrated ASP Index.

A review of the ASP indices leads to the following insights:

- *Insights.* Over the past 20 years (1998–2017), the total risk associated with precursors (295 total precursors) is dominated by degraded conditions associated with issues dating back to initial plant construction. These 38 precursors account for approximately 32 percent of the total risk due to all precursors. The one significant precursor (Davis-Besse, 2002) accounts for approximately 21 percent of the total risk due to all precursors.[17] The 51 precursors due to a LOOP initiating event account for approximately 11 percent of the total risk due to all precursors. The other 205 precursors account for approximately 35 percent to the total risk due to all precursors.

- *Trends.* Over the past decade (2008–2017), the integrated ASP index exhibits a statistically significant decreasing trend (*p-value* = 0.02).[18] A statistically significant decreasing trend (*p-value* = 0.00001) is also present for the past 20 years (1998–2017). The 10-year trend is largely influenced by the seven precursors with CCDP or ΔCDP greater than or equal to 1×10^{-4} that occurred in the 2010–2012 period. The 20-year trend is largely due to the significant precursor (Davis-Besse, 2002) and precursors from high-risk, long-term degraded conditions in the late 1990s and early 2000s.[19]

- *Limitations.* In the past, there was an attempt to use the ASP index to make order-of-magnitude comparisons with the predicted core damage frequency (CDF) estimates provided by licensee PRAs and the NRC SPAR models. There is no effort to make these comparisons in this paper as these comparisons were widely deemed to be inappropriate,

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17 During the same period, the 20 precursors with a CCDP/ΔCDP greater than or equal to 1×10^{-4} (including the Davis-Besse significant precursor) account for approximately 64 percent of the total risk due to all precursors.

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

19 Examples of these high-risk, long-term degraded conditions are the potential common-mode failure of all AFW pumps at Point Beach, Units 1 and 2 (2001), and multiple high-energy line break (HELB) vulnerabilities at D.C. Cook, Units 1 and 2 (1999).

based on the following. 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.

10. PLANT PRECURSOR COUNTS

Since the inception of the ASP Program, on average eight precursors have been identified for each operating NPP. Over the past 20 years (1998–2017), an average of three precursors occurred for each operating NPP. The average drops to approximately one precursor for each operating NPP during the past decade (2008–2017). A summary of notable plant performance based on precursor data is provided in Table 3.

- *NPPs with No Precursors.* Comanche Peak (Unit 2), South Texas Project (Unit 2), and Watts Bar (Unit 2) have never had a precursor event. Eight plants have not had a precursor identified in the past 20 years (1997–2016). Over the past decade (2008–2017), 25 NPPs have not had a precursor identified.

Table 3. Notable Plant Performance Based on Precursor Data.

	NPPs
Plants with no precursors since initial plant operation	Comanche Peak 2; South Texas 2; Watts Bar 2
Plants with no precursors in the past 20 years (1998–2017)	Beaver Valley 1 and 2; Limerick 1; Peach Bottom 2; Salem 1; South Texas 2; Susquehanna 2; Vogtle 1
Plants with no precursors in the past 10 years (2008–2017)	Byron 1; Callaway; Calvert Cliffs 2; Comanche Peak 1 and 2; D.C. Cook 2; Diablo Canyon 1; Fermi; Fitzpatrick; Grand Gulf; Indian Point 2 and 3; McGuire 1 and 2; Nine Mile Point 1 and 2 Palo Verde 1 and 2; Peach Bottom 3; Quad Cities 1 and 2; Salem 2; St. Lucie 2; Summer; Turkey Point 4
Plants with at least four precursors in the past 10 years (2008–2017)	Arkansas Nuclear One Unit 2; Browns Ferry 1, 2, and 3; Dresden 3; Duane Arnold; Oconee 1; Oyster Creek; Pilgrim; Robinson; Waterford
Plants with at least eight precursors in the past 20 years (1998–2017)	Oconee 1, 2, and 3; Oyster Creek
Plants with at least 15 precursors since initial plant operation)	Arkansas Nuclear One Unit 1; Davis-Besse; Hatch 1; Oconee 1, 2, and 3; Oyster Creek; Palisades; Pilgrim

- *NPP with Highest Precursor Count.* Historically, Pilgrim has the most (23) precursors associated with a single unit NPP. However, only four precursors have been identified over the past 20 years (with all of these events occurring over the past 6 years). Of the 23 precursors, there have been 13 LOOP precursors. Eleven of these LOOP precursors have been caused by severe weather (e.g., ice storms, lightning, etc.). Nine other plants have experienced at least 15 precursors over the same period, including: Arkansas Nuclear One (Unit 1), Davis-Besse; Hatch (Unit 1); Oconee (Units 1, 2, and 3); Oyster Creek; and Palisades.
- *NPP Site with Highest Precursor Count.* Historically, Oconee has experienced 58 total precursors between Units 1, 2, and 3. Brunswick Units 1 and 2 had experienced 31 precursors in total and is the only other site that has more than 30 total precursors. Sites with at least 20 total precursors include: Arkansas Nuclear One (Units 1 and 2); Browns

Ferry (Units 1, 2, and 3); D.C. Cook (Units 1 and 2), Dresden (Units 2 and 3); Hatch (Units 1 and 2); Indian Point (Units 2 and 3); Sequoyah (Units 1 and 2); St. Lucie (Units 1 and 2); and Turkey Point (Units 3 and 4).

- *Recent Counts.* Over the past decade (2008–2017), only three NPPs have had at least five precursors, Oyster Creek (7), Waterford (5) and H.B. Robinson (5). During the same time period, several plants have had four precursors, including: Arkansas Nuclear One (Unit 2); Browns Ferry (Units 1, 2, and 3); Dresden (Unit 3); Duane Arnold; Oconee (Unit 1); and Pilgrim. The relatively large number of BWRs with four or more precursors over the past decade largely influences the increasing trend in BWR precursors in the past 20 years.

11. COMPARISON OF RECENT PROGRAM PESULTS

The eight precursors identified in 2017 using an independent ASP analysis were compared with results from MD 8.3 and SDP analyses, as shown in Table 4. Given the three programs have different functions, it is expected that the results are likely to be different. A comparison of analysis results for the three programs for past events (2010–2016) in which an independent ASP analysis was performed is provided in Appendix C.

Table 4. 2017 Independent ASP Analysis Comparison.

Event Description	MD 8.3 Results	SDP Results	ASP Results	SPAR Model/Methodology Improvements and Insights
Waterford; 382-17-002; 7/17/2017. Automatic reactor scram due to the failure of fast bus transfer relays to automatically transfer station loads to offsite power on a main generator trip	CCDP = 6×10^{-5}, which led to a special inspection. See IR 05000293/2015007 (ML17212B191) for additional information.	A *Green* finding was identified for an inadequate design change that rendered the fast bus transfer system inoperable. The ΔCDF was determined to be less than 1×10^{-6} per year for a 45-exposure period. Some FLEX credit was provided; see IR 05000382/2017011 (ML17354A690) for additional information.	CCDP = 2×10^{-5}; plant-centered LOOP. Offsite power was recoverable almost immediately. See final ASP analysis (ML18066A196) for additional information.	Performed sensitivity analyses including credit for FLEX battery charging to allow for continued turbine-driven emergency feedwater pump operation.
Turkey Point 3; 250-17-001; 3/18/2017. Loss of 3A 4 kV vital bus results in reactor trip, safety system actuations and loss of safety injection function	CCDP = mid-10^{-6} to 3×10^{-5}, which led to a special inspection.	Two *Green* findings were identified associated with the licensee failure to (a.) implement adequate fire watches following a HEAF on 4.16 kV safety related bus 3A, which resulted in inadequate fire detection capability in switchgear room '3B' for approximately 28 hours, and (b.) incorporate appropriate instructions to prevent foreign material from entering nearby electrical equipment when installing Thermo-Lag insulation. The ΔCDF was determined to be less than 1×10^{-6} per year for both findings. The LER is closed; see IR 05000250/2017002 (ML17223A012) for additional information.	CCDP = 2×10^{-5}; non-recoverable loss of safety-related bus 3A initiating event with both Unit 4 high-head safety injection (HHSI) pumps unavailable due to maintenance. See final ASP analysis (ML18038B063) for additional information.	Both the SDP and ASP analysis identified significant SPAR model changes and corrections were made, including: • Revised RCP seal modeling given the installation of N9000 Flowserve RCP seals. • Modification of HHSI pump success criterion requiring only one of four pumps (instead of two) to mitigate small and medium LOCAs. • Crediting turbine driven AFW pumps or the standby SG feedwater pumps to achieve a safe/stable end state for loss of all safety related AC power scenarios (assuming no LOCA) with available safety-related DC power, which either unit can supply.

Event Description	MD 8.3 Results	SDP Results	ASP Results	SPAR Model/Methodology Improvements and Insights
Arkansas 1; 313-17-001; 4/26/2017. Automatic start of an emergency diesel generator due to the loss of offsite power due to severe weather	No deterministic criteria were met; therefore, a formal risk evaluation was not required.	No inspection findings were identified with this event.	CCDP = 2×10^{-5}; a non-recoverable loss of condenser heat sink and partial LOOP. Offsite power was not recoverable to the affected buses. See final ASP analysis (ML17319B035) for additional information.	Electrical system fault tree logic was modified to support analysis.
Vogtle 2; 425-17-001; 3/9/2017. Power supply failure results in operation in a condition prohibited by technical specifications	No deterministic criteria were met; therefore, a formal risk evaluation was not required.	No inspection findings were identified with this event. Inspectors determined that it was not reasonable for the licensee to have identified that the power supplies had failed prior to March 8, 2017.	ΔCDP = 8×10^{-5}; unavailability of both power supplies for EDG 2A for 15b days. A single power supply was also failed for additional 34 days. Potential common-cause failure (CCF) of other EDG power supplies dominates risk result. See final ASP analysis (ML17250B343) for additional information.	Significant modifications were made to the SBO event tree, including RCP seal LOCA modeling and offsite power recovery times based on battery depletion rates.
LaSalle 2; 374-2017-003-01; 2/11/2017. High-pressure core spray system inoperable due to injection valve stem-disc separation	CCDP = 2×10^{-5}, which led to a special inspection. See IR 05000374/2017009 (ML17243A098) for additional information.	A violation related to inadequate design control for the HPCS injection valve 2E2-F004 was identified; however, the NRC exercised enforcement discretion because no licensee performance deficiency was identified. Therefore, no SDP evaluation was performed.	ΔCDP = 2×10^{-5}; 1-year unavailability of HPCS due to failed injection valve. Assumed injection valve would be required to cycle open more than five times to fulfil HPCS safety function for complete PRA mission time (24 hours). See final ASP analysis (ML18072A326) for additional information.	Identified SPAR model limitation concerning potential dependency between multiple human failure events (HFEs) within the same cut set. The limited HFE dependency evaluation within the base SPAR models is a global issue. RES is planning to conduct a scoping study to determine common HFE combinations for each plant type and perform dependency evaluation for incorporation into base SPAR models.

Event Description	MD 8.3 Results	SDP Results	ASP Results	SPAR Model/Methodology Improvements and Insights
Cooper; 298-17-001; 2/5/2017. Concurrent unavailabilities—residual heat removal loop 'A', reactor core isolation cooling, and emergency station service transformer	ΔCDP = 4×10^{-6}, which led to a special inspection. See IR 05000298/2017009 (ML17179A282) for additional information.	Five *Green* findings were identified with these windowed conditions. The licensee failed to follow procedures and correct a condition adverse to quality. See IRs 05000298/2017009 (ML17179A282), 05000298/2017001 (ML17122A362), 05000298/2017011 (ML17223A459), and 05000298/2017012 (ML17354A634) for additional information.	ΔCDP = 6×10^{-6}; windowed unavailabilities of RHR loop 'A', RCIC, and emergency station service transformer (ESST). The ΔCDP is dominated by concurrent unavailabilities of the RHR loop 'A' and the ESST for 127 hours. See final ASP analysis (ML18068A724) for additional information.	The affected RHR valves and associated CCF events were not included in the base SPAR model and were added to support analysis. In addition, electrical system fault tree logic was modified to support analysis.
Columbia; 397-16-004; 12/18/2016. Initiating event automatic scram due to offsite load reject	CCDP = 9×10^{-5}, which led to a special inspection. See IR 05000397/2017008 (ML17096A781) for additional information.	Three *Green* findings were identified with the licensee failure to follow procedures and correct a condition adverse to quality. All three findings were screened as Green in Phase 1. The LER is closed, see IR 05000397/2017008 (ML17096A781) for additional information.	CCDP = 1×10^{-5}; a non-recoverable loss of condenser heat sink and partial LOOP. Offsite power was recoverable to the affected buses. See final ASP analysis (ML17249A968) for additional information.	Incorrect electrical system fault tree logic was identified and corrected.
Palo Verde 3; 530-16-002; 12/15/2016. Emergency diesel generator failure resulting in a condition prohibited by technical specifications	ΔCDP = 4×10^{-6}, which led to a special inspection. See IR 05000530/2017008 (ML17100A130) for additional information.	No inspection findings were identified with this event.	ΔCDP = 2×10^{-5}; unavailability EDG 3B for 119 days. In addition, the EDG underwent repairs for 57 days. See final ASP analysis (ML17313B159) for additional information.	Performed sensitivity analyses to credit successful EDG run time for additional offsite power recovery time throughout exposure period. This credit resulted in a 36 percent reduction in ΔCDP for the 119 day exposure period.

12. LER SCREENING QUALITY ASSURANCE REVIEW

A quality assurance review of the LER screening performed by Idaho National Laboratory (INL) was performed by the staff. The purpose of this review is to verify that all potentially risk-significant LERs are screened into the ASP Program. In addition, the review confirms that the coding scheme is logical and assesses if any revisions are necessary to ensure ASP analyst resources are focused on potential precursors. Screening LERs using the cASP criteria is described in Section 4. For some screened-in events, the reviewer may identify a different criterion code than was identified by the contractor. This situation is acceptable because it is possible that multiple criteria may apply to an event. As a result of the screening review in 2016, criterion 3i "Primary safety relief valve(s) or pressurizer power operated relief valve(s)" was added to ensure that these types of potential precursor events would be consistently reviewed by ASP analysts.

For the review of events in 2017, the staff selected 92 LERs (74 LERs that screened out and 18 LERs identified as potential precursors) for independent assessment based on the cASP criteria. Of the 74 LERs screened out by INL, there were 10 instances in which the staff believed that the event could have screened in as a potential precursor, depending on the interpretation of the screening criteria. Events with conflicting screening results typically involve tornado-missile vulnerabilities and reactor trips with potential equipment recovery. While these instances highlight areas for improvement in the clarity of the screening criteria, the staff believes that the risk of these events is low and they do not represent instances where a precursor was potentially overlooked. The staff agreed with INL's assessment for 17 LERs that screened in as potential precursors. The staff disagreed with one of INL's screen-in assessments, which was associated with an LER relating to a failure of refueling floor supply isolation dampers.

Compared to previous years, the LER quality assurance review was intentionally more thorough in 2017 based on a recommendation from an internal review of the ASP Program. The recommendation indicated that the cASP criteria should be analyzed to determine if changes in scope and clarity could improve the screening efficiency, while also further focusing limited resources on the most risk significant events. The staff felt that conducting a thorough review of the 2017 screening would provide a valuable first step in this process. The results of this screening review will be used during the 2018 screening criteria revision and will be combined with a quantitative analysis of past screening criteria compared with the percentage of events that resulted in precursor-level core damage probabilities.

The staff performed an additional quality assurance review of the LER screening by comparing potential precursors with the SDP tracking sheet maintained by Office of Nuclear Reactor Regulation (NRR). The SDP tracking sheet provides up-to-date tracking of active, final, and historical SDP findings. While there will be instances in which an SDP finding is outside of the ASP Program scope (e.g., security performance deficiencies), other cornerstones (e.g., initiating event and mitigating systems) represent events that may be important to analyze within the ASP Program. In addition to reviewing the SDP tracking sheet, an ASP analyst now participates in the NRR Operating Experience Clearinghouse meetings, which is held 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. ASP analyst participation will provide another information source to help ensure that risk significant events are captured by the ASP Program.

In 2017, there were two *White* findings (Perry and Catawba 2) identified on the SDP tracking sheet that were not associated with an LER. Because the ASP Program relies on LERs as its primary means of identifying events of interest, these two events were not previously evaluated by the ASP Program. The *White* findings were reviewed and accepted as the final ASP Program results.

Appendix A: 2017 ASP Program Screened Analyses

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 the purpose of including greater-than-*Green* findings as ASP 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.

LER: 260-17-001 **Plant:** Browns Ferry 2 **Event Date:** 2/16/17
LER Report Date: 4/14/17 **LER Screening Date:** 4/27/17 **cASP Criterion:** 3d
ASP Completion Date: 5/15/17 **Classification:** Analyst Screen-Out

Analyst Justification: Not discussed in any inspection report (IR) to date; LER remains open. On February 16, 2017, operators received a high-pressure coolant injection (HPCI) power failure alarm in the control room. Upon further investigation, it was determined that a fuse failure rendered HPCI unavailable. The fuse was replaced within 1 hour and HPCI was declared operable approximately 31 hours later after post maintenance testing was completed. All other emergency core cooling systems (ECCS) equipment remained operable during the event. A search of LERs did not yield any windowed events that would impact the risk significance of this event. The duration of HPCI unavailability was less than the technical specification (TS) allowed outage time; therefore, this event is screened out and is not considered a precursor under the ASP Program. A bounding condition assessment assuming HPCI unavailability for a 31-hour exposure period, without credit for recovery, yielded a ΔCDP = 1×10^{-7}, which confirms that this event is not a precursor.

LER: 263-16-003 **Plant:** Monticello **Event Date:** 11/27/16
LER Report Date: 1/25/17 **LER Screening Date:** 2/21/17 **cASP Criterion:** 3d
ASP Completion Date: 5/15/17 **Classification:** Analyst Screen-Out

Analyst Justification: Not discussed in any IR to date; LER remains open. HPCI was inoperable and would not have fulfilled its safety function from November 21, 2016, until it was repaired on December 1, 2016 (approximately 245 hours). The HPCI inoperability was caused by post-maintenance testing that resulted in valve seat leakage, which led to accumulation of condensate in the HPCI turbine. A malfunctioning HPCI turbine exhaust drain pot limit switch prevented the condensate from draining properly. During this period of HPCI inoperability, core spray was unavailable (test/maintenance) for approximately 2 hours, and both LPCI trains were unavailable (test/maintenance) for approximately 2.5 hours. The periods of unavailability of core spray and LPCI did not overlap. Note that core spray and LPCI were recoverable, if needed. A search of LERs did not yield any windowed events that would impact the risk significance of this event. A bounding risk assessment that accounted for the non-recoverable unavailabilities of HPCI along with short duration concurrent unavailabilities with core spray and LPCI yielded a ΔCDP of 3×10^{-7}. This is below the ASP threshold of 1×10^{-6} and, therefore, is not a precursor.

LER: 293-17-001 **Plant:** Pilgrim **Event Date:** 1/16/17
LER Report Date: 3/15/17 **LER Screening Date:** 3/29/17 **cASP Criterion:** 3g
ASP Completion Date: 5/15/17 **Classification:** Analyst Screen-Out

Analyst Justification: Not discussed in any IR to date; LER remains open. During surveillance testing on January 16, 2017, the secondary containment refueling floor supply isolation dampers failed to close on demand. The dampers were manually closed approximately 11 minutes later. Following cleaning and lubrication, the dampers were successfully tested and returned to service. The function of secondary containment isolation dampers is to limit the release of radioactive material to the environment following a postulated design basis accident. The ASP Program focuses on accident sequences that lead to core damage as part of a Level 1 probabilistic risk assessment (PRA). Offsite releases and secondary containment performance are part of Level 2 and 3 PRAs, and are outside the scope of the ASP Program. Therefore, this event is screened out and not considered a precursor. A search for windowed events is not necessary in this case because damper performance does not impact the risk significance of core damage.

LER: 316-16-002 **Plant:** Cook 2 **Event Date:** 12/13/16
LER Report Date: 2/9/17 **LER Screening Date:** 2/24/17 **cASP Criterion:** 3e
ASP Completion Date: 6/1/17 **Classification:** SDP Screen-Out

Analyst Justification: *Green* Finding (IR 05000316/2017001); LER remains open. On December 13, 2016, the Unit 1 AB EDG developed a fuel oil leak from a fuel injector pump delivery valve holder (DVH) during a surveillance run. The licensee determined that nineteen additional suspect DVHs were installed in the Unit 1 and Unit 2 EDGs. A licensee investigation determined that the DVH failure was attributed to a previously identified condition for a design and manufacturing flaw and the suspect DVHs were susceptible to a similar failure. As noted by the inspectors in the inspection report, testing and analysis (performed by an outside firm for the licensee) on a representative sample of removed DVHs showed that the EDGs could fulfill their safety functions for the required run times. Since no loss of safety function was experienced, this event is screened out of the ASP Program and is not considered a precursor. A review of potential windowed events was not needed because there was no loss of safety function.

LER: 321-17-002 **Plant:** Hatch 1 **Event Date:** 2/8/17
LER Report Date: 4/7/17 **LER Screening Date:** 4/26/17 **cASP Criterion:** 3d
ASP Completion Date: 6/26/17 **Classification:** Analyst Screen-Out

Analyst Justification: Briefly discussed in IR 05000321/2017001; LER remains open. On February 8, 2017, at 11:51 a.m., the HPCI suction and discharge pressure indicators were noted to be downscale, and plant personnel subsequently discovered that the output voltage of the HPCI direct current (DC) to alternating current (AC) inverter was degraded. The inverter provides power to the HPCI flow controller and power supply. The HPCI turbine would not have fulfilled its safety function with the degraded inverter and HPCI was declared inoperable. When asked, the senior resident inspector informed the ASP Analyst that the HPCI system was restored to operable status approximately 5 hours later following replacement of the inverter. Automatic depressurization, core spray, low pressure coolant injection, and reactor core isolation cooling were verified operable during the 5-hour exposure period. A search of LERs did not yield any windowed events that would impact the risk significance of this event. The duration of HPCI unavailability was less than the TS allowed outage time; therefore, this event is screened out and is not considered a precursor under the ASP Program. A bounding condition assessment assuming HPCI unavailability for a 5-hour exposure period, without credit for recovery, yielded a ΔCDP of 5×10^{-8}, which confirms that this event is not a precursor.

LER: 333-17-003 **Plant:** FitzPatrick **Event Date:** 4/4/17
LER Report Date: 6/5/17 **LER Screening Date:** 6/20/17 **cASP Criterion:** 3d
ASP Completion Date: 6/26/17 **Classification:** Analyst Screen-Out

Analyst Justification: Not discussed in IRs through 05000333/2017001; the LER remains open. On April 4, 2017, a technician mistakenly connected an energized voltage source to the HPCI high area temp master trip unit, resulting in closure of the HPCI steam isolation valves. The HPCI system was restored to operable status approximately 5 hours after the unplanned valve isolation. Automatic depressurization, core spray, and low pressure coolant injection were verified operable during the 5-hour exposure period. A search of LERs did not yield any windowed events that would impact the risk significance of this event. The duration of HPCI unavailability was less than the TS allowed outage time; therefore, this event is screened out and is not considered a precursor under the ASP Program. A bounding condition assessment assuming HPCI unavailability for a 5-hour exposure period, without credit for recovery, yielded a ΔCDP of 1×10^{-8}, which confirms that this event is not a precursor.

LER: 382-17-001 | **Plant:** Waterford 3 | **Event Date:** 3/8/17
LER Report Date: 5/4/17 | **LER Screening Date:** 5/17/17 | **cASP Criterion:** 3d
ASP Completion Date: 6/26/17 | **Classification:** Analyst Screen-Out

Analyst Justification: Briefly mentioned in IR 05000382/2017001; the LER remains open. On March 8, 2017, at 1608, low-pressure safety injection (LPSI) train 'A' was declared inoperable in accordance with TS when maintenance personnel commenced work to inspect the stem threads and obtain measurements on reactor coolant loop 2 shutdown cooling warmup valve SI-135A. At 1627, operators in the control room identified that SI-135B was open, instead of SI-135A, resulting in LPSI train 'B' being declared inoperable. With both LPSI train inoperable, TS require that one LPSI train be restored to operability within 1 hour. LPSI train 'B' was declared operable at 1705 after operators closed SI-135B and verified operability by performing stroke time testing in accordance with the surveillance procedure. The inoperability of both LPSI trains was less than the TS limit of 1 hour. An engineering analysis performed by the licensee revealed that flow from LPSI train 'B' with SI-135B in the open position would still provide 2,330 gpm to the reactor coolant system, which the licensee determined would have fulfilled its safety function for all required accident conditions. Because no loss of safety function was experienced, this event is screened out of the ASP Program and is not considered a precursor. A review of potential windowed events was not needed because there was no loss of safety function.

LER: 397-17-001 | **Plant:** Columbia | **Event Date:** 1/25/17
LER Report Date: 3/20/17 | **LER Screening Date:** 3/29/17 | **cASP Criterion:** 3d
ASP Completion Date: 6/26/17 | **Classification:** Analyst Screen-Out

Analyst Justification: IR 05000397/2017001 briefly mentions the fan failure in association with inspection samples for post-maintenance testing, maintenance risk assessments, and maintenance effectiveness. No detailed information is provided, and no inspection finding has been identified to date. On January 25, 2017, the normally running diesel mixed air fan (DMA-FN-32) failed. This normally running fan maintains temperature within the division III diesel generator room to ensure equipment operability during an emergency. An additional fan (DMA-FN-31) automatically starts when the EDG is started. A review of the licensee PRA model revealed that a loss of either fan (DMA-FN-31 and DMA-FN-32) will result in the failure of the division III diesel generator to fulfill its safety function. The HPCS system was undergoing maintenance at the time and, therefore, the fan failure did not render HPCS unavailable (i.e., the system was already unavailable due to maintenance). Note that the division III diesel generator only supports high-pressure core spray (HPCS) during a loss of offsite power to bus SM4. Typically, failures of normally running equipment are quickly identified and repaired in compliance with TS (or the plant is shutdown). A sensitivity analysis reveals that DMA-FN-32 would need to have been failed for over 2 months for the ΔCDP to exceed the ASP Program threshold of 1×10^{-6}. Since this failure did not result in the unavailability of HPCS, this event is screened out of the ASP Program, and is not considered a precursor. A review of LERs revealed no windowed events.

LER: 445-17-001 | **Plant:** Comanche Peak 1 | **Event Date:** 1/11/17
LER Report Date: 5/17/17 | **LER Screening Date:** 6/6/17 | **cASP Criterion:** 3g
ASP Completion Date: 6/26/17 | **Classification:** Analyst Screen-Out

Analyst Justification: Not discussed in IRs through 05000445/2017001; the LER remains open. On December 12, 2016, TEFLON was found to be installed in the suction and discharge pressure gauge diaphragm seal assemblies for the Unit 1 and 2 containment spray pumps. On January 11, 2017, an evaluation performed by the licensee determined that the containment spray systems on both units had been inoperable since initial plant licensing on April 17, 1990. TEFLON is not radiation tolerant and could degrade over time, resulting in inoperability of the containment spray systems due to exceeding system leakage and dose limits. Containment spray pumps are not typically included in the Level-1 PRA modeling for pressurized-water reactors (PWRs), as the system does not play a role in mitigation of core damage. Therefore, a search for windowed events is not required, this event is screened out, and is not considered a precursor under the ASP Program.

LER: 293-17-002 **Plant:** Pilgrim **Event Date:** 3/27/17
LER Report Date: 5/25/17 **LER Screening Date:** 6/20/17 **cASP Criterion:** 3d
ASP Completion Date: 6/30/17 **Classification:** Analyst Screen-Out

Analyst Justification: Not discussed in IRs through 05000293/2017001; the LER remains open. During reactor core isolation cooling system testing, plant personnel heated the incorrect temperature switch causing an isolation of the HPCI system. A licensee review determined that the two technicians deviated from procedure requirements. The HPCI system isolation resulted in a loss of safety function for 33 minutes before operators realigned the system. Since the HPCI inoperability was less than the limits of technical specifications limiting condition for operation 3.5.C.2 (14 days), this event is screened out and is not considered a precursor under the ASP Program. A search of LERs did not yield any windowed events that would impact the risk significance of this event.

LER: 313-17-002 **Plant:** Arkansas 1 **Event Date:** 5/27/17
LER Report Date: 7/26/17 **LER Screening Date:** 8/14/17 **cASP Criterion:** 3h
ASP Completion Date: 9/1/17 **Classification:** SDP Screen-Out

Analyst Justification: *Green* finding identified in IR 05000313/2017002; the LER remains open. On May 27, 2017, operators attempted to start the red train of high-pressure injection (HPI) in support of upcoming maintenance on the swing HPI pump (P-36B). The red train HPI pump (P-36A) failed to start due to the breaker not being fully racked in. Operations personnel manually racked the breaker and the pump was declared operable. The red train of HPI was determined to have been inoperable since May 11th, when personnel racked the breakers in anticipation of restarting the unit following an outage. This resulted in a violation of TS 3.5.2, "Emergency Core Cooling System - Operating," and a performance deficiency was identified for failure to ensure the operability of the P-36A HPI pump after reinstalling its feeder breaker during the unit outage. The green train of HPI, along with the swing HPI pump, remained operable during the exposure time. A detailed risk analysis was performed in support of the SDP, which calculated a ΔCDF of 4×10^{-8} per year. This analysis was reviewed and determined to be appropriate for ASP Program needs. The calculated risk is below the precursor threshold of 1×10^{-6}; therefore, this event is not considered a precursor. A search of LERs did not yield any windowed events that would impact the risk significance of this event.

LER: 389-17-002 **Plant:** St. Lucie 2 **Event Date:** 5/15/17
LER Report Date: 7/14/17 **LER Screening Date:** 8/14/17 **cASP Criterion:** 3h
ASP Completion Date: 9/19/17 **Classification:** Analyst Screen-Out

Analyst Justification: Discussed in IR 05000389/2017002 with no findings identified; the LER remains open. On May 15, 2017, the 2A3 4.16 kilovolt (kV) bus undervoltage protection relays actuated, removing power to the bus by opening the incoming breaker. Despite an automatic start signal, emergency diesel generator (EDG) 2A did not start because it was removed from service for maintenance. The cause of activation of the undervoltage protection relays was blown fuses in the 2A3 secondary side potential transformer. Power was restored to the 2A3 bus approximately 6 hours later by replacing the blown fuses (within the 8-hour TS limit). The unit remained at 100 percent power throughout the event, with redundant safety loads capable of being powered by the 2B3 bus. A search of LERs did not yield any windowed events. The duration of loss of power to the 2A3 bus was less than the TS allowed outage time; therefore, this event is screened out and not considered a precursor under the ASP Program. A bounding condition assessment assuming loss of power to the 2A3 bus, including unavailability of EDG 2A due to maintenance, for a 6-hour exposure period, without credit for recovery, yielded a ΔCDP of 6.6×10^{-7}, which confirms that this event is not a precursor.

LER: 416-17-001 **Plant:** Grand Gulf **Event Date:** 1/27/17
LER Report Date: 3/28/17 **LER Screening Date:** 4/12/17 **cASP Criterion:** 3d
ASP Completion Date: 9/19/17 **Classification:** Analyst Screen-Out

Analyst Justification: Not yet mentioned in any inspection report. Reviewed IRs up to 05000416/2017010, dated 5/16/2017. On January 27, 2017, the HPCS jockey pump failed due to the thrust bearing being degraded causing the pump to seize while the plant was in Mode 2 raising power to return to power operations so the HPCS system was declared inoperable. A sensitivity analysis reveals that assuming HPCS inoperable for 2 days would result in a ΔCDP of 2×10^{-7}. Since this failure resulted in a ΔCDP well below the ASP Program threshold of 1E-6 and the plant was in Mode 2, this event is screened out of the ASP Program and is not considered a precursor. A review of LERs revealed no windowed events.

LER: 341-17-003	**Plant:** Fermi 2	**Event Date:** 5/22/17
LER Report Date: 7/21/17	**LER Screening Date:** 8/14/17	**cASP Criterion:** 3c
ASP Completion Date: 9/20/17	**Classification:** Analyst Screen-Out	

Analyst Justification: Not discussed in any IR to date; LER remains open. On May 22, 2017, the division 2 residual heat removal service water (RHRSW) discharge flow control valve (FCV) failed to fully open. Troubleshooting discovered that the direct cause was the failure of the anti-rotation bushing stem key. The FCV was unable to perform its design basis function from May 3, 2017, (when it was last successfully stroked under dynamic conditions) through May 24, 2017 (when it was repaired and returned to service). In addition to supplying cooling water to the division 2 RHR heat exchanger, division 2 RHRSW can provide an alternative source of low pressure injection to the reactor. Since the FCV is downstream of the injection line, this capability was maintained. Division 1 RHRSW was available throughout the duration of the event except on two occasions during mechanical draft cooling tower maintenance activities on May 9th and May 11th (approximately 29 hours total). A search of LERs did not reveal any potential windowed events. A bounding condition assessment with no recovery credit was performed consisting of two separate exposure periods. The first exposure period assumed the unavailability of division 2 RHRSW to supply its RHR heat exchanger for 486 hours. The second exposure period assumed unavailability of division 2 RHRSW to supply its RHR heat exchanger concurrent with the complete unavailability of division 1 RHRSW for 29 hours. The summation of the two exposure periods yields a ΔCDP of 8.6×10^{-7}. This is below the ASP threshold of 1×10^{-6} and, therefore, is not a precursor.

LER: 286-17-001	**Plant:** Indian Point 3	**Event Date:** 5/14/17
LER Report Date: 7/13/17	**LER Screening Date:** 8/14/17	**cASP Criterion:** 3d
ASP Completion Date: 10/3/17	**Classification:** SDP Screen-Out	

Analyst Justification: *Green* finding identified in IR 05000286/2017002; the LER remains open. On May 14, 2017, at 2:33 am, Unit 3 entered Mode 4 as part of coming out of outage 3R19 and preparing for power operations. The operations test group was preparing for performance of 3-PTCS004, “Residual Heat Removal Check Valve Testing,” and gathered for a pre job brief in accordance with the requirements of EN-HU-102, “Human Performance Traps and Tools Procedure.” At the time, the only allowable access point to the inner crane wall was through the double gate combination of gates ‘D’ and ‘E’, which requires one gate to be maintained closed and secured at all times. However, three people went through gate ‘C’ despite a posted sign stating that the gate was not to be used in Modes 1 through 4. While the valve manipulations were in progress, the NRC Resident Inspector identified that gate ‘C’ was not properly secured. Gate ‘C’ being open in this plant condition resulted in a safety system functional failure, since the containment sumps are inoperable when gate ‘C’ is not secured. In a postulated loss-of-coolant accident, debris bypassing the gate has the potential to clog the screens that maintain net positive suction to the internal recirculation and residual heat removal pumps. A conservative detailed risk evaluation was performed in support of the SDP, which calculated a ΔCDF of 2×10^{-8} per year. This analysis was reviewed and determined to be appropriate for ASP Program needs. The calculated risk is below the precursor threshold of 1×10^{-6}; therefore, this event is not considered a precursor. A search of LERs did not yield any potential windowed events that would impact the risk significance of this event.

LER: 293-17-008 | **Plant:** Pilgrim | **Event Date:** 5/3/17
LER Report Date: 6/30/17 | **LER Screening Date:** 8/14/17 | **cASP Criterion:** 3d
ASP Completion Date: 10/4/17 | **Classification:** Analyst Screen-Out

Analyst Justification: This event is not discussed in any IR to date; the LER remains open. During a refueling outage, testing revealed a relay failure that resulted in the unavailability of the 480 volt (V) bus B6 to automatically transfer to its backup source of power. This relay had previously been replaced after a failure was identified in April 2015 (the previous refueling outage). Note that operators still had the ability to manually transfer the bus B6 supply power from bus B1 (normal source) to bus B2 (backup source), which is directed by procedure 2.4.B.6, "Loss of Bus B6." Base standardized plant analysis risk (SPAR) model modifications were needed to improve bus B6 electrical dependencies (e.g., low-pressure coolant injection valves). This test/limited use model also includes basic events representing the failure of the bus B6 automatic power transfer and an operator action to manual switch bus B6 power from bus B1 to bus B2. An analysis assuming the unavailability of the auto-transfer for a 1-year exposure period results in a $\Delta CDP = 2\times10^{-7}$, which is below the ASP Program threshold. Note that this result is potentially conservative because the actual time of failure is unknown and, therefore, a maximum exposure time of 1 year was used, which is consistent with ASP Program guidelines. Given the long exposure period (possibly an entire fuel cycle), a search of other Pilgrim LERs yields many events that are potentially windowed with this event. Many of the LERs describe events that have a negligible contribution to the risk of core damage. However, some LERs describe events that would increase the risk during the exposure period of this event. A review of these events reveals that the risks are additive in nature (i.e., the dominant accident sequences/cut sets are different for each event). In addition, the results of completed and preliminary ASP analyses for these events indicate that it is not likely that the combined risk would exceed the ASP Program threshold. Therefore, this event is screened out of the ASP Program and is not considered a precursor.

LER: 263-17-004 | **Plant:** Monticello | **Event Date:** 6/19/17
LER Report Date: 8/16/17 | **LER Screening Date:** 8/24/17 | **cASP Criterion:** 3d
ASP Completion Date: 10/4/17 | **Classification:** Analyst Screen-Out

Analyst Justification: This event is not discussed in any IR to date; the LER remains open. Following planned maintenance on the HPCI system, operators attempted to start the HPCI pump, but the steam stop valve (HO-7) failed to open resulting in a safety system functional failure. The failure of HO-7 to open was caused by an oil relay failure. Valve HO-7 was last validated to open properly on June 15, 2017. The HO-7 relay was repaired and the HPCI system was returned to operable status on June 23, 2017. Since the HPCI inoperability was less than the limits of TS limiting condition for operation (LCO) 3.5.A.3 (14 days), this event is screened out and is not considered a precursor under the ASP Program. A confirmatory risk analysis assuming the unavailability of the HPCI system for 8 days results in a $\Delta CDP = 2.6\times10^{-7}$. A search of LERs did not yield any windowed events.

LER: 341-16-009 | **Plant:** Fermi 2 | **Event Date:** 4/24/16
LER Report Date: 12/20/16 | **LER Screening Date:** 8/24/17 | **cASP Criterion:** 3e
ASP Completion Date: 10/16/17 | **Classification:** SDP Screen-Out

Analyst Justification: A *Green* finding was identified in IR 05000341/2016004; the LER is closed. On April 24, 2016, the output voltage signal from the potential transformer for 4160 volt buses 64A and 64C was lost, resulting in the actuation of one half of the loss-of-voltage and degraded-voltage relays for bus 64C. The other halves of the loss-of-voltage and degraded-voltage relays were not tripped and, therefore, the loss-of-power instrumentation trip logic was in a half tripped state. Within 2.5 hours, operators were able to restore transformer 64 output voltage. Additional complications as a result of this event include the following: (a.) the degraded-voltage relays may not have reset upon a loss-of-coolant accident (LOCA) auto-start of essential safety feature (ESF) equipment in order to stay connected to the preferred offsite power source; (b.) the division 1 AC power source lost its functionality due to the inability of transformer 64 to deliver three-phase AC power at the required voltage range stemming from its loss-of-voltage reference that is required for load tap changer automatic operation; and (c.) EDG 12 lost its voltage reference required for synchronization across the breaker, which would prevent the EDG 12 from being manually synchronized with offsite power to allow load transfer back to offsite power. NRC inspectors determined that the licensee's failure to satisfy applicable technical specification limiting conditions for operations requirements for inoperable loss-of-power instrument channels and inoperable AC power sources was a performance deficiency. A detailed risk evaluation was performed in support of the (SDP. The major analysis assumptions modeled three separate exposure periods accounting for: (a.) the unavailability of EDG 12 for approximately 10 days; (b.) the concurrent unavailability of offsite power to the division 1 ESF bus with ESF buses 64B and 64C assumed to be failed for postulated design basis accidents for 2.5 hours; and (c.) the concurrent unavailabilities of EDG 12 and ESF buses 64B and 64C (recoverable) for 24 hours. The combined ΔCDF of this detailed risk evaluation was 7.7×10^{-8} per year (included internal fires and external hazards); therefore, the performance deficiency was determined to be *Green* (i.e., very low safety significance). This detailed risk assessment is potentially conservative because the licensee determined that the inoperable loss-of-power relays would not impact the capability of EDG 12 to start and load onto the ESF bus when demanded, and the loss-of-power instrument trip logic remained capable of starting the EDG upon sensing a degraded grid condition. A search of LERs did not yield any windowed events that would impact the risk significance of this event. However, LER 341-16-009 noted that EDGs 13 and 14 were inoperable on six occasions during the 10-day exposure time in which EDG 12 was assumed to be unavailable. The LER states that both EDGs were able to fulfill their safety function because the EDGs were undergoing surveillance testing (i.e., the EDGs were not undergoing maintenance). Given this information and the conservative nature of the detailed risk evaluation, the SDP result has been deemed appropriate for ASP Program use. The calculated risk is below the ASP Program threshold of 1×10^{-6} and, therefore, this event is not considered a precursor.

LER: 390-17-001	**Plant:** Watts Bar 1	**Event Date:** 11/10/16
LER Report Date: 1/9/17	**LER Screening Date:** 1/18/17	**cASP Criterion:** 3c
ASP Completion Date: 10/19/17	**Classification:** SDP Screen-Out	

Analyst Justification: *Green* finding from IR 05000390/2016004. The LER is closed by the inspection report but the Licensee states that the cause of the failure is under investigation and will be reported in a supplement to the LER which has not as yet been issued. Each of the eight emergency raw cooling water (ERCW) pumps contains a non-reverse assembly to keep the motor from rotating backwards, since starting the motor during backwards rotation could cause an overcurrent trip and pump/motor damage due to mechanical stresses. On November 10, 2016, the non-reverse clutch key was found sheared on ERCW motor B-A. Previous failures were identified on this and other ERCW motors. Immediately following a pump stop, the water contained in the vertical pump column will drain back to river elevation. Testing showed that with the anti-reverse clutch completely disabled, the pump will spin backwards for approximately 55 seconds after pump trip. During a LOOP event the pump will trip and 30 seconds after EDG start, the four required ERCW pumps will start and should not be rotating backwards provided proper non-reverse clutch key operation as previously explained. The licensee performed an immediate determination of operability on November 29, 2016, without appropriately considering the LOOP concern. The licensee performed a prompt determination of operability on December 1, 2016. The performance deficiency was more than minor because reasonable assurance of operability did not exist for the ERCW pumps from November 29th to November 30th and therefore should have been declared inoperable. The event is of very low safety significance (*Green*) because it did not represent an actual loss of function for at least a single train for longer than its technical specification allowed outage time. A search of LERs did identify a windowed event regarding an ERCW strainer flush valve through-wall leak (LER 390-2017-003) existing from January 31, 2016, until its replacement on January 5, 2017, because subsequent analysis of the valve demonstrated that it remained structurally sound with the leak, and would not have impacted the operability of the ERCW system and hence no safety significance. Therefore, this non-reverse clutch key event is not considered a precursor under the ASP Program.

LER: 334-17-002	**Plant:** Beaver Valley 1	**Event Date:** 7/9/17
LER Report Date: 9/13/17	**LER Screening Date:** 10/5/17	**cASP Criterion:** 3e
ASP Completion Date: 10/31/17	**Classification:** Analyst Screen-Out	

Analyst Justification: Not discussed in any IR to date; the LER remains open. In accordance with NRC Regulatory Issue Summary 2015-06, "Tornado Missile Protection," the licensee performed an evaluation and determined that both Unit 1 EDG exhaust stacks are vulnerable to tornado-generated missiles. This condition is part of the original design and has existed since plant construction. Both EDGs were declared inoperable on July 19, 2017, and Enforcement Guidance Memorandum (EGM) 15-002 Rev. 1 "Enforcement Discretion for Tornado-Generated Missile Protection Noncompliance" was applied. The EDG exhaust stacks are protected on two sides and the top from tornado missiles, but are open on the remaining two sides. As a compensatory measure, the licensee updated its severe weather procedure to provide guidance for operators to identify potential missiles before a possible tornado and to prioritize checking the status of the EDG exhaust stacks following a tornado. By implementing the compensatory measure, the EDGs were declared operable but nonconforming. For a tornado missile-induced scenario to occur, a tornado would have to touch down at the site and result in the generation of missiles that would hit and fail the EDG exhaust stacks in a manner that is non-repairable and non-recoverable. For example, the exhaust stacks would have to be crimped in a manner that would prevent the exhaust of combustion products; however, if the exhaust stacks were sheared off completely, the EDGs would likely remain operable. At Beaver Valley, the frequency of a tornado with wind speeds greater than 111 mph (i.e., rated 2 or higher according to the Enhanced Fujita Scale) is estimated to be 8.87×10^{-6} per year (using available tornado data through 2006 and methods in NUREG-4461, Revision 2). Given this low probability of a tornado event combined with the low probability of missile strikes on the unprotected sides of both EDG exhaust stacks that result in “crimping” damage only, this event is screened out and not considered a precursor within the ASP Program.

LER: 348-16-007 **Plant:** Farley 1 **Event Date:** 11/17/16
LER Report Date: 1/13/17 **LER Screening Date:** 2/1/17 **cASP Criterion:** 3a
ASP Completion Date: 11/7/17 **Classification:** Analyst Screen-Out

Analyst Justification: Discussed in IR 05000348/2017002 with no finding identified; the LER is closed. On November 17, 2016, with the unit at 99 percent power, the plant initiated a shutdown in accordance with TS because the two steam flow channels for 'C' steam generator (SG) were outside their acceptance criteria. This condition resulted in the engineered safety feature actuation system (ESFAS) instrumentation function for high steam flow in the 'C' steam line to be declared inoperable. Steam flow channels perform a safety function by providing high steam flow input to main steam line isolation logic circuitry. A high steam flow signal from one of the two steam flow transmitters on two of the three SGs coincident with a low-low reactor coolant system (RCS) average temperature signal from two of the three RCS temperature channels generates a main steam line isolation signal that closes all main steam line isolation valves. This signal mitigates the consequences of a main steam line break accident. Two additional means (low steam pressure main steam line isolation signal and containment pressure signal) of providing a main steam isolation remained fully capable of performing the main steam line isolation function during the periods that the steam flow channels were known to be out of tolerance. The loss of the main steam line isolation from the high steam flow and low-low RCS average temperature signal was determined to be of low risk due to redundant trips for mitigation of a steam line break remaining operable. Steam flow channels are not commonly included in SPAR models, partially due to the defense in depth of the reactor protection system (RPS) to cause a trip via alternate and diverse means. As such, a search for windowed events is not necessary. Similar NRC analyses were performed in support of the SDP (IR 05000348/2013004 Section 4OA7, IR 05000348/2014002 Section 4OA7, and IR 05000348/2014003 Section 4OA7) resulting in *Gree*n findings for the failure of a steam flow instrument channel at Farley. The RPS design for defense in depth to trip the reactor via alternate and diverse means contributed to the low risk significance of this event and is sufficient to screen this event as not being a precursor under the ASP Program.

LER: 390-17-009 **Plant:** Watts Bar 1 **Event Date:** 7/12/17
LER Report Date: 9/11/17 **LER Screening Date:** 10/5/17 **cASP Criterion:** 3c
ASP Completion Date: 11/13/17 **Classification:** Analyst Screen-Out

Analyst Justification: Not discussed in any IR to date; the LER remains open. On July 12, 2017, a preliminary licensee analysis indicated the potential for inadequate ERCW during a design basis accident (i.e., large loss-of-coolant accident (LLOCA)) on one unit, while the other unit is using the residual heat removal system to cooldown. In addition, this preliminary analysis revealed that Unit 2 may not receive adequate ERCW flow to meet cooldown requirements during a design basis accident. Current procedural guidance was determined to be inadequate to ensure the proper system alignment in establishing the correct ERCW component cooling water flow rates for either unit's cooldown requirements. A subsequent licensee review of the ERCW discharge valve positions from the component cooling water heat exchangers was performed. This review determined that in all cases, ERCW train B flow would have been adequate for accident conditions on either unit. However, the licensee determined that ERCW train A was not able to perform its safety function for a design basis accident on Unit 2 for 0.252 years. Additional information on how this exposure period was calculated was not provided in the LER. A bounding condition assessment was performed assuming the failure of train A recirculation during a design basis accident due to inadequate ERCW flow for a 1-year exposure period, which results in a $\Delta CDP = 9\times10^{-8}$. A search of LERs did not yield any windowed events that would impact the risk significance of this event (i.e., no other events impact the risk of a LLOCA) and, therefore, this event is not considered a precursor under the ASP Program.

LER: 323-17-001	**Plant:** Diablo Canyon 2	**Event Date:** 7/29/17
LER Report Date: 10/3/17	**LER Screening Date:** 10/18/17	**cASP Criterion:** 3i
ASP Completion Date: 11/15/17	**Classification:** SDP Screen-Out	

Analyst Justification: *Green* finding identified in IR 05000323/2017003; the LER remains open. A nitrogen accumulator relief valve leak resulted in a degraded condition for power-operated relief valve (PORV) PCV-455C. The reactor pressurizer is equipped with two safety-related PORVs and one nonsafety-related PORV. The condition existed from December 1, 2016, until July 30, 2017. In the event of a loss of instrument air, the degraded PORV would be inoperable due to low nitrogen pressure. Safety-related PORVs and their associated backup nitrogen accumulators are credited to mitigate feedwater line breaks, spurious safety injections, steam generator tube ruptures, and low temperature overpressure events. The licensee assessed the risk significance of the inoperability of PCV-455C and concluded that the PORV would be available for the most risk significant functions. The performance deficiency was assessed under the SDP and screened as a *Green* finding. The licensee stated that the other safety-related PORV (PCV-456) was inoperable for testing multiple times during the exposure period. The ASP analyst determined that the concurrent unavailability of the two safety-related PORVs during periods of planned maintenance represents a minimal increase in the risk associated with this event due to the expected short duration for valve maintenance and the likelihood of system recovery from maintenance in the event of an initiating event. Therefore, the SDP screening is accepted as the final result for the ASP Program and the event is not considered a precursor. A search of LERs did not reveal any windowed events.

LER: 390-17-005	**Plant:** Watts Bar 1	**Event Date:** 5/10/17
LER Report Date: 7/10/17	**LER Screening Date:** 7/24/17	**cASP Criterion:** 3d
ASP Completion Date: 11/15/17	**Classification:** Analyst Screen-Out	

Analyst Justification: This event was discussed in IR 05000390/2017002; the LER remains open. While at power, the 1B-B safety injection (SI) pump discharge isolation valve (1-ISV-63-527) was found closed. The valve was closed, but not tagged as directed by the procedure, to support an EDG blackout surveillance test on April 11, 2017. As a result of not being tagged, there was no programmatic control in place to return the valve to the open position upon completion of the surveillance test. The valve remained closed for 30 days and caused the B train of SI to be inoperable. The valve was immediately opened upon discovery during operator rounds on May 10th. During this time period, the 1A-A SI pump was also inoperable for 21 minutes on May 9th. The SDP analysis resulted in a ΔCDF of less than 1×10^{-6} per year, with the finding determined to be of very low safety significance (*Green*). A bounding condition assessment under the ASP Program was performed with the 1B-B SI pump discharge check valve set failed for 30 days and both SI pump discharge check valves set failed for 1 hour. The ASP analysis resulted in a total ΔCDP of 1×10^{-7}. A search of LERs revealed windowed events involving two manual reactor trips on May 2nd and May 4th due to a failed reactor coolant pump (RCP) power transfer during plant startup (LER 390-2017-004). The concurrent inoperability of SI train B was analyzed with the manual trip general transient resulting in a CCDP of 3.4×10^{-6}. The ASP Program acceptance threshold is a CCDP of 1×10^{-6} or the CCDP equivalent of an uncomplicated reactor trip with a non-recoverable loss of main feedwater and condenser heat sink, whichever is higher. For Watts Bar 1 the higher precursor threshold is established by the CCDP for a loss of condenser heat sink initiating event or a loss of main feedwater initiating event, which both have a CCDP of 3.9×10^{-6}. This manual trip concurrent with the loss of 1B-B SI pump does not rise to the ASP Program threshold and, therefore, is not considered a precursor under the ASP Program.

LER: 374-17-002 **Plant:** La Salle 2 **Event Date:** 1/30/17
LER Report Date: 3/31/17 **LER Screening Date:** 4/12/17 **cASP Criterion:** 3d
ASP Completion Date: 11/15/17 **Classification:** SDP Screen-Out

Analyst Justification: A *Green* finding was identified in IR 05000374/2017001; the LER remains open. On January 10, 2017, operators were unable to open the division 3 diesel generator cooling water (DGCW) strainer backwash valve (2E22-F319) during the performance of monthly surveillance testing. Subsequently, the licensee declared the division 3 diesel generator and HPCS system inoperable. The licensee determined that valve 2E22-F319 had failed due to a stem-disc separation caused by erosion of carbon-steel valve internals in a raw water system environment. The DGCW system remained functional as the system retained the ability to provide the required flow through the system. The failed valve was replaced with a stainless steel model and the HPCS system was declared operable on February 2nd. A performance deficiency was identified with the licensee failure associated with control and administration of preventive maintenance that failed to ensure that valve 2E22–F319 was replaced or refurbished at a frequency that would prevent corrosion-related stem-disc separation. A detailed risk assessment was performed as part of the SDP. The analysis assumed that the HPCS system (including the division 3 diesel generator) was unable to fulfil its safety function for an exposure time of 19 days resulting in a ΔCDF of 8.3×10^{-7} per year (includes both internal and external hazards). Therefore, the finding was determined to be of very low safety significance (*Green*). A search of LERs reveals that LER 374-2017-003-01 reports that another valve failure occurred in February 11, 2017, which could also have resulted in a loss of safety function of HPCS. Any “windowed” effects of these two events will be considered in the analysis of LER 374-2017-003-01. No other events that would impact the risk significance of this event were identified and, therefore, the result of the SDP risk assessment has been deemed appropriate for ASP Program use. Because the calculated risk is below the ASP Program threshold of 1×10^{-6}, this event is not considered a precursor.

LER: 373-17-006 **Plant:** La Salle 1 **Event Date:** 5/17/17
LER Report Date: 7/17/17 **LER Screening Date:** 7/27/17 **cASP Criterion:** 3d
ASP Completion Date: 11/29/17 **Classification:** SDP Screen-Out

Analyst Justification A *Green* finding was identified in IR 05000373/2017003; the LER is closed. On May 17, 2017, with the plant at 100 percent power, a low-pressure core spray (LPCS) flow switch failed causing the automatic closure of the LPCS minimum flow valve (1E21-F011). The cause of the flow switch failure was due to a faulty diaphragm, which allowed for water intrusion into the device. The failed flow switch was replaced and LPCS was returned to service approximately 10 hours later; therefore, the LPCS inoperability was less than the limits of TS LCO 3.5.1.A.1 (7 days). In addition, the failure of 1E21-F011 would not prevent the LPCS from performing its safety function; however, if reactor pressure is not sufficiently low upon system initiation, a failed (closed) minimum flow valve could result in damage to the LPCS pump due to a “dead head” condition. NRC inspectors determined that the licensee’s failure to ensure that the LPCS system was being effectively controlled in accordance with maintenance rule program requirements was a performance deficiency. This performance deficiency was determined to be *Green* (i.e., very low safety significance) using the screening questions provided in Appendix A of Inspection Manual Chapter 0609 (Exhibit 2). A search of LERs did not yield any windowed events.

LER: 373-17-007 **Plant:** La Salle 1 **Event Date:** 6/22/17
LER Report Date: 8/18/17 **LER Screening Date:** 8/24/17 **cASP Criterion:** 3d
ASP Completion Date: 11/29/17 **Classification:** Analyst Screen-Out

Analyst Justification: This event is not discussed in any inspection report to date; the LER remains open. On June 22, 2017, with the plant at 100 percent power and preparing for shutdown for a planned maintenance outage, the common diesel generator cooling pump received an automatic trip signal while being secured. The LPCS system was declared inoperable due to loss of motor and corner room area cooling. Upon entering Mode 4 for the maintenance outage 18 hours later, the LPCS TS LCO was exited. The licensee determined that the most likely reason for the common diesel generator pump failure was a breaker malfunction caused by either a faulty contact or hand switch. Both of these components were replaced and the LPCS was declared operable on June 24th. Since the LPCS inoperability was less than the limits of TS LCO 3.5.1.A.1 (7 days), this event is screened out and is not considered a precursor under the ASP Program. A confirmatory risk analysis assuming the unavailability of the common diesel generator pump for 18 hours results in a ΔCDP = 4.6×10^{-8}. A search of LERs did not yield any windowed events.

LER: 395-17-002 **Plant:** Summer **Event Date:** 6/9/17
LER Report Date: 8/25/17 **LER Screening Date:** 9/25/17 **cASP Criterion:** 3d
ASP Completion Date: 11/29/17 **Classification:** Analyst Screen-Out

Analyst Justification: This event was reviewed in IR 05000395/2017002 with no inspection findings being identified; however, the LER remains open. On June 29, 2017, with the plant operating at 100 percent power, an automatic reactor trip occurred due to the spurious closure of feedwater regulating valve (1FV00488-FW), which resulted in low SG 'B' level coincident with low feedwater flow. The plant response to the reactor trip was normal, with both motor driven and turbine-driven emergency feedwater starting on low-low SG level (as per design). It should be noted that some secondary atmospheric dump valves lifted and reseated due to the pressure excursion experienced as a result of the reactor trip. The closure of 1FV00488-FW was caused by its solenoid valve being intermittently deenergized, which resulted in the opening of the quick exhaust valve and the subsequent venting of the feedwater regulating valve actuator. A search of LERs did not yield any windowed events that would impact the risk significance of this event. This event is bounded by a non-recoverable loss of feedwater transient and, therefore, is not considered a precursor under the ASP Program.

LER: 293-17-007 **Plant:** Pilgrim **Event Date:** 4/24/17
LER Report Date: 6/22/17 **LER Screening Date:** 7/24/17 **cASP Criterion:** 3i
ASP Completion Date: 12/4/17 **Classification:** SDP Screen-Out

Analyst Justification: A *Green* finding was identified in IR 05000293/2017003; the LER remains open. During a refueling outage, a high resistance was measured across the solenoid pilot valve coil of SV203-3A while performing testing of the safety relief valves (SRV). This solenoid pilot valve was subsequently replaced. NRC inspectors identified a performance deficiency associated with the licensee using an incorrect replacement frequency for solenoid pilot valves. The affected SRV was determined to be able to fulfill its safety function for events that would not cause extreme environment conditions (e.g., high temperature, humidity) inside containment. Therefore, the SDP risk assessment assumed that only a loss-of-coolant accident would cause a loss of safety function to SV203-3A, which resulted in ΔCDF = 6×10^{-7} (internal and external hazards) for a 1-year exposure time. Therefore, the licensee performance deficiency was determined to be *Green* (i.e., very low safety significance). Given the long exposure period (possibly an entire fuel cycle), a search of other Pilgrim LERs yields many events that are potentially windowed with this event. Many of the LERs describe events that have a negligible contribution to the risk of core damage. However, some LERs describe events that would increase the risk during the exposure period of this event. A review of these events reveals that the risks are additive in nature (i.e., the dominant accident sequences/cut sets are different for each event). In addition, the results of completed ASP analyses for these events indicate that it is not likely that the combined risk would exceed the ASP Program threshold. Therefore, this event is screened out of the ASP Program and is not considered a precursor.

LER: 390-17-010 **Plant:** Watts Bar 1 **Event Date:** 8/17/17
LER Report Date: 10/16/17 **LER Screening Date:** 11/1/17 **cASP Criterion:** 3h
ASP Completion Date: 12/7/17 **Classification:** Analyst Screen-Out

Analyst Justification: This event is not discussed in any inspection report to date; the LER remains open. On August 17, 2017, at 12:05 p.m., Unit 1 lost power to 6.9 kV shutdown board 1B-B. EDG 1B was out of service for maintenance and did not start to maintain voltage on shutdown board 1B-B. The loss of power to this safety-related bus resulted in an automatic start of the turbine-driven auxiliary feedwater pump. No other system actuations occurred as a result of this event. The plant entered several TS due to the loss of 6.9 kV shutdown board 1B-B, with actions A and B of LCO 3.8.4 (the plant must be placed in Mode 3 within 8 hours) being the most limiting. In addition, the plant entered LCO 3.0.3 (plant must be place in Mode 3 within 7 hours) at 12:58 p.m. due to multiple analog rod position indication signals being outside their limits (caused by increased containment temperatures as the result of the loss shutdown board 1B-B). Shutdown board 1B-B was restored at 3:05 p.m. on August 17th. Since shutdown board 1B-B was unavailable for less than the TS allowed outage times, this event is screened out and is not considered a precursor under the ASP Program. A confirmatory risk analysis assuming the unavailability of the shutdown board 1B-B system for 3 hours results in a ΔCDP = 2×10^{-7}. A search of LERs did not yield any windowed events.

LER: 353-17-006 **Plant:** Limerick 2 **Event Date:** 7/27/17
LER Report Date: 9/25/17 **LER Screening Date:** 10/12/17 **cASP Criterion:** 3d
ASP Completion Date: 12/7/17 **Classification:** Analyst Screen-Out

Analyst Justification: This event is not discussed in any IR to date; the LER remains open. On July 27, 2017, the HPCI system was rendered inoperable for approximately 20 minutes because the operators closed the suction valve during post maintenance testing. These post-maintenance testing instructions were determined to be inadequate/incorrect. Operators reestablished the HPCI suction source from the suppression pool resulting in the HPCI system being restored to an operable status. Since the HPCI was unavailable for less than the limits of TS LOC 3.5.1.c (14 days), this event is screened out and is not considered a precursor under the ASP Program. A confirmatory risk analysis assuming the unavailability of the HPCI system for 1 hour results in a ΔCDP = 3×10^{-9}. A search of LERs did not yield any windowed events.

LER: 325-17-001 **Plant:** Brunswick 1 and 2 **Event Date:** 2/7/16
LER Report Date: 3/22/17 **LER Screening Date:** 3/29/17 **cASP Criterion:** 3e
ASP Completion Date: 12/11/17 **Classification:** Analyst Screen-Out

Analyst Justification: This event is discussed in IRs 05000325/2016002, 05000325/2016004, and 05000325/2017001; the LER is closed in IR 05000325/2017001. This event is an expansion of the inoperable exposure period for EDG 1 that was analyzed and reported as a reject under the ASP Program in 2016, “Emergency Diesel Generator 3 Inoperable Due to Failure to Auto-Start” (ML17109A455). A conservative SPAR model run was performed for the new time period from February 7, 2016 at 2:04 p.m. to February 20, 2016 at 6:06 p.m. (previously determined unavailability start) for an additional 13 days that EDG 1 was found to be inoperable at the same time that EDG 3) was inoperable which resulted in the Unit 1 ΔCDP increasing to 7.1×10^{-8} and the Unit 2 ΔCDP increasing to 2.5×10^{-7}. Since this would not increase the previous analysis above the precursor threshold of a ΔCDP greater than 1×10^{-6} and this increased exposure period brings no new risk sequence insights into what was discussed in the previous ASP analysis (ML17109A455), this event is screened out of the ASP Program and is not considered a precursor. A search of LERs did not yield any windowed events that would impact the risk significance of this event.

LER: 416-17-006 **Plant:** Grand Gulf **Event Date:** 8/29/17
LER Report Date: 10/12/17 **LER Screening Date:** 10/30/17 **cASP Criterion:** 3h
ASP Completion Date: 12/6/17 **Classification:** Analyst Screen-Out

Analyst Justification: This event is not discussed in any IR to date; the LER remains open. On August 22, 2017, residual heat removal (RHR) pump 'A' was declared inoperable after a surveillance test revealed that the pump differential pressure was lower than its specified limit. A plant shutdown was initiated on August 29th, in accordance with TS 3.5.1, 3.6.1.7, and 3.6.2.3. The cause is under investigation; however, this event is similar to a previous event at Grand Gulf in 2016 (LER 416-2016-007). The ASP analyst performed a bounding risk assessment assuming that RHR pump A would not have fulfilled its safety function for the exposure period beginning with its last successful quarterly surveillance test (i.e., 3 months). This analysis resulted in a ΔCDP = 3×10^{-7} using the internal events, at-power model. It is important to note that RHR pump A may have been able to fulfill its safety function despite the decreased differential pressure of 119 psid (compared to the TS limit of 131 psid), in which case the risk during the at-power portion of this event would be significantly reduced. In addition to this, RHR pump 'A' was unavailable for 25 days following plant shut down while a new pump was being installed. The analyst performed a risk assessment for the 25-day exposure period using the Grand Gulf SPAR shutdown model assuming the plant was in early Mode 4. This analysis resulted in a ΔCDP = 4×10^{-7}. The sum of these two results is below the threshold of 1×10^{-6}; therefore, this event is not considered a precursor under the ASP Program. A search of LERs did not yield any windowed events that would impact the risk significance of this analysis.

LER: 296-17-001 **Plant:** Browns Ferry 3 **Event Date:** 9/1/17
LER Report Date: 10/31/17 **LER Screening Date:** 11/15/17 **cASP Criterion:** 3h
ASP Completion Date: 12/20/17 **Classification:** Analyst Screen-Out

Analyst Justification: Not discussed in any IR to date; the LER remains open. On September 1, 2017, at 10:06 am, the 3A RHR pump failed to start during the performance of surveillance. Maintenance troubleshooting revealed that the 3A RHR pump motor breaker's closing spring failed to charge, preventing the breaker from closing on demand. Malfunction of the 3A RHR pump motor breaker resulted in the 3A RHR pump failing to start during manual or automatic actuation. Operations personnel declared the 3A RHR pump inoperable. A past operability evaluation performed by the licensee concluded that the 3A RHR pump was inoperable from July 26, 2017, to September 1, 2017, which exceeds the outage time allowed by technical specifications. The direct cause of this event was binding of the charged/uncharged indication flag, which prevented the closing spring from charging the 3A RHR pump motor breaker. A bounding condition assessment was performed assuming the failure to start of the 3A RHR pump during a design basis accident for a 37-day exposure period, which resulted in a ΔCDP = 2×10^{-8}. A search of LERs did not yield any windowed events and, therefore, this event is not considered a precursor under the ASP Program.

LER: 416-17-007 **Plant:** Grand Gulf **Event Date:** 9/8/16
LER Report Date: 6/29/17 **LER Screening Date:** 7/24/17 **cASP Criterion:** 3h
ASP Completion Date: 12/21/17 **Classification:** Analyst Screen-Out

Analyst Justification: This event is discussed in IR 05000416/2016008; the LER remains open. On September 4, 2016, RHR pump 'A' was declared inoperable after a surveillance test revealed that the pump differential pressure was lower than its specified limit. The cause of the low differential pressure was due to manufacturer defects. A plant shutdown was initiated on September 8th. The TS LOC 3.5.1, 3.6.1.7, and 3.6.2.3 were entered, each having completion times of 7 days. On September 9, 2016, operation crews cooled down the plant to Mode 4 (Cold Shutdown). With the plant in Mode 4 and RHR subsystem 'A' inoperable, TS required that an alternate method of decay heat removal be available. The licensee inappropriately credited the alternate decay heat removal (ADHR) system which was not actually in standby or available to satisfy TS requirement because the ADHR heat exchangers cooling water system had been clearance-tagged closed since August 10, 2016 according to LER 416/2016-008-01. This condition was not identified until September 23, 2016, after the RHR pump 'A' was installed and returned to operable status. The ASP analyst performed a bounding risk assessment assuming that RHR pump A was unable to fulfill its safety function during the reactor shutdown and for a period of 90 days since its last surveillance test for a period of approximately 95 days which resulted in a ΔCDP of 4×10^{-7}. It is important to note that RHR pump A may have been able to fulfill its safety function despite the decreased differential pressure, in which case the risk during the at-power portion of this event would be significantly reduced). In addition to this, RHR pump A was unavailable for 15 days following in Mode 4 while a new pump was being installed during which time ADHR was credited for being available, but was not available. Following the repair of RHR pump A, ADHR remained unavailable for approximately 5 days. The analyst performed a risk assessment for the 15-day exposure period that RHR pump A and ADHR were unavailable and the approximately 5 days that ADHR was unavailable using the Grand Gulf SPAR shutdown model assuming the plant was in early mode 4. This analysis resulted in a ΔCDP = 3×10^{-7}. The sum of these results is below the threshold of 1×10^{-6}; therefore, this event is not considered a precursor under the ASP Program. A search of LERs did not yield any windowed events in addition to LER 416/2016-008-01 that would impact this analysis.

LER: 249-17-001	**Plant:** Dresden 3	**Event Date:** 9/12/17
LER Report Date: 11/10/17	**LER Screening Date:** 11/28/17	**cASP Criterion:** 3g
ASP Completion Date: 12/21/17	**Classification:** Analyst Screen-Out	

Analyst Justification: This event is discussed in inspection report 05000249/2017003; the LER remains open. On September 10, 2017, with the Unit 3 standby liquid control (SLC) system in standby operation, an equipment operator identified sodium pentaborate crystallization build-up under piping insulation. The licensee removed the insulation and noted a dry sodium pentaborate stain on the stainless steel discharge line of SLC pump ‘A’. The licensee shift manager made an immediate operability determination of operable based on the dry nature of the stain and its location. On September 12th, the division 1 SLC pump was started to pressurize the system during testing when a leak of approximately one drop per minute was identified on the common discharge line of the SLC pumps. Both SLC system subsystems were declared inoperable due to the leak, and TS 3.1.7, condition B was entered, which requires SLC operability be restored within 8 hours. If the requirements of condition B cannot be met, condition C is entered, which requires that the plant be placed in Mode 3 within 12 hours. Enforcement discretion for the completion time was requested by the licensee and approved by the NRC. At 8:35 p.m. on September 12, 2017, the failed piping was replaced, thereby restoring operability to the Unit 3 SLC system within the TS completion time. NRC inspectors opened an unresolved issue associated with the potential noncompliance with required action B.1 for TS 3.1.7. There is no definitive information on when this leak began. However, a one drop per minute leak is not expected to effect the safety function of the SLC system. A sensitivity analysis shows that the SLC system would need to be inoperable for at least 5 months to exceed the precursor threshold of a ΔCDP greater than or equal to 1×10^{-6}. Given this information, the event is screened out of the ASP Program. A search of LERs did not yield any windowed events.

LER: 440-17-006	**Plant:** Perry	**Event Date:** 10/4/17
LER Report Date: 12/1/17	**LER Screening Date:** 12/19/17	**cASP Criterion:** 3e
ASP Completion Date: 1/3/18	**Classification:** Analyst Screen-Out	

Analyst Justification: This event is not discussed in any inspection report to date; the LER remains open. On October 4, 2017 at 1:55 a.m., with the plant at 100 percent rated thermal power, train ‘A’ of the motor control center (MCC), switchgear, and miscellaneous electrical equipment area heating, ventilation, and air conditioning (HVAC) and battery room exhaust systems was shutdown and declared inoperable due to a report of excessive drive belt noise and malfunctioning belts on supply fan ‘A’. Concurrently, control complex chilled water (CCCW) chiller B was out of service for planned maintenance resulting in train B of the MCC, switchgear, and miscellaneous electrical equipment area HVAC and battery room exhaust systems being inoperable. The concurrent unavailability resulted in a loss of safety function of the AC and DC electrical distribution subsystems. TS) 3.8.7, 3.8.4, and 3.8.1 were entered, with operators required to enter LCO 3.0.3 (due to TS 3.8.7, action E) per plant procedures. Due to the inoperability of both trains of the MCC, switchgear, and miscellaneous electrical equipment area HVAC and battery room exhaust systems, the high-pressure core spray system was also declared inoperable according to TS. At 2:00 a.m., MCC, switchgear, and miscellaneous electrical equipment area HVAC and battery room exhaust systems were shifted from train ‘A’ to train ‘B’ with nonsafety-related CCCW chiller ‘C’ already running, restoring cooling to the affected electrical rooms. At 2:50 a.m., operators commenced a plant shutdown in accordance with LCO 3.0.3. Following belt replacement, train ‘A’ of the MCC, switchgear, and miscellaneous electrical equipment area HVAC and battery room exhaust systems was declared operable at 6:20 a.m., and TS 3.0.3 was exited. Since the MCC, switchgear, and miscellaneous electrical equipment area HVAC and battery room exhaust systems were unavailable for less than the TS allowed outage times, this event is screened out and is not considered a precursor under the ASP Program. A search of LERs did not yield any windowed events.

LER: 352-17-004	**Plant:** Limerick 1	**Event Date:** 10/5/17
LER Report Date: 12/4/17	**LER Screening Date:** 12/19/17	**cASP Criterion:** 3d
ASP Completion Date: 1/16/18	**Classification:** Analyst Screen-Out	

Analyst Justification: Not discussed in any IR to date; the LER remains open. On October 5, 2017, the 1C core spray (CS) pump breaker failed to close when the breaker hand switch was placed in start during a pump valve and flow test. The breaker failed to close because the breaker limit switch that energizes the closing springs charging motor became dislodged, thus prohibiting the charging motor from charging the closing springs. This condition existed since the previous 1C CS pump motor test on July 17, 2017. The ASP analyst performed a condition assessment for failure to start of the 1C CS pump during an 81-day exposure period, which yielded a ΔCDP = 2×10^{-8}. The licensee reported that the opposite train of CS was concurrently unavailable for a total time of 4 hours during the 81-day exposure period. The unavailability of both trains of CS was within the technical specification limit of 12 hours and, therefore, this simultaneous unavailability presents a negligible addition to the overall risk. A search of LERs did not yield any windowed events and the risk result is below the ASP Program threshold; therefore, this event is not considered a precursor.

Appendix B: Brief Summary of Significant Precursors[20]

Date	LER	Plant	Brief Description	CCDP/ΔCDP
2/27/02	346-02-002	Davis-Besse	***Reactor pressure vessel head leakage of control rod drive mechanism nozzles, potential unavailability of sump recirculation due to screen plugging, and potential unavailability of boron precipitation control.*** The analysis included multiple degraded conditions discovered on various dates. These conditions included cracking of control rod drive mechanism nozzles and reactor pressure vessel (RPV) head degradation, potential clogging of the emergency sump, and potential degradation of the high-pressure injection pumps during recirculation.	6×10^{-3}
2/6/96	414-96-001	Catawba 2	***Plant-centered loss of offsite power (transformer ground faults) with an emergency diesel generator unavailable due to maintenance.*** When the reactor was at hot shutdown, a transformer in the switchyard shorted out during a storm, causing breakers to open and resulting in a loss of offsite power event. Although both emergency diesel generators started, the output breaker of emergency diesel generator 1B, to essential bus 1B failed to close on demand, leaving bus 1B without alternate current (AC) power. After 2 hours and 25 minutes, operators successfully closed the emergency diesel generator 1B output breaker.	2×10^{-3}
9/17/94	482-94-013	Wolf Creek	***Reactor coolant system blowdown (9,200 gallons) to the refueling water storage tank.*** When the plant was in cold shutdown, operators implemented two unpermitted simultaneous evolutions, which resulted in the transfer of 9,200 gallons (34,825 liters) of reactor coolant system inventory to the refueling water storage tank. Operators immediately diagnosed the problem and terminated the event by closing the residual heat removal cross-connect motor-operated valve. The temperature of the reactor coolant system increased by 7°F (4°C) as a result of this event.	3×10^{-3}
4/3/91	400-91-008	Shearon Harris	***High-pressure injection unavailable for one refueling cycle because of inoperable alternate minimum flow valves.*** A degraded condition resulted from relief valve and drain line failures in the alternative minimum flow systems for the charging/safety injection pumps, which would have diverted a significant amount of safety injection flow away from the reactor coolant system. The root cause of the degradation is believed to have been water hammer, as a result of air left in the alternative minimum flow system following system maintenance and test activities.	6×10^{-3}
12/27/86	250-86-39	Turkey Point 3	***Turbine load loss with trip; control rod drive auto insert fails; manual reactor trip; power-operated relief valve sticks open.*** The reactor was tripped manually following a loss of turbine governor oil system pressure and the subsequent rapid electrical load decrease. Control rods failed to insert automatically because of two cold solder joints in the power mismatch circuit. During the transient, a power-operated relief valve opened but failed to close (the block valve had to be closed). The loss of governor oil pressure was the result of a cleared orifice blockage and the auxiliary governor dumping control oil.	1×10^{-3}

20 The table is sorted by event date. The event at Three Mile Island, Unit 2 is not included in this list of precursors because the event resulted in an actual accident at the plant. The role that this event played in the development of the ASP Program is discussed in Section 1 of this report.

Date	LER	Plant	Brief Description	CCDP/ΔCDP
6/13/86	413-86-031	Catawba 1	***CVCS system leak (130 gpm) from the component cooling water/CVCS heat exchanger joint (i.e., small-break loss-of-coolant accident).*** A weld break on the letdown piping, near the component cooling water/chemical and volume control system heat exchanger caused excessive reactor coolant system leakage. A loss of motor control center power caused the variable letdown orifice to fail open. The weld on the 1-inch (2.54-cm) outlet flange on the variable letdown orifice failed as a result of excessive cavitation-induced vibration. This event was a small-break loss-of-coolant accident.	3×10^{-3}
6/9/85	346-85-013	Davis-Besse	***Loss of feedwater; scram; operator error fails emergency feedwater; power-operated relief valve fails open.*** While at 90-percent power, the reactor tripped with main feedwater pump 1 tripped and main feedwater pump 2 unavailable. Operators made an error in initiating the steam and feedwater rupture control system and isolated emergency feedwater to both steam generators. The power-operated relief valve actuated three times and did not reseat at the proper reactor coolant system pressure. Operators closed the power-operated relief valve block valves, recovered emergency feedwater locally, and used high-pressure injection pump 1 to reduce reactor coolant system pressure.	1×10^{-2}
5/15/85	321-85-018	Hatch 1	***Heating, ventilation, and air conditioning (HVAC) water shorts panel; safety relief valve fails open; high-pressure coolant injection fails; reactor core isolation cooling unavailable.*** Water from an HVAC vent fell onto an analog transmitter trip system panel in the control room (the water was from the control room HVAC filter deluge system which had been inadvertently activated as a result of unrelated maintenance activities). This resulted in the lifting of the safety relief valve four times. The safety relief valve stuck open on the fourth cycle, initiating a transient. Moisture also energized the high-pressure coolant injection trip solenoid making high-pressure coolant injection inoperable. Reactor core isolation cooling was unavailable due to maintenance.	2×10^{-3}
9/21/84	373-84-054	LaSalle 1	***Operator error causes scram; reactor core isolation cooling unavailable; residual heat removal unavailable.*** While at 23-percent power, an operator error caused a reactor scram and main steam isolation valve closure. Reactor core isolation cooling was found to be unavailable during testing (one reactor core isolation cooling pump was isolated, and the other pump tripped during the test). Residual heat removal was found to be unavailable during testing because of an inboard suction isolation valve failing to open on demand. Both residual heat removal and reactor core isolation cooling may have been unavailable after the reactor scram.	2×10^{-3}
2/25/83	272-83-011	Salem 1	***Trip with automatic reactor trip capability failed.*** When the reactor was at 25 percent power, both reactor trip breakers failed to open on demand of a low-low steam generator level trip signal. A manual trip was initiated approximately 3 seconds after the automatic trip breaker failed to open, and was successful. The same event occurred 3 days later, at 12 percent power. Mechanical binding of the latch mechanism in the breaker under-voltage trip attachment failed both breakers in both events.	5×10^{-3}

Date	LER	Plant	Brief Description	CCDP/ΔCDP
6/24/81	346-81-037	Davis-Besse	***Loss of vital bus; failure of an emergency feedwater pump; main steam safety valve lifted and failed to reseat.*** With the plant at 74-percent power, the loss of bus E2 occurred because of a maintenance error during control rod drive mechanism breaker logic testing. A reactor trip occurred, due to loss of control rod drive mechanism power (bus E2), and instrumentation power was also lost (bus E2 and a defective logic card on the alternate source). During the recovery, emergency feedwater pump 2 failed to start because of a maladjusted governor slip clutch and bent low speed stop pin. A main steam safety valve lifted, and failed to reseat (valve was then gagged).	2×10^{-3}
4/19/81	325-81-032	Brunswick 1	***Loss of shutdown cooling due oyster shell buildup in the residual heat removal heat exchanger.*** While the reactor was in cold shutdown during a maintenance outage, the normal decay heat removal system was lost because of a failure of the single residual heat removal heat exchanger that was currently in service. The failure occurred when the starting of a second residual heat removal service water pump caused the failure of a baffle in the water box of the residual heat removal heat exchanger, thereby allowing cooling water to bypass the tube bundle. The redundant heat exchanger was inoperable because maintenance was in progress.	7×10^{-3}
1/2/81	336-81-005	Millstone 2	***Loss of DC power and one emergency diesel generator as a result of operator error; partial loss of offsite power.*** When the reactor was at full power, the 125 volt (V) direct current (DC) emergency bus was lost as a result of operator error. The loss of the bus caused the reactor to trip, but the turbine failed to trip because of the unavailability of DC bus ‘A’. Loads were not switched to the reserve transformer (following the manual turbine trip) because of the loss of DC bus ‘A’. Two breakers (on the B 6.9 kilovolt (kV) and 4.16 kV busses) remained open, thereby causing a loss of offsite power. Emergency diesel generator ‘B’ tripped as a result of leakage of the service water flange, which also caused the 4.16 kV bus ‘B’ to be de-energized. An operator recognition error caused the power-operated relief valve to be opened at 2380 psia.	5×10^{-3}
6/11/80	335-80-029	St. Lucie 1	***Reactor coolant pump seal loss-of-coolant accident due to loss of component cooling water; top vessel head bubble.*** At 100-percent power, a moisture-induced short circuit in a solenoid valve caused a component cooling water containment isolation valve to shut causing loss of component cooling water to all reactor coolant pumps. While pressure was reduced to initiate the shutdown cooling system, the top head water flashed to steam, thus forming a bubble (initially undetected by the operators). During the cooldown, the shutdown cooling system relief valves lifted and low-pressure safety injection initiated (i.e., one low-pressure safety injection pump started charging, while the other was used for cooldown).	1×10^{-3}
4/19/80	346-80-029	Davis-Besse	***Loss of two essential buses leads to loss of decay heat removal.*** When the reactor was in cold shutdown, two essential busses were lost because of breaker ground fault relay actuation during an electrical lineup. The decay heat drop line valve was shut, and air was drawn into the suction of the decay heat removal pumps, resulting in loss of a decay heat removal path.	1×10^{-3}

Date	LER	Plant	Brief Description	CCDP/ΔCDP
2/26/80	302-80-010	Crystal River	***Loss 24V DC non-nuclear instrumentation causes reactor trip and stuck-open power-operated relief valve and subsequent steam generator dry out.*** The 24 V power supply to non-nuclear instrumentation was lost as a result of a short to ground. This initiated a sequence of events in which the power-operated relief valve opened (and stayed open) as a direct result of the loss of non-nuclear instrumentation power supply. High-pressure injection initiated as a result of depressurization through the open power-operated relief valve, and with approximately 70 percent of non-nuclear instrumentation inoperable or inaccurate, the operator correctly decided that there was insufficient information available to justify terminating high-pressure injection. Therefore, the pressurizer was pumped solid, one safety valve lifted, and flow through the safety valve was sufficient to rupture the reactor coolant drain tank rupture disk, thereby spilling approximately 43,000 gallons (162,800 liters) of primary water into the containment.	5×10^{-3}
11/20/79	325-79-089	Brunswick 2	***Reactor trip with failure of reactor core isolation cooling and high-pressure coolant injection unavailable due to maintenance.*** Following a reactor scram, the reactor core isolation cooling turbine tripped on mechanical over-speed with high pressure core injection out for maintenance. Reactor core isolation cooling was reset and manually set into operation. The reactor water level had reached -40 inches.	3×10^{-3}
10/2/79	282-79-027	Prairie Island 1	***Steam generator tube rupture.*** With the reactor at 100% power, a 390 gpm tube break occurred in steam generator A. The reactor tripped and safety injection actuated due to low pressurizer level. The reactor coolant system was placed in cold shutdown and drained. The break resembled a classic overpressure break. Two other tubes showed reduction in wall thickness.	2×10^{-3}
9/3/79	NSIC152187	St. Lucie 1	***Loss of offsite power with the subsequent failure of an emergency diesel generator while plant is shutdown.*** While in cold shutdown during the passage of Hurricane David, a cable fell across the lines of startup transformer B, causing a lockout on the east bus and de-energization of the startup transformer. Emergency diesel generator B failed to start due to the binding of a relay in the diesel auto start circuitry. Analysis assumed 0.75 probability that event could have occurred at power.	3×10^{-3}
6/3/79	366-79-045	Hatch 2	***Reactor trip with subsequent failure of high-pressure coolant injection pump to start and reactor core isolation cooling unavailable.*** During a power increase, the reactor tripped because a condensate system trip. High-pressure coolant injection failed to initiate on low-low level due to a failed turbine stop valve. In addition, water from leaking mechanical seal lines and an unknown valve caused water to back up and contaminate the pump oil. Reactor core isolation cooling was out of service for unspecified reasons.	1×10^{-2}
5/2/79	219-79-014	Oyster Creek	***Reactor trip results in loss of feedwater with subsequent failure of isolation condenser.*** During testing of the isolation condenser, a reactor scram occurred. The feedwater pump tripped and failed to restart. The recirculation pump inlet valves were closed. The isolation condenser was used during cooldown.	3×10^{-2}

Date	LER	Plant	Brief Description	CCDP/ΔCDP
1/18/79	334-79-005	Beaver Valley 1	***Stuck open steam dump valves lead to reactor trip and safety injection.*** A load reduction was in progress due to a tripped heater drain pump, when the condenser steam dump valves opened causing high steam flow. The valves failed to close because the operators were subjected to excessively cold temperatures as a result of improperly positioned ventilation dampers. The open valves resulted in low steam line pressure and consequent reactor trip and safety injection initiation. Event was modeled as a main steam line break.	1×10^{-3}
11/27/78	272-78-073	Salem 1	***Loss of vital bus results in reactor trip and inadvertent safety injection with failure of emergency feedwater pump.*** While the reactor was at 100 percent power, vital instrument bus 1B was lost as a result of the failure of an output transformer and two regulating resistors. Loss of the vital bus caused a false low reactor coolant system loop flow signal, thereby causing a reactor trip. Two emergency feedwater pumps failed to start (one because of the loss of vital bus 1B, and the other because of a maladjustment of the over-speed trip mechanism). Inadvertent safety injection occurred as a result of decreasing average coolant temperature and safety injection signals.	5×10^{-3}
7/28/78	334-78-043	Beaver Valley 1	***Loss of offsite power and subsequent emergency diesel generator failure.*** An electrical fault occurred in the station main transformer resulting in generator, turbine, and reactor trip and safety injection. Approximately 4 minutes later a loss of offsite power occurred. Both emergency diesels generators started, but the emergency diesel generator 2 failed due to field flash failure.	6×10^{-3}
5/14/78	335-78-017	St. Lucie 1	***Loss of offsite power during refueling with an emergency diesel generator out for maintenance.*** Improper switching at a substation, in combination with incorrect wiring of protective relays, resulted in a loss of offsite power. One emergency diesel generator was out of service for maintenance. The other emergency diesel started and provided electrical power to its respective bus.	5×10^{-3}
4/23/78	320-78-033	TMI 2	***Reactor trip with subsequent stuck-open relief valves.*** Following a reactor trip from 30 percent power, the main steam relief valves did not reseat at the correct pressure. The relief valves eventually reseated in approximately 4 minutes. The reactor coolant system rapidly cooled down and depressurized, which cause a safety injection initiation. Pressurizer level was lost for approximately 1 minute.	6×10^{-3}
4/13/78	317-78-020	Calvert Cliffs 1	***Loss of offsite power while plant was shut down and failure of emergency diesel generator.*** With the plant shut down, a protective relay automatically opened the switchyard breakers, resulting in a loss of offsite power. Emergency diesel generator 11 failed to start. Emergency diesel generator 22 started and supplied the safety busses.	5×10^{-3}
3/25/78	348-78-021	Farley 1	***Reactor trip with all emergency feedwater pumps ineffective.*** A low-level condition in a single steam generator resulted in a reactor trip. The turbine-driven emergency feedwater pump failed to start. Both motor-driven emergency feedwater pumps started, but were deemed ineffective because all recirculation bypass valves were open (thereby diverting flow). A recirculation valve was manually closed.	1×10^{-2}

Date	LER	Plant	Brief Description	CCDP/ΔCDP
3/20/78	312-78-001	Rancho Seco	***Failure of non-nuclear instrumentation leads to reactor trip and steam generator dry out.*** When the reactor was at power, a failure of the non-nuclear instrumentation power supply resulted in a loss of main feedwater, which caused a reactor trip. Because instrumentation drift falsely indicated that the steam generator contained enough water, control room operators did not act promptly to open the emergency feedwater flow control valves to establish secondary heat removal. This resulted in steam generator dry out.	3×10^{-1}
12/11/77	346-77-110	Davis-Besse	***Both emergency feedwater pumps found inoperable during testing.*** During emergency feedwater pump testing, operators found that control over both pumps was lost because of mechanical binding in the governor of one pump and blown control power supply fuses for the speed changer motor on the other pump.	3×10^{-2}
11/29/77	346-77-098	Davis-Besse	***Reactor trip with subsequent momentary loss of offsite power with the failure of an emergency diesel generator.*** Power was lost to all four reactor coolant pumps following a temporary loss of 13.8 kV power caused by operators inadvertently opening the main generator breakers due to a procedural error shortly after a turbine trip. Electrical power was supplied from emergency diesel generator 2 in 7 seconds and normal offsite power was returned within 11 seconds on bus 'B' and 25 seconds on bus 'A'. During the temporary loss of offsite power, emergency diesel generator 1 started but failed to supply power to bus C1 due to the diesel tripping on over-speed.	1×10^{-3}
9/24/77	346-77-016	Davis-Besse	***Partial trip signal leads to stuck-open power-operated relief valve and subsequent reactor trip.*** A spurious half-trip of the steam and feedwater rupture control system initiated closure of the startup feedwater valve. This resulted in reduced water level in steam generator 2. The pressurizer power-operated relief valve lifted nine times and then stuck open because of rapid cycling.	1×10^{-3}
8/31/77	298-77-040	Cooper	***Blown fuse leads to partial loss of feedwater and subsequent reactor trip; reactor core isolation cooling and high-pressure coolant injection pump fail to reach rated speed.*** A blown fuse caused the normal power supply to the feedwater and reactor core isolation cooling controllers to fail. The alternate power supply was unavailable because of an unrelated fault. A partial loss of feedwater occurred, and the reactor tripped on low water level. Reactor core isolation cooling and high-pressure coolant injection operated, however, both pumps did not accelerate to full speed (reactor core isolation cooling because of the failed power supply and high-pressure coolant injection because of a failed governor actuator).	1×10^{-2}
7/15/77	324-77-054	Brunswick 2	***Reactor trip and subsequent stuck open safety relief valve.*** A turbine trip resulted in a reactor scram. High pressure coolant injection and reactor core isolation cooling initiated; however, the pumps tripped on high water level. Safety relief valves were opened three times to maintain reactor pressure below 1050 psig. One of the safety relief valves failed to close after opening for the third time. Reactor core isolation cooling was started and provided injection to the reactor; however, the pump's capacity was insufficient. Operators then started high-pressure coolant injection and reactor water level was restored.	2×10^{-3}
7/12/77	304-77-044	Zion 2	***Incorrect signals on reactor protection system leads to loss of accurate instrumentation and trip settings during testing.*** With the reactor in hot shutdown, testing caused operators to lose indications of reactor and secondary system parameters. In addition, inaccurate inputs were provided to control and protection systems.	1×10^{-3}

Date	LER	Plant	Brief Description	CCDP/ΔCDP
3/28/77	331-77-026	Duane Arnold	***Six main steam relief valves fail to lift properly during testing.*** During bench testing of six main steam relief valves failed to lift at the required pressure. Four valves failed to open and the remaining two lifted at elevated pressures.	2×10^{-3}
3/3/77	302-77-020	Crystal River	***Inverter failure leads to loss of vital bus and subsequent reactor trip and loss of condenser heat sink.*** An inverter output diode failed, resulting in loss of vital bus B and subsequent reactor trip, turbine trip, and 50% opening of the atmospheric dump valves. Emergency feedwater was used for decay heat removal.	1×10^{-3}
7/16/76	336-76-042	Millstone 2	***Loss of offsite power with failure of emergency diesel generator load shed signals.*** With the reactor at power, a main circulating water pump was started, which resulted in an in-plant voltage reduction to below the revised trip set point. This isolated the safety-related busses and started the emergency diesel generators. Each time a major load was tied onto the diesel, the revised under-voltage trip set points tripped the load. As a result, at the end of the emergency diesel generator loading sequence, all major loads were isolated, even though the emergency diesel generators were tied to the safety-related busses.	1×10^{-2}
11/5/75	305-75-020	Kewaunee	***Clogged suction strainers for emergency feedwater pumps.*** Mixed bed resin beads were leaking from the demineralizer in the makeup water system and migrated to the condensate storage tank. As a result, during startup, both motor-driven emergency feedwater pump suction strainers became clogged, thereby resulting in low pump flow. The same condition occurred for the turbine-driven emergency feedwater pump suction strainer.	3×10^{-2}

Date	LER	Plant	Brief Description	CCDP/ΔCDP
5/1/75	261-75-009	Robinson	***Reactor coolant pump seal failure leads to loss-of-coolant accident and subsequent reactor trip.*** The plant was at power and diluting for xenon control. The number 1 seal for reactor coolant pump (RCP) 'C' was exhibiting gradual flow variations associated with the reactor coolant system (RCS) inventory addition. The RCP 'C', number 1 seal leak-off spiked several times, oscillated full range several times, then stabilized with a seal flow greater than 6 gpm. Plant load was reduced and RCP 'C' was idled. A reactor trip occurred due to turbine trip on high steam generator level, resulting from the rapid load reduction and cooldown. The flow control valve in the combined return line from the three RCP thermal barrier cooling lines closed due to high flow caused by cooling water flashing in the thermal barrier for RCP 'C'. The flashing was caused by hot primary coolant flowing upward through the thermal barrier. Closure of the flow control valve resulted in loss of thermal barrier cooling in all three RCPs. RCPs 'A' and 'B' were manually tripped. The RCP C number 1 seal return flow isolation valve was closed to decrease pressure surges in the letdown line. Seal flow was lost on RCP 'A' and 'B'. Leakage through RCP 'C' No. 2 seal resulted in high reactor cooldown drain tank (RCDT) pressures. The RCDT was drained to the containment sump. The flow control valve in the combined return line from the three RCP thermal barriers was blocked open, restoring thermal barrier cooling on all three RCPs. RCP C was started with increased seal flow and RCS cooldown was started using the condenser via the steam dump valves. A high standpipe alarm was received for RCP ''C and the pump was stopped. Rapidly falling pressurizer level indicated failure of RCP 'C' number 2 and 3 seals. The safety injection pumps were started to make up for rapidly decreasing pressurizer level. Pressurizer level was stabilized and operators reduced safety injection. Auxiliary pressurizer spray was used to reduce plant pressure to the operating pressure of the residual heat removal (RHR) system. During this pressure reduction, the accumulators partially discharged into the RCS before their isolation valves were closed. Cooldown via the RHR system was used to achieve cold shutdown conditions.	3×10^{-3}
4/29/75	324-75-013	Brunswick 2	***Multiple valve failures including stuck-open relief valve with reactor core isolation cooling inoperable.*** At 10-percent power, the reactor core isolation cooling system was determined to be inoperable, and safety relief valve 'B 'was stuck open. The operator failed to scram the reactor according to the emergency operating procedures. The high-pressure coolant injection system failed to run and was manually shut down as a result of high torus level. Loop B of residual heat removal failed as a result of a failed service water supply valve to the heat exchanger. The reactor experienced an automatic scram on manual closure of the main steam isolation valve.	3×10^{-3}
3/22/75	259-75-006	Browns Ferry 1	***Cable tray fire caused extensive damage and loss of electrical power to safety systems.*** The fire was started by an engineer, who was using a candle to check for air leaks through a firewall penetration seal to the reactor building. The fire resulted in significant damage to cables related to the control of Units 1 and 2. All Unit 1 emergency core cooling system were lost, as was the capability to monitor core power. Unit 1 was manually shut down and cooled using remote manual relief valve operation, the condensate booster pump, and control rod drive system pumps. Unit 2 was shut down and cooled for the first hour by the reactor core isolation cooling system. After depressurization, Unit 2 was placed in the residual heat removal shutdown cooling mode with makeup water available from the condensate booster pump and control rod drive system pump.	4×10^{-1}

Date	LER	Plant	Brief Description	CCDP/ΔCDP
5/8/74	250-74-LTR	Turkey Point 3	***Failure of three emergency feedwater pumps to start during test.*** Operators attempted to start all three emergency feedwater pumps while the reactor was at power for testing. Two of the pumps failed to start as a result of over-tightened packing. The third pump failed to start because of a malfunction in the turbine regulating valve pneumatic controller.	3×10^{-2}
4/7/74	266-74-LTR	Point Beach 1	***Clogged suction strainers for emergency feedwater pumps.*** While the reactor was in cooldown mode, motor-driven emergency feedwater pump 'A' did not provide adequate flow. The operators were unaware that the in-line suction strainers were 95 percent plugged (both motor-driven pumps 'A' and 'B'). A partially plugged strainer was found in each of the suction lines for both turbine-driven emergency feedwater pumps.	3×10^{-2}
1/19/74	213-74-003	Haddam Neck	***Loss of offsite power due to ice storm with failure of emergency diesel generator service water pump to start.*** A total loss of offsite power occurred during an ice storm due to a momentary fault in one line and a subsequent inadvertent trip on the other due to improper blocking relay placement. Both emergency diesel generators started, but one emergency diesel generator service water pump had to be manually started due to a malfunction in the time delay under-voltage relay in the pump motor start circuit.	1×10^{-2}
11/19/73	259-73-LTR-1	Browns Ferry 1	***Turbine trip leads to loss of offsite power during testing.*** In preparation for the turbine trip and loss of offsite power testing, the 4 kV unit boards were plated in manual to prevent automatic transfer. The turbine was manually tripped due to vibration. This resulted in a scram since offsite power could no longer be supplied. The reactor core isolation cooling and high-pressure coolant injection systems could not be started until the standby diesels were energized because there reset logic required AC power.	3×10^{-3}
11/19/73	259-73-LTR-2	Browns Ferry 1	***Reactor core isolation cooling and high-pressure coolant injection fail during startup.*** During startup testing the reactor core isolation cooling system failed to operate due to the failure of the steam supply valve to open. High-pressure coolant injection was manually initiated to maintain vessel water level; however, the pump tripped. The operator reset the isolation circuit and successfully reinitiated high-pressure coolant injection, which successfully maintained reactor water level.	3×10^{-3}
10/21/73	244-73-010	Ginna	***Loss of offsite power, excessive reactor coolant system cooldown, and failure of a vital instrument bus.*** With 1 of 4 transmission circuits out of service due to construction, a second line was lost due to a ground fault. Power fluctuations resulted in the remaining two 115 kV transmission lines to trip, causing a total loss of offsite power and a turbine trip. An electrical disturbance on an instrument bus causes a reactor trip on a false overpower/high ΔT signal. The emergency diesel generators successfully started and supplied electrical power to the vital buses. The auxiliary feedwater (AFW) pumps started on low steam generator level. The operator secured the AFW pumps due to increasing water level and decreasing reactor coolant system temperature; however, safety injection was automatically initiated due to low pressurizer pressure caused by the excessive cooldown. Vital bus 1A momentarily failed and caused the boric acid storage tank level transmitters powered from this bus to fail.	2×10^{-3}

Date	LER	Plant	Brief Description	CCDP/ΔCDP
6/18/73	251-73-007	Turkey Point 4	***Reactor trip and subsequent failure of auxiliary feedwater pumps to start automatically.*** During startup and low power physics testing, the turbine generator control valves opened rapidly. As a result of high steam flow and reduced reactor coolant system temperature, safety injection was actuated. All three auxiliary feed pumps failed to start due to failure to install 125 V DC power supply fuses in the AFW pump auto-start logic circuits. Operators manually started the auxiliary feedwater pumps.	1×10^{-3}
10/10/71	245-71-099	Millstone 1	***Reactor trip with a stuck open relief valve and failure of turbine bypass valve to close.*** A malfunction in the turbine pressure control system caused a pressure transient which resulted in a reactor trip on high neutron flux. The turbine was manually tripped, which caused the turbine bypass valve to open (as expected). A bypass valve failed to close so the operator manually closed the main steam isolation valves. The blowdown continued through an open relief valve until the reactor pressure reached 263 psig when it reseated. The operator initiated the isolation condenser and proceeded with a controlled cooldown. A total of 75,000 gallons of water was lifted from the torus.	2×10^{-3}
9/2/71	255-71-LTR-1	Palisades	***Loss of offsite power and emergency diesel generator output breaker failed to close automatically.*** A loss of offsite power due to the trip of one line and inadvertent tripping of two breakers caused by a faulty breaker failure relay. Both diesel generators started; however, the output breaker for emergency diesel generator 1-2 failed to close automatically. Operators manually closed the breaker.	6×10^{-3}
3/24/71	409-71-LTR-2	La Crosse	***Loss of offsite power due to switchyard fire.*** Failure of a potential transformer in the switchyard caused a fire, loss of power to the reactor, a load rejection, and a scram. The shutdown condenser and core spray were used for reactor temperature and pressure control. Offsite power was restored in 61 minutes.	2×10^{-2}
3/8/71	261-71-057	Robinson	***Failure of both emergency diesel generators during testing.*** Both diesel generators failed to run after new low oil pressure switches were remounted on a wall 15 feet from the diesels. The failures to run were determined to be caused by low lube oil pressure at the pressure switches caused by trapped air and high viscosity cold lube oil.	1×10^{-3}
2/5/71	266-71-053	Point Beach 1	***Loss of offsite power while plant in hot standby due to ice storm.*** With the reactor in hot standby during an ice storm, breakers on all three high lines opened resulting in a loss of offsite power and subsequent reactor trip. Both emergency diesel generators started and supplied safety-related loads. Due to the continuing storm conditions, the reactor coolant system was borated to the cold shutdown level and cooled down to 300°F.	2×10^{-3}
1/12/71	266-71-LTR-1	Point Beach 1	***Failure of containment sump isolation valves.*** During a routine check of the containment tendon access gallery, air was observed leaking from the packing of one sump isolation valve. Operators attempted to open the valve, but the valve failed to open because of a shorted solenoid in the hydraulic positioner. The redundant sump isolation valve was also found inoperable because of a stuck solenoid in the hydraulic positioner.	2×10^{-3}

Date	LER	Plant	Brief Description	CCDP/ΔCDP
7/17/70	133-70-LTR	Humboldt Bay	***Loss of offsite power with subsequent failure of isolation condenser valve.*** A switching error at the Humboldt substation caused protective relaying which resulted in a generator and turbine trip, loss of the 60 kV bus, and consequent loss of offsite power. The loss of offsite power resulting in an automatic reactor scram, loss of feedwater flow, loss of drywell cooling, and loss of control room indication of reactor vessel pressure and level. The emergency propane generator started and assumed safety-related loads. A control rod drive pump was started to provide reactor inventory makeup. The emergency condenser return valve failed closed due to an incorrectly adjusted torque switch. Reactor vessel level decreased to the low water level set point (due to the opening of a safety valve) and resulted in the actuation of the reactor vent system. The low pressure core flood and core spray systems subsequently automatically initiated and were used for core cooling until normal power was restored.	$9{\times}10^{-3}$
7/15/69	213-69-LTR	Haddam Neck	***Loss of offsite power.*** One of the two 115 kV offsite power lines was removed from service. When the dispatcher opened other terminals on the Montville line, trip signals were generated which caused the two station service transformer low side breakers to open, resulting in a loss of offsite power. All three emergency diesel generators started and assumed safety related loads. A charging pump tripped during the starting sequence and one reactor coolant pump seal failed with excessive leakage, requiring 15 gpm of seal injection.	$2{\times}10^{-3}$

Appendix C: Program Results Comparison

The Accident Sequence Precursor (ASP) Program is one of three agency programs that assess the risk significance of events at operating nuclear power plants (NPPs). The other two programs are the Significance Determination Process (SDP) and Management Directive (MD) 8.3. To prevent duplicative analyses by the programs (see program similarities described in Section 3 of the main report), beginning in 2006, SDP results have been used in lieu of independent ASP analyses in specific instances where the SDP evaluations considered all concurrent degraded conditions or equipment unavailabilities that existed during the time period of the condition (see Regulatory Issue Summary 2006-24 for additional information).

The SDP evaluates the risk significance of a single licensee performance deficiency, while the risk assessments performed under MD 8.3 are used to determine, in part, the appropriate level of reactive inspection in response to an event.[21] Analyses as part of the ASP Program include all concurrent degraded/unavailable structures, systems, and components (SSCs); human errors; and the occurrence of an initiating event, regardless of the cause. SDP evaluations and ASP analyses have the benefit of information obtained from the completion of inspection activities, whereas MD 8.3 assessments are typically performed within a day or two after the event notification. Analysis modeling assumptions for ASP and SDP evaluations are typically the same when the event is driven by a single performance deficiency. For initiating events, many of the modeling assumptions made for MD 8.3 analyses can be adopted by ASP analyses. However, some modeling assumptions are revised as detailed information about the event becomes available. Given these differences, it is expected that the programs will sometimes have different results.

Table C-1 provides a brief comparison of the MD 8.3, SDP, and ASP results for precursors that have been identified via an independent ASP analysis since 2010. Section 10 of the main report provides the comparison for 2017 precursors identified by an independent ASP analysis.

[21] The ROP integrates all individual inspection findings and performance indicators within the action matrix for each NPP unit.

Table C-1. NRC Program Results Comparison (2010–2016).

Event Description	MD 8.3 Results	SDP Results	ASP Results	SPAR Model/Methodology Improvements and Insights
Catawba; 413-16-001; 3/28/16. Mispositioned breaker with concurrent emergency diesel generator (EDG) unavailability results in potential loss of recirculation capability.	No MD 8.3 evaluation was performed.	A *Green* finding was identified due to the licensee failure to adequately implement procedures for operation of the residual heat removal (RHR) system. The SDP evaluation determined that there was no loss of safety function of emergency core cooling systems (ECCS) train ‘B’. The licensee event report (LER) was closed in inspection report (IR) 05000413/2016002 (ML16202A116).	ΔCDP = 1×10^{-6}; concurrent unavailabilities of RHR train ‘B’ valve (mispositioned breaker) for 104 days. EDG ‘A’ was concurrently unavailable due to maintenance for 51 hours. See final ASP analysis (ML17038A307) for additional information.	Analysis-specific breaker interlock modeling for RHR valve created.
Brunswick; 325/16-001; 2/7/16. Electrical bus fault results in lockout of startup auxiliary transformer and loss of offsite power.	No deterministic criteria were met; therefore, a formal risk evaluation was not required.	A *Green* finding was identified due to the licensee’s failure to have adequate procedures to perform maintenance on the station auxiliary transformer (SAT) and associated cables. The LER was closed in IR 05000325/2016008 (ML16195A012).	CCDP = 3×10^{-5}; single-unit, plant-centered loss of offsite power (LOOP) with failed SAT. Offsite power could not be restored prior to depletion of safety-related batteries (3 hours) during a postulated station blackout (SBO). See final ASP analysis (ML17109A269) for additional information.	None.
Hatch 2; 366-16-003; 8/18/16. EDG 2C fails during surveillance test.	No MD 8.3 evaluation was performed.	No performance deficiency has been identified for this event; therefore, no SDP evaluation has been performed.	ΔCDP = 1×10^{-5}; unavailability of EDG 2C for 220 days. Concurrent unavailability of EDG 1B (swing EDG) due to maintenance. See final ASP analysis (ML17102A999) for additional information.	Analysis-specific inhibit logic for swing EDG created. Explored crediting run time of failed EDG via a sensitivity analysis. Will continue to examine this modeling issue, including consideration of revisions to RASP handbook guidance.

Event Description	MD 8.3 Results	SDP Results	ASP Results	SPAR Model/Methodology Improvements and Insights
Wolf Creek; 482/16-001; 10/6/14. Power potential transformer overloading results in emergency diesel generator inoperability.	No MD 8.3 evaluation was performed.	A *Green* finding was identified due to new testing results that showed that over half of the excitation system diodes that were originally installed in the EDGs had manufacturing defects. The LER was closed in IR 05000482/2016004 (ML16195A012).	ΔCDP **=** 1×10^{-5}; unavailability of EDG 'B' for 123 days. Concurrent unavailability of EDG A due to maintenance. See final ASP analysis (ML17108A730) for additional information.	Similar analysis to Hatch 2 precursor.
Waterford; 382-15-007; 8/26/15. Both EDGs declared inoperable.	ICDP = 7×10^{-7}, baseline inspection performed. Different modeling assumptions (when compared to the ASP analysis) led to lower result.	No findings were identified; LER was closed in IR 50000382/2016002 (ML16218A383).	ΔCDP **=** 6×10^{-6}; concurrent degradations of both EDGs over a 33-day period. Credit for manually opening of the EDG 'B' damper is provided for an applicable portion of the exposure period. Temporary diesel generators failed due to coolant leak. See final ASP analysis (ML16308A447) for additional information.	Tested methodology for crediting additional time for offsite power recovery given observed failure-to-run. Identified issue related to convolution factors and duplicate cut sets.
Waterford; 382-15-004 and -005; 6/3/15. Manual reactor trip due to low steam generator levels, emergency feedwater (EFW) system flow oscillations, and failure of bus fast transfer.	CCDP = 1×10^{-6}, baseline inspection performed. Slightly different modeling assumptions (when compared to the ASP analysis) led to lower result.	An inspection revealed two *Green* findings (i.e., very low safety significance) related to this event. The first *Green* finding occurred because the licensee did not follow procedural guidance when changing materials used for feed heater drain level control valves. The second *Green* finding occurred because the licensee failed to verify the adequacy of the EFW system design. Additional information is provided in IRs 05000382/2015003 (ML15316A476) and 0500382/2016001 (ML16116A210).	CCDP = 4×10^{-6}; non-recoverable loss of condenser heat sink with failure of automatic transfer of electrical loads to the startup transformer. See final ASP analysis (ML16306A336) for additional information.	Base SPAR model contains logic for failure of fast transfer of electrical loads after a reactor trip; therefore, no model modifications for this analysis were required. This modeling is not typically included in most SPAR models.

Event Description	MD 8.3 Results	SDP Results	ASP Results	SPAR Model/Methodology Improvements and Insights
Pilgrim; 293-15-001; 1/27/15. Loss of offsite power due to Winter Storm Juno.	CCDP = 7×10^{-5}, which led to a special inspection. See IR 05000293/2015007 (ML15147A412) for additional information.	A *White* finding (using Appendix M; finalized on 9/1/2015) was identified due to the licensee failing to identify, evaluate, and correct the failure of a safety relief valve (SRV) to open upon manual actuation during a plant cool down on February 9, 2013, following a previous loss of offsite power event. This failure to perform the proper corrective actions resulted in another SRV failing to open due to a similar cause during this winter storm. In addition, five *Green* findings were identified. See IR 05000293/2015007 (ML15147A412) and 05000293/2015011 (ML15230A217) for additional information.	CCDP = 4×10^{-5}; loss of offsite power event resulted in reactor trip. The 23 kilovolt (kV) power source (via the shutdown transformer) was available if the EDGs would have failed. Increased probability of SRVs failing to reclose was accounted for; however, the ability of the SRVs to open at low pressures was not evaluated (i.e., the SRVs are only needed for reactor depressurization during a LOOP). See the final ASP analysis (ML16153A372) for additional information.	Additional model changes to the LOOP/SBO event trees were made (beyond those completed as part of previous Pilgrim ASP analyses) and a revision of a post-processing rule that was inappropriately applying offsite power recovery to breaker failures (i.e., failures that would preclude recovery).
D.C. Cook 1; 315-14-003; 11/1/14. Turbine-driven auxiliary feedwater (AFW) pump failed to run following a loss of main condenser event due to a storm-induced debris damage of the circulating water system pumps.	No deterministic criteria were met; therefore, a formal risk evaluation was not required.	No findings were identified; LER was closed in IR 50000315/2016001 (ML15132A744).	CCDP = 5×10^{-6}; non-recoverable loss of condenser heat sink with subsequent failure of turbine-driven AFW pump. During a severe storm, debris led to fouling of the circulating water traveling water screens resulting in a loss of condenser heat sink. See the final ASP analysis (ML16165A510) for additional information.	None.

Event Description	MD 8.3 Results	SDP Results	ASP Results	SPAR Model/Methodology Improvements and Insights
Farley 2; 364-14-002; 10/14/14. Manual reactor trip due to loss of a startup transformer.	CCDP = 6×10^{-6}, baseline inspection performed. Slightly different modeling assumptions yielded similar result to the ASP analysis.	A *Green* finding was identified with the licensee failed to adequately assess and manage the increase in risk while component cooling water (CCW) train ‘B’ was in service and supplying the miscellaneous header and cooling to the reactor coolant pumps (RCPs). The ΔCDF was determined to be < 1×10^{-6} per year. LER is closed; see IR 50000364/2014005 (ML15040A564) for additional information.	CCDP = 6×10^{-6}, lightning strike causes a loss of startup auxiliary transformer and subsequent reactor trip. EDG ‘B’ was undergoing maintenance at the time of the event. Operators tripped RCPs due to loss of on-service component cooling water pumps. Operator manually started and aligned SBO diesel generator. See the final ASP analysis (ML16103A572) for additional information.	None.
Millstone 2 and 3; 336-14-006; 5/25/14. Dual unit loss of offsite power.	CCDP = 4×10^{-6} (Unit 2) and 1×10^{-5} (Unit 3), special inspection initiated. Some bounding assumptions used for Unit 3 analysis; Unit 3 given preference for SBO diesel generator. See IR 05000336/2014011 (ML14240A006) for additional information.	Two *Green* findings and a *Severity Level 3* finding were identified. See IR 05000336/2014011 (ML14240A006) for additional information.	CCDP = 1×10^{-5} and 2×10^{-5}, for Units 2 and 3, respectively. Grid-related, dual unit loss of offsite power. Offsite power was recovered in approximately 3 hours. See the final ASP analysis (ML15149A510) for additional information.	To adjust the potential for each unit needing the SBO diesel generator, the combined failure probability of each unit’s dedicated EDGs was calculated for a 3-hour mission time.
Calvert Cliffs 2, 318-14-001; 1/21/14. Reactor trip due to inadequate protection against weather-related water intrusion.	CCDP determined to be in the low 10^{-6} range; special inspection initiated. See IR 05000317/2014008 (ML14072A474) for additional information.	No findings associated with this event were identified.	CCDP = 5×10^{-6}. Loss of 13 kV AC bus 21 initiating event was modeled. See the final ASP analysis (ML15238B710) for additional information.	Unnecessary logic in the once-through cooling fault tree was identified and corrected.
Shearon Harris; 400-14-001; 1/18/14. Manual reactor trip due to indications of a fire.	CCDP = 5×10^{-6}; baseline inspection performed. Transient initiating event modeled with 6.9 kV bus 1D failed.	*Green* finding associated with the licensee failure to perform adequate corrective action to prevent reoccurrence from similar event that occurred in 2013. No risk evaluation was performed (screened in Phase 1). See IR 05000400/2014002 (ML14118A441) for additional information.	CCDP = 6×10^{-6}. Loss of MFW transient with failures of 6.9 kV auxiliary bus 1D and transformer 1D2. See the final ASP analysis (ML15238B708) for additional information.	None.

Event Description	MD 8.3 Results	SDP Results	ASP Results	SPAR Model/Methodology Improvements and Insights
ANO 2; 368-13-004; 12/9/13. Fire and explosion of the unit auxiliary transformer.	No deterministic criteria were met; therefore, a formal risk evaluation was not required.	Two Green findings were identified. Both finding were associated for licensee failures to install components associated with the unit auxiliary transformer. No risk evaluation was performed for these two findings (both screened in Phase 1). See IR 05000313/2014002 (ML14132A255) for additional information.	CCDP = 2×10^{-6}. Loss of MFW with partial LOOP to bus 4.16 kV 2A2 was modeled. See the final ASP analysis (ML15238B714) for additional information.	The consequential LOOP fault tree was modified to require the loss of offsite power to both safety-related buses. In addition, SBO diesel generator logic was modified to require a LOOP to occur before competing effects for the SBO diesel generator are queried.
Pilgrim; 293-13-009; 10/14/13. Loss of offsite power during line maintenance.	No deterministic criteria were met; therefore, a formal risk evaluation was not required.	No inspection findings associated with this event. See IR 05000293/2013005 (ML14041A203) for additional information.	CCDP = 3×10^{-5}; loss of offsite power event resulted in reactor trip. The 23 kV power source (via the shutdown transformer) was available if the EDGs would have failed. See the final ASP analysis (ML14294A591) for additional information.	None.
LaSalle 1 and 2; 373-13-009; 4/17/13. Loss of offsite power due to lightning strike.	CCDP = 6×10^{-5} and 1×10^{-4}, for Units 1 and 2, respectively. Special inspection was performed. Modeled as a dual-unit loss of offsite power event with a failure to run of RHR pump 2C and a failure of the Unit 1 low-pressure core spray (LPCS) injection valve to open. See IR 05000373/2013009 (ML13199A512) for additional information.	*Severity Level 3 and 4* findings. The ΔCDF associated with the LPCS inoperability was determined to be < 1×10^{-7} per year. Enforcement discretion used for finding not associated with performance deficiency. See IRs 05000373/2013009 (ML13199A512) and 05000373/2015010 (ML15308A566) for additional information.	CCDP = 1×10^{-5} and 2×10^{-5}, for Units 1 and 2, respectively. Dual-unit LOOP with offsite power not recoverable within 2 hours. RHR pump failed to start due load sequencer failure. Increased probability of stuck-open SRVs. See the final ASP analysis (ML15071A343) for additional information.	Modified swing EDG logic to allow it to supply both units unless a loss-of-coolant accident (LOCA) occurs. Inserted RHR pump ‘C’ basic event for failed sequencer dependency.

Event Description	MD 8.3 Results	SDP Results	ASP Results	SPAR Model/Methodology Improvements and Insights
Pilgrim; 293-13-002; 2/8/13. Loss of offsite power events due to Winter Storm Nemo.	No MD 8.3 evaluation was performed because it was determined that a LOOP (by itself) does not meet the deterministic criteria for a loss of safety function.	No inspection findings associated with this event. See IR 05000293/2013002 (ML13129A212) for additional information.	CCDP = $8{\times}10^{-5}$; non-recoverable LOOP results in reactor trip. Result greatly affected by change in battery depletion time (switchyard batteries determined to be more limiting). See the final ASP analysis (ML14273A261) for additional information.	Extensive SPAR model modifications included LOOP/SBO event tree changes and revised battery depletion timings. Additional information on changes is found in the final ASP analysis (ML14273A261).
Oyster Creek; 219-12-001; 7/23/12. Fault on 230 kV transmission line leads to loss of offsite power and subsequent reactor trip.	No deterministic criteria were met; therefore, a formal risk evaluation was not required.	No inspection findings associated with this event. See IR 05000219/2013003 (ML13219B131) for additional information.	CCDP = $6{\times}10^{-5}$. Grid-related LOOP initiating event modeled. Potential for offsite power recovery was available within 30 minutes. See the final ASP analysis (ML13199A503) for additional information.	Modified human failure dependency post-processing rules to make more consistent with other boiling-water reactors (BWRs).
River Bend; 458-12-003; 5/24/12. Loss of normal service water, circulating water, and feedwater due to electrical fault.	CCDP = $1{\times}10^{-4}$, augmented inspection performed. Revised analysis resulted in CCDP = $6{\times}10^{-5}$. See IR 05000458/2012009 (ML12221A233) for additional information.	Eight *Green* findings. See IR 05000458/2012010 (ML12328A178) for additional information.	CCDP = $2{\times}10^{-4}$. Loss of normal service water initiating modeled along with loss of power to all service water pumps. Operator require to restart RCIC due high reactor water level trip. See the final ASP analysis (ML13322A833) for additional information.	Analysis-specific fault tree modification needed.
Browns Ferry 3; 296-12-003; 5/22/12. Reactor trip and subsequent loss of offsite power due failure of unit station system transformer differential relay.		*Green* finding was identified with the licensee failure to adequately review a vendor design calculation that resulted in an erroneous transformer phase shift of the differential current protection relay. No risk evaluation was performed for this finding (screened in Phase 1). See IR 05000296/2012004 (ML12319A182) for additional information.	CCDP = $2{\times}10^{-5}$. Plant-centered LOOP initiating event modeled. HPCI pump unavailable due to maintenance, but recoverable within 15 minutes. Offsite power from alternate source throughout the event. See the final ASP analysis (ML13115A955) for additional information.	Analysis-specific fault tree modification needed.

Event Description	MD 8.3 Results	SDP Results	ASP Results	SPAR Model/Methodology Improvements and Insights
Catawba 1; 413-12-001; 4/4/12. Reactor trip due to faulted reactor coolant pump cable and an error in protective relay actuation causes a subsequent loss of offsite power.	CCDP = 1×10^{-4}, special inspection performed. See IR 05000458/2012009 (ML12221A233) for additional information.	*White* finding was identified with the licensee failure to restore a qualified offsite power circuit within 72 hours while in Mode 1. An additional *Green* finding was identified. See IR 05000413/2012010 (ML12285A100) for additional information.	CCDP = 9×10^{-6}. LOOP initiating event modeled. Offsite power from Unit 2 crosstie was available within 1 hour. See the final ASP analysis (ML13060A208) for additional information.	None.
Byron 2; 455-12-001; 1/30/12. Transformer and breaker failures cause loss of offsite power, reactor trip, and de-energized safety buses.	Initial CCDP = 7×10^{-6}, which led to a special inspection. Non-recoverable LOOP modeled; EDG failure to load was not considered (zero test/ maintenance modeling used). A revised evaluation calculated a CCDP = 4×10^{-5}.	Initially, a potential performance deficiency was evaluated as *White*; however, it was determined later that no performance deficiency existed (the lack of loss-of-phase protection was considered outside the licensing basis). No findings were identified with this event; see IR 05000455/2012008 (ML12087A213) for additional information.	CCDP = 1×10^{-4}; non-recoverable LOOP results in reactor trip. In addition, if operators fail to isolate fault (by open transformer feeder breakers) EDG would not be able to load to safety buses (causing an SBO like condition). Final CCDP was strongly dependent on human error probability (HEP). See the final ASP analysis (ML13182A031) for additional information.	SPAR model changes were limited to analysis-specific modifications.
Wolf Creek; 482-12-001; 1/13/12. Multiple switchyard faults cause reactor trip and subsequent loss of offsite power.	CCDP = 8×10^{-5}, augmented inspection performed. Switchyard-centered LOOP with recovery of offsite power not possible prior to 3 hours. In addition, the diesel-powered fire water system was modeled as failed. See IR 05000482/2012008 (ML12095A414) for additional information.	*Yellow* finding was identified with the licensee failure to implement maintenance of safety-related equipment in accordance with written procedures. An additional three *Green* findings were identified. See IR 05000482/2012009 (ML12227A919) for additional information.	CCDP = 5×10^{-4}. Switchyard-centered LOOP initiating event modeled with startup transformer failed. Offsite power was recoverable after 1 hour. Increased probability of stuck-open power-operated relief valves. Diesel-driven firewater pump assumed to unavailable. See the final ASP analysis (ML13115A190) for additional information.	None.

Event Description	MD 8.3 Results	SDP Results	ASP Results	SPAR Model/Methodology Improvements and Insights
North Anna 1 and 2; 8/23/11; 338-11-003. Dual unit loss of offsite power caused by earthquake that coincided with the Unit 1 turbine-driven auxiliary feedwater pump being out-of-service because of testing and the subsequent failure of a Unit 2 emergency diesel generator.	CCDP = 1×10^{-4}, augmented inspection performed. Switchyard-centered LOOP with failure to run for EDG 2H. In addition, the turbine-driven AFW was considered unavailable for maintenance; all other maintenance was set to zero. See IR 05000338/2011011 (ML113040031) for additional information.	*White* finding was identified with the licensee failure to establish and maintain emergency diesel generator maintenance procedures as recommended by Regulatory Guide 1.33. See IR 05000338/2012010 (ML12136A115) for additional information.	CCDP = 3×10^{-4} and 6×10^{-5}, for Units 1 and 2, respectively. Switchyard-centered, dual-unit LOOP with recovery of offsite power not possible prior to 3 hours. Unit 1 turbine-driven AFW pump unavailable due to maintenance, but recoverable. EDG 2H failed to run. See the final ASP analysis (ML12278A188) for additional information.	Performed sensitivity analyses for postulated seismic failures of key safety-related equipment.
Browns Ferry 1, 2, and 3; 259-11-001; 4/27/11. Extended loss of offsite power because of a tornado and a subsequent loss of shutdown cooling occurred because of an emergency diesel generator failure while the plant was in cold shutdown.		Three *Green* findings were identified. See IRs 05000259/2011003 (ML112210368) and 05000259/2011004 (ML113180503) for additional information.	CCDP = 1×10^{-5} (all units). Site-wide, weather-related LOOP initiating event modeled. EDG 3B was unavailable due to maintenance. Offsite power from the 161 kV source was available throughout the event. See the final ASP analysis (ML12180A062) for additional information.	None.
Surry 1 and 2; 280-11-001; 4/16/11. Dual unit loss of offsite power because of switchyard damage caused by a tornado.		No inspection findings associated with this event. See IR 05000280/2011003 (ML112092845) for additional information.	CCDP = 9×10^{-5} and 7×10^{-5}, for Units 1 and 2, respectively. LOOP initiating event with offsite power not recoverable before 5 hours and 30 minutes. See the final ASP analysis (ML121210463) for additional information.	None.
Robinson; 261-10-007; 9/9/10. Reactor trip with a loss of main feedwater and pressurizer power-operated relief valve opening on demand.		No inspection findings associated with this event. See IR 05000261/2010005 (ML110280299) for additional information.	CCDP = 3×10^{-6}. Loss of main feedwater transient with pressurizer power-operated relief valve opening (successfully reclosed). See the final ASP analysis (ML112560288) for additional information.	None.

Event Description	MD 8.3 Results	SDP Results	ASP Results	SPAR Model/Methodology Improvements and Insights
Susquehanna 1; 387-10-003; 7/16/10. Manual reactor scram due to leakage from the circulating water system and subsequent flooding of the condenser bay.	No deterministic criteria were met; therefore, a formal risk evaluation was not required. However, a risk assessment for a loss of condenser heat sink initiating event was performed, resulting in a CCDP of 2×10^{-6}.	*White* finding was identified with the licensee failure to provide adequate procedures that complicated plant response during the event. In addition, two *Green* finding were identified. See IRs 05000387/2010004 (ML103160334) 05000387/2010008 (ML12125A374) and for additional information.	CCDP = 4×10^{-6}. Loss of condenser heat sink initiating event with high reactor water level trip of high-pressure coolant injection (HPCI) and reactor core isolation cooling (recoverable). See the final ASP analysis (ML112411361) for additional information.	None.
Robinson; 261-10-002; 3/28/10. Electrical fault causes fire and subsequent reactor trip with losses of main feedwater and RCP seal injection/cooling.	CCDP = 4×10^{-5}, which led to an augmented inspection. Initial evaluation recommended a special inspection because it did not consider the loss of RCP seal injection/cooling (information was not known at the time of the initial assessment. See IR 05000261/2010009 (ML101830101) for additional information.	Two *White* findings were identified and were based on an assessment of licensee performance deficiencies involving inadequate training and procedures. In addition, five *Green* findings were identified. See IRs 05000261/2010013 (ML103620095), 05000261/2010004 (ML103160382), and 05000261/2011008 (ML110310469) for additional information.	CCDP = 4×10^{-4}; non-recoverable loss of MFW was modeled with RCP seal injection diverted away from RCP seals (unknown to operators) and CCW isolated via return isolation valve (recovered by operators). See the final ASP analysis (ML112411359) for additional information.	Improved state of knowledge on RCP seal LOCA size variability and small LOCA mitigation credit.
Robinson; 261-10-001; 2/22/10. Emergency diesel generator inoperable due to failed output breaker while another emergency diesel generator was unavailable due to testing and maintenance.	CCDP = 3×10^{-6}; baseline inspection performed.	Violation identified with failed EDG because it was unavailable for greater than technical specifications allowed (7 days); enforcement discretion used (failure beyond licensee control). See IR 05000261/2010005 (ML110280299) for additional information.	CCDP = 3×10^{-6}; analysis considered two exposure periods: (1) EDG 'B' unavailable for 641 hours and (2) both EDGs unavailable for 7 hours; results dominated by the first exposure period. See the final ASP analysis (ML110280299) for additional information.	None.

Event Description	MD 8.3 Results	SDP Results	ASP Results	SPAR Model/Methodology Improvements and Insights
Calvert Cliffs 2; 318-10-01; 2/18/10. Failure of emergency diesel generator to start during partial loss of offsite power due to faulty relay.	CCDP = low 10^{-6} (Unit 1) and low 10^{-5} (Unit 2), special inspection performed. See IR 05000317/2010006 (ML101650723) for additional information.	A White finding was identified for the licensee failure to establish, implement, and maintain preventive maintenance requirements associated with safety-related relays. In addition, four Green findings were identified. See IR 05000317/2010006 (ML101650723) for additional information	CCDP = 2×10^{-5}. Partial LOOP results in loss of condenser heat sink. In addition, EDG 2B failed. Offsite power to bus 24 was credited. See the final ASP analysis (ML112560283) for additional information.	Analysis-specific model changes to account the lack of time for offsite power recovery during postulated loss of RCP seal cooling/injection.

Appendix D: ASP Program Frequently Asked Questions

1. What is an accident sequence precursor (ASP)?

- An accident sequence precursor is an observed event and/or condition at a plant which, when combined with one or more postulated events (e.g., equipment failures, human errors), could result in core damage.

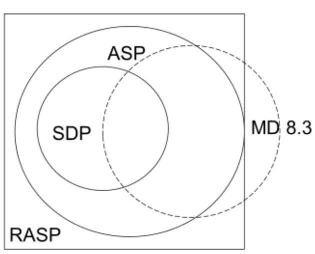
2. What is an ASP analysis?

- An ASP analysis is a plant-specific risk analysis performed to determine the conditional likelihood of a core damage accident given an initiating event and/or plant equipment failures or unavailability.
- Concurrent events and/or failed conditions are set to "TRUE" in the risk model.
- Potential for common cause failure (CCF) is set higher than the baseline for known performance deficiencies.
- Observed successes are generally set at their nominal frequency or failure probability.
  - Includes successful tests and operations, and passed inspections.
  - In other words, "luck" is treated probabilistically, not with absolute certainty.
- This analysis concept is known as the "failure memory" approach.

3. What are the ASP thresholds of merit?

- Precursors: conditional core damage probability (CCDP)/increase in core damage probability (ΔCDP) greater than or equal to 10^{-6}
  - For initiating events, a plant-specific CCDP for the non-recoverable loss of feedwater and condenser heat sink, with no degradation of safety related equipment, is used as the precursor threshold if greater than 10^{-6}.
- Significant Precursors: CCDP/ΔCDP greater than or equal to 10^{-3}.
- Thresholds are consistent with the ASP limits of resolution and NRC Safety Goal Policy.

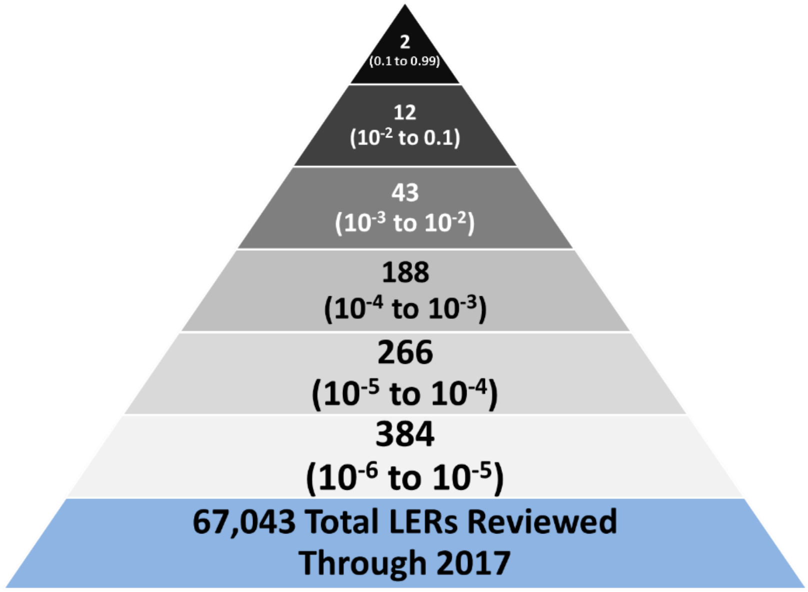
4. What are the overlaps with other regulatory programs?[22]



ASP encompasses a wider range of operating events. Significance Determination Process (SDP) results are used in the ASP Program for applicable degraded conditions. Management Directive 8.3 evaluation details are not formally documented. All programs generally follow the RASP handbook guidance.

[22] This program comparison is specific to operating events as part of the initiating event, mitigating system, and barrier integrity Reactor Oversight Program cornerstones.

5. How many precursors have been identified?



ASP Program results from 1969–2017

6. What are the uses of ASP Program results?

- Input to NRC performance measures reported in the annual performance and accountability report to Congress.
- Inform NRC senior managers, the public, and licensees of the risk significance of complex events.
- Enhancement of NRC's probabilistic risk assessment (PRA) capability.
  - Feedback to improve PRA standardized plant analysis risk (SPAR) models
  - Staff risk assessment capabilities
  - Input into other agency processes (e.g., SDP and generic issues)
  - FLEX impact
- Risk-informing regulatory programs
  - Operating Experience Program
  - Decisions to develop generic communications
  - Research programs
- Supports reactive inspections, such as special inspection team and augmented inspection team.
- Knowledge management repository of risk-important events (ASP database containing 909 precursors since 1969).
- Provides effectiveness feedback to other agency processes.
  - Reactive Inspection Program (Management Directive 8.3)
  - SDP (RASP handbook)