U.S. Nuclear Regulatory Commission Accident Sequence Precursor Program 2016 Annual Report

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Executive Summary

The Accident Sequence Precursor (ASP) Program assesses licensee event reports (LERs) at U.S nuclear power plants (NPPs) to identify potential precursors to core damage. The insights gained from evaluating the risk significance and potential generic applicability of these events assist in fulfilling the U.S. Nuclear Regulatory Commission (NRC) Safety Objective #1 to prevent and mitigate accidents and ensure radiation safety. Information from ASP analyses provides input into the NRC's long-term operating experience program; communicates risk-significance insights related to overall plant performance on a plant-specific and fleet-wide basis, including events resulting from performance deficiencies, design deficiencies, and external initiating events; and contributes to ongoing efforts in improvement of probabilistic risk assessment. In providing fleet-wide insights on NPP performance, the ASP Program independently verifies the effectiveness of NRC programs [e.g., Reactor Oversight Process (ROP) and the Maintenance Rule]. Fleet-wide risk profiles and trends can also provide insights and potential lessons-learned from the NRC's licensing activities, including initiatives in risk-informing the regulatory process.

This report provides the ASP Program results for all LERs issued in 2016. Note that LERs go through an initial screening process to ensure agency resources are focused on potentially risk significant events (i.e., potential precursors). This initial process typically screens out 70–85 percent of the LERs issued in a given year. Of the 352 LERs issued in 2016, 289 (82 percent) were screened out in the initial screening process and 63 potential precursors were identified for further analysis.

Of the 63 potential precursors identified in 2016, 11 events were determined to exceed the ASP Program threshold and, therefore, are precursors. No *significant* precursors were identified in 2016. Of these 11 precursors, 8 precursors utilized Significance Determination Process (SDP) results in accordance with Regulatory Issue Summary (RIS) 2006-24, "Revised Review and Transmittal Process for Accident Sequence Precursor Analyses." The remaining three precursors were identified via independent ASP analyses. Two of these events identified by ASP analyses had a CCDP or ΔCDP greater than or equal to 1×10^{-5}. Note that an additional precursor (Wolf Creek, LER 482-16-001) was identified using an independent ASP analysis; however, this event occurred in October 2014 and is therefore not included in the 2016 data trending. The remaining potential precursor events did not exceed the ASP Program threshold as determined by a combination of the acceptance of SDP results (i.e., *Green* findings), completion of a simplified/bounding analysis, or a detailed ASP analysis. Note that there are two potential precursors in which the inspection process has yet to be completed and are pending a final assessment.

The number of precursors identified (11) in 2016 is considered low compared to previous years. Since 1980, only seven other years (1995, 1997, 1998, 1999, 2002, 2007, and 2015) had fewer precursors. In 2015, the five precursors identified matched the previous historic low precursor count in 1997. A review of the trends for all precursor groups (e.g., total precursors, initiating events, and degraded conditions) over the past decade (2007–2016) reveals no statistically significant increasing or decreasing trends. This is a positive indication given that increasing trends were identified within the past few years for higher-risk precursors and precursors associated with losses of offsite power. A review of longer-term trends (i.e., 20 years) reveals two statistically significant increasing trends for precursors at boiling-water reactors (BWRs) and precursors involving degraded conditions due to emergency diesel generator (EDG) failures. The increasing trend in precursors at BWRs is largely influenced by the low precursor counts in the late 1990s and early 2000s, and several plants with four or more precursors in the past decade (e.g., Oyster Creek; Browns Ferry, Units 1, 2, and 3; Cooper; Dresden, Unit 3; Duane Arnold; and Pilgrim). The staff will continue to examine the increasing trend in precursors involving degraded conditions due to EDG failures, in conjunction with the preliminary increasing trend in EDG failures to run identified via the systems studies performed under contract with Idaho National Laboratory.

The integrated ASP index reveals a decreasing trend in the total risk associated with precursors over the past 20 years. This decreasing trend is largely influenced by no *significant* precursors identified since 2002 (Davis-Besse) and the lack of high-risk, long-term degraded conditions over the past decade. Note that the integrated ASP index retroactively applies the risk of degraded conditions in every year that the degradation existed, while individual SDP evaluations and ASP analyses limit the exposure time to 1 year.

The ASP Program results show that current agency oversight programs and licensing activities remain effective. The ROP continues to focus on plant events based on safety significance, and the ASP events and trends do not show "gaps" in licensee performance areas not currently covered by the ROP (for example, an analysis of the ASP events does not indicate safety-important areas that may be outside the "scope" of the ROP's performance indicators). The ASP results also continue to show that licensee risk management initiatives (e.g., in response to the Maintenance Rule) are effective in maintaining a flat or decreasing risk profile for the industry.

In the area of licensing activities, the risk profiles and trends from the ASP Program do not show indications of increasing risk due to the potential "cumulative impact" of risk-informed initiatives. An evaluation of the ASP data does not reveal changes in the risk levels or profiles, does not reveal new component failure modes or mechanisms, and the likelihoods and impacts of accident sequences have not changed.

The staff is exploring opportunities to improve the ASP Program and ensure that program results and insights are properly communicated and considered by applicable internal and external stakeholders. For example, the staff is considering publishing pertinent and applicable ASP results and insights in documents such as the inspector newsletters to better inform our inspection process and highlight potential "smart samples" for plant inspectors. In addition, the staff plans to continue to evaluate precursor data to determine if additional insights can be identified. For example, the staff could monitor short- and longer-term trends as an independent review of our plant life extension activities to determine if there is a potential trend in age-related failures. The staff could also investigate plant and industry risk profiles to determine the effectiveness (in terms of risk reduction credit) of initiatives such as implementation of NFPA 805 and the incorporation of FLEX equipment.

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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 and mitigate accidents and ensure radiation safety.
- The ASP Program is a contributing activity for Safety Strategy 1 to evaluate domestic and international operating events and trends for risk significance and generic applicability.

- Assists in fulfillment of agency Safety Performance Goal 4 to prevent accident precursors and reductions of safety margins at commercial nuclear power plants (operating or under construction) that are of high safety significance.[1]
- 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.[2]
- 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 knowledge by discussing and reviewing key modeling issues and assumptions with licensees.
- Communicating risk-significant insights not associated with licensee performance to enable consideration of plant improvements.

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 a day or two after the event notification.

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.,

[1] *Significant* precursors are an input into the annual Abnormal Occurrence (AO), Congressional Budget Justification, and Performance and Accountability reports to Congress.

[2] There are three other program that provide this function: the Reactor Oversight Process (ROP), AO Report, and the Industry Trends Program (ITP). Note that the ITP was terminated in 2015 as part of Project AIM.

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. 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., seismic, internal fires, 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 serve their respective objectives in an efficient manner.

There are similarities in the risk assessments conducted by the three programs. All programs use SPAR models, the same documented methods and guidance in the Risk Assessment Standardization Project (RASP) manual, and similar analysis assumptions, except where program 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 independent 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 practical 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 10 CFR 50.73. In recent years, there are approximately 300–400 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 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), and
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, and
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, and
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),[3]
e. Safety-related electrical power systems,
f. Ultimate heat sink,
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, and
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.

[3] 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.

Criterion 4—Risk Significant Events Based on a Probabilistic Risk Assessment (PRA). Events in which the licensee indicates the conditional core damage probability (CCDP) or increase in core damage probability (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, 70–85 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. For LERs that are determined to be potential precursors, the staff utilizes 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., 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). The ASP Program uses the plant-specific CCDP for the non-recoverable loss of feedwater and condenser heat sink, with no degradation of safety related equipment, as the initiating event precursor threshold if it is greater than 10^{-6}. 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.

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

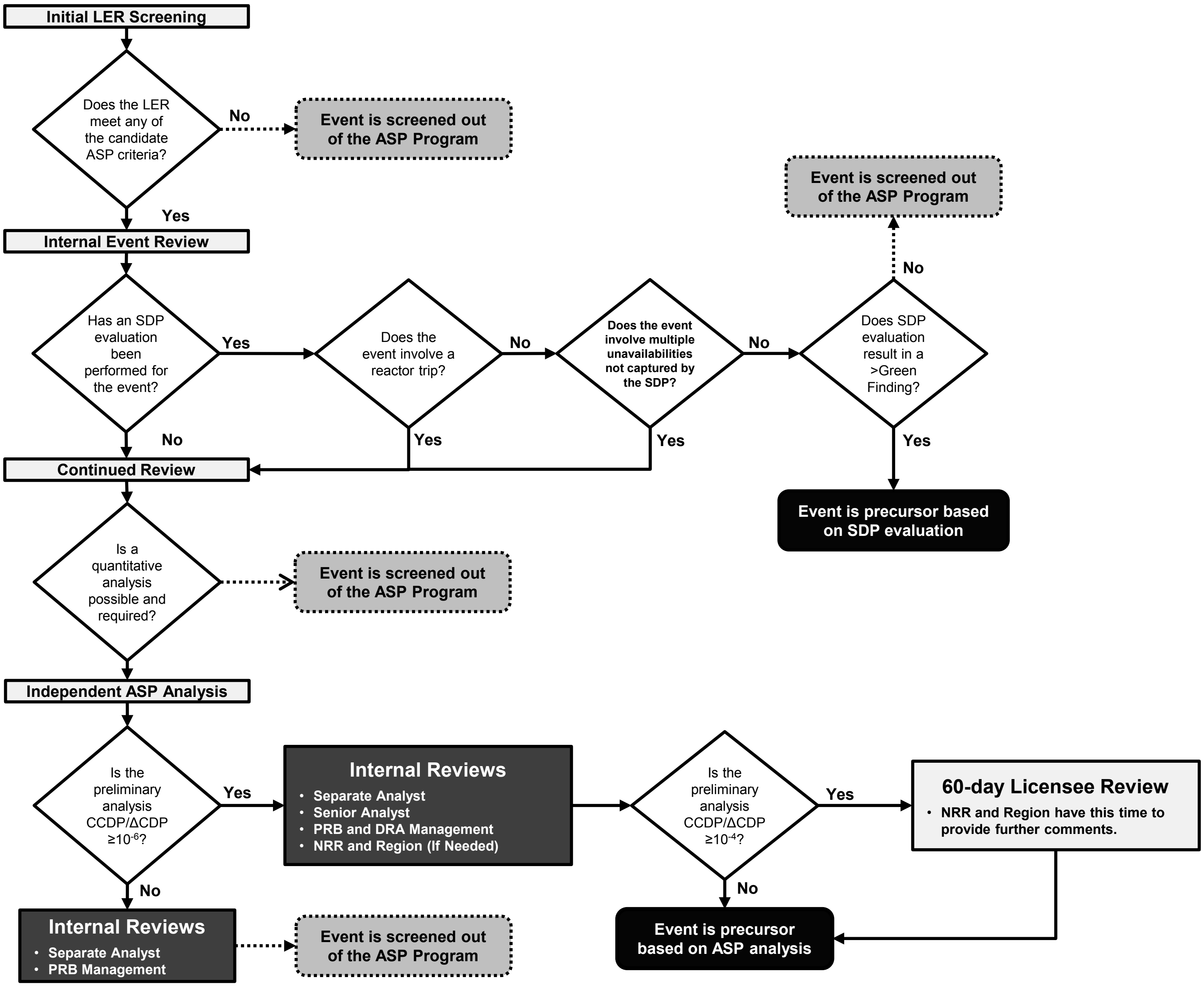

Figure 1. ASP Process Diagram.

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[4]

There were 352 LERs reviewed during calendar year 2016.[5] From these 352 LERs, 289 (approximately 82 percent) were screened out in the initial screening process and 63 events were selected and analyzed as potential precursors.[6] Of the 63 potential precursors, 11 events were determined to exceed the ASP Program threshold and, therefore, are precursors.[7] For eight of these precursors, the performance deficiency identified under the ROP 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 three precursors. Table 1 provides a brief description of all precursors identified in 2016.

After further analysis, the remaining 52 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 (16 events), completion of a simplified/bounding analysis (23 events), or a detailed ASP analysis (11 events).[8] Table 2 provides a list of the LERs that were determined not to be precursors using a detailed ASP analysis.

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.

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4 A summary of ASP results for the final quarter of calendar year 2014 and calendar year 2015 were not reported given the cancelation of the annual Commission paper. A summary of these results are provided in Appendix D.

5 The LER count reflects exclusive events (i.e., LERs with multiple revisions are counted singularly).

6 An additional potential precursor was identified at Diablo Canyon, Unit 2, associated with containment isolation valve failure for which no LER was issued.

7 An additional precursor, Wolf Creek (LER 482-16-001) emergency diesel generator (EDG) failure, has an event date in 2014 and, therefore, this precursor is counted in that year for trending purposes.

8 There are currently two 2016 LERs for which the ASP Program evaluation is not complete. The first event, LER 440-16-003, is associated with an unresolved issue (URI) at Perry concerning the installed design of the safety-related 4kV under-voltage protection scheme (see IR 05000440/2016008 for additional information). The second event, LER 293-16-008, is associated with a preliminary finding at Pilgrim concerning unavailability of an EDG due to low gearbox oil caused by a leaking relief valve. The significance of this preliminary finding has yet to be determined as inspectors require additional information from the licensee.

Table 1. 2016 Precursors.[9]

Plant	LER	Event Date	Exposure Period	Description	CCDP/ΔCDP SDP Color	ADAMS Accession #
Oyster Creek[10]	219-16-005	9/19/16	1 year	**EA-16-241**; One electromatic relief valve inoperable for greater than allowed outage time	*White* Finding	ML17101A422
ANO 2	368-16-001	9/16/16	117 days	**EA-16-247**; Emergency diesel generator fails during testing due to insufficient lubrication of the inboard generator bearing	*White* Finding	ML17055A727
St. Lucie 1	335-16-003	8/21/16	Initiating Event	**EA-17-013**; Generator lockout relay actuation during power ascension results in reactor trip	*White* Finding	ML17108A232
Hatch 2	366-16-003	8/18/16	220 days	Emergency diesel generator 2C fails during surveillance test	**$1{\times}10^{-5}$**	ML17102A999
Hope Creek	354-16-002	8/6/16	44 days	**EA-16-184**; Moisture in oil system results in failure of high-pressure coolant injection pump during testing	*White* Finding	ML17033B541
Dresden 3	249-16-001	6/27/16	1 year	**EA-16-236**; High-pressure coolant injection pump failure during testing	*White* Finding	ML17058A419
Diablo Canyon 2	No LER Issued	5/16/16	286 days	**EA-16-168**; Containment sump isolation valve fails to open during testing	*White* Finding	ML16363A429
Catawba 1	413-16-001	3/28/16	104 days	Mis-positioned breaker with concurrent emergency diesel generator unavailability results in potential loss of recirculation capability	$1{\times}10^{-6}$	ML17038A307
Monticello	263-16-001	3/22/16	10 months	**EA-16-175**; High-pressure coolant injection pump loss of safety function due to excessive oil leakage	*White* Finding	ML16347A616
Brunswick 1	325-16-001	2/7/16	Initiating Event	Electrical bus fault results in lockout of startup auxiliary transformer and loss of offsite power	**$3{\times}10^{-5}$**	ML17109A269
Oyster Creek	219-16-001	1/4/16	168 days	**EA-16-057**; Failure of the emergency diesel generator during surveillance testing due to a cooling water system leak	*White* Finding	ML16188A014

9 An addition precursor for Wolf Creek (LER 482-16-001) was not issued until March 28, 2016. The EDG failure occurred in October 2014 and, therefore, this precursor (ML17108A730) is included in 2014 for ASP trending purposes.

10 A review of Oyster Creek LERs revealed concurrent degradations of EDG 1 (LERs 219-15-003 and 219-16-001) with the electromatic relief valve failure. These two issues were determined to be a separate precursors based on SDP evaluations (*White* findings). An analysis of these windowed conditions reveals that the risks for the electromatic relief valve and EDG failures do not affect the same accident sequences. Consequently, the ΔCDP calculated from analyzing the concurrent degradation of these sets of equipment is equivalent to analyzing each separately and summing the results. In addition, because the risk from these three events is not synergistic, and does not highlight a vulnerability of higher risk significance than that resulting from the individual events, it is appropriate to maintain these three events as separate precursors for the purpose of trending and insights within the ASP Program.

Table 2. 2016 Events Screened Out Using a Detailed ASP Analysis.

Plant	LER	Event Date	LER Title	LER Report Date	Date Assigned by INL	Candidate ASP Criterion	ASP Completion Date	ADAMS Accession #
Peach Bottom 3	278-15-001	12/31/15	Loss of high pressure coolant injection system function as a result of failed flow controller signal converter	2/26/16	2/29/16	3d	8/23/16	ML16237A427
Pilgrim	293-16-001	4/12/16	Both emergency diesel generators inoperable	6/9/16	6/20/16	3e	9/9/16	ML16265A467
Susquehanna 2	388-16-005	5/13/16	Unit 2 high-pressure coolant injection manually overridden prior to manual scram during a plant transient	7/12/16	7/18/16	3d	12/6/16	ML16344A443
South Texas 1	498-15-001	12/21/15	Manual reactor trip due to lowering steam generator levels and valid auxiliary feedwater system actuation following a manual main turbine trip	2/18/16	3/14/16	4a	12/6/16	ML16347A325
Fitzpatrick	333-16-001	1/23/16	System actuations during manual scram in response to frazil ice blockage and residual transfer	3/23/16	3/28/16	1k	12/12/16	ML16349A563
Farley 1	348-15-005	11/20/15	Condition prohibited by technical specifications due to turbine driven auxiliary feedwater design issue	1/15/16	1/25/16	3b	12/23/16	ML17011A202
Pilgrim	293-16-002	4/19/16	Online maintenance test configuration prohibited by technical specifications	6/20/16	6/27/16	3e	12/29/16	ML17005A527
Brunswick 1	325-16-002	3/4/16	Emergency diesel generator 3 inoperable due to failure to auto-start	5/2/16	5/23/16	3e	4/20/17	ML17109A455
Perry	440-16-001	1/24/16	Drywell leakage, level 8 automatic scram, and APRM loss of safety function	3/23/16	3/28/16	3a	4/28/17	ML17118A145
Browns Ferry 3	296-16-001	1/19/16	Inoperable residual heat removal pump results in condition prohibited by technical specifications and safety system functional failure	3/21/16	3/21/16	3d	5/1/17	ML17121A462
Robinson 2	261-16-005	10/8/16	Reactor trip and automatic system actuation due to weather-related loss of offsite power	12/7/16	12/19/16	2a	5/12/17	ML17135A148

7. 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.[11] 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., 2007–2016). In addition, data and trending information for the past 20 years (i.e., 1997–2016) is provided for historical perspective.

7.1. All Precursors

Trending of all precursor analyses provides insights as part of the agency's long-term operating experience program.[12]

- *Trend.* Over the past decade (2007–2016), the mean occurrence rate of all precursors does not exhibit a statistically significant trend (*p-value* = 0.31).[13] See Figure 2 for additional information.

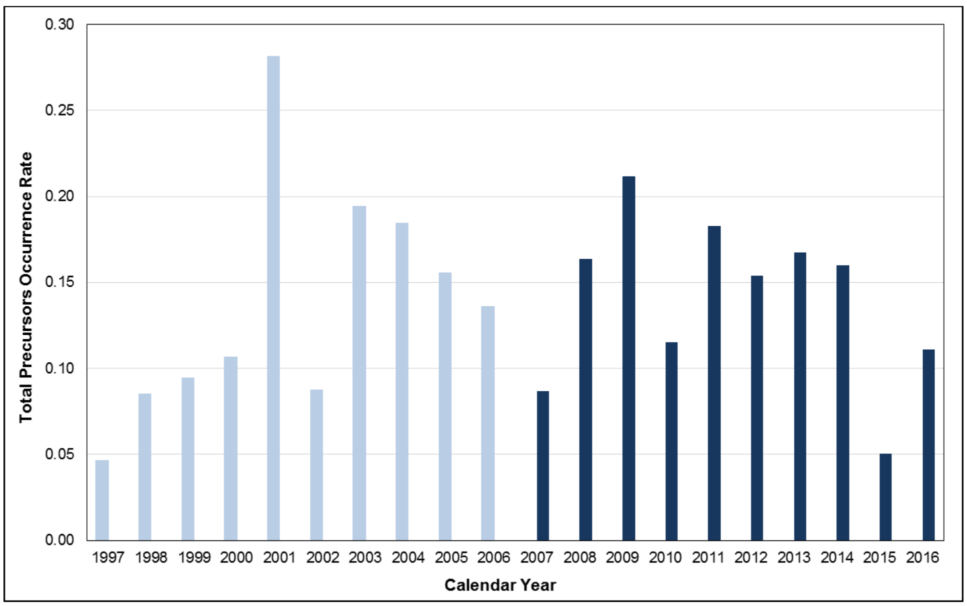

Figure 2. Occurrence Rate of All Precursors.

- *Long-Term Trend.* There is no statistically significant trend (*p-value* = 0.39) for the mean occurrence rate of all precursors over the past 20 years (1997–2016).

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11 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.

12 Agency Safety Performance Indicator 4 has been replaced by agency Safety Performance Goal 4—prevent accident precursors and reductions of safety margins at commercial nuclear power plants (operating or under construction) that are of high safety significance.

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

- *Use of SDP Results.* Over the past decade, 69 percent of all precursors utilized SDP evaluation results for the ASP Program purposes. These precursors typically involve a single unavailability/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.

7.2. 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 2016. 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.

7.3. 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. Staff did not identify any precursors with a CCDP or ΔCDP greater than or equal to 1×10^{-4} in 2016.

- *Trend*. Over the past decade (2007–2016), 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* = 0.78). See Figure 3 for additional information.

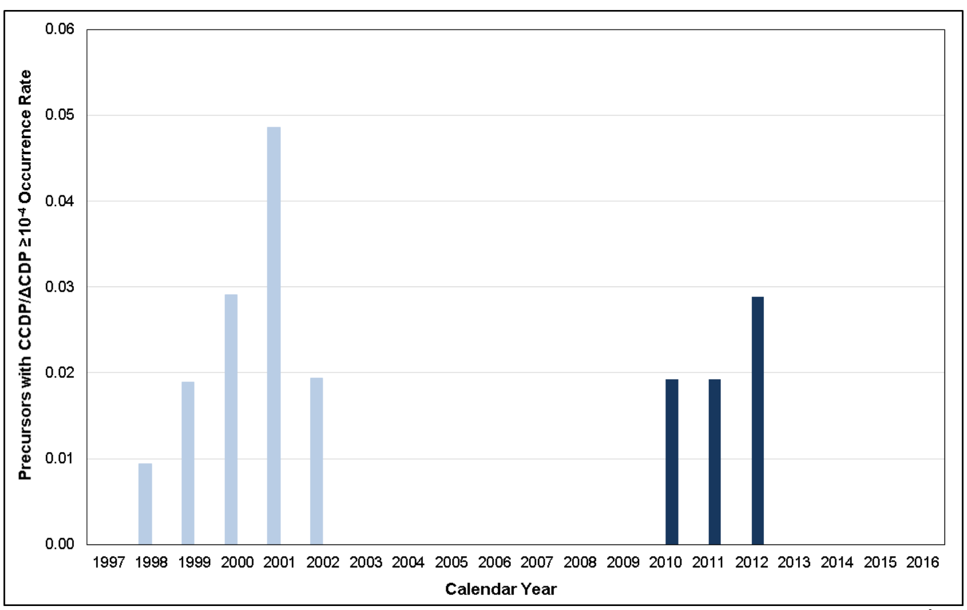

Figure 3. Occurrence Rate of Precursors with a CCDP or ΔCDP ≥ 1×10^{-4}.

- *Long-Term Trend.* There is no statistically significant trend (*p-value* = 0.08) 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 (1997–2016). Note that the *p-value* is very close to indicating a statistically significant decreasing trend.

- *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 2013–2016, 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.[14]

- *Precursor Counts*. Over the past decade, a total of seven precursors with CCDP or ΔCDP greater than or equal to 1×10^{-4} were identified, with all of these precursors occurring in 2010–2012. See Table 3 for additional information on these seven precursors. Six of the seven precursors involved events in electrical distribution systems.

Table 3. Recent Precursors with 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***
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.	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***

[14] 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.

Date	Plant (Risk Measure)	Description	Risk Insights
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).	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***

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

Significant events are events that have a CCDP or ΔCDP greater than or equal to 1×10^{-5}. The staff identified two precursors with a CCDP or ΔCDP greater than or equal to 1×10^{-5} in 2016. Both of these precursors were identified by an independent ASP analysis. The first of these precursors occurred at Brunswick (Unit 1), and involved a LOOP due to a lockout of the startup auxiliary transformer (CCDP = 3×10^{-5}). The second precursor occurred at Hatch (Unit 2), and involved an unavailability of an EDG to fulfill its full safety function for approximately 220 days (CCDP = 1×10^{-5}).

- *Trend*. Over the past decade (2007–2016), 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* = 0.86). See Figure 4 for additional information.

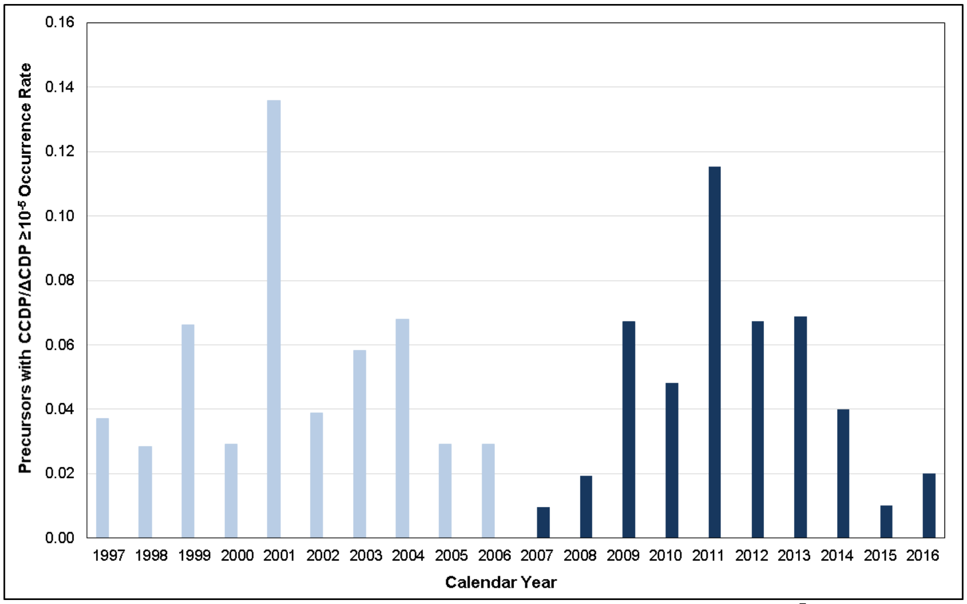

Figure 4. Precursors with a CCDP or ΔCDP ≥ 1×10^{-5}.

- *Long-Term Trend.* There is no statistically significant trend (*p-value* = 0.58) 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 (1997–2016).
- *Past Trends*. The Industry Trends Program (ITP)[15] annual paper to the Commission in 2011 identified a statistically significant increasing trend in "significant" events for FYs 2002–2011. Historically low counts of precursors in 2015 resulted in eliminating this increasing trend.
- *Initiating Event Impact.* Historically, precursors due to initiating events make up approximately 66 percent of all precursors with a CCDP or ΔCDP greater than or equal to 1×10^{-5}. Over the past decade (2007–2016), the percentage is approximately 58 percent. The vast majority (82 percent) of the precursors with a CCDP or ΔCDP greater than or equal to 1×10^{-5} are due to LOOP initiating events.

7.5. 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 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 and degraded conditions do not exhibit statistically significant trends (*p-values* = 0.47 and 0.09, respectively). See Figure 5 and Figure 6 for additional information. Note that the *p-value* is close to indicating a statistically significant decreasing trend for precursors involving degraded conditions.

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15 The ITP was eliminated are part of agency re baselining activities in 2016. See SECY-16-09, "Recommendations Resulting from the Integrated Prioritization and Re Baselining of Agency Activities," for additional information.

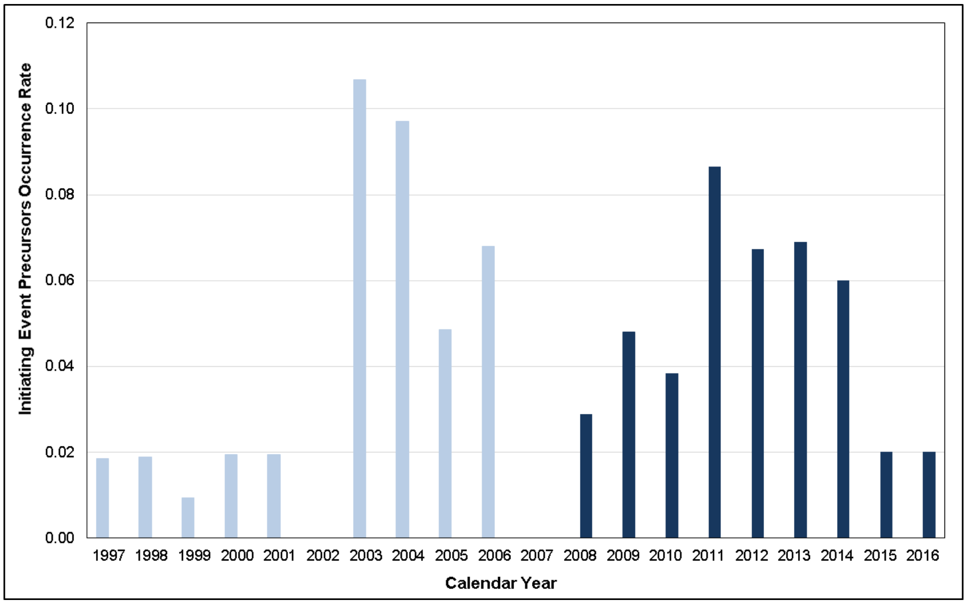

Figure 5. Occurrence Rate of Precursors Involving an Initiating Event.

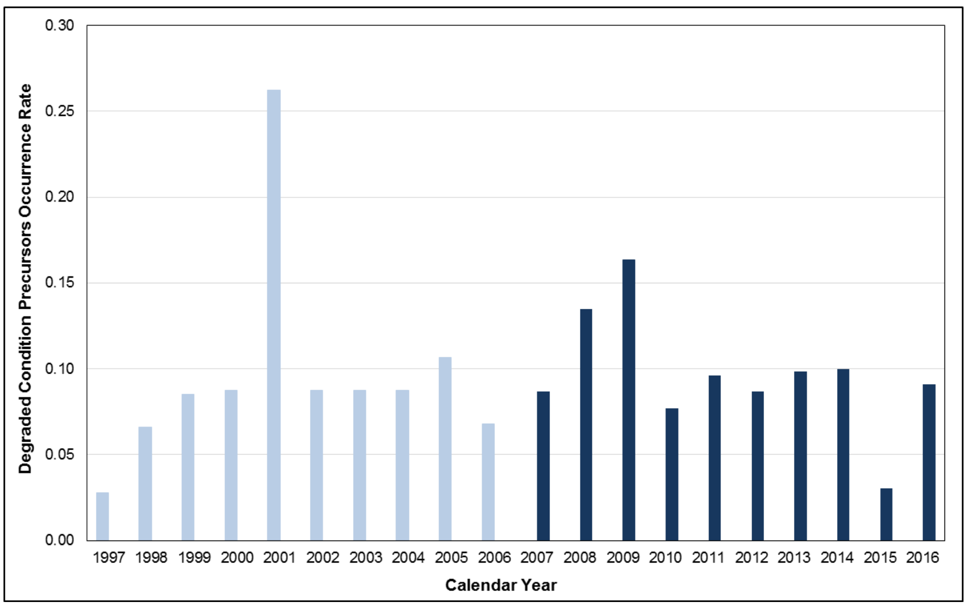

Figure 6. Occurrence Rate of Precursors Involving Degraded Condition(s).

- *Long-Term Trend.* The mean occurrence rates of precursors involving initiating events and degraded conditions do not exhibit statistically significant trends (*p-values* = 0.06 and 0.82, respectively). Note that the *p-value* is very close to indicating a statistically significant increasing trend for precursors involving initiating events.

A review of the data for the past decade (2007–2016) reveals the following insights:

- *Precursor Counts.* Precursors involving degraded conditions (99 precursors) outnumbered initiating events (45 precursors) by a factor of approximately 2.
- *Initiating Event Precursor Breakdown*. Of the 45 precursors involving initiating events, 26 precursors (58 percent) were LOOP events and 18 precursors (40 percent) were

complicated trips.[16] There were two initiating events that occurred while the affected plant was shut down. Typically, the CCDP estimates for LOOPs are higher than for complicated trips.

- *EDG Failure Trends*. The mean occurrence rate of precursors involving degraded conditions due to EDG failures reveals a statistically significant increasing trend (*p-value* = 0.047) over the past 20 years.[17] Over the past decade, no statistically significant trend (*p-value* = 0.20) exists for this precursor group.
- *Long-Term Degraded Conditions*. Of the 99 precursors involving degraded conditions, 28 precursors (28 percent) involved degraded conditions existing for a decade or longer.[18] Of these 28 precursors, 13 precursors involved degraded conditions dating back to initial plant construction.

7.6. Precursors Involving a LOOP Initiating Event

A LOOP initiating event involves a reactor trip and the simultaneous loss of electrical power to 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. In 2016, two LOOP initiating events occurred.

- *Trend*. Over the past decade (2007–2016), the mean occurrence rate of precursors involving LOOP precursor events does not exhibited a statistically significant trend (*p-value* = 0.18). See Figure 7 for additional information.
- *Long-Term Trend.* There is no statistically significant trend (*p-value* = 0.16) for the mean occurrence rate for precursor involving a LOOP over the past 20 years (1997–2016).
- *Past Trends*. An increasing trend in precursors involving a LOOP was reported in SECY-15-0124, "Status of the Accident Sequence Precursor Program and the Standardized Plant Analysis Risk Models." However, only three LOOP precursors identified within the past two years (2015 and 2016) has eliminated the increasing trend.

A review of the data for the past decade (2007–2016) reveals the following insights:

- *Precursor Counts.* Of the 143 precursors that occurred during the past decade, 26 precursors (18 percent) were LOOP precursor events that occurred at 21 NPP sites. Of the 26 LOOP precursor events, 18 precursors occurred in the 2011–2014 period.
- *Concurrent Unavailability of an Emergency Power Train*. Of the 26 LOOP precursor events, 2 precursors 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.

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

17 There is preliminary increasing trend associated with EDG failures to run identified by system studies performed by INL. Once the system studies are finalized for 2016, the staff will determine if any insights can be gained from these two increasing trends.

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

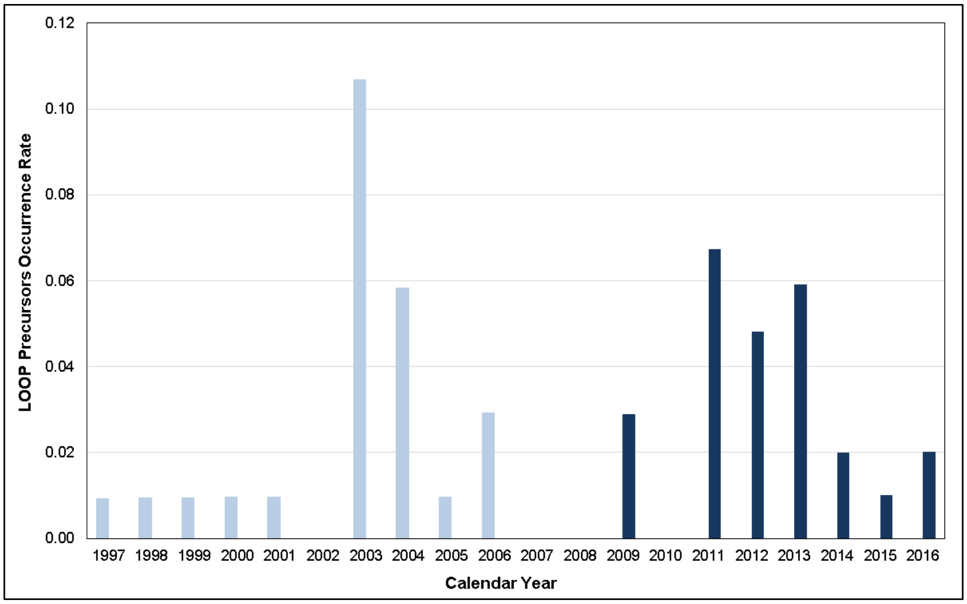

Figure 7. Occurrence Rate of Precursors Involving a LOOP.

- *External Hazards.* Of the 26 LOOP precursor events, 12 (48 percent) precursors resulted from external hazards, including: 2 tornados (5 precursors), Hurricane Katrina (1 precursor), 3 other weather-related events (4 precursors), and the 2011 Virginia earthquake (2 precursors). All units at the five multi-unit NPP sites involved in these events were affected by the external events. Of these 12 LOOP precursor events, 7 (58 percent) occurred in 2011.
- *Outside Plant Boundary*. Of the 26 LOOP precursor events, 4 (16 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 precursor events, 13 precursors occurred at all units at a multi-unit NPP site, 7 precursors occurred at a single unit on a multi-unit site, and 6 precursors occurred at a single-unit site.

7.7. 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.[19]

- *Trends*. Over the past decade (2007–2016), the mean occurrence rates of precursors that occurred at BWRs and PWRs do not exhibit a statistically significant trend (*p-values* = 0.83 and 0.14, respectively). See Figure 8 and Figure 9 for additional information.

19 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.

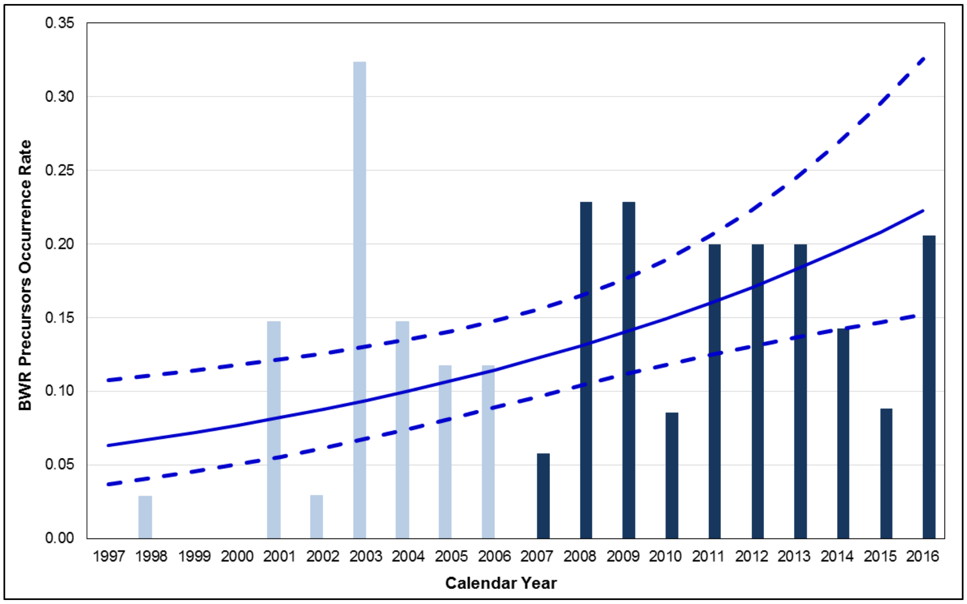

Figure 8. Precursors at BWRs. (The mean occurrence rate of precursors at BWRs exhibits a statistically significant increasing trend (*p-value* = 0.001) over the past 20 years (1997–2016). No trend was detected over the past 10 years (2007–2016).

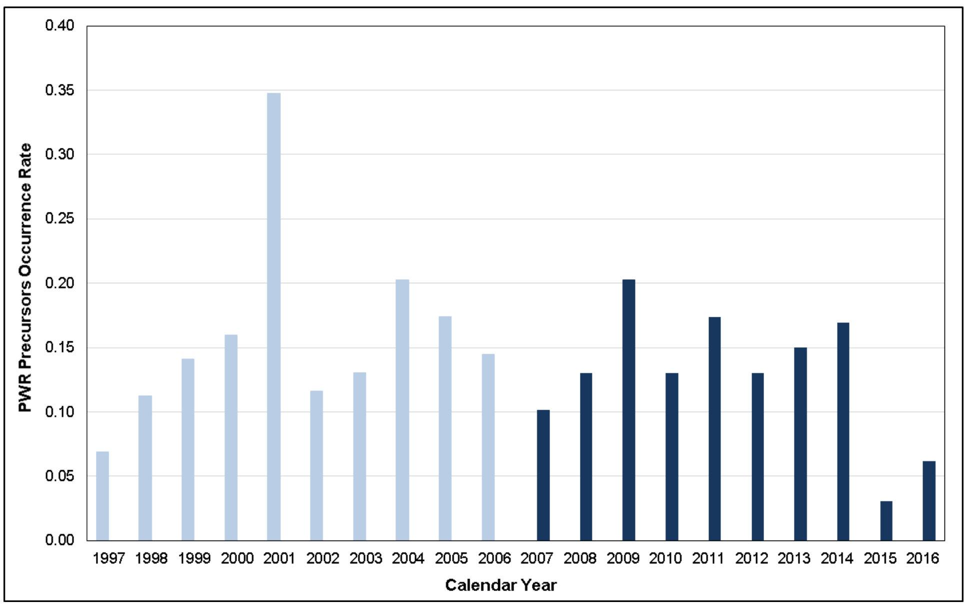

Figure 9. Precursors at PWRs.

- *Long-Term Trends.* The mean occurrence rate of precursors at BWRs exhibits a statistically significant increasing trend (*p value* = 0.001) over the past 20 years (1997–2016). During the same period, the mean occurrence rate for precursors at PWRs does not exhibit a statistically significant trend (*p-value* = 0.20).

A review of the data for the past decade (2007–2016) reveals the following insights:

- *LOOPs by Plant Type*. Of the 18 precursors involving initiating events at BWRs, 12 precursors (67 percent) were complete LOOP events. Of the 27 precursors involving initiating events at PWRs, 14 precursors (52 percent) were complete LOOP events.

- *BWR Degraded Condition Breakdown*. Of the 39 precursors involving degraded condition(s) at BWRs, most were caused by failures in the emergency power system (14 precursors or 36 percent), others were caused by failures in emergency core cooling systems (5 precursors or 13 percent), and safety-relief valves (4 precursors or 10 percent).
- *BWR External Hazards.* Of the 39 precursors involving degraded condition(s) at BWRs, 11 precursors (28 percent) were associated with postulated external hazards (fire, flood, etc.). Of these 11 precursors, 8 precursors were degradations related to fires and 3 precursors were associated with degradations related to floods.
- *PWR Degraded Condition Breakdown*. Of the 60 precursors involving degraded condition(s) at PWRs, most were caused by failures in the emergency power system (12 precursors or 20 percent), others were caused by failures in the auxiliary feedwater system (6 precursors or 10 percent), safety-related cooling water systems (6 precursors or 10 percent), electrical distribution system (5 precursors or 8 percent), or emergency core cooling systems (5 precursors or 8 percent).
- *PWR External Hazards.* Of the 60 precursors involving degraded condition(s) at PWRs, 11 precursors (18 percent) were associated with degradations related to postulated floods.[20]
- *PWR Sump Recirculation*. Of the 5 precursors involving failures in the emergency core cooling systems, 4 precursors (80 percent) were because of conditions affecting sump recirculation during postulated loss-of-cooling accidents of varying break sizes.
- *Degraded AFW systems*. All 6 precursors involving failures of the auxiliary feedwater system involved turbine-driven pump train unavailability.

8. 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 each 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 after 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 1997 to 2016.

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

- *Insights.* Over the past 20 years (1997–2016), the total risk associated with precursor is dominated by degraded conditions associated with issues dating back to initial plant construction. These 42 precursors account for approximately 43 percent of the total risk due to all precursors. The one *significant* precursor (Davis-Besse, 2002) accounts for

[20] There was one precursor associated with fires at PWRs in the past 10 years. In addition, there was one precursor related to the lack of tornado missile protection.

approximately 19 percent of the total risk due to all precursors.[21] The 52 precursors due to a LOOP initiating event account for approximately 10 percent of the total risk due to all precursors. The other 191 precursors account for approximately 29 percent to the total risk due to all precursors.

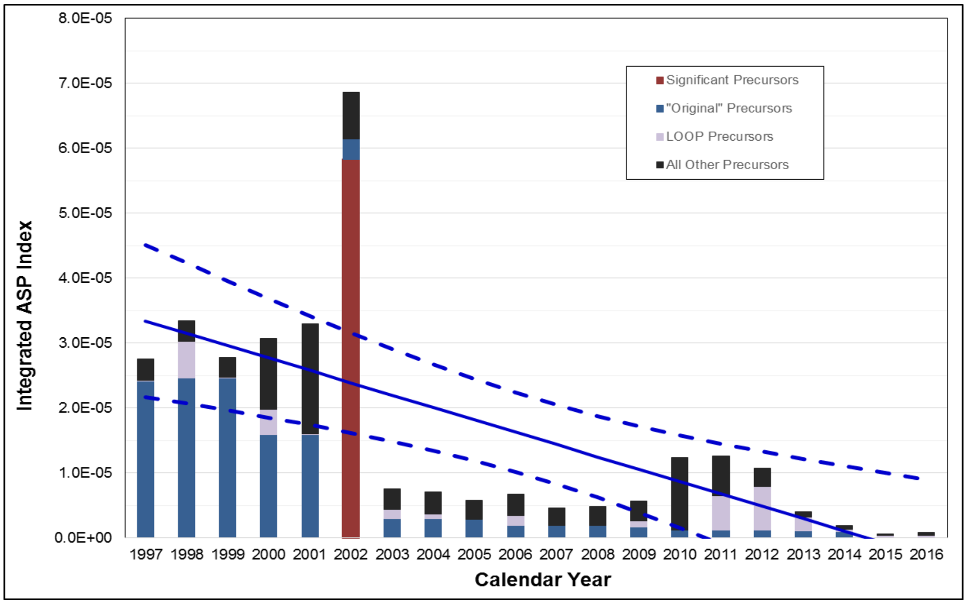

Figure 10. Integrated ASP Index. (The integrated ASP index exhibits a statistically significant decreasing trend (*p-value* = 0.001) over the past 20 years (1997–2016). No trend was detected over the past 10 years (2007–2016).

- *Trends.* Over the past 20 years (1997–2016), the integrated ASP index exhibits a statistically significant decreasing trend (*p-value* = 0.001).[22] This decreasing 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.[23] Over the past decade (2007–2016), no statistically significant trend for the integrated ASP index was identified.
- *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. These comparisons were deemed by many to be inappropriate. There has been no effort to make these comparisons in this paper. 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 precursors. In addition, 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 way to see the total risk effect of longer-term degraded conditions that is not fully captured in the individual analyses.

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21 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.

22 Linear regression was used for the trend analysis of the integrated ASP index.

23 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 HELB vulnerabilities at D.C. Cook, Units 1 and 2 (1999).

9. PLANT PRECURSOR COUNTS

Since the inception of the ASP Program, on average approximately eight precursors have been identified for each operating NPP. Over the past 20 years (1997–2016), an average of 2 precursors occur for each operating NPP. The average drops to 1 precursor for each operating NPP during the past decade (2007–2016). Figure 11 shows the precursor counts for each U.S. NPP still in operation.

- *NPPs with No Precursors.* Over the past decade (2007–2016), 37 NPPs have not had a precursor identified. Ten plants have not had a precursor identified in the past 20 years (1997–2016). Comanche Peak (Unit 2) and South Texas Project (Unit 2) have never had a precursor event.

  NPP with Highest Precursor Count. Historically, Pilgrim has the most (23) precursors associated with a single unit NPP. However, only 4 precursors have been identified over the past 20 years (with all of these events occurring over the past 5 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.). Eights other plants have had at least 15 precursors over the same period, including: Oconee, Units 1, 2, and 3; Davis-Bess; Palisades; Oyster Creek; Hatch, Unit 1; and Brunswick, Unit 2.

- *NPP Site with Highest Precursor Count.* Historically, the Oconee has had 58 total precursors between Units 1, 2, and 3. No other site has more than 30 total precursors. Sites that have had at least 20 total precursors include: Arkansas Nuclear One, Units 1 and 2; Browns Ferry, Units 1, 2, and 3; Dresden, Units 2 and 3; 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 (2007–2016), only 2 NPPs have had at least 5 precursors over the past decade, Oyster Creek (7) and H.B. Robinson (5). During the same time period, several plants have had 4 precursors over the past decade, including: Arkansas Nuclear One, Unit 2; Browns Ferry, Units 1, 2, and 3; Cooper; Dresden, Unit 3; Duane Arnold; Oconee, Unit 1; Pilgrim; and Waterford. The relatively large number of BWRs with 4 or more precursor over the past decade largely influences the increasing trend in BWR precursors in the past 20 years.

10. COMPARISON OF RECENT PROGRAM PESULTS

The four precursors identified in 2016 (including a 2014 event) using an independent ASP analysis were compared with results from MD 8.3 and SDP analyses, as shown in Table 4.[24] Given the three programs have different functions, it is expected that the results are different. A comparison of the three programs for past events (2010–2015) in which an independent ASP analysis was performed is provided in Appendix C.

11. LER SCREENING QUALITY ASSURANCE REVIEW

A quality assurance review of the LER screening performed by 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 "candidate" ASP screening criteria is described in Section 4. For some screened-in events, the reviewer may identify a different criterion code

[24] As previously noted, one of these precursors, Wolf Creek (LER 482-16-001), is associated with a 2014 event date.

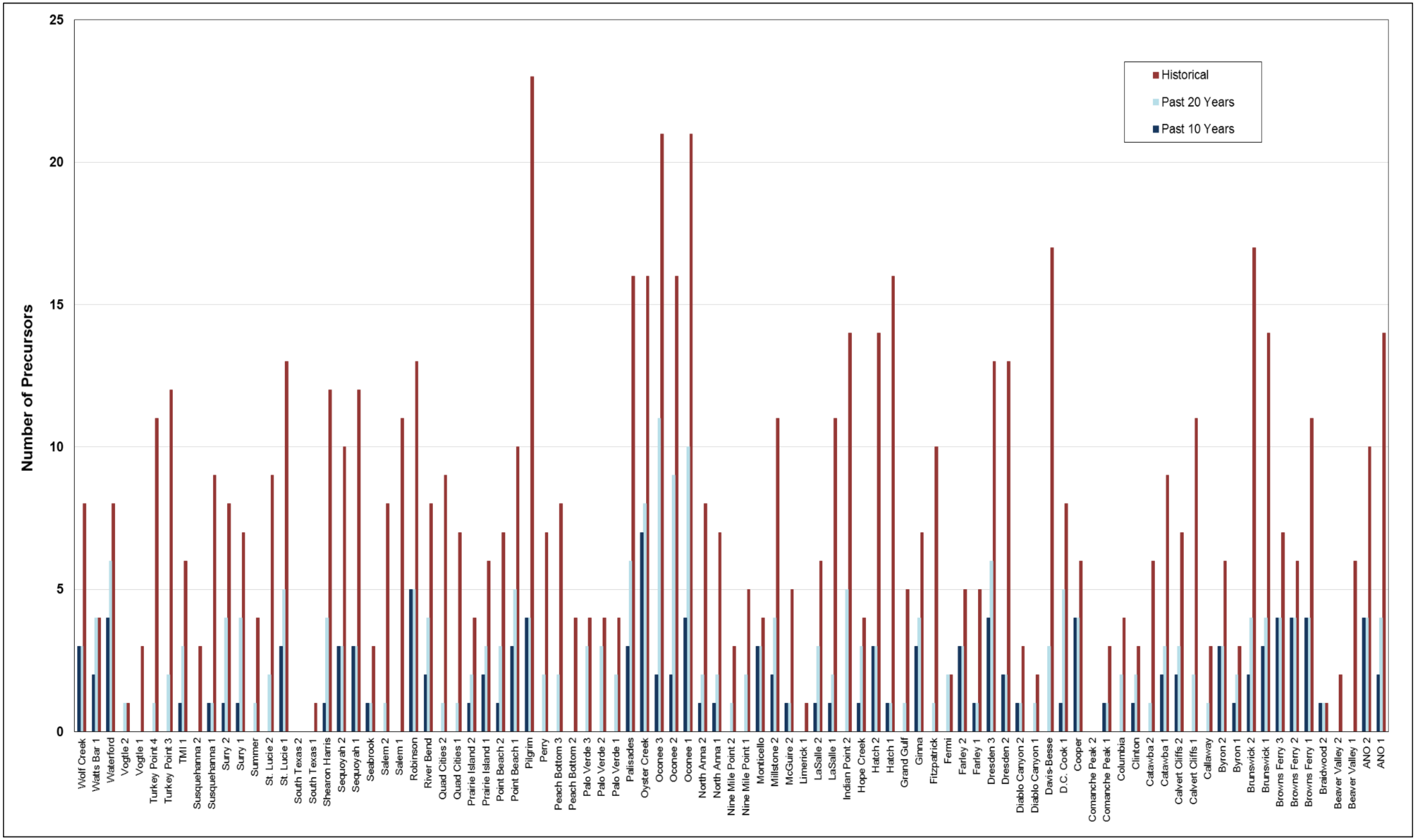

Figure 11. Precursor Counts by Plant.

Table 4. 2016 Independent ASP Analysis Comparison.

Event Description	MD 8.3 Results	SDP Results	ASP Results	SPAR Model/Methodology Improvements and Insights
Catawba; 413-16-001; 3/28/16. Mis-positioned breaker with concurrent 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 ECCS train B. The LER was closed in IR 05000413/2016002 (ML16202A116).	ΔCDP = 1×10^{-6}; concurrent unavailabilities of train B RHR valve (mis-positioned 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 is 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 LOOP with failed SAT. Offsite power could not be restored prior to depletion of safety-related batteries (3 hours) during a postulated SBO. See final ASP analysis (ML17109A269) for additional information.	None.
Hatch 2; 366-16-003; 8/18/16. Emergency diesel generator 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. The LER remains open.	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.
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.

than was identified by the contractor. This situation is acceptable because it is possible for an event to be covered by multiple criterion.

The staff selected 50 LERs (42 LER that were screened out and 8 LERs that were screened-in) and independently assessed them based on the “candidate” ASP screening criteria. Of the 42 LERs screened out by INL, there were two instances where the staff believed that the event should have screened as a potential precursor. In the first instance, the LER was discussed with the contractor and properly included as a potential precursor. The LER was determined to be a precursor based on acceptance of the SDP finding. After a review of the LER language and screening criteria, it was agreed that no further clarification of “candidate” ASP screening criteria was warranted. The second LER highlighted a potential area of ambiguity in the “candidate” ASP criterion regarding reactor trips at-power versus in a shutdown condition. The staff continues to review this event in light of possible clarifications and will revise the “candidate” ASP criteria, if necessary. The staff agreed with the eight LERs that INL screened in as potential precursors.

The staff performed an additional quality assurance review of the LER screening by comparing potential precursors with the SDP tracking sheet maintained by NRR. The SDP tracking sheet provides up-to-date tracking of active, final, and historical SPD findings. While there will be instances that a 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 2016, there was a *White* finding (Diablo Canyon) identified on the SDP tracking sheet that was not associated with an LER. Because the ASP Program relies on LERs as its main means of identifying events of interest, this event was not previously evaluated by the ASP Program. The SDP White finding was reviewed and accepted as the final ASP Program result. Determining the proper LER reporting requirements is outside of the scope of the ASP Program; however, this event will be reported to NRR and the applicable region for their consideration.

12. OPERATING EXPERIENCE INSIGHTS FEEDBACK FOR PRA STANDARDS AND GUIDANCE

One objective of the ASP Program is to provide insights into the adequacy of current PRA standards and guidance. ASP analyses, both precursors and events that did not exceed the ASP Program threshold, from 2016 were reviewed against the PRA elements described in the American Society of Mechanical Engineers (ASME)/American Nuclear Society (ANS) RA-Sb-2013, “Addenda to ASME/ANS RA-S-008 Standard for Level 1/Large Early Release Frequency Probabilistic Risk Assessment for Nuclear Power Plant Applications,” as endorsed in Regulatory Guide 1.200, “An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities.” This review sought to identify aspects of the event analyses for which the risk-significant ASME/ANS PRA Standard did not provide adequate guidance. None of the 2016 event analyses indicated an inadequacy in the PRA elements as described in ASME/ANS RA-Sb-2013. The staff continues to work with ASME/ANS on refining the standard to ensure that it provides sufficient guidance.

Appendix A: 2016 ASP Program Screened Analyses

This appendix provides the justification for each LER that was screened out of the ASP Program based on a simplified/bounding analysis or by acceptance of SDP results. Note that the justification reflects the status of the LER (open or closed) at the time of the ASP completion date. While ASP analysts monitor the final SDP determination 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 in the final SDP determination.

LER: 328-15-002 **Plant:** Sequoyah 2 **Event Date:** 11/10/15
LER Report Date: 1/6/16 **LER Screening Date:** 1/11/16 **cASP Criterion:** 3d
ASP Completion Date: 11/1/16 **Classification:** Analyst Screen-Out

Analyst Justification: Not discussed in inspection reports (IRs) through 05000328/2016002. There are no windowed LERs within the one hour exposure period on November 10, 2015. Two containment drains were declared inoperable when two cold weather suits were dropped into the equipment pit portion of the reactor cavity. The suits could have blocked both containment recirculation drains, and therefore, resulting in a loss of high- and low-pressure recirculation. A bounding condition assessment analysis was performed to evaluate the risk significance of the event. The calculation conservatively assumed that emergency core cooling system (ECCS) recirculation (via containment sump) would have been unavailable for approximately 1 hour during a postulated loss of coolant accident (LOCA). Note that the containment drains are not typically included in Level-1 PRAs (including the SPAR models). This bounding analysis calculated a ΔCDP = 1×10^{-7}, which is conservative. The bounding ΔCDP is below the ASP Program threshold; therefore, this event is screened out of the ASP Program.

LER: 341-16-001 **Plant:** Fermi 2 **Event Date:** 1/6/16
LER Report Date: 3/4/16 **LER Screening Date:** 3/7/16 **cASP Criterion:** 3a
ASP Completion Date: 11/3/16 **Classification:** SDP Screen-Out

Analyst Justification: *Green* finding; LER closed in IR 05000341/2016001. A SDP bounding risk evaluation was performed for this event. The evaluation utilized SPAR-H to adjust the probability that operators would fail to manually trip the turbine, accounting for high stress. It conservatively used an exposure time of 5 minutes (event was 3.5 minutes) and a plant transient frequency of 1.0 per year (from 0.72 per year). The SDP bounding analysis resulted in a change in core damage frequency of less than 1×10^{-9} per year. This analysis has been reviewed and was determined to be appropriate for ASP Program needs. A search for other LERs at Fermi 2 was conducted to determine if there were any potential windowed events. It was determined that LERs 341-2015-007 and 341-2016-002 are not windowed events.

LER: 341-16-002 **Plant:** Fermi 2 **Event Date:** 1/22/16
LER Report Date: 3/22/16 **LER Screening Date:** 3/28/16 **cASP Criterion:** 3d
ASP Completion Date: 11/3/16 **Classification:** SDP Screen-Out

Analyst Justification: *Green* finding; LER closed in IR 05000341/2016002. A SDP bounding risk evaluation was performed for this event. The evaluation modeled the unavailability of all 4 residual hear removal (RHR)/low pressure coolant injection (LPCI) pumps for an exposure time of 1.8 hours (for LOCA scenarios only). The SDP bounding analysis resulted in a change in core damage frequency of less than 1×10^{-9} per year. For additional verification, a conservative/bounding ASP analysis was performed that modeled all 4 RHR/LPCI pumps unavailable (fail-to-run) with a condition duration of 2 hours. The analysis resulted in an increase in core damage probability (ΔCDP) of 3.5×10^{-8}, which is below the ASP Program precursor threshold of a ΔCDP greater than or equal to 1×10^{-6}. A search for other LERs at Fermi 2 was conducted to determine if there were any potential windowed events. It was determined that LERs 341-2016-001 and 341-2016-004 are not windowed events.

LER: 265-16-002 **Plant:** Quad Cities 2 **Event Date:** 4/25/16
LER Report Date: 6/24/16 **LER Screening Date:** 7/4/16 **cASP Criterion:** 3d
ASP Completion Date: 11/4/16 **Classification:** Analyst Screen-Out

Analyst Justification: No finding; LER closed in IR 05000265/2016003. A SDP bounding risk evaluation was not performed for this event. In LER 265-2016-002, the licensee documented an inoperable condition of the high pressure coolant injection (HPCI) outboard steam isolation valve for a specific period of 48-hours although the HPCI system remained capable of performing its intended design/safety function. During this period, the licensee did not find a simultaneous and/or overlapping unavailability or inoperability of other mitigating systems for LOCAs, transients, and other external events. For additional verification, a conservative/bounding ASP analysis was performed that modeled the HPCI pump fails to start which would effectively make the HPCI system inoperable with a condition duration of 49 hours. The analysis resulted in an increase in core damage probability (ΔCDP) of 6.9×10^{-9}, which is below the ASP Program precursor threshold of a ΔCDP greater than or equal to 1×10^{-6}. A search for other LERs at Quad Cities was conducted to determine if there were any potential windowed events. It was determined that LERs 265-2016-001 and 265-2016-003 are not windowed events.

LER: 317-16-004 **Plant:** Calvert Cliffs 1 **Event Date:** 11/13/15
LER Report Date: 7/20/16 **LER Screening Date:** 8/2/16 **cASP Criterion:** 3c
ASP Completion Date: 11/22/16 **Classification:** SDP Screen-Out

Analyst Justification: Two *Green* findings (IRs 05000317/2015004 and 05000317/2016002); LER is still open. A high-energy line break (HELB) barrier was opened on two occasions (for 3.5 minute each), which would have resulted in a loss of both service water trains, a motor-driven auxiliary feedwater (AFW) pump, and some other equipment during a postulated HELB. This barrier is required to be opened for transporting a new service water pump motor; however, work orders did not have had appropriate instructions per plant procedures (barrier should have been held open and not blocked). In addition, the licensee should have declared the system inoperable per technical specifications while the barrier was opened. The SDP analysis for this issue was bounding assessment that assumed the failure of all applicable equipment during a postulated HELB. This bounding analysis resulted in a maximum ΔCDF of 4×10^{-9} per year. This analysis has been reviewed and was determined to be appropriate for ASP Program needs. Even though there are multiple findings associated with this LER; they are both related to the same equipment; and therefore, an independent ASP analysis is not required. A review of Calvert Cliffs Unit 1 LERs reveal no events/degradations that would affect the potential risk of this event.

LER: 285-16-001 **Plant:** Fort Calhoun **Event Date:** 2/10/16
LER Report Date: 4/8/16 **LER Screening Date:** 4/11/16 **cASP Criterion:** 3g
ASP Completion Date: 11/22/16 **Classification:** Analyst Screen-Out

Analyst Justification: Not discussed in IRs through 05000285/2016002; LER remains open. On February 10, 2016, the licensee was alerted by a 10 CFR 21.21 notification from Canberra Industries, Inc. that a time delay relay installed in Containment and Auxiliary Building Stack Gaseous Swing Radiation Monitor RM-052 had not been properly verified or evaluated. The part was installed on July 23, 2013, and was replaced with a properly qualified time delay relay on March 19, 2016. RM-052 is one of three radiation monitors capable of initiating a containment high radiation signal with subsequent ventilation high radiation signal. During the time when RM-052 contained an unqualified part, there was always a least one radiation monitor capable of initiating a containment radiation high signal. This condition is of low safety significance. Process Radiation Monitoring is not typically modeled in Level-1 probabilistic risk assessment (PRA), as the system does not play a role in mitigation of core damage. Therefore, a search for windowed events is not required.

LER: 280-16-001 **Plant:** Surry 1 **Event Date:** 5/11/16
LER Report Date: 7/11/16 **LER Screening Date:** 8/12/16 **cASP Criterion:** 3c
ASP Completion Date: 11/22/16 **Classification:** SDP Screen-Out

Analyst Justification: *Green* finding; LER closed in IR 05000280/2016003. The SDP risk assessment performed a bounding analysis assuming the ESW pump B would be rendered unavailable for 1 year given a seismic event, which resulted in a ΔCDF of 6.3×10^{-8} per year. This result also includes two (short) periods of simultaneous unavailability of the other two ESW pumps. This analysis has been reviewed and was determined to be appropriate for ASP Program needs. A review of additional LERs revealed that there were no events that would have affected this seismic-related unavailability.

LER: 346-16-001 **Plant:** Davis-Besse **Event Date:** 1/29/16
LER Report Date: 3/29/16 **LER Screening Date:** 4/4/16 **cASP Criterion:** 4a
ASP Completion Date: 12/6/16 **Classification:** Analyst Screen-Out

Analyst Justification: Three *Green* findings (IRs 05000346/2016001 and 05000346/2016002); LER is closed (IR 05000346/2016002). None of the performance deficiencies resulted in a loss of function of a safety-related system or a loss of equipment designated as high safety-significance in accordance with the licensee's maintenance rule program. During the event, 1 of 4 offsite power sources was lost; however, offsite power was maintained throughout the event to all plant electrical buses. In addition, the auxiliary feedwater system continued to operate throughout this event and the reactor was verified to be stable. While there were several anomalies associated with the plant trip, an ASP analysis for this event is bounded by a loss of condenser heat sink initiating event and, therefore, this event is screened out of the ASP Program. A review of Davis-Besse LERs (i.e., for windowed events) revealed that during the recovery of main feedwater after the January 29th reactor trip, the licensee experienced another automatic actuation of the steam and feedwater line rupture control system (documented in LER 346-2016-002). An additional *Green* finding was identified related to this issue (IR 05000346/2016001) and LER 346-2016-002 was closed (IR 05000346/2016002). This additional issue does not affect the January 29, 2016, reactor trip being bounded by a loss of condenser heat sink because it assumes that main feedwater is not recoverable. All other LERs reviewed were determined to not affect this event.

LER: 247-16-007 **Plant:** Indian Point 2 **Event Date:** 6/10/16
LER Report Date: 8/9/16 **LER Screening Date:** 8/23/16 **cASP Criterion:** 3d
ASP Completion Date: 12/8/16 **Classification:** SDP Screen-Out

Analyst Justification: *Green* finding (IR 05000247/2016002); LER remains open. With the unit in Mode 4, two barrier gates for the sump were simultaneously open for approximately 1 hour while scaffolding was moved out of the crane wall. These two simultaneously open gates resulted in a violation of Technical Specification 3.5.3 (ECCS-Shutdown), which requires one RHR subsystem and one ECCS recirculation subsystem to be operable in Mode 4. The operability basis for the ECCS sump requires that at least one door be secured in Modes 1–4 to prevent debris blockage of the containment and recirculation sumps in the event of a LOCA. An SDP analysis calculated a $\Delta CDF = 7\times10^{-9}$ for this event, which conservatively assumes the complete failure of both sumps for an exposure period of 1 day. In addition, this analysis does not account for the lower LOCA probabilities (and subsequent decrease in debris generation) while in Mode 4. This bounding analysis has been reviewed and was determined to be appropriate for ASP Program needs. The calculated risk is below the ASP precursor threshold of 1×10^{-6} and a search of LERs did not yield any windowed events with this condition; therefore, this event is screened out and not considered a precursor under the ASP Program.

LER: 251-16-001 **Plant:** Turkey Point 4 **Event Date:** 5/3/16
LER Report Date: 6/30/16 **LER Screening Date:** 7/18/16 **cASP Criterion:** 3a
ASP Completion Date: 12/9/16 **Classification:** Analyst Screen-Out

Analyst Justification: Not discussed in IRs through 05000251/2016003; LER remains open. Reactor protection system over-temperature delta T (OTDT) and overpressure delta T (OPDT) channel III was inoperable for 5 days due to incorrect coefficient inputs to a resistance temperature detector. OTDT and

OPDT are three channel systems that require two out of three logic to activate a reactor trip. During the 5 days when channel III was inoperable, the remaining channels were taken out of service for test and maintenance totaling 4 hours (without setting the test/maintenance channel in the trip condition). As a result, the OTDT and OPDT systems were not capable of activating the reactor protection system during a 4 hour period because the two out of three logic could not be satisfied with only one operable channel. This is in violation of Technical Specification 3.3.1 (reactor trip system instrumentation). Individual reactor trip system functional units are not commonly modeled in SPAR models, partially due to the defense in depth of the reactor protection system to cause a trip via alternate and diverse means. A similar NRC analysis performed in support of the SDP (IR 05000251/2016002 Section 1R17.2) estimated a ∆CDF of 1×10^{-8} per year for the failure of OPDT and OTDT trips at Turkey Point. A search of LERs did not reveal any windowed events. The defense in depth of reactor trips combined with the short exposure period are sufficient to qualitatively screen this event as not being a precursor under the ASP Program.

LER: 346-16-004 **Plant:** Davis-Besse **Event Date:** 4/5/16
LER Report Date: 6/6/16 **LER Screening Date:** 6/13/16 **cASP Criterion:** 3a
ASP Completion Date: 12/13/16 **Classification:** SDP Screen-Out

Analyst Justification: Two *Green* findings (IR 05000346/2016003); LER is closed (IR 05000346/2016003). Davis-Besse operated with degraded RCS resistance temperature detectors (RTDs) for longer than their allowed technical specification outage time. The reactor coolant system includes 12 RTDs arranged in pairs (3 pairs per coolant loop) that supply temperature inputs to the Reactor Protection System (RPS) and other monitoring systems. The RTDs input into two of the reactor trip signals (High RCS Hot Leg Temperature and Variable Low RCS Pressure). The high temperature trip is not required as the primary protection for any transient, and the variable low pressure is the primary trip for only a RCS letdown line rupture event. Two performance deficiencies (PDs) were identified in relation to this event. The first PD involved inadequate instructions to correctly assemble electrical conductor seal assemblies that provide an environmental barrier for the RTDs. The second PD identified incorrectly designed and installed insulation packages around the RTDs. Wire insulation degradation due to the identified PDs rendered the RTDs incapable of performing their reactor trip safety function during the previous operating cycle. A detailed risk analysis performed in support of the SDP (IR 05000346/2016003 Section 4OA3.5) resulted in a ∆CDF of less than 1×10^{-7} per year for the inoperability of more than one channel of RPS due to the degradation of the RTDs. 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. This analysis was determined to be appropriate for ASP Program needs. The calculated risk is below the ASP precursor threshold of 1×10^{-6} and a search of LERs did not yield any windowed events that impact the risk significance of this condition; therefore, this event is screened out and not considered a precursor under the ASP Program.

LER: 311-15-003 **Plant:** Salem 2 **Event Date:** 11/23/15
LER Report Date: 1/22/16 **LER Screening Date:** 2/1/16 **cASP Criterion:** 3d
ASP Completion Date: 12/15/16 **Classification:** Analyst Screen-Out

Analyst Justification: Additional information related to the event is not provided in IRs through 05000311/2016003; LER remains open. While the plant was in Mode 3, the boron injection tank (BIT) relief valve exhibited increase leakage (during troubleshooting of low BIT pressure) resulting in reactor coolant system (RCS) leak >10 gpm. Leakage was terminated within 1 minute when operators closed the BIT inlet isolation valve, which resulted in the inoperability of high-head charging flow. Note that the safety injection pumps remained operable. Technical Specification 3.0.3 was entered and the plant was placed in Mode 4 within 6 hours and Mode 5 within 12 hours. A bounding analysis was run assuming the unavailability of high-head charging flow for 1 day (Technical Specification 3.0.3 requires the plant to be in Mode 5 within 24 hours). The ΔCDP for this analysis was calculated to be 4×10^{-8}, which is conservative. A search of LERs did not yield any windowed events with this condition; therefore, this event is not considered a precursor under the ASP Program.

LER: 324-16-001 **Plant:** Brunswick 2 **Event Date:** 6/15/16
LER Report Date: 8/8/16 **LER Screening Date:** 8/29/16 **cASP Criterion:** 3h
ASP Completion Date: 12/15/16 **Classification:** SDP Screen-Out

Analyst Justification: *Green* finding; LER closed in IR 05000324/2016003. Between June 4, 2016, and June 15, 2016, two incorrectly positioned valves would have prevented the 2B residual heat removal service water (RHRSW) subsystem pumps to start on demand. This condition violates Technical Specification 3.7.1, which requires both RHRSW subsystems to be operable in Mode 1. A detailed risk analysis performed in support of the SDP resulted in a finding of very low safety significance (*Green*) for an 11 day exposure period. Possible recovery actions that contribute to the low risk significance of the event include repositioning the valves and/or pushing service water through the inoperable pumps to provide adequate cooling in non-LOCA sequences. This analysis was determined to be appropriate for ASP Program needs. The calculated risk is below the ASP precursor threshold of 1×10^{-6} and a search of LERs did not yield any windowed events that impact the risk significance of this condition; therefore, this event is screened out and not considered a precursor under the ASP Program.

LER: 324-16-002 **Plant:** Brunswick 2 **Event Date:** 7/5/16
LER Report Date: 8/29/16 **LER Screening Date:** 9/15/16 **cASP Criterion:** 3d
ASP Completion Date: 12/21/16 **Classification:** SDP Screen-Out

Analyst Justification: *Green* finding; LER closed in IR 05000324/2016003. The SDP risk assessment performed a detailed risk review using SAPHIRE for the failure of the high pressure coolant injection (HPCI) auxiliary oil pump motor overload relay which resulted in the inoperability of the Unit 2 HPCI pump and determined that the CDF risk was less than 1×10^{-6}. This inspection report stating the results of the analysis has been reviewed and did not necessitate a reanalysis for the ASP Program. This event is not a precursor. A review of additional LERs revealed no windowed events.

LER: 259-16-002 **Plant:** Browns Ferry 1 **Event Date:** 4/20/16
LER Report Date: 9/19/16 **LER Screening Date:** 9/29/16 **cASP Criterion:** 3d
ASP Completion Date: 12/22/16 **Classification:** SDP Screen-Out

Analyst Justification: *Green* finding; LER is closed (IR 05000259/2016003). On July 20, 2016, operations personnel attempted to restore the HPCI system after scheduled maintenance; however, the steam line inboard primary containment isolation valve (1-FCV-0730002) could not be opened. Since this valve is located inside primary containment, operators manually shutdown the reactor on July 26th to initiate repairs. The cause of the inoperability was tensile failure of the valve stem caused by unintentional back-seating during the valve stroke test on April 20, 2016. The valve remained open despite the stem fracture until it was closed for maintenance on July 18th. A detailed risk analysis performed in support of the SDP resulted in a finding of very low safety significance (*Green*) for a 7-day exposure period. This analysis was determined to be appropriate for ASP Program needs. The calculated risk is below the ASP precursor threshold of 1×10^{-6}. This event is potentially windowed with LER 259-16-004, and the ASP review of LER 259-16-004 will account for any potential risk significance of these concurrent degradations. Therefore, this event is not considered a precursor under the ASP Program.

LER: 387-16-007 **Plant:** Susquehanna 1 **Event Date:** 3/5/16
LER Report Date: 5/3/16 **LER Screening Date:** 5/9/16 **cASP Criterion:** 3d
ASP Completion Date: 12/23/16 **Classification:** Analyst Screen-Out

Analyst Justification: No finding to date; LER remains open. During surveillance testing, an automatic transfer switch (ATS) failed to close in on the alternate power supply. The cause was determined to be an upper linkage rod that was too long resulting in continuous cycling of the switch without latching in the alternate position. With the ATS in an unlatched state, any required LPCI injection from Division 2 RHR would not occur as designed because valves would not be in the proper alignment for injection. The scenario in which this degraded condition is applicable is a LOCA (when LPCI is required) with a coincident LOOP (primary source of power). There was no unavailability of LPCI (actual loss of function) unless the primary power source is assumed lost. Under the SDP, this event should screen to *Green*. During the period when this degraded condition existed, Division 1 RHR was unavailable due to scheduled maintenance. Therefore, an ASP analysis was performed to confirm the disposition of this event. A screening analysis resulted in a ΔCDP of 6×10^{-8} for the 64-hour period when both LPCI injection valves would not have opened and 4×10^{-8} for the 30-day period when the B LPCI injection valve would not have opened. The aggregate risk from these two periods is less than the ASP Program threshold of 1×10^{-6}. This analysis is significantly conservative because a LOCA would have to occur coincident with a LOOP. The frequencies of these events are on the order of 10^{-4} and 10^{-2} per year, respectively. A review of Susquehanna Unit 1 LERs did not yield any windowed events that impact the risk significance of this condition; therefore, this event is screened out and not considered a precursor under the ASP Program.

LER: 298-16-001 **Plant:** Cooper **Event Date:** 4/25/16
LER Report Date: 6/21/16 **LER Screening Date:** 7/4/16 **cASP Criterion:** 3d
ASP Completion Date: 12/23/16 **Classification:** Analyst Screen-Out

Analyst Justification: See Notes section for LER 298-2016-002; LERs 298-2016-001 and 298-2016-002 were considered windowed.

LER: 298-16-002 **Plant:** Cooper **Event Date:** 4/26/16
LER Report Date: 6/27/16 **LER Screening Date:** 7/11/16 **cASP Criterion:** 3d
ASP Completion Date: 12/23/16 **Classification:** Analyst Screen-Out

Analyst Justification: LER 298-2016-001 was closed in IR 05000298/2016002; no findings were identified. LER 298-2016-002 was also closed in IR 05000298/2016002; however, a *Green* finding was identified for the licensee's failure to provide adequate design control measures associated with a 1984 design modification that eliminated a resistor that served to protect the starter circuit from shorting (due to indication light bulb failures). Both LERs indicated that service water pump B and service water booster pump B were inoperable during the period of HPCI pump inoperability; therefore, an ASP analysis is required to disposition this event. On April 25, 2016, operators observed that the green off light for HPCI auxiliary oil pump was not illuminated. Investigation determined that the auxiliary oil pump could not be started due to a failed relay. The relay had been recently installed as part of preventive maintenance activities on April 19, 2016. The relay was subsequently replaced and HPCI was declared operable on April 26th at 1:14 p.m. The licensee concluded that the relay had failed on April 25th after only 133 hours of service. Within a few hours, operators observed that the HPCI auxiliary oil pump green off light was not lit (again). Operators attempted to start the auxiliary oil pump, but it failed to start and HPCI was declared inoperable at 5:54 p.m. Investigations revealed that HPCI auxiliary oil pump green light bulb had shattered in its socket. The green bulb and its associate socket were replaced (along with the red bulb and 125V DC fuses). HPCI was declared operable at 12:45 p.m., on April 28th. A bounding ASP condition assessment was performed assuming the HPCI pump, service water pump B, and service water booster pump B were conservatively (concurrently) unavailable for 9 days (April 19th to April 28th). The calculated ΔCDP was 6×10^{-7} which is below the ASP Program precursor threshold of 1×10^{-6}. A review of Cooper Nuclear Station LERs did not yield any other windowed events; therefore, this event is not considered a precursor under the ASP Program.

LER: 296-16-006 **Plant:** Browns Ferry 3 **Event Date:** 6/8/16
LER Report Date: 8/5/16 **LER Screening Date:** 12/16/16 **cASP Criterion:** 3d
ASP Completion Date: 12/23/16 **Classification:** Analyst Screen-Out

Analyst Justification: Not discussed in IRs through 05000296/2016003; LER remains open. During surveillance testing of the HPCI system on June 8, 2016, the HPCI turbine stop valve exhibited erratic opening and closing behavior before settling in an open position. The ASP analyst assumed that if a valid HPCI initiation signal was given prior to the performance of this surveillance test, the HPCI system would have started normally and provided the design flow rate to the reactor vessel. An engineering analysis identified a degraded reset spring in the HPCI mechanical trip valve as the cause of the HPCI turbine stop valve instability. The spring was replaced and HPCI was returned to service on June 10th. The duration of HPCI unavailability was less than the technical specifications allowed outage time; therefore, there is sufficient evidence to qualitatively screen this event as not a precursor. To confirm this classification, a bounding condition assessment assuming HPCI unavailability for a 2-day exposure period, without credit for recovery, was performed by an ASP analyst and yielded a ΔCDP = 9×10^{-8}. The calculated risk is below the ASP precursor threshold of 1×10^{-6} and a search of LERs did not yield any windowed events that impact the risk significance of this condition; therefore, this event is screened out and not considered a precursor under the ASP Program.

LER: 237-16-002 **Plant:** Dresden 2 **Event Date:** 5/16/16
LER Report Date: 9/30/16 **LER Screening Date:** 12/16/16 **cASP Criterion:** 3d
ASP Completion Date: 12/28/16 **Classification:** SDP Screen-Out

Analyst Justification: *Green* finding; LER closed in IR 05000237/20160. A through-wall steam leak was observed in the HPCI inlet drain pot drain piping. A performance deficiency was identified due to the licensee failure to establish maintenance planning procedures appropriate to the circumstances that could affect the performance of safety-related equipment. The SDP determination of very low safety significance (i.e., *Green*) associated with this performance deficiency was completed using IMC 0609, Appendix A, Exhibit 2 (i.e., no loss of safety function). A search of LERs did not yield any windowed events with this condition; therefore, this event is not considered a precursor under the ASP Program.

LER: 260-16-002 **Plant:** Browns Ferry 2 **Event Date:** 3/16/16
LER Report Date: 9/13/16 **LER Screening Date:** 9/29/16 **cASP Criterion:** 3d
ASP Completion Date: 12/28/16 **Classification:** Analyst Screen-Out

Analyst Justification: Severity Level IV NCV identified for failure to notify the NRC of a condition that could have prevented the fulfillment of a safety function (IR 05000260/2016002); LER is closed (IR 05000260/2016003). HPCI steam admission valve failed a surveillance test due to a stuck contactor in the valve motor breaker. The failure was likely the result of excessive cycling during maintenance repacking of the valve on March 17, 2016. The valve was repaired and returned to service on March 21, 2016. HPCI would not have fulfilled its safety function for the 3 day 4 hour period of time when the valve was failed. Upon discovery of the failed HPCI valve, the RCIC system was verified operable in accordance with Technical Specification 3.5.1 (ECCS). Bounding analyses conducted by the ASP Program Analyst and Reviewer for a 4-day exposure period yielded a ΔCDP = 2.8×10^{-7} (did not include any recovery action for manually positioning the valve). The calculated risk is below the ASP precursor threshold of 1×10^{-6} and a search of LERs did not yield any windowed events that impact the risk significance of this condition; therefore, this event is screened out and not considered a precursor under the ASP Program.

LER: 220-16-002 **Plant:** Nine Mile Point 1 **Event Date:** 7/28/16
LER Report Date: 9/26/16 **LER Screening Date:** 10/11/16 **cASP Criterion:** 3d
ASP Completion Date: 12/28/16 **Classification:** Analyst Screen-Out

Analyst Justification: Additional information related to the event is not provided in IRs through 05000220/2016003; the LER remains open. An uninterruptible power supply unexpectedly transferred to its bypass power supply. Unexpectedly, and as a result of this transfer, the RPS channel 11 instrument bus and its associated output loads were de-energized. This resulted in numerous half scram and half isolation signals. In addition, both emergency condensers were isolated. Operators restored operability to both emergency condensers within 1 hour. The LER states that the emergency condensers were recoverable and plant procedures direct these restoration activities. Bounding analyses by the ASP analyst and reviewer for the (non-recoverable) unavailability of both emergency condensers for 1 hour yields a ΔCDP of 1.5×10^{-8}. A search of LERs did not yield any windowed events with this condition; therefore, this event is not considered a precursor under the ASP Program.

LER: 336-16-001 **Plant:** Millstone 2 **Event Date:** 4/27/16
LER Report Date: 6/27/16 **LER Screening Date:** 7/4/16 **cASP Criterion:** 3b
ASP Completion Date: 12/28/16 **Classification:** Analyst Screen-Out

Analyst Justification: Not discussed in IRs through 05000336/2016003; LER remains open. High-energy line break (HELB) barrier door was propped open for 1 hour on April 27, 2016. Auxiliary feedwater (both motor-driven pumps and the turbine-driven pump), condensate (3 pumps), and main feedwater (2 pumps) systems could have been inoperable due to a HELB. A bounding condition assessment for 1 hour was conducted by the ASP Analyst and Reviewer using the SPAR model, resulting in a ΔCDP of 2.2×10^{-7} for the steam line break outside of containment event tree. The calculated results for the steam line break outside of containment event tree were used because the postulated unavailability only occurs during this type of initiating event. This calculation conservatively assumes the HELB occurs within the turbine building auxiliary feedwater pump room. The calculated risk is below the ASP precursor threshold of 1×10^{-6} and a search of LERs did not yield any windowed events that impact the risk significance of this condition; therefore, this event is screened out and not considered a precursor under the ASP Program.

LER: 293-16-007 **Plant:** Pilgrim **Event Date:** 9/6/16
LER Report Date: 11/4/16 **LER Screening Date:** 11/23/16 **cASP Criterion:** 4a
ASP Completion Date: 1/12/17 **Classification:** Analyst Screen-Out

Analyst Justification: Not discussed in IRs through 05000293/2016003; LER remains open. Operators manually scrammed the reactor due to increasing reactor water level caused by a failed feedwater regulating valve. During the event, the reactor high water alarm led to closure of the MSIVs, which operators subsequently reopened. This event is bounded by a non-recoverable loss of condenser heat sink (CCDP = 1.7×10^{-5}). Note that the LER provides a conservative risk assessment for this event that resulted in CCDP of 3.5×10^{-6}. A search of LERs did not yield any windowed events with this condition; therefore, this event is not considered a precursor under the ASP Program.

LER: 327-16-004 **Plant:** Sequoyah 1 and 2 **Event Date:** 5/16/16
LER Report Date: 7/15/16 **LER Screening Date:** 7/18/16 **cASP Criterion:** 3e
ASP Completion Date: 1/13/17 **Classification:** SDP Screen-Out

Analyst Justification: *Green* finding in IR 05000327/2016007; LER remains open. In May and June 2016, two potential nonconforming conditions were identified involving emergency diesel generator (EDG) operability in the event of a postulated tornado strike. First, it is possible that the differential pressure generated by a tornado could result in failure of the ventilation fire dampers in a way that impedes EDG cooling. Second, the differential pressure generated by a tornado could potentially activate the EDG crankcase pressure trip (requiring a manual reset before EDGs can start on a normal or emergency signal). Note, the EDG crankcase pressure trip is bypassed when EDGs are already running, and would not impact the operability of the EDGs if a weather-related LOOP occurred prior to the tornado-generated winds reaching the site. As compensatory measures, the licensee will block open the fire dampers and start the EDGs in the event that a tornado watch/warning is issued for the local area. The failure to install components important to safety that can withstand the effects of a design basis tornado as required by Section 3.1.2 of the UFSAR is a performance deficiency. A risk analysis performed in support of the SDP resulted in a finding of very low safety significance (*Green*). The risk was mitigated by the low tornado frequency and the potential for recovery by the operators. This analysis was determined to be appropriate for ASP Program needs. The calculated risk is below the ASP precursor threshold of 1×10^{-6}; therefore, this event is not considered a precursor in the ASP Program. A review of LERs within 1 year of the nonconforming conditions was performed and did not yield any windowed events that would impact the risk significance of this event assessment.

LER: 346-16-006 | **Plant:** Davis-Besse | **Event Date:** 6/16/16
LER Report Date: 8/15/16 | **LER Screening Date:** 8/24/16 | **cASP Criterion:** 3e
ASP Completion Date: 1/13/17 | **Classification:** Analyst Screen-Out

Analyst Justification: Not mentioned in any IR to date; LER remains open. An industry operating experience report issued in June 2016 identified the potential for differential pressure changes caused by a tornado to actuate the EDG high crankcase pressure switches, which would result in the lock out of the affected EDG(s). An EDG lockout would prevent the manual or automatic start of the affected EDG(s) until operators manually reset the lockout. At Davis Besse, 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 1.2×10^{-5} (using available tornado data through 2006 and methods in NUREG-1461, Revision 2). As such, this is a low likelihood event. Given this low frequency combined with a number of factors, the risk (ΔCDP) of this degraded condition is expected to be below the ASP threshold of 1×10^{-6}. This conclusion is based on, first, not all tornadoes that hit the site would cause the differential pressures within the EDG rooms to trigger the high crankcase pressure switch that would result in the lockout of both EDGs. Secondly, the EDGs would have to be in standby mode when the tornado strikes the site in order to be susceptible to the high crankcase pressure lockout. It is more likely that the tornado would originate away from the site and cause a LOOP resulting in an automatic start of the EDGs prior to the tornado hitting the EDG rooms. Lastly, as the tornado moves away from the site, it is likely that operators could recover at least one EDG after resetting the lockout because the differential pressure condition would no longer exist. In addition, severe weather abnormal operating procedures may preemptively direct an equipment operator to the diesel generator rooms given the potential for grid instability. Based on these assumptions, this event is qualitatively screened out as not a precursor in the ASP Program. A review of the LERs within 1 year of the event date was performed, no windowed events were identified. Note that after this issue was identified, the licensee developed and implemented a temporary modification to disable the EDG high crankcase pressure switch trip function for the EDGs.

LER: 390-16-010 | **Plant:** Watts Bar 1 | **Event Date:** 6/8/16
LER Report Date: 8/8/16 | **LER Screening Date:** 8/26/16 | **cASP Criterion:** 3e
ASP Completion Date: 1/13/17 | **Classification:** Analyst Screen-Out

Analyst Justification: Not mentioned in any IR to date; LER remains open. An industry operating experience report issued in June 2016 identified the potential for differential pressure changes caused by a tornado to actuate the EDG high crankcase pressure switches, which would result in the lock out of the affected EDG(s). An EDG lockout would prevent the manual or automatic start of the affected EDG(s) until operators manually reset the lockout. At Watts Bar, 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 2.2×10^{-5} (using available tornado data through 2006 and methods in NUREG-1461, Revision 2). As such, this is a low likelihood event. Given this low frequency combined with a number of factors, the risk (ΔCDP) of this degraded condition is expected to be below the ASP threshold of 1×10^{-6}. This conclusion is based on, first, not all tornadoes that hit the site would cause the differential pressures within the EDG rooms to trigger the high crankcase pressure switch that would result in the lockout of both EDGs. Secondly, the EDGs would have to be in standby mode when the tornado strikes the site in order to be susceptible to the high crankcase pressure lockout. It is more likely that the tornado would originate away from the site and cause a LOOP resulting in an automatic start of the EDGs prior to the tornado hitting the EDG rooms. Lastly, as the tornado moves away from the site, it is likely that operators could recover at least one EDG after resetting the lockout because the differential pressure condition would no longer exist. In addition, severe weather abnormal operating procedures may preemptively direct an equipment operator to the diesel generator rooms given the potential for grid instability. Based on these assumptions, this event is qualitatively screened out as not a precursor in the ASP Program. A review of the LERs within 1 year of the event date was performed, no windowed events were identified. Note that after this issue was identified, the licensee established a compensatory measure to start and run the EDGs during the time a tornado warning is in effect.

LER: 346-16-009 **Plant:** Davis-Besse **Event Date:** 9/10/16
LER Report Date: 11/9/16 **LER Screening Date:** 11/23/16 **cASP Criterion:** 4
ASP Completion Date: 3/9/17 **Classification:** Analyst Screen-Out

Analyst Justification: *Green* finding; LER closed in IR 05000346/2016004 (aspects of this event were also discussed in IR 05000346/2016003). On September 10, 2016, a reactor trip occurred after rain water migrated into the automatic voltage regulator cabinet causing a main electrical generator lockout. Following the reactor trip, the steam feedwater rupture control system (SFRCS) actuated due to high steam generator (SG) 1 level. This complicated the response to the trip by removing main feedwater and initiating AFW to supply both SGs, and by removing the main condenser as the plant's heat sink, forcing operators to vent steam to the atmosphere. It was determined that the high SG 1 level was a result of a failure of the integrated control system to maintain water level due to a circuit component failure. The SDP analysis for the rainwater intrusion event screened to Green (very low safety significance). The SDP analysis, appropriately, did not consider the effects of the SFRCS actuation because it was a result of an independent failure mechanism in which there was no licensee performance deficiency. As such, an independent review of this event is required by the ASP Program to account for the potential combined effects of the reactor trip and loss of mitigation equipment. An ASP analysis for this event is bounded by a loss of condenser heat sink initiating event and, therefore, is not considered a precursor in the ASP Program. A review of Davis-Besse LERs (i.e., for windowed events) did not reveal any events/degradations that would affect the potential risk of this event.

LER: 382-16-002 **Plant:** Waterford 3 **Event Date:** 8/12/16
LER Report Date: 10/11/16 **LER Screening Date:** 11/3/16 **cASP Criterion:** 3g
ASP Completion Date: 3/17/17 **Classification:** SDP Screen-Out

Analyst Justification: *Green* finding; LER closed in IR 05000382/2016004. On August 12, 2016, the licensee entered Technical Specification (TS) 3.0.3., which requires shutting down the plant within 1 hour, due to the simultaneous unavailability of both trains of chilled water. Within 1 hour, the licensee declared essential chiller AB operable and exited TS 3.0.3. In troubleshooting the event, the licensee found that the guide vane arm and actuator linkage for essential chiller B was assembled inappropriately. Essential chiller A was already inoperable due to a previous component failure. The failure to perform post-maintenance testing on essential chiller B with procedures that included appropriate quantitative or qualitative acceptance criteria for determining that maintenance activities were satisfactorily accomplished was a performance deficiency. The SDP determination of very low safety significance (i.e., *Green*) associated with this performance deficiency was completed using IMC 0609, Appendix A, Exhibit 2. A search of LERs did not yield any windowed events with this condition; therefore, this event is not considered a precursor under the ASP Program.

LER: 361-16-003 **Plant:** Robinson 2 **Event Date:** 8/11/16
LER Report Date: 10/10/16 **LER Screening Date:** 11/3/16 **cASP Criterion:** 3e
ASP Completion Date: 3/17/17 **Classification:** SDP Screen-Out

Analyst Justification: *Green* finding; LER closed in IR 05000261/2016004. On August 11, 2016, the licensee determined that the failure of the two Lake Robinson tainter gates to open during testing represented an unanalyzed condition that significantly degraded the plant's ability to cope with the worst case design basis external site flooding events. Corrosion buildup on the chains caused the tainter gates to bind, preventing full travel. Inspectors determined that the licensee's failure to scope the external flood protection function of the tainter gates in the Maintenance Rule monitoring program was a performance deficiency. In IR 05000261/2016003, as part of the SDP, a detailed risk evaluation was performed in accordance with IMC 0609 Appendix A and Appendix M (SDP Using Qualitative Criteria). The high uncertainty associated with estimating flood frequencies was the reason for using the Appendix M approach. The resulting ΔCDF was less than 1×10^{-6} per year, which corresponds to a *Green* finding (very low safety significance). The risk was mitigated by the low flood frequency and the potential recovery of the tainter gates prior to site flooding. A search of LERs did not yield any windowed events that impacted the risks associated with this event; therefore, this event is not considered a precursor under the ASP Program.

LER: 361-16-001 **Plant:** Robinson 2 **Event Date:** 1/19/16
LER Report Date: 3/21/16 **LER Screening Date:** 3/28/16 **cASP Criterion:** 3b
ASP Completion Date: 3/17/17 **Classification:** SDP Screen-Out

Analyst Justification: *Green* finding; LER closed in IR 05000261/2016001. In 1978, the licensee installed a valve outside of design specifications for the service water system. This was a performance deficiency. When the valve failed, it resulted in a reduction of cooling water flow to the motor-driven auxiliary feedwater (AFW) pump trains. This degraded condition rendered the “A” motor-driven train of the AFW system inoperable for approximately 38 days. A detailed risk evaluation was performed in support of the SDP, which calculated a ΔCDF of 7.6×10^{-7} (including internal fires and external hazards). The major analysis assumptions included exposure periods for loss of a single motor-driven AFW train for 38 days and loss of both trains of motor-driven AFW for a period of 3 hours. No recovery was assumed. The risk associated with this event was mitigated by the availability of alternate AFW trains. Reviews by the ASP Program analyst and reviewer on the basis for the *Green* finding found that it was appropriate for ASP Program needs. The calculated risk is below the ASP precursor threshold of 1×10^{-6} and a search of LERs did not yield any windowed events that impact the risk significance of this condition; therefore, this event is not considered a precursor under the ASP Program.

LER: 458-16-005 **Plant:** River Bend **Event Date:** 2/4/16
LER Report Date: 4/25/16 **LER Screening Date:** 5/17/16 **cASP Criterion:** 3e
ASP Completion Date: 3/17/17 **Classification:** SDP Screen-Out

Analyst Justification: *Green* finding; LER closed in IR 05000458/2016003. A performance deficiency was identified due to the licensee failure to appropriately resolve binding vulnerabilities in Masterpact circuit breakers which could have adversely affected the emergency diesel generator room ventilation fans, standby gas treatment fans, auxiliary building coolers, and containment coolers. Specifically, these breakers may not have automatically closed after receiving simultaneous 'open' and 'close' signals (e.g., during concurrent LOOP and LOCA). The SDP risk assessment calculated the risk increase given that concurrent LOOP and LOCA condition would result in breaker failures to automatically close in the affected systems during a maximum exposure period of 1 year. Credit for operators to manually close the breakers was provided in the analysis. This analysis resulted in a ΔCDF of 2.1×10^{-7}. This analysis has been reviewed and was 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 in the ASP Program. A review of additional LERs revealed that there were no windowed events that would affect the frequency of simultaneous 'open' and close signals for the affected breakers (i.e., concurrent LOOP and LOCA event).

LER: 528-16-002 **Plant:** Palo Verde 1 **Event Date:** 9/7/16
LER Report Date: 11/4/16 **LER Screening Date:** 11/17/16 **cASP Criterion:** 4
ASP Completion Date: 3/10/17 **Classification:** Analyst Screen-Out

Analyst Justification: Discussed in IRs 05000528/2016003 and 05000528/2016004 (no findings); LER remains open. Pressurizer spray valve 100F remained approximately 5% open despite a close signal from the spray valve controller. The pressurizer spray valve stuck open due to binding of a pneumatic volume booster following a voltage transient that resulted in a calibration offset. The reactor was manually tripped on September 7, 2016, due to low pressurizer pressure, and the RCPs were secured to terminate pressurizer spray flow. Prior to the observation of a stuck pressurizer spray valve, a leaking sprinkler head in a fire protection line resulted in water intrusion into a 480 VAC load center. In order to perform an inspection of the load center, several loads were transferred to their alternate power sources. A failed circuit component caused a malfunction in the D11 transfer switch, resulting in the voltage transient that mis-positioned the pressurizer spray valve. The plant responded to the trip as designed and no ESF actuations occurred. The ASP analyst determined that this initiating event is bounded by a non-recoverable loss of condenser heat sink; therefore, this event is not considered a precursor under the

ASP Program. The risk significance of this transient is not impacted by the lack of forced circulation from the RCPs. The tripping of the RCPs may decrease the risk of a LOCA during a loss of all RCP seal cooling/injection. This event is windowed with LER 528-19-003, which reports a failed containment isolation valve. However, this concurrent degradation does not affect the risk of core damage; therefore, is not considered in the risk assessment of LER 528-16-002.

LER: 278-16-001	**Plant:** Peach Bottom 3	**Event Date:** 9/26/16
LER Report Date: 11/22/16	**LER Screening Date:** 12/11/16	**cASP Criterion:** 3d
ASP Completion Date: 4/12/17	**Classification:** Analyst Screen-Out	

Analyst Justification: The unplanned unavailability of HPCI was mentioned in IR 05000278/2016003 (Sections 1R13 and 1R19) as part of baseline inspection activities; no findings were identified; the LER remains open. The HPCI system was declared inoperable as a result of a small leak (two drops per minute) in a drain line. The pressure boundary of the HPCI system must be maintained for operability. However, if a design basis event had occurred, the HPCI system would have been able to perform its design function. The leak was discovered on 9/26/16 and was repaired on 9/28/16. The HPCI system was last operated the previous day (9/25/16) and no leaks were noted. A bounding analysis by the ASP Program Analyst and Reviewer for the (non-recoverable) unavailability of HPCI for 4 days yielded a ΔCDP of 2.5×10^{-7}. The calculated risk is below the ASP precursor threshold of 1×10^{-6} and a search of LERs did not yield any windowed events with this condition; therefore, this event is not considered a precursor under the ASP Program.

LER: 440-16-002	**Plant:** Perry	**Event Date:** 2/8/16
LER Report Date: 4/8/16	**LER Screening Date:** 4/18/16	**cASP Criterion:** 4
ASP Completion Date: 4/28/17	**Classification:** Analyst Screen-Out	

Analyst Justification: *Green* finding (IR 05000440/2016008); LER closed in IR 05000440/2016002. A pressure/level perturbation in an instrumentation reference leg caused 13 SRVs to open, 11 immediately closed and 2 remained open as designed until a manual scram due to suppression pool temperature rise, with reduced pressure, caused the remaining two SRVs to close. The *Green* SDP finding was due to the licensee failure to provide proper instruction to fill and vent the reactor water level reference leg purge system. The SDP evaluation determined this performance deficiency to be of very low safety significance (i.e., *Green*) because the finding did not result in exceeding the RCS leak rate for a small LOCA, cause a reactor trip, involve the complete or partial loss of a support system that contributes to the likelihood of, or cause an initiating event; and did not affect mitigation equipment. An ASP analysis is required since an initiating event occurred. A bounding analysis assuming a stuck-open relief valve initiating event, which is conservative for this event since the relief valve closed after the reactor was scrammed. This analysis resulted in a CCDP of 4×10^{-6}, which is less than plant-specific CCDP for a non-recoverable loss of feedwater and condenser heat sink (5×10^{-6}). Therefore, this event is below the ASP Program threshold for an initiating event, and thus, is not a precursor. An event occurring the previous month does not affect this analysis. Another event occurring three days later is still under review. That subsequent review will capture any increased risk associated with this event.

LER: 354-16-001	**Plant:** Hope Creek	**Event Date:** 4/7/16
LER Report Date: 10/4/16	**LER Screening Date:** 11/3/16	**cASP Criterion:** 3d
ASP Completion Date: 4/21/17	**Classification:** Analyst Screen-Out	

Analyst Justification: Discussed briefly in IR 05000354/2016003; LER remains open. During post maintenance testing on April 7, 2016, the HPCI turbine was momentarily tripped by the over-speed assembly, and then reset itself with no operator action. The condition could have been present since the system was last successfully run for testing on March 1, 2016. The system remained capable of injecting water into the reactor vessel but, because of the momentary trip and reset, the system would not have met the full flow injection time TS limit of 35 seconds (took a little over a minute to reach full flow). The ASP analyst determined that this HPCI full flow injection time limit delay did not significantly impact the safety function and inspectors determined that minor performance deficiencies did not impact the operability of the HPCI system. Troubleshooting determined that the reset spring had relaxed to a tension of one pound, which is outside the prescribed range of 2 to 5 pounds. The spring was adjusted to 3.5 pounds and the system retested satisfactorily. Because the HPCI system remained capable of fulfilling its safety function, there is sufficient evidence to qualitatively screen this event as not a precursor. A search of LERs did not yield any windowed events that impact the risk significance of this condition; therefore, this event is screened out and not considered a precursor under the ASP Program.

LER: 341-16-011 **Plant:** Fermi **Event Date:** 10/28/16
LER Report Date: 12/20/16 **LER Screening Date:** 1/13/17 **cASP Criterion:** 3g
ASP Completion Date: 4/21/17 **Classification:** Analyst Screen-Out

Analyst Justification: Not discussed in any IR to date; LER remains open. While operating at 100 percent power on October 28, 2016, the main control room received an alarm for standby liquid control (SLC) tank level. The SLC storage tank was manually measured below the high SLC storage tank level alarm set point. A chemistry sample was requested and indicated that the sodium pentaborate concentration was 8.3 percent (required concentration range is between 8.5 and 9.5 percent). The most recent prior sample on October 13, 2016, resulted in a concentration of 8.7 percent. It is reasonable to assume that the concentration decrease, due to leak-by of the SLC storage tank demineralized water isolation valves increasing tank level and lowering concentration, was approximately linear. This would result in reaching the lower limit of the required concentration range being met about 180 hours (7.5 days) prior to the SLC tank level alarm. The licensee determined an increase in conditional core damage probability of 9×10^{-10}. To confirm this, a bounding condition assessment assuming SLC unavailability for 180-hour exposure period due to operator failure to start or control SLC, without credit for recovery, was performed by an ASP analyst and yielded a ΔCDP = 7×10^{-8}. The calculated risk is below the ASP precursor threshold of 1×10^{-6} and a search of LERs did not yield any windowed events that impact the risk significance of this condition; therefore, this event is screened out and not considered a precursor under the ASP Program.

LER: 298-16-007 **Plant:** Cooper **Event Date:** 10/28/16
LER Report Date: 12/19/16 **LER Screening Date:** 1/13/17 **cASP Criterion:** 3d
ASP Completion Date: 4/21/17 **Classification:** Analyst Screen-Out

Analyst Justification: Not discussed in any IR to date; the LER remains open. At approximately 9:24 a.m., on October 28, 2016, with the plant in Mode 5, a maintenance activity disturbed a relay causing a shutdown cooling isolation valve to close resulting in the trip of the running RHR pump A. Alternate decay heat removal remained in service throughout the event and reactor coolant temperature did not change. Shutdown cooling was declared operable approximately 20 hours later. There is not a shutdown model for Cooper; however, analyses using the SPAR models for a similar BWR (Brunswick) reveal very low risks (CCDP < 1×10^{-10}) for a loss of shutdown cooling in Mode 5. Although these analyses are not specific to Cooper, the low risk results combined with the availability of the alternate decay heat removal system and the restoration of SDC to operability within 20 hours, qualitatively indicate that this event's risk is below the ASP Program threshold, and therefore, is not a precursor. A review of other recent LERs at Cooper reveal no windowed events.

LER: 259-16-004 **Plant:** Browns Ferry 1 **Event Date:** 10/8/16
LER Report Date: 12/7/16 **LER Screening Date:** 12/19/16 **cASP Criterion:** 3e
ASP Completion Date: 5/25/17 **Classification:** SDP Screen-Out

Analyst Justification: *Green* Finding (IR 05000259/2017001); LER is closed. A performance deficiency was identified due to the licensee's failure to develop work instructions to change the TS1A and TS1B transformer configurations to their proper setting. As a result, these transformers had incorrect voltage tap settings which could have resulted in a loss of their safety function (i.e., supplying power to the 480V shutdown boards) during a LOOP or degraded grid condition. An engineering evaluation performed by the licensee determined that the minimum voltage required to preserve the safety function of the transformers is 414V, provided the upstream 4kV boards remained at or above 3.9kV. Note that the 4kV shutdown boards automatically transfer to their respective EDGs at 3.9kV. An electrical calculation software evaluation performed with the TS1A and TS1B taps set on the incorrect setting of 4160/480V concluded that the voltages at 480V Shutdown Board 1A and 1 B would be 431V and 433V, respectively. The SDP determination of very low safety significance (i.e., Green) associated with this performance deficiency was completed using IMC 0609, Appendix A, Exhibit 2 (i.e., no loss of safety function). Since a loss of safety function did not occur, this event is not a precursor and a review of potential windowed events is not required.

Appendix B: Brief Summary of Significant Precursors[25]

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 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 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}

[25] Note that 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/CVCS 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	***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 125V 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 6.9kV and 4.16kV 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 B 4.16 kV bus 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 24V 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% 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 13.8kV 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 makeup 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 4kV 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 115kv 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 feed 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 125V 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 60kV 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.	9×10^{-3}
7/15/69	213-69-LTR	Haddam Neck	***Loss of offsite power.*** One of the two 115kV 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.	2×10^{-3}

Appendix C: Program Results Comparison

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 SDP and 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 RIS 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.[26] Analyses as part of the ASP Program include all concurrent degraded/unavailable 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 upon completion of inspection activities. 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 2016 precursors identified by an independent ASP analysis.

[26] 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 (2010–2015).

Event Description	MD 8.3 Results	SDP Results	ASP Results	SPAR Model/Methodology Improvements and Insights
Waterford; 382-15-007; 8/26/15. Both emergency diesel generators (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 opened EDG B damper is provided for 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 23kV 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 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 is 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 train B of component cooling water (CCW) was on service and supplying the miscellaneous header and cooling to the reactor coolant pumps (reactor coolant pumps). 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 13kV 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.

Event Description	MD 8.3 Results	SDP Results	ASP Results	SPAR Model/Methodology Improvements and Insights
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 6.9kv 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 6.9kV auxiliary bus 1D and transformer 1D2. See the final ASP analysis (ML15238B708) for additional information.	None.
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 is 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 4.16kV 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 is 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 23kV power source (via the shutdown transformer) was available if the EDGs would have failed. See the final ASP analysis (ML14294A591) for additional information.	None.

Event Description	MD 8.3 Results	SDP Results	ASP Results	SPAR Model/Methodology Improvements and Insights
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 LOCA occurs. Inserted RHR pump C basic event for failed sequencer dependency.
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 = 8×10^{-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 230kV transmission line leads to loss of offsite power and subsequent reactor trip.	No deterministic criteria were met; therefore, a formal risk evaluation is not required.	No inspection findings associated with this event. See IR 05000219/2013003 (ML13219B131) for additional information.	CCDP = 6×10^{-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 BWRs.
River Bend; 458-12-003; 5/24/12. Loss of normal service water, circulating water, and feedwater due to electrical fault.	CCDP = 1×10^{-4}, augmented inspection performed. Revised analysis resulted in CCDP = 6×10^{-5}. See IR 05000458/2012009 (ML12221A233) for additional information.	Eight *Green* findings. See IR 05000458/2012010 (ML12328A178) for additional information.	CCDP = 2×10^{-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.

Event Description	MD 8.3 Results	SDP Results	ASP Results	SPAR Model/Methodology Improvements and Insights
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 = 2×10^{-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.
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.

Event Description	MD 8.3 Results	SDP Results	ASP Results	SPAR Model/Methodology Improvements and Insights
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.
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 161kV source was available throughout the event. See the final ASP analysis (ML12180A062) for additional information.	None.

Event Description	MD 8.3 Results	SDP Results	ASP Results	SPAR Model/Methodology Improvements and Insights
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.
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; a risk evaluation was 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 and reactor core isolation cooling (recoverable). See the final ASP analysis (ML112411361) for additional information.	None.

Event Description	MD 8.3 Results	SDP Results	ASP Results	SPAR Model/Methodology Improvements and Insights
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 SLOCA 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.
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: 2015 ASP Program Results

Between October 2014 and December 2015, 330 LERs were issued. From these 330 LERs, 252 (76 percent) were screened out in the initial screening process and 78 events were selected and analyzed as potential precursors. Of the 78 potential precursors, 12 events were determined to exceed the ASP Program threshold and, therefore, are precursors.[27] For five of these precursors, the performance deficiency identified under the ROP 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 five precursors. Table D-1 provides a brief description of all precursors identified in the October 2014 through December 2015 period.

There were 66 LERs determined to be potential precursors by the initial LER screening (as described in Section 2), but were determined to not exceed the ASP Program threshold. Additional information on these LERs is provided in Table D-2.

[27] Two of these precursors incorporated multiple LERs (i.e., "windowed" events).

Table D-1. Precursors (October 2014–December 2015).

Plant	LER	Event Date	Exposure Period	Description	CCDP/ΔCDP SDP Color	ADAMS Accession #
Duane Arnold	331-15-002	10/9/14	> 1 year	Degraded primary containment suppression pool coating	*White* Finding	ML15106A595
Farley 2	364-14-002	10/14/14	Initiating Event	Manual reactor trip due to loss of a start-up transformer	6×10^{-6}	ML16103A572
D.C. Cook 1	315-14-003	11/1/14	Initiating Event	Dual unit uncomplicated manual trip due to circulating water intake debris	1×10^{-6}	ML16165A510
Dresden 3	249-14-001	11/6/14	349 days	Electromatic relief valve failed to actuate during surveillance testing	*White* Finding	ML15085A273
River Bend	458-14-006	12/25/14	> 1 year	Automatic reactor scram and primary containment isolation due to loss of power on the division 2 reactor protection system with a concurrent division 1 half-scram	*White* Finding	ML15253A352
Pilgrim	293-15-001 293-15-002	1/27/15	Initiating Event	Automatic reactor scram due to main turbine trip following loss of offsite power	4×10^{-5}	ML16153A372
Dresden 2	237-15-002	2/7/15	210 days	Electromatic relief valve failed to actuate during extent of condition testing	*White* Finding	ML15260A508
Waterford	382-15-004 382-15-005	6/3/15	Initiating Event	Manual reactor trip due to low steam generator levels with emergency feedwater oscillations	4×10^{-6}	ML16306A336
Waterford	382-15-007	8/26/15	33 days	Both emergency diesel generators declared inoperable	6×10^{-6}	ML16308A447
Oyster Creek	219-15-003	11/19/15	15 days	Failure of the emergency diesel generator to start during surveillance testing	*White* Finding	ML16216A097

Table D-2. Potential Precursors Evaluated to Not Exceed the ASP Program Threshold (October 2014–December 2015).

Plant	LER	Event Date	LER Title	LER Screening Date	Candidate ASP Criterion	ASP Completion Date	Notes	ADAMS Accession #
North Anna 1	338-14-002	12/10/14	Inadvertent loss of vital instrumentation during maintenance due to personnel error	2/16/15	3g	9/11/15	*Green* finding with ΔCDF $<1\times10^{-6}$ (05000338/2015001); LER is closed.	N/A
Monticello	263-14-011	12/28/14	Two emergency diesels inoperable due to human error	3/2/15	3e	9/11/15	*Green* finding allowed by technical specifications (05000263/2015001); LER is closed.	N/A
Indian Point 3	286-15-001	1/8/15	Safety system functional failure due to inoperable refueling water storage tank level alarms due to freezing of the level instrument sensing lines caused by a failed strip heater	3/16/15	3d	9/11/15	No finding; LER is closed (05000286/2015002). Instruments were quickly recovered and returned to service; therefore, low risk event.	N/A
Quad Cities 2	265-14-004	11/4/14	Unit 2 HPCI inlet drain pot level switch failure	3/30/15	3d	9/11/15	No finding since HPCI still operable thus low risk event; LER is closed (05000265/2015001).	N/A
Wolf Creek	482-15-001	1/28/15	Personnel error causes two inoperable residual heat removal trains	4/13/15	3d	9/11/15	*Green* finding with ΔCDF $<1\times10^{-6}$ (05000482/2015001); LER is closed.	N/A
Brunswick 1	325-15-001	2/12/15	High pressure coolant injection (HPCI) system inoperable due to auxiliary oil pump failure	4/27/15	3d	9/11/15	No finding since HPCI did not exceed Technical Specifications outage time (05000325/2015007); LER is closed.	ML16183A139
Quad Cities 1 and 2	265-15-001	3/5/15	Unit 1 HPCI watertight door found open results in Unit 2 HPCI inoperability	5/4/15	3d	9/11/15	No finding since HPCI remained available and was always able to perform its safety function thus low risk event; LER is closed (05000265/2015002).	N/A
Susquehanna 1 and 2	387-15-001	3/2/15	Inoperability of the 'B' emergency diesel generator due to fuel oil leakage	5/4/15	3h	9/11/15	*Green* finding (05000387/2015001) with no actual loss of safety function with very low safety significance; LER is closed (05000387/2015002).	N/A
Brunswick 1 and 2	325-15-002	3/21/15	Emergency diesel generator loss of safety function	6/1/15	3e	9/11/15	Two *Green* findings with ΔCDF $<1\times10^{-6}$ (05000325/2015007); LER is closed.	N/A
Hope Creek	354-15-001	3/31/15	Conditions prohibited by technical specifications due to core spray inoperabilities	6/8/15	3d	9/11/15	No finding with ΔCDF $\leq1\times10^{-6}$ (05000354/2015002); LER is closed.	N/A

Plant	LER	Event Date	LER Title	LER Screening Date	Candidate ASP Criterion	ASP Completion Date	Notes	ADAMS Accession #
Point Beach 1 and 2	266-15-001	11/19/14	Inadequately sealed pipe penetrations result in unanalyzed condition for internal flooding	1/26/15	3d	12/22/15	Two *Green* findings (05000266/2015003) with ΔCDF $<1\times10^{-6}$; LER is closed.	N/A
Millstone 3	423-14-004	12/12/14	Unlatched dual train HELB door results in potential loss of safety function	2/23/15	3e	12/22/15	No finding (05000423/2015003); LER is closed. Short-term, low-risk event since HELB boundary door would not properly latch for less than 35 minutes.	N/A
Surry 1 and 2	280-15-001	1/27/15	Inadequate missile protection due to failure to procedurally control sliding missile shields	4/20/15	3b	12/22/15	*Green* finding (05000280/2015003) with ΔCDF $<1\times10^{-6}$; LER is closed.	N/A
Browns Ferry 1, 2, and 3	259-15-001	2/21/15	"D" emergency diesel generator inoperable due to mis-positioned switch	4/27/15	3h	12/22/15	Two *Green* findings (05000259/2015001) with ΔCDF $<1\times10^{-6}$; LER is closed (05000259/2015002).	N/A
Millstone 3	423-15-001	2/19/15	Unlatched dual train HELP door results in potential loss of safety function	5/4/15	3e	12/22/15	No finding (05000423/2015003); LER is closed. Short-term, low risk event since HELB boundary door would not properly latch for less than 35 minutes.	N/A
Columbia	397-15-001	3/2/15	Non-conservative compensatory measure for flooding barriers	5/11/15	3d	12/22/15	*Green* finding (05000397/2015001) with ΔCDF $<1\times10^{-6}$; LER is closed (05000397/2015002).	N/A
South Texas 2	499-15-001	3/4/15	Technical specification action statement time exceeded due to turbine-driven auxiliary feedwater pump test failure not recognized	5/18/15	3b	12/22/15	*Green* finding (05000499/2015002) did not lead to an actual loss of safety function of the system or cause a component to be inoperable; LER is closed.	N/A
Quad Cities 1	254-15-004	3/21/15	Automatic depressurization system trip logic failure	6/8/15	3d	12/22/15	*Green* finding (05000254/2015003) with ΔCDF $<1\times10^{-8}$; LER is closed.	N/A
Limerick 2	353-15-001	4/5/15	Inoperable high pressure coolant injection system due to a small electrical fire	6/8/15	3d	12/22/15	*Green* finding (05000353/2015003) did not lead to a failure of system operability or functionality since the only affected portions of the HPCI system were associated with the HPCI vacuum tank condensate pump is not required for system operability or functionality; LER is closed.	N/A

Plant	LER	Event Date	LER Title	LER Screening Date	Candidate ASP Criterion	ASP Completion Date	Notes	ADAMS Accession #
Browns Ferry 3	296-15-004	5/12/15	High pressure coolant injection system inoperable due to failed pressure switch	8/3/15	3d	12/22/15	No finding (05000296/2015003); LER is closed. Short-term low risk event since HPCI inoperable for 21 minutes.	N/A
Byron 1	454-15-003	10/8/14	One train of the diesel generator system inoperable longer than allowed by technical specifications due to loss of diesel fuel oil system volume	8/3/15	3h	12/22/15	Two *Green* findings (05000454/2015007) that although inoperable, the 1B EDG would be available for 24 hours with this condition present and that ΔCDF for this issue was negligible; LER is closed (05000454/2015-003). SPAR run for EDG 1B fail-to-run for 55 days resulted in ΔCDP = 8×10^{-7}.	N/A
Cooper	298-15-004	5/30/15	Isolation of shutdown cooling results in a loss of safety function	8/10/15	3d	12/22/15	*Green* finding with no quantitative assessment because adequate mitigating equipment remained available (05000298/2015003); LER is closed.	N/A
Browns Ferry 1	259-15-002	7/22/15	High pressure coolant injection system inoperable due to slow containment isolation valve closing time	9/21/15	3d	12/22/15	No finding (05000259/2015003); LER is closed. Short-term low risk event since HPCI Inoperable within technical specifications (3 days).	N/A
Perry	440-14-004	10/20/14	Automatic reactor scram on loss of feedwater	1/12/15	2i	4/5/16	No finding; LER is closed (05000440/2015001).	ML16138A336
Perry	440-14-005	11/7/14	Automatic reactor scram due to loss of feedwater	1/12/15	2i	4/5/16	Two *Green* findings (05000440/2014005) and *Green* finding (05000440/2015003); LER is closed (05000440/2015003).	ML16138A334
Pilgrim	293-15-004	4/23/15	480 volt bus b6 auto transfer function degraded	6/29/15	3d	2/11/16	*Green* finding (05000293/2015004) due to LPCI declared inoperable, but failed relay only affects motor-operated valve bus transfer on degraded voltage condition so low risk event; LER is closed.	N/A
Pilgrim	293-15-006	8/9/15	Ultimate heat sink and salt service water system declared inoperable	10/19/15	3f	2/11/16	No finding (05000293/2015004) with no safety component failure; LER is closed.	N/A

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Callaway 1	483-14-005	11/18/14	All ECCS accumulator isolation valve operator breakers closed in mode 3 with RCS pressure greater than 1000 psig	1/26/15	3d	4/18/16	*Green* finding (05000483/2014005) did not result in a loss of system function; LER is closed (05000483/2015004).	N/A
LaSalle 2	374-15-001	12/29/14	High pressure core spray inoperable due to division 3 diesel generator cooling water pump casing leak	3/9/15	3d	4/18/16	No finding (05000374/2015004); LER is closed. Short-term low risk event since HPCS Inoperable within Technical Specifications (6 days).	N/A
Farley 2	364-15-001	1/9/15	Turbine driven auxiliary feedwater pump in a condition prohibited by technical specifications due to a design issue	3/16/15	3b	4/18/16	*Green* finding (05000364/2015004) determined by SRA detailed risk evaluation using Farley SPAR model; LER is closed (05000483/2015004).	N/A
Calvert Cliffs 1 and 2	317-15-001	1/22/15	Component cooling and shutdown heat exchanger lineup potential to exceed design basis temperatures	3/30/15	3g	4/18/16	*Green* finding (05000317/2015001) per SRA bounding significance determination assuming a complete loss of safety function; LER is closed (05000317/2015004).	N/A
Davis-Besse	346-15-001	2/11/15	Borated water storage tank (BWST) rendered inoperable due to use of non-seismic purification system	4/20/15	3d	4/18/16	*Green* finding (05000346/2015008) with ΔCDF $\leq 1\times10^{-6}$; LER is closed (05000346/2015004).	N/A
Browns Ferry 3	296-15-001	2/11/15	High pressure coolant injection and reactor core isolation cooling inoperable due to no suction source aligned	5/4/15	3d	5/11/16	No finding (05000296/2015002); LER is closed.	ML16145A114
Comanche Peak 1 and 2	445-15-001	2/19/15	Unanalyzed condition during MSSV testing	5/4/15	3e	4/18/16	*Green* finding (05000445/2015001) with ΔCDF $<1\times10^{-7}$; LER is closed (05000445/2015004).	N/A
Fermi	341-15-002	3/9/15	Loss of both divisions of the residual heat removal low pressure coolant injection functions due to 480 volt swing bus inoperable	5/11/15	3d	5/3/16	No finding since HPCI still not reasonably within licensee's ability to foresee and correct; LER is closed (05000341/2015002). May require condition assessment for both trains of LPCI unavailable less than 8 hours.	ML16138A335
Fort Calhoun	285-15-002	4/2/15	Inoperable auxiliary feedwater system due to inadequate procedure change	6/8/15	3b	4/18/16	*Green* finding determined from SRA evaluation due to brief time period; LER is closed (05000285/2015004).	N/A

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Cook 1	315-15-001	6/1/15	Plant shutdown required by technical specifications	8/3/15	4a	4/20/16	Windowed event with LER 315-2015-002. *Green* finding (05000315/2015003); LER is closed (05000315/2015004).	ML16113A198
Cook 1	315-15-002	6/14/15	Technical specification violation due to inoperable residual heat removal pump	4/11/16	3d	4/20/16	Windowed event with LER 315-2015-001. *Green* finding (05000315/2015003); LER is closed (05000315/2016001).	ML16113A198
Fitzpatrick	333-15-002	6/1/15	Safety relief valve upward set point drift	8/3/15	3h	4/18/16	*Green* finding since set point drift did not result in the loss of the overpressure relief safety function (05000333/2015004); LER is closed.	N/A
Browns Ferry 2	260-15-001	6/17/15	Failure of the 2A RHR pump to manually start from the control room due to a loose fastener	8/24/15	4a	4/18/16	*Green* finding (05000260/2015004) since failure to re-tighten terminal screw did not represent an actual loss of function; LER is closed (05000260/2015004).	N/A
Brunswick 2	324-15-003	4/8/15	Oil leak renders residual heat removal service water system pump inoperable	8/24/15	3d	4/18/16	*Green* finding with ΔCDF $<1\times10^{-7}$ (05000324/2015004); LER is closed.	N/A
Perry	440-15-001	6/16/15	Degraded voltage relay found outside the allowable value	8/24/15	3d	4/18/16	No finding (05000440/2015003) within analytical limit; LER is closed.	N/A
Columbia	397-15-005	6/25/15	Reactor pressure vessel level indication switch failures	8/31/15	3a	4/18/16	*Green* finding with ΔCDF $<1\times10^{-6}$ (05000397/2015004); LER is closed.	N/A
Browns Ferry 1, 2, and 3	259-15-003	7/14/15	Loss of cooling to the Unit 1 and Unit 2 shutdown board rooms due to fouled chiller coils	9/21/15	3e	4/18/16	*Green* finding (05000259/2015004), control bay chiller inoperable for 6 hours and 37 minutes, thus a short-term low risk event; LER is closed (05000259/2015004).	N/A
Three Mile Island 1	289-15-001	8/6/15	Seismically qualified BWST aligned to non-seismic piping	10/12/15	3d	4/18/16	*Green* finding with ΔCDF $<1\times10^{-6}$ (05000289/2014002); LER is closed (05000289/2015004).	N/A
Dresden 2	237-15-005	9/23/15	Unit 2 HPCI motor gear unit would not return to full flow during testing	11/9/15	3d	4/18/16	No finding (05000237/2015004) since HPCI was degraded and not inoperable for less than 2 days; LER is closed.	N/A

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Fort Calhoun	285-15-004	6/5/15	Inoperability of auxiliary feedwater trains due to failure of steam generator isolation valve	8/10/15	3b	4/20/16	Three *Green* findings (05000285/20150011) with ΔCDF <1×10^{-6}; LER is closed (05000285/2016001).	N/A
Waterford	382-14-004	10/22/14	Emergency diesel generators rendered inoperable by potential water intrusion into diesel fuel oil feed tanks	12/29/14	3e	4/25/16	Three *Green* findings (05000382/2014007 and 05000382/2015009); LER is closed (05000382/2016001).	N/A
Duane Arnold	331-15-006	7/23/15	HPCI and RCIC condensate storage tank suction transfer inoperable	2/29/16	3d	4/25/16	Two *Green* findings (05000331/2015004) with ΔCDF <1×10^{-7}; LER is closed (05000331/2016001).	N/A
Hope Creek	354-15-004	6/2/15	As-found values for safety relief valve lift set points exceed technical specification allowable limit	8/3/15	3h	5/10/16	*Green* finding (05000354/2016001) because SRVs would have functioned to prevent a reactor vessel over-pressurization; LER is closed.	N/A
River Bend	458-15-004	5/21/15	Potential loss of safety function of onsite ac/dc distribution systems due to postulated main control building heat-up following loss of ventilation cooling system	8/3/15	3e	5/11/16	*Green* finding (05000458/2016001) with ΔCDF <1×10^{-6}; LER is closed.	N/A
Susquehanna 1 and 2	388-15-001	1/21/15	Condition prohibited by technical specifications due to drift of reactor pressure steam dome - low switches	3/30/15	3d	5/12/16	*Green* finding because the ability to open low pressure ECCS injection valves remained available (05000388/2016001); LER is closed.	N/A
Limerick 2	353-15-005	9/3/15	Condition that could have prevented fulfillment of the high pressure coolant injection system safety function	11/9/15	3d	5/12/16	No finding (05000353/2016001) with minimal potential safety consequences and HPCI inoperable for 23 hours; LER is closed. SPAR run HPCI pump inoperable for 23 hours (fail-to-start) resulted in ΔCDP of 3×10^{-8}.	N/A
Browns Ferry 2	260-15-002	9/16/15	High pressure coolant injection system inoperable due to turbine steam supply valve packing failure	11/23/15	3d	5/13/16	Two Green findings (05000260/2016001; LER is closed (05000260/2015004). HPCI was degraded, but operable.	N/A
Calvert Cliffs 1 and 2	317-15-002	4/7/15	Automatic reactor trip due to loss of offsite power to safety related buses	6/15/15	1c	5/23/16 9/21/16	No findings (05000317/2015009); LER is closed (05000317/2015004).	ML16167A305 ML16266A230

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Callaway 1	483-15-004	8/11/15	Auxiliary feedwater control valve inoperable due to faulty electronic positioner card	10/19/15	3b	6/7/16	*Green* finding (05000483/2015009); LER is closed (05000483/2016001). Windowed event with LER 483-2015-003.	ML16160A095
Nine Mile Point 1	220-15-004	9/4/15	Unplanned automatic scram and specified system actuations due to MSIV closure	11/23/15	1j	6/7/16	No finding (05000220/2016001); LER is closed.	ML16160A094
Diablo Canyon 1	275-15-001	12/31/14	Both trains of residual heat removal inoperable due to circumferential crack on a socket weld	3/9/15	3d	6/9/16	*Green* finding (05000273/2015004); LER is closed (05000273/2016002).	ML16165A280
Fermi 2	341-15-006	9/13/15	Reactor scram due to loss of turbine building closed cooling water	11/9/15	1k	6/30/16	*Green* finding (05000341/2016001); LER is closed (05000341/2016002).	ML16187A366
Cooper	298-14-005	10/13/14	Lube oil leak results in a potential condition prohibited by technical specifications and a potential loss of safety function	12/29/14	3e	9/21/16	The LER was retracted since both EDGs are not required to be operable while in Mode 5. According to the licensee, EDG would have fulfilled its safety function prior to entering Mode 5.	N/A
Shearon Harris	400-15-004	5/4/15	Failure of 'A' train emergency service water pump	7/6/15	3c/3d	9/21/16	*Green* finding (05000400/2015003) with ΔCDF $<1\times10^{-6}$; LER is closed (05000400/2015008).	N/A
Shearon Harris	400-15-005	6/16/15	Unrecognized impact of opening of barrier doors on high energy line break analysis	8/24/15	3d	9/21/16	*Green* finding (05000400/2015003) with ΔCDF $<1\times10^{-6}$; LER is not yet closed.	N/A
Indian Point 2	247-15-002	8/18/15	Safety system functional failure due to fuses for residual heat removal heat exchanger outlet valves that would not remain operable under degraded voltage conditions	11/2/2015	3d	9/21/16	Two *Green* findings (05000247/2015007) with ΔCDF $<1\times10^{-6}$; LER is closed (05000286/2016004).	N/A
Calvert Cliffs 1 and 2	317-15-003	6/17/15	Diesel generator inoperable due to lube oil filter fouling due to coolant leak-by on a cylinder liner	11/16/2015	3e	9/21/16	*Green* finding (05000317/2015003); LER is closed (05000317/2016003).	N/A
Byron 1	454-15-006	10/1/15	Mode 3 entered with turbine trip safety function disabled due to safety related relay leads lifted	12/7/2015	3a	10/20/16	*Green* finding (05000454/2016001); LER is closed (05000454/2016001).	N/A
Watts Bar 1	390-15-006	10/19/15	Source range level trip channels (N-31 and N-32) inoperable during plant startup	12/28/2015	3a	10/24/16	*Green* finding (05000390/2015004); LER is closed (05000390/2016003).	N/A