Significance Determination Process for Plant Condition Assessment

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ABSTRACT

In evaluating the significance of a plant condition that has been corrected but could have earlier been detrimental to the plant's nuclear safety, the United States Nuclear Regulatory Commission (USNRC) now uses probabilistic methods and criteria. The objective of these methods is to determine the change (or delta) in the core damage probability (CDP) and large, early release probability (LERP) of the plant with and without the condition. Based on the delta CDP and delta LERP, the USNRC determines the significance of the condition, which is expressed as a red, yellow, white or green color, in decreasing order of risk significance. The color of the finding identifies the severity of the condition and is used by the regulators to determine the scope and extent of future inspections, enforcement actions, and communications in order to help avoid future safety-significant conditions in the plant.

In this paper, a brief discussion of the significance determination process (SDP) is provided together with two recent case studies – each for a US nuclear plant. For both plants, it turned out that seismic induced flooding, albeit at different locations, was considered to be the regulatory finding because mitigating mechanisms were not in place at the time the conditions were discovered. Of course, appropriate corrective actions in terms of modifications and administrative controls were immediately taken to rectify the adverse conditions that were found. Those structures, systems and components that had the potential to fail in a seismic event were evaluated by performing a seismic fragility analysis. A flooding specific seismic event tree was developed for each plant and seismic core damage frequencies for various sequences in the event tree were calculated using the integration of fragilities with the site seismic hazard. Although the process is based primarily on probabilistic analysis, plant walkdowns and detailed structural analyses were substantial elements of the SDP. The regulators, with substantial technical input from the licensee, assessed the risk of core damage and large, early release for the two seismic induced flooding issues discussed here. They determined that one of them should be a green finding (very low safety significance) and the other a yellow finding (substantial safety significance). The paper concludes that probabilistic analyses of highly complex issues, such as seismic induced flooding, can provide a reasonable quantitative measure for the significance determination of potentially adverse plant conditions, and this approach can be applied in a uniform manner in conducting an SDP for a nuclear plant.

INTRODUCTION

The USNRC implemented a revised reactor oversight process (ROP) in April 2000. The oversight process is based upon a pilot program, which included nine nuclear power plants of different designs and varying performance levels located in different locations of United States. The oversight process monitors performance in three strategic performance areas: reactor safety, radiation safety, and safeguards. Each of the strategic performance areas is further subdivided into essential elements of performance called cornerstones of safety. The reactor safety cornerstone includes initiating events that could lead to an accident and requires consideration of mitigating systems, barrier integrity, and emergency preparedness. The radiation safety cornerstone includes occupational radiation safety that protects plant employees and public radiation safety that protects public health and safety. The safeguards cornerstone includes security and physical protection against threats of radiological sabotage. Each cornerstone is defined by established performance objectives, which in turn determine whether the safety mission is fulfilled. The cornerstones are monitored either by plant performance indicators or by inspection conducted by regulators. Performance indicator data provide periodic information about plant performance in key safety areas. The inspections focus on safety significant aspect of cornerstones that are not easily monitored by performance indicator data. The inspections also focus on the plant's problem identification and resolution program, safety program and human performance program. In addition, the inspections verify that the performance indicator data is being collected correctly and reported accurately.

Findings identified during the inspection process are assessed using a significance determination process and are color-coded for safety significance. The significance determination process is based on risk-informed, performance-based models. Two case studies are discussed in this paper. Both cases are related to seismic-induced flooding concerns identified during plant inspections. The basic elements of the significance determination process are discussed and the risk-based approach used in each of the two cases is illustrated.

SIGNIFICANCE DETERMINATION PROCESS

Risk characterization tools have been developed and formalized [1 through 6] within the past several years to support a significance determination process (SDP) that establishes the significance of inspection findings that relate to a defined threshold of risk-informed plant performance indicators (PI). A probabilistic risk assessment (PRA) is used to quantify the risk for a consistent SDP across a spectrum of events. The use of deterministic evaluations, coupled with expert opinion on the event, does not by itself provide a consistent determination of risk. Therefore, the PRA is considered as a useful tool in this process. The technical adequacy of the risk based SDPs depends on the availability and quality of a relevant PRA. Computer based risk models are developed and used. Risk informed approach, performance deficiency, concurrent degraded conditions, and treatment of uncertainty are integrated in the PRA process. As a result, an open and deliberative process that calls for proper input and ensures bases upon which assumptions are made is used. Consequently, uncertainties are clearly understood and accounted in the final SDP result.

USNRC Regulatory Guide 1.174 [6] provides the basis and mathematical treatment of change in the core damage frequency (CDF) (i.e., delta CDF) and core damage probability (CDP). The use of the term CDP is primarily with reference to degraded conditions which exist for a period less than one year. Color-coded performance indicators are tied-in to threshold limit predetermined by expert judgement. Green/white thresholds for the performance indicators for initiating events and mitigating systems are set at 95^{th} percentile of peer performance. Quantitatively, a green/white threshold of 10^{-6} increase in CDF is used. The white/yellow and yellow/red thresholds on an assessment of a performance indicator are tied-in to increases of CDF of 10^{-5} and 10^{-4} per reactor year respectively. These thresholds are shown pictorially in Figure 1.

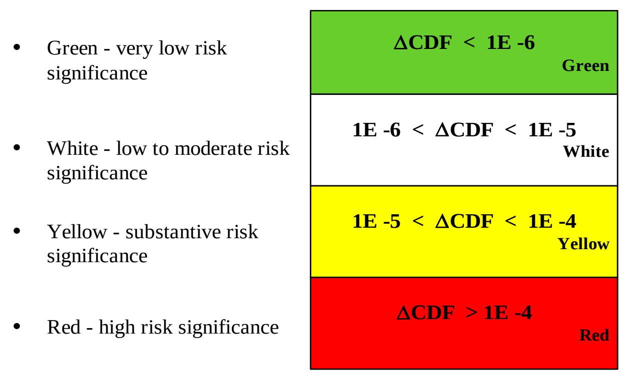

Figure 1

Because of the importance to public health and safety, the acceptance guidelines for increase in large early release frequency (LERF) thresholds are set at an order of magnitude lower than the increases of CDF. As a result, the green/white, white/yellow, and yellow/red thresholds are set to increases in LERF of 10^{-7}, 10^{-6}, and 10^{-5} per reactor year respectively. Both sets of acceptance guidelines, one for CDF and one for LERF, should be used with the most limiting used to define the risk significance and associated color. The basis behind the threshold for change in performance indicators (PI) or inspection findings is that if the root cause for changes were not corrected, there would be an increase in the CDF and LERF. It is relatively straightforward to relate the changes in the PI to changes in risk because in some sense, the PIs correspond to parameters of PRA models. On the other hand, for the inspection findings, which may relate to a time-limited deficient condition, the model has to be linked to a performance issue for the purpose of quantification. The risk significance for the inspection finding should then be evaluated to the same thresholds as the performance indicator.

The impact of a finding can be associated with the unavailability of a structure, system or component (SSC) for a specified period. In such a case, the increase in the CDF/LERF must take into consideration the concurrent unavailability of other SSCs. If the root cause of the unavailability of an SSC associated with the finding is known, then this fact should be considered while considering the unavailability of other SSCs. The unavailability could occur randomly or due to scheduled maintenance activity. Therefore, the effect of unavailability of SSC is accounted for with appropriate weight.

Mathematically, for a simple unavailability, ΔCDP equates to ΔCDF over one year as follows:

$CDF = [T_0/ (T_0+ T_1)].CDF_0+ [T_1/ (T_0+ T_1)].CDF_1$,

Where T_0 is the time when the SSC is available, and T_1 the time when it is not (i.e., $T_0+ T_1 = 1$ year), CDF_0 is the CDF evaluated with the SSC available (i.e., unavailability = 0), and CDF_1 is the CDF calculated with the SSC unavailable, (i.e., unavailability =1). This means that the addition of CDP from a particular unavailability finding is equal to an increase in CDF (assuming the condition exists for an entire year or more).

To simplify, the cut sets for CDF can be split into two groups, those that do not contain the SSC, which therefore correspond to CDF_0, and those that contain SSC. The latter would typically be of the form x.y.z.U, where U is the unavailability of the SSC in question.

CDF_1 then becomes $CDF_0 + \Sigma(x.y.z.U)$ with the value of unavailability (U) set to 1.

Thus the equation for CDF becomes:

$CDF = CDF_0 + [T_1/ (T_0+ T_1)]\ \Sigma(x.y.z.U)$ with the value of unavailability (U) set to 1.

Now if we replace the value of U by $[T_1/ (T_0+ T_1)]$, we get the usual CDF expression.

In summary, during an SDP, an integral under a CDF impact is evaluated, which is equal to an increase in CDF for the year in which the finding occurred (assuming the condition exists for an entire year or more).

CASE STUDIES

Two safety-significant conditions that were identified as a result of inspections are described here. They were discovered in the recent past at two different pressurized water reactor (PWR) plants in the US. The inspections and analyses that were done to complete the significance determination process, the insights gained, and the feedback from the regulators for these two conditions are discussed.

CASE 1:

The first case involved the determination of seismic risk from flooding scenarios in the Turbine Building/Emergency Switchgear Room (ESGR) of the plant. It resulted from a USNRC inspection finding that the turbine building flood control system did not provide adequate protection for all licensing basis flood scenarios. Specifically, portions of the flooding detection and mitigation circuitry would not be available in a flooding event that involved Loss of Offsite Power (LOOP) because the Flood Control Panel, which was located in the Turbine Building, was not powered by a class 1E or emergency power supply. Following the inspection, corrective actions were completed, which included installation of a design change to provide redundant, vital bus powered detection and warning of flood that alarms in the control room.

A seismic risk analysis was performed to assess the impact of this condition on the CDF. Various SSCs that could contribute to a seismic-induced flood were examined. Several of the components were considered inconsequential because the fluid inventory would be insufficient to cause a detrimental flood in the areas of concern, even if they were to fail catastrophically in a seismic event. Those structures and components that were screened-in included Turbine Building, Condenser, Bearing Cooling Water Heat Exchangers, seismic category 1 piping systems, and a 10” fiberglass piping system. The components were located in the Turbine Building of the plant. For the screened-in structures and components, fragility calculations were performed, primarily using the guidance from [7]. The fragility calculations considered all potential failure modes due to seismic vibratory loads. For some components, non-linear pushover or limit analyses were performed. Typically, the median capacities (A_m) of components were bounded by anchor bolt failures, saddle plate failure for the heat exchangers, and piping overstress conditions. The randomness (β_R) and uncertainty (β_U) variabilities, expressed in terms of logarithmic standard deviations, were determined and the high-confidence-low-probability-of-failure (HCLPF) values were calculated (HCLPF = $A_m\, e^{-1.65\,(\beta_u+\beta_r)}$). Table 1 shows the fragility parameters of the relevant structures and components that were analyzed:

TABLE 1
Fragilities for Seismic Induced Turbine Building Flooding PRA

Equipment	Median Capacity (g)	β_R	β_U	HCLPF$_{50}$ (g)
Loss of offsite power from switchyard, grid or transformers	0.30	0.25	0.35	0.111
Turbine Building Severe Damage	0.71	0.40	0.40	0.190
Seismic Category 1 Safety-related Piping in Turbine Building	1.00	0.30	0.30	0.372
Condenser	0.713	0.27	0.154	0.354
Bearing Cooling Heat Exchangers	0.643	0.232	0.154	0.340
10” Non-Safety Fiberglass Piping	0.89	0.31	0.24	0.359

A seismic event tree was constructed which consisted of success and failure paths of events – sequentially with initiation of an earthquake, seismic induced switchyard failure, failure of bearing cooling heat exchanger, failure of condenser, failure of 10” fiberglass pipe and failure of seismic category 1 piping. Conditional core damage probabilities (CCDP) for the events were assigned to each applicable sequence for the mitigation of flood before the emergency switchgear room is flooded. The quantification of CCDP functions for each damage state included only operator errors, determined from a human reliability analysis, since the hardware failures were at least an order of magnitude lower. Boolean equations for each event were developed. The sequence quantification was performed using computer code “Seismic” [11] that uses Monte Carlo simulation and integrates the seismic hazard with fragilities. The mean hazard curves developed by Electric Power Research Institute (EPRI) in 1989 [9] were used; however, a sensitivity analysis was performed with the hazard curves developed by Lawrence Livermore National Laboratory (LLNL) [10]. The failure frequency for each sequence was multiplied by the corresponding CCDP, which gave the sequence CDF. The sequence CDFs were added together to obtain the total CDF. The Turbine Building failure accident sequence was excluded from the total since the flood control panel would have provided no benefit whether it was powered by emergency power or not. When the condenser fails and spray shields on the 96” expansion joints are damaged, the flooding was estimated to be large enough such that auto-isolation is not fast enough before the ESGR is flooded. Thus the resulting CDF is the same whether the flood panel has emergency power or not. However, in a sensitivity analysis, when uncertainties in the expansion joint and spray shield design were factored in, the CCDP changes. Table 2 provides the CDF results for both cases for this analysis.

TABLE 2
Increase in CDF Calculation

Sequence Description	**Failure Frequency (per year)**	**Case A - Flood Control Panel <u>does not</u> have Emergency Power CCDP/CDF (/yr)**	**Case B - Flood Control Panel has Emergency Power CCDP/CDF (/yr)**
Failure of Category 1 Safety-related Piping in Turbine Building	1.023E-7	CCDP = 1.0 CDF = 1.023E-7	CCDP = 1.0 CDF = 1.023E-7
Failure of 10” Non-Safety Fiberglass Piping	1.530E-7	CCDP = 8.5E-4 CDF = 1.3E-10	CCDP = 8.5E-4 CDF = 1.3E-10
Failure of Condenser	2.932E-7	CCDP = 1.0 CDF = 2.932E-7	CCDP = 5.0E-2 CDF =
Failure of Bearing Cooling Heat Exchangers	6.652E-7	CCDP = 1.0 CDF = 6.652E-7	CCDP = 1.0 CDF = 6.652E-7
	Total CDF:	1.06E-6 /year	7.82E-7 /year
	Increase in CDF:	**2.8E-7 /year**	

From Table 2, since ΔCDF of 2.8E-7 /year is less than 1.0E-6, the upper threshold for characterizing the finding is green, i.e., it was a very low risk-significant condition. The USNRC reviewed the analyses and conducted confirmatory plant walkdowns. Under the cornerstone – mitigating systems, the finding was assigned a green disposition. It was noted that the finding is greater than minor because it affects the design control attribute of the mitigating system objective. The very low safety significance (green) was due to the low frequency of an earthquake of sufficient magnitude to fail offsite power and the circulating water piping connected to the condenser, but of insufficient magnitude to cause catastrophic failure of the turbine building.

CASE 2:

The second case, also for a PWR plant, involved a performance deficiency that was identified in a USNRC inspection report regarding internal flooding design features. The inspectors found that there was inadequate design control to protect class I (safety-related) equipment against damage from the rupture of a non-class I pipe or a tank resulting in serious flooding or excessive steam release to the extent that the class 1 equipment’s function could be impaired. Specifically, the design did not ensure that 480V and 4160V safeguard buses, safe-shutdown panel, emergency diesel generators and other equipment in the area would be protected from random or seismically induced failures of non safety-related systems in the turbine building. Flood paths were present from the turbine building to the safeguards alley compartments that contained the identified class 1 equipment. These flood paths included floor drains without check valves, doors with bottom clearances to allow water to pass through and open floor trenches. Plant modifications were performed to eliminate these flood paths.

The past safety significance of this performance deficiency was evaluated by performing a PRA of the subject internal flooding scenarios leading to core damage. The flood initiating events considered included, among others, random failures, condenser expansion joint failures, steam line breaks leading to fire protection sprinkler actuation and seismic induced failures. For evaluating the seismic risk, the systems that were analyzed included: circulating water, condensate storage tanks and associated piping, fire protection piping, large condensate feedwater piping, small condensate feedwater piping and service water. These systems were primarily located in the turbine building of the plant, but portions of the systems were also in other areas including the auxiliary building and the tank storage building. In addition to the above, structures and block walls that could affect the integrity of these systems were analyzed. Certain other systems were also evaluated, but did not have any significant impact on the flooding scenarios.

Plant walkdowns of systems, equipment items and piping were conducted to identify any field concerns or vulnerabilities. Each pipe segment was reviewed for unusual geometry, high stress concentration areas from fabrication, interactions, stiff lateral supports connected to pipes with flexible supports and non-ductile or cast-iron valves or fittings. The scope of systems and pipe segment that were considered was large therefore, based on the walkdowns, either generic fragilities were assigned or specific fragility values were calculated. A median capacity level of 2.9g was established to screen out structures and components from further evaluation. Stress criteria were developed based on median properties. The EPRI developed [9] plant-specific median seismic hazard curves were used for developing in-structure spectra and the subsequent fragility calculations and the Lawrence Livermore National Laboratory (LLNL) [10] were used in a sensitivity analysis. Median fragilities were established using both - conservative deterministic failure margin (CDFM) approach and direct calculation of median capacities and variabilities using guidance from [7]. In the CDFM approach, the HCLPF capacity is typically based on 84% non-exceedance probability (NEP) spectral shape whereas in a seismic PRA, the fragility curve is generally based on a median or 50% probability spectrum. For a composite variability or logarithmic standard deviation βc of 0.4, HCLPF = $A_m\, e^{-2.33x.4}$ or $A_m/2.54$. Since a median spectral curve was used, the 84% shape was estimated by using a 1.22 factor [7]. Therefore, from the CDFM approach, the median capacity is derived as $A_m \approx 2.54/1.22$ x $HCLPF_{84}$ or $A_m \approx 2.1$ x $HCLPF_{84}$. Composite variabilities ($\beta c = \sqrt{(\beta_r^2 + \beta_u^2)}$) were established as 0.4, 0.4 and 0.5 for equipment, bock walls and piping respectively. In general, structures, block-walls and piping were found to have sufficiently high capacities with certain systems with brittle components exhibiting low capacities. The free standing condensate storage tanks and the reactor make-up water storage tanks also had low HCLPF values of about 0.3g based on their overturning moment capacities.

A detailed flooding seismic event tree was developed and the integration of seismic hazard and fragilities was done using the SHIP computer code [12]. Following the seismic risk quantification, accident sequence progression for each initiating event was evaluated, including operator actions needed to isolate a flood and human error probabilities for actions that would vary for each flooding initiating event. A conservative assessment of occurrence, plant response and operator response to a flooding event was performed in a detailed PRA analysis. The analysis showed that more than 84% of the CDF was due to four flood scenarios: large breaks in an inlet circulating water expansion joint (47%), feedwater line breaks that result in full flow fire sprinkler discharge from the fire pumps (15%), main steam line breaks that result in full flow fire sprinkler discharge from the fire pumps (12%), and seismic induced failures of firewater, service water and condensate and reactor makeup water storage tanks (11%). The total contribution to CDF from the deficiency was calculated to be 5.9E-05 per year, which would be classified as mid-yellow in the reactor oversight process SDP risk determination. The total large early release frequency (LERF) contribution from this deficiency was estimated to be at least a factor of 10 below the CDF, and thus not limiting in the USNRC reactor oversight process SDP risk determination. Sensitivity analyses were performed to determine the impact of key assumptions such as initiating event frequencies, human error probabilities and the use of LLNL hazard curves; however, these evaluations did not change the CDF results sufficiently and the deficiency remained yellow. The USNRC reviewed the SDP assessment and also concluded that the inspection finding is appropriately characterized as yellow, i.e., an issue with substantial importance to safety that resulted in additional inspection and other actions. The plant performance for this issue was determined to be in the degraded cornerstone band.

CONCLUSIONS

The current USNRC reactor oversight process can trigger a significance determination process evaluation if conditions are discovered during inspections that could have led to a significant safety risk at a nuclear plant. As discussed in this paper, the significance determination of an adverse condition is a well-defined process and is an integral part of the reactor oversight process within the current US regulations. The SDP is based on using risk-informed, performance-based methods and criteria.

Two cases – both for US PWR nuclear plants discussed herein demonstrate how the process works. In both cases, modifications were performed to address the conditions and reduce the risk. The risk reduction due to the modification for the flood panel power supply was small, given the low CDF. However, the risk reduction in the second case study due to the turbine building flooding modification was very large (delta CDF > 1E-5/year). While the seismic portion of the turbine building flooding risk was not the major contributor, it was nevertheless very significant.

Insights realized from these two cases include: (1) the difficulty in establishing the stress criteria and assessing the fragilities of non-seismically designed piping, including fiberglass piping, (2) the significant risk contribution of seismic failures in fire water system piping at a plant due to the large fire water source capacity (e.g., a very large lake) and inability to stop the firewater pumps from the control room or an area unaffected by the flooding, (3) the lack of prior consideration of random and seismic-induced failure of non-seismically designed piping, heat exchangers, certain brittle components such as cast iron valves and unanchored tanks leading to risk significant flooding in a plant, (4) the differences determined from sensitivity analyses from using EPRI versus LLNL seismic spectra and hazard curves on the overall results in some cases, (5) the inter-relationships between the various methods such as CDFM, separation of variables, composite variability and pushover analyses to determine seismic risk parameters and fragilities for structures and components, (6) the difficulty and significant manpower/cost in the effort required to develop or upgrade a seismic PRA model to address SDP issues on an expedited basis, and (7) the failure of prior risk assessments, including the Individual Plant Examinations and Individual Plant Examinations of External Events to uncover certain risk significant vulnerabilities at a plant such as seismic induced internal flooding that could affect the function of safety-related electrical equipment.

The issuance of USNRC Regulatory Guide (RG) 1.200 Revision 1 (impacting internal events PRAs) in January 2007, which will become effective in January 2008, and the anticipated issuance of USNRC RG 1.200 Revision 2 (impacting external events PRAs including fire and seismic) on or about December 2008, which will become effective one year later in January 2010, will create an expectation that nuclear power plant licensees must upgrade their existing PRA models or create new PRA models which meet Category II of the associated endorsed ASME/ANS PRA standards. The process of achieving compliance with these regulatory guides will likely uncover similar risk-significant vulnerabilities as those identified in the two cases and provide an opportunity to reduce plant risk by modification or procedure changes. While use of these USNRC regulatory guides will be voluntary, plants which elect not to meet them will lose almost all capability to obtain relief from exigent plant conditions which could lead to a forced shutdown or burdensome license conditions that increase cost or outage duration. In addition, as seen in the two cases described in this paper, development of an upgraded seismic PRA will likely be needed by many licensees to respond to future regulatory inspection issues in the USNRC SDP to avoid exigent development of seismic PRA models. Certain additional enhancements, not considered in the above two cases, will likely be required in a future seismic PRA to be used for decision-making. These include meeting the criteria of a capability category I and likely category II seismic PRA in accordance with the ANS external events standard [8]. It is noted however, that this standard is being reviewed within the US nuclear industry and may be updated based on pilot seismic PRAs currently being done to examine whether any roadblocks exist in complying with the current version of the standard. Another enhancement that would be needed is to perform the seismic PRA quantification using an updated, site-specific seismic hazard that is derived using probabilistic seismic hazard analysis (PSHA) with modeling techniques developed by Electric Power Research Institute (EPRI) in 2004. Currently, two USNRC regulatory guides – RG 1.165 and RG 1.208 provide methods on how to conduct a PSHA to obtain a safe-shutdown earthquake shape. Recent use of these RGs has shown that the seismic ground response spectra, particularly for rock sites in the Central and Eastern US, are quite different than those used in the past in that they contain significant high frequency content in the 20 to 60 Hz range. For future seismic PRAs and SDPs, industry wide compliance with the above mentioned USNRC regulatory guides and industry standards is anticipated.

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