March 7, 2001

Mr. Valeri Tolstykh
Regulatory Activities Unit
Safety Assessment Section
Division of Nuclear Installation Safety
International Atomic Energy Agency
Wagramer Strasse 5
P.O. Box 100, A-1400
Vienna, Austria

Dear Mr. Tolstykh:

Enclosed are the following IRS reports:

- Causes and Significance of Design-Basis Issues at U.S. Nuclear Power Plants (NRC NUREG-1275, Volume 14).
- Regulatory Effectiveness of the Station Blackout Rule.
- Evaluation of Air-Operated Valves at U.S. Light-Water Reactors (NRC NUREG-1275, Volume 13).

Each report is being submitted in the following two media: (1) a hard copy of the input file for the AIRS database; and (2) a 3.5-inch HD diskette containing the input file for the AIRS database in Microsoft Word 6.0 format.

If you have any questions regarding these reports, please call Eric J. Benner of my staff. He can be reached at (301) 415-1171.

Sincerely,

/RA/
Ledyard B. Marsh, Chief
Events Assessment, Generic Communications and
Non-Power Reactors Branch
Division of Regulatory Improvement Programs
Office of Nuclear Reactor Regulation

Enclosures: as stated

cc w/enclosures 1 and 2:
Mr. Lennart Carlsson
Nuclear Safety Division
Nuclear Energy Agency
Organization for Economic
Cooperation and Development
Le Seine Saint Germain
12, Boulevard des Iles
92130, Issy-les-Moulineaux, France

Mr. Valeri Tolstykh March 7, 2001
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INCIDENT REPORTING SYSTEM

IRS NO.	EVENT DATE	DATE RECEIVED
	2000/11/01	

EVENT TITLE

Causes and Significance of Design-Basis Issues at U.S. Nuclear Power Plants
(NRC NUREG-1275, Volume 14)

COUNTRY	PLANT AND UNIT	REACTOR TYPE
USA	Generic	(BWR or PWR)

INITIAL STATUS	RATED POWER (MWe NET)
N/A	N/A

DESIGNER	1st COMMERCIAL OPERATION
(WEST, GE, CE, B&W)	N/A

ABSTRACT

This IRS report summarizes the United States Nuclear Regulatory Commission's (USNRC) systematic and comprehensive study of DBI trends and patterns following a limited-scope AEOD review that began in early 1997. The goal of the study was to develop and document insights from reported DBIs with respect to: (1) their causes, significant patterns within both the power reactor industry and power reactor systems, frequency trends, safety consequences, and risk significance; (2) the regulatory effectiveness of NRC inspection and plant performance assessment processes and the definition of plant design basis applicable at the time the DBIs were reported in LERs and; (3) regulatory burden implications related to current NRC licensee event reporting requirements for DBIs. It is intended that the insights from this report assist NRC and industry ongoing efforts to make NRC's regulatory framework and oversight process more risk-informed and performance-based and to reduce unnecessary regulatory burden. The complete report is publically available through the USNRC Agencywide Documents Access and Management System (ADAMS) at accession number ML003773633.

Please refer to the dictionary of codes corresponding to each of the sections below and to the coding guidelines manual.

1.	**Reporting Categories:**	1.4		
2.	**Plant Status Prior to the Event:**	2.0		
3.	**Failed/Affected Systems:**	3.Z		
4.	**Failed/Affected Components:**	4.0		
5.	**Cause of the Event:**	5.1.0		
6.	**Effects on Operation:**	6.0		
7.	**Characteristics of the Incident:**	7.0		
8.	**Nature of Failure or Error:**	8.0		
9.	**Nature of Recovery Actions:**	9.0		

ADAMS ACCESSION NUMBER ML003773633

NUREG-1275 Vol. 14

Causes and Significance of Design-Basis Issues at U.S. Nuclear Power Plants

Manuscript Completed: October 2000
Date Published: November 2000

Prepared by
R. L. Lloyd, J.R. Boardman, S.V. Pullani

Division of Systems Analysis and Regulatory Effectiveness
Office of Nuclear Regulatory Research
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

For a number of years the Nuclear Regulatory Commission has been concerned about the continuing discovery and reporting of design-basis issues (DBIs) at nuclear power plants. These concerns were heightened in 1995 when design issues emerged at Millstone and at other nuclear power plant facilities, raising concerns regarding the ability of licensees to operate their facilities within their design basis. In January 1997, the Office for Analysis and Evaluation of Operational Data (AEOD)* was requested by the Executive Director for Operations to assess and periodically report on the trends and patterns of DBIs identified by nuclear power plant licensees in event notifications and licensee event reports (LERs).

This report documents the results of a systematic and comprehensive study of DBI trends and patterns following a limited-scope AEOD review that began in early 1997. The goal of the study was to develop and document insights from reported DBIs with respect to: (1) their causes, significant patterns within both the power reactor industry and power reactor systems, frequency trends, safety consequences, and risk significance; (2) the regulatory effectiveness of NRC inspection and plant performance assessment processes and the definition of plant design basis applicable at the time the DBIs were reported in LERs and; (3) regulatory burden implications related to current NRC licensee event reporting requirements for DBIs. It is intended that the insights from this report assist NRC and industry ongoing efforts to make NRC's regulatory framework and oversight process more risk-informed and performance-based and to reduce unnecessary regulatory burden.

For this study, a DBI was generally defined and captured in accordance with the licensee event reporting requirement in 10 CFR 50.73(a)(2)(ii). This requirement states that licensees shall report an actual or a potential event (condition) that resulted in the nuclear power plant, including its principal safety barriers, being seriously degraded, in an unanalyzed condition, in a condition outside the plant's design basis, or in a condition not covered by the plant's operating or emergency procedures. The initial data for the study came from a special database of DBIs reported in LERs for 1997 and compiled by AEOD. All of the LERs for 1997 were reviewed manually to determine if they involved a DBI as documented by the licensee. Although there was agreement with the licensees' determinations in most cases, there were some differences. Automated searches and sorts of the Sequence Coding and Search System (SCSS) LER database, maintained by the Oak Ridge National Laboratory (ORNL), were performed to determine the trends and patterns of DBIs over the period 1985–1997. The Accident Sequence Precursor (ASP) database was used to obtain risk perspectives in terms of conditional core damage probability (CCDP) of the DBI events.

The study found that U.S. nuclear power plants reported over 3100 LERs with DBIs during the period 1985–1997, or on average, about 240 per year. For the period 1985–1987 the number of DBIs ranged from 155–184 per year. For 1988 and 1989, the number significantly increased to 254 and 251, respectively. This increase coincided with the broad implementation, beginning in 1987, of NRC safety systems functional inspections and safety systems outage modification inspections. There was another significant increase in the number of DBIs reported in LERs in 1996 (from 194 to 377) and again in 1997 (from 377 to 563). These increases appeared to coincide with certain NRC initiatives including: NRC team inspections with a significant design element, NRC surveys of licensees on DBIs, licensee review in response to elevated NRC focus on DBIs, and NRC generic communications.

* Effective March 28, 1999, the Office for Analysis and Evaluation of Operational Data (AEOD) was disbanded. The work described in this report which was initiated by AEOD is being completed by the Regulatory Effectiveness Assessment and Human Factors Branch of the NRC's Office of Nuclear Regulatory Research.

For 1997, the study identified 1975 LERs (when considering multi-plant applicability) that were submitted for the 110 nuclear power plants in the United States. As indicated above, of these, 563 involved DBIs, or about 29 percent of the total. For 1997, the most common causes of DBIs were original design error, procedure deficiency and human error. Licensees often cited multiple causes of DBIs. The most frequent contributing causes included design errors dating back to the time of original plant licensing (70 percent), procedure deficiencies (28 percent), human error (23 percent), poor work control practices (15 percent), and plant modifications (14 percent).

The study found a significant variation among plants in the number of reported DBIs. For 1997, the average number of DBIs reported in LERs for the 110 operating plants was 5.1. However, 6 PWRs accounted for about 28 percent of the reported DBIs: Crystal River 3 (37 DBIs), Point Beach 1 (27 DBIs), Point Beach 2 (26 DBIs), Millstone 3 (26 DBIs), D.C. Cook 2 (22 DBIs), and D.C. Cook 1 (19 DBIs). Additionally, during the period 1990–1997, 11 plants (9 pressurized water reactors [PWRs] and 2 boiling water reactors [BWRs]) accounted for about 29 percent of the reported DBIs.

Only a few safety-related systems accounted for about half of the DBIs. For 1997, 6 of the 26 safety-related plant system categories used for the study accounted for approximately 64 percent of the 563 DBIs reported in LERs. These systems were: emergency core cooling (16 percent), emergency ac/dc power (14 percent), containment and containment isolation (12 percent), primary reactor (9 percent), essential service water (6 percent), and auxiliary/ emergency feedwater (7 percent).

Older plants (those licensed before 1975) generally reported more DBIs than newer plants (licensed after 1984) reported. For 1997, newer plants reported an average of about 3.6 DBIs while older plants reported an average of about 6.1 DBIs.

Of the 563 DBIs reported in LERs for 1997, 449 were screened, characterized and ranked by potential risk significance. The remaining 114 LERs with DBIs which were not risk ranked involved either seismic or fire protection deficiencies. These were excluded because significant uncertainties exist in the current risk assessment methods for these kinds of design issues. The risk category for each DBI was assessed on the basis of the Phase 1 process step documented in SECY-99-007A, “Recommendations for Reactor Oversight Process Improvements,” Appendix A, “Process for Characterizing the Risk Significance of Inspection Findings.” The specific guidance used for characterizing DBI risk significance was the generic risk information matrices (RIMs) tables for PWRs and BWRs documented in “Development of Risk-Informed Baseline Inspection Program,” dated February 10, 1999. DBIs were categorized as either “potentially risk significant,” “minimal risk,” or “no risk significance.” A DBI was categorized as potentially risk significant if it involved structures, systems, and components (SSCs) which were in the RIMs table and it was relevant to one or more of the sequences which placed the SSC in the RIMs table. A DBI was categorized as involving minimal risk if it involved an SSC that was either not in the RIM table or it involved an adverse effect on an SSC which was not relevant to any of the reasons the SSC was in the RIMs table. A DBI was categorized as having no risk significance if the DBI was only programmatic. That is, it involved inadequate design basis analysis documentation and where the remedial actions only involved correcting or completing the design basis analysis.

Of the 449 DBIs reported in LERs in 1997 that were screened for risk significance, a small fraction (22 percent) were identified as potentially risk significant. The majority (78 percent) were determined to only involve either minimal risk or no risk significance. A sorting of these DBIs by system found that 3 of the 26 safety-related systems accounted for about 58 percent of the of the potentially risk significant DBIs. These systems were: emergency core cooling (33 percent)

emergency ac power (15 percent) and containment and containment isolation (10 percent).

In general, “older” plants (operating license between 1964 and 1974) reported more potentially risk significant DBIs than “newer’ plants (operating license between 1985 and 1997). About 57 percent of the “older” plants had at least one DBI categorized as potentially risk significant, whereas, about 19 percent of the “newer” plants had at least one DBI categorized as potentially risk significant. This tendency was also more pronounced at multi-unit sites than at single-unit sites. Consequently, “older” multi-unit sites had a higher percentage of potentially risk significant DBIs than did “older” single-unit sites. The apparent reasons for the difference included: generally lower quality, level of completeness and accessibility of plant design basis information at older plants. Shared systems was believed to be the major reason for the higher percentage of potentially risk significant DBIs for multi-unit sites. The percentage of plants associated with multi-unit sites that had at least one potentially risk significant DBI was 63, 50, and 21 for “older,” “medium” (operating license between 1975 and 1984) and “newer” licensed plants respectively, whereas, for single-unit sites that had at least one potentially risk significant DBI, the percent was 50, 33, and 17 for “older,” “medium,” and “newer” licensed plants respectively.

Potentially risk significant DBIs also varied by NRC region. For 1997, plants in Regions I and III reported the largest number (35 and 36 respectively) of potentially risk significant DBIs, while plants in Regions II and IV reported the fewest number of potentially risk significant DBIs (22 and 6 respectively). Region III plants also had the highest percentage of plants with at least one potentially risk significant DBI (59 percent), followed by Region I (52 percent), Region II (36 percent) and Region IV (19 percent). The lower incidence of potentially risk significant DBIs in Regions II and IV may have been due in part to the generally fewer engineering inspection hours and the higher percentage of newer plants (i.e., better design basis documentation) in these regions.

During the period from 1991 to 1997, the percent of DBIs reported in LERs that were ASP events steadily decreased, while the number of DBIs reported in LERs increased. In 1991, about 8.3 percent of DBIs reported in LERs were determined to be ASP events (i.e., CCDP $\geq 10^{-6}$). However, by 1997, only about 0.5 percent of the LERs with DBIs were classified as ASP events. However, 3 of the 5 ASP events in 1997 involved DBIs indicating that DBIs were an important contributor to the relatively few risk significant operating events which occurred. The study also found that during 1992–1997 there were a total of 14 “important” ASP events (CCDP $\geq 10^{-4}$) . Of these, 12 occurred at PWRs and 2 occurred at BWRs. However, three of the 14 important ASP events during this period involved DBIs, and all of these occurred at PWRs.

The study also examined apparent correlations of the number of DBIs (total and potentially risk significant) reported in LERs with other NRC program areas and initiatives. These efforts were intended to explore insights and potential lessons which might be associated with NRC regulatory effectiveness and regulatory burden.

The study found that increases in the number of reported DBIs coincided with NRC initiatives. The number varied from a low of 155 in 1985 to a high of 563 in 1997. Significant increases in the number of reported DBIs from the previous years were observed in 1988 and 1989, and again in 1996 and 1997. The increases appeared to coincide with certain NRC initiatives including: NRC team inspections with a significant design element, NRC surveys of licensees on DBIs, licensee reviews in response to elevated NRC focus on DBIs, and NRC generic communications.

For the period from 1995 to 1997, the number of reported DBIs appeared to correlate with NRC engineering inspection effort. The study found that during this period, as NRC engineering

inspection hours at a plant increased, the number of DBIs reported by the plant generally increased. The increase was considered to be the result of both NRC inspection teams finding DBIs at the plant and licensees increasing their efforts to identify DBIs in connection with these NRC inspections. NRC generic communications on DBIs during the period was also considered a factor. Conversely, thirteen of the 20 plants that reported no DBIs during 1997, received less than the median number of engineering inspection hours.

As noted above, if a plant had a thorough engineering inspection for design compliance, it often reported more DBIs. The study also found that this often resulted in the plant receiving a lower plant engineering rating (under the former Systematic Assessment of Licensee Performance (SALP) program) in the subsequent assessment period. In some instances, the lower assessment rating led to increased regional or agency oversight. The correlation between engineering inspection effort, the number of reported DBIs and subsequent performance ratings was evident for the SALP program, and may also be relevant to the NRC's revised reactor oversight program which features decision criteria leading to additional inspection efforts for selected plants that meet an established performance threshold.

Also as noted above, the majority of the DBIs reported in LERs involved minimal or no safety significance. In this regard, it would appear that the staff's ongoing efforts to make 10 CFR 50.73(a)(2)(ii) more risk-informed should have a significant impact on reducing unnecessary regulatory burden.

NRC engineering inspection teams and design inspection teams have been particularly successful in identifying DBIs at nuclear power facilities. When DBIs are identified as part of an NRC inspection they frequently resulted in the licensee submitting an LER for the DBI and the staff documenting the finding in an inspection report. However, based on the ASP program insights, most DBIs, by themselves, have been of relatively low safety significance. It is anticipated that the inspection reports which conforms to the revised reactor oversight program will screen out DBI-related inspection findings that are of low risk significance and include only those that are significant in a risk-informed, performance-based context.

NRC and industry awareness and recognition of significant and potentially generic DBIs have emerged over time from the coalescing of insights that are drawn from operating experience, performance information, safety analyses, and system analyses and reviews. The safety importance and applicability of DBIs documented and fed back to industry in NRC generic communications occasionally has taken several years for some licensees to fully recognize and address. However, with NRC's generic communications program and reactor inspection program becoming more risk-informed, the timeliness and reliability of licensee corrective actions for applicable risk-significant DBIs in NRC generic communications should be expected to improve.

As a final observation, as evidenced by the ASP program, over the period from 1990 to 1997, there has been a steady decline in the ratio of the number of ASP events with DBIs to the total number DBIs reported in LERs. By 1997, less than 1 percent of all DBIs reported in LERs were ASP events. However, 60 percent (3 of 5) of the ASP events for 1997 involved DBIs. Thus, although the percentage of DBIs that are risk significant is very small, it may be expected that, to the extent that ASP events occur (and risk significant NRC inspection findings are identified), DBIs may continue to be an important contributor.

INCIDENT REPORTING SYSTEM

IRS NO.	EVENT DATE	DATE RECEIVED
	2000/08/15	

EVENT TITLE

Regulatory Effectiveness of the Station Blackout Rule

COUNTRY	PLANT AND UNIT	REACTOR TYPE
USA	Generic	(BWR or PWR)

INITIAL STATUS	RATED POWER (MWe NET)
N/A	N/A

DESIGNER	1st COMMERCIAL OPERATION
(WEST, GE, CE, B&W)	N/A

ABSTRACT

This IRS report summarizes the United States Nuclear Regulatory Commission's (USNRC) review of the station blackout (SBO) rule, to determine if the requirements are achieving the desired outcomes. This initiative is part of an evolving program to make USNRC activities and decisions more effective, efficient, and realistic. This report evaluates the effectiveness of the SBO rule by comparing regulatory expectations to outcomes. A set of baseline expectations was established from the SBO rule and related regulatory documents in the areas of coping capability, risk reduction, emergency diesel generator reliability, and value-impact. The report concludes that although there are opportunities to improve the clarity of SBO related regulatory documents, the SBO rule is effective and the industry and the USNRC costs to implement the SBO rule were reasonable considering the outcome. The complete report is publically available through the USNRC Agencywide Documents Access and Management System (ADAMS) at accession number ML003741781.

Regulatory Effectiveness of the Station Blackout Rule

Please refer to the dictionary of codes corresponding to each of the sections below and to the coding guidelines manual.

1.	Reporting Categories:	1.4		
2.	Plant Status Prior to the Event	2.0		
3.	Failed/Affected Systems:	3.E		
4.	Failed/Affected Components:	4.3.1	4.3.2	4.3.5
5.	Cause of the Event:	5.1.2		
6.	Effects on Operation:	6.0		
7.	Characteristics of the Incident:	7.9	7.10	
8.	Nature of Failure or Error:	8.0		
9.	Nature of Recovery Actions:	9.0		

ADAMS ACCESSION NUMBER: ML003741781

Regulatory Effectiveness of the Station Blackout Rule

Prepared by:
William S. Raughley

The Nuclear Regulatory Commission's Office of Nuclear Regulatory Research (RES) is reviewing selected regulations, starting with the station blackout (SBO) rule, to determine if the regulatory expectations are achieving the desired outcomes. This initiative is part of an evolving program to make NRC activities and decisions more effective, efficient, and realistic. As part of this program, RES is also reviewing the effectiveness of generic safety issue resolution.

The NRC designated SBO, which is a loss of all offsite and onsite ac power concurrent with a turbine trip, as Unresolved Safety Issue A-44 in 1980. In 1988, the Commission concluded that additional SBO regulatory requirements were justified and issued the SBO rule (10 CFR 50.63) to provide further assurance that a loss of both offsite and onsite emergency ac power systems would not adversely affect public health and safety. The SBO rule expected a reduction in the risk as a result of licensees maintaining highly reliable onsite emergency ac electric power supplies; ensuring that the plants can cope with an SBO for some period of time; developing procedures and training to restore offsite and onsite emergency ac power should either become unavailable; and making modifications necessary to meet the SBO rule requirements.

To assess the regulatory effectiveness of the SBO rule, the expectations were established from objective measures as stated in SBO related regulatory documents in the areas of coping capability, risk reduction, emergency diesel generator (EDG) reliability, and value-impact. The outcomes were obtained from realistic information to include the operating experience and NRC equipment reliability studies based on actual safety performance. Comparison of the expectations to the outcomes showed whether the expectations were achieved. Discrepancies between expectations and outcomes prompted a review of the related regulatory documents to find areas that need NRC staff attention. To increase public confidence, earlier drafts of the report were made publicly available and stakeholder comments were openly addressed in an appendix of the report.

The report's conclusion is that the SBO rule was effective considering that the risk expectations were achieved, and that industry and NRC costs to implement the SBO rule were reasonable. In implementing the SBO rule, some plants made hardware modifications (e.g., the addition of diesel generator or gas turbine generator power supplies); and all plants generally maintained EDG reliability at 0.95 or better, and established SBO coping and recovery procedures. Consequently, the plants have gained SBO coping capability, reduced risk, increased the tolerance to a loss of ac offsite or onsite power; and many plants benefitted economically from the addition of power supplies. To elaborate:

- The reduction in the estimated mean SBO core damage frequency (CDF) was approximately 3.2E-05 per reactor year, slightly better than the 2.6E-05 per reactor year expected after implementation of the SBO rule. As a result of the improvements made under the SBO rule, more plants achieved a lower SBO CDF than expected, and the plants with the greatest numbers of loss of offsite power from plant events and extremely severe weather conditions made the most improvement by providing access to an alternate ac power supply. In addition, maintaining high EDG target reliability levels provides assurance that probabilistic risk assessment/individual plant examination EDG performance assumptions are valid. With some exceptions, the observed EDG reliability performance generally exceeds the mean reliability EDG performance assumptions in the probabilistic risk assessment/individual plant examinations, indicating that SBO CDFs are smaller and better than stated in many probabilistic risk assessment/individual plant examinations. As the SBO rule risk reduction objectives have been exceeded, further investigation of strategies for reducing SBO frequencies (as suggested in NUREG–1560, "Individual Plant Examination Program: Perspectives on Reactor Safety and Plant Performance," December 1997) may not be needed.

- As a result of the SBO rule all plants have (1) established SBO coping and recovery procedures; (2) completed training for these procedures; (3) implemented modifications as necessary to cope with an SBO; and (4) ensured a 4- or 8-hour coping capability.

- Before the SBO rule was issued, only 11 of 78 plants surveyed had a formal EDG reliability program, 11 of 78 plants had a unit average EDG reliability less that 0.95, and 2 of 78 had a unit average EDG reliability of less that 0.90. Since the SBO rule was issued, all plants have established an EDG reliability program that has improved EDG reliability. A report shows that only 3 of 102 operating plants have a unit average EDG reliability less than 0.95 and above 0.90 considering actual performance on demand, and maintenance (and testing) out of service (MOOS) with the reactor at power. However, the analysis of EDG performance on demand indicates MOOS with the reactor at power is more than expected and can have a significant effect on the EDG reliability calculations. Increased MOOS explains why licensees appear to be having difficulty meeting a 0.975 EDG target reliability. Decreased EDG reliabilities and/or increased MOOS unavailabilities erode the risk benefits obtained from implementing the SBO rule.

- The operating experience indicates that the SBO rule has increased defense-in-depth. The SBO related hardware and procedures have been used in response to unplanned events and provided additional protection. The SBO rule provides additional defense-in-depth to compensate for potential degradation of the ac offsite power system that may result from deregulation of the electric power industry or longer than expected recovery of offsite power after extremely severe weather conditions.

- A comparison of the value-impact expectations to the outcomes indicates that the value-impact was within the expected range of reductions in public dose-per-dollar of cost. As expected, there was wide variation in plant-specific values and impacts because the SBO rule allowed flexibility. Not expected was the addition of costly power supplies, which accounted for 75 percent of the estimated industry cost impact and explains why the NRC value-impact analysis underestimated the cost by a factor of 4. However, it appears licensees justified the cost of the power supplies by counting on offsetting monetary benefits, such as more operating flexibility from increased EDG allowed outage times. Thus the value was also underestimated. The remaining 25 percent of the estimated industry cost impact appears reasonable, considering the outcomes: known coping capabilities, industry risk reduction from plant-specific procedural and hardware enhancements, and additional defense-in-depth.

A comparison of the SBO rule expectations to the corresponding outcomes indicates that resolution of the generic issue of SBO was effective as no additional generic actions are warranted and no new generic safety issues have been identified.

Although the SBO rule was effective for the reasons stated above, consistent with adhering to Principles of Good Regulation that include clarity (coherent and practical regulations) and reliability (regulations based on operating experience) there are opportunities to revise the regulatory guidance and inspection documents. The proposed revisions are not intended to impose any new regulatory requirements, are consistent with the SBO technical basis (NUREG–1032); ensure high levels of EDG reliability; maintain present levels of safety by ensuring the risk benefits obtained from implementing the SBO rule do not erode; provide practical guidance for reactor shutdowns with limited offsite or onsite power sources; and use operating experience to improve the predictability and consistency of NRC decisions in the area of EDG reliability. The opportunities are as follows:

(1) Regulatory Guides 1.155, “Station Blackout,” August 1988; RG 1.9, “Selection, Design, Qualification of Diesel-Generator Units Used as Standby (Onsite) Electric Power Systems at Nuclear Power Plants,” Revision 3, July 1993; and RG 1.160, “Monitoring the Effectiveness of Maintenance at Nuclear Power Plants,” Revision 2, March 1997; which address use of the existing EDG reliability terms, criteria, and measurements may need to be revised in a coherent manner to: (a) clarify that EDG unavailability because of MOOS with the reactor at power should be included in the reliability calculation; (b) clarify that licensees should balance increased EDG reliability against the increased EDG unavailability to maintain the RG 1.155 minimum individual EDG target reliabilities; (c) clarify that the EDG system boundary used in the reliability calculation should include the load sequencer and the bus between the EDG and the loads; and (d) establish common EDG start and load-run criteria for the guidance.

Inspection documents Temporary Instruction 2515/125, “Inspection of Implementation of Station Blackout Rule,” (no date); and Inspection Procedure 62706, “Maintenance Rule,” December 31, 1997; may need revision to delete use of the Nuclear Management and Resources Council (NUMARC)(now NEI) trigger values to assess compliance with the 0.95 and 0.975 EDG target reliability. The NUMARC trigger values, which are not endorsed by the regulatory guidance, do not provide high levels of confidence that the EDG target reliability is being met; this is inconsistent with ensuring high EDG reliability, delays corrective action, and erodes the risk benefits obtained from implementing the SBO rule.

(2) Operating events indicate that the availability of some Aac power supplies is dependent on offsite or onsite power supplies. SBO-related inspection documents may need inspection attributes to verify that the Aac sources meet NUMARC 87-00, “Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors,” Revision 1, May 1993; Appendix B, B.8, “Minimal Potential For Common Cause Failure.”

(3) Regulatory Guide 1.93, “Availability of Electric Power Sources,” December 1974; the basis for technical specifications in the area of ac onsite and offsite power supply availability, provides for shutdown of the reactor following extended ac power supply unavailability. Plant shutdown with one or more offsite or onsite power supplies unavailable could exacerbate the grid condition or remove redundant sources to operate decay heat removal systems, increasing the likelihood of an SBO. Additional practical guidance may minimize the likelihood of an SBO.

(4) Follow-up at 2 plants revealed a large difference between the unit average EDG reliability based on load-run tests and unplanned demands and the reliability calculated by the licensee based on the last 100 start and load-run tests and unplanned demands. This difference confirms a previous finding in INEL-95/0035, “Emergency Diesel Generator Power System Reliability,” February 1996, that the current testing and inspection activities (as prescribed by the NRC) may not be focusing on the dominant contributors to unreliability during actual demands. Accordingly, NRC inspection documents may need to be modified to better factor in the conditions and experiences gained from actual system demands to facilitate inspection of EDG compliance.

As lessons learned: (a) to the extent that the NRC staff revises existing regulatory documents to be more risk-informed and performance-based, they may need to be modified to ensure consistent interpretation and use of terms, goals, criteria, and measurements; and (b) new regulations or the accompanying regulatory documents should include quantitative objectives to facilitate evaluation of its regulatory effectiveness.

INCIDENT REPORTING SYSTEM

IRS NO.	EVENT DATE	DATE RECEIVED
	2000/02/29	

EVENT TITLE

Evaluation of Air-Operated Valves at U.S. Light-Water Reactors
(NRC NUREG-1275, Volume 13)

COUNTRY	PLANT AND UNIT	REACTOR TYPE
USA	Generic	(BWR or PWR)

INITIAL STATUS	RATED POWER (MWe NET)
N/A	N/A

DESIGNER	1st COMMERCIAL OPERATION
(WEST, GE, CE, B&W)	N/A

ABSTRACT

This IRS report summarizes a study was conducted by the United States Nuclear Regulatory Commission's Office of Nuclear Regulatory Research to collect information to form the basis for determining if additional regulatory attention is needed to address air-operated valves (AOVs). This report and its companion document, Idaho National Engineering and Environmental Laboratory report NUREG/CR-6654, "A Study of Air-Operated Valves in U.S. Nuclear Power Plants," present the results of a comprehensive review of AOV operating experience and visits to 7 U.S. light water reactor sites at which there are 11 operating reactors. The complete report is publically available through the USNRC Agencywide Documents Access and Management System (ADAMS) at accession number ML003691726.

Please refer to the dictionary of codes corresponding to each of the sections below and to the coding guidelines manual.

1.	**Reporting Categories:**	**1.4**		
2.	**Plant Status Prior to the Event:**	**2.0**		
3.	**Failed/Affected Systems:**	**3.B**	**3.C**	**3.D**
4.	**Failed/Affected Components:**	**4.2.3**		
5.	**Cause of the Event:**	**5.1.0**		
6.	**Effects on Operation:**	**6.0**		
7.	**Characteristics of the Incident:**	**7.0**		
8.	**Nature of Failure or Error:**	**8.0**		
9.	**Nature of Recovery Actions:**	**9.0**		

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EVALUATION OF AIR-OPERATED VALVES AT U.S. LIGHT-WATER REACTORS

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This study was conducted by the Nuclear Regulatory Commission's Office of Nuclear Regulatory Research to collect information to form the basis for determining if additional regulatory attention is needed to address air-operated valves (AOVs). This report and its companion document, Idaho National Engineering and Environmental Laboratory report NUREG/CR-6654, "A Study of Air-Operated Valves in U.S. Nuclear Power Plants," present the results of a comprehensive review of AOV operating experience and visits to 7 U.S. light water reactor sites at which there are 11 operating reactors.

Plant visits were conducted to obtain information about AOV operating experience and AOV maintenance and support activities. Discussions of operating experience focused on the root causes of AOV failures and corrective actions. Features of the AOV programs that were discussed included identification of risk-important AOVs, design margins, design verification, diagnostic testing, maintenance practices, ageing, participation in industry AOV activities, and parallelisms between AOV and motor-operated valve experience and activities.

Each plant visited had an AOV program. The licensees' AOV programs identified, categorized, and prioritized the plants' AOV populations in order to determine the level of effort that needed to be focused on AOV analysis, testing, and maintenance activities. Recognizing the application of the single failure criterion and defense in depth, failure of a single AOV would generally not be a cause of concern. However, all licensees identified "important" AOVs based on a variety of methods including plant specific probabilistic risk assessments, individual plant examinations, or maintenance rule expert panel reviews. Many licensees identified individual AOVs whose failure would result in increased risk as indicated by high risk achievement worth or high Fussell Vesely risk rankings.

The major safety concern of this study from a risk perspective is the simultaneous common-cause failure of AOVs, which disable redundant trains of a safety system. The scenario of most concern is that during an accident or transient, AOVs in redundant trains of a safety system fail when subjected to pressure, temperature, and flow conditions different from those seen during normal operation or testing. Similar to the situation with MOVs which led to issuance of Generic Letter 89-10, errors in design parameters, such as valve factors, and other design, manufacturing, or maintenance errors could result in lower than expected AOV valve operator force or greater than expected valve friction. Normal testing or routine operation of these valves, if performed under pressure, temperature, flow conditions different from those expected during an accident or transient, may not reflect the actual capability of the valve to perform during an accident or transient.

Several instances from operating experience are noted in this study where AOVs were shown to be unable to operate under the conditions expected during an accident or transient. These were usually found through diagnostic testing methods similar to those utilized to verify MOV operability in response to Generic Letter 89-10 and its supplements. Some failed to operate in real events. Current inservice testing and technical specification operability tests may not assure AOV capability for pressure and flow conditions during an accident or transient.

Another concern is the potential for simultaneous common-cause failure of two or more AOVs in important safety systems due to contamination from the pneumatic system or from fabrication and maintenance activities. Rust, dirt, or water in the air system can affect many valves. Fabrication and maintenance activities can introduce excessive thread locker or other contaminants which cause sticking or binding. Degradation of elastomers have resulted in common-cause failures. AOV failures from these conditions are expected to be more random than the design errors and fabrication errors described above, but could still have the impact of disabling multiple trains of safety systems.

As discussed in the study, some licensees found that certain AOVs had high risk achievement worth and/or Fussell Vesely risk rankings. Table 6 of NUREG/CR-6654 includes the risk achievement worth values for AOVs that were calculated by licensees at three plants. These calculations showed that, in some cases, the risk achievement worth could increase by one or two orders of magnitude as a result of CCFs. Risk achievement worth for common-cause AOV failures at those three plants ranged from slightly over 1 to 202.

The implementation of an effective AOV program, incorporating the use of analysis, diagnostic testing, and lessons learned from operating experience, can minimize the likelihood of AOV failures resulting in risk significant events. Such a program would:

- Identify safety related AOVs which are normally in a non-safety position and are expected to move to their safety position during accidents or transients. (These will subsequently be referred to as safety related active AOVs.)

- Identify safety related active AOVs which contribute the most to risk should they fail to operate, using plant-specific application of appropriate risk-ranking methodologies. For those valves with unconfirmed design margin or diagnostic testing, risk calculations which appropriately consider failures of redundant valves in both trains of a system may be appropriate.

- Establish confidence that risk significant safety related active AOVs will operate as required, subject to the actual pressures, temperatures, and flows during transient and accident conditions, by application of accepted and verified analysis or diagnostic testing methods. Assure continued operability of these valves through periodic testing.

- Establish operations and maintenance practices which prevent introduction of contaminants to the pneumatic system or to the valves and their sub-components and replace aging elastomers as appropriate.

Cooperation between the NRC and industry to develop the guidance for AOV programs would facilitate and optimize the implementation of these programs.