RAS 15103

THE ASSEMBLY
STATE OF NEW YORK
ALBANY

RICHARD L. BRODSKY
Assemblyman 92ND District
Westchester County

CHAIRMAN
Committee on
Corporations, Authorities
and Commissions

DOCKETED
USNRC
February 21, 2008 (6:50pm)
OFFICE OF SECRETARY
RULEMAKINGS AND
ADJUDICATIONS STAFF

February 19, 2008

Office of the Secretary
U.S. Nuclear Regulatory Commission
Sixteenth Floor
One White Flint North
11555 Rockville Pike
Rockville, Maryland 20852

**Re**: Indian Point License Renewal, Docket No. 50-247/286-LR

To Whom It May Concern:

Enclosed please find a CD-ROM containing an exact copy of the Petitioners Westchester Citizen's Awareness Network (WestCAN), Rockland County Conservation Association, Inc (RCCA), Promoting Health and Sustainable Energy, Inc. (PHASE), Sierra Club – Atlantic Chapter (Sierra Club), and New York State Assemblyman Richard L. Brodsky Reply Brief in response to the NRC Staff and Entergy.

Also enclosed is a copy of the signed transmittal letter, the Certificate of Service, Table of Contents, and Exhibits. All documents are in Adobe PDF format, and are provided as distinct files. The documents are electronic versions of the hardcopy documents sent February 15, 2008 by courier, as well as the Petitioners Reply sent by email last Friday.

You may note the hyperlinking capability embedded in the Reply and Declarations as well as the Table of Contents. Simply click on the exhibit in the petition to go directly to that exhibit. In the Table of Contents simply click on the specific pdf file link and again you will be taken directly to that document. These links are visible as a blue underline, or blue highlighted text.

Attachment 1 is the service list. Please note that every effort was made to comply with the directions contained in the Board's Order dated February 1, 2008. If you have any concerns or are unable to open a file please contact me immediately.

Sincerely,

[signature] for

Sarah L. Wagner
Attachment 1—Service List

TEMPLATE = SECY-037

SECY-02

# Attachment 1

## Service List for CD-ROM Disc Containing:

(1) Table of Contents,
(2) Reply Brief w/ Exhibits
(3) Copy of February 15, 2008 letter transmitting hardcopy of the file

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

| | | |
|---|---|---|
| In the Matter of | ) | |
| | ) | |
| ENTERGY NUCLEAR OPERATIONS, INC. | ) | Docket Nos. 50-247/286-LR |
| (Indian Point Nuclear Generating) Units 2 and 3) | ) | |
| | ) | |

## CERTIFICATE OF SERVICE

I hereby certify that copies of the foregoing Reply of WestCAN et al. dated February 15, 2008, have been served upon the following by electronic mail where email address provided, this 15th day of February, 2008 and a signed original and two paper copies have been deposit with a courier service on the Office of the Secretary, U.S. Nuclear Regulatory, Sixteenth Floor, One Flint North, 11555 Rockville Pike Rockville, Maryland 20852, and a courtesy paper copy has been sent to Staff:

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Sarah L. Wagner, Esq.

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| Exhibit R | Flow-Accelerated Corrosion failures. | Oct 2007 repair to service water pipe.pdf | Pg. 104; exhibit M. |
| Exhibit S | Petitioners further claim that Entergy has failed to demonstrate "a good track record with use of CHECWORKS." We note with interest that this same program implemented another Entergy plant currently in renewal proceedings, and was not just admitted, but also denied motion for summary disposition only months ago | See petition filed December 10 and clarified | Pg. 104 |
| Exhibit T | Identical program | See petition filed December 10 and clarified | Pg. 105 |
| Exhibit U | Atomic Industry Forum... Trade comments to draft General Design Criteria and Erroneously claim of publication in the Federal Register for public comment in July, 1967 | See petition filed December 10 and clarified | Pg. 71 |
| Exhibit V | General Design Criteria for the LRA and subsequently approved by the Atomic Energy Commission under the 1970 Safety Evaluation Report | See petition filed December 10 and clarified | Pg. 72 |
| Exhibit W | Documents cited or submitted in the applicant's LRA. The commission dealt with the design basis and license failures with a stroke of a pen in 1992 | See petition filed December 10 | Pg. 4 of Exhibit Q |
| Exhibit Y | Technical Spec Bases Requirements, update of 2004. | IP3 Technical Specifications Bases Manual October 2004 | Pg. 84; Page 5 of Exhibit Q |
| Exhibit Z. | General Design Criteria 45( p 14) | See exhibit Z at page 14 form original petition | Pg. 85 |
| Exhibit AA | Baffle bolt testing: alter chemistry tests vs. automated testing components such as baffle bolts that hold down springs, lower core barrel, and lower core plate are routinely UT or VT'd during outages and often replaced | See petition filed December 10 and clarified | Pg. 85 |

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| Exhibit DD | This Declaration contained in Exhibit Q | See Exhibit Q | Pg. 89 |
| Exhibit EE | Audit of NRC's License Renewal Program OIG-07-A-15 September 6, 2007 | Provided under Exhibit N | Pg. 89 |
| Exhibit FF | Office instruction for Nuclear Reactor Regulation LIC-100 | Provide also under Exhibit Q | Pg. 89 |

THE ASSEMBLY
STATE OF NEW YORK
ALBANY

RICHARD L. BRODSKY
Assemblyman 92ND District

Westchester County

CHAIRMAN
Committee on
Corporations, Authorities
and Commissions

February 15, 2008

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Also enclosed is the original signed hard copy of the Reply, the Certificate of Service, Table of Contents, Exhibits. A courtesy CD-ROM is being sent separately.

As you are aware I was experiencing problems with the NRC's server as we discussed with Rebecca Gitter. We transmitted the document as a word file, but are concerned it may be corrupted, if it arrived at all. We transmitted an Adobe PDF file via another office which we believe successfully went to all the parties. Therefore please delete the first transmittal, the "word document", and consider the Abode PDF file the Reply.

Sincerely,

Sarah L. Wagner

❑ ALBANY OFFICE: Room 422, Legislative Office Building, Albany, New York 12248, (518) 455-5753
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UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

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| In the Matter of | ) | |
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# TABLE OF CONTENTS

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|---|---|---|---|
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| Exhibit F | Declaration of Ulrich Witte "agreements to agree" in lieu of programs that are by the rule necessary in specificity and particularity for the application to be complete. | Exhibit F LGA Declaration.pdf | Pg.54 |
| Exhibit G | Omitted | | |
| Exhibit H | IGS-2006-02 " Staff Guidance on Acceptance Review for Environmental Requirements | isg--2006-02.pdf | Pg. 56 |
| Exhibit I | Amendment Nine of the Operating License | Provided with petition and as clarifed | Pg. 71 |
| Exhibit J | GZA Environmental, Inc. "Hydogeologic Site Investigation Report, Indian Point Entergy Center, January 7, 2008, file No. 41.0017369.10 | (Provided by Entergy in January 22 Response—therefore not supplied here) | Pg. 5 of Exhibit F |
| Exhibit K | omitted | | |
| Exhibit L | omitted | | |
| Exhibit M | Supplemental Declaration of Ulrich Witte regarding Flow-accelerated Corrosion | FAC Declaration Supplemental.pdf | n.a. |
| Exhibit N | Audit of NRC's License Renewal Program OIG-07-A-15 September 6, 2007 | OIG report on License Renewal.pdf | |
| Exhibit O | Curriculum Vitae Ulrich Witte (Referred as Attachment 2) | UlrichKonradWitte resume.pdf | Page 2 of Exhibit F; Page 2 of Exhibit Q Page 2 of Exhibit M |
| Exhibit P | NRC BULLETIN 2003-02: leakage from reactor pressure vessel lower Head penetrations and reactor coolant pressure Boundary integrity | Bulletin 2003-02 and IP response b.pdf | Page 86, page 6 of Exhibit Q |
| Exhibit Q<br>(Note that Exhibit Q as reference on page 104 should be Exhibit M) | Supplemental Declaration of Ulrich Witte regarding misrepresentation of design, construction and operation of Unit 2 and Unit 3 to draft GDCs. | GDC Declaration Supplmental.pdf | Pg. 86, p104 |
| Exhibit R | Flow-Accelerated Corrosion failures. | Oct 2007 repair to service water | Page 104; page xx of |

| | | | |
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| | | pipe.pdf | exhibit M. |
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# Reference 2

United States General Accounting Office

GAO

Report to Congressional Requesters

May 2004

# NUCLEAR REGULATION

# NRC Needs to More Aggressively and Comprehensively Resolve Issues Related to the Davis-Besse Nuclear Power Plant's Shutdown

GAO

Accountability * Integrity * Reliability

GAO-04-415

GAO
Accountability • Integrity • Reliability

# Highlights

Highlights of GAO-04-415, a report to congressional requesters

### Why GAO Did This Study

In March 2002, the most serious safety issue confronting the nation's commercial nuclear power industry since Three Mile Island in 1979 was identified at the Davis-Besse plant in Ohio. After the Nuclear Regulatory Commission (NRC) allowed Davis-Besse to delay shutting down to inspect its reactor vessel for cracked tubing, the plant found that leakage from these tubes had caused extensive corrosion on the vessel head—a vital barrier preventing a radioactive release. GAO determined (1) why NRC did not identify and prevent the corrosion, (2) whether the process NRC used in deciding to delay the shutdown was credible, and (3) whether NRC is taking sufficient action in the wake of the incident to prevent similar problems from developing at other plants.

### What GAO Recommends

Because the nation's nuclear power plants are aging, GAO is recommending that NRC take more aggressive actions to mitigate the risk of serious safety problems occurring at Davis-Besse and other nuclear power plants.

NRC disagreed with two of the report's five recommendations—that it develop (1) additional means to better identify safety problems early and (2) guidance for making decisions whether to shut down a plant. GAO continues to believe these recommendations are appropriate and should be implemented.

www.gao.gov/cgi-bin/getrpt?GAO-04-415.

To view the full product, including the scope and methodology, click on the link above. For more information, contact Jim Wells at (202) 512-3841 or wellsj@gao.gov.

May 2004

# NUCLEAR REGULATION

## NRC Needs to More Aggressively and Comprehensively Resolve Issues Related to the Davis-Besse Nuclear Power Plant's Shutdown

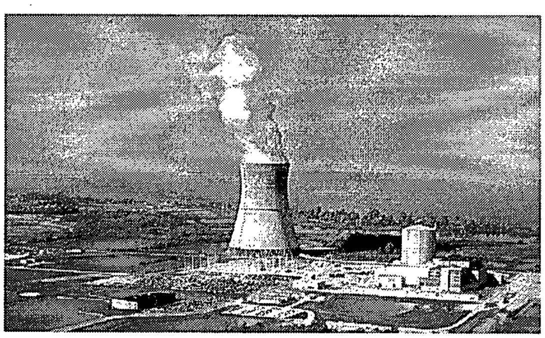
### What GAO Found

NRC should have but did not identify or prevent the corrosion at Davis-Besse because its oversight did not generate accurate information on plant conditions. NRC inspectors were aware of indications of leaking tubes and corrosion; however, the inspectors did not recognize the indications' importance and did not fully communicate information about them. NRC also considered FirstEnergy—Davis-Besse's owner—a good performer, which resulted in fewer NRC inspections and questions about plant conditions. NRC was aware of the potential for cracked tubes and corrosion at plants like Davis-Besse but did not view them as an immediate concern. Thus, NRC did not modify its inspections to identify these conditions.

NRC's process for deciding to allow Davis-Besse to delay its shutdown lacks credibility. Because NRC had no guidance specifically for making a decision on whether a plant should shut down, it used guidance for deciding whether a plant should be allowed to modify its operating license. NRC did not always follow this guidance and generally did not document how it applied the guidance. The risk estimate NRC used to help decide whether the plant should shut down was also flawed and underestimated the amount of risk that Davis-Besse posed. Further, even though underestimated, the estimate still exceeded risk levels generally accepted by the agency.

NRC has taken several significant actions to help prevent reactor vessel corrosion from recurring at nuclear power plants. For example, NRC has required more extensive vessel examinations and augmented inspector training. However, NRC has not yet completed all of its planned actions and, more importantly, has no plans to address three systemic weaknesses underscored by the incident. Specifically, NRC has proposed no actions to help it better (1) identify early indications of deteriorating safety conditions at plants, (2) decide whether to shut down a plant, or (3) monitor actions taken in response to incidents at plants. Both NRC and GAO had previously identified problems in NRC programs that contributed to the Davis-Besse incident, yet these problems continue to persist.

**The Davis-Besse Nuclear Power Plant in Oak Harbor, Ohio**



Source: FirstEnergy.

# Contents

## Abbreviations

| | |
|---|---|
| NRC | Nuclear Regulatory Commission |
| PRA | Probabilistic risk assessment |

GAO
Accountability * Integrity * Reliability

United States General Accounting Office
Washington, D.C. 20548

May 17, 2004

Congressional Requesters

In 2002, the most serious safety issue confronting the nation's commercial nuclear power industry since the accident at Three Mile Island in 1979 was identified at the Davis-Besse nuclear power plant in northwestern Ohio. On March 7, 2002, during shutdown for inspection and refueling, the owner of the Davis-Besse plant—FirstEnergy Nuclear Operating Company—discovered a pineapple-sized cavity in the plant's carbon steel reactor vessel head. The reactor vessel head is an 18-foot-diameter, 6-inch-thick, 80-ton cap that is bolted to the reactor vessel. The vessel head is an integral part of the reactor coolant pressure boundary that serves as a vital barrier for protecting the environment from any release of radiation from the reactor core. In pressurized water reactors such as the one at Davis-Besse, the reactor vessel contains the nuclear fuel, as well as water with diluted boric acid that cools the fuel and helps control the nuclear reaction. At the Davis-Besse plant, vertical tubes had cracked that penetrate the reactor vessel head and that contain this water as well as drive mechanisms used to lower and raise the fuel, thus allowing leaked boric acid to corrode the reactor vessel head. The corrosion had extended through the vessel head to a thin stainless steel lining and had likely occurred over a period of several years. The lining, which is less than one-third of an inch thick and was not designed as a pressure barrier, was found to have a slight bulge with evidence of cracking. Had this lining given way, the water within the reactor vessel would have escaped, triggering a loss-of-coolant accident, which—if back-up safety systems had failed to operate—likely would have resulted in the melting of the radioactive core and a subsequent release of radioactive materials into the environment. In March 2004, after 2 years of increased NRC oversight and considerable repairs by FirstEnergy, NRC approved the restart of Davis-Besse's operations.

Under the Atomic Energy Act of 1954, as amended, and the Energy Reorganization Act of 1974, as amended, the Nuclear Regulatory Commission (NRC) and the operators of nuclear power plants share the responsibility for ensuring that nuclear reactors are operated safely. NRC is responsible for issuing regulations, licensing and inspecting plants, and requiring action, as necessary, to protect public health and safety; plant operators have the primary responsibility for safely operating the plants in accordance with their licenses. NRC has the authority to order plant operators to take actions, up to and including shutting down a plant, if licensing conditions are not being met and the plant poses an undue risk to

## Abbreviations

NRC Nuclear Regulatory Commission
PRA Probabilistic risk assessment

GAO

Accountability * Integrity * Reliability

**United States General Accounting Office**
**Washington, D.C. 20548**

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Congressional Requesters

In 2002, the most serious safety issue confronting the nation's commercial nuclear power industry since the accident at Three Mile Island in 1979 was identified at the Davis-Besse nuclear power plant in northwestern Ohio. On March 7, 2002, during shutdown for inspection and refueling, the owner of the Davis-Besse plant—FirstEnergy Nuclear Operating Company—discovered a pineapple-sized cavity in the plant's carbon steel reactor vessel head. The reactor vessel head is an 18-foot-diameter, 6-inch-thick, 80-ton cap that is bolted to the reactor vessel. The vessel head is an integral part of the reactor coolant pressure boundary that serves as a vital barrier for protecting the environment from any release of radiation from the reactor core. In pressurized water reactors such as the one at Davis-Besse, the reactor vessel contains the nuclear fuel, as well as water with diluted boric acid that cools the fuel and helps control the nuclear reaction. At the Davis-Besse plant, vertical tubes had cracked that penetrate the reactor vessel head and that contain this water as well as drive mechanisms used to lower and raise the fuel, thus allowing leaked boric acid to corrode the reactor vessel head. The corrosion had extended through the vessel head to a thin stainless steel lining and had likely occurred over a period of several years. The lining, which is less than one-third of an inch thick and was not designed as a pressure barrier, was found to have a slight bulge with evidence of cracking. Had this lining given way, the water within the reactor vessel would have escaped, triggering a loss-of-coolant accident, which—if back-up safety systems had failed to operate—likely would have resulted in the melting of the radioactive core and a subsequent release of radioactive materials into the environment. In March 2004, after 2 years of increased NRC oversight and considerable repairs by FirstEnergy, NRC approved the restart of Davis-Besse's operations.

Under the Atomic Energy Act of 1954, as amended, and the Energy Reorganization Act of 1974, as amended, the Nuclear Regulatory Commission (NRC) and the operators of nuclear power plants share the responsibility for ensuring that nuclear reactors are operated safely. NRC is responsible for issuing regulations, licensing and inspecting plants, and requiring action, as necessary, to protect public health and safety; plant operators have the primary responsibility for safely operating the plants in accordance with their licenses. NRC has the authority to order plant operators to take actions, up to and including shutting down a plant, if licensing conditions are not being met and the plant poses an undue risk to public health and safety. In carrying out its responsibilities, NRC relies on, among other things, on-site NRC resident inspectors to assess plant conditions and quality assurance programs, such as those for maintenance and operations, that operators establish to ensure safety at the plant.

Before the discovery of the cavity in the Davis-Besse reactor vessel head, NRC had requested that operators of Davis-Besse and other similar pressurized water reactors (1) thoroughly inspect the vertical tubing on their reactor vessel heads by December 31, 2001, for possible cracking, or (2) justify why their tubing and reactor vessel heads were sufficiently safe without being inspected. This request was a reaction to cracked vertical tubing found on a pressurized water reactor vessel head at another plant. Such thorough inspections require that the reactor be shut down. FirstEnergy, believing that its reactor vessel head was safe, asked NRC if its shutdown could be delayed until the end of March 2002 to coincide with an already scheduled shutdown for refueling—during which time it would conduct the requested inspection. FirstEnergy provided evidence supporting its assertion that the reactor could continue operating safely. After considerable discussion, and after NRC developed a risk assessment estimate for deciding that Davis-Besse would not pose an unacceptable level of risk, NRC and FirstEnergy compromised, and FirstEnergy agreed to shut down the reactor in mid-February 2002 for inspection. Soon after Davis-Besse was shut down, the cracked tubes and the significant reactor vessel head corrosion were discovered.

You asked us to determine (1) why NRC did not identify and prevent the vessel head corrosion at Davis-Besse, (2) whether the process NRC used when deciding to allow FirstEnergy to delay its shutdown was credible, and (3) whether NRC is taking sufficient action in the wake of the Davis-Besse incident to prevent similar problems from developing in the future at Davis-Besse and other nuclear power plants. As agreed with your offices, our review focused on NRC's role in the events leading up to Davis-Besse's shutdown, NRC's response to the problems discovered, and NRC's management controls over programs and processes that may have contributed to the Davis-Besse incident. We did not evaluate the role of FirstEnergy because, at the time of our review, NRC's Office of Investigations and the Department of Justice were conducting separate inquiries into the potential liability of FirstEnergy concerning its knowledge of conditions at Davis-Besse, including the condition of the reactor vessel head. We also did not review NRC's March 2004 decision to allow the plant to restart.

## Scope and Methodology

To determine why NRC did not identify and prevent the vessel head corrosion at the Davis-Besse nuclear power plant, we reviewed NRC's lessons-learned task force report;[1] FirstEnergy's root cause analysis reports;[2] NRC's Office of the Inspector General reports on Davis-Besse;[3] NRC's augmented inspection team report;[4] and NRC's inspection reports and licensee assessments from 1998 through 2001. We also reviewed NRC generic communications issued on boric acid corrosion and on nozzle cracking. In addition, we interviewed NRC regional officials who were involved in overseeing Davis-Besse at the time corrosion was occurring, and when the reactor vessel head cavity was found, to learn what information they had, their knowledge of plant activities, and how they communicated information to headquarters. We also held discussions with the resident inspector who was at Davis-Besse at the time that corrosion was occurring to determine what information he had and how this information was communicated to the regional office. Further, we met with FirstEnergy and NRC officials at Davis-Besse and walked through the facility, including the containment building, to understand the nature and extent of NRC's oversight of licensees. Additionally, we met with NRC headquarters officials to discuss the oversight process as it related to Davis-Besse, and the extent of their knowledge of conditions at Davis-Besse. We also met with county officials from Ottawa County, Ohio, to discuss their views on NRC and Davis-Besse plant safety. Further, we met with representatives from a variety of public interest groups to obtain their thoughts on NRC's oversight and the agency's proposed changes in the wake of Davis-Besse.

[1]NRC, *Degradation of Davis-Besse Nuclear Power Station Reactor Pressure Vessel Head Lessons-Learned Report* (Washington, D.C.; Sept. 30, 2002).

[2]FirstEnergy, Davis-Besse Nuclear Power Station, *Root Cause Analysis Report: Significant Degradation of the Reactor Pressure Vessel Head, CR 2002-089* (Oak Harbor, Ohio; Aug. 27, 2002) and *Root Cause Analysis Report: Failure to Identify Significant Degradation of the Reactor Pressure Vessel Head, CR-02-0685, 02-0846, 02-0891, 02-1053, 02-1128, 02-1583, 02-1850, 02-2584, and 02-2585* (Oak Harbor, Ohio; Aug. 13, 2002).

[3]NRC, Office of the Inspector General, *NRC's Regulation of Davis-Besse Regarding Damage to the Reactor Vessel Head* (Washington, D.C.; Dec. 30, 2002) and *NRC's Oversight of Davis-Besse Boric Acid Leakage and Corrosion during the April 2000 Refueling Outage* (Washington, D.C.: Oct. 17, 2003).

[4]NRC, *Davis-Besse Nuclear Power Station NRC Augmented Inspection Team—Degradation of the Reactor Pressure Vessel Head* (Washington, D.C.; May 3, 2002).

To determine whether the process NRC used was credible when deciding to allow Davis-Besse to delay its shutdown, we evaluated NRC guidelines for reviewing licensee requests for temporary and permanent license changes, or amendments to their licenses. We also reviewed NRC guidance for making and documenting agency decisions, such as those on whether to accept licensee responses to generic communications, as well as NRC's policies and procedures for taking enforcement action. We supplemented these reviews with an analysis of internal NRC correspondence related to the decision-making process, including e-mail correspondence, notes, and briefing slides. We also reviewed NRC's request for additional information to FirstEnergy following the issuance of NRC's generic bulletin for conducting reactor vessel head and nozzle inspections, as well as responses provided by FirstEnergy. In addition, we reviewed the draft shutdown order that NRC prepared before accepting FirstEnergy's proposal to conduct its inspection in mid-February 2002. We reviewed these documents to determine whether the basis for NRC's decision was clearly laid out, persuasive, and defensible to a party outside of NRC.

As part of our analysis for determining whether NRC's process was credible, we also obtained and reviewed NRC's probabilistic risk assessment (PRA) calculations that it developed to guide its decision making. To conduct this analysis, we relied on the advice of consultants who, collectively, have an extensive background in nuclear engineering, PRA, and metallurgy. These consultants included Dr. John C. Lee, Professor and Chair, Nuclear Engineering and Radiological Sciences at the University of Michigan's College of Engineering; Dr. Thomas H. Pigford, Professor Emeritus, at the University of California-Berkeley's College of Engineering; and Dr. Gary S. Was, Associate Dean for Research in the College of Engineering, and Professor, Nuclear Engineering and Radiological Sciences at the University of Michigan's College of Engineering. These consultants reviewed internal NRC correspondence relating to NRC's PRA estimate, NRC's calculations, and the basis for these calculations. These consultants also discussed the basis for NRC's estimates with NRC officials and outside contractors who provided information to NRC as it developed its estimates. These consultants were selected on the basis of recommendations made by other nuclear engineering experts, their résumés, their collective experience, lack of a conflict of interest, and previous experience with assessing incidents at nuclear power plants such as Three Mile Island.

To determine whether NRC is taking sufficient action in the wake of the Davis-Besse incident to prevent similar problems from developing in the future, we reviewed NRC's lessons-learned task force recommendations, NRC's analysis of the underlying causes for failing to identify the corrosion of the reactor vessel head, and NRC's action plan developed in response to the task force recommendations. We also reviewed other NRC lessons-learned task force reports and their recommendations, our prior reports to identify issues related to those at Davis-Besse, and NRC's Office of the Inspector General reports. We met with NRC officials responsible for implementing task force recommendations to obtain a clear understanding of the actions they were taking and the status of their efforts, and discussed NRC's recommendations with NRC regional officials, on-site inspectors, and representatives from public interest groups. We conducted our review from November 2002 through May 2004 in accordance with generally accepted government auditing standards.

## Results in Brief

NRC should have but did not identify or prevent the vessel head corrosion at Davis-Besse because both its inspections at the plant and its assessments of the operator's performance yielded inaccurate and incomplete information on plant safety conditions. With respect to inspections, NRC resident inspectors had information revealing potential problems, such as boric acid deposits on the vessel head and air monitors clogged with boric acid deposits, but this information did not raise alarms about the plant's safety. NRC inspectors did not know that these indications could signal a potentially significant problem and therefore did not fully communicate their observations to other NRC staff, some of whom might have recognized the significance of the problem. However, even if these staff had been informed, according to NRC officials, the agency would have taken action only if these indications were considered significant safety concerns. Furthermore, NRC's assessments of Davis-Besse, which include inspection results as well as other data, did not provide complete and accurate information on FirstEnergy's performance. For example, NRC consistently assessed Davis-Besse's operator as a "good performer" during those years when the corrosion was likely occurring, and the operator was not correctly identifying the source of boric acid deposits. NRC had been aware for several years that corrosion and cracking were issues that could possibly affect safety, but did not view them as immediate safety concerns and therefore had not fully incorporated them into its oversight process.

NRC's process for deciding whether Davis-Besse could delay its shutdown to inspect for nozzle cracking lacks credibility because the guidance NRC used was not intended for making such a decision and the basis for the decision was not fully documented. In the absence of written guidance specifically intended to direct the decision-making process for a shutdown, NRC used guidance designed for considering operator requests for license amendments. This guidance describes safety factors that NRC should consider in deciding whether to approve a license amendment, as well as a process for considering the relative risk the amendment could pose. However, the guidance does not specify how NRC should use the safety factors, and we could not determine if NRC appropriately followed this guidance because it did not clearly document the basis for its decision. For example, NRC initially decided that several safety factors were not met and considered issuing a shutdown order. Regardless, the agency allowed FirstEnergy to delay its shutdown, even though it is not clear whether—and if so, how—the safety factors were subsequently met. Further, NRC did not provide a rationale for its decision for more than a year. NRC also did not follow other aspects of its guidance. In the absence of specific guidance, and with little documentation of the decision-making process, we could not judge whether the agency's decision was reasonable. Our consultants identified substantial problems with how NRC developed and used its risk estimate when making the decision. For example, NRC did not perform an analysis of the uncertainty associated with the risk estimate; if it had, our consultants believe the uncertainty would have been so large as to render NRC's risk estimate of questionable value. Further, the risk estimate indicated that the likelihood of an accident occurring at Davis-Besse was greater than the level of risk generally accepted as being reasonable by NRC.

Responding to the Davis-Besse incident, NRC has taken several significant actions to help prevent boric acid from corroding reactor vessel heads at nuclear power plants. NRC issued requirements that licensees more extensively examine their reactor vessel heads, revised NRC inspection guidance used to identify and resolve licensee problems before they affect operations, augmented training to keep its inspectors better informed about boric acid and cracking issues, and revised guidance to better ensure that licensees implement commitments to change their operations. However, NRC has not yet implemented more than half of its planned actions, and resource constraints could affect the agency's ability to fully and effectively implement the actions. More importantly, NRC is not addressing three systemic problems underscored by the Davis-Besse incident. First, its process for assessing safety at nuclear power plants is not adequate for detecting early indications of deteriorating safety. In this respect, the process does not effectively identify changes in the operator's performance or approach to safety before a more serious safety problem can develop. Second, NRC's decision-making guidance does not specifically address shutdown decisions or explain how different safety considerations, such as quantitative estimates of risk, should be weighed. Third, NRC does not have adequate management controls for systematically tracking actions that it has taken in response to incidents at plants to determine if the actions were sufficient to resolve underlying problems and thereby prevent future incidents. Analyses of earlier incidents at other plants identified several issues, such as inadequate communication, that contributed to the Davis-Besse incident. Such management controls may have helped to resolve these issues before the Davis-Besse incident occurred. While NRC is monitoring how it implements actions taken as a result of the Davis-Besse incident, the agency has not yet committed to a process for assessing the effectiveness of actions taken.

Given NRC's actions in response to Davis-Besse, severe vessel head corrosion is unlikely to occur at a plant any time soon. However, in part because of unresolved systemic problems, another incident unrelated to vessel head corrosion could occur in the future. As a result, we are recommending that NRC take more aggressive and specific actions in several areas, such as revising how it assesses plant performance, establishing a more specific methodology for deciding to shut down a plant, and establishing management controls for monitoring and assessing the effectiveness of changes made in response to task force findings.

In commenting on a draft of this report, NRC generally addressed only those findings and recommendations with which it disagreed. While commenting that it agreed with many of our findings, the agency said that the report overall does not appropriately characterize or provide a balanced perspective on NRC's actions surrounding the discovery of the reactor vessel head condition at Davis-Besse or its efforts to incorporate the lessons learned from that experience into its processes. More specifically, NRC stated that the report does not acknowledge that NRC must rely heavily on its licensees to provide complete and accurate information. NRC also expressed concern about the report's characterization of its use of risk estimates. We believe that the report fairly and accurately describes NRC's actions regarding the Davis-Besse incident. Nonetheless, we expanded our discussion of NRC's roles and responsibilities to point out that licensees are required to provide NRC with complete and accurate information.

NRC disagreed with our recommendations to develop (1) specific guidance and a well-defined process for deciding when to shut down a plant and (2) a methodology to assess early indications of deteriorating safety at nuclear power plants. NRC stated that it has sufficient guidance to make plant shutdown decisions. NRC also stated that, as regulators, the agency is not charged with managing licensees' facilities and that direct involvement with those aspects of licensees' operations that could provide it with information on early indications of deteriorating safety crosses over to a management function. We continue to believe that NRC should develop specific guidance and a well-defined process to decide when to shut down a plant. In absence of such guidance for making the Davis-Besse shutdown decision, NRC used its guidance for considering operators' requests for amendments to their licenses. This guidance describes safety factors that NRC should consider in deciding whether to approve license changes, as well as a process for considering the relative risk the amendment would pose. This guidance does not specify how NRC should use the safety factors. We also continue to believe that NRC should develop a methodology to assess aspects of licensees' operations as a means to have an early warning of developing safety problems. In implementing this recommendation, we envision that NRC would be analyzing data for changes in operators' performance or approach to safety, not prescribing how the plants are managed.

# Background

## NRC's Role and Responsibilities

NRC, as an independent federal agency, regulates the commercial uses of nuclear material to ensure adequate protection of public health and safety and the environment. NRC is headed by a five-member commission appointed by the President and confirmed by the Senate; one commissioner is appointed as chairman.[5] NRC has about 2,900 employees who work in its headquarters office in Rockville, Maryland, and its four regional offices. NRC is financed primarily by fees that it imposes on commercial users of the nuclear material that it regulates. For fiscal year 2004, NRC's appropriated budget of $626 million includes about $546 million financed by these fees.

NRC regulates the nation's commercial nuclear power plants by establishing requirements for plant owners and operators to follow in the design, construction, and operation of the nuclear reactors. NRC also

[5]Two commissioner positions are currently vacant.

licenses the reactors and individuals who operate them. Currently, 104 commercial nuclear reactors at 65 locations are licensed to operate.[6] Many of these reactors have been in service since the early to mid-1970s. NRC initially licensed the reactors to operate for 40 years, but as these licenses approach their expiration dates, NRC has been granting 20-year extensions.

To ensure the reactors are operated within their licensing requirements and technical specifications, NRC oversees them by both inspecting activities at the plants and assessing plant performance.[7] NRC's inspections consist of both routine, or baseline, inspections and supplemental inspections to assess particular licensee programs or issues that arise at a power plant. Inspections may also occur in response to a specific operational problem or event that has occurred at a plant. NRC maintains inspectors at every operating nuclear power plant in the United States and supplements the inspections conducted by these resident inspectors with inspections conducted by staff from its regional offices and from headquarters. Generally, inspectors verify that the plant's operator qualifications and operations, engineering, maintenance, fuel handling, emergency preparedness, and environmental and radiation protection programs are adequate and comply with NRC safety requirements. NRC also oversees licensees by requesting information on their activities. NRC requires that information provided by licensees be complete and accurate and, according to NRC officials, this is an important aspect of the agency's oversight.[8] While we have added information to this report on the requirement that licensees provide NRC with complete and accurate information, we believe that NRC's oversight program should not place undue reliance on this requirement.

Nuclear power plants have many physical structures, systems, and components, and licensees have numerous activities under way, 24-hours a

[6]These licensed reactors include Browns Ferry Unit 1—one of three reactors owned by the Tennessee Valley Authority in Alabama—which was shut down in 1985. The Tennessee Valley Authority plans to restart the reactor in 2007, which will require NRC approval.

[7]NRC's oversight program has changed significantly since the beginning of 1998. The third and most recent change occurred in mid-2000, when the agency adopted its Reactor Oversight Process. Under this process, NRC continues to rely on inspection results to assess licensee performance. However, it supplements this information with other indicators of self-reported licensee performance, such as how frequently unscheduled shutdowns occur.

[8]10 C.F.R. § 50.9 requires that information provided by licensees be complete and accurate in all material respects.

day, to ensure the plants operate safely. Programs to ensure quality assurance and safe operations include monitoring, maintenance, and inspection. To carry out these programs, licensees typically prepare several thousand reports per year describing conditions at the plant that need to be addressed to ensure continued safe operations. Because of the large number of activities and physical structures, systems, and components, NRC focuses its inspections on those activities and pieces of equipment or systems that are considered to be most significant for protecting public health and safety. NRC terms this a "risk-informed" approach for regulating nuclear power plants. Under this risk-informed approach, some systems and activities that NRC considers to have relatively less safety significance receive little NRC oversight. NRC has adopted a risk-informed approach because it believes it can focus its regulatory resources on those areas of the plant that the agency considers to be most important to safety. In addition, it was able to adopt this approach because, according to NRC, safety performance at nuclear power plants has improved as a result of more than 25 years of operating experience.

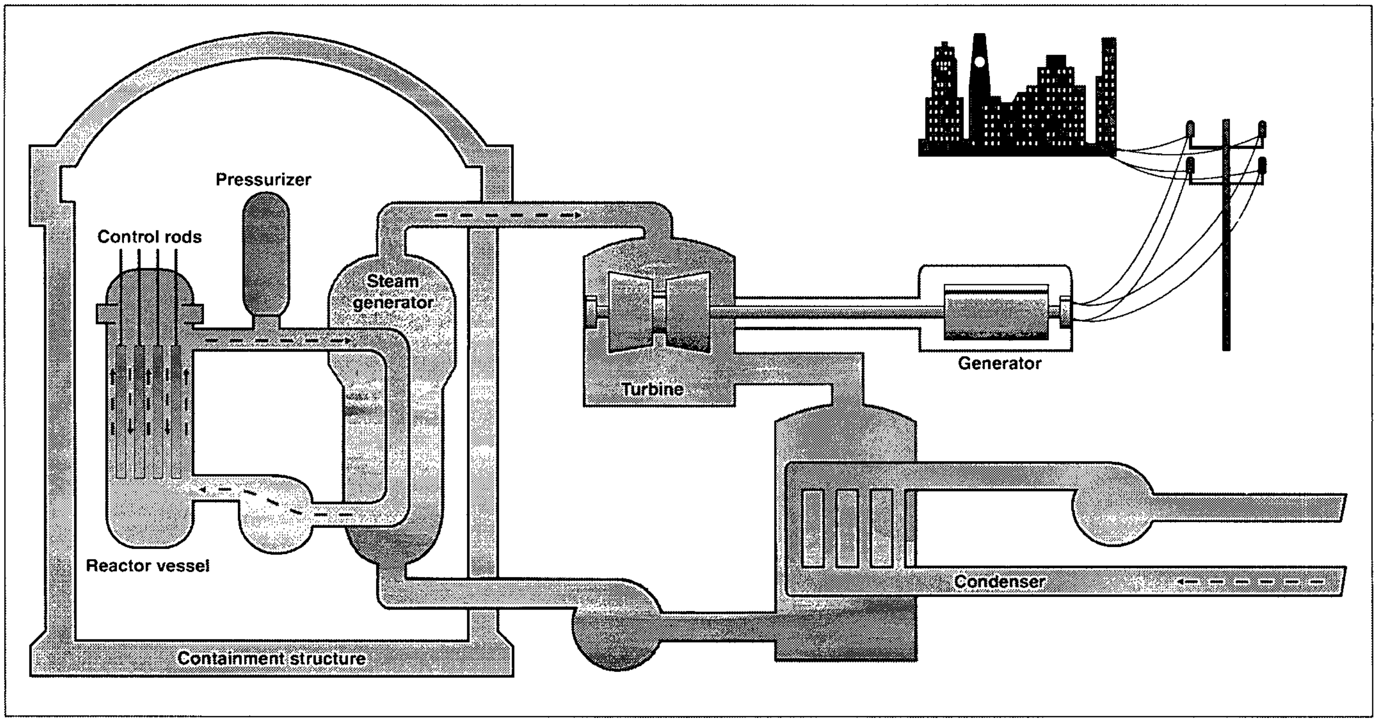
To decide whether inspection findings are minor or major, NRC uses a process it began in 2000 to determine the extent to which violations compromise plant safety. Under this process, NRC characterizes the significance of its inspection findings by using a significance determination process to evaluate how an inspection finding impacts the margin of safety at a power plant. NRC has a range of enforcement actions it can take, depending on how much the safety of the plant had been compromised. For findings that have low safety significance, NRC can choose to take no formal enforcement action. In these instances, nonetheless, licensees remain responsible for addressing the identified problems. For more serious findings, NRC may take more formal action, such as issuing enforcement orders. Orders can be used to modify, suspend, or even revoke an operating license. NRC has issued one enforcement order to shut down an operating power plant in its 28-year history—in 1987, after NRC discovered control room personnel sleeping while on duty at the Peach Bottom nuclear power plant in Pennsylvania. In addition to enforcement orders, NRC can issue civil penalties of up to $120,000 per violation per day. Although NRC does not normally use civil penalties for violations associated with its Reactor Oversight Process, NRC will consider using them for issues that are willful, have the potential for impacting the agency's regulatory process, or have actual public health and safety consequences. In fiscal year 2003, NRC proposed imposing civil penalties totaling $120,000 against two power plant licensees for the failure to provide complete and accurate information to the agency.

NRC uses generic communications—such as bulletins, generic letters, and information notices—to provide information to and request information from the nuclear industry at large or specific groups of licensees. Bulletins and generic letters both usually request information from licensees regarding their compliance with specific regulations. They do not require licensees to take any specific actions, but do require licensees to provide responses to the information requests. In general, NRC uses bulletins, as opposed to generic letters, to address significant issues of greater urgency. NRC uses information notices to transmit significant recently identified information about safety, safeguards, or environmental issues. Licensees are expected to review the information to determine whether it is applicable to their operations and consider action to avoid similar problems.

## Operation of Pressurized Water Nuclear Power Plants and Events Leading to the March 2002 Discovery of Serious Corrosion

The Davis-Besse Nuclear Power Station, owned and operated by FirstEnergy Nuclear Operating Company, is an 882-megawatt electric pressurized water reactor located on Lake Erie in Oak Harbor, Ohio, about 20 miles east of Toledo. The power plant is under NRC's Region III oversight, which is located in Lisle, Illinois. Like other pressurized water reactors, Davis-Besse is designed with multiple barriers between the radioactive heat-producing core and the outside environment—a design concept called "defense-in-depth." Three main design components provide defense-in-depth. First, the reactor core is designed to retain radioactive material within the uranium oxide fuel, which is also covered with a layer of metal tubing. Second, a 6-inch-thick carbon steel vessel, lined with three-sixteenth-inch-thick stainless steel, surrounds the reactor core. Third, a steel containment structure, surrounded by a thick reinforced concrete building, encloses the reactor vessel and other systems and components important for maintaining safety. The containment structure and concrete building are intended to help not only prevent a release of radioactivity to the environment, but also shield the reactor from external hazards like tornados and missiles. The reactor vessel, in addition to housing the reactor core, contains highly pressurized water to cool the radioactive heat-producing core and transfer heat to a steam generator. Consequently, the vessel is referred to as the reactor pressure vessel. From the vessel, hot pressurized water is piped to the steam generator, where a separate supply of water is turned to steam to drive turbines that generate electricity. (See fig. 1.)

Figure 1: Major Components of a Pressurized Water Reactor



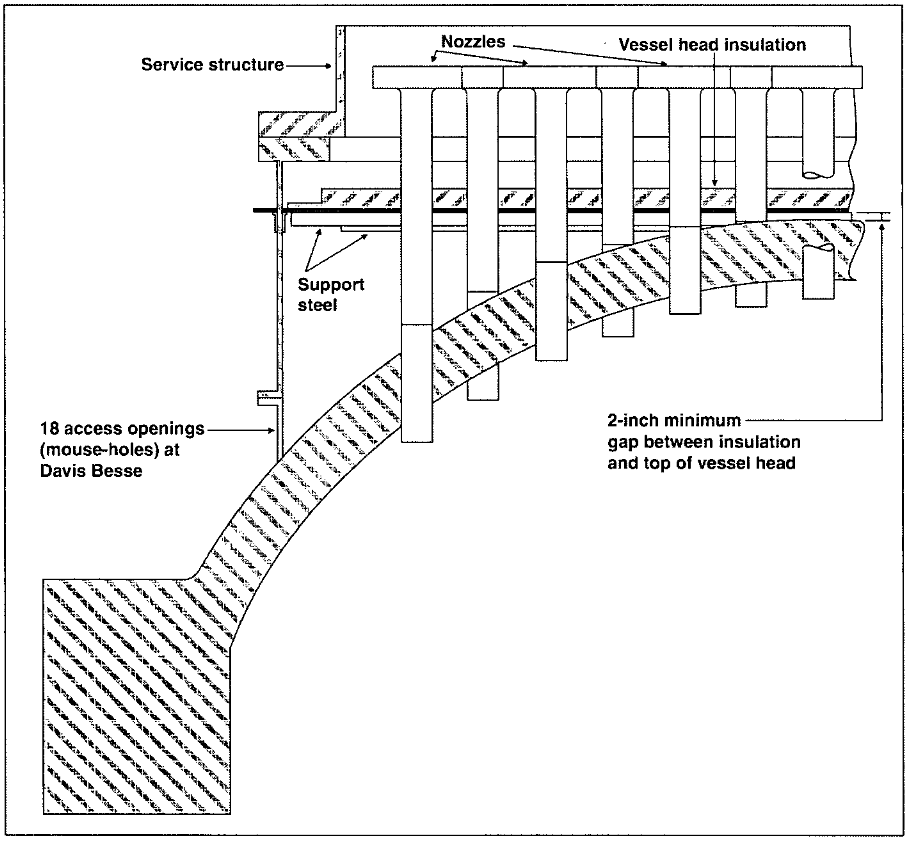

Source: NRC.

The top portion of the Davis-Besse reactor pressure vessel consisted of an 18-foot-diameter vessel head that was bolted to the lower portion of the pressure vessel. At Davis-Besse, 69 vertical tubes penetrated and were welded to the vessel head. These tubes, called vessel head penetration nozzles, contained control rods that, when raised or lowered, were used to moderate or shut down the nuclear reaction in the reactor.[9] Because control rods attach to control rod drive mechanisms, these types of nozzles are referred to as control rod drive mechanism nozzles. A platform, known as the service structure, sat above the reactor vessel head and the control rod drive mechanism nozzles. Inside the service structure and above the pressure vessel head was a layer of insulation to help contain the heat emanating from the reactor. The sides of the lower portion of the service

[9]While Davis-Besse had 69 nozzles, 7 were spare and 1 was used for head vent piping.

structure were perforated with 18 5- by 7-inch rectangular openings, termed "mouse-holes," that were used for vessel head inspections. In pressurized water reactors such as Davis-Besse, the reactor vessel, the vessel head, the nozzles, and other equipment used to ensure a continuous supply of pressurized water in the reactor vessel are collectively referred to as the reactor coolant pressure boundary. (See fig. 2.)

**Figure 2: Major Components of the Davis-Besse Reactor Vessel Head and Pressure Boundary**




Source: FirstEnergy.

To better control the nuclear reaction at nuclear power plants, boron in the form of boric acid crystals is dissolved in the cooling water contained within the reactor vessel and pressure boundary. Boric acid, under certain conditions, can cause corrosion of carbon steel. For about 3 decades, NRC and the nuclear power industry have known that boric acid had the potential to corrode reactor components. In general, if leakage occurs from the reactor coolant system, the escaping coolant will flash to steam and leave behind a concentration of impurities, including noncorrosive dry boric acid crystals. However, under certain conditions, the coolant will not flash to steam, and the boric acid will remain in a liquid state where it can cause extensive and rapid degradation of any carbon steel components it contacts. Such extensive degradation, in both domestic and foreign pressurized water reactor plants, has been well documented and led NRC to issue a generic letter in 1988 requesting information from pressurized water reactor licensees to ensure they had implemented programs to control boric acid corrosion. NRC was primarily concerned that boric acid corrosion could compromise the reactor coolant pressure boundary. This concern also led NRC to develop a procedure for inspecting licensees' boric acid corrosion control programs and led the Electric Power Research Institute to issue guidance on boric acid corrosion control.[10]

NRC and the nuclear power industry have also known that nozzles made of alloy 600,[11] used in several areas within nuclear power plants, were prone to cracking. Cracking had become an increasingly topical issue as the nuclear power plant fleet has aged. In 1986, operators at domestic and foreign pressurized water reactors began reporting leaks in various types of alloy 600 nozzles. In 1989, after leakage was detected at a domestic plant, NRC identified the cause of the leakage as cracking due to primary water stress corrosion.[12] However, NRC concluded that the cracking was not an immediate safety concern for a few reasons. For example, the cracks had a low growth rate, were in a material with an extremely high flaw tolerance and, accordingly, were unlikely to spread. Also, the cracks were axial—that is, they ran the length of the nozzle rather than its circumference. NRC and

[10]The Electric Power Research Institute is a nonprofit energy research consortium whose members include utilities. It provides science and technology-based solutions to members through its scientific research, technology development, and product implementation program.

[11]Alloy 600 is an alloy of nickel, chromium, iron, and minor amounts of other elements. The alloy is highly resistant to general corrosion but can be susceptible to cracking at high temperatures.

[12]Primary water stress corrosion cracking refers to cracking under stress and in primary coolant water. The primary water coolant system is that portion of a nuclear power plant's coolant system that cools the reactor core in the reactor pressure vessel and deposits heat to the steam generator.

the nuclear power industry were more concerned that circumferential cracks could result in broken or snapped nozzles. NRC did, however, issue a generic information notice in 1990 to inform the industry of alloy 600 cracking. Through the early 1990s, NRC, the Nuclear Energy Institute,[13] and others continued to monitor alloy 600 cracking. In 1997, continued concern over cracking led NRC to issue a generic letter to pressurized water reactor licensees requesting information on their plans to monitor and manage cracking in vessel head penetration nozzles as well as to examine these nozzles.

In the spring of 2001, licensee inspections led to the discovery of large circumferential cracking in several vessel head penetration nozzles at the Oconee Nuclear Station, in South Carolina. As a result of the discovery, the nuclear power industry and NRC categorized the 69 operating pressurized water reactors in the United States into different groups on the basis of (1) whether cracking had already been found and (2) how similar they were to Oconee in terms of the amount of time and the temperature at which the reactors had operated. The industry had developed information indicating that greater operating time and temperature were related to cracking. In total, five reactors at three locations were categorized as having already identified cracking, while seven reactors at five locations were categorized as being highly susceptible, given their similarity to Oconee.[14]

In August 2001, NRC issued a bulletin requesting that licensees of these reactors provide, within 30 days, information on their plans for conducting nozzle inspections before December 31, 2001.[15] In lieu of this information, NRC stated that licensees could provide the agency with a reasoned basis for their conclusions that their reactor vessel pressure boundaries would continue to meet regulatory requirements for ensuring the structural integrity of the reactor coolant pressure boundary until the licensees

[13]The Nuclear Energy Institute comprises companies that operate commercial power plants and supports the commercial nuclear industry; and universities, research laboratories, and labor unions affiliated with the nuclear industry. Among other things, it provides a forum to resolve technical and business issues and offers information to its members and policymakers on nuclear issues.

[14]Reactors that were categorized as having already identified cracking or were highly susceptible included Arkansas Nuclear reactor unit 1; D.C. Cook reactor unit 2; Davis-Besse; North Anna reactor units 1 and 2; Oconee reactor units 1, 2 and 3; Robinson reactor unit 2; Surry reactor units 1 and 2; and Three Mile Island reactor unit 1.

[15]NRC, "Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles" (Bulletin 2001-01, Aug. 8, 2001).

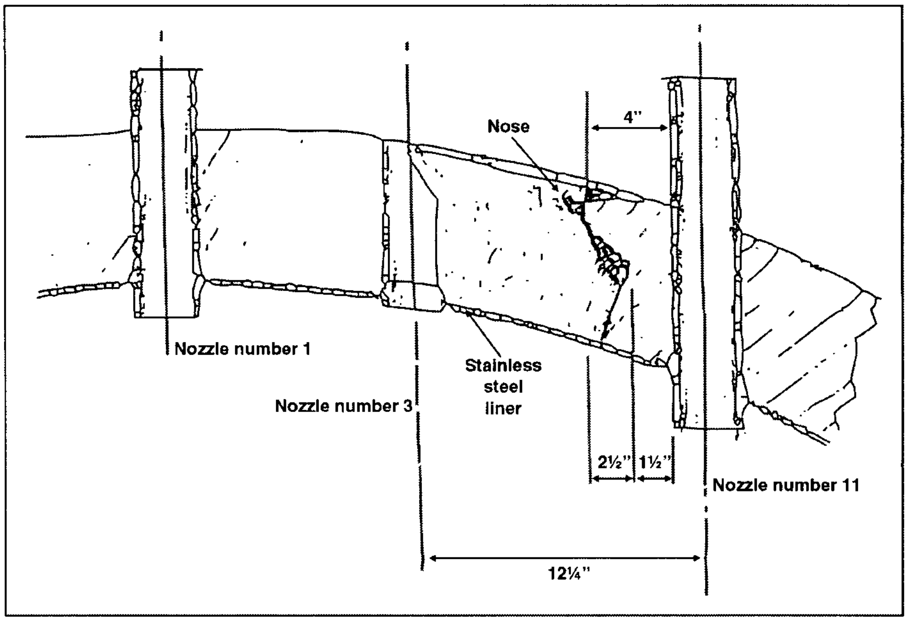
conducted their inspections. NRC used a bulletin, as opposed to a generic letter, to request this information because cracking was considered a significant and urgent issue. All of the licensees of the highly susceptible reactors, except Davis-Besse and D.C. Cook reactor unit 2, provided NRC with plans for conducting inspections by December 31, 2001.[16]

In September 2001, FirstEnergy proposed conducting the requested inspection in April 2002, following its planned March 31, 2002, shutdown to replace fuel. In making this proposal, FirstEnergy contended that the reactor coolant pressure boundary at Davis-Besse met and would continue to meet regulatory requirements until its inspection. NRC and FirstEnergy exchanged information throughout the fall of 2001 regarding when FirstEnergy would conduct the inspection at Davis-Besse. NRC drafted an enforcement order that would have shut down Davis-Besse by December 2001 for the requested inspection in the event that FirstEnergy could not provide an adequate justification for safe operation beyond December 31, 2001, but ultimately compromised on a mid-February 2002 shutdown date. NRC, in deciding when FirstEnergy had to shut down Davis-Besse for the inspection, used a risk-informed decision-making process, including probabilistic risk assessment (PRA), to conclude that the risk that Davis-Besse would have an accident in the interim was relatively low. PRA is an analytical tool for estimating the probability that a potential accident might occur by examining how physical structures, systems, and components, along with employees, work together to ensure plant safety.

Following the mid-February 2002 shutdown and in the course of its inspection in March 2002, FirstEnergy removed about 900 pounds of boric acid crystals and powder from the reactor vessel head, and subsequently discovered three cracked nozzles. The number of nozzles that had cracked, as well as the extent of cracking, was consistent with analyses that NRC staff had conducted prior to the shutdown. However, in examining the extent of cracking, FirstEnergy also discovered that corrosion had caused a pineapple-sized cavity in the reactor vessel head. (See figs. 3 and 4.)

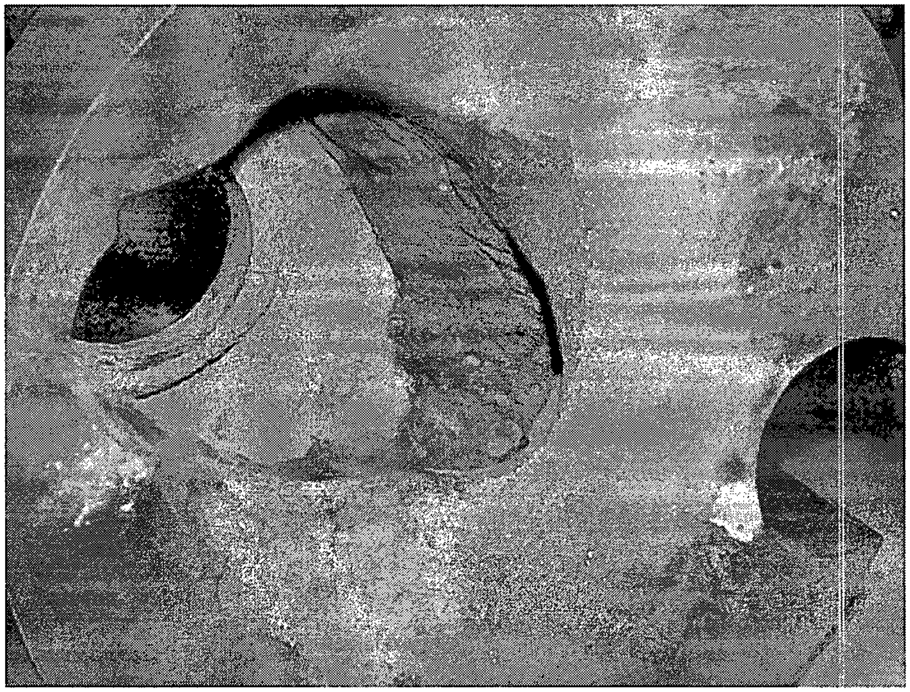
[16]The licensee for D.C. Cook reactor unit 2 proposed to shut down in mid-January 2002 for its inspection. NRC agreed to the delay after crediting D.C. Cook for having been shut down for about a month during the fall of 2001, thus reducing the reactor's operating time.

Figure 3: Diagram of the Cavity in Davis-Besse's Reactor Vessel Head




Source: FirstEnergy.

Figure 4: The Cavity in Davis-Besse's Reactor Vessel Head after Discovery



Source: FirstEnergy.

After this discovery, NRC directed FirstEnergy to, among other things, determine the root cause of the corrosion and obtain NRC approval before restarting Davis-Besse. NRC also dispatched an augmented inspection team consisting of NRC resident, regional, and headquarters officials.[17] The inspection team concluded that the cavity was caused by boric acid corrosion from leaks through the control rod drive mechanism nozzles in the reactor vessel head. Primary water stress corrosion cracking of the nozzles caused through-wall cracks, which led to the leakage and eventual corrosion of the vessel head. NRC's inspection team also concluded, among other things, that this corrosion had gone undetected for an extended period of time—at least 4 years—and significantly compromised the plant's

[17]NRC forms such inspection teams to ensure that the agency investigates significant operational events in a timely, objective, systematic, and technically sound manner, and identifies and documents the causes of such events.

safety margins. As of May 2004, NRC had not yet completed other analyses, including how long Davis-Besse could have continued to operate with the corrosion it had experienced before a vessel head loss-of-coolant accident would have occurred.[18] However, on May 4, 2004, NRC released preliminary results of its analysis of the vessel head and cracked cladding. Based on its analysis of conditions that existed on February 16, 2002, NRC estimated that Davis-Besse could have operated for another 2 to 13 months without the vessel head failing. However, the agency cautioned that this estimate was based on several uncertainties associated with the complex network of cracks on the cladding and the lack of knowledge about corrosion and cracking rates. NRC plans to use this data in preparing its preliminary analysis of how, and the likelihood that, the events at Davis-Besse could have led to core damage. NRC plans to complete this preliminary analysis in the summer of 2004.

NRC also established a special oversight panel to (1) coordinate NRC's efforts to assess FirstEnergy's performance problems that resulted in the corrosion damage, (2) monitor Davis-Besse's corrective actions, and (3) evaluate the plant's readiness to resume operations. The panel, which is referred to as the Davis-Besse Oversight Panel, comprises officials from NRC's Region III office in Lisle, Illinois; NRC headquarters; and the resident inspector office at Davis-Besse. In addition to overseeing FirstEnergy's performance during the shutdown and through restart of Davis-Besse, the panel holds public meetings in Oak Harbor, Ohio, where the plant is located, and nearby Port Clinton, Ohio, to inform the public about its oversight of Davis-Besse's restart efforts and its views on the adequacy of these efforts. The panel developed a checklist of issues that FirstEnergy had to resolve prior to restarting: (1) replacing the vessel head and ensuring the adequacy of other equipment important for safety, (2) correcting FirstEnergy programs that led to the corrosion, and (3) ensuring FirstEnergy's readiness to restart. To restart the plant, FirstEnergy, among other things, removed the damaged reactor vessel head, purchased and installed a new head, replaced management at the plant, and took steps to improve key programs that should have prevented or detected the corrosion. As of March 2004, when NRC gave its approval for Davis-Besse to resume

[18]NRC has an Accident Sequence Precursor Analysis Program to analyze significant events that occur at nuclear power plants to determine how, and the likelihood that, the events could have led to core damage.

operations, the shutdown and preparations for restart had cost FirstEnergy approximately $640 million.[19]

In addition, NRC established a task force to evaluate its regulatory processes for assuring reactor pressure vessel head integrity and to identify and recommend areas for improvement that may be applicable to either NRC or the nuclear power industry. The task force's report, which was issued in September 2002, contains 51 recommendations aimed primarily at improving NRC's process for inspecting and overseeing licensees, communicating with industry, and identifying potential emerging technical issues that could impact plant safety. NRC developed an action plan to implement the report's recommendations.

## NRC's Actions to Oversee Davis-Besse Did Not Provide an Accurate Assessment of Safety at the Plant

NRC's inspections and assessments of FirstEnergy's operations should have but did not provide the agency with an accurate understanding of safety conditions at Davis-Besse, and thus NRC failed to identify or prevent the vessel head corrosion. Some NRC inspectors were aware of the indications of corrosion and leakage that could have alerted NRC to corrosion problems at the plant, but they did not have the knowledge to recognize the significance of this information. These problems were compounded by NRC's assessments of FirstEnergy that led the agency to believe FirstEnergy was a good performer and could or would successfully resolve problems before they became significant safety issues. More broadly, NRC had a range of information that could have identified and prevented the incident at Davis-Besse but did not effectively integrate it into its oversight.

[19]FirstEnergy spent about $293 million on operations, maintenance, and capital projects (including $47 million for the new reactor vessel head) and $348 million to purchase power to replace the power that Davis-Besse would have generated over the 2-year shutdown period. In contrast, during a more routine refueling outage, Davis-Besse would spend about $60 million—about $37 million on operations, maintenance, and capital projects and $23 million on replacing the power that would have been generated over a 42-day shutdown period. These latter estimates are based on the Davis-Besse refueling outage in midcalendar year 2000.

## Several Factors Contributed to the Inadequacy of NRC's Inspections for Determining Plant Conditions

Three separate, but related, NRC inspection program factors contributed to the development of the corrosion problems at Davis-Besse. First, resident inspectors did not know that the boric acid, rust, and unidentified leaking indicated that the reactor vessel head might be degrading. Second, these inspectors thought they understood the cause for the indications, based on licensee actions to address them. Therefore, resident inspectors, as well as regional and headquarters officials, did not fully communicate information on the indications or decide how to address them, and therefore took no action. Third, because the significance of the symptoms was not fully recognized, NRC did not direct sufficient inspector resources to aggressively investigate the indicators. NRC might have taken a different approach to the Davis-Besse situation if its program to identify emerging issues important to safety had pursued earlier concerns about boric acid corrosion and cracking and recognized how they could affect safety.

### Inspectors Did Not Know Safety Significance of Observed Problems

NRC limits the amount of unidentified leakage from the reactor coolant system to no more than 1 gallon per minute. When this limit is exceeded, NRC requires that licensees identify and correct any sources of unidentified leakage. NRC also prohibits any leakage from the reactor coolant pressure boundary, of which the reactor vessel is a key component. Such leakage is prohibited because the pressure boundary is key to maintaining adequate coolant around the reactor fuel and thus protects public health and safety. Because of this, NRC's technical specification states that licensees are to monitor reactor coolant leakage and shut down within 36 hours if leakage is found in the pressure boundary.

In the years leading up to FirstEnergy's March 2002 discovery that Davis-Besse's vessel head had corroded extensively, NRC had several indications of potential leakage problems. First, NRC knew that the rates of leakage in the reactor coolant system had increased. Between 1995 and mid-1998, the unidentified leakage rate was about 0.06 gallon per minute or less, according to FirstEnergy's monitoring. In mid-1998, the unidentified reactor coolant system leakage rate increased significantly—to as much as 0.8 gallon per minute. The elevated leakage rate was dominated by a known problem with a leaking relief valve on the reactor coolant system pressurizer tank, which masked the ongoing leak on the reactor pressure vessel head. However, the elevated leak rate should have raised concerns.

To investigate this leakage, as well as to repair other equipment, FirstEnergy shut down the plant in mid-1999. It then identified a faulty relief valve that accounted for much of the leakage and repaired the valve.

However, after restarting Davis-Besse, the unidentified leakage rate remained significantly higher than the historical average. Specifically, the unidentified leakage rate varied between 0.15 and 0.25 gallon per minute as opposed to the historical low of about 0.06 gallon or less. While NRC was aware that the rate was higher than before, NRC did not aggressively pursue the difference because the rate was well below NRC's limit of no more than 1 gallon per minute, and thus the leak was not viewed as being a significant safety concern. Following the repair in 1999, NRC's inspection report concluded that FirstEnergy's efforts to reduce the leak rate during the outage were effective.

Second, NRC was aware of increased levels of boric acid in the containment building—an indication that components containing reactor coolant were leaking. So much boric acid was being deposited that FirstEnergy officials had to repeatedly clean the containment air cooling system and radiation monitor filters. For example, before 1998, the containment air coolers seldom needed cleaning, but FirstEnergy had to clean them 28 times between late 1998 and May 2001. Between May 2001 and the mid-February 2002 shutdown, the containment air coolers were not cleaned, but at shutdown, FirstEnergy removed 15 5-gallon buckets of boric acid from the coolers—which is almost as much as was found on the reactor pressure vessel head. Rather than seeing these repeated cleanings as an indication of a problem that needed to be addressed, FirstEnergy made cleaning the coolers a routine maintenance activity, which NRC did not consider significant enough to require additional inspections. Furthermore, the radiation monitors, used to sample air from the containment building to detect radiation, typically required new filters every month. However, from 1998 to 2002, these monitors became clogged and inoperable hundreds of times because of boric acid, despite FirstEnergy's efforts to fix the problem.

Third, NRC was aware that FirstEnergy found rust in the containment building. The radiation monitor filters had accumulated dark colored iron oxide particles—a product of carbon steel corrosion—that were likely to have resulted from a very small steam leak. NRC inspection reports during the summer and fall of 1999 noted these indications and, while recognizing FirstEnergy's aggressive attempts to identify the reasons for the phenomenon, concluded that they were a "distraction to plant personnel." Several NRC inspection reports noted indications of leakage, boric acid, and rust before the agency adopted its new Reactor Oversight Process in 2000, but because the leakage was within NRC's technical specifications and NRC officials thought that the licensee understood and would fix the problem, NRC did not aggressively pursue the indications. NRC's new oversight process, implemented in the spring of 2000, limited the issues that could be discussed in NRC inspection reports to those that the agency considers to have more than minor significance. Because the leakage rates were below NRC's limits, NRC's inspection reports following the implementation of NRC's new oversight process did not identify any discussion of these problems at the plant.

Fourth, NRC was aware that FirstEnergy found rust on the Davis-Besse reactor vessel head, but it did not recognize its significance. For instance, during the 2000 refueling outage, a FirstEnergy official said he showed one of the two NRC resident inspectors a report that included photographs of rust-colored boric acid on the vessel head. (See fig. 5.)

**Figure 5: Rust and Boric Acid on Davis-Besse's Vessel Head as Shown to Resident Inspector during the 2000 Refueling Outage**

Source: FirstEnergy.

According to this resident inspector, he did not recall seeing the report or photographs but had no reason to doubt the FirstEnergy official's statement. Regardless, he stated that had he seen the photographs, he would not have considered the condition to be significant at the time. He said that he did not know what the rust and boric acid might have indicated, and he assumed that FirstEnergy would take care of the vessel head before restarting. The second resident inspector said he reviewed all such reports at Davis-Besse but did not recall seeing the photographs or this particular report. He stated that it was quite possible that he had read the report, but because the licensee had a plan to clean the vessel head, he would have concluded that the licensee would correct the matter before plant restart. However, FirstEnergy did not accomplish this, even though work orders and subsequent licensee reports indicated that this was done. According to the NRC resident inspector and NRC regional officials, because of the large number of licensee activities that occur during a refueling outage, NRC inspectors do not have the time to investigate or follow up on every issue, particularly when the issue is not viewed as being important to safety. While the resident inspector informed regional officials about conditions at Davis-Besse, the regional office did not direct more inspection resources to the plant, or instruct the resident inspector to conduct more focused oversight. Some NRC regional officials were aware of indications of boric acid corrosion at the plant; others were not. According to the Office of the Inspector General's investigation and 2003 report on Davis-Besse,[20] the NRC regional branch chief—who supervised the staff responsible for overseeing FirstEnergy's vessel head inspection activities during the 2000 refueling outage—said that he was unaware of the boric acid leakage issues at Davis-Besse, including its effects on the containment air coolers and the radiation monitor filters. Had his staff been requested to look at these specific issues, he might have directed inspection resources to that area. (App. I provides a time line showing significant events of interest.)

## NRC Did Not Fully Communicate Indications

NRC was not fully aware of the indications of a potential problem at Davis-Besse because NRC's process for transmitting information from resident inspectors to regional offices and headquarters did not ensure that information was fully communicated, evaluated, or used. NRC staff communicated information about plant operations through inspection reports, licensee assessments, and daily conference calls that included

[20]NRC, Office of the Inspector General, *NRC's Oversight of Davis-Besse during the April 2000 Refueling Outage* (Washington, D.C.: Oct. 17, 2003).

resident, regional, and headquarters officials. According to regional officials, information that is not considered important is not routinely communicated to NRC management and technical specialists. For example, while the resident inspectors at Davis-Besse knew all of the indications of leakage, and there was some level of knowledge about these indications at the regional office level, the knowledge was not sufficiently widespread within NRC to alert a technical specialist who might have recognized their safety significance. According to NRC Region III officials, the region uses an informal means—memorandums sent to other regions and headquarters—of communicating information identified at plants that it considers to be important to safety. However, because the indications at Davis-Besse were not considered important, officials did not transmit this information to headquarters. Further, because the process is informal, these officials said they did not know whether—and if so, how—other NRC regions or headquarters used this information.

Similarly, NRC officials said that NRC headquarters had no systematic process for communicating information, such as on boric acid corrosion, cracking, and small amounts of unidentified leakage, that had not yet risen to a relatively high level of concern within the agency, in a timely manner to its regions or on-site inspectors. For example, the regional inspector that oversaw FirstEnergy's activities during the 2000 refueling outage, including the reactor vessel head inspection, stated that he was not aware of NRC's generic bulletins and letters pertaining to boric acid and corrosion, even though NRC issues only a few of these bulletins and generic letters each year.[21] In addition, according to NRC regional officials and the resident inspector at Davis-Besse, there is little time to review technical reports about emerging safety issues that NRC compiles because they are too lengthy and detailed. Ineffective communication, both within the region and between NRC headquarters and the region, was a primary factor cited by NRC's Office of the Inspector General in its investigation of NRC's oversight of Davis-Besse boric acid leakage and corrosion.[22] For example, it found that ineffective communication resulted in senior regional management being largely unaware of repeated reports of boric acid leakage at Davis-Besse. It also found that headquarters, in communications with the regions, did not emphasize the issues discussed in its generic

[21]Over the last 10 years, NRC has issued an average of about two generic bulletins and about four generic letters a year.

[22]NRC, Office of the Inspector General, *NRC's Oversight of Davis-Besse during the April 2000 Refueling Outage* (Washington, D.C.; Oct. 17, 2003).

letters or bulletins on boric acid corrosion or cracking. NRC programs for informing its inspectors about issues that can reduce safety at nuclear power plants were not effective. As a result, NRC inspectors did not recognize the significance of the indications at Davis-Besse, fully communicate information about the indications, or spend additional effort to follow up on the indications.

### Resource Constraints Affected NRC Oversight

NRC also did not focus on the indications that the vessel head was corroding because of several staff constraints. Region III was directing resources to other plants that had experienced problems throughout the region, and these plants thus were the subject of increased regulatory oversight. For example, during the refueling outages in 1998 and 2000, while NRC oversaw FirstEnergy's inspection of the reactor vessel head, the region lacked senior project engineers to devote to Davis-Besse. A vacancy existed for a senior project engineer responsible for Davis-Besse from June 1997 until June 1998, except for a one month period, and from September 1999 until May 2000, which resulted in fewer inspection hours at the facility than would have been normal. Other regional staff were also occupied with other plants in the region that were having difficulties, and NRC had unfilled vacancies for resident and regional inspector positions that strained resources for overseeing Davis-Besse.

Even if the inspector positions had been filled, it is not certain that the inspectors would have aggressively followed up on any of the indications. According to our discussions with resident and regional inspectors and our on-site review of plant activities, because nuclear power plants are so large, with many physical structures, systems, and components, an inspector could miss problems that were potentially significant for safety. Licensees typically prepare several hundred reports per month for identifying and resolving problems, and NRC inspectors have only a limited amount of time to follow up on these licensee reports. Consequently, NRC selects and oversees the most safety significant structures, systems, and components.

## NRC's Assessment Process Did Not Indicate Deteriorating Performance

Under NRC's Reactor Oversight Process, NRC assesses licensees' performance using two distinct types of information: (1) NRC's inspection results and (2) performance indicators reported by the licensees. These indicators, which reflect various aspects of a plant's operations, include data on, for example, the failure or unavailability of certain important operating systems, the number of unplanned power changes, and the amount of reactor coolant system leakage. NRC evaluates both the inspection results and the performance indicators to arrive at licensee assessments, which it then color codes to reflect their safety significance. Green assessments indicate that performance is acceptable, and thus connote a very low risk significance and impact on safety. White, yellow, and red assessments each represent a greater degree of safety significance. After NRC adopted its Reactor Oversight Process in April 2000, FirstEnergy never received anything but green designations for its operations at Davis-Besse and was viewed by NRC as a good performer until the 2002 discovery of the vessel head corrosion.[23] Similarly, prior to adopting the Reactor Oversight Process, NRC consistently assessed FirstEnergy as generally being a good performer. NRC officials stated, however, that significant issues were identified and addressed as warranted throughout this period, such as when the agency took enforcement action in response to FirstEnergy's failure to properly repair important components in 1999—a failure caused by weaknesses in FirstEnergy's boric acid corrosion control program.

Key Davis-Besse programs for ensuring the quality and safe operation of the plant's engineered structures, systems, and components include, for example,

- a corrective action program to ensure that problems at the plant that are relevant to safety are identified and resolved in a timely manner,
- an operating experience program to ensure that experiences or problems that occur are appropriately identified and analyzed to determine their significance and relevance to operations, and
- a plant modification program to ensure that modifications important to safety are implemented in a timely manner.

As at other commercial nuclear power plants, NRC conducted routine, baseline inspections of Davis-Besse to determine the effectiveness of these programs. Reports documenting these inspections noted incidences of boric acid leakage, corrosion, and deposits. However, between February 1997 and March 2000, the regional office's assessment of the licensee's performance addressed leakage in the reactor coolant system only once and never noted the other indications. Furthermore, Davis-Besse was not

[23]Before adopting the Reactor Oversight Process, NRC also assessed licensee performance based on inspection results and other information; however, NRC did not assign color codes to assessment results.

the subject of intense scrutiny in regional plant assessment meetings because plants perceived as good performers—such as Davis-Besse—received substantially less attention. Between April 2000—when NRC's revised assessment process took effect—until the corrosion was discovered in March 2002, none of NRC's assessments of Davis-Besse's performance noted leakage or other indications of corrosion at the plant. As a result, NRC may have missed opportunities to identify weaknesses in the Davis-Besse programs intended to detect or prevent the corrosion.

After the corrosion was discovered, NRC analyzed the problems that led to the corrosion on the reactor vessel head and concluded that FirstEnergy's programs for overseeing safety at Davis-Besse were weak, as seen in the following examples:

- Davis-Besse's corrective action program did not result in timely or effective actions to prevent indications of leakage from reoccurring in the reactor coolant system.
- FirstEnergy officials did not always enter equipment problems into the corrective action program because individuals who had identified the problem were often responsible for resolving it.
- For over a decade, FirstEnergy had delayed plant modifications to its service structure platform, primarily because of cost. These modifications would have improved its ability to inspect the reactor vessel head nozzles. As a result, FirstEnergy could conduct only limited visual inspections and cleaning of the reactor pressure vessel head through the small "mouse-holes" that perforated the service structure.

NRC was also unaware of the extent to which various aspects of FirstEnergy's safety culture had degraded—that is, FirstEnergy's organization and performance related to ensuring safety at Davis-Besse. This degradation had allowed the incident to occur with no forewarning because NRC's inspections and performance indicators do not directly assess safety culture. Safety culture is a group of characteristics and attitudes within an organization that establish, as an overriding priority, that issues affecting nuclear plant safety receive the attention their significance warrants. Following FirstEnergy's March 2002 discovery, NRC found numerous indications that FirstEnergy emphasized production over plant safety. First, Davis-Besse routinely restarted the plant following an outage, even though reactor pressure vessel valves and control rod drive mechanisms leaked. Second, staff was unable to remove all of the boric acid deposits from the reactor pressure vessel head because FirstEnergy's schedule to restart the plant dictated the amount of work that could be performed. Third, FirstEnergy management was willing to accept degraded equipment, which indicated a lack of commitment to resolve issues that could potentially compromise safety. Fourth, Davis-Besse's program that was intended to ensure that employees feel free to raise safety concerns without fear of retaliation had several weaknesses. For example, in one instance, a worker assigned to repair the containment air conditioner was not provided a respirator in spite of his concerns that he would inhale boric acid residue. According to NRC's lessons-learned task force report, NRC was not aware of weaknesses in this program because its inspections did not adequately assess it.

Given that FirstEnergy concluded that one of the causes for the Davis-Besse incident was human performance and management failures, the panel overseeing FirstEnergy's efforts to restart Davis-Besse requested that FirstEnergy assess its safety culture before allowing the plant to restart. To oversee FirstEnergy's efforts to improve its safety culture, NRC (1) reviewed whether FirstEnergy had adequately identified all of the root causes for management and human performance failures at Davis-Besse, (2) assessed whether FirstEnergy had identified and implemented appropriate corrective actions to resolve these failures, and (3) assessed whether FirstEnergy's corrective actions were effective. As late as February 2004, NRC had concerns about whether FirstEnergy's actions would be adequate in the long term. As a result, the Davis-Besse safety culture was one of the issues contributing to the delay in restarting the plant. In March 2004, NRC's panel concluded that FirstEnergy's efforts to improve its safety culture were sufficient to allow the plant to restart. In doing so, however, NRC officials stated that one of the conditions the panel imposed was for FirstEnergy to conduct an independent assessment of the safety culture at Davis-Besse annually over the course of the next 5 years.

## NRC Did Not Effectively Incorporate Long-Standing Knowledge about Corrosion, Nozzle Cracking, and Leak Detection into Its Oversight

NRC has been aware of boric acid corrosion and its potential to affect safety since at least 1979. It issued several notices to the nuclear power industry about boric acid corrosion and, specifically, the potential for it to degrade the reactor coolant pressure boundary. In 1987, two licensees found significant corrosion on their reactor pressure vessel heads, which heightened NRC's concern. A subsequent industry study concluded that concentrated solutions of boric acid could result in unacceptably high corrosion rates—up to 4 inches per year—when primary coolant leaks onto surfaces and concentrates at temperatures found on the surface of the reactor vessel.[24] After considering this information and several more instances of boric acid corrosion at plants, NRC issued a generic letter in 1988 requesting licensees to implement boric acid corrosion control programs.

In 1990, NRC visited Davis-Besse to assess the adequacy of the plant's boric acid corrosion control program. At that time, NRC concluded that the program was acceptable. However, in 1999, NRC became aware that FirstEnergy's boric acid corrosion control program was inadequate because boric acid had corroded several bolts on a valve, and NRC issued a violation. As a result of the violation, FirstEnergy agreed to review its boric acid corrosion procedures and enhance its program. NRC inspectors evaluated FirstEnergy's completed and planned actions to improve the boric acid corrosion control program and found them to be adequate. According to NRC officials, they never inspected the remaining actions—assuming that the planned actions had been implemented effectively. In 2000, NRC adopted its new Reactor Oversight Process and discontinued its inspection procedure for plants' corrosion control programs because these inspections had rarely been conducted due to higher priorities. Thus, NRC had no reliable or routine way to ensure that the nuclear power industry fully implemented boric acid corrosion control programs.

NRC also did not routinely review operating experiences at reactors, both in the United States and abroad, to keep abreast of boric acid developments and determine the need to emphasize this problem. Indeed, NRC did not fully understand the circumstances in which boric acid would result in corrosion, rather than flash to steam. Similarly, NRC did not know the rate at which carbon steel would corrode under different conditions. This lack of knowledge may be linked to shortcomings in its program to review operating experiences at reactors, which could have been exacerbated by the 1999 elimination of the office specifically responsible for reviewing operating experiences.[25] This office was responsible for, among other things, (1) coordinating operational data collection, (2)

[24]Westinghouse Electric Company, *Corrosion Effects of Boric Acid Leakage on Steel under Plant Operating Conditions—A Review of Available Data* (Pittsburgh: October 1987).

[25]NRC's Office for Analysis and Evaluation of Operating Data was established in response to a recommendation that we made to the agency in 1978 that it have a systematic process for analyzing operating experience and feeding this information back to licensees and the industry. NRC eliminated this office, and its responsibilities were transferred to other NRC offices in an effort to gain efficiencies.

systematically analyzing and evaluating operational experience, (3) providing feedback on operational experience to improve safety, (4) assessing the effectiveness of the agencywide program, and (5) acting as a focal point for interaction with outside organizations on issues pertaining to operational safety data analysis and evaluation. According to NRC officials who had overseen Davis-Besse at the time of the incident, they would not have suspected the reactor vessel head or cracked head penetration nozzles as the source of the filter clogging and unidentified leakage because they had not been informed that these could be potential problems. According to these officials, the vessel head was "not on the radar screen."

With regard to nozzle cracking, NRC, for more than two decades, was aware of the potential for nozzles and other components made of alloy 600 to crack. While cracks were found at nuclear power plants, NRC considered their safety significance to be low because the cracks were not developing rapidly. In contrast, other countries considered the safety significance of such cracks to be much higher. For example, concern over alloy 600 cracking led France, as a preventive measure, to institute requirements for an extensive nondestructive examination inspection program for vessel head penetration nozzles, including the removal of insulation, during every fuel outage. When any indications of cracking were observed, even more frequent inspections were required, which, because of economic considerations, resulted in the replacement of vessel heads when indications were found. The effort to replace the vessel heads is still under way. Japan replaced those vessel heads whose nozzles it considered most susceptible to cracking, even though no cracks had yet been found. Both France and Sweden also installed enhanced leakage monitoring systems to detect leaks early. However, according to NRC, such systems cannot detect the small amounts of leakage that may be typical from cracked nozzles.

NRC recognized that an integrated, long-term program, including periodic inspections and monitoring of vessel heads to check for nozzle cracking, was necessary. In 1997, it issued a generic letter that summarized NRC's efforts to address cracking of control rod drive mechanism nozzles and requested information on licensees' plans to inspect nozzles at their reactors. More specifically, this letter asked licensees to provide NRC with descriptions of their inspections of these nozzles and any plans for enhanced inspections to detect cracks. At that time, NRC was planning to review this information to determine if enhanced licensee inspections were warranted. Based on its review of this information, NRC concluded that the current inspection program was sufficient. As a result, between 1998 and

2001, NRC did not issue or solicit additional information on nozzle cracking or assess its requirements for inspecting reactor vessels to determine whether they were sufficient to detect cracks. At Davis-Besse, NRC also did not determine if FirstEnergy had plans or was implementing any plans for enhanced nozzle inspections, as noted in the 1997 generic letter. NRC took no further action until the cracks were found in 2001 at the Oconee plant, in South Carolina. NRC attributed its lack of focus on nozzle cracking, in part, to the agency's inability to effectively review, assess, and follow up on industry operating experience events. Furthermore, as with boric acid corrosion, NRC did not obtain or analyze any new data about cracking that would have supported making changes in either its regulations or inspections to better identify or prevent corrosion on the vessel head at Davis-Besse.

NRC's technical specifications regarding allowable leakage rates also contributed to the corrosion at Davis-Besse because the amount of leakage that can cause extensive corrosion can be significantly less than the level that NRC's specifications allow. According to NRC officials, NRC's requirements, established in 1973, were based on the best available technology at that time. The task of measuring identified and unidentified leakage from the reactor coolant system is not precise. It requires licensees to estimate the amount of coolant that the reactor is supposed to contain and identify any difference in coolant levels. They then have to account for the estimated difference in the actual amount of coolant to arrive at a leakage rate; to do this, they identify all sources and amounts of leakage by, among other things, measuring the amount of water contained in various sump collection systems. If these sources do not account for the difference, licensees know they have an unidentified source of leakage. This estimate can vary significantly from day to day between negative and positive numbers.

According to analyses that FirstEnergy conducted after it identified the corrosion in March 2002, the leakage rates from the nozzle cracks were significantly below NRC's reactor coolant system unidentified leakage rate of 1 gallon per minute. Specifically, the leakage from the nozzle around which the vessel head corrosion occurred was predicted to be 0.025 gallon per minute. If such small leakage can result in such extensive corrosion, identifying if and where such leakage occurs is important. NRC staff recognized as early as 1993 it would be prudent for the nuclear power industry to consider implementing an enhanced method for detecting small leaks during plant operation, but NRC did not require this action, and the industry has not taken steps to do so. Furthermore, NRC has not consistently enforced its requirement for reactor coolant pressure boundary leakage. As a result, the NRC Davis-Besse task force concluded that inconsistent enforcement may have reinforced a belief that alloy 600 nozzle leakage was not actually or potentially a safety significant issue.

## NRC's Process for Deciding Whether to Allow a Delayed Davis-Besse Shutdown Lacked Credibility

Although FirstEnergy operated Davis-Besse without incident until shutting it down in February 2002, certain aspects of NRC's deliberations allowing the delayed shutdown raise questions about the credibility of the agency's decision making, if not about the Davis-Besse decision itself. NRC does not have specific guidance for deciding on plant shutdowns. Instead, agency officials turned to guidance developed for a different purpose—reviewing requests to amend license operating conditions—and even then did not always adhere to this guidance. In addition, NRC did not document its decision-making process, as called for by its guidance, and its letter to FirstEnergy to lay out the basis for the decision—sent a year after the decision—did not fully explain the decision. NRC's lack of guidance, coupled with the lack of documentation, precludes us from independently judging whether NRC's decision was reasonable. Finally, some NRC officials stated that the shutdown decision was based, in part, on the agency's probabilistic risk assessment (PRA) calculations of the risk that Davis-Besse would pose if it delayed its shutdown and inspection. However, as noted by our consultants, the calculations were flawed, and NRC's decision makers did not always follow the agency's guidance for developing and using such calculations.

### NRC Did Not Have Specific Guidance for Deciding on Plant Shutdowns

NRC believed that Davis-Besse could have posed a potential safety risk because it was, in all likelihood, failing to comply with NRC's technical specification that no leakage occur in the reactor coolant pressure boundary. Its belief was based on the following indicators of probable leakage:

- All six of the other reactors manufactured by the same company as Davis-Besse's reactor had cracked nozzles and identified leakage.[26]
- Three of these six reactors had identified circumferential cracking.

[26]Davis-Besse's manufacturer was the Babcock and Wilcox Company, which is an operating unit of McDermott International.

- FirstEnergy had not performed a recent visual examination of all of its nozzles.

Furthermore, a FirstEnergy manager agreed that cracks and leakage were likely.

NRC has the authority to shut down a plant when it is clear that the plant is in violation of important safety requirements, and it is clear that the plant poses a risk to public health and safety.[27] Thus, if a licensee is not complying with technical specifications, such as those for no allowable reactor vessel pressure boundary leakage, NRC can order a plant to shut down. However, NRC decided that it could not require Davis-Besse to shut down on the basis of other plants' cracked nozzles and identified leakage or the manager's acknowledgement of a probable leak. Instead, it believed it needed more direct, or absolute, proof of a leak to order a shutdown. This standard of proof has been questioned. According to the Union of Concerned Scientists,[28] for example, if NRC needed irrefutable proof in every case of suspected problems, the agency would probably never issue a shutdown order. In effect, in this case NRC created a Catch-22: It needed irrefutable proof to order a shutdown but could not get this proof without shutting down the plant and requiring that the reactor be inspected.

Despite NRC's responsibility for ensuring that the public is adequately protected from accidents at commercial nuclear power plants, NRC does not have specific guidance for shutting down a plant when the plant may pose a risk to public health and safety, even though it may be complying with NRC requirements. It also has no specific guidance or standards for quality of evidence needed to determine that a plant may pose an undue risk. Lacking direct or absolute proof of leakage at Davis-Besse, NRC instead drafted a shutdown order on the basis that a potentially hazardous condition may have existed at the plant. NRC had no guidance for developing such a shutdown order, and therefore, it used its guidance for reviewing license amendment requests. NRC officials recognized that this guidance was not specifically designed to determine whether NRC should shut down a power plant such as Davis-Besse. However, NRC officials

[27]Ordinarily, NRC would not suspend a license for a failure to meet a requirement unless the failure was willful and adequate corrective action had not been taken.

[28]The Union of Concerned Scientists is a nonprofit partnership of scientists and citizens that augments scientific analyses and policy development for identifying environmental solutions to issues such as energy production.

stated that this guidance was the best available for deciding on a shutdown because, although the review was not to amend a license, the factors that NRC needed to consider in making the decision and that were contained in the guidance were applicable to the Davis-Besse situation.

To use its guidance for reviewing license amendment requests, NRC first determined that the situation at Davis-Besse posed a special circumstance because new information revealed a substantially greater potential for a known hazard to occur, even if Davis-Besse was in compliance with the technical specification for leakage from the reactor coolant pressure boundary. The special circumstance stemmed from NRC's determination that requirements for conducting vessel head inspections were not sufficient to detect nozzle cracking and, thus, small leaks.[29] According to NRC officials, this determination allowed NRC to use its guidance for reviewing license amendment requests when deciding whether to order a shutdown.

## The Extent of NRC's Reliance on License Amendment Guidance Is Not Clear

Under NRC's license amendment guidance, NRC considers how the license change affects risk, but not how it has previously assessed licensee performance, such as whether the licensee was viewed as a good performer. With regard to the Davis-Besse decision, the guidance directed NRC to determine whether the plant would comply with five NRC safety principles if it operated beyond December 2001 without inspecting the reactor vessel head. As applied to Davis-Besse, these principles were whether the plant would (1) continue to meet requirements for vessel head inspections, (2) maintain sufficient defense-in-depth, (3) maintain sufficient safety margins, (4) have little increase in the likelihood of a core damage accident, and (5) monitor the vessel head and nozzles. The guidance, however, does not specify how to apply these safety principles, how NRC can demonstrate it has followed the principles and ensured they are met, or whether any one principle takes precedence over the others. The guidance also does not indicate what actions NRC or licensees should take if some or all of the principles are not met.

[29]Specifically, reactor vessel head inspection requirements do not require that insulation be removed. Because of this, reactor vessel head inspections performed without removing the insulation above the vessel head could not result in 100 percent of the nozzles being visually inspected.

In mid-September 2001, NRC staff concluded that Davis-Besse complied with the first safety principle but did not meet the remaining four. According to the staff, Davis-Besse did not meet three safety principles because the requirements for vessel head inspections were not adequate. Specifically, the requirements do not require the inspector to remove the insulation above the vessel head, and thus allow all of the nozzles to be visually inspected. NRC therefore could not ensure that FirstEnergy was maintaining defense-in-depth and adequate safety margins or sufficiently monitoring the vessel head and nozzles. The staff believed that Davis-Besse did not meet the fourth safety principle because the risk estimate of core damage approached an unacceptable level and the estimate itself was highly uncertain.

Between early October and the end of November 2001, NRC requested and received additional information from FirstEnergy regarding its risk estimate of core damage—its PRA estimate—and met with the company to determine the basis for the estimate. NRC was also developing its own risk estimate, although its numbers kept changing. At some point during this time, NRC staff also concluded that the first safety principle was probably not being met, although the basis for this conclusion is not known.

At the end of November 2001, NRC contacted FirstEnergy and informed it that a shutdown order had been forwarded to the NRC commissioners and asked if FirstEnergy could take any actions that would persuade NRC to not issue the shutdown order. The following day, FirstEnergy proposed measures to mitigate the potential for and consequences of an accident. These measures included, among other things, lowering the operating temperature from 605 degrees Fahrenheit to 598 degrees Fahrenheit to reduce the driving force for stress corrosion cracking on the nozzles, identifying a specific operator to initiate emergency cooling in response to an accident, and moving the scheduled refueling outage up from March 31, 2002, to no later than February 16, 2002. NRC staff discussed these measures, and NRC management asked the staff if they were concerned about extending Davis-Besse's operations until mid-February 2002. While some of the staff were concerned about continued operations, none indicated to NRC management that cracking in control rod drive mechanism nozzles was likely extensive enough to cause a nozzle to eject from the vessel head, thus making it unsafe to operate. NRC formally accepted FirstEnergy's compromise proposal within several days, thus abandoning its shutdown order.

## NRC Did Not Fully Explain or Document the Basis for Its Decision

We could not fully assess NRC's basis for accepting FirstEnergy's proposal. NRC did not document its deliberations, even though its guidance requires that it do so. This documentation is to include the data, methods, and assessment criteria used; the basis for the decisions made; and essential correspondence sufficient to document the persons, places, and matters dealt with by NRC. Specifically, the guidance requires that the documentation contain sufficient detail to make possible a "proper scrutiny" of NRC decisions by authorized outside agencies and provide evidence of how basic decisions were formed, including oral decisions. NRC's guidance also states that NRC should document all important staff meetings.

In reviewing NRC's documentation on the Davis-Besse decision, we found no evidence of an in-depth or formal analysis of how Davis-Besse's proposed measures would affect the plant's ability to satisfy the five safety principles. Thus, it is unclear whether the safety principles contained in the guidance were met by the measures that FirstEnergy proposed. However, several NRC officials stated that FirstEnergy's proposed measures had no impact on plant operations or safety. For example, according to one NRC official, FirstEnergy's proposal to reduce the operating temperature would have had little impact on safety because the small drop in operating temperature over a 7-week period would have had little effect on the growth rate of any cracks in a nozzle. As such, this official considered the measures as "window dressing." A proposed measure that NRC staff did consider as having a significant impact on the risk was for FirstEnergy to dedicate an operator for manually turning on safety equipment in the event that a nozzle was ejected. Subsequent to approving the delayed shutdown, NRC learned that FirstEnergy had not, in fact, planned to dedicate an operator for this task—rather, FirstEnergy planned to have an operator do this task in addition to other regularly assigned duties.

According to an NRC official, once NRC decided not to issue a shutdown order for December 2001, NRC staff needed to discuss how NRC's assessment of whether the five safety principles had been met had changed in the course of the staff's deliberations. However, there was no evidence in the agency's records to support that this discussion was held, and other key meetings, such as the one in which the agency made its decision to allow Davis-Besse to operate past December 31, 2001, were not documented. Without documentation, it is not clear what factors influenced NRC's decision. For example, according to the NRC Office of the Inspector General's December 2002 report that examined the Davis-Besse incident, NRC's decision was driven in large part by a desire to lessen the financial impact on FirstEnergy that would result from an early shutdown.[30] While NRC disputed this finding, we found no evidence in the agency's records to support or refute its position.

In December 2001, when NRC informed FirstEnergy that it accepted the company's proposed measures and the February 16, 2002, shutdown date, it also said that the company would receive NRC's assessment in the near future. However, NRC did not provide the assessment until a full year later—in December 2002. In addition, the December 2002 assessment, which includes a four-page evaluation, does not fully explain how the safety principles were used or met—other than by stating that if the likelihood of nozzle failure were judged to be small, then adequate protection would be ensured. Even though NRC's regulations regarding the reactor coolant pressure boundary dictate that the reactor have an extremely low probability of failing, NRC stated it did not believe that Davis-Besse needed to demonstrate strict conformance with this regulation. As evidence of the small likelihood of failure, NRC cited the small size of cracks found at other power plants, as well as its preliminary assessment of nozzle cracking, which projected crack growth rates. NRC concluded that 7 weeks of additional operation would not result in an appreciable increase in the size of the cracks.[31] While NRC included its calculated estimates of the risk that Davis-Besse would pose, it did not detail how it calculated its estimates.

## NRC's PRA Estimate Was Flawed and Its Use in Deciding to Delay the Shutdown Is Unclear

In moving forward with its more risk-informed regulatory approach, NRC has established a policy to increase the use of PRA methods as a means to promote regulatory stability and efficiency. Using PRA methods, NRC and the nuclear power industry can estimate the likelihood that different accident scenarios at nuclear power plants will result in reactor core damage and a release of radioactive materials. For example, one of these accident scenarios begins with a "medium break" loss-of-coolant accident in which the reactor coolant system is breached and a midsize—about 2- to 4-inch—hole is formed that allows coolant to escape from the reactor

[30]NRC, Office of the Inspector General, *NRC's Regulation of Davis-Besse Regarding Damage to the Reactor Vessel Head* (Washington, D.C.; Dec. 30, 2002).

[31]NRC, *Preliminary Staff Technical Assessment for Pressurized Water Reactor Vessel Head Penetration Nozzles Associated with NRC Bulletin 2001-01, "Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles"* (Washington, D.C.; Nov. 6, 2001).

pressure boundary. The probability of such an accident scenario occurring and the consequences of that accident take into account key engineering safety system failure rates and human error probabilities that influence how well the engineered systems would be able to mitigate the consequences of an accident and ensure no radioactive release from the plant.

For Davis-Besse, NRC needed two estimates: one for the frequency of a nozzle ejecting and causing a loss-of-coolant accident and one for the probability that a loss-of-coolant accident would result in core damage. NRC first established an estimate, based partially on information provided by FirstEnergy, for the frequency of a plant developing a cracked nozzle that would initiate a medium break loss-of-coolant accident. NRC estimated that the frequency of this occurring would be about $2x10^{-2}$, or 1 chance in 50,[32] per year. NRC then used an estimate, which FirstEnergy provided, for the probability of core damage given a medium break loss-of-coolant accident. This probability estimate was $2.7x10^{-3}$, or about 1 chance in 370.[33] Multiplying these two numbers, NRC estimated that the potential for a nozzle to crack and cause a loss-of-coolant accident would increase the frequency of core damage at Davis-Besse by about $5.4x10^{-5}$ per year, or about 1 in 18,500 per year.[34] Converting this frequency to a probability associated with continued operation for 7 weeks, NRC calculated that the increase in the probability of core damage was approximately $5x10^{-6}$, or 1 chance in 200,000.[35] While NRC officials currently disagree that this was the number it used, this is the number that it included in its December 2002 assessment provided to FirstEnergy. Further, we found no evidence in the agency's records to support NRC's current assertion.

According to our consultants, the way NRC calculated and used the PRA estimate was inadequate in several respects. (See app. II for the consultants' detailed report.) First, NRC's calculations did not take into

[32]Here is how to calculate the frequency estimate: $2x10^{-2}$ equates to 0.02, or 2/100, which equals 1/50.

[33]Here is how to calculate the probability estimate: $2.7x10^{-3}$ equates to 0.0027, or 27/10,000, which equals 1/370.37.

[34]Here is how to calculate the frequency estimate: $5.4x10^{-5}$ equates to 0.000054, or 54/1,000,000, which equals 1/18,518.52.

[35]Here is how to calculate the probability estimate: $5x10^{-6}$ equates to 0.000005, or 5/1,000,000, which equals 1/200,000.

account several factors, such as the possibility of corrosion and axial cracking that could lead to leakage. For example, the consultants concluded that NRC's estimate of risk was incorrectly too small, primarily because the calculation did not consider corrosion of the vessel head. In reviewing how NRC developed and used its PRA estimates for Davis-Besse, our consultants noted that the calculated risk was smaller than it should have been because the calculations did not consider corrosion of the reactor vessel from the boric acid coolant leaking through cracks in the nozzles. According to the consultants, apparently all NRC staff involved in the Davis-Besse decision were aware that coolant under high pressure was leaking from valves, flanges, and possibly from cracks but evidently thought that the coolant would immediately flash into steam and noncorrosive compounds of boric acid. Our consultants, however, stated that because boric acid could potentially cause corrosion, except at temperatures much higher than 600 degrees Fahrenheit, NRC should have anticipated that corrosion could occur. Our consultants further stated that as evaporation occurs, boric acid becomes more concentrated in the remaining liquid—making it far more corrosive—and as vapor pressure decreases, evaporation is further slowed. They said it should be expected that some of the boric acid in the escaping coolant could reach the metal surfaces as wet or moist, highly corrosive material underlying the surface layers of dry noncorrosive boric acid, which is evidently what happened at Davis-Besse.

Our consultants concluded that NRC staff should have been aware of the experience at French nuclear power plants, where boric acid corrosion from leaking reactor coolant had been identified during the previous decade, the safety significance had been recognized, and safety procedures to mitigate the problem had been implemented. Furthermore, tests had been conducted by the nuclear power industry and in government laboratories on boric acid corrosion that were widely available to NRC. They stated that keeping abreast of safety issues at similar plants, whether domestic or foreign, and conveying relevant safety information to licensees are important functions of NRC's safety program. According to NRC, the agency was aware of the experience at French nuclear power plants. For example, NRC concluded, in a December 15, 1994, internal NRC memo, that primary coolant leakage from a through-wall crack could cause boric acid corrosion of the vessel head. However, because it concluded that some analyses indicated that it would take at least 6 to 9 years before any corrosion would challenge the structural integrity of the head, NRC concluded that cracking was not a short-term safety issue.

Our consultants also stated that NRC's risk analysis was inadequate because the analysis concerned only the formation and propagation of circumferential cracks that could result in nozzle failure, loss of coolant, and even control rod ejection. Although there is less chance of axial cracks causing complete nozzle failure, these cracks open additional pathways for coolant leakage. In addition, their long crevices provide considerably greater opportunity for the coolant to concentrate near the surface of the vessel head. However, according to our consultants, NRC was convinced that the boric acid they saw resulted from leaking flanges above the reactor vessel head, as opposed to axial cracks in the nozzles.

Second, NRC's analysis was inadequate because it did not include the uncertainty of its risk estimate and use the uncertainty analysis in the Davis-Besse decision-making process, although NRC staff should have recognized large uncertainties associated with its risk estimate. Our consultants also concluded that NRC failed to take into account the large uncertainties associated with estimates of the frequency of core damage resulting from the failure of nozzles. PRA estimates for nuclear power plants are subject to significant uncertainties associated with human errors and other common causes of system component failures, and it is important that proper uncertainty analyses be performed for any PRA study. NRC guidance and other NRC reports on advancing PRA technology for risk-informed decisions emphasize the need to understand and characterize uncertainties in PRA estimates. Our consultants stated that had the NRC staff estimated the margin of error or uncertainty associated with its PRA estimate for Davis-Besse, the uncertainty would likely have been so high as to render the estimate of questionable value.

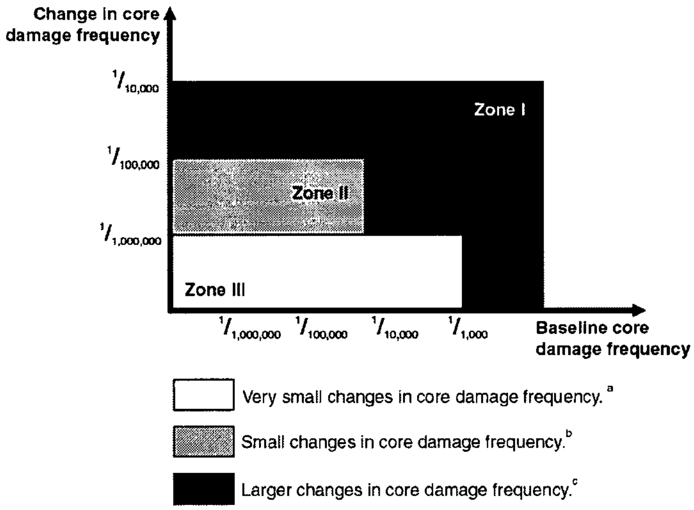
Third, NRC's analysis was inadequate because the risk estimates were higher than generally considered acceptable under NRC guidance. Despite PRA's important role in the decision, our consultants found that NRC did not follow its own guidance for ensuring that the estimated risk was within levels acceptable to the agency. NRC required the nuclear power industry to develop a baseline estimate for how frequently a core damage accident could occur at every nuclear power plant in the United States. This baseline estimate is used as a basis for deciding whether changes at a plant that affect the core damage frequency are acceptable. The baseline core damage frequency estimate for the Davis-Besse plant was between $4x10^{-5}$

and $6.6 \times 10^{-5}$ per year (which is between 1 chance in 25,000[36] per year and about 1 chance in 15,150[37] per year). NRC guidance for reviewing and approving license amendment requests indicates that any plant-specific change resulting in an increase in the frequency of core damage of $1 \times 10^{-5}$ per year (which is 1 chance in 100,000 per year) or more would fall within the highest risk zone: In this case, NRC would generally not approve the change because the risk criterion would not be met. If a license change would result in a core damage frequency change of $1 \times 10^{-5}$ per year to $1 \times 10^{-6}$ per year (which is 1 chance in 100,000 per year to 1 chance in 1 million per year), the risk criterion would be considered marginally met and NRC would consider approving the change but would require additional analysis. Finally, if a license change would result in a core damage frequency change of $1 \times 10^{-6}$ per year (which is 1 chance in 1 million per year) or less, the risk would fall within the lowest risk zone and NRC would consider the risk criterion to be met and would generally consider approving the change without requiring additional analysis. (See fig. 6.)

[36]Here is how to calculate the frequency estimate: $4 \times 10^{-5}$ equates to 0.00004, or 4/100,000, which equals 1/25,000.

[37]Here is how to calculate the frequency estimate: $6.6 \times 10^{-5}$ equates to 0.000066, or 66/1,000,000, which equals 1/15,151.51.

Figure 6: NRC's Acceptance Guidelines for Core Damage Frequency




Source: NRC.

[a]Risk criterion is met and license changes would generally be considered.

[b]Risk criterion is considered marginally met and while license changes are generally considered, they require additional analysis.

[c]Risk criterion is not met and license changes are generally not allowed.

However, NRC's PRA estimate for Davis-Besse—an increase in the frequency of core damage of $5.4 \times 10^{-5}$, or 1 chance in about 18,500 per year—was higher than the acceptable level. While an NRC official who helped develop the risk estimate said that additional NRC and industry guidance was used to evaluate whether its PRA estimate was acceptable, this guidance also suggests that NRC's estimate was too high. NRC's estimate of the increase in the frequency of core damage of $5.4 \times 10^{-5}$ per year equates to an increase in the probability of core damage of $5 \times 10^{-6}$, or 1 chance in 200,000, for the 7-week period December 31, 2001, to February 16, 2002.[35] NRC's guidance for evaluating requests to relax NRC technical specifications suggests that a probability increase higher than $5 \times 10^{-7}$, or 1 chance in 2 million[38], is considered unacceptable for relaxing the specifications. Thus, NRC's estimate would not be considered acceptable

[38]Here is how to calculate the probability estimate: $5 \times 10^{-7}$ equates to 0.0000005, or 5/10,000,000, which equals 1/2,000,000.

under this guidance. NRC's estimate would also not be considered acceptable under Electric Power Research Institute or Nuclear Energy Institute guidance unless further action were taken to evaluate or manage risk. According to NRC officials, NRC viewed its PRA estimate as being within acceptable bounds because it was a temporary situation—7 weeks—and NRC had, at other times, allowed much higher levels of risk at other plants. However, at the time that NRC made its decision, it did not document the basis for accepting this risk estimate, even though NRC's guidance explicitly states that the decision on whether PRA results are acceptable must be based on a full understanding of the contributors to the PRA results and the reasoning must be well documented. In defense of its decision, NRC officials said that the process they used to arrive at the decision is used to make about 1,500 licensing decisions such as this each year.

Lastly, NRC's analysis was inadequate because the agency does not have clear guidance for how PRA estimates are to be used in the decision-making process. Our consultants concluded that NRC's process for risk-informed decision making is ill-defined, lacks guidelines for how it is supposed to work, and is not uniformly transparent within NRC. According to NRC officials involved in the Davis-Besse decision, NRC's guidance is not clear on the use of PRA in the decision-making process. For example, while NRC has extensive guidance, this guidance does not outline to what extent or how the resultant PRA risk number and uncertainty should be weighed with respect to the ultimate decision. One factor complicating this issue is the lack of a predetermined methodology to weigh risks expressed in PRA numbers against traditional deterministic results and other factors.[39] Absent this guidance, the value assigned to the PRA analysis is largely at the discretion of the decision maker. The process, which NRC stated is robust, can result in a decision in which PRA played no role, a partial role, or one in which it was the sole deciding factor. According to our consultants, this situation is made worse by the lack of guidelines for how, or by whom, decisions in general are made at NRC.

It is not clear how NRC staff used the PRA risk estimate in the Davis-Besse decision-making process. For example, according to one NRC official who

[39]The deterministic approach considers a set of safety challenges and how those challenges should be mitigated through engineering safety margins and quality assurance standards. The probabilistic approach extends this by allowing for the consideration of a broader set of safety challenges, prioritizing safety challenges based on risk significance, and allowing for a broader set of mitigation mechanisms.

was familiar with some of the data on nozzle cracking, these data were not sufficient for making a good probabilistic decision. He stated that he favored issuing an order requiring that Davis-Besse be shut down by the end of December 2001 because he believed the available data were not sufficient to assure a low enough probability for a nozzle to be ejected. Other officials indicated that they accepted FirstEnergy's proposed February 16, 2002, shutdown date based largely on NRC's PRA estimate for a nozzle to crack and be ejected. According to one of these officials, allowing the additional 7 weeks of operating time was not sufficiently risk significant under NRC's guidance. He stated that safety margins at the plant were preserved and the PRA number was within an acceptable range. Still another official said he discounted the PRA estimate and did not use it at all when recommending that NRC accept FirstEnergy's compromise proposal. This official also stated that it was likely that many of the staff did base their conclusions on the PRA estimate. According to our consultants, although the extent to which the PRA risk analysis influenced the decision making will probably never be known, it is apparent that it did play an important role in the decision to allow the shutdown delay.

## NRC Has Made Progress in Implementing Recommended Changes, but Is Not Addressing Important Systemic Issues

NRC has made significant progress in implementing the actions recommended by the Davis-Besse lessons-learned task force. While NRC has implemented slightly less than half—21 of the 51—recommendations as of March 2004, it is scheduled to have more than 70 percent of them implemented by the end of 2004. For example, NRC has already taken actions to improve staff training and inspections that would appear to help address the concern that NRC inspectors viewed FirstEnergy as a good performer and thus did not subject Davis-Besse to the level of scrutiny or questioning that they should have. It is not certain when actions to implement the remaining recommendations will occur, in part because of resource constraints. NRC also faces challenges in fully implementing the recommendations, also in part because of resource constraints, both in the staff needed to develop specific corrective actions and in the additional staff responsibilities and duties to carry them out. Further, while NRC is making progress, the agency is not addressing three systemic issues highlighted by the Davis-Besse experience: (1) an inability to detect weakness or deterioration in FirstEnergy's safety culture, (2) deficiencies in NRC's process for deciding on a shutdown, and (3) lack of management controls to track, on a longer-term basis, the effectiveness of actions implemented in response to incidents such as Davis-Besse, so that they do not occur at another power plant.

## NRC Does Not Expect to Complete Its Actions until 2006, in Part Because of Resource Constraints

NRC's lessons-learned task force for Davis-Besse developed 51 recommendations to address the weaknesses that contributed to the Davis-Besse incident. Of these 51 recommendations, NRC rejected 2 because it concluded that agency processes or procedures already provided for the recommendations' intent to be effectively carried out.[40] To address the remaining 49 recommendations, NRC developed a plan in March 2003 that included, for each recommendation, the actions to be taken, the responsible NRC office, and the schedule for completing the actions. When developing its schedule, NRC placed the highest priority on implementing recommendations that were most directly related to the underlying causes of the Davis-Besse incident as well as those recommendations responding to vessel head corrosion. NRC assigned a lower priority to the remaining recommendations, which were to be integrated into the planning activities of those NRC offices assigned responsibility for taking action on the recommendations. In assigning these differing priorities, NRC officials stated they recognized that the agency has many other pressing matters to address that are not related to the Davis-Besse incident, such as renewing operating licenses, and they did not want to divert resources away from these activities. (App. III contains a complete list of the task force's recommendations, NRC actions, and the status of the recommendations as of March 2004.)

To better track the status of the agency's actions to implement the recommendations, we split two of the 49 recommendations that NRC accepted into 4; therefore, our analysis reflects NRC's response to 51 recommendations. As shown in table 1, as of March 2004, NRC had made progress in implementing the recommendations, although some completion dates have slipped.

[40]These two recommendations were for NRC to (1) review how industry considers economic factors in making decisions to repair equipment and consider these factors in developing guidance for nonvisual inspections of vessel head penetration nozzles, and (2) revise the criteria for reviewing industry topical reports that have not been formally submitted to NRC for review but that have generic safety implications.

**Table 1: Status of Davis-Besse Lessons-Learned Task Force Recommendations, as of March 2004**

| Status | Number of recommendations |
|---|---|
| *Completed as of March 2004* | 21 |
| Scheduled for completion April through December 2004 | 17 |
| Scheduled for completion in 2005 | 6 |
| Completion date yet to be determined | 7 |
| **Total** | **51** |

Source: GAO analysis of NRC data.

Note: This table does not include the two recommendations NRC rejected.

As the table shows, as of March 2004, NRC had implemented 21 recommendations and scheduled another 17 for completion by December 2004. However, some slippage has already occurred in this schedule—primarily because of resource constraints—and NRC has rescheduled completion of some recommendations. NRC's time frames for completing the recommendations depend on several factors—the recommendations' priority, the amount of work required to develop and implement actions, and the need to first complete actions on other related recommendations.

Of the 21 implemented recommendations, 10 called upon NRC to revise or enhance its inspection guidance or training. For example, NRC revised the guidance it uses to assess the implementation of licensees' programs to identify and resolve problems before they affect operations. It took this action because the task force had concluded that FirstEnergy's weak corrective action program implementation was a major contributor to the Davis-Besse incident. NRC has also developed Web-based training modules to improve NRC inspectors' knowledge of boric acid corrosion and nozzle cracking. The other 11 completed recommendations concerned actions such as

- collecting and analyzing foreign and domestic information on alloy 600 nozzle cracking,
- fully implementing and revising guidance to better assure that licensees carry out their commitments to make operational changes, and
- establishing measurements for resident inspector staffing levels and requirements.

By the end of 2004, NRC expects to complete another 17 recommendations, 12 of which generally address broad oversight or programmatic issues, and 5 of which provide for additional inspection guidance and training. On the broader issues, for example, NRC is scheduled to complete a review of the effectiveness of its response to past NRC lessons-learned task force reports by April 2004. By December 2004, NRC expects to have a framework established for moving forward with implementing recommended improvements to its agencywide operating experience program.

In 2005, 4 of the 6 recommendations scheduled for completion concern leakage from the reactor coolant system. For example, NRC is to (1) develop guidance and criteria for assessing licensees' responses to increasing leakage levels and (2) determine whether licensees should install enhanced systems to detect leakage from the reactor coolant system. The fifth recommendation calls for NRC to inspect the adequacy of licensees' programs for controlling boric acid corrosion, and the final recommendation calls on NRC to assess the basis for canceling a series of inspection procedures in 2001.

NRC did not assign completion dates to 7 recommendations because, among other things, their completion depends on completing other recommendations or because of limited resources. Even though it has not assigned completion dates for these recommendations, NRC has begun to work on 5 of the 7:

- Two recommendations will be addressed when requirements for vessel head inspections are revised. To date, NRC has taken some related, but temporary, actions. For example, since February 2003, it has required licensees to more extensively examine their reactor vessel heads. NRC has also issued a series of temporary instructions for NRC inspectors to oversee the enhanced examinations. NRC expects to replace these temporary steps with revised requirements for vessel head inspections.
- Two recommendations call upon NRC to revise requirements for detecting leaks in the reactor coolant pressure boundary. In response, NRC has, for example, begun to review its barrier integrity requirements and has contracted for research on enhanced detection capabilities.
- One recommendation is directed at improving follow-up of licensee actions taken in response to NRC generic communications. NRC is currently developing a temporary inspection procedure to assess the effectiveness of licensee actions taken in response to generic

communications. Additionally, as a long-term change in the operating experience program, the agency plans to improve the verification of how effective its generic communications are.

The remaining two recommendations address NRC's need to (1) evaluate the adequacy of methods for analyzing the risks posed by passive components, such as reactor vessels, and integrate these methods and risks into NRC's decision-making process and (2) review a sample of plant assessments conducted between 1998 and 2000 to determine if any identified plant safety issues have not been adequately assessed. NRC has not yet taken action on these recommendations.

Some recommendations will require substantial resources to develop and implement. As a result, some implementation dates have slipped and some plans in response to the recommendations have changed in scope. For example, owing to resource constraints, NRC has postponed indefinitely the evaluation of methods to analyze the risk associated with passive reactor components such as the vessel head. Also, in part due to resource constraints, NRC has reconceptualized its plan to review licensee actions in response to previous generic communications, such as bulletins and letters.

Staff resources will be strained because implementing the recommendations adds additional responsibilities or duties—that is, more inspections, training, and reviews of licensee reports. For example, NRC's revised inspection guidance for more thorough examinations of reactor vessel heads and nozzles, as well as new requirements for NRC oversight of licensees' corrective action programs, will require at least an additional 200 hours of inspection per reactor per year. As of February 2004, NRC was also revising other inspection requirements that are likely to place additional demands on inspectors' time. Thus, to respond to these increased demands, NRC will either need to add inspectors or reduce oversight of other licensee activities.

To its credit, in its 2004 budget plan, NRC increased the level of resources for some inspection activities. However, it is not certain that these increases will be maintained. The number of inspection hours has fallen by more than one-third between 1995 and 2001. In addition, NRC is aware that resident inspector vacancies are filled with staff having varying levels of experience—from the basic level that would be expected from a newly qualified inspector to the advanced level that is achieved after several years' experience. According to the latest available data, as of May 2003, about 12 percent of sites had only one resident inspector; the remaining 88 percent had two inspectors of varying levels of experience. Because of this situation, NRC augments these inspection resources with regional inspectors and contractors to ensure that, at a minimum, its baseline inspection program can be implemented throughout the year. Because of surges in the demand for inspections, NRC in 2003 increased its use of contractors and temporarily pulled qualified inspectors from other jobs to help complete the baseline inspection program for every plant. According to NRC, it did not expect to require such measures in 2004.

Similarly, NRC may require additional staff to identify and evaluate plants' operating experiences and communicate the results to licensees, as the task force recommended. NRC has currently budgeted an increase of three full-time staff in fiscal year 2006 to implement a centralized system, or clearinghouse, for managing the operating experience program. However, according to an NRC official, questions remain about the level of resources needed to fully implement the task force recommendations. NRC's operating experience office, before it was disbanded in 1999, had about 33 staff whose primary responsibility was to collect, evaluate, and communicate activities associated with safety performance trends, as reflected in licensees' operating experiences, and participate in developing rulemakings. However, it is too early to know the effectiveness of this clearinghouse approach and the adequacy of resources in the other offices available for collecting and analyzing operating experience information. Neither the operating experience office before it was disbanded nor the other offices flagged boric acid corrosion, cracking, or leakage as problems warranting significantly greater oversight by NRC, licensees, or the nuclear power industry.

## NRC Has Not Proposed Any Specific Actions to Correct Systemic Weaknesses in Oversight and Decision-Making Processes

NRC's Davis-Besse task force did not make any recommendations to address two systemic problems: evaluating licensees' commitment to safety and improving the agency's process for deciding on a shutdown.

### NRC's Task Force Recommendations Did Not Address Licensee Safety Culture

NRC's task force identified numerous problems at Davis-Besse that indicated human performance and management failures and concluded that FirstEnergy did not foster an environment that was fully conducive to ensuring that plant safety issues received appropriate attention. Although the task force report did not use the term safety culture, as evidence of FirstEnergy's safety culture problems, the task force pointed to

- an imbalance between production and safety, as evidenced by FirstEnergy's efforts to address symptoms (such as regular cleanup of boric acid deposits) rather than causes (finding the source of the leaks during refueling outages);
- a lack of management involvement in or oversight of work at Davis-Besse that was important for maintaining safety;
- a lack of a questioning attitude by senior FirstEnergy managers with regard to vessel head inspections and cleaning activities;
- ineffective and untimely corrective action;
- a long-standing acceptance of degraded equipment; and
- inadequate engineering rigor.

The task force concluded that NRC's implementation of guidance for inspecting and assessing a safety-conscious work environment and employee concerns programs failed to identify significant safety problems. Although the task force did not make any specific recommendations that NRC develop a means to assess licensees' safety culture, it did recommend changes to focus more effort on assessing programs to promote a safety-conscious work environment.

NRC has taken little direct action in response to this task force recommendation. However, to help enhance NRC's capability to assess licensee safety culture by indirect means, NRC modified the wording in, and revised its inspection procedure for, assessing licensees' ability to identify and resolve problems, such as malfunctioning plant equipment. These revisions included requiring inspectors to

- review all licensee reports on plant conditions,
- analyze trends in plant conditions to determine the existence of potentially significant safety issues, and
- expand the scope of their reviews to the prior 5 years in order to identify recurring issues.

This problem identification and resolution inspection procedure is intended to assess the end results of management's safety commitment rather than the commitment itself. However, by measuring only the end results, early signs of a deteriorating safety culture and declining management performance may not be readily visible and may be hard to interpret until clear violations of NRC's regulations occur. Furthermore, because NRC directs its inspections at problems that it recognizes as being more important to safety, NRC may overlook other problems until they develop into significant and immediate safety problems. Conditions at a plant can quickly degrade to the extent that they can compromise public health and safety.

The International Atomic Energy Agency and its member nations have developed guidance and procedures for assessing safety culture at nuclear power plants, and today several countries, such as Brazil, Canada, Finland, Sweden, and the United Kingdom, assess plant safety culture or licensees' own assessments of their safety culture.[41] In assessing safety culture, an advisory group to the agency suggests that regulatory agencies examine whether, for example, (1) employee workloads are not excessive, (2) staff training is sufficient, (3) responsibility for safety has been clearly assigned within the organization, (4) the corporation has clearly communicated its safety policy, and (5) managers sufficiently emphasize safety during plant meetings. One reason for assessing safety culture, according to the Canadian Nuclear Safety Commission, is because management and human performance aspects are among the leading causes of unplanned events at licensed nuclear facilities, particularly in light of pressures such as deregulation of the electricity market. Finland specifically requires that nuclear power plants maintain an advanced safety culture and its inspections target the importance that has been embedded in factors affecting safety, including management. NRC had begun considering methods for assessing organizational factors, including safety culture, but in 1998, NRC's commissioners decided that the agency should have a performance-based inspection program of overall plant performance and should infer licensee management performance and competency from the results of that program. They chose this approach instead of one of four other options:

[41]The International Atomic Energy Agency is an international organization affiliated with the United Nations that provides advice and assistance to its members on nuclear safety matters.

- conduct performance-based inspections in all areas of facility operation and design, but not infer or articulate conclusions regarding the performance of licensee management;

- assess the performance of licensee management through targeted operations-based inspections using specific inspection procedures, trained staff, and contractors to assess licensee management—a task that would require the development of inspection procedures and significant training—and to document inspection results;

- assess the performance of licensee management as part of the routine inspection program by specifically evaluating and documenting management performance attributes—a larger effort that would require the development of assessment tools to evaluate safety culture as well as additional resources; or

- assess the competency of licensee management by evaluating management competency attributes—an even larger effort that would require that implementation options and their impacts be assessed.

When adopting the proposal to infer licensee management performance from the results of its performance-based inspection program, NRC eliminated any resource expenditures specifically directed at developing a systematic method of inferring management performance and competency. NRC stated that it currently has a number of means to assess safety culture that provide indirect insights into licensee safety culture. These means include, for example, (1) insights from augmented inspection teams, (2) lessons-learned reviews, and (3) information obtained in the course of conducting inspections under the Reactor Oversight Process. However, insights from augmented inspection teams and lessons-learned reviews are reactionary and do not prevent problems such as those that occurred at Davis-Besse. Further, before the Davis-Besse incident, NRC assumed its oversight process would adequately identify problems with licensees' safety culture. However, NRC has no formalized process for collectively assessing information obtained in the course of its problem identification and resolution inspection to ensure that individual inspection results would identify poor management performance. NRC stated that its licensee assessments consider inputs such as inspection results and insights, correspondence to licensees related to inspection observations, input from resident inspectors, and the results of any special investigations. However, this information may not be sufficient to inform NRC of problems at a plant in advance of these problems becoming safety significant.

In part because of Davis-Besse, NRC's Advisory Committee on Reactor Safeguards[42] recommended that NRC again pursue the development of a methodology for assessing safety culture. It also asked NRC to consider expanding research to identify leading indicators of degradation in human performance and work to develop a consistent comprehensive methodology for quantifying human performance. During an October 2003 public meeting of the advisory committee's Human Performance Subcommittee, the subcommittee's members again reiterated the need for NRC to assess safety culture. Specifically, the members recognized that certain aspects of safety culture, such as beliefs, perceptions, and management philosophies, are ultimately the nuclear power industry's responsibility but stated that NRC should deal with patterns of behavior and human performance, as well as organizational structures and processes. At this meeting, NRC officials discussed potential safety culture indicators that NRC could use, including, among other things, how many times a problem recurs at a plant, timeliness in correcting problems, number of temporary modifications, and individual program and process error rates. Committee members recommended that NRC test various safety culture indicators to determine whether (1) such indicators should ultimately be incorporated into the Reactor Oversight Process and (2) a significance determination process could be developed for safety culture. As of March 2004, NRC had yet to respond to the advisory committee's recommendation.

Despite the lack of action to address safety culture issues, NRC's concern over FirstEnergy's safety culture at Davis-Besse was one of the last issues resolved before the agency approved Davis-Besse's restart. NRC undertook a series of inspections to examine Davis-Besse's safety culture and determine whether FirstEnergy had (1) correctly identified the underlying causes associated with its declining safety culture, (2) implemented appropriate actions to correct safety culture problems, and (3) developed a process for monitoring to ensure that actions taken were effective for resolving safety culture problems. In December 2003, NRC noted significant improvements in the safety culture at Davis-Besse, but expressed concern with the sustainability of Davis-Besse's performance in this area. For example, a survey of FirstEnergy and contract employees conducted by FirstEnergy in November 2003 indicated that about 17

[42]The Advisory Committee on Reactor Safeguards is an independent committee comprising nuclear experts that advises NRC on matters of licensing and safety-related issues, and provides technical advice to aid the NRC commissioners' decision-making process.

percent of employees believed that management cared more about cost and schedule than resolving safety and quality issues—again, production over safety.

### NRC's Task Force Recommendations Did Not Address NRC's Decision-Making Process

NRC's task force also did not analyze NRC's process for deciding not to order a shutdown of the Davis-Besse plant. It noted that NRC's written rationale for accepting FirstEnergy's justification for continued plant operation had not yet been prepared and recommended that NRC change guidance requiring NRC to adequately document such decisions. It also made a recommendation to strengthen guidance for verifying information provided by licensees. According to an NRC official on the task force, the task force did not assess the decision-making process in detail because the task force was charged with determining why the degradation at Davis-Besse was not prevented and because NRC had coordinated with NRC's Office of the Inspector General, which was reviewing NRC's decision making.

## NRC's Failure to Track the Resolution of Identified Problems May Allow the Problems to Recur

The NRC task force conducted a preliminary review of prior lessons-learned task force reports to determine whether they suggested any recurring or similar problems. As a result of this preliminary review, the task force recommended that a more detailed review be conducted to determine if actions that NRC took as a result of those reviews were effective. These previous task force reports included: Indian Point 2 in Buchanan, New York, in February 2000; Millstone in Waterford, Connecticut, in October 1993; and South Texas Project in Wadsworth, Texas, from 1988 to 1994.[43] NRC's more detailed review, as of May 2004, was still under way. We also reviewed these reports to determine whether they suggested any recurring problems and found that they highlighted broad areas of continuing programmatic weaknesses, as seen in the following examples:

- *Inspector training and information sharing.* All three of the other task forces also identified inspector training issues and problems with information collection and sharing. The Indian Point task force called

[43]NRC formed the Indian Point lessons-learned task force in response to a steam-generator-tube rupture that forced a reactor shutdown. NRC formed the Millstone lessons-learned task force because the plant operated outside its design standards while refueling. NRC formed the South Texas task force in response to concerns about the effectiveness of NRC's inspection program and the adequacy of the licensee's employee concerns program.

upon NRC to develop a process for promptly disseminating technical information to NRC inspectors so that they can review and apply the information in their inspection program.

- *Oversight of licensee corrective action programs.* Two of the three task forces also identified inadequate oversight of licensee corrective action programs. The South Texas task force recommended improving assessments of licensees' corrective action programs to ensure that NRC identifies broader licensee problems.

- *Better identification of problems.* Two of the three task force reports also noted the need for NRC to develop a better process for identifying problem plants, and one report noted the need for NRC inspectors to more aggressively question licensees' activities.

Over the past two decades, we have also reported on underlying causes similar to those that contributed, in part, to the incident at Davis-Besse. (See Related GAO Products.) For example, with respect to the safety culture at nuclear power plants, in 1986, 1995, and 1997, we reported on issues relevant to NRC assessing plant management so that significant problems could be detected and corrected before they led to incidents such as the one that later occurred at Davis-Besse. Regardless of our 1997 recommendation that NRC require that the assessment of management's competency and performance be a mandatory component of NRC's inspection process, NRC subsequently withdrew funding to accomplish this. In terms of inspections, in 1995 we reported that NRC, itself, had concluded that the agency was not effectively integrating information on previously identified and long-standing issues to determine if the issues indicated systemic weaknesses in plant operations. This report further noted that NRC was not using such information to focus future inspection activities. In 1997 and 2001, we reported on weaknesses in NRC's inspections of licensees' corrective action programs. Finally, with respect to learning from plants' operating experiences, in 1984 we noted that NRC needed to improve its methods for consolidating information so that it could evaluate safety trends and ensure that generic issues are resolved at individual plants. These recurring issues indicate that NRC's actions, in response to individual plant incidents and recommendations to improve oversight, are not always institutionalized.

NRC guidance requires that resolutions to action plans be described and documented, and while NRC is monitoring the status of actions taken in response to Davis-Besse task force recommendations and preparing quarterly and semiannual reports on the status of actions taken, the Davis-Besse action plan does not specify how long NRC will monitor them. It also does not describe how long NRC will prepare quarterly and semiannual status reports, even though, according to NRC officials, these semiannual status reports will continue until all items are completed and the agency is required to issue a final summary report. The plan also does not specify what criteria the agency will use to determine when the actions in response to specific task force recommendations are completed. Furthermore, NRC's action plan does not require NRC to assess the long-term effectiveness of recommended actions, even though, according to NRC officials, some activities already have an effectiveness review included. As in the past and in response to prior lessons-learned task force reports and recommendations, NRC has no management control in place for assessing the long-term effectiveness of efforts resulting from the recommendations. NRC officials acknowledged the need for a management control, such as an agencywide tracking system, to ensure that actions taken in response to task force recommendations effectively resolve the underlying issue over the long term, but the officials have no plans to establish such a system.

## Conclusions

It is unlikely, given the actions that NRC has taken to date, that extensive reactor vessel corrosion will occur any time soon at another domestic nuclear power plant. However, we do not yet have adequate assurances from NRC that many of the factors that contributed to the incident at Davis-Besse will be fully addressed. These factors include NRC's failure to keep abreast of safety significant issues by collecting information on operating experiences at plants, assessing their relative safety significance, and effectively communicating information within the agency to ensure that oversight is fully informed. The underlying causes of the Davis-Besse incident underscore the potential for another incident unrelated to boric acid corrosion or cracked control rod drive mechanism nozzles to occur. This potential is reinforced by the fact that both prior NRC lessons-learned task forces and we have found similar weaknesses in many of the same NRC programs that led to the Davis-Besse incident. NRC has not followed up on prior task force recommendations to assess whether the lessons learned were institutionalized. NRC's actions to implement the Davis-Besse lessons-learned task force recommendations, to be fully effective, will require an extensive effort on NRC's part to ensure that these are effectively incorporated into the agency's processes. However, NRC has not estimated the amount of resources necessary to carry out these recommendations, and we are concerned that resource limitations could constrain their effectiveness. For this reason, it is important for NRC to not only monitor the implementation of Davis-Besse task force recommendations, but also determine their effectiveness, in the long term, and the impact that resource constraints may have on them. These actions are even more important because the nation's fleet of nuclear power plants is aging.

Because the Davis-Besse task force did not address NRC's unwillingness to directly assess licensee safety culture, we are concerned that NRC's oversight will continue to be reactive rather than proactive. NRC's oversight can result in NRC making a determination that a licensee's performance is good one day, yet the next day NRC discovers the performance to be unacceptably risky to public health and safety. Such a situation does not occur overnight: Long-standing action or inaction on the part of the licensee causes unacceptably risky and degraded conditions. NRC needs better information to preclude such conditions. Given the complexity of nuclear power plants, the number of physical structures, systems, and components, and the manner in which NRC inspectors must sample to assess whether licensees are complying with NRC requirements and license specifications, it is possible that NRC will not identify licensees that value production over safety. While we recognize the difficulty in assessing licensee safety culture, we believe it is sufficiently important to develop a means to do so.

Given the limited information NRC had at the time and that an accident did not occur during the delay in Davis-Besse's shutdown, we do not necessarily question the decision the agency made. However, we are concerned about NRC's process for making that decision. It used guidance intended to make decisions for another purpose, did not rigorously apply the guidance, established an unrealistically high standard of evidence to issue a shutdown order, relied on incomplete and faulty PRA analyses and licensee evidence, and did not document key decisions and data. It is extremely unusual for NRC to order a nuclear power plant to shut down. Given this fact, it is more imperative that NRC have guidance to use when technical specifications or requirements may be met, yet questions arise over whether sufficient safety is being maintained. This guidance does not need to be a risk-based approach, but rather a more structured risk-informed approach that is sufficiently flexible to ensure that the guidance is applicable under different circumstances. This is important because NRC annually makes about 1,500 licensing decisions relating to operating commercial nuclear power plants. While we recognize the challenges NRC will face in developing such guidance, the large number and wide variety of decisions strongly highlight the need for NRC to ensure that its decision-making process and decisions are sound and defensible.

## Recommendations for Executive Action

To ensure that NRC aggressively and comprehensively addresses the weaknesses that contributed to the Davis-Besse incident and could contribute to problems at nuclear power plants in the future, we are recommending that the NRC commissioners take the following five actions:

- Determine the resource implications of the task force's recommendations and reallocate the agency's resources, as appropriate, to better ensure that NRC effectively implements the recommendations.

- Develop a management control approach to track, on a long-term basis, implementation of the recommendations made by the Davis-Besse lessons-learned task force and future task forces. This approach, at a minimum, should assign accountability for implementing each recommendation and include information on the status of major actions, how each recommendation will be judged as completed, and how its effectiveness will be assessed. The approach should also provide for regular—quarterly or semiannual—reports to the NRC commissioners on the status of and obstacles to full implementation of the recommendations.

- Develop a methodology to assess licensees' safety culture that includes indicators of and inspection information on patterns of licensee performance, as well as on licensees' organization and processes. NRC should collect and analyze this data either during the course of the agency's routine inspection program or during separate targeted assessments, or during both routine and targeted inspections and assessments, to provide an early warning of deteriorating or declining performance and future safety problems.

- Develop specific guidance and a well-defined process for deciding on when to shut down a nuclear power plant. The guidance should clearly set out the process to be used, the safety-related factors to be considered, the weight that should be assigned to each factor, and the standards for judging the quality of the evidence considered.

- Improve NRC's use of probabilistic risk assessment estimates in decision making by (1) ensuring that the risk estimates, uncertainties, and assumptions made in developing the estimates are fully defined, documented, and communicated to NRC decision makers; and (2) providing guidance to decision makers on how to consider the relative importance, validity, and reliability of quantitative risk estimates in conjunction with other qualitative safety-related factors.

## Agency Comments and Our Evaluation

We provided a draft of this report to NRC for review and comment. We received written comments from the agency's Executive Director for Operations. In its written comments, NRC generally addressed only those findings and recommendations with which it disagreed. Although commenting that it agreed with many of the report's findings, NRC expressed an overall concern that the report does not appropriately characterize or provide a balanced perspective on NRC's actions surrounding the discovery of the Davis-Besse reactor vessel head condition or NRC's actions to incorporate the lessons learned from that experience into its processes. Specifically, NRC stated that the report does not acknowledge that NRC must rely heavily on its licensees to provide it with complete and accurate information, as required by its regulations. NRC also expressed concern about the report's characterization of its use of risk estimates—specifically the report's statement that NRC's estimate of risk exceeded the risk levels generally accepted by the agency. In addition, NRC disagreed with two of our recommendations: (1) to develop specific guidance and a well-defined process for deciding on when to shut down a plant and (2) to develop a methodology to assess licensees' safety culture.

With respect to NRC's overall concern, we believe that the report accurately captures NRC's performance. Our draft report, in discussing NRC's regulatory and oversight role and responsibilities, stated that according to NRC, the completeness and accuracy of the information provided by licensees is an important aspect of the agency's oversight. To respond further to NRC's concern, we added a statement to the effect that licensees are required under NRC's regulations to provide the agency with complete and accurate information. While we do not want to diminish the importance of this responsibility on the part of the licensees, we believe that NRC also has a responsibility, in designing its oversight program, to implement management controls, including inspection and enforcement, to ensure that it has accurate information on and is sufficiently aware of plant conditions. In this respect, it was NRC's decision to rely on the premise that the information provided by FirstEnergy was complete and accurate. As we point out in the report, the degradation of the vessel head at Davis-Besse occurred over several years. NRC knew about several indications that problems were occurring at the plant, and the agency could have requested and obtained additional information about the vessel head condition.

We also believe that the report's characterization of NRC's use of risk estimates is accurate. The NRC risk estimate that we and our consultants found for the period leading up to the December 2001 decision on Davis-Besse's shutdown, including the risk estimate used by the staff during key briefings of NRC management, indicated that the estimate for core damage frequency was $5.4x10^{-5}$, as used in the report. The $5x10^{-6}$ referenced in NRC's December 2002 safety evaluation is for core damage probability, which equates to a core damage frequency of approximately $5x10^{-5}$—a level that is in excess of the level generally accepted by the agency. The impression of our consultants is that some confusion about the differences in these terms may exist among NRC staff.

Concerning NRC's disagreement with our recommendation to develop specific guidance for making plant shutdown decisions, NRC stated that its regulations, guidance, and processes are robust and do provide sufficient guidance in the vast majority of situations. The agency added that from time to time a unique situation may present itself wherein sufficient information may not exist or the information available may not be sufficiently clear to apply existing rules and regulations definitively. According to NRC, in these unique instances, the agency's most senior managers, after consultation with staff experts and given all of the information available at the time, decide whether to require a plant shutdown. While we agree that NRC has an array of guidance for making decisions, we continue to believe that NRC needs specific guidance and a well-defined process for deciding when to shut down a plant. As discussed in our report, the agency used its guidance for approving license change requests to make the decision on when to shut down Davis-Besse. Although NRC's array of guidance provides flexibility, we do not believe that it provides the structure, direction, and accountability needed for important decisions such as the one on Davis-Besse's shutdown.

In disagreeing with our recommendation concerning the need for a methodology to assess licensees' safety culture, NRC said that the Commission, to date, has specifically decided not to conduct direct evaluations or inspections of safety culture as a routine part of assessing licensee performance due to the subjective nature of such evaluations. According to NRC, as regulators, agency officials are not charged with managing licensees' facilities, and direct involvement with organizational structure and processes crosses over to a management function. We understand NRC's position that it is not charged with managing licensees' facilities, and we are not suggesting that NRC should prescribe or regulate the licensees' organizational structure or processes. Our recommendation is aimed at NRC monitoring trends in licensees' safety culture as an early warning of declining performance and safety problems. Such early warnings can help preclude NRC from assessing a licensee as being a good performer one day, and the next day being faced with a situation that it considers a potentially significant safety risk. As discussed in the report, considerable guidance is available on safety culture assessment, and other countries have established safety culture programs.

NRC's written response also contained technical comments, which we have incorporated into the report, as appropriate. (NRC's comments and our responses are presented in app. IV.)

As arranged with your staff, unless you publicly announce its contents earlier, we plan no further distribution of this report until 30 days from its issue date. At that time, we plan to provide copies of this report to the appropriate congressional committees; the Chairman, NRC; the Director, Office of Management and Budget; and other interested parties. We will also make copies available to others upon request. In addition, this report will be available at no charge on the GAO Web site at http://www.gao.gov. If you or your staff have any questions, please call me at (202) 512-3841. Key contributors to this report are listed in appendix V.

Jim Wells

Jim Wells
Director, Natural Resources
and Environment

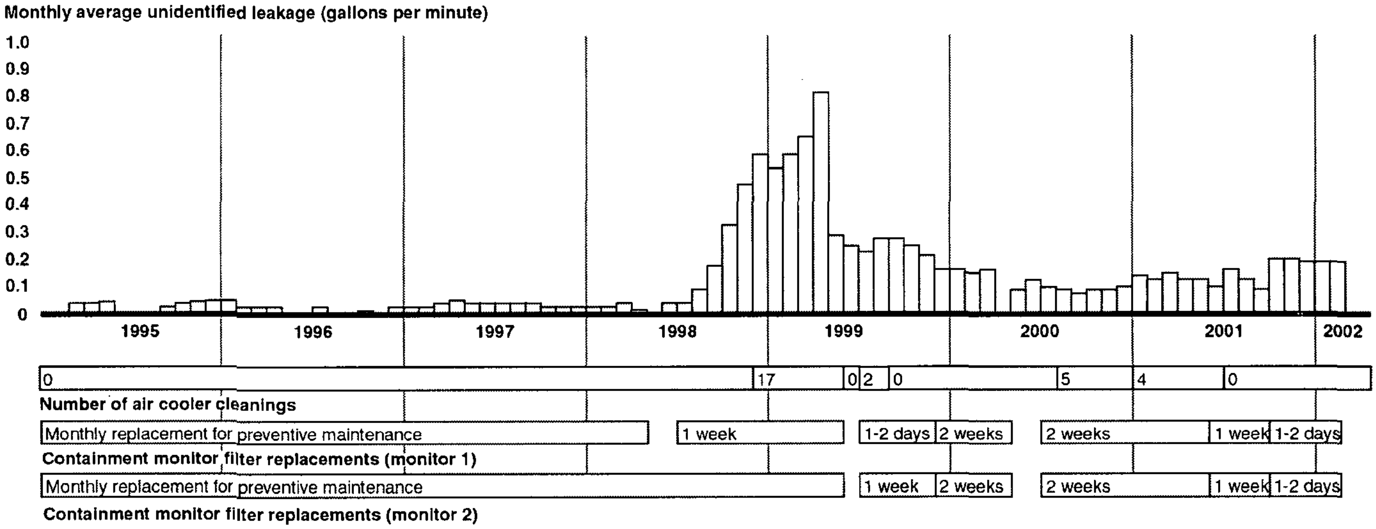
*List of Congressional Requesters*

The Honorable George V. Voinovich
United States Senate

The Honorable Dennis J. Kucinich
House of Representatives

The Honorable Steven C. LaTourette
House of Representatives

# Time Line Relating Significant Events of Interest




Source: GAO analysis of FirstEnergy, Electric Power Research Institute, and Dominion Engineering data.

# Analysis of the Nuclear Regulatory Commission's Probabilistic Risk Assessment for Davis-Besse

**Report of the Committee to Review the NRC's Oversight of the Davis-Besse Nuclear Power Station**

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**Report of the Committee to Review the NRC's Oversight of the Davis-Besse Nuclear Power Station**

**1. Scope of the Review**

The U. S. General Accounting Office formed a committee in September-October 2003 to review the oversight that the U. S. Nuclear Regulatory Commission provided on matters related to the pressure vessel head corrosion at the Davis-Besse (DB) Nuclear Power Station. The GAO charge to the committee was to respond to the questions:

(1) What probabilistic risk assessment model did NRC use and is it an appropriate model?
(2) What was the source of key data used to run NRC's probabilistic risk assessment and were these data valid?
(3) What key assumptions implicit in the model did NRC use to govern the estimated risk of different scenarios and were these reasonable?
(4) Is probabilistic risk assessment an appropriate tool for making such decision in these instances?
(5) How could NRC improve its use of probabilistic risk assessment to make more informed decisions?

The committee was initially provided with a set of 53 documents, which included GAO's preliminary analysis of the issues involved and chronology of the DB events during 2001 and 2002. The GAO reports summarized NRC-DB interactions in fall 2001 related to NRC Bulletin 2001-01 on control rod drive mechanism (CRDM) nozzle cracking, the eventual shutdown of the plant on 16 February 2002, and the subsequent discovery of pressure vessel head corrosion. Included also were:

(1) Official NRC documents, Generic Letters, Bulletins, and Information Notices transmitted to licensees including Davis-Besse,
(2) DB reports submitted to NRC related to the CRDM nozzle issues,
(3) NRC documents summarizing the staff's positions and discussions,
(4) Summaries of NRC staff presentations to NRC's Advisory Committee on Reactor Safeguards (ACRS) and to the Commission Technical Assistants,
(5) Event inquiry report of the NRC Office of Inspector General (OIG) and response from the NRC Chair,
(6) Redacted transcripts of OIG interviews of NRC staff, and
(7) Transcripts of GAO interviews with NRC staff.

The committee reviewed the initial set of documents received from GAO and conducted discussion on the phone and quite frequently via email. One member (GSW) provided a set of initial questions, which GAO used in a meeting with the NRC staff in October 2003. Another member (JCL) met with Mark Reinhart of NRC at the November American Nuclear Society meeting to discuss relevant technical issues and to prepare for a meeting of the review committee with NRC staff, which took place on December 11, 2003. At the meeting, two members (GSW, JCL) discussed technical and management issues with a total of nine NRC officials.

The review committee also consulted a number of experts from the industry and national laboratories, and reviewed a number of additional materials including:

(1) Several NRC Regulatory Guides,
(2) NRC Augmented Inspection Report and Lessons-Learned Task Force Report,

(3) Additional NRC reports on significance assessment of the DB CRDM degradations and the October 2003 OIG review of NRC's oversight on DB,
(4) Reports (including one proprietary version) from Electric Power Research Institute and Nuclear Energy Institute,
(5) Notes from William Shack, Argonne National Laboratory (ANL), describing his calculation of CRDM nozzle failure probability,
(6) DB probabilistic risk assessment (PRA) study performed for NRC by the Idaho National Engineering and Environmental Laboratory,
(7) Transcripts of several ACRS meetings during 2001–2003, and
(8) Select papers in engineering journals and proceedings.

The committee conducted an extensive review and discussion on the probabilistic risk calculations performed both by the FirstEnergy Nuclear Operating Company (FENOC) and NRC for Davis-Besse. One committee member (JCL) also developed a simplified analytical model to determine the CRDM failure probability, which provided a rough check on numerical calculations performed at ANL.

Following the 11 December 2003 meeting with the NRC staff, the committee made an effort to follow up on a number of questions that required additional information or clarifications. One essential piece of information is the core damage probability due to the postulated CRDM failure and ejection that NRC actually used in connection with the decision to allow continued DB operation until February 16, 2002. After a long wait, finally on February 24, 2004, the committee received a response from Jin Chung, Richard Barrett, and Gary Holahan, summarizing, to the extent they could reconstruct, how NRC arrived at key quantitative risk estimates in November 2001.

We present in Section 2 key findings of the committee on NRC's oversight related to the DB issues. We provide responses to the first four GAO charges in Sections 3 through 6, in a slightly restructured format, covering (a) PRA methodology and data used in NRC's risk assessment, (b) assumptions and uncertainties in the risk assessment, (c) relevant regulations and guidelines, and (d) November 2001 NRC decision. Our response to the fifth GAO charge is finally presented in Section 7.

**2. Key Findings of the Committee**

The committee presents key findings of its review on NRC's oversight on Davis-Besse and related safety and regulatory issues:

(1) <u>NRC's Risk Analysis for Davis-Besse</u>

(a) To guide a risk-informed decision on whether to grant an extension beyond its December 31, 2001 date for shutdown of Davis-Besse for nozzle inspection, NRC relied on its PRA of risks from crack-induced failure of control-rod housing nozzles. The calculated risk was incorrectly small because the calculations did not consider corrosion of the reactor vessel due to boric acid in coolant leaking through the cracks. The calculated risk was also subject to large uncertainties. As a result, NRC staff found it difficult to balance results of quantitative risk calculations against qualitative considerations. Regulatory Guide 1.174 provided little help in this regard.

(b) NRC did not perform uncertainty analysis in applying PRA in the DB decision-making process and there was confusion regarding the interpretation of core damage frequency (CDF) and core damage probability (CDP) as risk attributes within the framework of RG 1.174. NRC staff should have recognized large uncertainties associated with the CDF estimated for CRDM nozzle failures

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(c) NRC's risk analysis was poorly documented and inadequately understood by NRC staff.

(d) Even now, NRC is unable to provide estimates of the risk from continued operation of Davis-Besse from December 31, 2001 to February 16, 2002, taking into account the large corrosion cavity in the reactor vessel head found in March 2002. The risks from that operation prior to shutdown are likely to have been unacceptably large. Thus, with proper risk analysis, quantified risk calculations would have provided clear guidance for prompt shutdown.

(2) Relevant Regulations and Guidelines

(a) Coolant leakage through flanges and valves was allowed under the DB Technical Specifications, leading the DB personnel and NRC resident inspectors to treat boric acid deposits in various locations in the containment as routine events, and hence not risk significant.

(b) NRC has no predetermined methodology to weigh PRA against deterministic factors. NRC needs to develop a set of guidelines for the use of PRA in decision-making.

(3) November 2001 Davis-Besse Decision

(a) The proposed shutdown date of 31 December 2001 was arbitrary. There was significant pressure from DB to delay the shutdown for financial reasons, but no cost-benefit analysis was presented.

(b) Communication was seriously lacking between NRC headquarters and Region III and also between resident inspectors and Region III administrators regarding the extent of coolant leakage and boric-acid corrosion.

(c) NRC staff incorrectly assumed that the visible white deposits of anhydrous boric acid resulted entirely from rapid evaporation and drying of the leaking coolant and were not associated with corrosion.

(d) The transparency of the decision-making process within NRC is not uniform. The NRC lacks an established and well-defined process for decision-making.

(4) General Safety and Regulatory Issues

(a) How to ensure safety from corrosion by leaking coolant is generic to all pressurized water reactors (PWRs). There is no evidence that it has been evaluated as such by NRC's Advisory Committee on Reactor Safeguards.

(b) The root cause of this near miss of a serious accident at Davis-Besse is human error: inadequate evaluation of the effect of simplifying assumptions in the risk analysis and inadequate perception and understanding of the many clues that challenged those assumptions.

(c) NRC is slow to integrate new safety information into its programs, and to share that information with its licensees.

## 3. NRC Probabilistic Risk Assessment Model and Database

### 3.1 Basic PRA Methodology and Data Used for the DB Risk Analysis

The NRC staff relied on a Standardized Plant Analysis Risk (SPAR) study [Sat00] for Davis-Besse that Idaho National Engineering and Environmental Laboratory performed. The Saphire code [Sap98] provided the PRA tools and database for key system failure rates and human error probabilities in the SPAR study. The PRA methodology combines semi-pictorial structures of event and fault trees to estimate the probability of occurrence of rare events, in particular, the core damage frequency (CDF) and large early release frequency (LERF) of radioactivity associated with the operation of a nuclear power plant. An event tree is constructed for each major sequence of events beginning with an initiating event, e.g., a medium-break loss-of-coolant accident (MBLOCA), and following through multiple stages of safety systems to be activated. The probability of failure or unreliability of a safety system that is called upon to function is determined as the probability of the top event of a fault tree, which is determined through Boolean logic representing failure probabilities of components making up the top event. Uncertainties in the CDF and LERF are then obtained by a Monte Carlo convolution of probability density functions representing failure rates of components in fault trees and of safety systems in event trees.

The MBLOCA, which is assumed to occur following the failure and ejection of CRDM nozzles at Davis-Besse, is analyzed in the SPAR report [Sat00] as one of 12 major internal events postulated to lead to core damage and radioactivity release. A baseline CDF of $1.0\times10^{-7}$/year for MBLOCA results from a generic value [Pol99] of the initiating event frequency of $4.0\times10^{-5}$/year for the MBLOCA combined with the failure probabilities of a number of engineered safety features, including high- and low-pressure injection systems. This results in an estimate of $2.5\times10^{-3}$ for the conditional core damage probability (CCDP) for MBLOCA. The CCDP of $2.5\times10^{-3}$ is almost entirely due to the failure of low-pressure recirculation pumps, which in turn depends heavily on the ability of the operator to properly align and start the pumps. Based on human factor analysis, an estimate of $1.0\times10^{-3}$ for the operator error is included in determining the CCDP of $2.5\times10^{-3}$. The baseline or point-estimate CDF of $1.0\times10^{-7}$/year for MBLOCA contributes 0.5% toward the total baseline CDF of $2.0\times10^{-5}$/year, with uncertainties represented as CDF = {5th percentile, median, mean, 95th percentile | $6.3\times10^{-6}$, $1.6\times10^{-5}$, $5.1\times10^{-5}$, $9.6\times10^{-5}$} per year. The SPAR report for Davis-Besse provides only baseline CDF estimates for individual core damage events; hence no uncertainty estimates are available for the MBLOCA event. The mean overall CDF = $5.1\times10^{-5}$/year for Davis-Besse compares well with the those for internal initiating events for three PWR plants analyzed extensively as part of NRC's severe accident evaluation project in NUREG-1150 [Nrc90]: Surry Unit 1, $4\times10^{-5}$/year; Sequoyah Unit 1, $6\times10^{-5}$/year; and Zion Unit 1, $6\times10^{-5}$/year. The CDF estimates for the four PWRs are, however, an order of magnitude larger than those for two boiling water reactors analyzed in NUREG-1150: Peach Bottom Unit 2, $5\times10^{-6}$/year, and Grand Gulf Unit 1, $4\times10^{-6}$/year.

### 3.2 DB Calculation of Risk due to CRDM Nozzle Failures

The DB calculation of the nozzle failure probability consisted of the following steps [Cam01c]. The nozzles were divided into three groups based on the extent of visual inspection possible during refueling outage (RFO) 10, 11 and 12. Group 1 consisted of 15 nozzles that were not inspected during RFO 10 and 11. Group 2 consisted of 5 additional nozzles that were not inspected during RFO 12. Group 3 consisted of 45 nozzles, all of which were inspected during all outages. This analysis accounts for 65 nozzles, four short of the total number of nozzles on the DB head. The four nozzles not

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included in this analysis are at the center of the head. They were determined by a Structural Integrity Associates analysis [Cam01d] to have no demonstrable annular gaps, and therefore, were considered as not susceptible to circumferential cracking and were excluded from the calculation. This particular assumption turned out to be quite inappropriate, since the February-March 2002 inspection revealed that three central nozzles (Nos. 1, 2, 3) had developed through-wall axial cracks and that nozzle 2 also had a circumferential crack.

Leak frequencies were determined for each group according to the equation: leak frequency = 1.1/year × $F_i$, where $F_i$ is the fraction of the total nozzles (65) in group $i$, and the value of 1.1 is the estimated frequency of CRDM leaks per reactor year based on observations on 5 other Babcock and Wilcox (B&W) plants. Data on CRDM cracking noted in the 2001-01 NRC Bulletin were incorporated into the PRA analysis [Cam01c] in calculating the leak frequency. Specifically, recent inspections had revealed that there were sixteen leaking nozzles identified in the B&W plants, Arkansas Nuclear One Unit 1 (ANO-1), Crystal River Unit 3 (CR-3), Oconee Nuclear Station Unit 1 (ONS-1), ONS-2 and ONS-3. The assumption was made that all leaks appeared during the most recent two fuel cycles. Assuming 1.5 years per fuel cycle, 2 cycles per plant and 5 plants, a product of these three values yields 15 reactor years of operation. Sixteen leaking nozzles over 15 years of operation yields a leak frequency of about 1.1 leaks per reactor year. This value then incorporated the most recent data on CRDM cracking at other B&W plants.

An event tree was constructed for each CRDM group, beginning with the CRDM leak frequency, accounting for crack growths and failures during subsequent operation and CRDM nozzle inspection failures, and culminating with a total CDF. The event tree analysis included CCDP = $2.7\times10^{-3}$ for all groups. The resulting total CDF summed over all three groups was $6.97\times10^{-6}$/year. Dividing by the CCDP yielded a value of the initiating event (IE) frequency of $2.58\times10^{-3}$/year representing an MBLOCA due to CRDM nozzle ejection. Using the IE frequency, one would then calculate an IE probability of $3.4\times10^{-4}$ for continued DB operation for another 0.13 year, representing the period between 31 December 2001 and 16 February 2002. We note here also that the DB estimation of CCDP = $2.7\times10^{-3}$ agrees closely with the SPAR estimate of $2.5\times10^{-3}$ discussed in Section 3.1.

The probability of missing a leak in an inspection was estimated by Framatome [Cam01b] using human reliability analysis. Their estimates [Cam01d] indicated that the probability of missing a leak was 0.06 in the first inspection (RFO 10), 0.065 in the second inspection (RFO 11) and 0.11 in subsequent inspections. Davis-Besse's analysis [Cam01c], however, uses a single probability of value 0.05 applied to all of the nozzles covered in RFO 10, 11 and in subsequent inspections. The document [Cam01c] references the Framatome analysis [cam01b], but does not indicate why a different value was used and why a single, lower value was applied for all inspections. Correcting, however, the calculation to account for the three separate failure detection probabilities results in an IE frequency of $2.64\times10^{-3}$/year vs. $2.58\times10^{-3}$/year assumed [Cam01c].

3.3 NRC Calculation of Risk due to CRDM Nozzle Failures

Although documents provided to the review committee do not provide sufficient details on how NRC arrived at the incremental CDF or core damage probability (CDP), it appears that the NRC staff used the DB estimate of CCDP = $2.7\times10^{-3}$ for the MBLOCA initiated by CRDM nozzle failure and ejection. The NRC did not have the in-house expertise to determine the nozzle ejection probability for Davis-Bessie. They had two sources for estimates of the nozzle ejection probability. One source was Dr. William Shack at Argonne National Laboratory (ANL). Dr. Shack conducted a rather extensive analysis of the failure probability consisting of 5 steps: 1) the number of cracked nozzles, 2) the crack size distribution, 3) the crack growth rate, 4) a time to failure based on initial crack size and crack growth rate, and 5) a probability of failure, based on a Monte Carlo analysis of failure times. The end result was a plot and a table with failure probability vs. time that was provided to NRC and is described in several references [Sha01, Sha03, Nrc01a]. The second source of information on the MBLOCA frequency was the DB estimate [Cam01c] for IE frequency of $2.58\times10^{-3}$/year, discussed in Section 3.2.

Documents provided to the review committee [Rei03, Chu04] list the IE probability of $2.0\times10^{-3}$ for continued operation for another 0.13 year, representing the period between 31 December 2001 and 16 February 2002, but reference Dr. Shack as the source. However, the values provided by Shack to the NRC [Sha01] do not agree with this number and apparently NRC decided not to use the ANL analysis, as it was viewed as preliminary, and a work in progress.

In a final response [Chu04] to questions the review committee raised following the 11 December 2003 meeting with nine NRC staff, Jin Chung, Richard Barrett, and Gary Holahan confirmed that NRC used the DB estimate of CCDP = $2.7\times10^{-3}$, coupled with the IE frequency of $2.0\times10^{-2}$/year, to obtain an incremental CDF = $5.4\times10^{-5}$/year, associated with the postulated CRDM failure and ejection leading to an MBLOCA. They indicate that, instead of allowing for the inspection failure probability of 0.05 for RFO 10, assumed in the Framatome risk calculation [Cam01c], NRC allowed no credit to discover the nozzle cracking. NRC, however, used the same crack growth and failure rates as in the Framatome PRA submittal to arrive at the IE frequency of $3.4\times10^{-2}$/year, which is an order of magnitude larger than the Framatome estimate of $2.58\times10^{-3}$/year. Dr. Chung then decided to reduce the IE frequency to $2.0\times10^{-2}$/year to "reflect best estimate rather than 75 percentile fracture mechanics," which is the best description of the adjustment that NRC is able to present in February 2004. The adjusted value of IE frequency = $2.0\times10^{-2}$/year is then used together with CCDP = $2.7\times10^{-3}$ to yield the incremental CDF = $5.4\times10^{-5}$/year. Finally, to convert the incremental CDF to an incremental CDP, associated with the continued DB operation for 0.13 year, NRC again rounded off the resulting CDP = $7.0\times10^{-6}$ to $5.0\times10^{-6}$. In the deliberations leading to the 28 November 2001 DB decision, NRC apparently used the adjusted, rounded-off risk estimates: incremental CDF = $5.4\times10^{-5}$/year and incremental CDP = $5.0\times10^{-6}$.

The conclusion of the review committee is that the determination of IE probability is questionable, and that the error or uncertainty associated with this probability is likely to be very high, rendering it of questionable value. In the February 2004 response [Chu04] to the review committee questions, NRC confirms that no uncertainty analysis was performed on the incremental CDF and CDP estimates they used in November 2001. Furthermore, NRC proposes an unusual use of the incremental CDF and CDP values to compare with the quantitative guidelines given in RG 1.174 [Nrc02a]. This will be discussed further in Section 5.1.

**4. Assumptions and Uncertainties in NRC Risk Analysis**

4.1 The Discovery of Massive Corrosion Wastage at Davis-Besse

The most serious shortcoming in NRC's risk analysis was the complete neglect of any consideration of corrosion of the reactor vessel by boric acid in reactor coolant known to be leaking from the high-pressure cooling system. After finally shutting down the reactor and inspecting the control housing nozzles, Davis-Besse discovered extensive corrosive wastage of the steel pressure vessel. Boric acid in leaking coolant had reacted with iron to form a mass of corrosion products which, when removed, left a cavity the size of a

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pineapple. Corrosion had penetrated the 6-inch thick steel head of the reactor vessel and exposed the thin corrosion-resistant vessel liner, found to be only about 0.2 inches thick at that location.

The reactor had been operating for months, maybe years, perilously close to rupture of the vessel liner and rapid loss of reactor coolant. In response to our repeated requests to NRC to share with us what it has learned about the risks from corrosion-induced failure of the coolant pressure boundary, NRC states that such analysis has not been completed, awaiting completion of laboratory tests on relevant failure mechanics at the Oak Ridge National Laboratory. That answer is most disappointing.

An earmark of a responsive safety program is prompt incorporation of new safety information, by undertaking new risk analysis, whether deterministic, probabilistic, or both, to guide new procedures that would avoid such a potential accident and to guide research and testing necessary for proper risk-informed decision making. Now, some two years since the discovery of massive and dangerous corrosion wastage at Davis-Besse, NRC seems unable to supply even preliminary analysis of the magnitude of potential safety problems arising from coolant leakage and corrosion. This harks back to the 1977-79 era, when NRC failed to recognize the implications of a near miss of a serious reactor accident at Davis-Besse, discussed further in Section 6.6. If NRC had made a prompt analysis of Davis-Besse's 1977 operator errors and the implications for a more serious accident if not corrected, and if that analysis had been communicated to other licensees, the tragic accident at Three Mile Island could have been avoided. It appears that NRC has not fully recovered from its mistakes in 1977-79.

4.2 Assumption that Boric Acid in Hot Escaping Coolant Will Not Corrode

Apparently all NRC staff who were involved in the November 2001 decision on Davis-Besse were aware that high-pressure coolant was leaking from valves, flanges, and possibly from cracks, but they evidently thought that the hot coolant, at 600 °F, would immediately flash into steam and non-corrosive anhydrous compounds of boric acid. As evidence, they referred to the readily visible deposits of white fluffy anhydrous boric acid observed on plant equipment. But evaporation concentrates boric acid in the remaining liquid, which becomes far more corrosive. Its vapor pressure decreases and slows further evaporation. Thus, one should expect that some of the boric acid in the escaping coolant can reach the metal surfaces as wet or moist highly corrosive material underlying the white fluffy surface layers. That is evidently what happened. It should have been anticipated.

Also the geometry of a cracked nozzle was not considered in NRC's thoughts about boric acid corrosion. NRC was focused on the metal surface because they were convinced that the boric acid they saw came from "dripping" from the leaky valves above the head. However, in a leaking nozzle, the escape path of the water is some 6-8 inches – from the clad to the vessel surface. Such a long crevice provides considerably greater opportunity for concentration of the liquid behind the evaporation front at or near the vessel head surface where the steam escapes.

NRC staff should also have been aware of experience at the French nuclear plants, where boric acid corrosion from leaking reactor coolant had been identified during the previous decade, the safety significance had been recognized, and safety procedures to mitigate the problem had been implemented. Keeping abreast of safety issues at similar plants, whether domestic or abroad, and conveying relevant safety information to its licensees is an important function of NRC's safety program.

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NRC staff were involved a few years earlier in discussions regarding boric acid deposits on the reactor pressure vessel head [Epr01]. Boric-acid corrosion programs were initiated. But to the NRC staff involved in the November 2001 decision on Davis-Besse, boric-acid corrosion was not viewed as a significant safety concern; rather, there was concern that the anhydrous crystals could obscure indication of leakage from the nozzles above the reactor head. But already several tests of boric acid corrosion had been underway in industry and government laboratories. Representative tests of nozzle leakage showed that corrosion rates from boric acid solutions dripping onto carbon steel at 600 °F can be in the range of four inches per year [Nrc02b]. Drip tests sponsored by the Electric Power Research Institute [Sri98, Epr01] showed that the corrosion rate is much higher for carbon-steel surfaces at 600 °F than at lower temperature. Only at temperatures much higher than 600 °F is the vaporization rate high enough to produce anhydrous boric acid crystals with little corrosion.

NRC personnel involved in the November 2001 safety review evidently were not aware of these corrosion tests or else they had forgotten about them. An NRC resident inspector at Davis-Besse was shown, by a Davis-Besse engineer, a photograph that revealed streaks of rust-colored corrosion products on the head of the reactor vessel, in the midst of the expected white crystals. But the inspector was not aware of the significance of these rust streaks, and he did not report this information to other NRC personnel. At other times, Davis-Besse reported the presence of airborne rust particles that had lodged on the surveillance filters, but the significance of this information was not recognized.

After the discovery of the corrosion wastage in 2002, an NRC official was asked about the corrosion data reported by the Electric Power Research Institute (EPRI). He replied that those data were not considered in the discussions with Davis-Besse because EPRI had not "submitted" the report of those data to NRC. EPRI points out that the corrosion data had been published in 1998 in a widely available technical report, well known to industry and NRC. EPRI had not formally "submitted" the report because NRC charges a fee for the submittal process.

4.3 Control Rod Ejection and Reactivity Transient

In discussions related to the consequences of CRDM nozzle ejections at Davis-Besse, NRC duly considered the effects of the control rods ejected, thereby made inoperable, in the resulting LOCA. They apparently concluded before the 28 November 2001 Davis-Besse decision that the negative reactivity feedback resulting from the overheating and boiling of coolant in a LOCA would easily overshadow any potential decrease in the amount of subcritical reactivity that would ensure safe shutdown of the reactor. Furthermore, a more recent NRC report [Dye03] evaluating the significance of the Davis-Besse CRDM penetration cracking and pressure vessel head degradation presents a similar conclusion. Here, a combined thermal-hydraulic and reactivity transient analysis performed with the RELAP code indicates that the boiling of the reactor coolant coupled with the addition of boric acid in the emergency coolant water injected is sufficient to maintain the shutdown condition, thereby obviating the concern for an anticipated transient without scram (ATWS).

One consequence of the CRDM nozzle ejection that has not been, however, analyzed is the positive reactivity inserted into the reactor core when the control rod ejection occurs in a hot zero power (HZP) rather than a hot full power (HFP) condition. The consequences of postulated control rod ejection accidents are generally more severe, if initiated in a HZP condition when the system is fully pressurized but at low power. This is because at HZP the control rods would be inserted deeply into the core, thereby adding

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a larger positive reactivity when the rods are ejected, than that resulting in a HFP rod ejection accident. Thus, a HZP CRDM nozzle ejection could result in a power level above rated power before a significant coolant heating or boiling occurs. This combination of postulated accidents requires an integrated analysis of two PWR design basis accidents, LOCA and rod ejection accident, and should be performed for a complete evaluation of CRDM nozzle ejection consequences.

4.4 Need to Account for Corrosion in Risk Analysis

NRC's analysis of risks from nozzle cracking was concerned only with the formation and propagation of circumferential cracks that could result in nozzle failure, loss of coolant, and even control rod ejection. The formation of axial cracks was neglected in the risk analysis. There is less chance of axial cracks causing complete failure of a nozzle but they do open additional pathways for coolant leakage. Leakage from axial cracks is believed to have been the main source for the massive corrosion wastage at Davis-Besse.

Neglecting axial cracking and corrosion wastage that could result in rupture of the reactor vessel and a more serious loss-of-coolant accident was a principal deficiency in NRC's risk assessment.

NRC has not described to us any plans for extensions to its risk analysis that would predict the dangers of corrosion wastage. In our view, the necessary additional ingredients of the probabilistic risk analysis must include:

- Formation and growth of axial cracks in control-rod-housing nozzles,
- Flow of leaking coolant from cracks,
- Evaporation of leaking coolant and concentration of boric acid,
- Corrosion of the steel pressure vessel,
- Time-dependent penetration of the corrosion front into the pressure vessel,
- Corrosion and stress-corrosion cracking of the vessel liner,
- Time-dependent calculation of stress on the vessel and its failure if ruptured, and
- Loss-of-coolant analysis of reactor core damage if rupture occurs.

Some of the possible parameters for such an analysis were developed for this report from sources other than NRC, as outlined in the next section. The wide variations in some of the key parameters illustrate uncertainties that must be resolved to make accurate predictions of risk and its uncertainty.

4.5 Uncertainties in Predicting Risks from Nozzle Cracking

For risk-informed decision making, it is important to include calculation of uncertainties in the predicted risks. NRC informs us that it has not calculated uncertainties in its present risk assessments of nozzle cracking. It does believe that its present results on core-damage risks are accurate "to within a factor of 2 or 3". NRC did not provide the basis for their belief. The information necessary for probabilistic risk calculation should include enough data for uncertainty analysis. NRC should perform uncertainty calculations.

A major uncertainty arises in attempting to predict the corrosion wastage that would rupture the reactor vessel, particularly after boric-acid-induced corrosion has penetrated all the way through the carbon steel and exposed the thin stainless steel liner that would serve as the reactor coolant system pressure boundary, as occurred at Davis-Besse. From other sources [Pin03a,b], we are informed that in early 2003 an internal NRC memo concluded that there was no danger of imminent rupture of the Davis-Besse reactor prior to its shutdown in February 2002. The memo cited calculations by the Oak Ridge National Laboratory that the as-discovered cavity could have supported twice the operating pressure of 2185 psia before rupturing and that, "had the cavity enlarged under continued operation, at least twelve months remained before the cavity would reach a size that rupture would occur at normal operating temperature and pressure." It was assumed that "the wastage cavity was actively growing at a maximum rate of seven inches per year" [Pin03a], much greater than the 4 inches per year quoted earlier by NRC. The NRC memo stated that the need for more accurate data on the morphology and depth of cladding cracks necessitates a revision of these calculations and expects a possible reduction in the amount of margin that was originally calculated.

A report by Structural Integrity Associates [Sia02], commissioned by FirstEnergy, calculated that the cladding could withstand pressures of more than 5000 psia. Davis-Besse concluded that vessel rupture "was therefore considered not to be a credible event". Later in 2003, an Oak Ridge National Laboratory study, conducted on a spare reactor-vessel head with a machined-out cavity simulating wastage, reported two rupture tests, one occurring at 2000 psia, the other at 2700 psia. If these two results are applicable, Davis-Besse had been operating at 2185 psia with significant probability of vessel rupture. NRC's project manager for these tests stated in October 2003 that the Oak Ridge test results would be made public "probably within weeks." The report is not yet released.

An important feature of the Oak Ridge tests was taking into account the "dissimilar weld" between the carbon-steel vessel head and the stainless steel cladding. The Union of Concerned Scientists pointed out that the Oak Ridge tests revealed that the weld overlay process used for the Davis-Besse vessel left a thin interface that was not as strong as either of the adjoining layers. Also, the tests were conducted quasi-statically, whereas pressure transients during reactor operation must be considered [Pin03b].

These are examples of crucial data uncertainties that need to be resolved. Such uncertainties must be considered in reporting probabilistic risks.

It is not enough to finesse such uncertainties by instituting new procedures intended to eliminate the possibility of operator error. The near accident at Davis-Besse resulted from human error, errors by reactor operators, by NRC on-site inspectors and by the staffs at Davis-Besse and NRC. The experience at Three Mile Island has taught us that human errors can occur and must be included in responsible risk analysis.

4.6 Lack of Uncertainty Analysis in DB Risk Estimation

As discussed in Section 4.5, an important issue regarding the application of quantitative guidelines for risk management and regulatory decisions, as in the Davis-Besse case under review, is the need to account for uncertainties in risk values determined through PRA techniques. It was noted in Sections 3.1 and 3.3 that we are unable to obtain any uncertainty estimates for the SPAR baseline CDF of $1.0\times10^{-7}$/year for Davis-Besse MBLOCA, without CRDM nozzle failures, or the NRC estimate of $5.4\times10^{-5}$/year for the corresponding MBLOCA CDF accounting for CRDM nozzle failures. It is well known among the PRA community that all quantitative risk estimates for nuclear power plants are subject to significant uncertainties and that it is imperative that proper uncertainty analysis be performed for any PRA study for nuclear power plants. This point was made abundantly clear in a recent NRC report [Fle03], prepared at the request of NRC's Advisory Committee on Reactor Safeguards (ACRS), for the purpose of evaluating practices and issues regarding PRA applications. The need to understand and characterize uncertainties in PRA and risk-informed regulatory activities was also emphasized in both RG 1.174 [Nrc02a] and RG 1.200 [Nrc03]. Furthermore, it was primarily for the purpose of duly accounting for uncertainties in the calculated risks of postulated severe accidents that NRC and its contractors had to go through two draft versions of the massive volumes of the severe accidents risk study of NUREG-1150 [Nrc90] before releasing the final version in 1990. Nonetheless, it is rather clear to the review committee that the NRC staff and management did not give due considerations to the impact of large uncertainties, in particular, in the frequency of MBLOCA initiated by the postulated Davis-Besse CRDM nozzle ejection in their Davis-Besse deliberations in November 2001. In addition, the SPAR calculation of CCDP = $2.5\times10^{-3}$ is subject to significant uncertainties associated with human errors and common cause failures represented in the fault tree analysis. Questions were also raised in GAO interviews with the NRC staff if the staff had the proper understanding of the impact on the CCDP estimate of the compensatory measures proposed by Davis-Besse before the November 2001 decision.

During the 11 December 2003 meeting with the NRC staff, we got the indication that several NRC staff felt that Regulatory Guide 1.174 [Nrc02a], with its PRA framework, does account for uncertainties in risk estimates including the effects of unknown events, e.g., the Davis-Besse pressure vessel head wastage, through the defense-in-depth philosophy. As discussed in detail in the February 2003 NRC Region III report [Dye03], it is very much doubtful how the system modeling uncertainties and unknown events could possibly have been represented through a simple application of RG 1.174. It is noteworthy that the ACRS, at its first full committee meeting [Acr02] after the Davis-Besse cavity findings, repeatedly criticized the NRC staff for not having performed any uncertainty analysis for the CRDM nozzle failure issues and suggested that the staff had drifted away from the RG 1.174 guidelines. Had the staff gone through even a simple analysis, without any detailed uncertainty calculations or invoking RG 1.174, they should have realized that the *incremental* CDF of $5.4\times10^{-5}$/year would result in doubling the total CDF for Davis-Besse, even with the mean SPAR value of $5.1\times10^{-5}$/year. Note furthermore that the SPAR baseline CDF is $1.6\times10^{-5}$/year. Thus, the staff should have readily recognized the risk significance of the incremental CDF = $5.4\times10^{-5}$/year estimated in November 2001 for the CRDM nozzle failure event.

One regulatory decision-making case where PRA applications were questioned is the ATWS issue. A recent review [Rau03] emphasizes that the uncertainty in the calculated values of the reactor scram system reliability requires maintaining defense in depth regarding ATWS, rather than relying heavily on PRA results. Thus, despite small values of scram failure probabilities calculated in the early 1980s, system changes, including improved reactor shutdown systems and circuits, were implemented but only after incipient ATWS events had occurred at the Salem Unit 1 plant in 1983 [Sci83]. We suggest that the NRC staff should have applied the lessons learned from the ATWS rulemaking case to the DB case, which would have reduced the NRC staff's heavy reliance on the quantitative risk. Although we will never be able to determine the extent by which the incremental CDF or CDP values influenced the decision making, it is rather apparent to the review committee that the quantitative risk values, without due considerations for uncertainties, did play an important role in the 28 November 2001 decision.

**5. Relevant Regulations and Guidelines**

5.1 Use of Regulatory Guide 1.174 and Other Guidelines in the DB Decision

One key set of guidelines discussed extensively among the NRC staff and management before the 28 November 2001 DB decision is RG 1.174 [Nrc02a], which is intended to promote risk-informed decisions on plant-specific changes. Included in RG 1.174 is one particular quantitative metric in the form of incremental CDF. According to Figure 3 illustrating acceptance guidelines, any plant-specific changes resulting in an incremental CDF of $1\times10^{-5}$/year or higher should not be allowed. In addition, there apparently was considerable discussion and lack of unanimity among the NRC staff prior to the 28 November 2001 decision if the other four safety principles of RG 1.174 were satisfied. The February 2003 NRC Region III report [Dye03] documenting the significance of the Davis-Besse CRDM penetration cracking and pressure vessel head degradation leaves, however, no question that all five safety principles of REG 1.174 were violated at Davis-Besse in November 2001. Included in this report is a revised estimate of incremental MBLOCA frequency of $3.0\times10^{-2}$/year, yielding estimates of incremental CDF in the range of $[1\times10^{-5}, 1\times10^{-4}]$ per year, due to the ejection of three central CRDM nozzles. These estimates of incremental CDF bracket the value of $5.4\times10^{-5}$/year presented to the review committee [Rei03] and would have clearly resulted in violation of the sole quantitative metric of RG 1.174.

Although the February 2003 findings of NRC rendering Davis-Besse in the "red" status are attained certainly with the benefits of hindsight, it is worth summarizing the reasoning presented in the report, rather than presenting the review committee's evaluations:

(1) Principle 1: *Regulations were not met*, because reactor coolant system (RCS) pressure boundary leakage occurred over an extended period of time and the RCS was not inspected and maintained properly. This resulted in violation of the General Design Criteria.
(2) Principle 2: Performance and maintenance deficiency *degraded the level of defense in depth* required for safe operation of the plant.
(3) Principle 3: *Safety margins were not maintained* because the integrity of the RCS pressure boundary relied solely on the vessel lining, which was not designed for this purpose.
(4) Principle 4: *Calculated risk violated the quantitative guideline.*
(5) Principle 5: There was *no basis for assuring that degradations* due to CRDM leaks *would be properly monitored and managed.*

It goes without saying that nobody anticipated in November 2001 the severe vessel wastage that was uncovered in March 2002, which resulted in an unambiguous verdict regarding Principle 3 above. Nonetheless, there were sufficient indications in November 2001 to question if safety margins were not violated, as voiced by a number of the NRC staff before the 28 November 2001 decision. This in turn raises questions if NRC made proper application of RG 1.174 in arriving at the decision to allow a delay of the shutdown of Davis-Besse for the pressure vessel head inspection required in NRC Bulletin 2001-01 [Nrc01c].

During the 11 December 2003 meeting with the NRC staff, the review committee was offered a number of other NRC and industry guidelines that the NRC staff apparently used for the Davis-Besse decision. A review of these additional guidelines further suggests that the NRC value for the incremental CDF = $5.4\times10^{-5}$/year for seven weeks of additional Davis-Besse operation could not have satisfied these guidelines either. To clarify the point here, we follow the process NRC used to convert the incremental CDF = $5.4\times10^{-5}$/year to the incremental core damage probability (CDP) for seven weeks or 0.13 year: incremental CDP = $5.4\times10^{-5}$/year × 0.13 year = $7.0\times10^{-6}$, rounded off to $5.0\times10^{-6}$, which is roughly equivalent to approximating 7 weeks as 0.1 year. We may now compare this incremental CDP estimate with three additional guidelines for risk-informed decision-making processes:

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(1) RG 1.177 [Nrc98] intended for evaluating Technical Specification changes suggests that an incremental CDP of $5\times10^{-7}$ is acceptable for relaxation of allowed outage time or surveillance test intervals.
(2) PSA Applications Guidelines [Tru95] proposed by the Electric Power Research Institute indicates that an incremental CDP in the range of [$1\times10^{-6}$, $1\times10^{-5}$] requires assessment of non-quantifiable factors.
(3) NUMARC 93-01 [Nei96] suggests that an incremental CDP in the range of [$1\times10^{-6}$, $1\times10^{-5}$] requires risk management actions, adding further that any decisions resulting in an incremental CDP greater than $1\times10^{-5}$ should not be allowed.

Thus, NRC's incremental CDP value of $5\times10^{-6}$ would have resulted in violation of RG 1.177 and would have required risk management actions according to both the EPRI and Nuclear Energy Institute guidelines. In addition, during the 11 December 2003 meeting with the NRC staff, Richard Barrett insisted that the quantitative RG 1.174 guidelines are supposed to be applied in terms of incremental CDP, not incremental CDF as stipulated clearly in the Regulatory Guide. In the February 2004 response [Chu04] to the review committee questions, NRC now proposes that the incremental CDF used as a key metric in RG 1.174 is meant to be an annual average. Thus, NRC now suggests that the incremental CDF = $5.4\times10^{-5}$/year for 13% of a year should be combined with CDF = 0.0 for the remaining 87% of the year to yield an annual-average incremental CDF = $5\times10^{-6}$/year. This new interpretation is at best unusual and certainly is inconsistent with clear RG 1.174 guidelines regarding the use of incremental CDF. This reinforces the impression of the review committee that perhaps there was in November 2001 and possibly is still some confusion among the NRC staff regarding basic quantitative metrics that should be considered in evaluating regulatory and safety issues.

A recent release of RG 1.200 [Nrc03] is intended to provide guidance for determining the technical adequacy of PRA results in regulatory decision making. The Regulatory Guide discusses various technical characteristics and attributes that should be included in PRA, and highlights the importance of capturing system dependencies in risk evaluations. RG 1.200 also emphasizes that understanding uncertainties in PRA is an essential aspect of risk characterization and refers to RG 1.174 for guidance on how to address the uncertainties. As reviewed in connection with the DB decision-making process, however, we feel that the guidelines in RG 1.174 are not specific enough, especially for PRA results subject to large uncertainties and for representing events not well understood.

5.2 Technical Specifications and General Design Criteria Regarding Coolant Leak

Davis-Besse technical specification 3.4.6.2 requires that no reactor coolant pressure boundary (RCPB) leakage is allowed. The *General Design Criteria, 10 CFR 50* Appendix A, addresses reactor coolant pressure boundary leakage in GDC 14, GDC 31, and GDC 32. GDC 14 specifies that the RCPB have an extremely low probability of abnormal leakage, or rapidly propagating failure, and of gross rupture. GDC 31 specifies that the probability of rapidly propagating fracture of the RCPB be minimized. GDC 32 specifies that components which are part of the RCPB have the capability of being periodically inspected to assess their structural and leaktight integrity.

The FENOC response [Cam01a] to the NRC Bulletin 2001-01 applies the GDC against the situation of potentially cracked nozzles at Davis-Besse. Specifically the following points were made:

- The presence of cracked and leaking vessel head penetration (VHP) nozzles is not consistent with GDC14 or GDC 31.
- Inspection practices that do not permit reliable detection of VHP nozzle cracking are not consistent with GDC 32.

The situation regarding primary coolant leakage can be summarized as follows. The Davis-Besse technical specifications (TS) present a definitive criterion that allows no RCPB leakage. The GDC are not as definitive by virtue of their reference to *probability* of occurrence, which is not an absolute or definitive condition. GDC 14 and 31 are in agreement with the TS in principle, but not in their level of definitiveness. Therefore, there exists the possibility that a specific condition can be considered to satisfy the GDC but not the TS. Furthermore, the GDC implemented in the TS for DB allows for 1 gpm of unidentified reactor coolant system (RCS) leakage and 10 gpm of identified RCS leakage, with the interpretation that leakage past seals, flanges, and gaskets is not pressure boundary leakage.

GDC 32 refers to the capability to inspect the leaktight integrity of the nozzles. Inspections were acknowledged to be incomplete because of failure to inspect all nozzles. They were insufficient because it was acknowledged that visual inspection may be inadequate in detecting cracks. By virtue of the inadequacy of the inspections in achieving their intended purpose, GDC 32 was largely not satisfied.

According to the 2002 OIG Event Inquiry [Bel02], FENOC's own risk-informed evaluation estimated that Davis-Besse had between one and nine leaking CRDM nozzles, depending on the analysis used. According to the NRC, FENOC reported [Nrc02c] an estimate of 8.8 leaking nozzles to ACRS. From the results and analysis of the inspection data from five other B&W plants that revealed 16 cracked nozzles in 15 reactor years of operation [Cam01c] there should be 1-2 leaking nozzles since the last outage (RFO 12 in April 2000). So from the available data, it was *highly likely* that there were leaks in the pressure boundary. These data were circumstantial as there was no direct evidence of the leaks, in part due to the inadequacy of the visual inspection techniques.

Given that positive identification of nozzle leakage was not obtainable because of the nature and capability of the inspections, and given that multiple analyses show that as many as 9 leaking nozzles were likely, it can be concluded that Davis-Besse was *likely* in violation of their Technical Specifications. This point was further discussed in the NRC Significance Assessment Report [Dye03].

The incorporation of PRA into the decision-making process at NRC should have compelled the NRC to consider the likelihood of leaking nozzles in the decision on whether to allow Davis-Besse to continue to operate. However, "the NRR Director told OIG that from a legal point of view, there was an issue about constructing an order without knowing with *certainty* that there were cracks" [Bel02]. This position had a significant impact on the NRC decision as the key decision-maker in this case, Brian Sheron, believed that NRC had no case to shut down the plant based on the technical specification that there be no RCPB leakage. The potential conflict between PRA and legal considerations must be resolved for PRA to play any role in the decision-making process of the NRC.

5.3 Balance between Probabilistic and Deterministic Indicators for Risk Assessment

NRC management is responsible for decision-making. The technical staff is responsible for providing the technical case that serves as the foundation for decisions by management. The technical case includes both deterministic and PRA analysis that both involve models, data and calculations.

NRC has adopted "risk-informed" decision-making. However, the process is ill-defined and lacks guidelines as to exactly how it is supposed to work. The management does not have a set formula, process or procedure for incorporating PRA into its decision-making process. Brian Sheron was the key decision-maker in the Davis-Besse case. He stated in the December 11 interview with the review team that the PRA analysis was used as a "calibration point" that gives NRC a ballpark figure of the risk. He indicated that the PRA value is not of much consequence unless it is of a "wildly" extreme value. He also indicated that there is little clear guidance on the use of PRA in the decision-making process. This point was supported by comments from Jack Strosnider and Gary Holahan who confirmed in their December 11 interview with the review team that there is no documentation or guidance that outlines to what extent or how the NRC should weigh the resultant risk number and uncertainty with respect to the ultimate decision.

This viewpoint indicates that NRC has no predetermined methodology to weigh the PRA result against a deterministic result or other factors. That is, the value assigned to the PRA analysis is largely at the discretion of the decision-maker and there is no guidance as to the weight to assign to this result. Such a process can result in a decision in which PRA plays a role anywhere from 0 to 100%. Clearly, there is need for the NRC to provide guidance for the use of PRA in decision-making.

**6. Review of the November 2001 NRC Decision Regarding Davis-Besse**

6.1 Involvement of NRC Staff and Management in the DB Decision

The basis of the November 28 decision to allow Davis-Besse to operate until February 16 was a meeting involving both technical staff and management. The meeting was called by Brian Sheron and was held on November 28, 2001. Following discussion of the various issues regarding Davis-Besse, Brian Sheron asked the staff if they could accept an extension of operation of the plant until February 16, 2002. Three staff members had objections. Mr. Sheron then reframed the question and asked the staff if any of them thought that Davis-Besse was not safe to operate until that date. None thought that this was the case. Based on this result, NRC accepted the February 16, 2002 date proffered by FENOC.

During the discussion, both deterministic analyses and PRA results were considered. However, a cost-benefit type of analysis of the situation was not performed. In an interview with the review team, Richard Barrett explained that NRC followed the RG 1.174 and RIS 2001-02 [Nrc01b] argument, based on a "special circumstance." This special circumstance was that the regulations (ASME inspection codes) at the time were not adequate to detect cracked and/or leaking nozzles and thus NRC had to take special action to address the special circumstance. Once the existence of a special circumstance was established, NRC used RG 1.174 to determine if the problem was risk significant enough. NRC determined that the problem was not risk significant, per RG 1.174, because "defense-in-depth" was preserved. Therefore, NRC did not consider the third factor, which would have been "higher level NRC management thoughts," such as a "cost-benefit" analysis or impact/burden on license.

However, as noted by several staff, there was pressure on the NRC from industry, Congress and the NRC Commissioners to keep plants running. It is not clear how much influence this pressure had on the decision-making process.

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The transparency of the decision-making process within NRC is not uniform. In the case of a shutdown order, the Executive Director for Operations (Office Director) would be the official responsible for signing the order. If the issue does not involve an order, the process is less clear. The specification of decision-maker appears to depend on the importance of the issue. There does not appear to be a policy that identifies what individuals are empowered to make what decisions. Strosnider and Holahan indicated that a routine response to a generic letter may be handled by a project manager, or perhaps by the Divisions of Licensing Project Management, with the concurrence of the involved sections or other divisions. NRC has no standard process or guidelines for decision-making. Sometimes the decision process involves a memo describing the licensee's request and NRC's response that is routed around and signed off on by relevant NRC staff. Other times, NRC will pull together a meeting of decision stakeholders.

The lack of an established and well-defined process for decision-making within the agency is a significant problem that needs to be addressed.

6.2 Coordination among NRR, RES, and Inspectors

The analysis and decision-making process for the Davis-Besse case involved numerous individuals and offices. Included in the consideration of issues regarding Davis-Besse were the Directorate for Project Licensing & Technical Analysis, the Division of Engineering, and Division of System Safety and Analysis and the technical staff of the several Branches that report to those Division Directors of the Office of Nuclear Reactor Regulation (NRR). In addition, the Office of Research (RES) and ACRS played roles, as did the regional office and the regional inspector at Davis-Besse.

While there were a number of individuals and offices involved in the technical assessment of nozzle cracking, the interplay between offices and individuals is impossible to reconstruct. However, there are two cases that highlight problems with communication between offices and between individuals. The first is in the assessment of the initiating event probability. Based on interviews with some 12 different individuals, all significantly involved in the Davis-Besse issue and analysis, and spanning two Offices, one Directorate, two Divisions and several Branches, there was no sense of understanding about how the initiating event probability used in the PRA analysis was determined and by whom. In fact, the origin of the value for the initiating event probability that appears to have been used in the PRA analysis was variously ascribed to Bill Shack at ANL, FENOC, Framatome and EMC[2]. Further, the perception of who within NRC was responsible for establishing this quantity was not consistent. This situation indicates a very uneven understanding of one of the key underlying quantities for the entire PRA analysis. The origin of this term remains an outstanding issue, even with the February 2004 NRC response [Chu04]. It was clear that there was substantial interaction among offices and individuals during the period of intense analysis in the Fall of 2001. However, communication did not appear to be well structured, complete or effective in establishing a value for the initiating event probability.

A second problem was evident in the communication between the various components (headquarters, regional office, regional inspector at Davis-Besse) of the NRC. The resident inspector appears to have played little or no role in providing information relevant to the issues being analyzed at NRC HQ. Further, there appears to have been no communication between the resident inspector and HQ. In the December 11th interview with the review team, Mr. Strosnider stated that it was rare one would think a resident inspector would offer substantive help. He did not believe that the resident inspector at Davis-Besse was, in fact, contacted. He also believed that the resident inspector is busy with other things, and that he probably had not been part of the vessel head inspections, and that he lacked the technical aptitude needed to contribute to the issue.

There were several indications of operational irregularities that should have been noted by an inspector in residence at the plant. These include: 1) radiological surveys showing a contamination plume effect originating from the service structure ventilation exhaust over the East D-ring [Dye02], 2) significant increase in the cleaning of containment air coolers, 3) the removal of fifteen, 5-gallon buckets of boric acid from the ductwork and plenum of the containment air coolers and the discovery of significant boric acid elsewhere in the containment, such as service water piping, stairwells, and other areas of low ventilation, and 4) the sudden change to rust-colored boric acid in June of 1999. That these events were occurring without the knowledge or appreciation of the resident NRC inspector highlights a major weakness of the role of the resident inspector in helping to ensure safe operation of the plant at which he/she is stationed.

6.3 Arbitrariness of the Requested Shutdown Date

The 12/31/01 date for completing inspections of reactor vessel head nozzles imposed on licensees by the NRC was arbitrarily set. The arbitrariness of the 12/31/01 date was confirmed by Brian Sheron in his interview with the review committee in which he stated that there was nothing magical about the December 31st date, and that it just as easily could have been February 28th or March 31st.

The arbitrariness of the date caused difficulty for the NRC when challenged by FENOC. The challenge resulted in a perceived reversal of the burden of proof from the licensee to the NRC. NRC believed that they needed to make a case in order to force a shutdown of DB to look for cracks. Unfortunately, their authority to act was perceived to be undermined by the lack of a defensible rationale for the selection of the inspection date.

NRC has been encouraging the use of risk analysis as part of the risk-informed decision-making process. Yet NRC did not consider including risk analysis in the original call for inspection. The inclusion of risk analysis in the formulation of the inspection date could have provided the NRC with the justification for enforcement that they lacked under the present circumstances. If the call for inspection were based on a risk-informed decision-making strategy, then the calculations of the likelihood of nozzle failure and LOCA would have provided the support they needed to call for an inspection. The practical considerations in this strategy are not trivial. Yet had NRC followed its commitment to incorporate risk analysis in its decision-making process at the outset, the decision regarding Davis-Besse may have been much more straightforward.

6.4 The Role of NRC's Advisory Committee on Reactor Safeguards

Although we recognize that ACRS does not provide routine guidance on plant-specific issues, we feel that NRC staffs should have recognized the CRDM nozzle failures as a generic issue and should have solicited in-depth assistance from ACRS before the 28 November 2001 decision. Thus, relying on a narrow interpretation of the CRDM nozzle failure issues, the staff missed an opportunity to obtain important expert perspectives on the issues. We recommend that the NRC staff make more direct use of ACRS to augment in-house expertise on the staff, which may be limiting at times.

6.5 NRC Staff Workload Affecting Its Ability for Detailed Risk Assessment

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An NRC manager raised the question if NRC had sufficient personnel, given the workload, to perform detailed studies on complex regulatory or licensing issues such as the Davis-Besse case. Although the upper level management seems to be satisfied with the overall staff performance, we recommend a review of the workload and technical competence of the staff required to provide licensing and regulatory support in a timely manner.

6.6 Davis-Besse, NRC, and Three Mile Island

The human errors on the parts of Davis-Besse and NRC, resulting in a near miss of a serious accident, echo a similar chain of events that originated at Davis-Besse in 1977 and culminated in America's most serious reactor accident at Three Mile Island in 1979. It began in September 1977 at Davis-Besse when a relief valve on the reactor coolant pressurizer stuck open. The coolant pressure fell but the water level in the pressurizer increased, the result of an anomaly in the pressurizer piping. Thinking that the reactor was getting too much water, the operator improperly interfered with the high-pressure injection system. Fortunately, a supervisor recognized what was happening and closed the relief valve twenty minutes later and re-admitted coolant. No damage was done to the reactor because it had been operating at only 9 percent power.

The incident was investigated by both NRC and by B&W, the reactor supplier, but no information calling attention to the correct operating actions was provided to other utilities. A B&W engineer had stated in an internal memorandum that if the Davis-Besse event had occurred in a reactor operating at full power, "it is quite possible, perhaps probable, that core uncovering and possible fuel damage would have occurred."

In 1978 an NRC official pointed out the likelihood of erroneous operator action in B&W reactors. The NRC did not notify utilities about the lessons learned at Davis-Besse and the pressing need for new training to avoid the confusing interpretation of water level indicators at B&W plants. Fourteen months later the core-melt accident happened at Three Mile Island.

In March 1979, a similar B&W reactor was operating at full power at Three Mile Island in Pennsylvania. Again, the pressure relief valve stuck open, reactor coolant escaped, coolant pressure fell and the operators made the same mistake as had the operators two years earlier at Davis-Besse. They turned off the high-pressure coolant injection. Unfortunately, the ensuing control room confusion did not lead to early diagnosis and restoration of reactor water. With the high-pressure injection water incorrectly turned off, the reactor continued to generate heat and boil coolant, ultimately uncovering the reactor core and melting a substantial portion of the reactor fuel. When a supervisor finally diagnosed the problem and restored high-pressure injection water, some two hours later, enormous fuel damage had been done and considerable radioactivity released to the reactor building.

The President's Commission on the Accident at Three Mile Island [Kem79] concluded that the major factor that turned the TMI incident into a serious accident was inappropriate operator action, deficiencies in training and failure of responsible organizations, especially the NRC, to learn the proper lessons from previous incidents. There was a serious lack of recognition of the safety implications of new information and there was serious lack of questioning of the adequacy of assumptions made in the reactor design, in the operating procedures, and in the follow up of events. The Commission concluded that, starting with the Davis-Besse 1977 event and given all the deficiencies of the safety system and its regulation, an accident like Three Mile Island was eventually inevitable.

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For many months and even years it was not realized that the TMI accident had resulted in such extensive core damage. More responsive earlier analyses by NRC of the 1977 Davis-Besse precursor event and its potential consequences would have alerted NRC to forewarn the utilities of the incipient danger. Similarly, the seeming lack of aggressive followup by NRC and industry to understand the risks from the recent near miss at Davis-Besse is a serious concern. History should not be allowed to repeat itself.

**7. Recommendations for Improved Use of Probabilistic Risk Assessment**

There are several ways in which NRC can improve the use of PRA in its decision-making process:

(1) Establish an appreciation for PRA across the spectrum of NRC technical and managerial personnel. There is great divergence in the appreciation for, and understanding of PRA and its value in the decision-making process. In a sense, NRC needs to get their staff "on the same page" with regard to PRA applications in regulatory and licensing issues.

(2) Establish a set of guidelines for the use of PRA in decision-making. No guidelines currently exist for how PRA should be incorporated into the decision-making process other than the general philosophy that risk analysis should be part of a risk-informed decision-making process. A set of guidelines that establishes the level and nature of consideration of PRA is needed. In particular, guidance should be provided on how to balance PRA results against deterministic or qualitative evaluations, especially when the PRA results are subject to large uncertainties.

(3) Establish a set of guidelines for how decisions are made at NRC and by whom. This is a necessary precursor to the success of recommendation 2. The decision-making process must be defined in order to incorporate risk analysis into that process. Further, the offices and individuals responsible for making decisions need to be defined in order to successfully determine who needs to be aware of and familiar with PRA as discussed in recommendation 1.

(4) Establish a better protocol for estimating and incorporating uncertainties in PRA. PRA results without associated uncertainties are of little value. As a result, it is difficult to incorporate results of an analysis into a decision strategy without an understanding of the bounds of the validity of the result.

(5) Provide for unanticipated events. Corrosion of the Davis-Besse pressure vessel head was not an anticipated event. As put by NRC personnel, it was not even on the radar screen. As such, it was not incorporated into the event tree analysis in PRA. However, PRA needs to be able to anticipate the consequences of such oversight.

(6) Establish a better system at NRC for recognizing generic problems and transmitting information and concerns about these potential problems to other plants.

(7) NRC should issue preliminary analyses of risks from nozzle cracking that include leakage through axial cracks, evaporation of leaking coolant, concentration of and corrosion by boric acid, corrosion of the carbon-steel vessel and the vessel liner, the time-dependent probability of rupture of the corroded vessel, core damage resulting from loss of coolant, and the effects of human failure to make and interpret surveillance inspections. The results and possible interpretations of the recent Oak Ridge tests of vessel failure should be made known to the safety community.

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# Davis-Besse Task Force Recommendations to NRC and Their Status, as of March 2004

| Recommendation | NRC actions and status as of March 2004 |
| --- | --- |
| **Completed recommendations** | |
| Either fully implement or revise guidance to manage licensee commitments. Determine whether the periodic report on commitment changes submitted by licensees should continue. | Revised instructions for these submittals and reviews to ensure that these tasks are accomplished. Completed in May 2003. |
| Determine if stress corrosion cracking models are appropriate for predicting susceptibility of vessel head penetration nozzles to pressurized water stress corrosion cracking. Determine if additional analysis and testing is needed to reduce modeling uncertainties for their continued applicability in regulatory decision making. | Evaluated existing stress corrosion cracking models for their continuing use in determining susceptibility. Completed in July 2003. |
| Revise the problem identification and resolution approach so that safety problems noted in daily licensee reports are reviewed and assessed. Enhance guidance to prescribe the format of information that is screened when deciding which problems to review. | Revised inspection procedure for determining licensee ability to promptly identify and resolve conditions adverse to quality or safety. Completed in September 2003. |
| Provide enhanced inspection guidance to pursue issues and problems identified during reviews of plant operations. | Revised inspection procedure for determining licensee capability to promptly identify and resolve conditions adverse to quality or safety. Completed in September 2003. |
| Revise inspection guidance to provide for longer-term follow-up of previously identified issues that have not progressed to an inspection finding. | Revised inspection procedure for determining licensee capability to promptly identify and resolve conditions adverse to quality or safety. Completed in September 2003. |
| Revise inspection guidance to assess (1) the safety implications of long-standing unresolved licensee equipment problems, (2) the impact of phased in corrective actions, and (3) the implications of deferred plant modifications. | Revised inspection procedure for determining licensee capability to identify and resolve conditions adverse to quality or safety. Completed in September 2003. |
| Revise inspection guidance to allow for establishing reactor oversight panels even when a significant performance problem, as defined under NRC's Reactor Oversight Process, does not exist. | Revised inspection guidance for establishing reactor oversight panels. Completed in October 2003. |
| Assess the scope and adequacy of requirements for licensees to review operating experience. | Included in NRC's recommendation to develop a program for collecting, analyzing, and disseminating information on experiences at operating reactors. Completed in November 2003. |
| Ensure inspector training includes (1) boric acid corrosion effects and control, and (2) pressurized water stress corrosion cracking of nickel-based alloy nozzles. | Developed and implemented Web-based training and a means for ensuring training is completed. Completed in December 2003. |
| Provide training and reinforce expectations to managers and staff to (1) maintain a questioning attitude during inspection activities, (2) develop inspection insights from Davis-Besse on symptoms of reactor coolant leakage, (3) communicate expectations to follow up recurring and unresolved problems, and (4) maintain an awareness of surroundings while conducting inspections. Establish mechanisms to perpetuate this training. | Developed Web-based inspector training and a means for ensuring that training has been completed. NRC headquarters provided an overview of the training to NRC regional offices. (Training modules will be added and updated as needed.) Completed in December 2003. |
| Reinforce expectations that regional management should make every effort to visit each reactor at least once every 2 years. | Discussed at regional counterparts meeting. Completed in December 2003. |
| Develop guidance to address impacts of regional oversight panels on regional resource allocations and organizational alignment. | Evaluated past and present oversight panels. Developed enhanced inspection approaches for oversight panels and issued revised procedures. Completed in December 2003. |

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| Recommendation | NRC actions and status as of March 2004 |
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| Evaluate (1) the capacity to retain operating experience information and perform long-term operating experience reviews; (2) thresholds, criteria, and guidance for initiating generic communications; (3) opportunities for more gains in effectiveness and efficiency by realigning the organization (i.e., feasibility of a centralized operating experience "clearinghouse"); (4) effectiveness of the generic Issues program; and (5) effectiveness of internal dissemination of operating experience information to end users. | Developed program objectives and attributes and obtained management endorsement of a plan to implement the recommendation. Developed specific recommendations to improve program. Evaluation completed in November 2003. (Implementation of recommendations resulting from this evaluation expected to be completed in December 2004.) |
| Ensure that generic requirements or guidance are not inappropriately affected when making unrelated changes to other programs, processes, guidance, etc. | Revised inspection guidance. Completed in February 2004. |
| Develop inspection guidance to assess scheduler influences on amount of work performed during refueling outages. | Revised the appropriate inspection procedure. Completed in February 2004. |
| Establish guidance to ensure that NRC decisions allowing licensees to deviate from guidelines and recommendations issued in generic communications are adequately documented. | Update guidance to address documentation. Develop training and distribute to NRC offices and regions to emphasize compliance with the updated guidance. Follow up to assess the effectiveness of the training. Completed follow-up in February 2004. |
| Develop or revise inspection guidance to ensure that NRC reviews vessel head penetration nozzles and the reactor vessel head during licensee inspection activities. | Develop or revise inspection guidance to ensure that nozzles and the vessel head are reviewed during licensee inspection. Issued interim guidance in August 2003 and a temporary inspection procedure in September 2003. Additional guidance expected in March 2004. |
| Develop inspection guidance to assess (1) repetitive or multiple technical specification actions in NRC inspection or licensee reports, and (2) radiation dose implications for conducting repetitive tasks. | Revise the appropriate inspection procedure to reflect this need. Completion expected in March 2004. |
| Develop guidance to periodically inspect licensees' boric acid corrosion control programs. | Issued temporary guidance in November 2003. Completion of further inspection guidance changes expected in March 2004. |
| Reinforce expectations for managers responsible for overseeing operations at nuclear power plants regarding site visits, coordination with resident inspectors, and assignment duration. Reinforce expectations to question information about operating conditions and strengthen guidance for reviewing license amendments to emphasize consideration of current system conditions, reliability, and performance data in safety evaluation reports. Strengthen guidance for verifying licensee-provided information. | Update project manager handbook that provides guidance on activities to be conducted during site visits and interactions with NRC regional staff. Also, revise guidance for considering plant conditions during licensing action and amendment reviews. Completion expected in March 2004. |
| Assemble and analyze foreign and domestic information on Alloy 600 nozzle cracking. If additional regulatory action is warranted, propose a course of action and implement a schedule to address the results. | Assemble and analyze alloy 600 cracking data. Completion expected in March 2004. |
| **Recommendations due to be completed between April and December 2004** | |
| Conduct an effectiveness review of actions taken in response to past NRC lessons-learned reviews. | Review past lessons-learned actions. Completion expected in April 2004. |
| Provide inspection and oversight refresher training to managers and staff. | Develop a training module. Completion expected in June 2004. |

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| Recommendation | NRC actions and status as of March 2004 |
|---|---|
| Establish guidance for accepting owners group and industry recommended resolutions for generic communications and generic issues, including guidance for verifying that actions are taken. | Revise office instructions to provide recommended guidance. Completion expected in June 2004. |
| Review inspection guidance to determine the inspection level that is sufficient during refueling outages, including inspecting reactor areas inaccessible during normal operations and passive components. | Revised an inspection procedure to reflect these changes. Some inspection procedure changes were completed in November 2003, and additional changes are expected in August 2004. |
| Evaluate, and revise as necessary, guidance for proposing candidate generic issues. | Evaluate and revise guidance. Completion expected in October 2004 |
| Assemble and analyze foreign and domestic information on boric acid corrosion of carbon steel. If additional regulatory action is warranted, propose a course of action and implement a schedule to address the results. | Review Argonne National Laboratory study on boric acid corrosion. Analyze data to revise inspection requirements. Completion expected in October 2004. |
| Conduct a follow-on verification of licensee actions to implement a sample of significant generic communications with emphasis on those that are programmatic in nature. | Screen candidate generic communications to identify those most appropriate for follow-up using management-approved criteria. Develop and approve verification plan. Completion expected in November 2004. |
| Strengthen inspection guidance for periodically reviewing licensee operating experience. | Incorporated into the recommendation pertaining to NRC's capacity to retain operating experience information. Completion expected in December 2004. |
| Enhance the effectiveness of processes for collecting, reviewing, assessing, storing, retrieving, and disseminating foreign operating experience. | Incorporated into the recommendation pertaining to NRC's capacity to retain operating experience information. Completion expected in December 2004. |
| Update operating experience guidance to reflect the changes implemented in response to recommendations for operating experience. | Incorporated into the recommendation pertaining to NRC's capacity to retain operating experience information. Completion expected in December 2004. |
| Review a sample of NRC evaluations of licensee actions made in response to owners groups' commitments to identify whether intended actions were effectively implemented. | Conduct the recommended review. Completion expected in December 2004. |
| Develop general inspection guidance to periodically verify that licensees implement owners groups' commitments. | Develop inspection procedure to provide a mechanism for regions to support project managers' ability to verify that licensees implement commitments. Completion expected in December 2004. |
| Conduct follow-on verification of licensee actions pertaining to a sample of resolved generic issues. | No specific actions have been identified. Completion expected in December 2004. |
| Review the range of baseline inspections and plant assessment processes to determine sufficiency to identify and dispose of problems like those at Davis-Besse. | No specific actions have been identified. Completion expected in December 2004. |
| Identify alternative mechanisms to independently assess licensee plant performance for self-assessing NRC oversight processes and determine the feasibility of such mechanisms. | No specific actions have been identified. Completion expected in December 2004. |
| Establish measurements for resident inspector staffing levels and requirements, including standards for satisfying minimum staffing levels. | Develop standardized staffing measures and implement details. Metrics were developed in December 2003. Completion expected in December 2004. |
| Structure and focus inspections to assess licensee employee concerns and a "safety conscious work environment." | No specific actions have been identified. Completion expected in December 2004. |

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| Recommendation | NRC actions and status as of March 2004 |
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| **Recommendations due to be completed in calendar year 2005** | |
| Develop inspection guidance and criteria for addressing licensee response to increasing leakage levels and/or adverse trends in unidentified reactor coolant system leakage. | Develop recommendations for guidance with action levels to trigger greater NRC interaction with licensees in response to increased leakage. Completion expected in January 2005. |
| Reassess the basis for the cancellation, in 2001, of certain inspection procedures (i.e., boric acid control programs and operational experience feedback) to assess if these procedures are still applicable. | Review revised procedures and reactivate as necessary. Completion expected in March 2005. |
| Assess requirements for licensee procedures to respond to plant alarms for leakage to determine whether requirements are sufficient to identify reactor coolant pressure boundary leakage. | Review and assess adequacy of requirements and develop recommendations to (1) improve procedures to identify leakage from boundary, (2) establish consistent technical specifications for leakage, and (3) use enhanced leakage detection systems. Completion expected in March 2005. |
| Determine whether licensees should install enhanced systems to detect leakage from the reactor coolant system. | Re-evaluate the basis for current leakage requirements and assess the capabilities of current leakage detection systems. Develop recommendations to (1) improve procedures for identifying leakage, (2) establish consistent technical specifications, and (3) use enhanced leakage detection systems. Completion expected in March 2005 |
| Inspect the adequacy of licensee's programs to control boric acid corrosion, including effectiveness of implementation. | Develop guidance to assess adequacy of corrosion control programs, including implementation and effectiveness, and evaluate the status of this effort after the first year of inspections. Guidance expected to be developed by March 2004. Follow-up scheduled for completion in March 2005. |
| Continue ongoing efforts to review and improve the usefulness of barrier integrity performance indicators and evaluate the use of primary system leakage that licensees have identified but not yet corrected as a potential indicator. | Develop and implement improved performance indicators based on current requirements and measurements. Explore the use of additional performance indicators to track the number, duration, and rate of system leakage. Determine the feasibility of establishing a risk-informed performance indicator for barrier integrity. Completion expected in December 2005. |
| **Recommendations whose completion dates have yet to be determined** | |
| Encourage the American Society of Mechanical Engineers to revise inspection requirements for nickel-based alloy nozzles. Encourage changes to requirements for nonvisual, nondestructive inspections of vessel head penetration nozzles. Alternatively, revise NRC regulations to address the nature and scope of these inspections. | Monitor and provide input to industry efforts to develop revised inspection requirements. Participate in American Society of Mechanical Engineers' meetings and communicate with appropriate stakeholders. Decide whether to endorse the revised American Society of Mechanical Engineers' code requirements. These actions parallel a larger NRC rulemaking effort. Completion date yet to be determined. |
| Revise processes to require short- and long-term verification of licensee actions to respond to significant NRC generic communications before closing out issues. | Target date to be set upon completion of review of NRC's generic communications program. Completion date yet to be determined. |
| Determine whether licensee reactor vessel head inspection summary reports should be submitted to NRC and, if so, revise submission requirements and report disposition guidance, as appropriate. | Will be included as part of revised American Society of Mechanical Engineers' requirements for inspection of reactor vessel heads and vessel head penetration nozzles. Completion date yet to be determined. |

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| Recommendation | NRC actions and status as of March 2004 |
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| Evaluate the adequacy of methods for analyzing the risk of passive component degradation and integrate these methods and risks into NRC's decision-making processes. | No specific actions have been identified. Completion date yet to be determined. |
| Review pressurized water reactor technical specifications to identify plants that have nonstandard reactor coolant pressure boundary leakage requirements and change specifications to make them consistent among all plants. | Assessed plants for nonstandard technical specifications. Completed in July 2003. Change leakage detection specifications in coordination with other changes in leakage detection requirements. Completion date yet to be determined. |
| Improve requirements for unidentified leakage in reactor coolant system to ensure they are sufficient to (1) discriminate between unidentified leaks from the coolant system and leaks from the reactor coolant pressure boundary and (2) ensure that plants do not operate with pressure boundary leakage. | Issue regulations implementing the improved requirements when these requirements are determined. Completion date yet to be determined. |
| NRC should review a sample of plant assessments conducted between 1998 and 2000 to determine if any identified plant safety issues have not been adequately assessed. | No specific actions have been identified. Completion expected in March 2004. |
| **Recommendations rejected by NRC management** | |
| Review industry approaches licensees use to consider economic factors for inspection and repair and consider this information in formulating future positions on the performance of non-visual inspections of vessel head penetration nozzles. | Recommendation rejected by NRC management. No completion date. |
| Revise the criteria for review of industry topical reports to allow for NRC staff review of safety-significant reports that have generic implications but have not been formally submitted for NRC review in accordance with the existing criteria. | Recommendation rejected by NRC management. No completion date. |

Source: GAO analysis of NRC data.

# Comments from the Nuclear Regulatory Commission

Note: GAO comments supplementing those in the report text appear at the end of this appendix.

UNITED STATES
**NUCLEAR REGULATORY COMMISSION**
WASHINGTON, D.C. 20555-0001

May 5, 2004

Mr. James Wells, Director
Natural Resources and Environment
United States General Accounting Office
441 G Street, NW
Washington, D.C. 20548

Dear Mr. Wells:

On behalf of the U.S. Nuclear Regulatory Commission (NRC), I am responding to your letter of April 2, 2004, requesting the NRC's review of the draft report entitled "Nuclear Regulation: NRC Needs to More Aggressively and Comprehensively Resolve Issues Related to the Davis-Besse Nuclear Power Plant's Shutdown" (GAO-04-415). I appreciate the opportunity to provide comments to the General Accounting Office (GAO) on this report.

I am concerned that the draft report does not appropriately characterize or provide a balanced perspective on the NRC's actions surrounding the discovery of the Davis-Besse reactor vessel head condition or NRC's actions to incorporate the lessons learned from that experience into our processes. The NRC also does not agree with two of the report's recommendations, as discussed in the following paragraphs.

See comment 1.

The first sentence of the draft report states: "...oversight did not generate accurate, complete information on plant conditions." I agree that our oversight program should have identified certain evolving plant conditions for regulatory follow-up. This was also identified in the report of the Davis-Besse Lessons Learned Task Force (LLTF) that the NRC formed to ensure that lessons from the Davis-Besse experience are learned and appropriately captured in the NRC's formal processes. However, the draft report does not acknowledge that the NRC, in carrying out its safety responsibilities, must rely heavily on our licensees to provide us with complete and accurate information. In fact, Title 10 of the Code of Federal Regulations Section 50.9 requires that information provided to the NRC by a licensee be complete and accurate in all material respects. The report should clearly indicate that NRC's licensees are responsible for providing us with accurate and complete information. While the NRC's Davis-Besse LLTF concluded that the NRC, the Davis-Besse licensee (FirstEnergy), and the nuclear industry failed to adequately review, assess, and follow up on relevant operating experience, they also noted that the information that FirstEnergy provided in response to Bulletin 2001-01, "Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles" was inconsistent with information identified by the task force. Further, the LLTF report stated that had this information been known in the fall of 2001, "...the NRC may have identified the VHP [vessel head penetration] nozzle leaks and RPV [reactor pressure vessel] head degradation a few months sooner than the March 2002 discovery by the licensee." As you are aware, there is an ongoing investigation by the Department of Justice regarding the completeness and accuracy of information that FirstEnergy provided to the NRC on the condition of Davis-Besse.

See comment 2.

The NRC is particularly concerned about the draft report's characterization of the NRC's use of risk estimates. The statement in the report that the NRC's "estimate of risk exceeded the risk

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levels generally accepted by the agency" is not factually correct. NRC officials pointed out to GAO and GAO's consultants, both in interviews and in written responses to GAO questions, that our estimate of delta core damage frequency was $5x10^{-6}$ per reactor year, not $5x10^{-5}$ per reactor year as indicated in the report. In fact, the NRC staff safety evaluation (attached to a December 3, 2002, letter to FirstEnergy) stated that the change in core damage frequency due to the potential for control rod drive mechanism nozzle ejection was consistent with the guidelines of Regulatory Guide 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis." The enclosure to this letter provides detailed comments on issues of correctness and clarity in the report, many of which are related to the NRC's estimate of risk at Davis-Besse.

See comment 3.

We disagree with the finding that the NRC does not have specific guidance for deciding on plant shutdowns and with the report's related recommendation identifying the need for NRC to develop specific guidance and a well-defined process for deciding when to shut down a nuclear power plant. We believe our regulations, guidance, and processes that cover whether and when to shut down a plant are robust and do, in fact, provide sufficient guidance in the vast majority of situations. Plant technical specifications, as well as many other NRC requirements and processes, provide a spectrum of conditions under which plant shutdown would be required. Plants have shut down numerous times in the past in accordance with NRC requirements. From time to time, however, a unique situation may present itself wherein sufficient information may not exist or the information available may not be sufficiently clear to apply existing rules and regulations definitively. In these unique instances, the NRC's most senior managers, after consultation with staff experts and given all of the information available at the time, will decide whether or not to require a plant shutdown. Risk information is used in accordance with Regulatory Guide 1.174. This process considers deterministic factors as well as probabilistic factors (i.e., risk information). We regard the combined use of deterministic and probabilistic factors to be a strength of our decision-making process.

See comment 4.

Another issue identified in the draft report as a systemic weakness is that the NRC has not proposed specific actions to address a licensee's commitment to safety, also known as safety culture. We disagree with the report's recommendation that NRC should develop a methodology to assess licensees' safety culture that includes indicators of and/or information on patterns of licensee behavior, as well as on licensee organizational structures and processes. To date, the Commission has specifically decided not to conduct direct evaluations or inspections of safety culture as a routine part of assessing licensee performance due to the subjective nature of such evaluations. As regulators, we are not charged with managing our licensees' facilities. Direct involvement with safety culture, organizational structure, and processes crosses over to a management function. The NRC does conduct a number of assessments that adequately evaluate how effectively licensees are managing safety. These include an inspection procedure for assessing licensees' employee concerns programs, the NRC allegation program, enforcement of employee protection regulations, and safety-conscious work environment assessments during problem identification and resolution (PI&R) inspections. In addition, the NRC's LLTF made several recommendations (which are being addressed) to enhance the NRC's capability in this area. The NRC does not assess, nor does it plan to assess, licensee management competence, capability, or optimal organizational structure as part of safety culture.

See comment 5.

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While there are a number of factual errors in the draft report, as noted in the enclosure, we agree with many of the findings in the draft report. Most of GAO's findings are similar to the findings of the NRC's Davis-Besse LLTF. The NRC staff has made significant progress in implementing actions recommended by the LLTF and expects to complete implementation of more than 70 percent of them, on a prioritized basis, by the end of calendar year 2004. Reports tracking the status of these actions are provided to the Commission semiannually and will continue until all items are completed, at which time a final summary report will be issued.

I have enclosed the NRC's detailed comments on the draft report. If you have any questions, please contact Stacey L. Rosenberg, of my staff, at (301) 415-3868.

Sincerely,

William D. Travers for
Executive Director
for Operations

Enclosure:
1. NRC Comments on GAO Draft Report on Davis-Besse
2. Memorandum from EDO to OIG dated April 19, 2004

**NRC Comments on Draft Report, GAO-04-415**

See comment 1.

1. The draft report does not speak to a key issue, the responsibility of licensees to provide complete and accurate information to the NRC. In carrying out its safety responsibilities, NRC must rely heavily on our licensees to provide us with complete and accurate information. Title 10 of the Code of Federal Regulations Section 50.9 requires that information provided to the NRC by a licensee be complete and accurate in all material respects. By not recognizing this explicitly and its role in this matter, the draft report conveys the expectation that the NRC staff should have known about the thick layer of boron on the reactor vessel head. The Davis-Besse Lessons Learned Task Force (LLTF), which NRC formed to ensure that lessons from the Davis-Besse experience are learned and appropriately captured in the NRC's formal processes, noted that the information that FirstEnergy provided in response to Bulletin 2001-01, "Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles" was inconsistent with information identified by the task force. Further, the LLTF report stated that had this information been known in the fall of 2001, the NRC may have identified the vessel head penetration (VHP) nozzle leaks and reactor pressure vessel (RPV) head degradation a few months sooner than the March 2002 discovery by the licensee. See also the related information in response #2.

See comment 2.

2. Page 7, first sentence of the last paragraph states: ***"NRC should have but did not identify or prevent the vessel head corrosion at Davis-Besse because both its inspections at the plant and its assessments of the operator's performance yielded inaccurate and incomplete information on plant safety conditions."***

<u>Response</u>: This statement is misleading. We agree that our oversight program should have identified certain evolving plant conditions for regulatory follow-up. This was also

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identified in the report of the Davis-Besse Lessons LLTF. It is the responsibility of licensees to provide the NRC with complete and accurate information. In fact, Title 10 of the Code of Federal Regulations Section 50.9 requires that information provided to the NRC by a licensee be complete and accurate in all material respects. The report should clearly indicate that NRC's licensees are responsible for providing us with accurate and complete information. While the NRC's Davis-Besse LLTF concluded that the NRC, the Davis-Besse licensee (FirstEnergy), and the nuclear industry failed to adequately review, assess, and follow up on relevant operating experience, the LLTF also noted that the information that FirstEnergy provided in response to Bulletin 2001-01 was inconsistent with information identified by the task force. Further, the LLTF report stated that had this information been known in the fall of 2001, the NRC may have identified the vessel head penetration nozzle leaks and the reactor vessel head degradation a few months sooner than the March 2002 discovery by the licensee. As you are aware, there is an ongoing investigation by the Department of Justice regarding the completeness and accuracy of information that FirstEnergy provided to the NRC on the condition of Davis-Besse.

See comment 3.

3. Page 8, last sentence states: ***"Further, the risk estimate indicated that the likelihood of an accident occurring at Davis-Besse was greater than the level of risk generally accepted as being reasonable by NRC."***

Response: This is incorrect. NRC staff explained to the GAO consultants that NRC guidance produces an estimate for the change in core damage frequency of $5x10^{-6}$ per year, not $5x10^{-5}$ as indicated in the GAO report. According to Regulatory Guide (RG) 1.174, for Davis-Besse, this estimate is within acceptable bounds. NRC specifically documented the acceptability of the estimate in the December 2002 assessment. Thus, the December 3, 2002, safety evaluation concluded that the delta core damage frequency was consistent with the guidelines of RG 1.174.

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See comment 6.

4. Page 15 states that borax (i.e., sodium borate) is dissolved in the water. This is incorrect. Please replace the word "borax" with "boric acid crystals."

See comment 7.

5. Page 18, first full paragraph states: ***"NRC, in deciding on when FirstEnergy had to shutdown Davis-Besse for the inspection,..."***

   Response: In addition, the staff relied upon information provided by the licensee regarding the condition of the vessel head (i.e., previous leakage and action taken to repair leaks and clean the vessel head).

See comment 8.

6. Page 26, beginning on line 4, states: ***"According to the NRC regional branch chief—who supervised the staff responsible for overseeing FirstEnergy's vessel head inspection activities during the 2000 refueling outage—he was unaware of the boric acid leakage issues at Davis-Besse, including its effects on the containment air coolers and the radiation monitor filters."***

   Response: According to the individual to whom this statement is attributed, the statement would be correct if the phrase, "he was unaware...filters" is changed to "he was unaware that boric acid was found on the reactor vessel head during the outage."

See comment 9.

7. Page 27, first sentence states: ***"Similarly, NRC officials said that NRC headquarters had no systematic process for communicating information in a timely manner to its regions or on-site inspectors."***

   Response: If the "information" in question refers to issues of potential safety significance into which inspectors should look, then this statement is inaccurate. The systematic process for temporarily focusing inspection activity in a coordinated program-wide manner on high-priority issues is the "Temporary Instruction" (TI) process, which is well established within the NRC Inspection Manual and frequently used. The legitimate point

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to be made is that until the Davis-Besse event, the NRC had not concluded that boric acid corrosion was a sufficient safety concern that reached the threshold for using the TI process.

See comment 10.

8. Page 33, middle paragraph states: ***"For example, concern over alloy 600 cracking led France, as a preventive measure, to develop plans for replacing all of its reactor vessel heads and installing removable insulation to better inspect for cracking."***
Response: French regulators instituted requirements for an extensive, non-visual nondestructive examination inspection program for vessel head penetration nozzles that resulted in plant operators deciding, on the basis of economic considerations, to replace vessel heads in lieu of conducting such examinations.

See comment 11.

9. Page 34, last paragraph states: ***"If such small leakage can result in such extensive corrosion..."***
Response: Small leakage alone was not the cause of the corrosion. It was a combination of prolonged leakage in conjunction with allowing caked-on boron to remain on the vessel head.

See comment 12.

10. Page 36, middle paragraph states: ***"However, NRC decided that it could not order Davis-Besse to shut down on the basis of other plants' cracked nozzles and identified leakage or the manager's acknowledgment of a probable leak. Instead, it believed it needed more direct, or absolute, proof of a leak to order a shutdown."***
Response: As discussed at the NRC-GAO exit conference, plant Technical Specifications, as well as many other NRC requirements and processes, provide a number of circumstances in which a plant shutdown would or could be required, including the existence of reactor coolant pressure boundary leakage while operating at power.

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Please note that there was no legal objections to the draft order and the stated basis for deciding to not issue the order was not an insufficient legal basis.

11. Page 36, last paragraph states: ***"...NRC does not have specific guidance for shutting down a plant when the plant may pose a risk to public health and safety even though it may be complying with NRC requirements."***

See comment 4.

Response: We disagree with this finding and with the report's related recommendation on Page 63 identifying the need for NRC to develop specific guidance and a well-defined process for deciding when to shut down a nuclear power plant. We believe our regulations, guidance, and processes that cover whether and when to shut down a plant are robust and do, in fact, provide sufficient guidance in the vast majority of situations. Plant technical specifications, as well as many other NRC requirements and processes, provide a spectrum of conditions under which plant shutdown would be required. Plants have shut down numerous times in the past in accordance with NRC requirements. From time to time, however, a unique situation may present itself wherein sufficient information may not exist or the information available may not be sufficiently clear to apply existing rules and regulations definitively. In these unique instances, the NRC's most senior managers, after consultation with staff experts and given all of the information available at the time, will decide whether or not to require a plant shutdown. Risk information is used in accordance with RG 1.174. This process considers deterministic factors as well as probabilistic factors (i.e., risk information). We regard the combined use of deterministic and probabilistic factors to be a strength of our decisionmaking process.

See comment 13.

12. Page 38, third paragraph states: ***"At some point during this time, NRC staff also concluded that the first safety principle was probably not being met, although the basis for this conclusion is not known."***

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<u>Response</u>: The report should clarify GAO's basis for this statement. NRC staff believed that the regulations were met.

13. Page 40, last paragraph states: ***"However, NRC did not provide the assessment until a full year later—in December 2002. In addition, the December 2002 assessment, which includes a 4-page evaluation, does not fully explain how the safety principles were used or met—other than by stating that if the likelihood of nozzle failure were judged to be small, then adequate protection would be ensured."***

See comment 14.

<u>Response</u>: The attachment to the December 3, 2002, letter is an 8-page evaluation, not 4 pages. We note this to make sure GAO is referring to the same document. The assessment addresses four of the five safety principles. In the NRC's December 2002 safety evaluation, the staff stated that the criterion related to compliance with the regulations was being met because the inspections performed by the licensee were in conformance with the ASME Code. In addition, the safety evaluation stated that Davis-Besse met the criterion related to defense-in-depth because all three barriers against release of radiation were intact and reliable; they met the margin criterion because even the largest circumferential cracks found in pressurized-water reactors had considerable margin to structural failure, and they met the low-risk impact criterion based on a comparison of delta core damage frequency estimates with the guidelines of RG 1.174. The fifth safety principle, requiring a monitoring program, was not relevant to a decision that lasted only 6 weeks.

14. Page 42, first paragraph states: ***"Multiplying these two numbers, NRC estimated that the potential for a nozzle to crack and cause a loss-of-coolant accident would increase the frequency of core damage at Davis-Besse by about 5.4x10⁻⁵ per year, or about 1 in 18,500 per year. Converting this frequency to a probability, NRC***

See comment 15.

***calculated that the increase in probability of core damage was approximately $5.0x10^{-6}$, or 1 chance in 200,000. While NRC officials currently disagree that this was the number it used, this is the number that it included in its December 2002 assessment provided to FirstEnergy. Further, we found no evidence in the agency's records to support NRC's current assertion."***

Response: These statements mischaracterize the facts. NRC estimated that the probability of nozzle cracking leading to a loss-of-coolant accident during the first 6 weeks in 2002 would increase the annual core damage frequency (CDF) by about $5.4x10^{-6}$ per year, or about 1 in 185,000 per year. The estimate of $5x10^{-5}$ was an intermediate step in our calculation. The estimate of $5x10^{-5}$ represents the change in CDF if Davis-Besse were allowed to operate for one year without shutting down for inspection of the vessel head. Allowing Davis-Besse to continue to operate for one year was never a consideration. Thus, multiplying by the fraction of time in one year under consideration (in this case 7 weeks) was the final step in the calculation of delta CDF. The confusion about the estimate NRC used in the decisionmaking process may be due to NRC's method of calculating delta CDF for plant conditions which do not persist for the entire year. If this final step (the fraction of the year the plant is allowed to operate) were not part of the calculation, then the risk estimate of allowing the licensee to continue to operate for 7 weeks, as compared to one year, would be the same. Logically, this does not make sense. Therefore, the estimate of $5x10^{-5}$ does not automatically convert to a probability, as GAO's statement implies. Because the period of operation under consideration was approximately 0.13 years, the annual average change in CDF was about $5x10^{-6}$ per year, and the increase in the probability of core damage was about $5x10^{-6}$ as well. NRC officials **agree** that $5x10^{-6}$ was the estimate used in the decisionmaking process and is the estimate provided in the December 2002 assessment.

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15. Page 42, second paragraph states: ***"For example, the consultants concluded that NRC's estimate of risk was incorrectly too small, primarily because the calculation did not consider corrosion of the vessel head."***

See comment 16.

Response: An underlying assumption in any risk assessment is that you have complete and accurate information from the licensee. NRC staff was of the understanding that efforts had been made to remove boric acid accumulation from the vessel head during previous outages. For all six B&W plants that found signs of penetration leakage, the leakage manifested itself in the form of small amounts of dry boron crystals on the vessel head, which are not corrosive, and did not produce any corrosion on the vessel heads of these six B&W plants. Boron leaking onto a clean vessel head does not cause corrosion. Therefore, corrosion this extensive was not anticipated at the time. Also, it is important to note that had Davis-Besse shut down on December 31, 2001, the same corrosion would have been found.

16. Page 43, first full paragraph discusses the experience at French nuclear power plants.

See comment 17.

Response: The NRC staff was aware of the issue as illustrated in an internal memorandum dated December 15, 1994, from Brian Grimes to Charles Rossi.

17. Page 44, first full paragraph states: ***"Third, NRC's analysis was inadequate because the risk estimates were higher than generally considered acceptable under NRC guidance. Despite PRA's [probabilistic risk assessment's] important role in the decision, our consultants found that NRC did not follow its guidance for ensuring that the estimated risk was within levels acceptable to the agency.*** Page 45, first paragraph states: ***"...NRC's PRA estimate for Davis-Besse resulted in an increase in the frequency of core damage of $5.4x10^{-5}$ or 1 chance in about 18,500 per year was higher than the acceptable level."***

See comment 18.

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Response: This conclusion is not supported by the facts and it is misleading. The estimate referenced by GAO is an intermediate calculation in our process, and was not used, and should not be used, in the decisionmaking process. NRC staff explained to the GAO consultants that NRC guidance produces an estimate for the change in core damage frequency of $5x10^{-6}$ per year, not $5x10^{-5}$ as indicated in the GAO report. According to RG 1.174, for Davis-Besse, this estimate is within acceptable bounds. NRC specifically documented the acceptability of the estimate in the December 2002 assessment. Thus, the December 3, 2002, safety evaluation concluded that the delta CDF was consistent with the guidelines of RG 1.174.

18. Page 45, first paragraph states: ***"NRC's guidance for evaluating requests to relax NRC technical specifications suggests that a probability increase higher than $5x10^{7}$ or 1 chance in 2 million is considered unacceptable for relaxing the specifications. Thus, NRC's estimate would not be considered acceptable under this guidance."***

See comment 19.

Response: This criterion in RG 1.177 is not relevant to the Davis-Besse decision. It is confined to decisions on allowed outage times (AOT) for equipment, and is defined to avoid very high instantaneous risks (CDF > $10^{-3}$) for very short periods (5 hours).

19. Page 46, first full paragraph states: ***"Lastly, NRC's analysis was inadequate because the agency does not have clear guidance for how PRA estimates are to be used in the decision-making process."***

See comment 20.

Response: The NRC's process for risk-informed decision-making is considerably more robust than characterized in this section. Regulatory Guide 1.174 comprises 40 pages of guidance on how to use risk in decisions of this type, and it is backed up by equally detailed guidance for specific types of decisions such as technical specifications, in-service inspection programs, in-service testing, and quality assurance. The NRC has

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amassed a great deal of experience in application of the guidance. Risk assessment is a tool to help better inform decisions that are based on engineering judgements.

20. Page 46, last paragraph states: ***"It is not clear how NRC staff used the PRA risk estimate in the Davis-Besse decision-making process."***
Response: The December 3, 2002, safety evaluation clearly states how the PRA estimate was used in the decisionmaking process; the estimate was compared with the guidelines of RG 1.174. The safety evaluation also points out that NRC staff who are expert in non-PRA disciplines such as probabilistic fracture mechanics, gave more weight to deterministic factors, such as the structural margin that remains in the nozzles with circumferential cracks. The NRC considers the combined use of deterministic and probabilistic factors to be a strength of our decisionmaking process.

See comment 21.

21. Page 48, last paragraph states: ***"...NRC had made progress in implementing the recommendations, although some completion dates have slipped."***
Response: The schedules for implementation of all high priority recommendations have not slipped. The implementation schedule for certain low or medium priority recommendations slip only in accordance with NRC's Planning, Budgeting and Performance Management (PBPM) process, which explicitly considers safety significance when making budget priority decisions.

See comment 22.

22. Page 51, top of page, first full bullet states: ***"One recommendation is directed at improving NRC's generic communications program. NRC is..."***
Response: We recommend re-wording this as follows: "One recommendation is directed at improving follow up of licensee actions taken in response to NRC generic communications. A Temporary Instruction (Inspection Procedure) is currently being

See comment 23.

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developed to assess the effectiveness of licensee actions taken in response to generic communications. Additionally, improvements in the verification of effectiveness of generic communications are planned as a long-term change in the operating experience program."

See comment 24.

23. Page 51, last paragraph states: ***"...NRC's revised inspection guidance for more thorough examinations of reactor vessel heads and nozzles, as well as new requirements for NRC oversight of licensees' corrective action programs, will require at least an additional 200 hours of inspection per reactor per year."***
Response: It is unclear where this number comes from, but the changes to the corrective action program procedure require only about 16 hours per reactor year for the trend review.

See comment 25.

24. Page 53, first paragraph discusses the NRC's Office of the Inspector General's (OIG's) findings on communications.
Response: The NRC's actions are not limited primarily to improving communication about boric acid corrosion and cracking. There are multiple task force recommendations, and other NRC initiatives, that are aimed at addressing the broader implications stemming from communication lapses noted by the task force and the OIG. For example, actions have been implemented to more effectively disseminate operating experience to end users, reenforce a questioning attitude in the inspection staff, and discuss Davis-Besse lessons learned at various forums.

NRC's initial response to the OIG did not directly address the broader actions we are taking to improve communications. Our response to the OIG only indirectly addressed this by discussing the operating experience program enhancements. Part of the

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enhancements to the operating experience program is the expectations for improved communications. In addition, communication improvement initiatives with internal and external stakeholders are in progress to address shortcomings in this critical area. Our revised response to the OIG on this issue, dated April 19, 2004, is provided as Enclosure 2.

25. Page 53, second paragraph states: ***"NRC's Davis-Besse task force did not make any recommendations to address two systemic problems: evaluating licensees' commitment to safety and improving the agency's process for deciding on a shutdown."***

See comment 26.

Response: The LLTF did not make a recommendation for improving the agency's process for deciding on a shutdown. This area was not reviewed in detail by the task force because of coordination with the OIG. Moreover, the task force review efforts were focused on why the degradation cavity was not prevented. While related, the shutdown issue had little to do with the degradation cavity.

See comment 5.

The task force made multiple recommendations aimed at enhancing NRC's capability to evaluate the licensees' commitment to safety, by indirect means. Refer to task force recommendations: 3.2.5(1), 3.2.5(2), 3.3.2(2), 3.3.4(5), and Appendix F.

26. Page 54, last paragraph states: ***"This problem identification and resolution inspection procedure is intended to assess the end-results of management's safety commitment rather than the commitment itself."***

See comment 5.

Response: This statement is inaccurate. Regarding its accuracy, the PI&R inspection procedure (IP 71152) actually has six stated inspection objectives (refer to section 71152-01) including: (1) provide for early warning of potential performance issues that could

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result in crossing threshold in the action matrix and (2) to provide insights into whether licensees have established a safety-conscious work environment. Using this IP, inspectors seek factual evidence of the licensee's assumed commitment to safety (by reviewing their identification and correction of actual problems). Inspection issues routinely are raised with regard to a licensee's weakness in correcting recurrent problems or in adequately addressing issues that could become a future significant safety concern. The statement on Page 55 of the report, ***"Furthermore, because NRC directs its inspections at problems that it recognizes as being more important to safety, NRC may overlook other problems until they develop into significant and immediate safety problems"*** does not accurately reflect the stated objectives and demonstrable implementation of IP 71152.

27. Pages 55-56, discuss safety culture.

See comment 5.

Response: To a significant degree, the areas referenced in this draft report are addressed either by NRC requirements or inspection activities. For example, the NRC has requirements limiting work hours for critical plant staff members such as security officers and plant operators. The NRC has requirements governing operator training. Inspectors routinely monitor various licensee meetings and job briefings to evaluate the licensee's emphasis on safety.

Moreover, the NRC has a number of other means to indirectly assess safety culture. Other NRC tools that provide indirect insights into licensee safety culture include:

- inspection procedure for assessing the licensee's employee concerns program,
- NRC's allegation program,
- enforcement of employee protection regulations,

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- Safety-Conscious Work Environment (SCWE) assessments during problem identification and resolution inspections,
- lessons-learned reviews such as the one conducted for the Davis-Besse reactor pressure vessel head degradation; and
- Reactor Oversight Process cross-cutting issues of human performance, problem identification and resolution, and SCWE.

See comment 27.

28. Page 58, paragraph under the first header states: ***"It recognized that NRC's written rationale for accepting FirstEnergy's justification for continued plant operation was not prepared until 1 year after its decision..."***

    Response: For clarification, the documentation of the decision about one year later was corrective action from a task force finding.

See comment 28.

29. Page 58, paragraph under second header states: ***"The NRC task force did not address NRC's failure to learn from previous incidents at power plants and prevent their recurrence."***

    Response: This sentence is factually inaccurate. The task force performed a limited review of past lessons-learned reports and actually identified many more potentially recurring programmatic issues as a result of that review than the three examples cited by the GAO in this section of the draft report. As discussed during the NRC-GAO exit conference, the task force made a recommendation to perform a more detailed effectiveness review of the actions stemming from other past NRC lessons learned reviews (Appendix F). This review is currently in progress.

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UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

April 19, 2004

MEMORANDUM TO: Hubert T. Bell
Inspector General

FROM: William D. Travers ***/RA Carl J. Paperiello Acting For/***
Executive Director for Operations

SUBJECT: FEBRUARY 2, 2004, OFFICE OF INSPECTOR GENERAL (OIG) MEMORANDUM CONCERNING AGENCY RESPONSE TO OIG EVENT INQUIRY CASE NO. 03-02S (NRC'S OVERSIGHT OF DAVIS-BESSE BORIC ACID LEAKAGE AND CORROSION DURING THE APRIL 2000 REFUELING OUTAGE)

This memorandum responds to your memorandum to Chairman Diaz, dated February 2, 2004, concerning the Nuclear Regulatory Commission (NRC) staff's response of January 12, 2004, to OIG Event Inquiry 03-02S. The referenced OIG event inquiry was initiated in response to a Congressional request that OIG determine how the NRC staff handled Davis-Besse Condition Report (CR) 2000-0782 at the time of discovery in refueling outage (RFO) 12 (2000) and whether the CR was considered in the November 2001 decision to allow Davis-Besse to continue to operate to February 16, 2002. The NRC staff's previous response to OIG (January 12, 2004) regarding this issue provided a matrix of those recommendations from the Davis-Besse Lessons Learned Task Force (DBLLTF) report that specifically addressed the event inquiry findings and referenced the report for a complete picture of the staff's efforts. The OIG response of February 2, 2004, stated that the NRC staff had not addressed the problem of communications as an underlying cause of the findings of the OIG event inquiry and that the agency should include an expectation of improved communication between and among NRC Headquarters and regional staff and should outline specific guidance to achieve this goal. In addition, OIG specifically concluded that "had the [Davis-Besse Nuclear Power Station] DBNPS inspectors been better informed of ongoing NRC industry-wide efforts to address coolant pressure boundary leakage and the effects of boric acid corrosion, they would have recognized the significance of Condition Report 2000-0782 and highlighted the information to regional management."

The DBLLTF report discusses the NRC's and industry's failure to understand the significance of boric acid corrosion of the reactor vessel head. The NRC staff believes that this failure caused the underlying communications lapses. Although the potential for this type of degradation existed previously, the significance of boric acid deposits was not understood by the staff. The assumption throughout NRC was that the boric acid deposits would be in a dry, powder-like form that could easily be removed and would not accumulate in a condition that would be corrosive to the reactor vessel head. As identified in the event inquiry, the inspectors did communicate a substantial amount of information to the region and the NRR Project Manager, particularly regarding the fouling of the containment air coolers and radiation monitor filter

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415-1485

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elements; however, the significance of this information was also not appreciated at the time. This same failure to understand the significance of the situation was the cause of the lack of communication from Headquarters to the regions. Several elements of the matrixed DBLLTF Action Plans address this underlying issue of lack of recognition of the significance of the evidence. The desired outcome for these actions is for all NRC staff to maintain a questioning attitude and lower thresholds for communications concerning materials degradation corrosion.

More broadly, the NRC staff agrees that communications are of critical importance in all aspects of NRC activities and particularly important as an underlying cause for issues discovered at DBNPS. The corrective actions outlined in the DBLLTF Action Plans address communications beyond the topic of boric acid corrosion control. For example, corrective actions in the area of operating experience development and use are focused on enhancing communications. The recommendations to strengthen inspection guidance, institute training to reinforce a questioning attitude on the part of management and staff, and change the Inspection Manual to provide guidance for the staff to pursue issues identified during plant status reviews are intended to establish more definitive expectations for improved communications of operating experience. As discussed in the February 23, 2004, semiannual update report and at the February 26, 2004, Commission meeting, implementation plans for this area are still under development and may significantly influence the way the agency does business in the future. Developing the most effective and efficient communications channels will be key to the successful implementation of an effective operating experience program.

Beyond the DBLLTF Action Plan, the agency has several ongoing initiatives that provide examples of efforts to more broadly improve intra-agency communications. These examples include establishment of a Communication Council reporting to the Executive Director for Operations and the creation of a communications specialist position reporting to the Office of Nuclear Reactor Regulation (NRR) Associate Director for Inspections and Programs. NRR also continues to improve and enhance its Web site as a focused means of communicating with both internal and external stakeholders. From a regional perspective, examples of communication enhancements include lowering the threshold for communication of plant issues on morning status calls, devoting additional time to discussing lessons learned from plant events and inspection findings during counterpart meetings, and developing enhanced guidance for documenting significant operational event followup decisions. Collectively, these examples provide a strong indication that NRC Headquarters and regional staff have begun to internalize two of the most important lessons from the Davis-Besse event. These are that on occasion, information initially considered to have low significance by the first NRC recipient is later found to be of greater significance once the information is shared and evaluated more collegially; and with regard to the complex nature of commercial nuclear power operations, no one person can be aware of all aspects of an issue. As a result, the more information that is shared, the more likely significant problems will be identified and appropriate action(s) taken.

In summary, the NRC staff recognizes that communication failures were an underlying cause of the agency's problems concerning the delayed discovery of the boric acid corrosion at DBNPS. Our January 12, 2004, response to the event inquiry specifically addressed what we considered to be the root cause of the event-specific communication failures, namely that the entire staff did not recognize the potential significance of boric acid corrosion. Expectations for improved communications will be developed as an integral part of our operating experience program enhancements. More broadly, communication improvement initiatives with internal and external

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stakeholders are in progress to enhance agency performance in this critical area of our responsibilities. We regret that our initial response did not clearly address the broader actions we are taking to improve communications and appreciate the opportunity to clarify our response.

cc: Chairman Diaz
Commissioner McGaffigan
Commissioner Merrifield
SECY
LReyes

The following are GAO's comments on the Nuclear Regulatory Commission's letter dated May 5, 2004.

## GAO Comments

1. We agree with NRC that 10 C.F.R. § 50.9 requires that information provided to NRC by a licensee be complete and accurate in all material respects, and we have added this information to the report. NRC also states that in carrying out its oversight responsibilities, NRC must "rely heavily" on licensees providing accurate information. However, we believe that NRC's oversight program should not place undue reliance on applicants providing complete and accurate information. NRC also recognizes that it cannot rely solely on information from licensees, as evidenced by its inspection program and process for determining the significance of licensee violations. Under this process, NRC considers whether there are any willful aspects associated with the violation—including the deliberate intent to violate a license requirement or regulation or falsify information. We believe that management controls, including inspection and enforcement, should be implemented by NRC so as to verify whether licensee-submitted information considered to be important for ensuring safety is complete and accurate as required by the regulation. In this regard, as stated in NRC's enforcement policy guidance, NRC is authorized to conduct inspections and investigations (Atomic Energy Act § 161); revoke licenses for, among other things, a licensee's making material false statements or failing to build or operate a facility in accordance with the terms of the license (Atomic Energy Act § 186); and impose civil penalties for a licensee's knowing failure to provide certain safety information to NRC (Energy Reorganization Act § 206).

   With regard to the draft report conveying the expectation that NRC should have known about the thick layer of boron on the reactor vessel head, we note in the draft report that since at least 1998, NRC was aware that (1) FirstEnergy's boric acid corrosion control program was inadequate, (2) radiation monitors within the containment area were continuously being clogged by boric acid deposits, (3) the containment air cooling system had to be cleaned repeatedly because of boric acid buildup, (4) corrosion was occurring within containment as evidenced by rust particles being found, and (5) the unidentified leakage rate had increased above the level that historically had been found at the plant. NRC was also aware of the repeated but ineffective attempts by FirstEnergy to correct many of these recurring problems—evidence that the licensee's programs to identify and correct problems were not effective. Given these indications at Davis-Besse, NRC could have taken more aggressive follow-up action to determine the underlying causes. For example, NRC could have taken action during the fuel outage in 1998, the shutdown to repair valves in mid-1999, or the fuel outage in 2000 to ensure that staff with sufficient knowledge appropriately investigated the types of conditions that could cause these indications, or followed up to ensure that FirstEnergy had fully investigated and successfully resolved the cause of the indications.

2. With respect to the responsibility of the licensee to provide complete and accurate information, see comment 1. As to the Davis-Besse lessons-learned task force finding, we agree that some information provided by FirstEnergy in response to Bulletin 2001-01 may have been inconsistent with some information subsequently identified by NRC's lessons-learned task force, and that had some of this information been known in the fall of 2001, the vessel head leakage and degradation may have been identified sooner than March 2002. This information included (1) the boric acid accumulations found on the vessel head by FirstEnergy in 1998 and 2000, (2) FirstEnergy's limited ability to visually inspect the vessel head, (3) FirstEnergy's boric acid corrosion control procedures relative to the vessel head, (4) FirstEnergy's program to address the corrosive effects of small amounts of reactor coolant leakage, (5) previous nozzle inspection results, (6) the bases for FirstEnergy's conclusion that another source of leakage—control rod drive mechanism flanges—was the source of boric acid deposits on the vessel head that obscured multiple nozzles, and (7) photographs of vessel head penetration nozzles. However, various NRC officials knew some of this information, other information should have been known by NRC, and the remaining information could have been obtained had NRC requested it from FirstEnergy. For example, according to the senior resident inspector, he reviewed every Davis-Besse condition report on a daily basis to determine whether the licensee properly categorized the safety significance of the conditions. Vessel head conditions found by FirstEnergy in 1998 and 2000 were noted in such condition reports or in potential-condition-adverse-to-quality reports. According to a FirstEnergy official, photographs of the pressure vessel head nozzles were specifically provided to NRC's resident inspector, who, although he did not specifically recall seeing the photographs, stated that he had no reason to doubt the FirstEnergy official's statement. NRC had been aware, in 1999, of limitations in FirstEnergy's boric acid corrosion control program and, while it cited FirstEnergy for its failure to adequately implement the program, NRC officials did not

follow up to determine if the program had improved. Lastly, while NRC questioned the information provided by FirstEnergy in its submissions to NRC in response to Bulletin 2001-01 (regarding vessel head penetration nozzle inspections), NRC staff did not independently review and assess information pertaining to the results of past reactor pressure vessel head inspections and vessel head penetration nozzle inspections. Similarly, NRC did not independently assess the information concerning the extent and nature of the boric acid accumulations found on the vessel head by the licensee during past inspections.

On page 2 of the report, we note that the Department of Justice has an ongoing investigation concerning the completeness and accuracy of information that FirstEnergy provided to NRC on the conditions at Davis-Besse. The investigation may or may not find that FirstEnergy provided inaccurate or incomplete information. While NRC notes that it might have detected something months earlier if information had been known in the fall of 2001, we would also note that the degradation of the reactor vessel head likely took years to occur.

3. We believe that the statement is correct. NRC produced an estimate of $5x10^{-5}$ per year for the change in core damage frequency, as we state in the report. NRC specifically documented this calculation in its December 2002 assessment:

   *"The NRC staff estimated that, giving credit only to the [FirstEnergy] inspection performed in 1996, the probability of a [control rod drive mechanism] nozzle ejection during the period of operation from December 31, 2001, to February 16, 2002, was in the range of 2E-3 and was an increase in the overall [loss of coolant accident] probability for the plant. The increase in core damage probability and large early release probability were estimated as approximately 5E-6 and 5E-08, respectively."*[1]

   The probability of a large early release—5E-6—equates to a frequency of $5x10^{-5}$ per year.[2] As we note in the report, according to NRC's

[1]The numbers 2E-3, 5E-6, and 5E-8 can also be written as $2x10^{-3}$, $5x10^{-6}$, and $5x10^{-8}$.

[2]The probability of an event occurring is the product of the frequency of an event and a given time period. In this case, the time period—7 weeks—was approximated as one-tenth of the year. Thus, $5.4x10^{-5}$ per year multiplied by 0.10 equates to a probability of $5.4x10^{-6}$. According to NRC, it revised $5.4x10^{-6}$ to $5.0x10^{-6}$ to account for uncertainties.

regulatory guide 1.174, this frequency would be in the highest risk zone and NRC would generally not approve the requested change.

On several occasions, we met with the NRC staff that developed the risk estimate in an attempt to understand how it was calculated. We obtained from NRC staff the risk estimate information provided to senior management in late November 2001, as well as several explanations of how the staff developed its calculations. We were provided with no evidence that NRC estimated the frequency of core damage as being $5x10^{-6}$ per year until February 2004, after our consultants and we had challenged NRC's estimate as being in the highest risk zone under NRC's regulatory guide 1.174. Furthermore, several NRC staff involved in deciding whether to issue the order to shut down Davis-Besse, or to allow it to continue operating until February 16, 2002, stated that the risk estimate they used was relatively high.

4. We agree that existing regulations provide a spectrum of conditions under which a plant shutdown could occur and that could be interpreted as covering the vast majority of situations. However, we continue to believe that NRC lacks sufficient guidance for making plant shutdown decisions. We disagree on two grounds: First, the decision-making guidance used by NRC to shut down Davis-Besse was guidance for approving license change requests. This guidance provides general direction on how to make risk-informed decisions when licensees request license changes. It does not address important aspects of decision-making involved in deciding whether to shut down a plant. It also does not provide direction on how NRC should weigh deterministic factors in relation to probabilistic factors in making shutdown decisions. Secondly, while NRC views the flexibility afforded by its existing array of guidance as a strength, we are concerned that, even on the basis of the same information or circumstances, staff can arrive at very different decisions. Without more specific guidance, NRC will continue to lack accountability and the degree of credibility needed to convince the industry and the public that its shutdown decisions are sufficiently sound and reasoned for protecting public health and safety.

5. We are aware that the commissioners have specifically decided not to conduct direct evaluations or inspections of safety culture. We agree that as regulators, NRC is not charged with managing licensees' facilities, but disagree that any direct NRC involvement with safety culture crosses over to a management function. Management is an

embodiment of corporate beliefs and perceptions that affect management strategies, goals, and philosophies. These, in turn, impact licensee programs and processes and employee behaviors that have safety outcomes. We believe that NRC should not assess corporate beliefs and perceptions or management strategies, goals, or philosophies. Rather, we believe that NRC has a responsibility to assess licensee programs and processes, as well as employee behaviors. We cite several areas of safety culture in the report as being examples of various aspects of safety culture that NRC can assess which do not constitute "management functions." The International Atomic Energy Agency has extensive guidance on assessing additional aspects of licensee performance and indicators of safety culture.[3] Such assessments can provide early indications of declining safety culture prior to when negative safety outcomes occur, such as at Davis-Besse.

We also agree that NRC has indirect means by which it attempts to assess safety culture. For example, NRC's problem identification and resolution inspection procedure's stated objective is to provide an early warning of potential performance issues and insight into whether licensees have established safety conscious work environments. However, we do not believe that the implementation of the inspection procedure has been demonstrated to be effective in meeting its stated objectives. The inspection procedure directs inspectors to screen and analyze trends in all reported power plant issues. In doing so, the procedure directs that inspectors annually review 3 to 6 issues out of potentially thousands of issues that can arise and that are related to various structures, systems, and components necessary for the safe operation of the plant. This requires that inspectors judgmentally sample 3 to 6 issues on which they will focus their inspection resources. While we do not necessarily question inspector judgment when sampling for these 3 to 6 issues, NRC inspectors stated that due to the large number of issues that they can sample from, they try to focus on those issues that they believe have the most relevance for safety. Thus, if an issue is not yet perceived as being important to safety, it is less likely to be selected for follow up. Further, even if an issue were selected for follow up and this indicated that the licensee did not properly identify and resolve underlying problems that contributed to the issue, according to NRC officials, it is highly unlikely

[3]The International Atomic Energy Agency, International Nuclear Safety Advisory Group, *Safety Culture* (Vienna, Austria: February 1991).

that this one issue would rise to a high enough level of significance for it to be noted under NRC's Reactor Oversight Process. Additionally, the procedure is dependant on the inspector being aware of, and having the capability to, identify issues or trends in the area of safety culture. According to NRC officials, inspectors are not trained in what to look for when assessing licensee safety culture because they are, by and large, nuclear engineers. While they may have an intuition that something is wrong, they may not know how to assess it in terms of safety culture.

Additional specific examples NRC cites for indirectly assessing a selected number of safety culture aspects have the following limitations:

- NRC's inspection procedure for assessing licensees' employee concerns program is not frequently used. According to NRC Region III officials, approval to conduct such an inspection must be given by the regional administrator and the justification for the inspection to be performed has to be based on a very high level of evidence that a problem exists. Because of this, these officials said that the inspection procedure has only been implemented twice in Region III.

- NRC's allegation program provides a way for individuals working at NRC-regulated plants and the public to provide safety and regulatory concerns directly to NRC. It is a reactive program by nature because it is dependent upon licensees' employees feeling free and able to come forward to NRC with information about potential licensee misconduct. While NRC follows up on those plants that have a much higher number of allegations than other plants to determine what actions licensees are taking to address any trends in the nature of the allegations, the number of allegations may not always provide an indication of a poor safety culture, and in fact, may be the reverse. For example, the number of allegations at Davis-Besse prior to the discovery of the cavity in the reactor head in March 2002 was relatively small. Between 1997 and 2001, NRC received 10 allegations from individuals at the plant. In contrast, NRC received an average of 31 allegations per plant over the same 5-year period from individuals at other plants.

- NRC's lessons-learned reviews, such as the one conducted for Davis-Besse, are generally conducted when an incident having potentially serious safety consequences has already occurred.

- With respect to NRC's enforcement of employee protection regulations, NRC, under its current enforcement policy, would normally only take enforcement action when violations are of very significant or significant regulatory concern. This regulatory concern pertains to NRC's primary responsibility for ensuring safety and safeguards and protecting the environment. Examples of such violations would include the failure of a system designed to prevent a serious safety incident not working when it is needed, a licensed operator being inebriated while at the control of a nuclear reactor, and the failure to obtain prior NRC approval for a license change that has implications for safety. If violations of employee protection regulations do not pose very significant or significant safety, safeguards, or environmental concerns, NRC may consider such violations minor. In such cases, NRC would not normally document such violations in inspection reports or records, and would not take enforcement action.

- NRC's Reactor Oversight Process, instituted in April 2000, focuses on seven specific "cornerstones" that support the safety of plant operations to ensure reactor safety, radiation safety, and security. These cornerstones are: (1) the occurrence of operations and events that could lead to a possible accident if safety systems did not work, (2) the ability of safety systems to function as intended, (3) the integrity of the three safety barriers, (4) the effectiveness of emergency preparedness, (5) the effectiveness of occupational radiation safety, (6) the ability to protect the public from radioactive releases, and (7) the ability to physically protect the plant. NRC's process also includes three elements that cut across these seven cornerstones: (1) human performance, (2) a licensee's safety-conscious work environment, and (3) problem identification and resolution. NRC assumes that problems in any of these three crosscutting areas will be evidenced in one or more of the seven cornerstones in advance of any serious compromise in the safety of a plant. However, as evidenced by the Davis-Besse incident, this assumption has not proved to be true.

NRC also cites lessons-learned task force recommendations to improve NRC's ability to detect problems in licensee's safety culture, as a means to achieve our recommendation to directly assess licensee safety culture. These lessons-learned task force recommendations include (1) developing inspection guidance to assess the effect that a licensee's fuel outage shutdown schedule has on the scope of work conducted during a shutdown; (2) revising inspection guidance to provide for assessing the safety implications of long-standing, unresolved problems; corrective actions being phased in over the course of several years or refueling outages; and deferred plant modifications; (3) revising the problem identification and resolution inspection approach and guidance; and (4) reviewing the range of NRC's inspections and assessment processes and other NRC programs to determine whether they are sufficient to identify and dispose of the types of problems experienced at Davis-Besse. While we commend these recommendations, we do not believe that revising such guidance will necessarily alert NRC inspectors to early declines in licensee safety culture before they result in negative safety outcomes. Further, because of the nature of NRC's process for determining the relative safety significance of violations under NRC's new Reactor Oversight Process, we do not believe that any indications of such declines will result in a cited violation.

6. We have revised the report to reflect that boron in the form of boric acid crystals is dissolved in the cooling water. (See p. 13.)

7. On page 41 of the report, we recognize that NRC also relied on information provided by FirstEnergy regarding the condition of the vessel head. For example, in developing its risk estimate, NRC credited FirstEnergy with a vessel head inspection conducted in 1996. However, NRC decided that the information provided by FirstEnergy documenting vessel head inspections in 1998 and 2000 was of such poor quality that it did not credit FirstEnergy with having conducted them. As a result, NRC's risk estimate was higher than had these inspections been given credit.

8. The statement made by the NRC regional branch chief was taken directly from NRC's Office of the Inspector General report on NRC's oversight of Davis-Besse during the April 2000 refueling outage.[4]

9. We agree that up until the Davis-Besse event, NRC had not concluded that boric acid corrosion was a high priority issue. We clarified the text of the report to reflect this comment. (See p. 25.)

[4]NRC, Office of the Inspector General, *NRC's Oversight of Davis-Besse during the April 2000 Refueling Outage* (Washington, D.C.: Oct. 17, 2003).

10. We agree that plant operators in France decided to replace their vessel heads in lieu of performing the extensive inspections instituted by the French regulatory authority. The report has been revised to add these details. (See p. 31.)

11. We agree that caked-on boron, in combination with leakage, could accelerate corrosion rates under certain conditions. However, even without caked-on boron, corrosion rates could be quite high. Westinghouse's 1987 report on the corrosive effects of boric acid leakage concluded that the general corrosion rate of carbon steel can be unacceptably high under conditions that can prevail when primary coolant leaks onto surfaces and concentrates at the temperatures that are found on reactor surfaces. In one series of tests that it performed, boric acid solutions corroded carbon steel at a rate of about 0.4 inches per month, or about 4.8 inches a year. This was irrespective of any caked-on boron. In 1987, as a result of that report and extensive boric acid corrosion found at two other nuclear reactors that year—Salem unit 2 and San Onofre unit 2—NRC concluded that a review of existing inspection programs may be warranted to ensure that adequate monitoring procedures are in place to detect boric acid leakage and corrosion before it can result in significant degradation of the reactor coolant pressure boundary. However, NRC did not take any additional action.

12. We agree that NRC has requirements and processes that provide a number of circumstances in which a plant shutdown would or could be required. We also recognize that there were no legal objections to the draft enforcement order to shut down the plant, and that the basis for not issuing the order was NRC's belief that the plant did not pose an unacceptable risk to public health and safety. The statement in our report that NRC is referring to is discussing one of these circumstances—the licensee's failure to meet NRC's technical specification—and whether NRC believed that it had enough proof that the technical specification was not being met. The statement is not discussing the basis for NRC issuing an enforcement order. We revised the report to clarify this point. (See p. 34.)

13. The basis for our statement that NRC staff concluded that the first safety principle was probably not met was its November 29, 2001, briefing to NRC's Executive Director's Office and its November 30, 2001, briefing to the NRC commissioners' technical assistants. These briefings, the basis for which are included in documented briefing

slides, took place shortly before NRC formally notified FirstEnergy on December 4, 2001, that it would accept its compromise shutdown date.

14. We are referring to the same document that NRC is referring to—NRC's December 3, 2002, response to FirstEnergy (NRC's ADAMS accession number ML023300539). The response consists of a 2-page transmittal letter and an 7.3-page enclosure. The 7.3-page enclosure is 3 pages of background and 4.3 pages of the agency's assessment. The assessment includes statements that the safety principles were met but does not provide an explanation of how NRC considered or weighed deterministic and probabilistic information in concluding that each of the safety factors were met. For example, NRC concluded that the likelihood of a loss-of-coolant accident was acceptably small because of the (1) staff's preliminary technical assessment for control rod drive mechanism cracking, (2) evidence of cracking found at other plants similar to Davis-Besse, (3) analytical work performed by NRC's research staff in support of the effort, and (4) information provided by FirstEnergy regarding past inspections at Davis-Besse. However, the assessment does not explain how these four pieces of information successfully demonstrated if and how each of the safety principles was met. The assessment also states that NRC examined the five safety principles, the fifth of which is the ability to monitor the effects of a risk-informed decision. The assessment is silent on whether this principle is met. However, in NRC's November 29, 2001, briefing to NRC's Executive Director's Office and in its November 30, 2001, briefing to the NRC commissioners' technical assistants, NRC concluded that this safety principle was not met. As noted above, NRC formally notified FirstEnergy on December 4, 2001, that it would accept FirstEnergy's February 16, 2002, shutdown date.

15. See comment 3. We do not agree that the report statements mischaracterize the facts. Rather, we are concerned that NRC is misusing basic quantitative mathematics. In addition, with regard to NRC's concept of an annual average change in the frequency of core damage, NRC stated that the agency averaged the frequency of core damage that would exist for the 7-week period of time (representing the period of time between December 31, 2001, and February 16, 2002) over the entire 1-year period, using the assumption that the frequency of core damage would be zero for the remainder of the year—February 17, 2002, to December 31, 2002. According to our consultants, this calculation *artificially* reduced NRC's risk estimate to a level that is acceptable under NRC's guidance. By this logic, our consultants stated,

risks can always be reduced by spreading them over time; by assuming another 10 years of plant operation (or even longer) NRC could find that its calculated "risks" are completely negligible. They further stated that NRC's approach is akin to arguing that an individual, who drives 100 miles per hour 10 percent of the time, with his car otherwise garaged, should not be cited because his time-average speed is only 10 miles per hour.

Further, our consultants concluded that the "annual-average" core damage frequency approach was also clearly unnecessary, since one need only convert a core damage frequency to a core damage probability to handle part-year cases like the Davis-Besse case. Lastly, we find no basis for the calculation in any NRC guidance. According to our consultants, this new interpretation of NRC's guidance is at best unusual and certainly is inconsistent with NRC's guidelines regarding the use of an incremental core damage frequency. This interpretation also reinforces our consultants' impression that perhaps there was, in November 2001 and possibly is still today, some confusion among the NRC staff regarding basic quantitative metrics that should be considered in evaluating regulatory and safety issues. As noted in comment 3, we found no evidence of this calculation prior to February 2004.

16. While we agree that vessel head corrosion as extensive as later found at Davis-Besse was not anticipated, NRC had known that leakage of the primary coolant from a through-wall crack could cause boric acid corrosion of the vessel head, as evidenced by the Westinghouse work cited above. Regardless of information provided to NRC by individual licensees, such as FirstEnergy, NRC's model should account for known risks, including the potential for corrosion.

17. We agree that NRC was aware of control rod drive mechanism nozzle cracking at French nuclear power plants. NRC provided us additional information consisting of a December 15, 1994, internal memo, in which NRC concluded that primary coolant leakage from a through-wall crack could cause boric acid corrosion of the vessel head. However, because some analyses indicated that it would take at least 6 to 9 years before any corrosion would challenge the structural integrity of the head, NRC concluded that cracking was not a short-term safety issue. We revised the report to include this additional information. (See p. 40.)

18. See comment 15.

19. We agree that while not directly relevant to the Davis-Besse situation, NRC uses regulatory guide 1.177 to make decisions on whether certain equipment can be inoperable while a nuclear reactor is operating, which can pose very high instantaneous risks for very short periods of time. However, we include the reference to this particular guidance in the report because it was cited by an NRC official involved in the Davis-Besse decision-making process as another piece of guidance used in judging whether the risk that Davis-Besse posed was acceptable.

20. While regulatory guide 1.174 comprises 25 pages of guidance on how to use risk in making decisions on whether to allow license changes, it does not lay out how NRC staff are to use quantitative estimates of risk or probabilistic factors, or how robust these estimates must be in order to be considered along with more deterministic factors. The regulatory guide, which was first issued in mid-1998, had been in effect for only about 1.5 years when NRC staff was tasked with making their decision on Davis-Besse. According to the Deputy Executive Director of Nuclear Reactor Programs at the time the decision was being made, the agency was trying to bring the staff through the risk-informed decision-making process because Davis-Besse was a learning tool. He further stated that it was really the first time the agency had used the risk-informed decision-making process on operational decisions as opposed to programmatic decisions for licensing. At the time the decision was made, and currently, NRC has no guidance or criteria for use in assessing the quality of risk estimates or clear guidance or criteria for how risk estimates are to be weighed against other risk factors.

21. The December 3, 2002, safety assessment or evaluation did state that the estimated increase in core damage frequency was consistent with NRC's regulatory guidelines. However, as noted in comment 3, we disagree with this conclusion. In addition, while we agree that NRC has staff with risk assessment disciplines, we found no reference to these staff in NRC's safety evaluation. We also found no reference to NRC's statement that these staff gave more weight to deterministic factors in arriving at the agency's decision. While we endorse NRC's consideration of deterministic as well as probabilistic factors and the use of a risk-informed decision-making process, we continue to maintain that NRC needs clear guidance and criteria for the quality of risk estimates, standards of evidence, and how to apply deterministic as well as probabilistic factors in plant shutdown decisions. As the agency continues to incorporate a risk-informed process into much of its regulatory guidance and programs, such criteria will be increasingly

important when making shutdown as well as other types of decisions regarding nuclear power plants.

22. The information that NRC provided us indicates that completion dates for 2 of the 22 high priority recommendations have slipped.[5] One, the completion date for encouraging the American Society of Mechanical Engineers to revise vessel head penetration nozzle inspection requirements or, alternatively, for revising NRC's regulations for vessel head inspections has slipped from June 2004 to June 2006. Two, the completion date for assessing NRC's requirements that licensees have procedures for responding to plant leakage alarms to determine if the requirements are sufficient for identifying reactor coolant pressure boundary leakage has slipped from March 2004 to March 2005.

23. We agree with this comment and have revised the report to reflect this clarification. (See p. 49.)

24. Our estimate of at least an additional 200 hours of inspection per reactor per year is based on:

    - NRC's new requirement that its resident inspectors review all licensee corrective action items on a daily basis (approximately 30 minutes per day). Given that reactors are intended to operate continuously throughout the year, this results in about 3.5 hours per week for reviewing corrective action items, or about 182 hours per year. In addition, resident inspections are now required to determine, on a semi-annual basis, whether such corrective action items reflect any trends in licensee performance (16 to 24 hours per year). The total increase for these new requirements is about 198 to 206 hours per reactor per year.

    - A new NRC requirement that its resident inspectors validate that licensees comply with additional inspection commitments made in response to NRC's 2002 generic bulletin regarding reactor pressure vessel head and vessel head penetration nozzles. This requirement results in an additional 15 to 50 hours per reactor per fuel outage.

[5]Of NRC's 21 high priority recommendations, we categorized 1 recommendation as 2 so that we could better track actions taken to implement it. Thus, we have 22 recommendations categorized as high priority.

25. Our draft report included a discussion that NRC management's failure to recognize the scope or breadth of actions and resources necessary to fully implement task force recommendations could adversely affect how effective the actions may be. We made this statement based on NRC's initial response to the Office of the Inspector General's October 2003 report on Davis-Besse.[6] That report concluded that ineffective communication within NRC's Region III and between Region III and NRC headquarters contributed to the Davis-Besse incident. NRC, in its January 2004 response to the report, stated that among other things, it had developed training on boric acid corrosion and revised its inspection program to require semi-annual trend reviews. In February 2004, the Office of the Inspector General criticized NRC for limiting the agency's efforts in responding to its findings. Specifically, it stated that NRC did not address underlying and generic communication failures identified in the Office's report. In response to the criticism, on April 19, 2004 (while our draft report was with NRC for review and comment), NRC provided the Office of the Inspector General with additional information to demonstrate that its actions to improve communication within the agency were broader than indicated in the agency's January 2004 response. Based on NRC's April 19, 2004, response and the Office's agreement that NRC's actions appropriately address its concerns about communication within the agency, we deleted this discussion in the report.

26. We recognize that the lessons-learned task force did not make a recommendation for improving the agency's decision-making process because the task force coordinated with the Office of the Inspector General regarding the scope of their respective review activities and because the task force was primarily charged with determining why the vessel head degradation was not prevented. (See p. 55.)

27. We agree that NRC's December 3, 2002, documentation of its decision was prepared in response to a finding by the Davis-Besse lessons-learned task force. We revised our report to incorporate this fact. (See p. 55.)

28. We agree that NRC's lessons-learned task force conducted a preliminary review of reports from previous lessons-learned task forces

[6]NRC, Office of the Inspector General, *NRC's Oversight of Davis-Besse during the 2000 Refueling Outage* (Washington, D.C.: Oct. 17, 2003).

and, as a result of that review, made a recommendation that the agency perform a more detailed effectiveness review of the actions taken in response to those reviews. We revised the report to reflect that NRC's detailed review is currently underway. (See p. 55.)

# GAO Contacts and Staff Acknowledgments

## GAO Contacts

Jim Wells, (202) 512-3841
Ray Smith, (202) 512-6551

## Staff Acknowledgments

In addition, Heather L. Barker, David L. Brack, William F. Fenzel, Michael L. Krafve, William J. Lanouette, Marcia Brouns McWreath, Judy K. Pagano, Keith A. Rhodes, and Carol Hernstadt Shulman made key contributions to this report.

# Related GAO Products


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# Exhibit A

EXHIBIT "A"

UNITED STATES
NUCLEAR REGULATORY COMMISSION

*In the matter of*

| | | |
|---|---|---|
| **ENTERGY NUCLEAR INDIAN POINT 2, L.L.C.**<br>**ENTERGY NUCLEAR INDIAN POINT 3, L.L.C.** | ) | **LicenseNo. DPR-26 &DPR 64** |
| **Indian Point Energy Center Unit 2 &**<br>**Indian Point Energy Center 3**<br>**Entergy Nuclear Operations, Inc.** | ) | **Docket No. 50-247 & No. 50-286** |
| **License Renewal Application** | ) | **ASLBP No. 70-858-03-LR-BD01** |

## DECLARATION OF RICHARD L. BRODSKY

Richard L. Brodsky represents the 92nd Assembly District, which includes the Towns of Greenburgh and Mount Pleasant, the Villages of Ardsley, Dobbs Ferry, Elmsford, Hastings-on-Hudson, Irvington, Pleasantville, Sleepy Hollow, Tarrytown, a portion of the Village of Briarcliff Manor, and part of the City of Yonkers.

Assemblyman Brodsky has led efforts to investigate the Indian Point nuclear power plants, undertook the first independent analysis of the Evacuation Plans for Indian Point, and in February 2002, he released the Interim Report on the Evacuation Plans for the Indian Point Nuclear Generating Facility, which detailed the serious and systematic deficiencies which make it unable to "adequately protect the public health and safety," as required by law.

These findings were confirmed by the James Lee Witt Report released eleven months later. On June 13, 2002, Chairman Brodsky, along with numerous local, State, and federal elected officials, submitted a formal Petition to the Federal Emergency Management Agency requesting that they withdraw their approval of the Indian Point Evacuation Plans, marking the first formal challenge to a nuclear plant's evacuation plans.

He is also the lead Petitioner and Counsel, along with the Hudson River Sloop Clearwater, Pete and Toshi Seeger and others, in successful litigation seeking to compel the State Department of Environmental Conservation to effectively regulate the ongoing pollution of the Hudson River caused by Indian Point's intake of over two billion gallons of water daily.

He serves as Chairman of the Standing Committee on Corporations, Authorities, and Commissions, which oversees the state's public and private corporations. This includes jurisdiction over business corporation law and telecommunications, as well as all public authorities, such as the MTA, the Thruway Authority, the Public Service Commission, the Port Authority, and the Lower Manhattan Development Corporation.

From 1993 to 2002, Assemblyman Brodsky served as Chairman of the Committee on Environmental Conservation, where he structured the most dramatic legislative advances in environmental conservation in over two decades. His accomplishments include authoring the legislation that created the Environmental Protection Fund, the first dedicated fund for environmental protection in the history of New York State, and the Clean Air/Clean Water Bond Act, a $1.75 billion bond act passed by voters across New York to provide a funding mechanism for unfunded clean air and clean water projects throughout the State.

He lives within 15 miles of the plant in Elmsford , New York with his wife and two daughters.

I declare under penalty of perjury that the foregoing is true and correct.

Executed this 10th day of Dec, 2007, at Elmsford, NY.

Richard L. Brodsky

State of New York )
)ss.:
County of Westchester)

On the 10th day of December, in the year 2007 before me, the undersigned, personally appeared RICHARD BRODSKY, personally known to me or proved to me on the basis of satisfactory evidence to be the individual(s) whose name(s) is (are) subscribed to the within instrument and acknowledged to me that he/she/they executed the same in his/her/their capacity(ies), and that by his/her their signatures(s) on the instrument, the individual(s) or the person upon behalf of which the individual(s) acted, executed the instrument.

Notary Public

# EXHIBIT B

"Exhibit "B"

**UNITED STATES_NUCLEAR REGULATORY COMMISSION**

***In the matter of***

**ENTERGY NUCLEAR INDIAN POINT 2, L.L.C.**
**ENTERGY NUCLEAR INDIAN POINT 3, LLC**
**ENTERGY NUCLEAR OPERATIONS, LCC**
**Indian Point Energy Center Unit 2 & Indian Point Entergy Center Unit 3**

**LicenseNo. DPR-26 & DPR 64**

**) Docket No. 50-247 & No. 50-286**

**License Renewal Application**

**DECLARATION OF ALLEGRA DENGLER**

My name is Allegra Dengler . I live with my husband at 60 Judson Avenue, Dobbs Ferry, NY, 10522. We live approximately 18.5 miles from Indian Point. I am a member of the Sierra Club LHG and have served as Conservation Chair and Co-Chair of the group. I served four years as Trustee of the Village of Dobbs Ferry, and in that capacity participated in the many hearings about the adequacy of the emergency evacuation plans during the study by Witt Associates for the State of New York.

The Sierra Club represents my interests in a Petition to Intervene, Request for Hearing and Contentions and the Notice of Appearance, in the matter of Entergy Nuclear Indian Point 2 LLC and Indian Point 3 LLC, and Entergy Nuclear Operations, Inc. License Renewal Application.

I have lived in Dobbs Ferry since 1987. On September 11, 2001, I became acutely aware of how close Indian Pt was to Dobbs Ferry when I learned that one of the fateful planes of that day had flown over Indian Pt. Later it was revealed that terrorists had considered striking Indian Pt instead of the World Trade Center,

I spend time on the river canoeing. I spend many days at our waterfront park walking, taking in the sunset or attending our summer jazz concerts , which are very popular. There are many other events at our waterfront park on the banks of the Hudson, like auto shows and the American Legion Flea Mkt which I also attend, I served on the Village's Waterfront Committee to increase public use of the park and preserve part as natural area. As a Village Trustee, I chaired the Land Use Committee which shepherded the LWRP Local Waterfront Revitalization Plan through the approval process and it has been adopted by the Village.

As a Village Trustee I was well aware that any discharge into the river requires a permit to protect the river. I am very disturbed that Indian Pt can continue to discharge heated water into the Hudson River without any permit at all. This is unacceptable. I can't dump anything out of my canoe, and as a resident I can't dump anything toxic into village drains, but Indian Pt has been allowed to discharge heated water into the river year after year. Recently it has been discovered that Indian Pt has ongoing releases of radioactive materials into the ground, which are migrating into the Hudson. Additionally, their intake valves filter and kill millions of fish and other river life year after year. Shad is our last commercial fish in the Hudson, and the shad runs in the Hudson are decreasing to such an extent that the future of the species is at risk. Yet year after year Indian Pt minces them up in its intake valves and disturbs their development with heated water.

It is clear to me that for all of the above reasons Indian Point should be closed. I declare that the statements made in this declaration are true and correct to the best of my knowledge.

Executed this 30th day of January, 2008 at Dobbs Ferry, New York.

Allegra Dengler Allegra Dengler

State of New York )
)ss.:
County of Westchester )

On the 30 day of JANUARY in the year 2008 before me, the undersigned, personally appeared ALLEGRA DENGLER , personally known to me or proved to me on the basis of satisfactory evidence to be the individual(s) whose name(s) is (are) subscribed to the within instrument and acknowledged to me that he/she/they executed the same in his/her/their capacity(ies), and that by his/her their signatures(s) on the instrument, the individual(s) or the person upon behalf of which the individual(s) acted, executed the instrument.

Laurence G. Dengler
Notary Public

**LAURENCE G. DENGLER**
**Notary Public, State of New York**
**No 60-01DE0920075**
**Qualified in Westchester County**
**Commission Expires December 31, 2009**

**UNITED STATES**
**NUCLEAR REGULATORY COMMISSION**

***In the matter of***

| | | |
|---|---|---|
| **ENTERGY NUCLEAR INDIAN POINT 2, L.L.C.** | | **LicenseNo.** |
| **ENTERGY NUCLEAR INDIAN POINT 3, LLC** | **)** | **DPR-26 &** |
| **ENTERGY NUCLEAR OPERATIONS, LCC** | | **DPR 64** |
| **Indian Point Energy Center Unit 2 & Indian Point** | **)** | **Docket** |
| **Entergy Center Unit 3** | | **No. 50-247** |
| | | **& No. 50-** |
| | | **286** |

**License Renewal Application**

**DECLARATION OF** JOANNE STEELE

My name is Joanne Steele. I live 50 miles from Indian Point and I own property with a building permit in progress in Ulster Park, 47 miles from Indian Point.

Sierra Club represents my interests. I am Secretary of The Mid-Hudson Group of the Atlantic Chapter of the Sierra Club.

I am an avid Kayaker on The Hudson River, in particular South of Ulster Park: Newburgh, Croton, etc. We need no further danger from Indian Point. I am against the relisencing of any and all of Indian Point Nuclear plants. Thank you.

Sincerely,

Joanne Steele

State of New York

County of Ulster

ss.:

On the 31st day of January in the year 2008 before me, the undersigned, a notary public in and for said state, personally appeared Joanne Steele, personally known to me or proved to me on the basis of satisfactory evidence to be the individual(s) whose name(s) is (are) subscribed to the within instrument and acknowledged to me that he/she/they executed the same in his/her/their capacity(ies), and that by his/her/their signature(s) on the instrument, the individual(s), or the person upon behalf of which the individual(s) acted, executed the instrument.

Jennafer Romanczuk

Notary Public

JENNAFER ROMANCZUK
Notary Public, State of New York
Reg. 01RO6147225
Qualified in Dutchess County
Commission Expires May 30, 2010

**UNITED STATES**
**NUCLEAR REGULATORY COMMISSION**

***In the matter of***

| | | |
|---|---|---|
| **ENTERGY NUCLEAR INDIAN POINT 2, L.L.C.** | | **License No.** |
| **ENTERGY NUCLEAR INDIAN POINT 3, LLC** | **)** | **DPR-26 &** |
| **ENTERGY NUCLEAR OPERATIONS, LCC** | | **DPR 64** |
| **Indian Point Energy Center Unit 2 & Indian Point** | **)** | **Docket** |
| **Entergy Center Unit 3** | | **No. 50-247** |
| | | **& No. 50-** |
| | | **286** |

**License Renewal Application**

**DECLARATION OF JOHN GEBHARDS**

My name is John Gebhards; I live at 48 Wintergreen Ave., Newburgh, New York, 12550. Newburgh is located just up stream approximately 20 miles from the Indian Point power plant. I am a member of the Ramapo/Catskill Group, Atlantic Chapter of the Sierra Club. I have lived in Orange County, NY within 25 miles of the Indian Point power plant since 1982. The Hudson River is a historical and natural scenic treasure in our back yard.

The Sierra Club represents my interests in a Petition to Intervene, Request for Hearing and Contentions and the Notice of Appearance, in the matter of Entergy Nuclear Indian Point 2 LLC and Indian Point 3 LLC, and Entergy Nuclear Operations, Inc. License Renewal Application.

I often lead canoe or kayak trips on the Hudson River, often launching from the NYS DEC operated Kowawese Park in the Town of New Windsor. I participate in many cultural events and activities which are centered around the Hudson River such as Earth Day celebrations, Shad Bake fests, the Beacon Sloop Club from the Strawberry Fest in June through the Pumpkin Fest in the fall, the Swim Across the Hudson to support the creation of a in-river swimming pool at Beacon, the Great Hudson River Revival and many other river front festivals.

I am very concerned about the aging condition of these plants and the reported occasional leaks. Their location in a highly densely populated area make evacuation in the case of an emergency logistically impossible. Their proximity to our nation's premier military academy, West Point, and one of our nation's finest cities, New York, makes the potential either an accidental release or a terrorist provoked release of grave concern.

I feel that it is not prudent to reauthorize the operation of these aging Indian Point nuclear plants. I declare that the statements made in this declaration are true and correct to the best of my knowledge.

Executed this 31st day of January, 2008 at Newburgh, New York.

John Gebhards ________________ John Gebhards

State of New York )
)ss.:
County of Orange )

On the 31 day of JANUARY, in the year 2008 before me, the undersigned, personally appeared
JOHN GEBHARDS, personally known to me or proved to me on the basis of satisfactory evidence to be the individual(s) whose name(s) is (are) subscribed to the within instrument and acknowledged to me that he/she/they executed the same in his/her/their capacity(ies), and that by his/her their signatures(s) on the instrument, the individual(s) or the person upon behalf of which the individual(s) acted, executed the instrument.

________________
Notary Public

ANDREW J. ZARUTSKIE
Notary Public, State Of New York
No. 01ZA4502524
Qualified in Orange County
Commission Expires Nov. 30, 2009

**UNITED STATES**
**NUCLEAR REGULATORY COMMISSION**

***In the matter of***

| | | |
|---|---|---|
| **ENTERGY NUCLEAR INDIAN POINT 2, L.L.C.** | | **License No.** |
| **ENTERGY NUCLEAR INDIAN POINT 3, LLC** | **)** | **DPR-26 &** |
| **ENTERGY NUCLEAR OPERATIONS, LCC** | | **DPR 64** |
| **Indian Point Energy Center Unit 2 & Indian Point** | **)** | **Docket** |
| **Entergy Center Unit 3** | | **No. 50-247** |
| | | **& No. 50-** |
| | | **286** |

**License Renewal Application**

**DECLARATION OF Diana Krautter**

My name is Diana Krautter and I currently live at 48 Wintergreen Avenue in Newburgh, New York. I have lived in both Rockland and Orange County over 30 years within a distance of approximately 20 miles from Indian Point. I am the Membership Chair of the Sierra Ramapo/Catskill Group of the Atlanta Chapter and organize and participate in many kayaking adventures on the Hudson River as well as participate in numerous activities along its banks.

The Sierra Club represents my interests in a Petition to Intervene, Request for Hearing and Contentions and the Notice of Appearance, in the matter of Entergy Nuclear Indian Point 2 LLC and Indian Point 3 LLC, and Entergy Nuclear Operations, Inc. License Renewal Application.

Each year I see an increasing number of kayakers enjoying the waters of the Hudson. There is nothing I like better than introducing newcomers to this wonderful river from Manhattan to Albany.

One of my very favorite places is at Kowawese Unique Park in New Windsor, NY where I spend countless hours along the shore and on the Hudson picking up and dragging home all sizes of driftwood. And, I can never get enough of its scenic view of Bannerman Island, the hills above Beacon and its ever-changing shore line of weathered wood. Even the

Moodna Creek which flows into the Hudson is affected by its tides making each paddle up the creek an adventure. Wildlife and fauna abound along the Hudson and its tributaries.

We must protect all the species that inhabit the waters, its shores and its towns and cities from ever increasing harm. Indian Pont is one of our biggest threats. We cannot tolerate and must end the on-going hazards and its potential deadly components of Indian Point.

Executed this 31st day of January, 2008 at Newburgh, New York.

Diana Krautter Diana Krautter

State of New York )
)ss.:
County of ~~Rockland~~ ORANGE )

On the 31 day of JANUARY, in the year 2008 before me, the undersigned, personally appeared DIANA KRAUTTER, personally known to me or proved to me on the basis of satisfactory evidence to be the individual(s) whose name(s) is (are) subscribed to the within instrument and acknowledged to me that he/she/they executed the same in his/her/their capacity(ies), and that by his/her their signatures(s) on the instrument, the individual(s) or the person upon behalf of which the individual(s) acted, executed the instrument.

Notary Public

ANDREW J. ZARUTSKIE
Notary Public, State Of New York
No. 01ZA4502524
Qualified in Orange County
Commission Expires Nov. 30, 2009

**UNITED STATES**
**NUCLEAR REGULATORY COMMISSION**

***In the matter of***

| | | |
|---|---|---|
| **ENTERGY NUCLEAR INDIAN POINT 2, L.L.C.** | | **LicenseNo.** |
| **ENTERGY NUCLEAR INDIAN POINT 3, LLC** | **)** | **DPR-26 &** |
| **ENTERGY NUCLEAR OPERATIONS, LCC** | | **DPR 64** |
| **Indian Point Energy Center Unit 2 & Indian Point** | **)** | **Docket** |
| **Entergy Center Unit 3** | | **No. 50-247 & No. 50-286** |

**License Renewal Application**

## DECLARATION OF GEORGE KLEIN

My name is George Klein, I live at 74 Croton Dam Road, Ossining, NY 10562. I live approximately 10 miles from Indian Point. I am a member of the Sierra Club, and the chairman of the Sierra Club, Lower Hudson Group, representing about 5,000 members in Westchester, Putnam and Rockland counties. The Lower Hudson Group is one of 11 local groups of the Sierra Club, Atlantic Chapter, which is the New York State chapter.

The Sierra Club, Atlantic Chapter represents my interests in a Petition to Intervene, Request for Hearing and Contentions and the Notice of Appearance, in the matter of Entergy Nuclear Indian Point 2 LLC and Indian Point 3 LLC, and Entergy Nuclear Operations, Inc. License Renewal Application.

I have lived in the Hudson Valley since 1993 in locations such as New York City, Mount Kisco, New Castle and Ossining, New York.

I oppose the relicensing by NRC of any reactors at Indian Point, which is leaking radioactive waste into the local groundwater.Why allow Indian Point to continue leaking for another 20 years? This is a huge danger for public health and for the environment.

The evacuation plan is unworkable, and no locally responsible parties have approved it.

The ongoing buildup of spent fuel rods is another concern. They are a current danger, and one that increases every year. Everyone knows that they are a terrorist target. Why would we, as an intelligent society, increase the attractiveness of this as a terrorist target?

The increase in water temperature caused by using the Hudson River as a vast heat sink for Indian Point is another problem.

We do not need the electrical energy produced by Indian Point, and would rather get our energy from non-nuclear sources.

It is clear to me that for all of the above reasons Indian Point should be closed. I declare that the statements made in this declaration are true and correct to the best of my knowledge.

Executed this 31 day of January, 2008 at Ossining, New York.

George Q ______ George Klein

State of New York )
)ss.:
County of Westchester )

On the 31 day of JANUARY, in the year 2008 before me, the undersigned, personally appeared
GEORGE KLEIN, personally known to me or proved to me on the basis of satisfactory evidence to be the individual(s) whose name(s) is (are) subscribed to the within instrument and acknowledged to me that he/she/they executed the same in his/her/their capacity(ies), and that by his/her their signatures(s) on the instrument, the individual(s) or the person upon behalf of which the individual(s) acted, executed the instrument.

______
Notary Public

BERNARD HERRERA
Notary Public, State of New York
No. 01HE6144371
Qualified in Westchester County
My Commission Expires 4/24/10

# Exhibit C

Exhibit "C"

United States General Accounting Office

GAO

Report to the Honorable
Edward J. Markey,
House of Representatives

December 2001

# NUCLEAR REGULATION

# NRC's Assurances of Decommissioning Funding During Utility Restructuring Could Be Improved

GAO
Accountability * Integrity * Reliability

GAO-02-48

# Contents

**Tables**



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**Abbreviations**

| | |
|---|---|
| ALARA | as-low-as-reasonably-achievable |
| CERCLA | Comprehensive Environmental Response, Compensation and Liability Act |
| DOE | Department of Energy |
| EPA | Environmental Protection Agency |
| FASB | Financial Accounting Standards Board |
| FERC | Federal Energy Regulatory Commission |
| GAO | General Accounting Office |
| GTCC | Greater Than Class C (waste) |
| NRC | Nuclear Regulatory Commission |
| PECO | PECO Energy Company (formerly, Philadelphia Electric Company) |
| PSEG | Public Service Electric and Gas Company |
| PUC | Public Utility Commission |

GAO
Accountability * Integrity * Reliability
United States General Accounting Office
Washington, DC 20548

December 3, 2001

The Honorable Edward J. Markey
House of Representatives

Dear Mr. Markey:

This report responds to your request that we review how the Nuclear Regulatory Commission ensures, in a period of economic deregulation and restructuring of the electricity industry, that sufficient funds will be available to decommission nuclear power plants after the plants are permanently shut down.

Unless you publicly announce its contents earlier, we plan no further distribution of this report until 30 days after the date of this letter. At that time, we will send copies to the appropriate congressional committees; the Chairman, Nuclear Regulatory Commission; and the Director, Office of Management and Budget. We will also make copies available to others upon request.

Please contact me at (202) 512-3841 if you or your staff have any questions about this report. Key contributors to this report are listed in appendix II.

Sincerely yours,

Gary L. Jones

(Ms.) Gary L. Jones
Director, Natural Resources
and Environment

# Executive Summary

The Nuclear Regulatory Commission (NRC) has licensed 125 commercial nuclear power plants to operate in the United States, each for a finite number of years. For safety reasons, after a licensee retires a plant, the licensee must eventually dismantle it. The spent (used) fuel is removed from the nuclear reactor and usually stored at the plant site until the fuel can be removed for disposal. The other radioactive wastes from dismantling the plant are shipped to one or more off-site disposal facilities. Upon completion of this process, called "decommissioning," the plant site can be reused for other purposes.

The costs of decommissioning, which vary according to the size of the plant and the level of contamination, generally fall within the range of $300 million to $400 million per plant. To ensure the availability of adequate funds to pay for this process, NRC requires its licensees to select a method or combination of methods for financing future decommissioning activities from among the acceptable methods specified in its regulations.

Traditionally, plant owners amass decommissioning funds through charges imbedded in predetermined electricity rates, which state utility commissions and/or the Federal Energy Regulatory Commission regulate. However, with the deregulation of the electric utility industry in many states, a competitive market instead of regulated rates now determines the price that some plant owners can charge for producing electricity. Consequently, these plant owners can no longer collect decommissioning funds through the traditional method.

Deregulation has led many states and their electric utilities to restructure much of their electricity industry to separate the producers of electricity from those who transmit and distribute (sell) electricity to customers. As part of this restructuring, the ownership and/or operation of plants has changed for more than half of the nuclear power plants in the United States. Since 1998, for example, utilities that own all or part of eight nuclear plants have contracted the operation of these plants to other companies. And other utilities have sold or are in the process of selling all or part of 15 plants. Finally, the reorganizations and mergers of electric utilities have resulted in the transfer of licenses for more than 30 plants to companies formed specifically to produce electricity. The number of these transfers highlights the importance of NRC's regulatory role in ensuring that new licensees are financially qualified to operate, maintain, and eventually decommission these plants. The transfers also underscore the need for consistent financial disclosure of decommissioning liabilities to the potential investors in new companies formed, at least in part, to produce electricity from nuclear power plants.

Concerned about the adequacy of decommissioning funds, particularly in deregulated markets, Representative Edward Markey asked GAO to determine how (1) transfers of licenses to operate or own nuclear power plants have affected assurances that adequate funds will be available to operate and decommission these plants, (2) various site cleanup standards and proposed new decommissioning methods affect projected decommissioning costs, and (3) changes in financial reporting standards affect the disclosure and funding of decommissioning liabilities.

## Background

Before transferring a license to a new plant owner, NRC requires the prospective owner to demonstrate that it has both the technical ability and financial backing to safely own and operate the plant. NRC also requires owners to demonstrate that they will accumulate a prescribed minimum amount of funds to pay for the eventual decommissioning of their plants. Owners must ensure that these funds will be available by choosing one or a combination of the following options:

- periodic deposits (at least annually) into a trust fund outside of the owner's control;
- prepayment of the entire estimated decommissioning liability into a trust fund outside of the owner's control;
- obtaining a surety bond, insurance, letter of credit, or line of credit payable to a trust established for decommissioning costs; or
- guaranteeing the payment of decommissioning costs, provided that the guarantor (usually an affiliate or parent company to the owner) passes specific financial tests.

Until recently, essentially all plant owners chose to accumulate decommissioning funds through periodic deposits. However, in September 1998, NRC amended its regulations to restrict the use of this option in deregulated markets. Under the amended regulations, owners may rely on periodic deposits only to the extent that those deposits are guaranteed through regulated rates charged to consumers. In conjunction, NRC has issued written procedures, called a "standard review plan", describing how its staff should determine the adequacy of a prospective owner's financial qualifications to operate its plant(s) and its proposed method(s) for assuring the availability of funds to eventually decommission the plant(s).

To estimate future decommissioning costs, plant owners may use a mathematical formula that is provided in NRC's regulations or a site-specific estimate, if the costs developed from it are higher. The formula assumes that plant sites will be cleaned up in compliance with NRC's standards. By the time that a plant is decommissioned, however, other cleanup standards could apply. For example, the Environmental Protection Agency (EPA) has more restrictive cleanup standards that could, in some circumstances, be applied to a nuclear power plant site, and some states are establishing cleanup standards for decommissioning nuclear power plants and/or other nuclear facilities.

## Results in Brief

In most of the requests to transfer licenses to own or operate nuclear power plants that NRC has approved, the financial arrangements have either maintained or enhanced the assurance that adequate funds will be available to decommission those plants. Owners relying on outside companies to operate their plants have retained the responsibility for financing the future decommissioning of these plants and continue to collect funds for this purpose through their economically regulated sales of electricity. When new owners purchased all or parts of 15 plants from utility companies, the level of assurance was enhanced through the prepayment of the decommissioning trust funds and guarantees from affiliate or parent companies to pay any remaining decommissioning costs. However, when new owners proposed to continue relying on periodic deposits to external sinking funds, NRC's reviews were not always rigorous enough to ensure that decommissioning funds would be adequate. Moreover, NRC did not always adequately verify the new owners' financial qualifications to safely own and operate the plants. Accordingly, GAO is making a recommendation to ensure a more consistent review process for license transfer requests.

Varying cleanup standards and proposed new decommissioning methods introduce additional uncertainty about the costs of decommissioning nuclear power plants in the future. Plants decommissioned in compliance with NRC's requirements may, under certain conditions, also have to meet, at higher cost, more stringent EPA or state standards. New decommissioning methods being considered by NRC, which involve leaving more radioactive waste on-site, could reduce short-term decommissioning costs yet increase costs over the longer term. Moreover, they would raise significant technical and policy issues concerning the disposal of low-level radioactive waste at plant sites instead of in regulated disposal facilities. Adding to cost uncertainty, NRC allows plant owners to wait until 2 years before their license is terminated—relatively late in the decommissioning process—to perform overall radiological assessments to determine whether any residual radiation anywhere at the site will need further clean-up in order to meet NRC's site release standards. Accordingly, GAO is recommending that NRC reconcile its proposed decommissioning methods with existing waste disposal regulations and policies and require licensees to assess their plant sites for contamination earlier in the decommissioning process.

Changes to the Financial Accounting Standards Board's financial reporting standard will require, for the first time, owners of facilities that require significant end-of-life cleanup expenditures—such as nuclear power plants—to consistently report estimated decommissioning costs as liabilities in their financial statements. When this standard takes effect in mid-2002, many companies that are licensed by NRC to own nuclear power plants will have to change their current financial-reporting practices, and the reporting of estimated decommissioning costs will become more uniform. However, the new accounting standard is not intended to, and will not, establish a legal requirement that these licensees set aside adequate funding for decommissioning costs.

# Principal Findings

## Effect of License Transfers on Decommissioning Funding

The level of assurance that adequate decommissioning funds will be available when licensees retire nuclear power plants has remained the same or increased for most of the license transfers that NRC has reviewed and approved. When plant owners contracted out the operation of their plants, NRC required the owners to continue collecting decommissioning funds through their regulated electricity rates, thus maintaining the previous level of assurance. When NRC reviewed and approved the sale of all or parts of 15 plants to new generating companies, the level of assurance was enhanced because the selling utilities generally prepaid the projected decommissioning funds. To the extent that a few decommissioning trust funds were not fully prepaid, either the selling utility or the new owners' affiliated or parent companies provided additional guarantees consistent with NRC's requirements.

In instances when new owners continued to rely on periodic deposits to the transferred trust funds, however, NRC's review process did not consistently result in the same level of assurance that decommissioning funds would be adequate when the owners' plants shut down. For example, when a new company formed through a merger applied to transfer the licenses for the ownership of all or parts of 20 plants, including 4 retired plants, NRC did not verify whether there were contractual arrangements to transfer the decommissioning funds collected for the plants into the trust funds for those plants. Also, for the four plants that had permanently shut down, NRC did not request that the new owner (1) provide any more information on the status or plans for these prematurely shut down plants than it had for the 16 plants that were operating or (2) demonstrate how the owner planned to acquire the additional decommissioning funds as it had for another retired plant.

For the most part, NRC's reviews of new owners' financial qualifications have enhanced the level of assurance that they will safely own and operate their plants in a deregulated environment and not need to shut them down prematurely. However, NRC did not obtain the same degree of financial assurance in the case of one merger that created a new generating company that is now responsible for owning, operating, and decommissioning the largest fleet of nuclear plants in the United States. This new owner did not provide, and NRC did not request, guaranteed additional sources of revenue above the market sale of its electricity, as other new owners had. Moreover, NRC did not document its review of the financial information—including revenue projections, which were inaccurate—that the new owner submitted to justify its qualifications to safely own and operate 16 plants.

## Effect of Regulatory Policies on Decommissioning Costs

Varying radiation cleanup standards and the possibility that NRC will approve alternative decommissioning methods are two of the most significant factors that add uncertainty to estimates of future decommissioning costs. Depending on future circumstances, for example, plants decommissioned according to NRC's radiation cleanup standards could also have to meet more stringent EPA or state standards, potentially increasing the cost of decommissioning. EPA has indicated that if NRC does not tighten its standards, EPA could reconsider its policy of exempting decommissioned nuclear plant sites from the stricter cleanup standards that EPA enforces under the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended (also known as CERCLA or Superfund). In addition, the states of Maine, Massachusetts, New York, and New Jersey have already adopted radiation cleanup standards stricter than NRC's, and more states may do so. These stricter standards will require plant owners to incur significant additional decommissioning costs; for example, officials from one plant estimate that

Maine's standard will add $25 million to $30 million to the decommissioning costs for that plant.

Alternative decommissioning methods under consideration for NRC's approval would have an unknown affect on overall decommissioning costs. Because the methods involve leaving more radioactive waste on-site—either buried as rubble or encased within the reactor containment structure—they would reduce the waste-disposal component of decommissioning costs. However, they could add considerably to long-term costs because of the need for extended institutional control of the sites. Moreover, these methods appear to conflict with NRC's technical requirements for licensing low-level radioactive waste disposal facilities. In addition, the proposed methods may run counter to the policy expressed in the Low-Level Radioactive Waste Policy Amendments Act, which encourages states to manage low-level radioactive wastes on a regional basis and to provide centralized disposal facilities.

Another potentially significant factor contributing to the uncertainty about decommissioning cost is the lack of information on the degree of contamination at some plant sites. NRC's decommissioning requirements allow plant owners to wait until 2 years before the proposed license termination date to perform an overall survey of their plant sites for radiation contamination. Postponing the survey until this late in the decommissioning process increases the risk that owners will incur unplanned cleanup expenses after significant portions of the available decommissioning funds have already been expended.

## Disclosure of Liability for Decommissioning Costs

The Financial Accounting Standards Board has adopted a new financial reporting standard that, beginning in mid-2002, should result in more uniform reporting of decommissioning costs. Currently, companies disclose their liability for decommissioning costs using a number of different methods, making comparisons by investors difficult. Under the new standard, companies must report estimated decommissioning costs as liabilities in their financial statements, using a specified method to calculate the amount of the liability. However, the new standard applies not just to nuclear power plants but to other industries as well, and the method specified differs from the method that NRC requires for nuclear power plant licensees. The new standard will have no legal or regulatory affect on the actual accumulation of decommissioning funds and is not intended to do so.

## Recommendations for Executive Action

To ensure that the decommissioning assurance methods and financial qualifications of all new plant owners are consistently verified, validated, and documented, GAO recommends that the Chairman, NRC, revise the Commission's standard review plan and related management controls for reviewing license transfers to include a checklist or step-by-step process for its staff, management, and prospective plant owners to follow.

GAO also recommends that the Chairman, NRC, amend the Commission's ongoing consideration of modifications to radiological criteria for terminating licenses and alternative decommissioning approaches to address

- how the burial or entombment of low-level radioactive waste at nuclear plant sites, leading to a potentially large number of contaminated sites scattered around the country, may affect the federal policy under the Low-Level Radioactive Waste Policy Act to manage radioactive waste on a regional basis, and
- concerns about whether these decommissioning approaches are technically compatible with provisions of the Low-Level Radioactive Waste Policy Act, the interstate compact agreements that implement the act, and NRC's technical regulations on licensing disposal facilities for low-level radioactive waste.

To reduce the likelihood that site contamination will go undetected until late in the cleanup process, GAO recommends that the Chairman, NRC, require licensees to survey their plant sites for radiation as soon as possible after the announcement of their intentions to permanently cease operations, rather than allowing them to wait until 2 years before decommissioning is supposed to be complete.

## Agency Comments and GAO's Evaluation

GAO provided NRC with a draft of this report for review and comment. NRC said that GAO has provided constructive comments regarding documentation of the financial considerations associated with requests to transfer licenses for nuclear power plants. NRC also said it is concerned that GAO has not fully represented certain aspects of its review process for license transfers, nor entirely considered the various processes associated with the decommissioning of a nuclear plant. NRC provided specific comments on these matters, including reasons why, in some cases, it does not agree with GAO's recommendations. NRC's comments also, it said, supplied a more comprehensive perspective on our conclusions and recommendations. (NRC's comments are contained in app. I.)

Specifically, NRC disagreed that it should modify its review guidance to include a checklist or step-by-step process to be followed because many of the proposed license transfers are unique. GAO disagrees. Licensees have consistently used a few basic methods of providing decommissioning funding assurance. Revising the review guidance to ensure, on the basis of NRC's experiences to date, that each license transfer review is based on information that is consistent with other transfers that used similar methods of assurance could help NRC meet its goal of increasing its efficiency and effectiveness.

NRC also disagreed that it should address technical and policy issues associated with the potential on-site burial of radioactive waste from decommissioning nuclear plant sites because this waste would not be classified as low-level radioactive waste. GAO disagrees because it is difficult to discern why radioactive material buried on-site—material that has traditionally been shipped to disposal facilities designed and regulated for such purpose--does not merit the same protection as material sent to a low-level waste disposal site.

Finally, NRC disagreed that it should require licensees to make radiation surveys of their plant sites earlier because this proposed step would not add significant value to the decommissioning process. GAO disagrees, because plant employees most knowledgeable about historical plant operations and site conditions would more likely be available when a plant has been permanently shut down rather than later when decommissioning has been almost completed.

# Chapter 1: Introduction

Nuclear power plants generate about 20 percent of electricity in the United States. At the time of this review, there were 103 of these plants in operation.[1] No new nuclear power plants have been ordered since 1978, however, and 22 plants that previously operated under licenses issued by the Nuclear Regulatory Commission (NRC) have been permanently shut down. The licenses for 45 additional plants will expire within the next 15 years. The owners of these plants, therefore, will have to choose whether to retire their plants or to seek license extensions from NRC for up to an additional 20 years.

Radioactive contamination lingers long after power plants are closed. To protect public health and safety, the amount of residual radioactivity present at the site of a retired nuclear power plant must be reduced through a process known as decommissioning. After the spent (used) fuel has been removed from the plant's reactor vessel, the plant must be dismantled and the radioactive wastes shipped to one or more disposal facilities for radioactive wastes.[2] The decommissioning process is still relatively new—3 of the 22 retired commercial nuclear power plants have been decommissioned, 6 other plants are being decommissioned, and 13 plants are awaiting decommissioning. The process is also costly. Experience to date shows that decommissioning costs anywhere from $300 million to $400 million or more, depending on factors, such as plant size, the extent of contamination, and waste disposal costs.

NRC and plant owners must balance public health and safety with the cost and technical logistics of the decommissioning process. Moreover, the relatively high cost of decommissioning a nuclear power plant makes the process an issue for economic regulators, such as the Federal Energy Regulatory Commission (FERC) and state public utility commissions (PUC's), and the electricity industry in the relatively new environment of deregulating and restructuring the electricity industry.

[1] These numbers do not include one plant—the Tennessee Valley Authority's Brown's Ferry Unit 1 plant—that is licensed to operate. That plant, however, has not operated since March 1985, has no fuel loaded, and cannot load fuel and restart without NRC's approval.

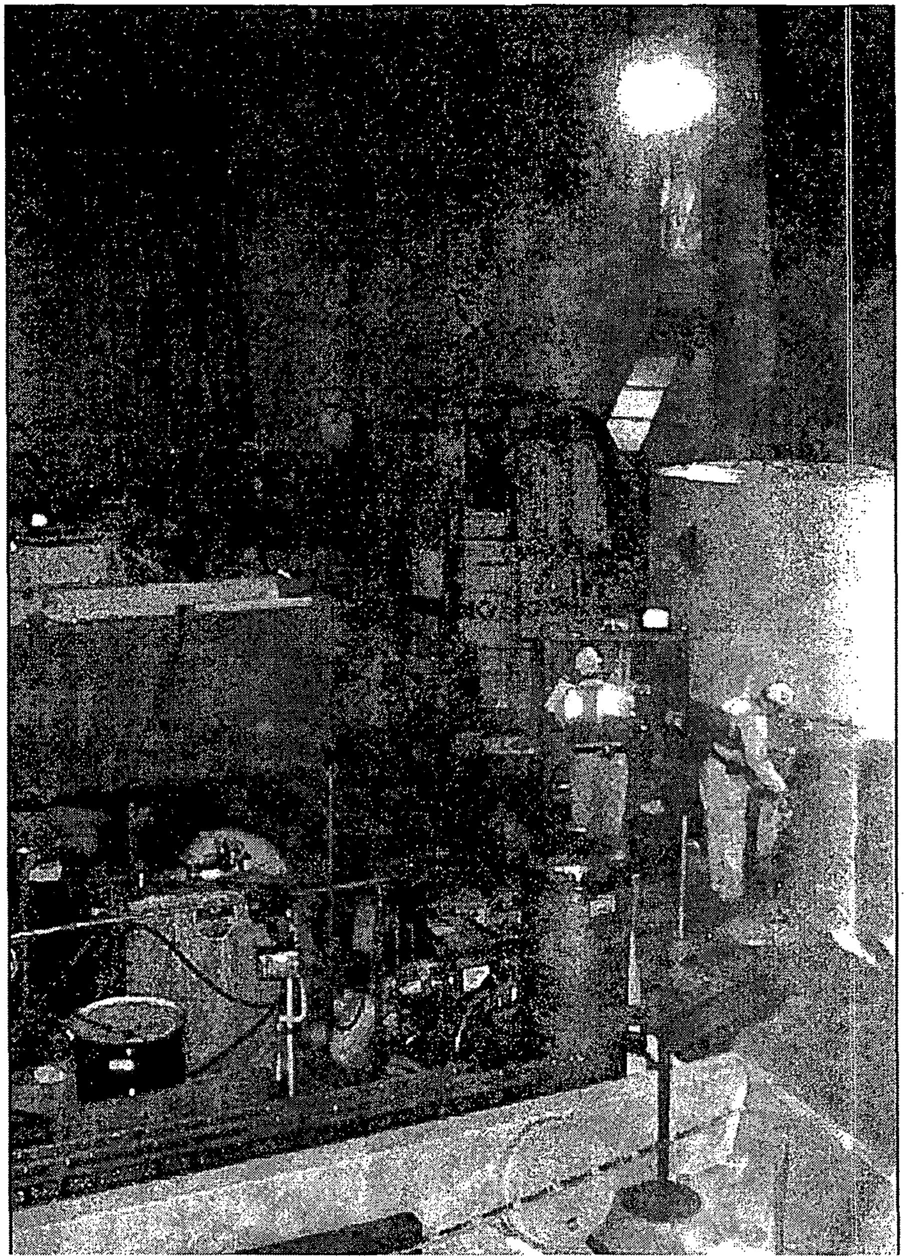
[2] The Department of Energy (DOE) is responsible for disposing of the spent fuel from commercial nuclear power plants in a geologic repository. Pending the approval and completion of the proposed Yucca Mountain repository project, owners of nuclear plants are storing their spent fuel at plant sites. NRC does not consider spent fuel storage and disposal costs as decommissioning costs.

## Decommissioning Regulations Outline Technical Procedures

Before obtaining a license to operate a nuclear power plant, the licensee must agree with NRC to decommission the plant after the plant has been permanently shut down. NRC established its decommissioning requirements in regulations issued in 1988. Under these regulations, NRC expected that decommissioned sites, with rare exceptions, would reduce levels of radiation to allow the plant site to be released for unrestricted use once the license was terminated. Licensees had two decommissioning alternatives.[3] They could either begin major site decontamination and dismantling activities shortly after the termination of operations or maintain the plant and site in a safe condition up to several decades before dismantling the plant. Delaying full-scale decontamination and dismantling activities could be advantageous if (1) more time was needed to accrue decommissioning funds by continuing to collect funds from ratepayers after the plant has closed; (2) other units operating at the site would be disrupted unless all were decommissioned simultaneously at a future time; (3) a reduction in waste disposal volume, cost, or radiation exposure was possible because of a reduction in residual radiation over time; or (4) a licensed disposal facility for radioactive waste was unavailable. (Figure 1 shows ongoing decontamination and dismantling activities at one plant.)

[3] A third alternative—encasing radioactive wastes within the reactor building—was used by the DOE to decommission three of its small reactors. NRC, in promulgating its decommissioning regulations in 1988, opposed use of this decommissioning method for its licensees unless warranted to protect public health and safety. Since then, no licensee has proposed using this decommissioning method.

Figure 1: Ongoing Decommissioning Work Within the Containment Building at the Connecticut Yankee Atomic Power Company Haddam Neck Plant



Source: GAO.

When power operations at a nuclear power plant cease, the licensee must notify NRC, permanently remove the fuel from the reactor vessel, and confirm this action to NRC. Within 2 years, the licensee must provide a report to NRC addressing, among other things, decommissioning plans and the estimated costs of these activities. NRC then publishes a notice of receipt, makes the document available for public comment, and holds a public meeting in the vicinity of the plant to discuss decommissioning plans. The licensee may not perform any major decommissioning activities until 90 days after NRC receives the post-shutdown decommissioning activities report and the certifications of permanent cessation of operations and fuel removal. NRC currently requires that decommissioning be completed within 60 years unless public health and safety reasons require that an extension be granted.

Concurrent with plant decommissioning, a licensee must supply NRC a plan for terminating its license at least 2 years before the planned termination date. At the end of the license termination process, the licensee must conduct a final radiation survey to prove that the site meets radiological criteria for release and must include the survey with the plan. The licensee remains accountable to NRC until decommissioning has been completed and the license is terminated.

NRC's 1988 decommissioning regulations outlined several acceptable approaches for decommissioning nuclear power plants, but regulations did not establish acceptable residual radioactivity levels for the unrestricted release of decommissioned sites. In 1996, NRC published its final rule on the decommissioning of nuclear power plants. This final rule (1) redefined the decommissioning process; (2) defined terminology related to decommissioning; (3) required licensees to provide the NRC with early notification of planned decommissioning activities at their facilities; and (4) explicitly stated the applicability of certain NRC requirements that are specific for reactors that are permanently shut down. However, NRC did not amend its regulations to include radiological criteria for license termination until 1997. The final rule included radiological criteria for releasing decommissioned sites for both unrestricted and restricted future uses. For restricted future uses, licensees must provide safeguards to ensure that access to the site will be restricted until dose levels decay to the radiation level set for unrestricted site releases. The safeguards include requirements for physical barriers, security, monitoring, maintenance, financial assurance provisions, and other institutional controls to ensure that access to the site remains restricted for the entire internment period.

On the basis of its regulations restricting the dosages to members of the public under both the unrestricted and restricted release scenarios, NRC is also now considering two alternative decommissioning approaches. One approach, called rubblization, would permit licensees to demolish plant concrete that is contaminated with radioactivity into rubble and bury the rubble in the underground portion of the dismantled plant. The other approach, called entombment, would involve the permanent encasement of the radioactive contaminants from a partially dismantled plant within the remaining structure of the plant. NRC is also considering extending the timeframe for completing decommissioning from 60 to 100 years or more. As with other decommissioning alternatives, licensees selecting rubblization or entombment would be required to demonstrate compliance with NRC's regulations for license termination, including a demonstration that residual radiation doses at the site are as low as is reasonably achievable.

NRC has primary regulatory authority over nuclear power plant operations and decommissioning, but it is not the only entity that promulgates radiation protection standards. The Environmental Protection Agency (EPA) also issues radiation standards and administers the Comprehensive Environmental Response, Compensation, and Liability Act of 1980 (CERCLA), which governs cleanups of federal and non-federal facilities. EPA has authority to evaluate NRC-regulated sites once the sites are decommissioned. NRC and EPA have historically disagreed over radiation protection standards. Differences in legislative mandates, agency missions, and regulatory strategies contribute to this disagreement, which remains essentially unchanged today despite resolution efforts spanning a number of years. States also have authority to issue their own standards, which may be more stringent than either NRC's or EPA's. Consequently, whereas NRC may approve decommissioning plans and terminate the NRC operating license based on its standards, plant owners may still be subject to other federal and state standards once the NRC license is terminated.

## Decommissioning Regulations Outline Financial Procedures

NRC has authority under the Atomic Energy Act of 1954, as amended, to require licensees to accumulate the funds necessary to decommission their nuclear power plants. Prior to 1988, NRC only required licensees to certify that sufficient funding would be available to decommission their plants when needed and did not require any specific financial provisions. On July 26, 1988, NRC strengthened its technical and financial requirements for decommissioning and offered several options for providing financial assurance. The options included:

- prepayment of the entire estimated decommissioning liability in cash or liquid assets into a separate, segregated account outside the licensee's control;
- external sinking funds segregated from other licensee assets and outside licensee control that are established and maintained by periodic funding;
- surety methods or insurance; or
- for federal licensees only, a statement of intent that decommissioning funds will be obtained when necessary.

Essentially, most if not all utilities eventually elected the option to establish external sinking funds (trust funds) to finance future decommissioning costs. Under this option, decommissioning funds are accumulated over the operational life of a nuclear power plant as part of the cost charged to customers for the electricity they use.

In establishing its regulations, NRC recognized that the external sinking fund option allowed the rate-setting authority of FERC and state public utility commissions to control the rate at which decommissioning funds could be accumulated. Given the additional uncertainty involved in estimating future decommissioning costs, NRC required only that licensees provide "reasonable assurance" that sufficient funds would be available to decommission their nuclear power plants when they are shut down. In 1998 , NRC also began requiring licensees to provide financial reports every 2 years on the status of their decommissioning funds. NRC provided licensees with a mathematical formula to initially determine and periodically adjust the estimated amounts required in the funds for radiological decontamination of their plant sites. Licensees may also base their decommissioning trust funds on site-specific estimates of decommissioning costs if these estimates exceed the amounts calculated using NRC's formula.

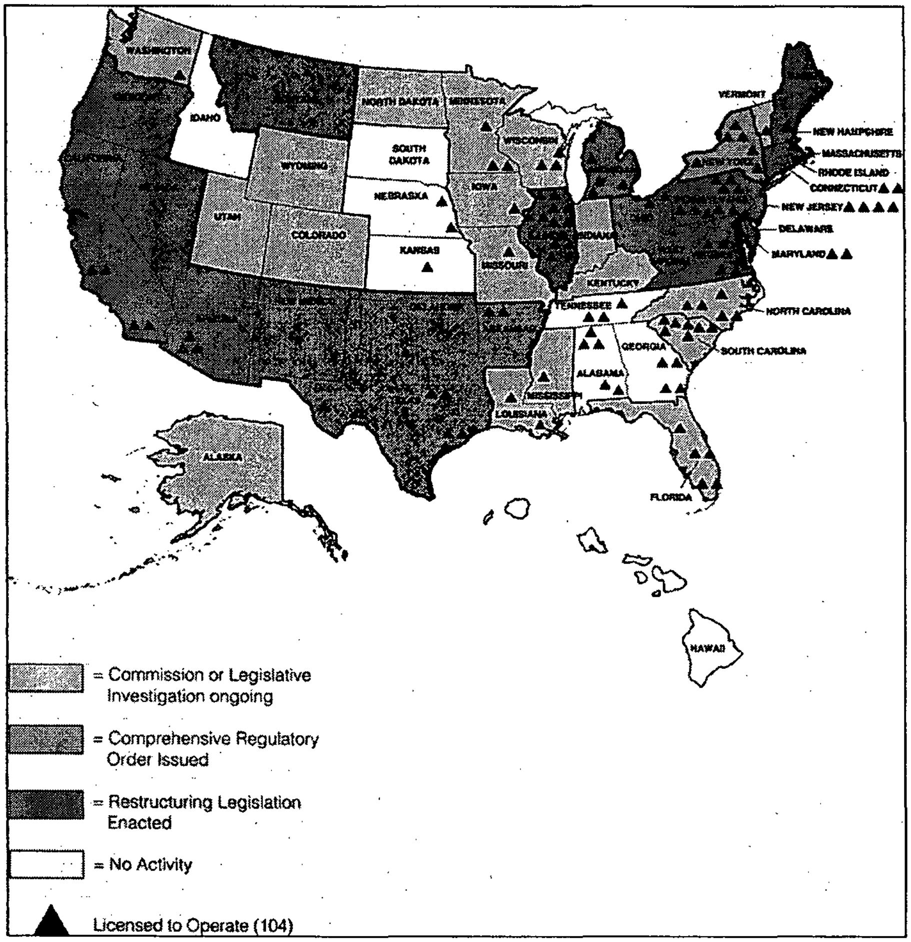
The length of time that a nuclear power plant remains in operation depends on several factors. NRC typically issues operating licenses for 40 years. Licensees with economically viable plants that still meet NRC's operational requirements may opt to extend operations rather than close their doors. On the other hand, licensees with financially marginal plants may decide to cease operations rather than shoulder large cost requirements for equipment upgrades or repairs, or to address NRC's concerns. An operational accident could also bring a premature end to operations, as could local public and political sentiment or NRC closure for safety reasons. As decommissioning funds are typically accumulated over the expected operational lifetime of the plant, plants that close prematurely may not have accumulated sufficient funds and may have to defer the decommissioning process. Furthermore, where several units are situated at the same site, licensees may delay decommissioning work until all plants can be decommissioned at the same time.

## Deregulation of Electric Utilities and Resultant Industry Restructuring

Historically, nuclear power plants were constructed and operated primarily by investor-owned utilities.[4] Beginning in the mid-1990s, however, many states began to deregulate the electricity industry and to mandate or encourage industry restructuring. Under deregulation, subject to federal oversight, the ownership and control of electricity generation was separated from the transmission and distribution functions to facilitate competition. Traditional utilities continue to serve the transmission and distribution functions, while new business entities—formed through operating arrangements, plant sales, corporate realignments, and mergers—often handle the electricity production function. In recent years, NRC has reviewed more than 60 license transfer requests. These transfer requests have affected about half the nuclear plants in the United States, and some licenses were transferred several times for multiple reasons.

[4] In addition, smaller investor-owned utilities, publicly-owned utilities, or cooperatives own or have owned a few entire plants or shares of some plants.

**Figure 2: Map of Nuclear Power Plants in the United States and Status of Deregulation by State**




Note: Includes Browns Ferry Unit 1, which has no fuel loaded and requires Commission approval to restart.

Source: Nuclear Regulatory Commission and Energy Information Administration Illustrations, as modified by GAO.

While the move to deregulate the electric industry has resulted in changes that affect the status of licensees in some states, many licensees today still remain investor-owned utilities that operate as state-regulated monopolies. NRC has provided its staff, managers, and licensees with guidance on how it will review requests to transfer licenses, including determining whether the new license holders would continue to operate under economic regulation or in an economically deregulated environment. This guidance is in the form of a standard review plan on nuclear power plant licensees' financial qualifications to operate their plants and assurances that the licensees will provide adequate funds to decommission the plants. The review plan discusses each of the review procedures that the NRC staff should use, as appropriate, to determine the adequacy of a prospective licensee's financial qualifications and decommissioning funding method(s). For example, the review plan discusses how NRC's staff should evaluate external sinking fund trust documents and other decommissioning financial assurance mechanisms.

## Objectives, Scope, and Methodology

Concerned about the adequacy of decommissioning funds, particularly in deregulated markets, Representative Edward Markey asked us to determine how (1) transfers of licenses to operate or own nuclear power plants affected the level of assurance that adequate funds will be available to operate and decommission these plants, (2) various site cleanup standards and proposed alternative decommissioning approaches affect projected decommissioning costs, and (3) proposed changes in financial reporting standards affect disclosure and funding of decommissioning liabilities.

To determine how license transfers for nuclear power plants affected NRC's level of assurance that adequate funds will be available to decommission these plants, we reviewed NRC's Standard Review Plan on Power Reactor Licensee Financial Qualifications and Decommissioning Funding Assurance, as well as related memoranda, regulations, policy statements, regulatory analyses, and regulatory guidance. We contacted NRC's Office of Inspector General to discuss the weaknesses it had reported in licensee's biennial reports to NRC regarding decommissioning fund balances. At NRC's headquarters in Rockville, Maryland, we met with officials from NRC's offices of Nuclear Reactor Regulation and Nuclear Material Safety and Safeguards to discuss decommissioning financial assurance issues regarding non-owner operating arrangements, nuclear plant sales, corporate reorganizations, and mergers. We also reviewed licensee information provided to NRC regarding these license transfers, and analyzed NRC's review and approval documents related to license transfer requests submitted for 9 non-owner operating arrangements, 19 sales, 3 corporate reorganizations, and one merger.

To determine how site cleanup standards and proposed alternative decommissioning approaches affect projected decommissioning costs, we obtained, from EPA and NRC, and reviewed memoranda, regulations and other documentation addressing decommissioning and radiation protection standards. We reviewed published GAO reports that dealt with decommissioning financial assurance, nuclear waste disposal, radiation protection standards, and other related issues. We also reviewed a recent National Research Council report that questioned the reliability of long-term institutional management controls at nuclear waste sites. We also contacted EPA and NRC staff regarding efforts to resolve interagency disagreement over radiation protection standards and related issues, and met with staff from NRC's offices of Nuclear Reactor Regulation and Nuclear Material Safety and Safeguards to discuss issues regarding radiation protection standards, past decommissioning methods and experience, and proposed decommissioning alternatives and their potential impact on decommissioning cost. In addition, we reviewed the minutes from an August 1999 NRC public workshop dealing with decommissioning and proposed waste disposal options.

To acquire a first-hand perspective on decommissioning, we obtained and reviewed the license termination plans from and made visits to the Connecticut Yankee Atomic Power Company plant at Haddam, Connecticut, and the Maine Yankee Atomic Power Company plant at Wiscasset, Maine. At the Haddam plant, we met and discussed decommissioning issues with officials from the Connecticut Yankee Atomic Power Company, Bechtel Power Corporation (the decommissioning contractor), and the Connecticut Department of Environmental Protection. We also toured the Haddam Plant and observed ongoing decommissioning work within the reactor building (containment). In addition, we met with local members of the Citizens Awareness Network, a non-profit volunteer organization, to discuss issues and concerns regarding the decommissioning of the Haddam Plant. In Maine, we met with two state senators knowledgeable about the controversy over original decommissioning plans to rubblize the Maine Yankee site and the involvement of the state legislature in the Maine Yankee decommissioning. We also met with a member of Friends of the Coast—a local citizens' environmental organization. We contacted officials from the Maine Department of Environmental Protection and Department of Human Services by telephone and discussed Maine Yankee decommissioning issues. In Washington, D.C., we met with members of the Nuclear Energy Institute, Union of Concerned Scientists, Nuclear Information and Resource Service, and Public Citizen to discuss decommissioning issues. In addition, we attended the Fifth Biennial Industry Conference on Decommissioning held in October 2000 and a NRC public decommissioning workshop held in November 2000.

To determine how a recently adopted financial reporting standard will affect the disclosure and funding of decommissioning liabilities, we reviewed the annual reports and/or annual filings with the Securities and Exchange Commission (Forms 10 K) for 55 utility companies that own nuclear power plants. From those, we determined the methods currently used to account for decommissioning costs. We also reviewed FASB Exposure Draft No. 206-B entitled "Accounting for Obligations Associated with the Retirement of Long-Lived Assets," (adopted in June 2001 as FASB Statement No. 143) as well as selected responses of public accounting firms and utility companies to the Exposure Draft. From our review, we determined how the new standard would affect the financial statements of utility companies with nuclear power plants.

We performed our review between June 2000 and August 2001 in accordance with generally accepted government auditing standards.

# Chapter 2: Most Restructuring License Transfers Have Maintained or Enhanced Assurance of Decommissioning Funding

As a result of restructuring in the electricity industry, NRC has approved requests to transfer the licenses to own or operate more than one-half of the nuclear power plants in the United States. Some license transfer requests involved a single owner of one or more plants transferring licenses to own or operate the plant(s) to one or more new owners or operators. Other requests involved transfers of licenses to own or operate one or more plants from multiple owners of these plants. For most of the requests that NRC reviewed to transfer licenses for one or more plants, the level of assurance that the plants' decommissioning funds will be adequate has been maintained or enhanced. For example, when plant owners requested that their operating licenses for eight plants be transferred to a contractor, NRC maintained the existing level of assurance by continuing to hold the plant owners responsible for collecting decommissioning funds. In addition, when NRC approved requests to transfer licenses related to the sale of 15 plants, decommissioning funding assurances were increased because the selling utilities prepaid all or most of the projected decommissioning costs, and either the sellers or the new owners provided additional financial guarantees for those projected costs that were not prepaid. However, when NRC approved requests to transfer licenses in which the new licensee intended to rely on periodic deposits into external sinking funds for decommissioning, it did not always obtain the same level of financial assurance as when plants were sold or their operations contracted out. Among other things, NRC approved two requests to transfer ownership of 25 plants without verifying that the new owners would have guaranteed access to the decommissioning charges that their affiliated utilities would collect.

NRC also requires prospective new owners of plants that will not be selling their electricity at regulated rates to demonstrate their financial qualifications to safely own and operate the nuclear power plants that they are acquiring. In almost all of its reviews of new owners' financial qualifications, NRC has required additional guarantees from parent or affiliated companies that the new owners would have sufficient revenue to cover the plants' operating costs. However, when reviewing one prospective owner's financial qualifications, NRC did not require additional guarantees and did not validate the information submitted by the new owner to demonstrate that the company was financially qualified to safely own and operate the largest fleet of nuclear plants in the United States.

## Funding Assurance Is Maintained for License Transfers Related to Contracting Out Operations

The level of assurance that decommissioning funds will be adequate has been maintained in all license transfer approvals that allowed plant owners to contract out plant operations. For example, traditional electric utilities that own 17 nuclear power plants have used companies that specialize in the operation, maintenance, and decommissioning of nuclear power plants to help them operate or decommission their plants. The owners of fifteen of these plants had to get NRC's approval to transfer their operating licenses. For the other two plants, NRC decided that the proposed arrangements did not require transfers of operating licenses. (See table 1.) For all 15 operating license transfers, NRC continues to hold the owners responsible for accumulating decommissioning funds, and the owners continue to collect these funds through regulated electricity rates. Accordingly, these operating license transfers have not changed the level of decommissioning funding assurance for these plants.

**Table 1: Nuclear Power Plants With Non-owner Operating Arrangements**

| Nuclear power plant | Operator's business arrangement with owner(s) | NRC operating license transfer required? |
|---|---|---|
| Duane Arnold Energy Center | Operating services agreement[a] | Yes |
| Kewaunee Nuclear Power Plant | Operating services agreement[a] | Yes |
| Monticello Nuclear Generating Plant | Operating services agreement[a] | Yes |
| Palisades Plant | Operating services agreement[a] | Yes |
| Point Beach Nuclear Plant, Unit 1 | Operating services agreement[a] | Yes |
| Point Beach Nuclear Plant, Unit 2 | Operating services agreement[a] | Yes |
| Prairie Island Nuclear Generating Plant, Unit 1 | Operating services agreement[a] | Yes |
| Prairie Island Nuclear Generating Plant, Unit 2 | Operating services agreement[a] | Yes |
| John M. Farley, Unit 1 | Affiliated company[b] | Yes |
| John M. Farley, Unit 2 | Affiliated company[b] | Yes |
| Edwin I Hatch, Unit 1 | Affiliated company[b] | Yes |
| Edwin I Hatch, Unit 2 | Affiliated company[b] | Yes |
| River Bend, Unit 1 | Affiliated company[b] | Yes |
| Vogtle, Unit 1 | Affiliated company[b] | Yes |
| Vogtle, Unit 2 | Affiliated company[b] | Yes |
| Clinton Power Station | Management services agreement[c] | No |
| Maine Yankee Atomic Power Plant | Management services agreement[c] | No |

[a]Operating licenses for eight plants were transferred to one company, Nuclear Management Company, which was formed by the plants' electric utility owners to provide operating and eventual decommissioning services for the plants. NRC approved the operating license transfers but continues to hold the utility-owners responsible for collecting decommissioning funds for the plants through their regulated electricity rates.

[b]Seven transfers of operating licenses resulted from corporate reorganizations or mergers in which an existing operations organization split off from an electric utility and formed a new affiliated company specializing in nuclear plant operations. The utility owners continue to collect decommissioning funds for the plants through their regulated electricity rates.

[c]In two cases, in which utility owners entered into management services agreements with outside companies to assist them with operating and decommissioning their plants, NRC did not require operating license transfers. In both cases, NRC determined that because the management services provided by the operating companies did not involve activities that would require a license, such as maintenance of safety-related equipment or the emergency preparedness program, and because the utility owners retained final decision-making authority, no transfer of operating authority had taken place that required NRC's approval. The utility owners continued to collect decommissioning funds through their regulated electricity rates.

Source: GAO's analysis of NRC data.

## Prepayment and Company Guarantee Methods Have Enhanced Funding Assurances When Licenses Are Transferred

When NRC has approved license transfers for plants that chose the prepayment and guarantee methods, assurance of adequate decommissioning funding has been enhanced. To date, all the transfers that NRC has reviewed as a result of plant sales have chosen either total prepayment or a combination of these methods. For example, as a direct response to deregulation legislation in many Northeast, Mid-Atlantic, and Midwest states, NRC has approved the transfer of the ownership interests in 15 nuclear power plants from traditional electric utilities to newly formed generating companies. The utilities selling 13 of these plants proposed to transfer prepaid decommissioning trust funds to the generating companies. NRC concurred with these proposals and also imposed conditions on how the new owners must manage these funds to ensure that they are preserved and accumulate as projected in a market environment. For the other two plants, the selling utility—the Power Authority of the State of New York—chose to retain control of the prepaid decommissioning trust funds for its two plants and not transfer them to the new owners (Entergy Nuclear Indian Point 3 and Entergy Nuclear Fitzpatrick). Because the Power Authority would no longer be a licensed owner or operator of the two plants, NRC imposed additional conditions upon these license transfers, allowing NRC intercession to release funds for decommissioning if the Power Authority does not comply with its responsibility to do so.

In three transfers the accumulated trust funds did not cover small portions—less than 8 percent—of the projected decommissioning costs. In these cases, either the buyer's or the seller's parent or affiliated companies passed NRC's financial test and provided contractual guarantees that they would provide additional funds as needed. Consequently, NRC has assurances that all approved new plant owners will have adequate funds available to decommission their plants in a deregulated environment. Table 2 lists the 15 plant sales that NRC has approved, along with the projected amount of decommissioning funding needed and the amount available in the trust funds at the time of the sales.

**Table 2: Decommissioning Funds Needed, Transferred, and Assurance Methods Used for Nuclear Power Plants Approved for Sale**

Dollars in millions

| Nuclear power plant | Percent sold | Projected funds needed | Funds approved to transfer | Decommissioning assurance method |
|---|---|---|---|---|
| Clinton Power Station | 100.00 | $347.880 | $210.000 | Prepayment + 2% interest[a] |
| James A Fitzpatrick | 100.00 | $358.000 | $343.968[b] | Prepayment + 2% interest[a]+ guarantee |
| Hope Creek | 5.00 | $18.014 | $9.681 | Prepayment + 2% interest[a] |
| Indian Point, Unit 3 | 100.00 | $292.000 | $315.225[b] | Prepayment + guarantee |
| Millstone, Unit 1[c] | 100.00 | $504.481 | $293.712 | Prepayment + guarantee + 2% interest[a] |
| Millstone, Unit 2 | 100.00 | $298.630 | $252.944 | Prepayment + 2% interest[a] |
| Millstone, Unit 3 | 93.47 | $316.728 | $246.838 | Prepayment + 2% interest[a] |
| Oyster Creek | 100.00 | $333.462 | $400.000 | Prepayment |
| Peach Bottom, Unit 2 | 15.02 | $56.401 | $44.775[d] | Prepayment + 2% interest[a] + guarantee |
| Peach Bottom, Unit 3 | 15.02 | $56.401 | $46.202[d] | Prepayment + 2% interest[a] + guarantee |
| Pilgrim | 100.00 | $327.000[e] | $396.000 | Prepayment |
| Salem, Unit 1 | 14.82 | $44.000 | $36.837 | Prepayment + 2% interest[a] |
| Salem, Unit 2 | 14.82 | $44.000 | $35.635 | Prepayment + 2% interest[a] |
| Three Mile Island, Unit 1 | 100.00 | $268.870 | $303.000 | Prepayment |
| Vermont Yankee | 100.00 | $328.300[f] | $280.000[f] | Prepayment + 2% interest[a] |

[a]NRC requirements in 10 CFR 50.75(E)(1)(i) and (ii) for the prepayment and external sinking fund assurance methods, respectively, allow licensees to take credit for future earnings on their trust funds at a real rate of return (i.e., adjusted for inflation) of up to 2 percent per year. Licensees may claim higher rates if specifically authorized by their rate regulator.

[b]The seller does not plan to transfer these funds to the new owner and will instead retain the trusts after the plants are sold. The seller has provided a guarantee that the funds will remain available for decommissioning. In addition, the seller has agreed, as a condition of the trust agreements that, since it will no longer be licensed, NRC may intercede to release the funds, if needed.

[c]This plant, permanently shut down in July 1998, has been defueled and placed in a "Cold and Dark" state by the seller. These funds are based on a site-specific estimate and include the buyer's parent company guarantee of $25,423,666. The funds are intended to support annual monitoring costs of $2,947,285 during SAFSTOR and to accumulate until 2054, when final decommissioning is anticipated.

[d]These funds are the cumulative funds collected by 2 utilities with equal selling shares; however, one utility has collected less than half of this amount. Originally both utilities, as subsidiaries of a single holding company, were to complete their sales at the same time and their combined funds were sufficient for prepayment assurance. However, the utility with the larger accumulation of funds delayed its transfer awaiting approval from its state public utility commission. Because the utility with less accumulated funds consummated its sale first, the other affiliated utility has guaranteed to make up the difference up to 50 percent of their cumulative amount until it completes its divestiture.

[e]This amount is the NRC generic formula estimate. A site-specific site cost estimate placed costs between $396 million and $466 million. The seller agreed to transfer $396 million to the buyer's decommissioning trust account and to create a provisional trust account of $70 million to cover the potential taxes that might be due. Any funds left in the provisional trust account after taxes, as of December 31, 2002, will be deposited in the decommissioning trust account.

[f]These are the amounts NRC approved in 2000; however in January 2001, the Vermont Public Service Board nullified this sale and, in the hope of receiving a better offer, ordered that the plant be sold at auction. These amounts will most likely change when the sale is consummated.

Source: GAO's analysis of NRC data.

## Funding Assurance Was Not Always Maintained in License Transfers That Continued to Rely on the External Sinking Fund Method

In approving license transfer requests that continued to rely on the external sinking fund method of decommissioning financial assurance, NRC's reviews did not consistently maintain the level of assurance that decommissioning funds would be adequate, as it had for license transfers that relied on prepayment or company guarantees. In most cases, the new owners, as a result of corporate reorganizations or mergers, are no longer considered traditional electric utilities that will collect decommissioning funds through predetermined rates, but instead are affiliated with electric utilities authorized by their state regulators to collect non-bypassable charges for decommissioning.[1] These affiliated utilities will not be licensed by NRC. While NRC's review plan does not explicitly describe procedures for its staff to follow in these situations, it does imply that the new owners should provide NRC with additional information regarding the calculation and collection of these charges and ways they will be deposited into their trust funds. NRC, however, did not consistently request this additional information, when owners did not provide it. Consequently, NRC was unable to consistently maintain assurance that these funds would accumulate adequately when new owners rely on the traditional external sinking fund assurance method in a deregulated environment.

### NRC Did Not Always Verify That New Plant Owners Would Have Access to Collected Decommissioning Charges

Our review of NRC's approval of license transfers for 28 plants from 3 corporate reorganizations and one merger revealed that the new plant owners had varying degrees of access to the future decommissioning charges collected for their plants. Even though NRC's regulations allow non-bypassable charges as an acceptable accumulation mechanism for external sinking funds, it assumes that NRC licensees will either collect these charges or have direct access to them. NRC did not consistently assure that when unlicensed affiliated utilities collect the charges, they would deposit them into the new owners' decommissioning trust funds.

For 3 of the 28 plants—units 1, 2, and 3 of the Palo Verde nuclear power facility in Arizona—NRC placed conditions on its approval of the license

[1] Non-bypassable charges are charges imposed over an established period of time by a government authority (such as a public utility commission) that affected entities are required to pay to cover the costs associated with the decommissioning of a nuclear power plant. Such charges include, but are not limited to, wire charges, stranded cost charges, transition charges, exit fees, or other similar charges.

transfers that contractual arrangements for collection and deposit of earmarked funds into the new licensees' decommissioning trust funds be completed. The three units are jointly owned by several traditional electric utilities, including the Public Service Company of New Mexico and El Paso Electric Company of Texas. These two companies are reorganizing their corporate structures to comply with new requirements to supply energy in New Mexico under deregulation. In accordance with these deregulation efforts, the two companies requested that NRC transfer their respective ownership licenses in the Palo Verde plants to new generating companies formed out of their corporate reorganizations—Manzano Energy Corporation in New Mexico and MiraSol Generating Company in Texas. In effect, these new generating companies also will inherit the external sinking funds intended to cover their respective shares of responsibility to eventually decommission the Palo Verde units. However, these external sinking funds were not sufficient to qualify as prepayment of estimated decommissioning costs. Therefore, each company provided NRC with copies of contractual agreements requiring their affiliated utilities to:

- collect decommissioning funds through their charges for distributing electricity in their service areas (also known as non-bypassable wires charges) imposed by their respective state public utility commissions or other regulatory entities, and
- deposit the collected money into the new generating companies' decommissioning trust funds periodically.

NRC approved the license transfers subject to obtaining final copies of the agreements between the affiliated utilities and the new generating companies and schedules showing how the decommissioning charges approved by the New Mexico and Texas state public utility commissions would fund the total decommissioning costs.[2] In both cases, NRC assured that the decommissioning charges collected by their affiliated utilities would be deposited into the new companies' external sinking funds and that the states' public utility commissions were assuring that the charges collected would be sufficient to cover the total decommissioning costs.

However, NRC approved applications to transfer the licenses for the other 25 plants without verifying that the new owners would have the same degree of access to the decommissioning charges or that the states' public

[2] The New Mexico legislature has extended the implementation of deregulation in its state for 5 years, and as a result, these corporate reorganizations have been postponed.

utility commissions would ensure the collection of the total decommissioning costs. For example, the Public Service Electric and Gas Company's (PSEG) corporate reorganization involved decommissioning trust funds for 5 plants. The New Jersey Board of Public Utilities authorized PSEG to continue collecting decommissioning funds through its distribution rates, yet NRC approved the trust funds to be transferred to PSEG Nuclear, the newly-formed generating company. NRC did not question the access PSEG Nuclear had to the funds collected by PSEG, its affiliate utility. In addition, NRC did not require a copy of a contractual agreement between the affiliates that guaranteed periodic deposits to the new owner's decommissioning trust funds as it did for Manzano Energy and MiraSol Generating Company. In support of its approval for these transfers, NRC staff told us that they also used publicly available sources of information, such as state restructuring laws or public utility commission web sites, when new owners did not provide information with their applications. Unfortunately, the staff did not document the content or use of such information in the records of these license transfer approvals so we could not verify the adequacy of NRC's review. Also, in the case of the five plants, the New Jersey restructuring legislation had authorized these charges. After 4 years, the Board of Public Utilities planned annual reevaluations to determine whether the decommissioning funds were overfunded or underfunded and then to authorize further charges accordingly. NRC's records do not show that its staff evaluated how New Jersey's proposed charges would affect the accumulation of the total costs needed to decommission each individual plant, despite guidance in its review plan and previous instances when the prepayment and company guarantee methods had been used. Yet, NRC approved the transfers after assuring itself that, in the aggregate, the 5 plants would achieve the full funding of their required decommissioning costs by the time they cease operations.

More significantly, in the merger of two companies that involved 20 nuclear plants in Illinois, New Jersey and Pennsylvania, the existing and new companies involved in the merger did not provide, nor did NRC request, copies of contractual agreements documenting that monies to be collected from utility customers in the states would be deposited in the respective decommissioning trust funds for each of the 20 plants. In this restructuring transaction, Unicom (the parent company of the electric utility known as Commonwealth Edison Company) and PECO Energy Company merged to form a parent entity—Exelon Corporation—and several wholly-owned subsidiary companies, including Exelon Generation Company, Commonwealth Edison, and PECO. The generating subsidiary company became the legal owner of Exelon Corporation's electricity generating assets. These assets included Commonwealth Edison's 10 operating nuclear power plants and 3 retired nuclear plants that have not yet been decommissioned. In addition, the assets included six operating and one retired nuclear power plant owned by PECO. The latter two subsidiary companies transmitted and distributed the electricity supplied by the generating subsidiary to electricity customers. As a part of this electricity restructuring, both Commonwealth Edison and PECO retained their responsibilities to collect charges from their customers for the future decommissioning of the 20 nuclear power plants now owned by Exelon Generation Company.

When Commonwealth Edison and PECO requested that NRC approve their proposed merger, the two utilities submitted similar, if not identical, statements that they would continue to collect decommissioning funds for their 20 nuclear power plants through their electricity distribution rates. The utilities added that they would also, as a matter of contract, transfer the funds collected to Exelon Generation Company—which would hold the operating licenses for the 20 plants—for deposit in each plant's respective decommissioning trust fund. However, unlike the license transfer cases involving the restructuring of Public Service Company of New Mexico and El Paso Electric, discussed above, Commonwealth Edison and PECO did not enclose copies of any intercompany agreements or rulings from their respective public utility commissions documenting these fund transfer arrangements. Furthermore, NRC neither requested either of the two utilities to submit such documentation nor, in the orders transferring the licenses for the 20 plants, did the NRC place any conditions that guaranteed that the utilities would collect and deposit decommissioning funds into the plants' trust funds held by Exelon Generation Company. Nevertheless, NRC's documents approving the Exelon merger state that Commonwealth Edison and PECO will collect the decommissioning costs through their distribution rates and then, as a matter of contract, pay these amounts to their affiliate, Exelon Generation Company, for deposit in the trust funds for each plant.

NRC's staff told us that they did not request documentation regarding Exelon Generation Company's access to the collected charges because this issue was covered by the deregulation legislation enacted in Illinois and Pennsylvania, copies of which they had obtained from publicly available sources. Conversely, because the implementation of the deregulation legislation in New Mexico and Texas had been delayed, the NRC staff needed to be sure that it received final copies of any agreements in the Palo Verde plants' transfers in order to assess their viability against any new legislative changes. However, neither Illinois' nor Pennsylvania's deregulation legislation refers to an unregulated newly-formed company's access to the charges collected by regulated affiliated utilities. We did locate an inter-company agreement attached to Commonwealth Edison's public-utility commission submission for approval of the merger, providing evidence that such an agreement exists and that the Illinois public utility commission is overseeing this access issue. However, NRC had no record of this agreement or the Commonwealth Edison and PECO submissions to their respective state public utility commissions. Also, while NRC staff told us that they accepted the companies' application as sworn statements that contractual arrangements existed, they did not document the basis for this opinion in their evaluation of the license transfer.

## Accumulation of Decommissioning Funds for Retired Plants Is Also a Concern

Concerns have also surfaced over whether the collection of utility surcharges is sufficient to cover total decommissioning costs when plants are prematurely shut down. NRC's review plan provides procedures for verifying the accuracy of annual deposits to such funds when plants are operating. However, when plants are prematurely shutdown, the plan does not provide staff procedures to follow, leaving them instead to determine how to review the funds on a case-by-case basis. NRC's approval documents state that the decommissioning funding mechanism for all 20 of Exelon Generation Company's plants—16 operating and 4 retired—is the regulated charge collected by its distributing utility affiliates and that the collecting utility will make deposits into the decommissioning trust funds over the generating life of each plant. If the plants no longer generate electricity, it is not clear from the information the utilities submitted or NRC's review plan just how the funds would be collected, much less (as discussed above) how the deposits would be made to the trust accounts of the closed plants. NRC staff subsequently told us that their review of the Illinois and Pennsylvania restructuring laws showed that they allow for the collection of non-bypassable charges for plants that are shutdown and that their evaluation report was in error on this point. However, the staff evaluation of this publicly available information is not documented in NRC's license transfer records for this merger.

In addition, NRC did not apply the same review standards when it approved the transfers for these four retired plants as it did for another retired plant,[3] Millstone 1, which was recently sold along with its sister

[3] The four retired plants are Dresden, Unit 1 and Zion, Units 1 and 2 in Illinois and Peach Bottom, Unit 1 in Pennsylvania.

plants that are currently operating. Dominion Resources, Inc., the new owners' parent company, showed NRC the expected annual accumulation of funds, forecast an expected shortfall of $26 million resulting from additional annual monitoring costs incurred while the plant awaits the retirement of its sister plants, and provided a company guarantee for this expected shortfall. In contrast, neither Commonwealth Edison nor PECO provided more detailed information for the 4 retired plants than they did for the 16 operating plants. The application documents that Commonwealth Edison and PECO provided and NRC's approval documents make it difficult to discern

- which phase of dismantlement these 4 plants are in;
- how much, if any, of the trust funds has been spent so far shutting down the plants;
- whether Exelon Generation Company will incur unanticipated long-term stewardship expenses as a result of having to monitor these plants (as was the case of the Millstone retired plant); or
- which costs in the site specific estimates of these retired plants might impact Exelon Generation Company's ability to effectively decommission the facilities or safely operate their collocated plants.

NRC staff told us that their regulations do not require this level of detail to review the status of decommissioning funds for retired plants; however, they could not document that these plants had been evaluated on a case-by-case basis as their review plan recommends. Despite these ambiguities, NRC concluded that Exelon Generation Company had provided adequate assurance, even though it continued to rely on the external sinking funds transferred from Commonwealth Edison and PECO, that it would, in a deregulated environment, accumulate sufficient funds to decommission almost one-fifth of the nuclear plant fleet of the United States.

## NRC's Reviews of New Owners' Financial Qualifications Have Been Complete, With One Significant Exception

Although NRC generally followed the guidance contained in its review plan when reviewing the financial qualifications of prospective licensees, it did not follow this guidance when it reviewed the financial qualifications of Exelon Generation Company to own and operate the 20 nuclear power plants formerly owned by Commonwealth Edison and PECO.

NRC requires prospective new owners of plants that do not qualify for "electric utility" status—licensees that will not be selling their electricity at regulated rates—to demonstrate that they are financially qualified to safely own and operate the nuclear power plants that they are acquiring. To review this aspect of proposed license transfers, NRC's review plan recommends that prospective new licensees demonstrate their financial qualifications to safely own and operate their nuclear power plants for the next 5-years by means of (1) contractual agreements with utilities that will purchase electric power from the licensee; (2) the sale of power from the licensee's non-nuclear generating capacity; (3) projections of market prices for the sale of power not covered by agreements; or (4) parent or affiliate company guarantees or lines of credit for contingency operating funds. NRC also compares a licensee's expected annual electricity production from its plants with past performance to determine the reasonableness of these projections. NRC uses this information to determine whether the prospective owners have demonstrated that they possess, or have reasonable assurance of obtaining, sufficient revenue to safely own and operate each plant.

For 19 sales, 2 reorganizations, and 1 merger—collectively involving transfers of licenses for almost 50 nuclear power plants—that we reviewed,[4] NRC found that the new licensees did not qualify for electric utility status.[5] Except for the merger, NRC received additional guarantees from parent or affiliated companies that the new owners would have sufficient revenue to cover the plants' operating costs. For example, the prospective new owners provided NRC additional assurance that they would produce enough revenue to cover the expected operating expenses of their plants through power purchase agreements, contingency funds, and lines of credit from affiliated or parent companies. In addition, one new generating company cited anticipated revenue from the sale of non-nuclear power that amounted to almost 75 percent of its total electricity production to supplement its ability to support its minority interest in 3 plants.

For each of the sales and reorganizations, the new owners provided some form of financial assurance for their ability to safely own and operate the plants they proposed to own in addition to the market sale of the electricity produced by the plants. NRC staff evaluated this information according to the guidance in its review plan. For the merger, however, the new owner did not submit and NRC did not request additional guarantees.

[4] The number of license transfers or transactions reviewed and plants affected are not equivalent. In many cases plant owners have reorganized, merged or sold their interests in the same plants and many plants have multiple owners.

[5] In one other reorganization, NRC found that the new licensee qualified as an electric utility.

In addition, NRC did not validate the information submitted by the new owner to demonstrate that the company was financially qualified to safely own and operate the largest fleet of nuclear plants in the United States.

When Unicom (Commonwealth Edison) and PECO merged into Exelon Corporation, the subsidiary Exelon Generation Company, which would hold the NRC operating licenses for the two companies' 16 operational and 4 retired nuclear power plants, did not meet NRC's definition of an electric utility. However, in their applications to NRC, Commonwealth Edison and PECO asked NRC to transfer their plants' licenses to Exelon Generation Company on essentially the same terms and conditions contained in their existing licenses—licenses which reflected that, as economically regulated utilities, Commonwealth Edison and PECO had guaranteed access to revenues to own and operate their nuclear plants. Commonwealth Edison and PECO addressed the issue of assurance that Exelon Generation Company would be financially qualified to own and operate their nuclear power plants by providing NRC with 5-year projections of expenses from the production and purchase of electricity and revenues from the market sale of this electric power. Among other things, this information included the estimated costs of:

- operating the new company's 16 operational nuclear power plants;[6]
- purchasing excess electric power from six nuclear power plants owned, or to be owned, by AmerGen Corporation. AmerGen, which was half-owned by PECO, was created to market electricity generated from power plants purchased and operated for that purpose. At that time, AmerGen owned three nuclear power plants and was attempting to purchase three other nuclear plants; and
- purchasing electricity from other suppliers for resale to Exelon customers, fuel costs, asset depreciation, and other administrative costs.

In addressing its potential revenue, Commonwealth Edison and PECO provided NRC with projections of revenues from, primarily, the sale of electricity produced by the 16 nuclear plants and the resale of the electricity purchased from AmerGen and other suppliers. Additional income, amounting to 6 percent of the total electric power to be sold, was

[6] Of these 16 plants, Commonwealth Edison and PECO owned majority interest and operated 14 plants. At two plants, Salem-Units 1 and 2, PECO owned a 42.59 percent interest and PSEG Nuclear operates the plants. Neither Commonwealth Edison nor PECO estimated annual electricity generation costs and revenue for individual plants.

derived from the market sale of 5,000 megawatts of power from non-nuclear plants.

Although Commonwealth Edison and PECO provided a financial projection to NRC in their license transfer applications, neither company provided, nor did NRC request, any additional support—power purchase agreements, contingency fund guarantees, or lines of credit—that would enable NRC to validate the Exelon Generation Company's financial qualifications to own and operate the largest fleet of nuclear plants in the United States. Also, Exelon did not provide, and NRC did not request, the 5-year projections of operating costs and estimated annual electricity generation for individual plants. For this reason, NRC could not, as its review plan recommends, compare plant-specific costs and production estimates to plants of similar size and type to confirm the reasonableness of the projections. Nonetheless, NRC concluded that Exelon's projected revenues, based solely on the market sale of electricity, would be sufficient to cover the costs associated with owning and operating 16 plants, even if it experienced simultaneous 6-month shutdowns of several of these nuclear plants.

Furthermore, NRC eventually transferred the licenses to Exelon Generation Company on the basis of projected financial information that both the affected companies and NRC knew to be inaccurate. When Commonwealth Edison and PECO updated their projected income statements for NRC in March 2000, they included income from three nuclear plants that AmerGen was attempting to purchase. However, there were no notes on this income statement to clarify that the statements included projected revenue from sales of electricity to be produced at nuclear plants that AmerGen did not yet own. (In contrast, Exelon Corporation did disclose this contingency in merger-related filings submitted to the Securities and Exchange Commission.) In June 2000, the merging utilities notified NRC that their March 2000 income statement was the most accurate. A month earlier, however, AmerGen had notified NRC that it had withdrawn its bid to purchase the two Nine Mile Point plants in New York. By December 2000 it was also apparent that AmerGen's bid to purchase the Vermont Yankee plant would not succeed. Therefore, AmerGen owned just 3 of the 6 plants Exelon Generation Company had included in its financial qualification statement. In January 2001—over 1 year after receiving the initial merger applications—NRC transferred Commonwealth Edison's and PECO's licenses to own and/or operate 20 nuclear power plants to Exelon Generation Company on the basis in part of projected financial information known to be inaccurate by the companies and NRC.

In defense of their review of the merger, NRC staff told us that their regulations only require that licensees demonstrate financial assurance through credible projections of 5 years of expenses and revenues. Also, because Exelon Generation Company was to be the licensee for all 16 operating plants, there was no compelling need to require plant specific information. The NRC staff maintain that they did perform an analysis of the impact of AmerGen's lost bids for the Nine Mile Point and Vermont Yankee plants and determined that there was no material impact on Exelon Generation Company's financial qualifications. Unfortunately, NRC did not document this evaluation in its review file and did not update the financial projections in their evaluation report to accommodate this analysis.

## Conclusions

NRC's inconsistent review and documentation of license transfer requests creates the appearance of different requirements for different owners or different types of transfers. Good business practices suggest that NRC follow one review process with all of its licensees. While its standard review plan offers a sound basis for obtaining consistency, NRC is clearly not consistently achieving the desired results. One modification that could help NRC's staff and management maintain consistency in their reviews of license transfers is the use of detailed checklists or step-by-step processes delineated more precisely within its standard review plan.

## Recommendation for Executive Action

To ensure that the decommissioning assurance methods and financial qualifications of all new nuclear plant owners are consistently verified, validated, and documented, we recommend that the Chairman, NRC, revise the Commission's standard review plan and related management controls for reviewing license transfers to include a checklist or step-by-step process for its staff, its management, and prospective owners to follow.

## Agency Comments and Our Response

We provided NRC with a draft of this report for its review and comment. (See app. I for NRC's comments.) NRC disagreed with our recommendation. According to NRC, revising its review plan will not greatly enhance the effectiveness of its license transfer reviews because many of these transfers have been complex and unique. We disagree. When NRC drafted its review plan, it had no experience in regulating licensees that generate electricity in competitive markets. Since then, NRC has processed over 60 requests to transfer licenses. Although the details of each transfer request may have been unique, the affected licensees have consistently used the same few basic methods permitted by NRC's regulations, such as prepayment and/or parent company guarantees, to provide NRC with assurance that decommissioning funding and financial qualifications are being met. However, NRC's reviews of these license transfer requests have been inconsistent. Therefore, revising the review plan to ensure, on the basis of NRC's experiences to date, that each decision to approve a license transfer is based on consistent supporting information could increase NRC's efficiency and effectiveness, thereby helping NRC to achieve one of its primary performance goals.[7]

NRC raised several issues regarding its reviews of the adequacy of decommissioning funding and the financial qualifications of new owners of plants. NRC said its reviews of the PSEG and Exelon license transfers were adequate and complete, led to the conclusion that there was reasonable assurance of decommissioning funding and, in the Exelon case, that the new owners were financially qualified. NRC acknowledged that it did not appropriately document some of these evaluations. However, NRC asserted that, by reviewing other, unspecified, sources of financial information and information on the appropriate state's non-bypassable charges requirements, it was able to obtain reasonable assurance of decommissioning funding and financial qualifications. We disagree, for reasons that go beyond the lack of review documentation. Specifically, NRC's staff could not, in response to our requests, identify the specific sources upon which they relied, but did not document, for other information. Furthermore, we independently reviewed the state laws on non-bypassable charges for decommissioning funding that NRC's staff had referred us to and found that, while these laws provided for utilities to collect these charges, the statutes were silent on the procedures for depositing the charges collected into the plants' decommissioning funds. These collection and transfer procedures were left to appropriate state public utility commissions and, in many cases, had not been determined

[7] NRC's four performance goals are to maintain safety, increase public confidence, reduce unnecessary regulatory burden, and enhance the effectiveness and efficiency of its activities and decisions.

when NRC conducted its license transfer reviews. Nevertheless, NRC did not require the prospective new plant owners to make binding commitments with affiliated utilities or other enforceable statements of assurance that the non-bypassable charges collected by these utilities from their electricity customers would be transferred to the appropriate decommissioning fund for the new owners' plants.

# Chapter 3: Regulatory Policies Under Consideration May Affect Decommissioning Costs and Nuclear Waste Policies

Varying radiation cleanup standards, the possibility that NRC will approve alternative decommissioning methods, and incomplete historical plant contamination data confound a licensee's ability to estimate future decommissioning costs. Varying radiation cleanup standards create uncertainty because plants decommissioned to NRC's radiation cleanup standards may also have to meet more stringent EPA or state standards, thus increasing the costs of decommissioning. Alternative decommissioning methods under consideration for approval would add uncertainty because no reliable data exist on their overall costs; they could reduce short-term decommissioning costs but add considerably to long-term costs. Moreover, implementing these methods would raise significant technical and policy issues pertaining to the management and disposal of radioactive wastes. Furthermore, the lack of complete historical information regarding plant contamination can translate into an unexpected increase in site cleanup costs late in the decommissioning process.

## Varying Cleanup Standards Create Cost Uncertainties

To terminate an operating license and to release a site for unrestricted use, an NRC licensee must decommission its plant so that the residual radiation remaining at the site after decommissioning has been reduced to levels that meet NRC's standard.[1] However, meeting NRC's radiation cleanup standard may not signal the end of the decommissioning costs, because either EPA or the host state could require additional cleanup activity to meet more stringent standards.

While NRC regulates the decommissioning of commercial nuclear facilities, EPA issues general standards for radiation protection and administers CERCLA, which governs the cleanup of contaminated facilities.[2] NRC and EPA have historically disagreed on how restrictive U.S. radiation protection standards should be, and in 1997, EPA's Administrator told NRC's Chairman that NRC's radiation cleanup standard should be tightened to 15 millirems per year. The Administrator also called for adding a separate standard limiting the concentration of radiation in

[1] Under regulations issued by NRC in 1997, decommissioned sites that are decontaminated to residual radiation levels of 25-millirems or less may be released for unrestricted future uses. Decommissioned sites with elevated residual radiation levels of up to 500-millirems may only be released for restricted use, with safeguards and institutional controls to prevent public exposure.

[2] NRC's regulatory authority derives from the Atomic Energy Act, while EPA's derives from Presidential Reorganization Plan No. 3 of 1970 and CERCLA.

groundwater to 4-millirems per year.[3] These limits would be consistent with EPA's standards for cleanup at Superfund sites. If NRC did not agree, the Administrator said, EPA would have to reconsider its policy of exempting the sites of facilities regulated by NRC from EPA's National Priorities List of Superfund sites. Such action could subject NRC-decommissioned and released sites to a second evaluation under EPA's Superfund standards. EPA could conduct these subsequent evaluations under its own authority or when asked to do so by other stakeholders. It has provided guidance to its regional offices on how to proceed in such instances. However, the agency believes that the vast majority of decommissioned nuclear power plants will meet Superfund protection standards and is not actively looking for NRC sites to evaluate. Nevertheless, failure to pass a Superfund evaluation could mean significant additional cleanup costs.

NRC, however, shows no sign of changing its standards. NRC disagrees with EPA's preferences and questions EPA's technical basis for proposing the extra groundwater protection. Differences in agency missions, legislative mandates, and regulatory strategies contribute to this disagreement, which, despite resolution efforts spanning a number of years, remains essentially unresolved.[4]

According to the NRC Chairman, the disagreement over acceptable radiation standards is eroding public confidence and is negatively affecting efforts to assure the public that decommissioning can be accomplished in a manner that protects public health, safety, and the environment. In fact, in part because of the uncertainty over the scientific basis supporting radiation protection standards and the dispute between EPA and NRC, several states have established, or are in the process of establishing, their own radiation protection standards. Because most of these proposed or

[3] EPA does not actually express radiation protection standards in millirems but uses a system of "slope factors" to assign risk limits to individual chemical and radioactive contaminant types alike. These limits equate to a risk threshold of 1 in 1,000,000 that an individual will develop cancer in a lifetime or, with regard to radiation, roughly to a 15-millirem–a-year all-pathway radiation dose limit and a separate four-millirem-a-year dose limit for groundwater.

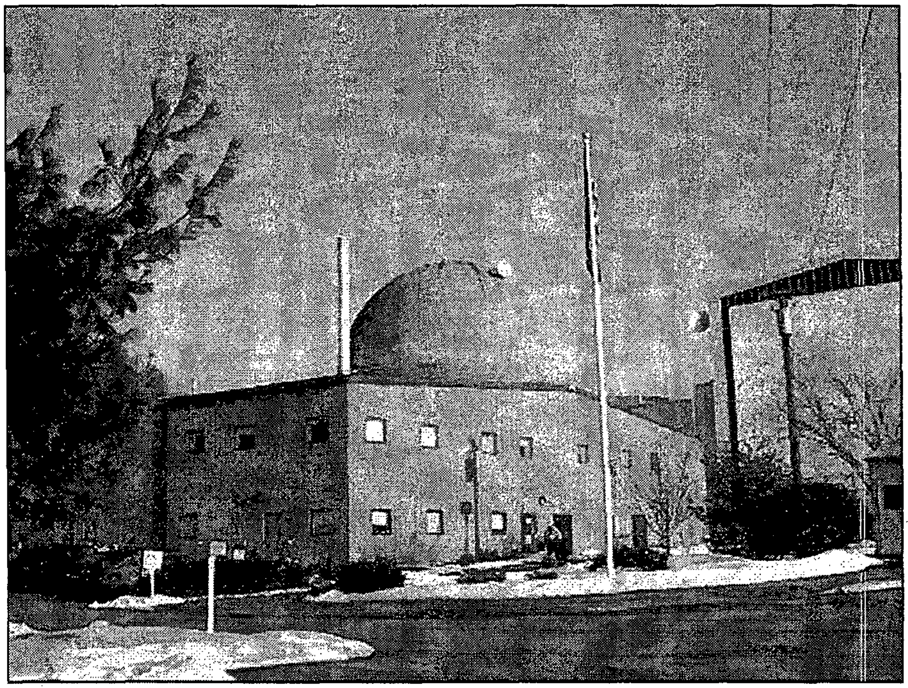
[4] *Radiation Standards: Scientific Basis Inconclusive, and EPA and NRC Disagreement Continues* (GAO/RCED-00-152, June 30, 2000); *Nuclear Regulation: Better Oversight Needed to Ensure Accumulation of Funds to Decommission Nuclear Power Plants* (GAO/RCED-99-75, May 3, 1999); and *Aging Nuclear Power Plants: Managing Plant Life and Decommissioning* (U.S. Congress, Office of Technology Assessment, OTA-E-575, Sept. 1993).

existing state standards are more stringent than either EPA's or NRC's standards, implementation of the states' standards could increase decommissioning costs.

For example, in April 2000, the state of Maine imposed a standard limiting the total effective annual dose from residual contamination at the Maine Yankee nuclear plant site to 10 millirems, with a separate 4-millirem dose standard for groundwater—which is below the dose allowed under either NRC's standard or EPA's preferred standard. Maine Yankee officials estimated that it would cost between $25 million and $30 million to ship and dispose of the waste materials that must be disposed of to meet the state's more restrictive standard.

Similarly, Massachusetts has set its own total effective annual dose equivalent standard of 10-millirem for decommissioned sites and New York has set a soil cleanup standard of 10-millirem for radioactive materials. New Jersey has set a 15-millirem residual radiation exposure standard, and the state of Connecticut is presently developing its own cleanup standards for commercial nuclear facilities. According to a state environmental department official, the new standard has not yet been officially approved, but will be the approximate equivalent of a 19-millirem dose limit, with a requirement to further reduce dose if it proves economically and environmentally feasible to do so. According to officials of the state and the Connecticut Yankee Power Company, the utility and the state are working together to ensure that the company will comply with the state's new standard, when issued, as well as NRC's and EPA's standards, in the decommissioning of the company's Haddam Neck nuclear power plant.

Figure 3: The Decommissioning Connecticut Yankee Haddam Neck Plant



Source: GAO.

## Alternative Decommissioning Methods May Marginally Decrease Costs but Raise Significant Technical and Policy Issues

NRC is considering whether to authorize licensees to leave more radioactively-contaminated material at their plant sites when decommissioning nuclear power plants by either (1) reducing contaminated concrete to rubble and then burying the rubble on site or (2) removing the most radioactive plant wastes and entombing the residual radioactive materials inside the thick, reinforced concrete containment structure of retired plants. The rubblization and entombment methods could, if approved and implemented, decrease off-site waste disposal costs during the decommissioning of plants. However, short-term cost savings for some sites could be more than offset over the long-term because institutional control measures will be needed to prevent public access.

### Short-Term Cost Savings Could Be Offset Over Time

According to the NRC Chairman, the low-level radioactive waste program in the United States is not working and the potential exists for the decommissioning process to be hampered at many sites unless alternative disposal options are pursued. States, the nuclear industry, and others have voiced similar concerns. Therefore, within the limits of its regulatory authority, NRC is considering decommissioning methods such as rubblization and entombment that would allow the permanent burial or encasement of radioactive waste at nuclear plant sites.

NRC believes that it is technically possible to approve a license termination plan that includes rubblization, as long as the total effective annual dose of radiation that a person living at the site would receive did not exceed the Commission's standards. Rubblization will be technically possible, NRC believes, as long as licensees are able to successfully address related issues, such as access to, and digging at, the sites where rubblization has occurred and the potential for reuse of extracted materials that are contaminated with radioactive elements.

Rubblization represents a departure from NRC's past licensing practice, which emphasized shipping low-level radioactive wastes from decommissioning sites to disposal facilities. Although NRC has estimated that rubblization could save a licensee from $10 million to $16 million in waste disposal costs during decommissioning, its Advisory Committee on Nuclear Waste has concluded that technical factors, such as the depth of radioactive contamination and the volume of rubblized waste, could significantly diminish the potential cost savings. The Advisory Committee also believes that evaluating radioactive material content and doses from rubblization, both at the site and in local groundwater, may prove difficult and expensive. The Committee has cautioned that estimates of cost savings from rubblization could be offset if extensive decontamination, sampling, and analyses are needed. Therefore, the Committee has recommended that NRC establish a test case for study to identify possible problems and solutions related to rubblization.

In April 1997, NRC's commissioners also requested NRC staff to revisit the entombment method of decommissioning, the use of which the commission had discouraged a decade earlier, to determine whether that method serves as a viable alternative to completely dismantling nuclear plants. The Commission added that, if the staff concluded that entombment is not a viable decommissioning method, the staff should describe the technical requirements and regulatory actions necessary for entombment to become viable, including the resources involved, potential decommissioning cost savings, and vulnerabilities.

NRC had considered entombment as a decommissioning method in 1988 but generally opposed its use because, among other things, (1) the method would require expenditures for maintenance, security, and other long-term institutional controls for at least 100 years that would about equal dismantlement costs and (2) regulatory changes occurring during the long entombment period might require additional costly decommissioning activity before entombed sites could be released for unrestricted use in the future. NRC determined that entombment would be acceptable only on a case-by-case basis when a licensee could demonstrate that (1) immediate or delayed dismantlement of its nuclear facility was infeasible, (2) radioactive decay would allow unrestricted release of a site in about 100 years, and (3) access to waste disposal facilities was not available. No licensee at any additional power reactors undergoing decommissioning has since proposed the entombment option.

On May 4, 1998, NRC's staff notified the Commission that, on the basis of its preliminary assessment of work performed for NRC by the Department of Energy's Pacific Northwest National Laboratory, consideration of entombment as a viable decommissioning method had merit. The Laboratory had estimated and compared decommissioning costs, radioactive waste disposal requirements, estimated radiation doses to persons, and institutional control requirements for the two decommissioning methods approved in 1988—immediate dismantlement and dismantlement after storage of 50 years or more—with two entombment variations. These entombment methods are immediate entombment of radioactive plant materials in the containment building and the storage of radioactive plant materials in the containment structure for over 100 years, followed by entombment.

Subsequently, on July 19, 1999, NRC's staff affirmed that entombment could be safe and viable, depending on specific site situations. NRC's staff said that entombment, when properly performed, should have little effect on health, safety, and the environment. In addition, the staff noted that the entombment of radioactive wastes within the containment building of a retired nuclear power plant could significantly reduce off-site waste disposal requirements and related costs—although cost reductions would be offset, to some degree, by the cost of maintaining and monitoring the entombed facility for 100 to 300 years.

The NRC staff's decision that entombment might reduce decommissioning costs is questionable. For instance, both plants that have already been decommissioned and plants in the process of decommissioning using the immediate decontamination and dismantlement option report higher costs than the figure used for this option in the Pacific Northwest National Laboratory analysis on which NRC's staff based its views. Furthermore, the minimum amounts required for this option (as determined by NRC's own generic formula) are significantly greater than the figure used in the laboratory's analysis. The laboratory's analysis also showed that neither immediate nor delayed entombment offer significant projected cost savings unless one assumed that entombment would lead to a reduction in long-term site security and insurance costs. Moreover, the laboratory's analysis showed that, even when reduced security and insurance costs are assumed, placing a retired plant in storage for approximately 50 years and then dismantling the plant is the least costly decommissioning method.

The laboratory also used a 130-year institutional control period in its analysis of the entombment method of decommissioning. NRC, however, has stated that if radioactive wastes entombed in a former nuclear plant include long-lived waste varieties, then the necessary period of institutional control could be extended to 300 years. In such a case, the cost for the additional 170 years of monitoring and surveillance needed could make both entombment options significantly more costly than the immediate dismantling of a plant and off-site disposal of its radioactive wastes.

Also, although the laboratory's analysis did not include entombment of Greater-Than-Class-C (GTCC) waste, NRC is considering the possibility of authorizing licensees to entomb GTCC waste rather than disposing of it in a geologic repository. Current regulations specify that GTCC waste is not generally acceptable for near-surface disposal without special processing and design and the case-by-case approval of NRC. GTCC waste from decommissioning a nuclear power plant is essentially comprised of radioactive internal reactor parts, which, while less radioactive than high-level waste such as spent fuel, remain radioactive for many thousands of years. However, including GTCC within the entombment structure would extend the required period of institutional control and its associated expense to thousands of years. Furthermore, regardless of the time period in which institutional controls would be required, a licensee would need to establish a funding mechanism to provide sufficient financial assurance that essential institutional controls would be carried out for the required time period. In contrast to immediately dismantling a plant and removing essentially all radioactive materials from the plant site, entombment would essentially make a former plant site a restricted storage or disposal facility for low-level radioactive waste for more than 100 years, which could hamper commercial reuse or resale of the site for the entombment period.

Finally, questions remain regarding the financial provisions for remediation in the event of a failure at an entombed site. According to NRC's staff, "very expensive remedies" could be required if an entombment configuration proved unable to adequately isolate radioactive contaminants over the 100-year or longer time period needed for radioactive decay. Given the length of time involved, states are concerned that they will have to pay remediation costs should an entombment fail.

## Technical Issues Surround Alternative Decommissioning Methods

Aside from questionable cost benefits, rubblization and entombment raise a number of technical issues. For instance, NRC does not intend to require that sites where rubblized radioactive materials would be buried have protection equivalent to off-site disposal facilities for low-level radioactive waste. Disposal facilities for commercial low-level radioactive waste, which are licensed and regulated by NRC or by a state (under agreement with NRC), must be designed, constructed, and operated according to NRC's regulations (or compatible regulations issued by the host state). In addition, to obtain a license to build and operate a disposal facility, the prospective licensee must characterize the facility site and analyze how the facility will perform for thousands of years. However, according to NRC, a rubblized site is not comparable to a low-level radioactive waste disposal facility because

- the quantity, forms, and range of radioactive waste types buried at a nuclear plant site would be less,
- rubblization is a decommissioning action subject to the license termination rule rather than a radioactive waste disposal action subject to the licensing provisions of 10 CFR Part 61, and
- NRC's regulations for disposing of low-level radioactive waste apply only to facilities that dispose of waste from other sites and sources and not to sites where contaminated materials are to be rubblized and buried on-site.

Nevertheless, 10 CFR Part 61 does not differentiate between what does or does not qualify as a low-level waste disposal action or facility on the basis of the quantity, forms, or range of the low-level radioactive waste to be buried. Furthermore, NRC's view that rubblization does not constitute the creation of a low-level radioactive waste disposal site is not shared by EPA and at least three agreement states. When the Maine Yankee Power Company was considering rubblization as the decommissioning method for the Maine Yankee nuclear power plant, the state of Maine and EPA expressed concern that burying low-level radioactive waste at the plant site would be tantamount to creating an unlicensed low-level radioactive waste disposal facility. In fact, Maine's attorney general found that a strict application of Maine state law would have classified rubblization of the plant as such. Such classification would have, in turn, required state legislature and voter approval, licensing by NRC or the state, and eventual state ownership of the plant site. Furthermore, when NRC sent a draft entombment rulemaking plan, an Advance Notice of Proposed Rulemaking (ANPR), and the PNNL entombment assessment to agreement states for comment on March 7, 2001, two out of the three agreement states that commented responded negatively.

New York, for example, opposed any new rulemaking that would allow low-level or GTCC waste to be entombed at reactor sites in the state. The state also contended that such an action would be contrary to the intent of the Nuclear Waste Policy Act and would adversely impact the financial viability of existing or planned low-level radioactive waste disposal facilities and state compacts. The state pointed out that data presented in the PNNL assessment (as discussed above) indicated that long term storage followed by dismantlement was preferable to entombment.

The state of Illinois also found entombment to be problematic as a decommissioning method, urged that NRC prohibit that approach, and said it would resist its implementation. The state found entombment to be inconsistent with the waste management policy established by Congress through the Low-Level Radioactive Waste Policy Act as amended. Regarding NRC's position that entombment is a decommissioning rather than a disposal action, the state said:

"It is beneath the NRC to engage in the semantical charade of denominating long-term isolation of reactor waste as anything other than disposal. The Agreement States' authority to license disposal of LLRW at reactor sites includes authority over entombment of LLRW. Any attempt by the NRC to repeal Agreement State authority under the pretext of merely licensing the decommissioning of commercial nuclear power reactors is virtually guaranteed to be vehemently [opposed] by Agreement States. If it is the NRC's objective to assert permanent federal control and responsibility over reactor sites, using those sites as a multitude of sacrifice areas throughout the United States, IDNS submits that NRC should make its proposal to Congress for a full and vigorous national debate."

Water intrusion is also a major concern for rubblized or entombed sites, and the fact that most nuclear power plants are situated in shallow water table or flood plain locations may limit the viability of these options. Furthermore, should NRC decide to allow GTCC waste in an entombment, integrity of the concrete configuration would have to be assured for many thousands of years. However, experts cannot guarantee or predict the integrity of concrete after 500 years.

Other technical concerns about rubblization include the potential for buried concrete to leach from rubblized sites, adversely affecting local water quality; the propriety of diluting contaminated material by mixing the material with non-contaminated materials; and, how to demonstrate that the estimated radiation dose at a rubblized site has been reduced to a level "as low as reasonably achievable," as required by NRC.[5] As with any proposed decommissioning method, the licensee would have to address any relevant issues in the License Termination Plan, as well as demonstrate compliance with the License Termination Rule and requirements for the reduction of resulting residual radiation to levels that are as low as reasonably achievable. NRC is in the process of updating its generic environmental impact statement on radiological criteria for terminating nuclear facility licenses. The update will address, among other things, rubblization as a decommissioning method and may include issues such as the acceptability of mixing or diluting contaminated material, the environmental effects of leaving contaminated concrete at decommissioned sites, and the potential effects of widespread use of the rubblization method because of economic considerations. NRC intends to require an environmental review for each site that proposes rubblization. The new generic statement should be useful to NRC in reviewing the environmental effects of license termination plans based on rubblization.

NRC staff recognized in reaching their favorable conclusions on the viability of entombment in 1999, that statutory, regulatory, technical, and implementation issues, such as the appropriateness of relying on intruder barriers over a 1,000-year period, required further development. For example, the usefulness of the entombment decommissioning method could be limited by concerns over the reliability of long-term institutional controls. Such concerns are indirectly addressed in a recent National Academy of Sciences report on the long-term management of DOE's nuclear sites.[6] Many of the weaknesses addressed in the Academy's report may apply to the restricted release of NRC-licensed sites as well. For example, according to the Academy:

The viability over time of land use restrictions is likely to be especially questionable in cases where contamination levels are not high enough to prohibit all public access but not

[5] NRC's "As-Low-As-Reasonably-Achievable (ALARA)" policy essentially requires licensees to reduce residual radiation at decommissioning below the level required for unrestricted release as long as it is economically and environmentally feasible to do so.

[6] *Long-Term Institutional Management of U.S. Department of Energy Legacy Waste Sites* (National Research Council, Committee on the Remediation of Buried and Tank Wastes, International Standard Book Number 0-309-07186-0, Copyright 2000, National Academy Press).

low enough to permit unrestricted use. Often the real issue is not **whether** use restrictions will eventually fail, but when and what the **consequences** will be when they do. [Emphasis in original.]

EPA has also questioned the reliability of long-term institutional controls, stating that among other things, long-term governmental controls may not be enforced effectively because of political and fiscal constraints on a state or local government's exercise of its police power.

NRC's Chairman has acknowledged that the need for long-term institutional controls is a significant weakness in decommissioning methods, such as entombment, in that states or other governmental agencies may not be willing to accept the responsibility for such controls. And, according to NRC's staff, the viability of entombment as a decommissioning method hinges, in part, on the Commission's decision on whether barriers to intrusion in the absence of institutional controls would effectively keep exposure to affected persons beneath the Commission's dose limits.

The reliability of institutional controls over entombments that include GTCC waste would be even more questionable because of the extremely long post-closure monitoring and surveillance timeframes that would be required. In fact, in its August 1988 generic environmental impact statement on decommissioning nuclear facilities, NRC's staff concluded that the entombment method with GTCC waste included in the encasement was not viable because the security of the site could not be assured for thousands of years. In 1998, NRC also said that analyses would be required to demonstrate that a proposed entombment was unlikely to fail over the proposed entombment period. Such a requirement would be difficult to meet if GTCC waste were stored in the entombment because, experts say, projections on the integrity of concrete after 500 years are speculative. Finally, NRC's staff has determined that the Low-Level Radioactive Waste Policy Amendments Act of 1985 and NRC's regulations essentially require that the disposal of GTCC waste be licensed and that GTCC waste be placed in a geologic repository.[7]

[7] During a NRC entombment workshop held in December 1999, DOE panel members stated that entombing GTCC waste in a reactor containment building is possible under existing legislation and that such an alternative was preferable to disposing of this type of waste in a geologic repository. The Low-Level Radioactive Waste Policy Act makes DOE responsible for disposing of commercially generated GTCC wastes.

Over the 100 to 300 year entombment period, early license termination and potential property ownership changes could also complicate the issue of financial responsibility for the entombment failure and subsequent responses. States are concerned that they may be obligated to pay the potential remediation costs if they have to assume oversight responsibility for an entombment after NRC has terminated a plant's operating license. For this reason, state representatives have said that, at least until experience with entombment has been acquired, NRC should continue to maintain some type of licensing responsibility at entombment sites. Such a step, however, would be contrary to NRC's goal of terminating licenses upon plant entombment.

## Alternative Decommissioning Methods Potentially Conflict With National Policy

On-site burial of rubblized low-level radioactive waste or the entombment of these wastes on-site may conflict with national policy on management and disposal of these wastes. The Low-Level Radioactive Waste Policy Act of 1980, as amended in 1985, established as federal policy that commercial low-level radioactive waste—except for GTCC waste—can be most safely and effectively managed by states on a regional basis. Through the act, the Congress encouraged states to form regional compacts to meet their collective disposal needs, minimize the number of new disposal sites, and more equitably distribute the responsibility for the management of low-level radioactive wastes among the states.

To encourage the formation of such regional compacts, congressionally approved compacts are allowed to prohibit the disposal of wastes generated outside their respective regions. To date, 44 states have entered into 10 compacts. However, despite some 20 years of effort and the expenditure of about $600 million, no new regional disposal facilities have been provided as a result of the act, and no state or compact is currently trying to identify a site for a disposal facility. [8]

Commercial generators of low-level radioactive waste, including licensees that are, or soon will be, decommissioning their nuclear power plants, currently have access to off-site disposal facilities for this waste. Of the three currently operating disposal facilities for commercial low-level radioactive waste, the Barnwell, South Carolina facility is both available to

[8] For a fuller discussion of states' implementation of the Low-Level Radioactive Waste Policy Act, see *Low-Level Radioactive Wastes: States Are Not Developing Disposal Facilities* (GAO/RCED-99-238, Sept. 17, 1999).

generators in all states and licensed to accept all classes of waste for which states must provide disposal. However, whether such access will continue, and at what cost, is uncertain. Access to the Barnwell facility is to be phased out for most generators by mid-2008. Another facility—Envirocare of Utah—which is located west of Salt Lake City, Utah, is available to generators in all states outside the Northwest Interstate Compact region but is licensed to accept only the least radioactive class of such wastes. In July 2001, the operator of this facility obtained a license amendment from the state of Utah to dispose of the more radioactive classes of low-level radioactive waste. However, the facility must also obtain the approval of the state's governor and legislature for such disposal. The company has announced that, at this time, it will not pursue such approvals because of controversy over an unrelated proposal to develop a storage facility for spent fuel from commercial nuclear power plants.

Unless Envirocare obtains the required governmental approvals in Utah and expands its existing disposal facility, and absent any new initiative by a compact of states to develop other disposal capacity, by mid-2008 waste generators in 36 states, Puerto Rico and the District of Columbia, will have *no access to a disposal facility for wastes that are not already approved for* disposal at the Envirocare facility.

The potential lack of access to disposal facilities prompted NRC and the nuclear industry to explore the rubblization and entombment decommissioning methods. Concerns have been voiced, however, that rubblization and/or entombment could adversely affect disposal costs and/or the profitability and economic well-being of the existing disposal facilities, while making it economically infeasible for a compact to develop new disposal facilities. Thus, the two decommissioning methods appear to run counter to the existing national policy of encouraging states to manage disposal of low-level radioactive wastes on a regional basis.

Moreover, the rubblization and/or entombment decommissioning methods may also contravene some state-compact agreement provisions. As discussed earlier, for example, if rubblization of the Maine Yankee plant had occurred, the state could have determined that the rubblized site was a disposal facility for low-level radioactive waste. In such a case, according to Maine's attorney general, the state could have been in violation of the Texas Low-Level Radioactive Waste Disposal Compact, of which Maine is a member, because the compact terms make Texas—not Maine—responsible for developing the compact's disposal capacity for low-level radioactive waste generated within Maine, Texas, and Vermont.

## Site Contamination Can Go Undetected Until Late in Cleanup Process

Site characterization is an essential step in the decommissioning process,[9] but NRC does not stipulate when site characterization must be done. The sole time constraint is that a site-characterization must accompany NRC licensee's license termination plan and that the license termination plan must be submitted to NRC at least 2 years before the requested termination date of the license. If site characterization work does not begin until the latter stages of decommissioning and survey work uncovers unexpected contamination, instances can occur where the balance remaining in the decommissioning trust fund may not be enough to cover the unplanned additional cleanup work required.

NRC requires licensees to document occurrences and locations of spills, leaks, and other events that may occur at the plant and result in site contamination. This documentation, combined with the institutional knowledge of plant employees, provides the basis for a plant's historical site assessment and characterization plans. Historical site assessment and characterization are essential to ensure and demonstrate that all impacted areas at the site have been identified and cleaned up to meet the appropriate dose level required for license termination.

In cases where nuclear power plants were operating before NRC imposed record keeping requirements for burials, spills, and so forth, or if required record-keeping was less than meticulous, the institutional knowledge of plant employees becomes an invaluable tool for disclosing incidents and locating where contamination might be present. However, once a plant announces its plans to decommission, employees are often let go or leave to take other jobs, diminishing the institutional knowledge. In situations where plants close and are placed in safe storage for a number of years before final decommissioning work begins, institutional knowledge may be all but lost. As a result, although surveys take place throughout the decommissioning process, some instances of contamination may not be discovered until comprehensive site characterization work begins.

For instance, one small nuclear plant—Saxton in Pennsylvania—was built on the site of an old steam generating plant. The nuclear reactor was purposely built on this site to utilize an existing turbine and associated equipment from the steam plant. The nuclear reactor was shut down in

[9] Site characterization entails radiological surveys of site grounds and facilities to insure that residual radiation at the site is in compliance with the appropriate NRC-prescribed dose limits for license termination and site release.

1972. In 1975 the steam plant was demolished and the basement was backfilled with demolition debris. The nuclear facility was maintained in a monitored condition, and full-scale decommissioning work did not begin until May 1998, 26 years after the plant was permanently shut down.

After initial site characterization and submission of the License Termination Plan in early 1999, unexpected additional contamination was discovered that required complete removal of all concrete in the containment structure and excavation, characterization, and remediation of the old steam plant basement. The estimated cost for this work exceeded the balance remaining in the decommissioning trust fund, forcing the owners to pay for it out of their general operating funds.

An NRC official told us that the plant owners are committed to doing a quality decommissioning job and that many of the problems found have been identified as a result of their diligence in approaching the decommissioning task. Nevertheless, historical site assessment efforts might have been easier to perform and more input from plant employees might have been obtained had initial site characterization work begun closer to plant shutdown and unexpected contamination problems been discovered sooner. Because the licensee was initially able to collect decommissioning costs from the ratepayers after the plant shut down, ratepayer contributions to the decommissioning fund might have been increased, or decontamination and dismantlement could have been delayed to allow for decommissioning fund investment income to grow to meet additional decommissioning costs before the principal was spent.

## Conclusions

The actual cost incurred to decommission a nuclear power plant site is affected by many factors, some of which lie beyond a licensee's control. One of these factors is uncertainty over the application of radiation protection standards. Though NRC's licensees accumulate funds to decommission their plants to NRC's standard, once the time to decommission a plant arrives, a licensee may find that it must also meet a more stringent EPA or state standard at higher than anticipated cost. Another factor is whether, in the future, licensees will have access to affordable disposal capacity for the low-level radioactive waste generated in the decommissioning process. Licensees' and NRC's interest in rubblization and entombment, as alternative approaches for decommissioning, attempts to address this uncertainty, but in turn raises equally important technical and policy issues pertaining to on- and off-site disposal of low-level radioactive wastes and the proliferation of radioactive waste disposal sites around the country. Also, the potential short-term cost savings from these methods may be more than offset if safeguards and institutional controls are required to ensure the safety of rubblized or entombed sites over the longer term. And the principal advantage of rubblization and entombment appears to be the disposal of radioactive waste at nuclear plant sites, which may not comport with current federal policy encouraging states, by means of congressionally-approved compacts, to be responsible for this function. Leaving low-level radioactive wastes buried or entombed at nuclear plant sites would make it more difficult for the existing low-level radioactive waste disposal program to succeed economically, thereby undermining the objectives of the Low-Level Radioactive Waste Policy Act, as amended.

There is, however, a way to alleviate some cost uncertainty in the decommissioning process without major technical and policy ramifications. Licensees could conduct historical site assessments/characterization surveys soon after the decision is made to permanently cease operations. Such early characterization would minimize the chances of the discovery of contamination problems late in the decommissioning process, when most or all of the funds have been spent. It would also provide licensees more time to adjust the accumulation of decommissioning funds accordingly.

## Recommendations for Executive Action

We recommend that the Chairman, NRC, in the Commission's ongoing consideration of modifications to radiological criteria for terminating licenses and alternative decommissioning approaches, address

- how the burial or entombment of low-level radioactive waste at nuclear plant sites, leading to a potentially large number of contaminated sites scattered around the country, affects the federal policy under the Low-Level Radioactive Waste Policy Act to manage radioactive waste on a regional basis; and
- concerns about whether these decommissioning approaches are technically compatible with provisions of the Low-Level Radioactive Waste Policy Act, the interstate compact agreements that implement the act, and NRC's technical regulations on licensing disposal facilities for low-level radioactive waste.

To reduce the likelihood that site contamination will go undetected until late in the cleanup process, we recommend that the Chairman, NRC, require licensees to survey their plant sites for radiation immediately following the announcement of intentions to permanently cease operations, rather than allowing them to wait until 2 years before decommissioning is supposed to be complete.

## Agency Comments and Our Response

NRC stated that it intends to consider our recommendations, as they pertain to the entombment alternative, during its ongoing rulemaking proceeding on that option. NRC added that it will obtain input from stakeholders on addressing the technical and policy concerns associated with the entombment decommissioning approach.

NRC disagreed with our recommendations as they pertain to rubblization. The burial of radioactive rubble at the site of a former nuclear plant, NRC said, would be subject to its license termination rules and not its regulations governing the development and operation of facilities for disposing of low-level radioactive wastes. We, however, like EPA and the State of Maine, find it difficult to discern why radioactive material buried on-site—material that has traditionally been shipped to disposal facilities designed and regulated for such purpose–does not merit the same protection as material sent to a low-level waste disposal site.

NRC also disagreed with our recommendation to require earlier characterization of sites where plants are to be decommissioned because earlier characterization, in its view, will not add significant value to the decommissioning process. We disagree. There is always the chance that contamination exists at a plant site that has not been documented. Although there is no guarantee that early historical site assessment and characterization work would identify all such instances, the chances of doing so would be enhanced by the availability of plant employees knowledgeable about past plant operations and site conditions. Delaying this work until essentially the end of the decommissioning process—after many employees who are familiar with a plant's operational history are gone—decreases the available institutional knowledge. Such delay also limits the ability of the licensee to acquire more decommissioning funds if necessary to cover increased decontamination expenses.

# Chapter 4: New Accounting Standard Improves Financial Reporting but Cannot Ensure Adequate Decommissioning Funding

Recent changes to financial reporting standards for asset retirement obligations, established by the Financial Accounting Standards Board in June 2001, will require owners of nuclear power plants, among other affected industries, to report estimated decommissioning costs as liabilities in their financial statements. When implemented, the new standard will improve consistency in plant owners' reporting of these costs, which previous accounting practices allowed to be reported in a variety of ways. However, as an accounting standard it cannot guarantee that licensees have the funds available for decommissioning.

The estimation of decommissioning costs for nuclear regulatory purposes is an uncertain process, influenced by such matters as applicable cleanup standards and the selection of a decommissioning method. Moreover, liability amounts that companies owning nuclear power plants disclose in their financial statements may differ from the amounts determined under NRC's regulatory requirements. The new accounting standard, for example, will require public utilities and electricity generating companies to measure the liability of decommissioning costs using the "fair value" method.[1] In contrast, NRC requires licensees to estimate the cost of decommissioning their plants using a generic formula that takes into account the electrical output of the plants and derives from technical analysis of previous decommissioning activities. Alternatively, NRC allows licensees to base decommissioning costs on site-specific cost estimates if these estimates exceed the amounts calculated under the minimum funding requirements prescribed by NRC.

Finally, the new accounting standard cannot ensure that funds will be available at the time of decommissioning. Accounting standards are concerned with how financial events and obligations are reported; they do not ensure that resources will be available to pay for future needs, including decommissioning costs.

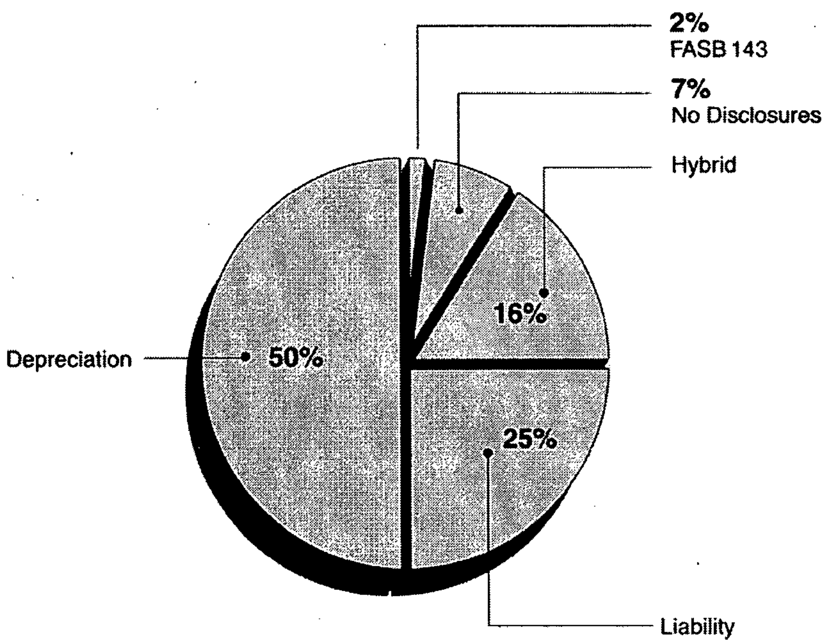
[1] Fair value is the amount that an entity would be required to pay in an active market to settle the asset retirement obligation in a current transaction in circumstances other than a forced or liquidation settlement.

## New Accounting Standard Will Improve Consistency of Reporting

Utility companies have used a variety of methods to report estimated costs of decommissioning nuclear power plants. Implementation of the new standard in mid-2002 will improve consistency in plant owners' reporting of these costs.

On the basis of our review of the 1999 annual financial reports of 55 utility companies, we determined that about 75 percent of the companies have used one of two methods—the depreciation method or the liability method—to account for their decommissioning costs. The remaining companies used either a hybrid method (16 percent); or the method included in the new accounting standard (2 percent). (See fig. 4.) We were unable to determine the method used by 7 percent of the utility companies because of insufficient disclosures in the financial statements.

Figure 4: Methods Currently Used to Account for Decommissioning Costs




Source: GAO analysis.

Utility companies most frequently accounted for nuclear decommissioning costs as a component of depreciation expense. Using this method, an expense is reported each year for a portion of the amounts collected from customers in utility rates; however, instead of recording a liability, the reported amount for the plant asset is reduced by the amount of the expense. This method could ultimately result in a negative book value for the plant asset.

Using the liability method, an expense is reported each year for a portion of the amounts collected from customers in utility rates, with an equal amount added to a liability. The "bottom-line" (net income), as well as net assets, remains the same under both methods.

A comparison of the depreciation and liability methods to the new accounting standard shows that only the new standard requires the total estimated liability to be reported at plant startup, as well as a corresponding plant asset. (See table 3.)

**Table 3: Comparison of Methods to Report Decommissioning Liability**

| Reporting approach | Depreciation method | Liability method | New standard |
| --- | --- | --- | --- |
| Full liability reported at inception | No | No | Yes |
| Liability gradually reported in an increasing amount | No | Yes | No |
| Plant asset cost amount includes the estimated decommissioning liability | No | No | Yes |

Source: GAO analysis.

In February 2000, the Financial Accounting Standards Board (FASB) issued for comment an exposure draft entitled Accounting for Obligations Associated with the Retirement of Long-Lived Assets, which discussed nuclear plant decommissioning, among other types of asset retirement obligations. After obtaining and considering public comments, in June 2001 the Board unanimously voted to issue the standard in final form, effective for fiscal years beginning after June 15, 2002. Under this new standard (Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations), the fair value of the decommissioning costs is capitalized as part of the cost of the nuclear plant and an equal amount is recorded as a liability on the balance sheet.

In addition to requiring utility companies to recognize the full estimated cost of decommissioning at plant start-up, the new accounting standard also requires additional disclosures to investors, including:

- a general description of the plant retirement obligation (the liability);
- the fair value of assets, if any, dedicated to satisfy the liability; and
- an explanation of any significant changes in the liability.

## New Accounting Standard Does Not Ensure Adequate Funding for Decommissioning Costs

The new accounting standard will not ensure that owners of nuclear power plants accumulate adequate funding for decommissioning costs. The Financial Accounting Standards Board is responsible for establishing standards of financial reporting, but not for ensuring that funding for liabilities reported under those standards will be available. The latter responsibility remains with NRC as a part of its regulation of nuclear power under the Atomic Energy Act of 1954, as amended, and other legislation.

## Agency Comments

NRC stated that it neither supports nor opposes the new accounting standard. NRC added that the accounting standard and NRC's biennial financial reporting requirements were developed by distinct organizations for different purposes. Finally, NRC said it understands that the purpose of the Financial Accounting Standards Board's standard is to ensure the consistency of financial reporting. The standard is not, NRC added, meant to duplicate NRC's responsibility of assuring the availability of adequate decommissioning funds.

# Appendix I: Comments From the Nuclear Regulatory Commission

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

November 2, 2001

Ms. Gary L. Jones, Director
Natural Resources and Environment
United States General Accounting Office
Washington, D.C. 20548

Dear Ms. Jones:

I am responding to your October 1, 2001 request that the U.S. Nuclear Regulatory Commission (NRC) provide comments on the draft General Accounting Office (GAO) report to the Honorable Edward J. Markey, House of Representatives, entitled "Nuclear Regulation - NRC's Assurances of Decommissioning Funding During Utility Restructuring Could be Improved."

The NRC provided the GAO with comments on the statement of facts associated with this report during an exit meeting with GAO staff on September 7, 2001. We are pleased that GAO incorporated many of the NRC's comments from the exit meeting in the October 1, 2001, draft report. GAO determined that most restructuring license transfers have maintained or enhanced assurance of decommissioning funding, and GAO also has provided constructive comments regarding documentation of the financial considerations associated with power reactor license transfer requests.

However, we continue to be concerned that GAO has not fully represented certain aspects of the NRC's license transfer review process, nor entirely considered the various processes associated with the decommissioning of a power reactor facility. The enclosed comments are intended to provide a more comprehensive perspective related to the conclusions and recommendations contained in GAO's draft report.

Sincerely,

William D. Travers
Executive Director for Operations

Enclosures: As stated

NRC COMMENTS ON DRAFT GENERAL ACCOUNTING OFFICE (GAO) REPORT TO THE HONORABLE EDWARD J. MARKEY, HOUSE OF REPRESENTATIVES, "NUCLEAR REGULATION - NRC'S ASSURANCES OF DECOMMISSIONING FUNDING DURING UTILITY RESTRUCTURING COULD BE IMPROVED"

1. GAO begins Chapter 2 of the draft report by stating (p. 20) that "for most of the requests that NRC reviewed to transfer licenses for one or more plants, the level of assurance that the plants' decommissioning funds will be adequate has been maintained or enhanced." However, GAO then cites two specific license transfer reviews that caused it concern, and GAO concludes Chapter 2 by stating (p. 33) that "NRC's inconsistent review and documentation of license transfer requests creates the appearance of different requirements for different owners or different types of transfers." Based on this conclusion, GAO recommends that NRC revise its standard review plan (NUREG-1577, Revision 1, "Standard Review Plan on Power Reactor Licensee Financial Qualifications and Decommissioning Funding Assurance," hereinafter referred to as the SRP) and related controls for reviewing license transfers to include a checklist for NRC staff to follow.

   NRC conducted two separate detailed financial reviews. The cited reviews concerned the corporate reorganization of Public Service Electric and Gas Company (PSEG) and the formation of Exelon Corporation (Exelon) through a merger between Unicom and PECO Energy Company.

   NRC believes that the actual decommissioning fund assurance (DFA) reviews associated with the PSEG and Exelon license transfers were adequate and that reasonable assurance of decommissioning funding was ascertained. In accordance

-1- Enclosure

NRC staff verified that adequate decommissioning funding would be maintained by reviewing other sources of financial information in addition to the application materials, including publicly available information concerning the appropriate State's non-bypassable charge requirements. In the PSEG review, NRC specifically documented a detailed and thorough evaluation of applicable State law pertaining to DFA, which, in conjunction with NRC license conditions required by the PSEG order, provides reasonable assurance of decommissioning funding for PSEG's plants. NRC staff also followed the SRP guidance regarding adequate review of applicable State legislation pertaining to DFA in the Exelon review to ensure conformance with applicable NRC regulations and to obtain reasonable assurance of decommissioning funding. NRC, however, agrees with GAO that the DFA aspect of the Exelon review was not appropriately documented.

With respect to financial qualifications reviews, GAO concludes (p. 30-31) that NRC's review of Exelon's financial qualifications for operating a large fleet of nuclear reactors was not complete and not conducted in accordance with the SRP guidance. Again, the NRC believes that this conclusion is a reflection of a lack of documentation, rather than any substantive deficiency in the actual review. NRC staff followed the SRP guidance by evaluating the appropriate information needed to obtain reasonable assurance of Exelon's financial qualifications to own and operate its reactors safely. NRC acknowledges, however, that some of the factors associated with the Exelon review were not appropriately documented, such as the NRC staff's finding that certain changes in financial projections would not have had a material effect on NRC's determination of Exelon's financial qualifications.

Regarding GAO's recommendation for developing a license transfer review checklist (p. 33), NRC does not believe that a checklist will greatly enhance the effectiveness of license transfer reviews because many of the reviews that have been performed over the last few years have been very complex and, in many aspects, unique. GAO's assessments of the PSEG and Exelon reviews appear to be based largely on the lack of adequate documentation supporting the decision-making logic provided in the SRP. Therefore, NRC believes that appropriate documentation of the logic supporting each license transfer review will help to further demonstrate the adequacy and effectiveness of each review. The NRC will seek to ensure proper documentation is maintained to address GAO's concern of the appearance of different requirements.

2. In Chapter 3 of the draft report, GAO concludes (p. 50) that the proposed alternative approaches for decommissioning (i.e., entombment and rubblization) raise equally important policy and technical issues. GAO also recommends (p. 50) that NRC require site radiation surveys to be performed immediately after a licensee announces its intention to permanently cease operations to minimize the chances of the discovery of contamination problems late in the decommissioning process.

NRC agrees that the issues raised in the draft report are important. Although NRC has previously identified DECON and SAFSTOR as the preferred alternatives, NRC is evaluating whether ENTOMB, under certain circumstances, may be an allowable alternative. NRC intends, during the ongoing entombment rulemaking effort documented in SECY-01-0099, to consider GAO's recommendation and obtain stakeholder input for addressing the technical and policy concerns associated with the

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entombment alternative approach. Regarding rubblization, NRC considers the rubblization process to be subject to the license termination rules of 10 CFR Parts 20, and 50, instead of the low-level waste requirements of 10 CFR Part 61 because the intent is not to create a low-level waste disposal site.

NRC believes that GAO's site survey recommendation would not add significant value to current decommissioning practices. Under current regulations, a licensee may begin substantial decommissioning activities, such as removing and dismantling various facility systems and structures, prior to site characterization. An immediate site characterization survey performed prior to these decommissioning activities, as recommended by GAO, would not necessarily identify all potential areas of radioactive contamination because there may be sources of radioactivity that cannot be identified or adequately assessed until many of the facility systems and structures are dismantled and removed. Therefore, GAO's recommendation may not necessarily be cost effective, because additional site characterization surveys may need to be performed in order to thoroughly understand the contamination remaining after the removal and dismantlement of facility systems and structures.

3. In Chapter 4, GAO (p. 53-54) states that the new accounting standard set forth in June 2001 by the Financial Accounting Standards Board (FASB) will improve the consistency of reporting estimated decommissioning costs in financial statements, but will not ensure that licensees will have adequate funds for decommissioning. The NRC neither supports nor opposes the new FASB standard. The NRC notes that, at one point, it intended to adopt the FASB standard for reporting decommissioning costs as a way to

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obtain additional information on the status of decommissioning funds, but that the FASB standard was delayed for several years. In September 1999, the NRC promulgated additional reporting requirements for the status of decommissioning funding, obviating NRC's need for the new FASB standard. The new FASB standard and the NRC's decommissioning funding status reports were developed by two distinct organizations for different purposes. The NRC agrees with GAO's statement that NRC, not FASB, is responsible for ensuring that NRC licensees will have adequate funds for decommissioning, and understands that the purpose of the FASB standard is to ensure the consistency of financial reporting and is not meant to provide a means of assuring the availability of adequate decommissioning funds.

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# Appendix II: GAO Contact and Staff Acknowledgments

## GAO Contact

Dwayne E. Weigel (202) 512-6876

## Acknowledgments

In addition, Michael J. Rahl, Carolyn K. McGowan, John Fretwell, Peggy Smith, Cynthia Norris, Doreen S. Feldman, and Barbara Timmerman made key contributions to this report.

# Related GAO Products


*Radiation Standards: Scientific Basis Inconclusive, and EPA and NRC Disagreement Continues* (GAO/RCED-00-152, June 30, 2000).

*Low-Level Radioactive Wastes: States Are Not Developing Disposal Facilities* (GAO/RCED-99-238, Sept. 17, 1999).

*Nuclear Regulation: Better Oversight Needed to Ensure Accumulation of Funds to Decommission Nuclear Power Plants* (GAO/RCED-99-75, May 3, 1999).

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# Exhibit D

# Indian Point Probabilistic Safety Study

## Overview and Highlights

Power Authority of the State of New York
Consolidated Edison Company of New York, Inc.

1982

## INTRODUCTION

In the past decade, society has grown increasingly aware of the direct and indirect risks that can accompany technological advancements. This awareness has led to new laws, new regulations, and new scientific methods for measuring technological risks. These new techniques attempt to quantify the two elements that make up "risks"—the likelihood of the damage occurring and the magnitude of any potential damage—or in risk assessment terms, the "probabilities" and the "consequences." These two components of risk—probabilities and consequences—cannot be separated; both are essential to decisions about benefits and the relative merits of alternative courses of action. By calculating both components of technological risk as precisely as possible, society can more knowledgeably compare the relative risks of competing technologies. Then, the risk of a technology in comparison to its benefits can be examined.

The energy production industries, particularly nuclear power, have been at the forefront of these advances in risk assessment. Nuclear power has adopted an advanced, sophisticated approach in detecting and measuring risks which has furthered our understanding of nuclear power plant safety. When all other forms of energy are similarly evaluated, a truer picture of the tradeoffs in energy decisions will emerge.

The purpose of this overview is to present some of the highlights of an extensive safety study performed on Indian Point Units 2 & 3. Since the study is a state-of-the-art investigation using sophisticated scientific tools, this overview provides some perspective for the general readership. It includes a discussion of nuclear power plant safety features and reactor safety analyses. Then, it describes a methodology called "probabilistic risk assessment" (PRA) followed by highlights of the Indian Point Probabilistic Safety Study.

## NUCLEAR POWER PLANT SAFETY

In decisions to license, build, and operate all nuclear power plants, the issue of safety dominates. Operators of nuclear power plants must demonstrate to the Nuclear Regulatory Commission (NRC)—the independent Federal agency responsible for licensing and regulating nuclear facilities—that each plant is designed and constructed with adequate safety features. Most of these safety features have one overall objective: to prevent or minimize accidents which can result in offsite radiation exposure or release of radioactive material from the plant.

### *Reactor Design Features*

Several physical barriers to prevent radioactive materials from escaping to the environment are designed into every nuclear power plant. They include:

- ***Fuel Rods.*** The tubes, or fuel rods which hold uranium fuel pellets, are made of a strong alloy called zircaloy which helps prevent the contained solids and gases from spreading through the reactor coolant system.
- ***Reactor Vessel.*** Surrounding the core of fuel rods is a reactor vessel some 8 inches thick manufactured of alloy steel to the most rigorous standards and lined with stainless steel.
- ***Containment Building.*** The reactor and its coolant system are surrounded by a massive concrete and steel building which is specially designed to prevent radioactive materials from reaching the environment in the event that piping systems should leak or break. The concrete in the containment is typically some 3 feet thick and lined with welded steel plate.

In addition to these physical safety barriers, nuclear power plants are designed and built with multiple and diverse safety systems. Outside the plant and at the site boundary, sensitive monitoring and surveillance instruments are installed to detect radiation releases.

Scientists are able to detect and measure radiation even in minute amounts better than virtually any other substance known to man. According to the Committee on the Biological Effects of Ionizing Radiation (BEIR) of the National Academy of Sciences, the average American receives about 100 millirems (a millirem—or one-thousandth of a rem—is a standard unit of radiation dose measurement) each year from background radiation. Natural background radiation comes from the sun, minerals in the earth, and other naturally radioactive elements in the air and in our food. Nuclear power plants and related activities contribute on the average only 0.3 millirems each year to natural background radiation levels under normal operating conditions.

Nonetheless, an accidental release of radioactive materials to the environment with higher exposure levels remains a remote possibility. Because this potential impact upon public health and safety exists at all, emergency plans have been developed and studies are done to continually improve the safety systems in nuclear power plants.

### *Reactor Safety Studies*

Safety analyses are performed for every nuclear power plant before it begins operating. These analyses determine whether the plant owners and operators have taken the appropriate precautions for safe operation of the plants. The techniques for conducting these studies have been refined over the years as the nuclear industry gains more experience. These refinements and improvements are made possible by a growing body of information about the performance of the designed safety features, the reliability of components, and the adequacy of safety margins for different systems and components. Further refinements are made possible by advances in computer technology—the ability to process and analyze large quantities of information to the smallest detail—and in the analytical techniques used by scientists to unravel complicated series of events and to estimate the impacts of those events.

From the early days of the nuclear industry—more than 25 years ago and 1,500 operating years of experience worldwide—safety thinking centered around the multiple-barrier approach, the physical layers of protection (such as the containment) and the series of backup safety systems (such as emergency core cooling) in case the primary system should malfunction. This safety concept is termed "defense in depth."

Observing "defense in depth" guidelines led to design requirements for nuclear plants that included hypothetical problems called design basis accidents and maximum hypothetical accidents. Engineers had to consider what damage could be caused by, for example, a loss of coolant to the reactor vessel, an earthquake, an airplane crash, a fire or pump failure. They then designed the different parts of the plant to withstand such accidents if these events were to occur.

Since physical simulation of each hypothetical accident is not feasible, additional calculations were made for the most serious possible damages to the plant. These "upper bounding" calculations helped ensure that the best engineering judgments about safety — for example, how much stress a piping system could take in the event of an earthquake — incorporated extra safety margins.

The "defense in depth" philosophy has served the cause of nuclear safety well. Carried to an extreme, however, it can be counterproductive. The introduction of unnecessary complexity could cause a net reduction in safety instead of the expected increase in levels of protection.

Therefore, with the accumulation of a substantial body of nuclear operating experience, scientists determined that tools other than "upper bounding" calculations were needed to make more accurate and realistic safety decisions about nuclear power plants.

Leaders in the field began to look at some of the new scientific tools that other industries — aerospace and defense, for example — were developing to deal with their own questions about safety, performance, and the risks involved. These tools seemed to suit many of the same issues that the nuclear industry confronted. Yet much more work needed to be done to achieve the accuracy and realism that the nuclear industry desired. Experts from a number of different fields pooled their knowledge to address the problem: how can we systematically evaluate even the most improbable accidents to determine the risk they could present to public health and welfare?

The Reactor Safety Study, commissioned by the NRC and directed by Dr. Norman C. Rasmussen of the Massachusetts Institute of Technology, was the first comprehensive study of the accident-related risk of nuclear power plants. Published in October 1975 after three years of work, it was the first attempt to quantify the risks resulting from nuclear power plant operation. It enabled a systematic classification of accidents according to their possible frequency and the possible consequences that could result.

The benchmark Reactor Safety Study report was thoroughly reviewed and critiqued by numerous groups in the years following its publication. The Lewis Report, an evaluation performed for the NRC by the Risk Assessment Review Group, contains both praise and criticism for the original study.

According to the Lewis Committee, the Reactor Safety Study was a significant improvement over earlier attempts to calculate the risks of nuclear power. It introduced a workable accident classification scheme and applied the rules of mathematical probability theory in order to quantify risks. It evolved "event tree" and "fault tree" procedures – described later in this report – to quantify the frequencies with which accidents could happen. It also examined a broader range of potential health effects. In addition to expressing risk in terms of injuries and fatalities that could occur immediately following an accident, the Reactor Safety Study considered the delayed effects of an accident by estimating latent fatalities and cancers. The Lewis Committee also criticized the Reactor Safety Study primarily for its lack of an adequate data base on which to perform some of the analyses and the way uncertainties in the results were portrayed.

Advances in reactor safety analysis since the Reactor Safety Study include:

- More extensive operating data and improved methods for handling data, including the treatment of uncertainty.
- Better documentation and models for systems to reflect the interaction of reactor operators and accident conditions.
- More comprehensive treatment of core damage and the response of the containment during an accident.
- More accurate modeling of specific conditions of the plant site, including initiating events.
- Improved methodology for assembling the results and working backwards to specific risk contributors.

The more recent probabilistic safety studies in this country and Europe built on the foundation of the Reactor Safety Study, addressed its criticisms and incorporated these advances. The Indian Point study, in particular, represents the current state of the art.

## UNDERSTANDING PROBABILISTIC RISK ASSESSMENT

Probabilistic risk assessment is considered the most advanced way to make practical decisions in a highly technical, complex society where risks cannot be eliminated, but must be controlled. It helps us understand which things are more likely than others to go wrong and provides a framework for deciding what, if anything, should be done about them.

People have sought ways to assess risk for centuries. Examples can be found in the insurance industries, the financial community, and others that deal with consumer protection. The challenge has been to assess risk systematically and to take into account unforeseen circumstances.

PRA allows you to do just that. Any accident can be examined, regardless of its likelihood. Uncertainties are clearly identified in the process. Analyzing "frequencies of occurrence" allows you to tag the most important accident scenarios among the many thousands examined. Human errors can be factored into the calculations as can complications unrelated to the accident itself that could change the levels of risk involved.

The use of PRA techniques is not limited to the nuclear industry. Others are already using a number of PRA techniques. That trend is expected to continue, with the nuclear industry in the vanguard.

Simply put, the PRA methodology asks three basic questions:

- What could go wrong?
- How likely is it that this will happen?
- If it happens, what are the consequences?

The answers to those questions help planners and decision makers to determine what, if anything, should be done to reduce the likelihood that a particular type of accident could happen or to reduce the level of damage that could occur. The answers help isolate the factors that pose the most substantial chance of adversely affecting public health and welfare.

***What Could Go Wrong?***

In analyzing risk, we are attempting to understand the effects of taking or failing to take a certain course of action. Since an outcome of a course of action involves a whole sequence of events, the term "scenario" is generally used in place of "outcome."

Developing a "scenario" begins with identifying an event that could precipitate an accident. For example, lightning striking the roof of a building could start a fire which destroys the building. The lightning strike is called the "initiating event" or beginning of an accident sequence.

The next step in developing a scenario, after identifying an "initiating event," is to frame a series of questions that ask: "If such and such occurs, *what could happen next?*" Two kinds of answers are given in response to the question: one assumes that a safety barrier erected to prevent further damage from the initiating event works; the second answer assumes that the safety barrier fails.

Using our lightning strike analogy, if the lightning strikes the building, it could hit the lightning rod installed on the roof (the safety barrier works) or it could hit another part of the roof, such as an air conditioning unit (the safety barrier fails). If it hits the air conditioning unit, what could happen next? The regulator on the unit could shut itself down because of the power surge (the next safety barrier works) or the regulator could malfunction and cause a small fire to start in the wiring system (safety barrier fails). And so on. The questioning continues in this manner until every sequence of events that could result from the initiating event is identified.

The process of identifying all of the events in a particular sequence, and assuming that a safety barrier either works or fails, is called building an "event tree." In PRA, complete event trees are developed for all conceivable initiating events.

The next step in answering the basic question, "What could go wrong?" is to determine *how* each of the failures in the succession of safety barriers can happen. How, for example, did the fire start in the wiring system? This requires an examination of the subsystem or components that make up the safety barrier in order to identify those factors which could lead to failure of an entire barrier system. The results of investigating how the failures can happen are diagrammed on a "fault tree."

Fault trees are used to determine the likelihood of failure of the safety systems identified in the event tree. In developing the fault trees, consideration is given to component failure, maintenance action, human error, and other causes. Each system is examined in sufficient detail to determine the *frequency* of failures by looking at the reliability of each of the parts involved.

***How Likely Is It That This Will Happen?***

The likelihood of something going wrong is based on data about a particular element in the fault tree. The data may include, for example, operating records on equipment or systems.

If there is a large amount of such data, the likelihood of success or failure can be calculated with a high degree of certainty, or "confidence." When there is less data, the calculated frequency, or likelihood, is more uncertain.

These uncertainties are described in terms of "probabilities." In the context of this study, a confidence level of 90% implies a probability that the parameter in question – frequency of occurrence of a particular event, for example – does not exceed a given value.

PRA studies include a rigorous mathematical assessment of uncertainty. The uncertainty of each element in the analysis is computed and is included in the final result. Thus, the likelihood of an event occurring is expressed in terms of frequency of occurrence *and* the level of confidence regarding the frequency. This format of communicating uncertainty is called the "probability of the frequency of occurrence."

PRA studies may consider literally millions of scenarios and their corresponding probability of the frequency of occurrence. These probabilities are tabulated individually and the results are usually presented on a graph.

If only one confidence level or "probability level" is used, the results would form one curved line. It is more common to look at several confidence levels:

- The 1 in 10 chance, or 0.10 probability
- The 5 in 10 chance, or 0.50 probability
- The 9 in 10 chance, or 0.90 probability

These results are normally computed on the same graph (three curved lines) and are called a "family of curves." The interval between the top curve and the bottom curve is the uncertainty band.

To translate these confidence statements into everyday language, consider the frequency at the 0.50 probability level as a "best" estimate and the frequency at 0.90 probability as an "upper bound." Upper bound estimates mean that "it is almost certain that the frequency of occurrence will not exceed this value." For purposes of communication, therefore, discussions of risk assessment results will use statements such as "the *best* estimate of the frequency of this scenario is once every 10,000 years and the *upper bound* is once every 1,000 years."

### *If It Happens, What Are the Consequences?*

The accident consequences of paramount concern are those affecting people's health. Consequences of accidents are evaluated using extensive computer programs to model accident scenarios, the conditions of the region around the site of the accident, population information, and any other relevant factors including protective measures that could offset some of the damage.

The results of the analysis of accident consequences are expressed as "damage levels," e.g., numbers of injuries, numbers of fatalities. The consequence analysis is combined with the plant and containment analyses to arrive at the "probability of frequency of different levels of damage." The combined results of damage levels with frequency of occurrence are translated in graphic form into risk curves.

The risk curves from a PRA convey considerable information, for example, what is the frequency of accidents resulting in any immediate fatalities, or what is the frequency of accidents resulting in 100 or more injuries. The degree of confidence (probability) with which the result is stated (10%, 50%, or 90%) is also conveyed.

Frequencies of occurrence are not predictions. They are expressions of the collective knowledge and experience of the experts who performed the probabilistic risk assessment. Frequencies of occurrence suggest what the odds (probabilities) are of something actually happening, and thus provide a basis for comparisons with other risks.

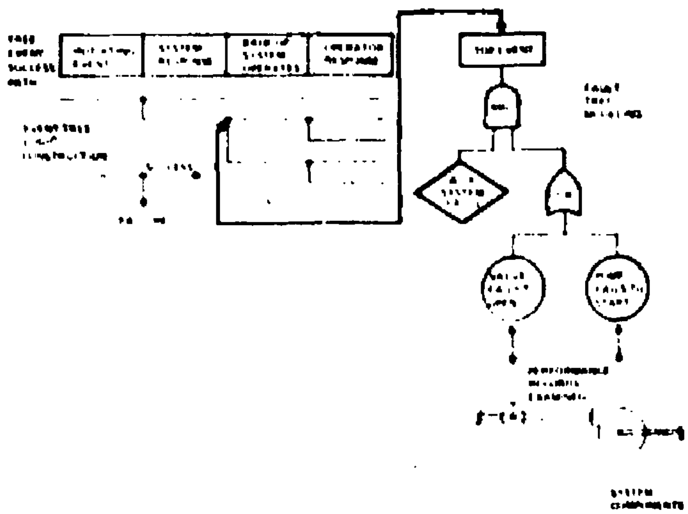
The risk curves link the likelihood that the accident could happen with the potential consequences of an accident. This is the proper way to view risk—probability coupled with consequences.

## PROBABILISTIC RISK ASSESSMENT: SOME GRAPHIC ILLUSTRATIONS

The PRA methodology involves a rigorous process that organizes a vast amount of data through highly detailed analyses. The following pages are a way to display the key steps, the intermediate features and the final results graphically. These are some very simplified examples of what is actually done in a fully developed study.

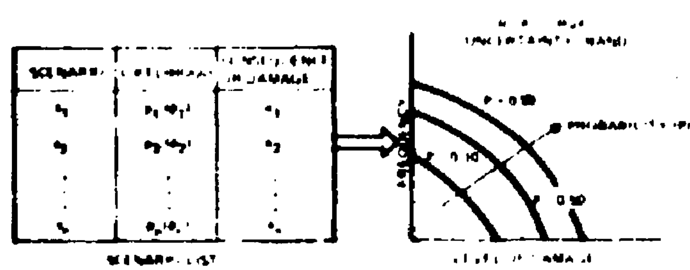
### *Quantifying Accident Sequence Probabilities*

Event trees diagram what could happen as a result of an initiating event which could lead to an accident. Branches of the tree illustrate the success or failure of the series of safety barriers and frame the answer to the question "what could happen next?" When a failure is identified, it becomes the "top event" in a fault tree analysis. Fault trees trace the failure back to its root causes, primarily using reliability performance information, to determine how the failure occurred.



### *Risk Results*

The list of accident scenarios, their likelihood of occurrence (including uncertainty), and their consequences number in the millions in a risk assessment study. After the confidence levels are determined, the computerized list format is translated into risk curves. Levels of damage (or consequences) are expressed in terms of numbers of people affected and the frequency of an accident occurring that could cause that kind of damage. Confidence levels for the results are labeled on the curves lines: 10% probability, 50% probability, and 90% probability. The interval between the 10% curve and the 90% curve is called the "uncertainty band," which shows the minimum and maximum potential consequences of an accident. The information in the scenarios list could be used to add more curves at other confidence levels if it were desired.



## THE INDIAN POINT PROBABILISTIC SAFETY STUDY

A comprehensive safety study using PRA techniques was conducted for Indian Point Units 2 & 3, beginning in January 1980. A team of more than 50 experts was involved in the project, including nuclear engineers, systems analysts, probability theorists, mathematicians, risk analysts, computer specialists; experts in thermohydraulics, chemistry, radiological effects, meteorology, seismology and wind, and nuclear power plant operators and designers. This work was reviewed and discussed with an independent review board. The final study report, more than 6,000 pages long, was submitted to the U.S. Nuclear Regulatory Commission in early 1982.

The Indian Point study has two basic purposes:

- To provide a thorough assessment of public risk resulting from the operation of Indian Point.
- To identify the dominant contributors to that risk in terms of plant design and operation. In that connection, the study postulated a variety of equipment malfunctions including progressive failures of multiple engineered safeguards leading to melting of the reactor core and failure of the containment building.

The study team began by collecting extensive information from several sources:

- Specific Indian Point operating data, covering the plant and the site. Plant data included, for example, component performance records, maintenance duration reports, and initiating event analyses. Site data included comprehensive examinations of meteorology, terrain, and demographics.
- Operating data from other nuclear power plants. Numerous data sources were analyzed to establish a comprehensive data base. Sources of data included (1) Licensee Event Reports and the NRC data summaries of these reports covering diesel generators, pumps, valves, and control rod drives; (2) the IEEE Guide to the Collection and Presentation of Electrical, Electronic, and Sensing Component Reliability Data for Nuclear Power Generating Stations; (3) the Reactor Safety Study; (4) the Nuclear Plant Reliability Data System; (5) the EPRI reports on Frequency of Anticipated Transients; and (6) the Handbook of Human Reliability Analysis with Emphasis on Nuclear Power Plant Applications.
- Expert judgment on equipment performance and accident initiators. Experts and their resources contributed additional insight and information about equipment performance and specific events that could initiate an accident or alter its course.

These data were examined using the PRA methodology discussed previously. In order to assess the possibility that public health could be endangered by an accident at Indian Point, the study identified accident sequences that could lead to release of harmful levels of radioactivity and isolated the dominant contributors to risk contained in those sequences.

The investigative process was exhaustive:

- Literally hundreds of thousands of accident scenarios were developed using the event tree/fault tree approach. Information about reactor operations and reliability of equipment was incorporated in the scenarios. These event trees and fault trees were used to evaluate various sequences leading to release of radioactivity.
- In order to isolate dominant risk contributors, initiating events from both internal and external causes were analyzed. Internal causes included plant malfunctions called "transients" and failures in heat removal systems such as loss of coolant accidents (LOCAs) which could lead to melting of the reactor core. External causes included earthquakes, fires, high velocity winds, tornadoes, floods, and aircraft accidents. Analyses of initiating events and accident sequences were not limited to hardware concerns; operator interaction with the plant systems and human response under accident conditions were also assessed.
- The response of the reactor core and containment under different core melt conditions was analyzed in extensive detail. The form and state of the damaged core and its interaction with structural materials, air, water, steam, and other reaction products were considered. The progress of core melt conditions was examined carefully; the pressure changes during a core melt and fluctuations in heat loads were quantified to define containment response; and release conditions for radioactive material were identified.
- The region around Indian Point was modeled, including information about population distribution and meteorological conditions. This information helped establish the level of risk which is partially dependent on wind speed and direction, the portions of the surrounding communities potentially affected, dispersion of radioactive material, and the like.
- After the dominant risk contributors were identified, along with their causes and probable frequency of occurrence, estimates were made of the potential damage to public health and safety. These estimates were compiled and displayed graphically as a family of risk curves which indicates the confidence level attached to the estimates.

### *Public Health Effects*

The results of the Indian Point Probabilistic Safety Study focus ultimately on public health effects. The risks to public health discussed in this overview are early, or "acute," fatalities occurring within a short time after exposure, non-fatal radiation injuries due to exposure, thyroid cancers (most of which are treatable and non-fatal), and latent cancer fatalities occurring over a 30-year period. The results are highlighted here for three levels – any effect, 100 effects, and 1,000 effects. In like manner, frequency of occurrence results have been computed for other levels of effects.

The results are also presented as "best" and "upper bound" estimates. By presenting two estimates, this analysis provides a more comprehensive picture of risk than would be the case if only a single health effect, a single level of effect, or a single confidence level were depicted.

*Indian Point Unit 2.* The most significant health effect, in terms of near-term impact, is acute fatalities. The estimates vary depending on the level of consequences analyzed. The best estimate for any effect is once in 17 million (17 million)* years of reactor operation. The best estimates of frequencies of occurrence for 100 and 1,000 effects are once in 100 million (4.8 million) years and once in a billion (29 million) years, respectively.

For radiation injuries, the best estimate for any effect is once in 370,000 (59,000) years. The best estimates for 100 effects are once in 2.9 million (290,000) years, and for 1000 effects once in 10 million (2.9 million) years.

In addition to the immediate health effects of an accident, delayed effects were also examined. For example, the best estimate of any thyroid cancers occurring is once in 2,500 (1,000) years of reactor operation. The best estimates for 100 effects are once in 5,900 (1,400) years and for 1,000 effects once in 12,000 (2,700) years.

Finally, the question of latent cancer fatalities occurring over a 30-year period was investigated. The best estimate for any effect is once in 3,000 (1,000) years. The best estimates for 100 effects are once in 5,000 (1,400) years, and for 1,000 effects once in 10,000 (2,400) years.

*Indian Point Unit 3.* The results for Indian Point 3 differ somewhat from Unit 2 due to some differences in design and equipment. The best estimate for any acute fatality is once in 83 million (10 million) years. The best estimates for 100 effects are once in 300 million (45 million) years, and once in 6.3 billion (290 million) years for 1,000 effects.

For radiation injuries, the best estimate for any effect is once in 2.6 million (130,000) years. For 100 effects, the best estimate is one in 20 million (2.4 million) years, and for 1,000 effects, the best estimate is once in 300 million (28 million) years.

* The numbers in parentheses are the upper bound estimates.

The best estimate for any latent thyroid cancers occurring is once in 12,000 (3,100) years. The best estimates for 100 effects are once in 63,000 (7,700) years, and for 1,000 effects once in 100,000 (12,000) years.

The best estimate for any latent cancer fatalities occurring over a 30-year period is once in 20,000 (5,000) years. The best estimates for 100 effects are once in 55,000 (8,000) years, and for 1,000 effects once in 100,000 (12,000) years.

The likelihood that an accident would cause any public health consequences is remote. Upper bound estimates indicate that an accident causing any acute fatality is once in 17 million years and that an accident resulting in 100 or more latent cancer fatalities is once in 1400 years. Information on accidental fatalities and latent cancer fatalities from *non-nuclear* causes provides some perspective on these potential health effects. For example, every year, based on the national average, there will be at least 100 accidental fatalities within a 10-mile radius of Indian Point and at least 30,000 cancer fatalities within a 50-mile radius of the plant, all unrelated to nuclear power.

### *The Results in Perspective*

The risk assessment for Indian Point identified the elements of an accident that would need to be present for any fatalities to result.

- *The Reactor Core Must Melt.* Coolant must be maintained in the reactor core to avoid fuel damage. Therefore, nuclear plants contain several backup cooling systems that can be called on to cool the core if the primary system should stop functioning. Only if these "emergency core cooling systems" should fail would some of the fuel rods melt or be damaged, causing a release of fission products into the reactor vessel and reactor coolant system.

  If there should be a core melt, this by no means suggests that there will necessarily be a significant release of radioactivity to the environment outside the plant. The containment structure of a nuclear plant is designed to contain the radioactive material and prevent such releases. A core melt by itself constitutes no real threat to public health and the study indicates that most core melts would be contained without significant release of radioactive material to the environment.

- *The Containment Must Fail or Be Bypassed.* If the containment serves its function, a core melt would only lead to some leakage of radiation around some of the piping passageways that connect the containment with other buildings in the plant. The risk of those small leaks would be of little or no consequence to the public health.

If the containment were to fail, the amount and type of risk to public health would depend upon conditions such as wind speed and direction, how quickly the radioactive "plume" is dispersed, and the effectiveness of protective steps like sheltering or evacuation. The possibility of bypassing the containment was also examined. Out of all accident categories studied for Indian Point, only about 1 in 1,000 core melt accidents leads to a release which could potentially cause any early fatalities.

A study with the scope and level of detail of the Indian Point safety assessment produces an extremely large body of information and results. Thousands of accident scenarios have been identified and their likelihood and consequences discussed. This overview presents only the key findings about public health effects and the safety of Indian Point.

The application of risk assessment to nuclear safety analyses, while adding immeasurably to our understanding of nuclear safety, has perhaps colored our perception of what the risks truly entail. Because comparable assessments have yet to be performed to the same level of detail for other energy sources and other industries, nuclear safety is being weighed in a vacuum.

Risk analyses in one sense may counteract their intended purpose. Events which are beyond reasonable belief tend to assume a degree of reality when they are analyzed in minute detail. Detailed analyses make people aware of possible hazards which in all probability will never result in injury. Ironically, risk analyses may demonstrate that certain risks are exceedingly remote yet fear of those same risks may increase by that very demonstration. The initial perception of "rare and remote" evolves into a growing uneasiness that "something just may happen." On the other hand, far greater risks unrelated to nuclear power may not be viewed with concern simply because they have not been so intensively investigated. Nuclear power – its safety and its risks – should be considered in that context.

# Indian Point Probabilistic Safety Study



Volume 1

Copy No. 15

## PREFACE

This report is a Probabilistic Safety Study of Indian Point Units 2 and 3, owned and operated by the Consolidated Edison Company of New York, Inc., and the Power Authority of the State of New York, respectively. The study includes: a discussion of probabilistic risk assessment methodology; plant, containment and site analyses; an analysis of initiating events including events external to the plant; an identification of the dominant contributors to risk; and a quantitative statement of the level of safety at the Indian Point nuclear power plants.

This study was prepared by Pickard, Lowe & Garrick, Inc., Westinghouse Electric Corporation, and Fauske & Associates under the supervision of the Utilities.

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## SECTION 0

## METHODOLOGY

### 0.1 INTRODUCTION AND PURPOSE

The purpose of this section is to give an overview of the basic methodology of risk analysis used in this safety study. Various individual segments of this methodology are developed in greater depth in later sections. The emphasis here is on the overall structure and flow of the process and on how the various segments fit together. The section is divided into three major parts: Part 1, Definition of Risk; Part 2, Modeling and Analysis; and Part 3, External Events.

To do a risk assessment, we obviously must first agree upon a precise and usable definition for the word risk. This is the purpose of Part 1. This part begins (in Section 0.2) by discussing some qualitative aspects of the notion of risk as used in this study. It then proceeds, in Section 0.3, to give a quantitative definition of risk in terms of a set of envisioned scenarios, or sequences of events, together with the probability and damage associated with each. This definition is called the "Level One" definition of risk. Section 0.4 explains the sense in which the word "probability" is used in this definition. For several reasons, given in this section, it is desirable to expand the Level One definition so that it may encompass some further subtleties of the idea of risk. Section 0.5 gives such an expansion and refers to it as the "Level Two" definition of risk. This latter definition then becomes the basis for the methodology of the study and the format for the presentation of the results.

Once the definition of risk is established, Part 2 then deals with the methods used to actually model and quantify the risk in a nuclear plant. Thus, with risk now defined fundamentally in terms of a list of scenarios, the next question is: "How does one identify and structure the scenarios on the list?" This question is addressed in Section 0.6. The key analytical device here is the "event tree" which is a structured presentation of the myriad of scenarios branching out of any given initiating event. Another key device is the notion of "pinch point" which allows the event trees to be partitioned into three segments: "plant," "containment," and "site."

With the scenarios identified and structured in terms of event trees, the next step is to determine frequencies of the various paths through the trees. This is done in terms of "split fractions" at the branch points of the tree in the manner discussed in Section 0.7.

Section 0.8 then addresses the question of assembling the information from this myriad of scenarios into a final presentation of the risk. The method chosen for this assembly takes maximum advantage of the structural properties of the list. Indeed, these properties and this method allow the results to be presented in a very clean and compact matrix form. This form also provides great visibility into the performance of various parts of the plant. Thus any potential problems can be readily seen and the effects of proposed hardware or procedure changes readily evaluated.

Sections 0.2 through 0.8, therefore, describe the definition of risk in terms of a list of scenarios; the identification, structuring, and quantifying of the list; and the assembly into a final presentation of risk curves. This much may be considered the "main stream" of the methodology. The remaining sections describe the numerous tributary flows into this stream.

Thus, Sections 0.9 and 0.10 describe the determination of the split fractions in terms of the frequencies of more basic "elemental" events. Section 0.11 describes the site modeling and consequence analysis, given releases of radioactivity from the containment. Sections 0.12 and 0.13 review some of the basic mechanics of probability distributions and probabilistic calculations. Section 0.14 outlines the sources of information about the elemental events and the basic mathematical principle (Bayes' theorem) for combining these different types of information into probability distributions for the frequencies of elemental events. Section 0.15 discusses the treatment of an important type of elemental event; human error. Section 0.16 discusses some further aspects of the process of combining "elemental" probability distributions during the course of system analysis. Several important pitfalls are identified here relating to the dependence of probability distributions and the use of lognormal curves.

Part 3, External Events (Sections 0.17 through 0.20), provides detail on the methods used for seismic, wind, and fire analyses; and a review of the methodology with respect to the question of completeness.

## 7.6 AIRCRAFT ACCIDENTS

### 7.6.1 AIRPORTS AND AIRWAYS

The airports and airfields within approximately 25 miles of the site are listed below (Reference 7.6-1).

| Airport/Location | Distance From Plant (miles) |
|---|---|
| 1. Danbury, Danbury, CN | 26 |
| 2. Greenwood, Greenwood Lake, NJ | 22 |
| 3. Mahopac, Mahopac, NY | 12 |
| 4. Orange County, Montgomery, NY | 22 |
| 5. Peekskill Seaplane Base, Verplanck, NY | 1 |
| 6. Ramapo Valley, Spring Valley, NY | 13 |
| 7. Stewart Air Force Base, NY | 17 |
| 8. Warwick, Warwick, NY | 18 |
| 9. Westchester County, NY | 18 |

The three closest airports are Mahopac, Ramapo Valley and Peekskill Seaplane Base. The other airports are more than 17 miles from the plant.

Mahopac Airport is a small airport for general aviation. It has a turf runway 1,800 feet long and is only operated during daylight. It normally supports approximately 15 flights per day, with an annual peak of perhaps 3,500 operations. The largest aircraft using the airport is a Piper Aztec (Reference 7.6-2).

Ramapo Valley Airport is a small, private airport for general aviation. It has a 2,200 foot long runway. Generally, it supports fewer than 50 flights per day. The largest aircraft presently based there is one Cessna 310 (Reference 7.6-3).

The Peekskill Seaplane Base is a general aviation airport at Verplanck Point, about 1-1/2 miles south of the Indian Point plant. There are about 20 aircraft normally stationed in the parking area on the edge of the Hudson River in addition to itinerant aircraft. The maximum size aircraft operating from the base is a four passenger Grumman seaplane with a weight of 5,500 pounds (Reference 7.6-4). The designated seaplane takeoff and landing pattern on the river is equivalent to runway 16/34 (see Figure 7.6-1). While these azimuths are generally southeast/northwest and parallel with the shoreline south of Verplanck Point and because of the short takeoff and landing distances required by these small aircraft, takeoffs are made on almost any azimuth south of the high voltage transmission lines crossing of the Hudson River. These lines serve the Orange-Rockland Utility Company.

There are between 3,000 and 4,000 takeoff and landing operations per year near the seaplane base, with a summertime peak of about 600 operations per month. A 100-foot high hill between the designated northerly takeoff or landing pattern and the Indian Point plant affords some protection and separation from low flying aircraft.

The airways within 12 miles of the plant site and the number of flights recorded by the FAA for each on a peak day in 1977 are indicated in Table 7.6-1. Aircraft using several of the nearby airports are vectored on courses that pass within about 5 miles southeast of the plant site. Airways or direct aircraft routings for which the edge of the airway is within 2 miles of the plant site are considered to be contributors to the hit probability estimate (Reference 7.6-5).

As seen in Figure 7.6-2, there is only one designated airway that lies within the 2-mile criteria. It is V157, which in this segment runs between the VORTACs at Kingston and Colts Neck, generally a north/south route. The centerline of this airway is 2 miles east of the plant site. The next closest designated airways are V292, about 8-1/2 miles south of the plant and running generally east/west; and J37, about 8-1/2 miles east of the plant and running generally north/south. The nearest edge of each of these airways is about 4-1/2 miles from Indian Point, so these airways are not considered in the overflight analysis.

There are two direct routings in the vicinity of the plant that are sometimes used in lieu of a designated airway. One of these, HUO-CMK, is a route between the Huguenot and Carmel VORTACs, with a centerline 5 miles northeast of the plant. The other is HUO128, the 128° radial out of Huguenot VORTAC, with a centerline 5 miles southwest of the plant. In each of these cases, the edge of the route is about 1/2 mile from Indian Point and, therefore, these routings are included in the overflight analysis.

## 7.6.2 AIRCRAFT HAZARDS ANALYSIS

The Mahopac and Ramapo Valley Airports do not present a landing or takeoff hazard to the plant because of the small size of the aircraft there and the large distance from the plant. The nearness of the Peekskill Seaplane Base to the plant, however, warrants a closer examination.

The probability of an aircraft operating from the seaplane base hitting the plant during landing or takeoff is based on the algorithm and aerial crash density given in the NRC Standard Review Plan (Reference 7.6-6).

The algorithm is

$$P = CNA$$

where

$P$ = annual probability of a plant strike by an aircraft

$C$ = aerial crash density for the appropriate category of aircraft (crashes per square mile of projected facilities area)

$N$ = number of annual operations on the runway

$A$ = area of the vulnerable structures whose failure could lead to core melt (square miles)

The critical facilities of concern for a light aircraft crashing at the site are the following:

1. Impact with the feeder high voltage line from Buchanan substation and a loss of offsite power to either or both units.

2. Impact on the station auxiliary transformer (loss of offsite power) of either Unit 2 or Unit 3.

3. Impact on the unit auxiliary transformer (loss of power from unit generator or offsite power) of either Unit 2 or Unit 3.

4. Impact on the Unit 2 diesel generator building (loss of diesel generator power).

5. Impact on the Unit 2 control building/control room (loss of manual control).

6. Impact on the Unit 1 superheater stack resulting in its collapse onto the Unit 2 diesel generator building (loss of diesel generator power) or onto the Unit 2 control building (loss of manual control), or onto the Unit 3 condensate storage tank (loss of condensate water).

7. Impact on the steam and feedwater piping between the turbine building and containment building (loss of steam generator cooling) of either Unit 2 or Unit 3.

8. Damage to the RWST or CST (loss of refueling water or condensate storage water) of either Unit 2 or Unit 3, or to the city water storage tank (backup to the CSTs).

9. Impact at the control room air intake (fuel explosion and fire in duct work to control room) of either Unit 2 or Unit 3.

10. Impact on the diesel fuel transfer pumps (loss of fuel to one or more diesel generators) of either Unit 2 or Unit 3.

11. Impact on the service water pumps of either Unit 2 or Unit 3.

12. Impact on the Unit 2 PAB top story (loss of MCCs for safeguard valves and of CCW surge tank or heat exchangers).

Most of the listed facilities, would be protected from a direct hit by a low trajectory northerly or southerly bound aircraft by a larger building, such as the turbine, containment, or primary auxiliary buildings. The control building is the only single building which, if hit, could lead to core melt. Impact by a low-flying errant plane on the Unit 2 control building does not appear to be possible because of the protection afforded by the Unit 2 and Unit 3 containment and turbine buildings and the Unit 1 superheater building. The concrete Unit 3 control building is protected from all but northbound aircraft, but even in that case, protection to the building contents is afforded by the building's concrete walls. Impact with the Unit 3 control room air intake duct, an explosion of the aircraft's fuel tank or the release of its contents, and release of toxic gases into the control room might be postulated for a southbound aircraft. The intake area, however, is well protected by the Unit 3 containment building, making this scenario extremely improbable. Impact from the south with the Unit 1 superheater stack could cause the stack to collapse onto the roof of the Unit 2 control room. However, considering the probability of missing the adjacent buildings, and considering the projected stack area, the probability of hitting the stack at the plant and causing it to fall on the small area of the control building is extremely small.

For general aviation aircraft and runway distance to the plant of a little over 1 mile, $C = 1.5 \times 10^{-7}$. The maximum exposure area, (A), for the Unit 2 control building is approximately 0.0004 square miles. Given that annual operations (N) are equal to 4,000, a figure that includes many flights off the designated runway azimuth, the Unit 2 control building hit probability, P, would be $2.4 \times 10^{-7}$ per year. The hazard for Unit 3 is substantially less.

The east bank tower of the Orange-Rockland transmission line which crosses the Hudson River near the plant is at Elevation 495'. Three sets of transmission lines span the river from the tower, with the lowest at 165-foot elevation at midspan. If a plane were to hit the transmission line it would be about 4,000 feet from the Unit 3 facilities. The plane's velocity would be low and its approach angle under this hypothesis would be no greater than about 6 degrees from the horizontal. At this low angle, and given a loss of engine power resulting from the impact with the transmission line, it is highly unlikely that the plane could even reach the plant. Further, the intervening hill provides protection.

The probability of an aircraft using a federal airway or other FAA air traffic controlled path and accidentally hitting the Indian Point plant is also estimated. The probability of an aircraft hitting the plant is based on the methodology used by the NRC (Reference 7.6-6). For airway traffic, the hit probability algorithm is

$$P = CNA/W$$

where

P = the probability of a hit by an aircraft, per year

C = the inflight accident rate, per mile flown

N = the annual number of flights on the specified airway

A = the effective area of the structures which could be hit, in square miles

W = the width of the airway, in miles

A study (Reference 7.6-7) was performed to determine the vulnerability of the Unit 2 containment to aircraft crashes. The study concluded that for planes up to the 727 class, and for striking velocities of up to 300 knots, the engine penetration into the reinforced concrete building would be less than 6 inches and scabbing thickness would be less than 18 inches. For the 54-inch wall and 42-inch dome thicknesses, there would not be a breach of containment. Based on the analysis, we conclude that for concrete wall thickness less than 8 to 10 inches and for exterior masonry walls, there could be scabbing of the interior surfaces. For metal wall or roof coverings or vessels, it is likely there would be penetration.

The area which could be hit, represented by all potentially vulnerable structures for each unit, is estimated to not exceed 0.01 square miles including an allowance for the shadow and skid areas.

The NRC Standard Review Plan suggests the use of an inflight accident rate of $3.0 \times 10^{-9}$ per mile flown and this rate is used.

The NRC Standard Review Plan suggests the width of the aircraft hit area (in order to calculate aerial crash density) be taken as the width of the airway. This corresponds with the assumption of uniform hit density throughout the entire width of the airway. The plan also suggests that if the area being considered lies outside of the full width of the airway, the equivalent width of the hit region should be increased by twice the distance from the edge of the airway to the impact area. The standard airway width is 8 nmi (±4 nmi about the centerline) which is 9.2 statute miles.

Aside from the takeoff and landing activities at the Peekskill Seaplane Base, only one airway and two direct routes occupy airspace within 2 miles of Indian Point. The traffic carried by these routes on the historical peak day in 1977 is used for the purpose of calculating the probability of an aircraft hit.

The values of each input variable and the resulting hit probability of an aircraft using the stated airway are listed in Table 7.6-2. The total hit probability from airways traffic is

$$P = 4.6 \times 10^{-8}/\text{year}$$

7.6.3 CONCLUSIONS

Operations from the seaplane base and their potential consequences have been evaluated. In summary, for landing and take off operations, the annual probability of hitting the Unit 2 control building by a light aircraft is $2.4 \times 10^{-7}$. This calculation conservatively assumes the aircraft landings are adjacent to the plant when, in fact, most landings are made south of the plant and transmission lines, or in another direction away from the plant, since seaplane landings and takeoffs occur across the width of the river. Potential aircraft accidents from air traffic in designated airways and routes in the vicinity of the plant have also been evaluated. The annual probability of a large aircraft hitting critical plant buildings is approximately 4.6 x $10^{-6}$. Therefore, the annual frequency of hitting a critical structure at Unit 2 is 2.9 x $10^{-7}$ and much less for Unit 3. The frequency of core melt from aircraft operations is less. In summary, accidents from aircraft using the airways in the vicinity of the plant, and all local airport operations, present no significant hazard to Indian Point.

7.6.4 REFERENCES

7.6-1 Schwartz, M., U.S. Corps of Engineers, New York District, personal communication to H. F. Perla, February 1981.

7.6-2 Reeves, K., Mahopac Airport, Mahopac, NY, personal communication to H. F. Perla, May 2, 1981.

7.6-3 Coopersmith, M., Ramapo Valley Airport, Spring Valley, NY, personal communication to H. F. Perla, February 17, 1981.

7.6-4 Martin, J., Airport Owner, Peekskill Seaplane Base, Verplanck, NY, personal communication to H. F. Perla, February 25, 1981.

7.6-5 U.S. Nuclear Regulatory Commission, Regulatory Guide 1.70, Revision 3, Section 3.5.1.6, November 24, 1975.

7.6-6 U.S. Nuclear Regulatory Commission, Standard Review Plan, NUREG 75/097, Section 3.5.1.6, November 24, 1975.

7.6-7 Sheth, P., et al, "Investigation of Effect of an Aircrash on the Containment Vessel at Indian Point No. 2," Franklin Institute Research Laboratories, 311-C3082-01, September 1971.

TABLE 7.6-1

**NUMBER OF FLIGHTS ON AIRWAYS WITHIN TWELVE MILES OF INDIAN POINT**

(Peak Day, 1977)

| Airways | Distance from Plant in Miles | Number of Flights Per Day |
|---|---|---|
| Designated Airways: | | |
| J37 | 8-1/2 | 11 |
| V157 | 2 | 6 |
| V34 | 12 | 65 |
| V292 | 9 | 0 |
| V3 | 11 | 89 |
| Direct Route Airways: | | |
| HUO 128 | 5 1/2 | 37 |
| 7JP-JFK (J37) | 8 1/2 | 64 |
| HUO-CMK | 5 | 2 |
| HNK-CMK (V34) | 12 | 2 |

TABLE 7.6-2

AIRWAYS TRAFFIC HIT PROBABILITIES

| Airway or Route | Distance, Centerline of Airway to Plant, Miles | Annual Number of Flights, N | Width of Hit Region, W, Miles | Probability, P, of a Hit Into Plant |
|---|---|---|---|---|
| V157 | 2 | 2,190 | 9.2 | $7.1 \times 10^{-9}$ |
| [illegible] 128 | 5-1/2 | 13,806 | 11.0 | $3.7 \times 10^{-8}$ |
| [illegible]-CMK | 5 | 730 | 10.0 | $2.2 \times 10^{-9}$ |
| TOTAL | | | | $4.6 \times 10^{-8}$/year |

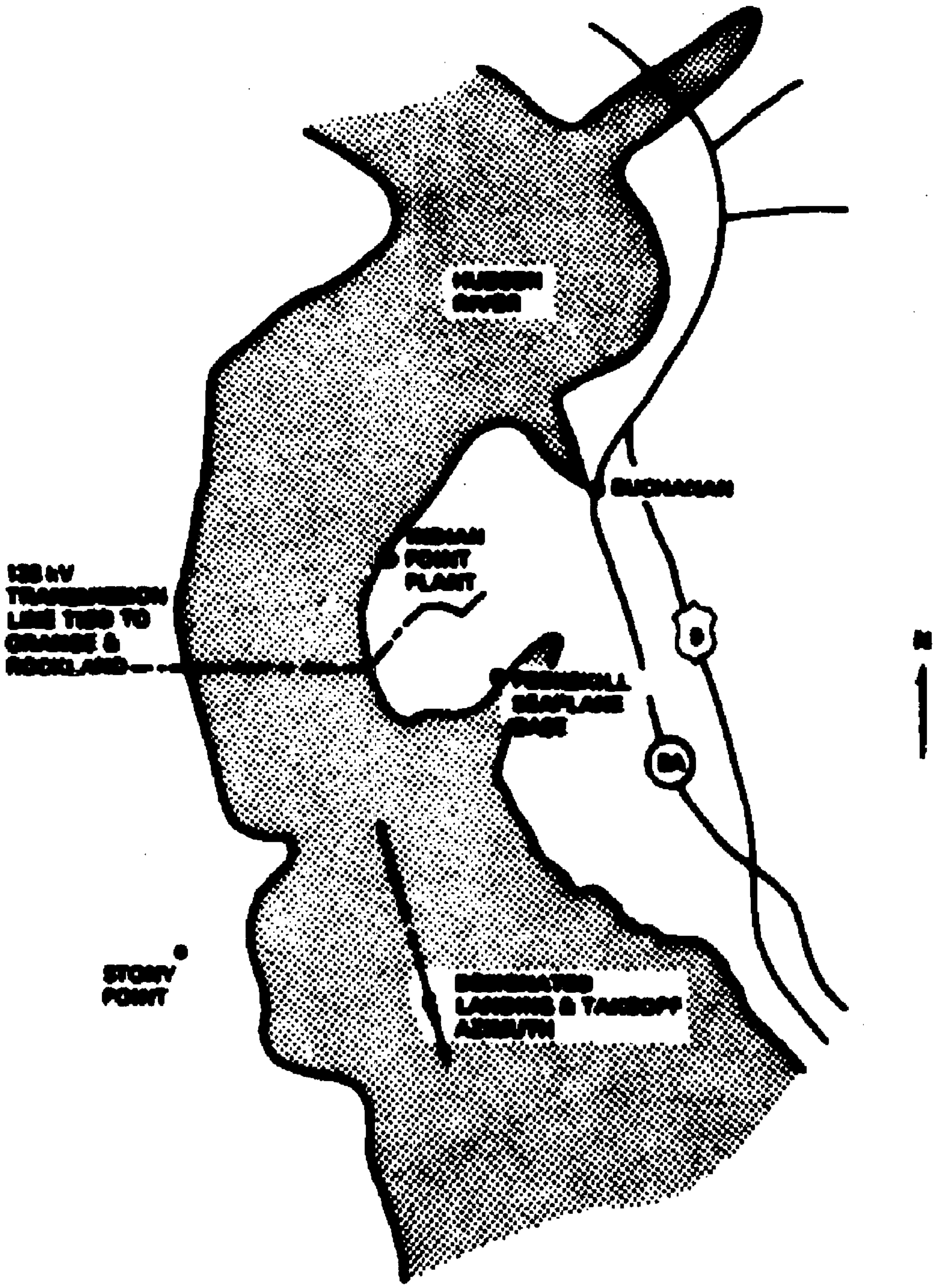


Figure 7.6-1. Peekskill Seaplane Base

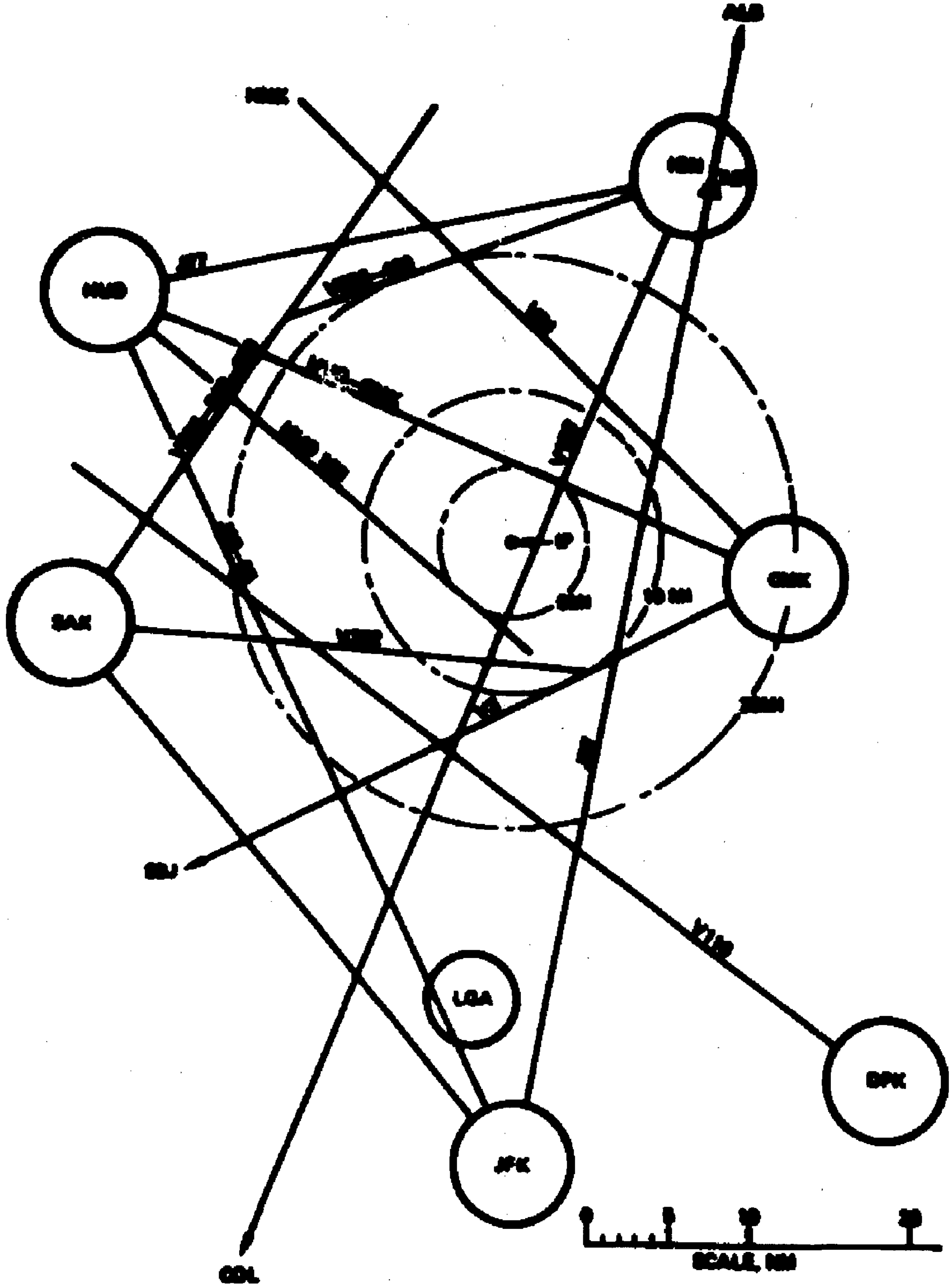


Figure 7.6-2. Airways in Vicinity of Indian Point

## 7.7 TRANSPORTATION AND STORAGE OF HAZARDOUS MATERIALS

This section describes the assessment of the probability of core melt at Indian Point resulting from offsite and onsite incidents involving transportation facilities and hazardous materials. Nearby transportation facilities and routes are examined as are proximate concentrations of hazardous materials of significance. The transportation facilities considered include rail, road, and shipping traffic. Aircraft traffic was considered in the previous section of this report.

### 7.7.1 RAIL TRANSPORTATION

The nearest rail facilities are located about 0.9 miles west and 0.6 miles east of the plant site. These CONRAIL lines carry freight, including a variety of hazardous chemicals. Chemicals having more than 30 shipments per year are required by Regulatory Guide 1.78 to be analyzed and are listed in Table 7.7-1. In addition to fuel oil, hazardous materials reportedly transported on the lines include chlorine, hydrochloric acid, sodium hydroxide, sulfuric acid, and phosphoric acid (Reference 7.7-1). There are no rail spurs on the site so none of these materials is shipped onsite by rail.

### 7.7.2 ROAD TRANSPORTATION

The nearest major road is New York Highway 9 extending north/south and located about 2 miles east of the plant site. Interstate highways I-684 and I-87 serve to relieve industrial traffic from Highway 9. Highway 9 carries truck traffic which may, on occasion, transport hazardous materials. For example, it is estimated that approximately 2 million gallons per year of liquid propane gas is transported by truck on this route. Onsite truck traffic is limited to the delivery of hydrogen, sodium hydroxide, sulfuric acid, diesel and gas turbine fuel oil, and minor quantities of ammonium hydroxide and hydrazine (Reference 7.7-1). The probability of core melt from incidents involving such deliveries is judged to be extremely small because of: (1) the controlled nature of onsite traffic, (2) the limited volumes delivered, and (3) the frequencies of such deliveries. The distances to major highway traffic also support this same conclusion.

### 7.7.3 BARGE AND SHIP TRAFFIC

Barge shipments to the Indian Point plant average three deliveries per year of about 3 million gallons of number 6 oil for house service boilers and one delivery of sodium hydroxide. The fuel barge capacity is 20,000 barrels. The river traffic is comprised of about 15,000 vessels in each direction each year (Reference 7.7-2). The maximum vessel draft permitted is 32 feet. Consequently, most of these vessels are tugs that direct barges and other low draft vessels. There are also numerous pleasure and passenger craft. The remaining traffic includes chemicals, grain, and other products which are transported to points between New York Harbor and Albany. Within this general category, about 600 tankers and 2,600 barges that carry petroleum products pass the plant on an annual basis. An accident involving passing barges might be postulated, from which there could be a fire at the shoreline or a release of sodium hydroxide.

A study to assess the probability of liquid natural gas spills in Boston Harbor (Reference 7.7-3) included examination of the frequency of accidents and spills involving vessels carrying the lighter petroleum fractions in well traveled areas as well as examination of the frequency of large, rapid spills (2,000 tons at a rate of 600 tons per minute or more) which could cause large fires or explosions. Some analogies can be drawn from that study to provide a conservative estimate of the probability of a fire adjacent to the Indian Point site caused by the collision of vessels in the Hudson River. Data in the Boston Harbor study were obtained from sources including the U.S. Coast Guard and the Oceanographic Institute of Washington State. The study concluded that the annual probability of large, rapid petroleum spills in Boston Harbor was between $2.0 \times 10^{-6}$ and $2.0 \times 10^{-5}$ per year. This was based on U.S. and worldwide data which indicated that the probability of collision casualties per harbor visit range from $2.0 \times 10^{-4}$ to $5.0 \times 10^{-3}$. Generally, less than half of the reported accidents result in a spill of any significant size, let alone a large, rapid spill. The probability of a large, rapid spill was estimated to be between $3.0 \times 10^{-6}$ and $3.0 \times 10^{-9}$ per vessel visit. Their data involved vessels with minimum drafts of from 7 to 23 feet and minimum weights of from 180 to 7,000 dead weight tons, respectively. The probability of a spill in Boston Harbor was based on a distribution of collision data for vessels of these various sizes.

Factors which affect the consequences of accidents and spills include the size and distribution of storage tanks per vessel (although penetration of more than one or two tanks of up to 5,000 DWT each has seldom been experienced), the speed and size of the striking vessels, the penetration of the storage tanks in a collision, and the amount of traffic in the area. Of 28,000 vessels passing the plant annually, only 3,200 carry petroleum products. Thus, given a collision between any two vessels, only about 1 in 10 would involve a vessel carrying petroleum products.

The transport route comprises about 200 miles of the river and it can be estimated that a collision within a mile of the plant could spill significant quantities of petroleum products that might be capable of a significant burn at the shoreline. Therefore, given a spill in the river, there is a 1:200 chance it will be in the vicinity of Indian Point. In fact, however, a spill is much more likely to occur at or near loading facilities where the traffic will congregate, and, therefore, a 1:1,000 chance of a spill near Indian Point is a better estimate.

Using the data from the Boston Harbor study and the data on the transport of petroleum products along the Hudson River, the probability of an accident resulting in a rapid spill in the vicinity of the Indian Point site is approximately

$$(3.0 \times 10^{-6} \text{ to } 3.0 \times 10^{-9}) \times 28{,}000 \times \frac{1}{10} \times \frac{1}{1{,}000}$$

$$= 8.4 \times 10^{-6} \text{ to } 8.4 \times 10^{-9}$$

The continuous river traffic is different from and safer than the harbor traffic because the latter is more confined and involves more maneuvering. Therefore, collision probabilities should be further reduced. Considering the requirement for the spill to remain sufficiently concentrated at the shoreline to support combustion and the requirement that there be an ignition, we can assign an annual frequency of fire occurring at the shoreline of about $1.0 \times 10^{-7}$ to $1.0 \times 10^{-9}$. A fire at that location would not affect any equipment that would preclude a safe shutdown and, therefore, the probability of a core melt from a river accident is extremely small.

### 7.7.4 GAS TRANSMISSION LINES

There are two natural gas transmission lines passing through the Indian Point site about 400 feet from the nearest Unit 3 plant structure and about 1,000 feet from the Unit 2 plant structures. Both gaslines, one 26-inch and the other 30-inch OD, were successfully hydrostatically tested after installation in 1952 and 1965, respectively, to at least 92% of yield stress (Reference 7.7-4). Since then, the Algonquin Gas Transmission Company has retested similar sections of 26-inch line with no adverse results. The trenches in which the carbon steel pipelines are buried were excavated in rock to about 3 feet and, therefore, are not expected to settle and cause failure. Each line contains a pressure relief valve at some distance from the plant, set at 750 psi which is less than 70% of the pipe's yield stress. The lines are now operated at a maximum of 650 psi. An automatic shutoff valve is located at the east side crossing of the Hudson River and in Yorktown, New York, some 10 miles away. Both lines are coated and are cathodically protected.

A review of the most recent "Annual Report on Pipeline Safety" published by the U.S. Department of Transportation (for calendar year 1979) was accomplished to determine the failure frequency of large gas transmission pipelines. The following pertinent statistics were taken from the reference.

1. About 70% of all failures result from damage by outside forces and about 30% occur due to corrosion, construction defects and material failures. Because the pipe is buried, well marked and not in a construction zone, only 30% of the failures are assumed to apply to the Algonquin pipelines.

2. There are about 200,000 miles of transmission pipelines similar to those near the site currently in operation in the United States.

3. Approximately 500 transmission and gathering pipeline accidents occur annually. Because gathering represents about 25,000 miles, it is assumed that about 450 of the accidents are associated with transmission pipelines.

4. The Algonquin Gas Transmission Company reports (Reference 7.7-4) that in 20 years there has been only 1 large leak and 13 small leaks reported. Therefore, it is assumed that about 7% of the accidents involve large leaks. This assumption may be high by a factor of 10.

To determine the probability of a large pipeline failure at the site using the above statistics, it was postulated that a hazard exists along a 1/2 mile section of the pipeline adjacent to the plant. Because there are two pipelines, the assumption involves a total of 1 mile of pipe. Only a large failure resulting in a large leak and fire is considered because smaller leaks would not jeopardize the plant. Examination of meteorological data indicates that the probability of wind blowing from the pipeline toward the plant (i.e., winds from the south/southeast) is 0.16.

There is an extensive preventive maintenance program associated with the Algonquin pipeline (Reference 7.7-4). For example, an aerial survey is performed twice a week over the entire pipeline to identify dead vegetation (indicative of gas leaks and fire hazards), construction in the vicinity, tree cutting activities, etc. A foot patrol is performed over the entire line twice a year using leak survey equipment. In addition, a monthly vehicle patrol inspects the pipeline near vehicle access points, and the cathodic protection system is inspected weekly. These inspections have been performed on the lines regularly for many years. Such inspections will preclude small leaks from growing to large leaks or ruptures through a lack of detection. On this basis, the probability of a large leak or rupture going undetected was estimated to be $1.0 \times 10^{-1}$.

The relationship used to determine failure probability is

$$P_{\ell f} = N_f D f_\ell f_w f_t f_d / L$$

where

$P_{\ell f}$ = annual probability of a large pipeline failure near the plant

$N_f$ = number of transmission line failures per year in the United States

$L$ = miles of transmission pipeline in the United States

$D$ = distance of pipe near site (miles)

$f_\ell$ = fraction of failures that are large

$f_w$ = fraction of time wind will blow toward plant from pipeline

$f_t$ = fraction of failures due to construction related failures and corrosion

$f_d$ = fraction of leaks going undetected

$$P_{\ell f} = 450 \times 1.0 \times 0.07 \times 0.14 \times 0.3 \times 0.1/200{,}000 = 4.5 \times 10^{-7}\ yr^{-1}$$

If a large leak occurred, the automatic shutoff valves would close with the drop in pressure and isolate the 10-mile section of the line passing the plant. In a controlled blowdown of the line, the gas empties out in a little over an hour. With a line break, it is estimated that gas would flow out and support combustion for a total of 15 to 20 minutes. Even with a large leak, there is still a possibility that it would not ignite. Nonetheless, if a fire occurred and threatened the plant, perhaps even destroying the offsite power supply transmission lines, the plant could be shut down using unit diesel generator or gas turbine power. This could be done before an initiating event could occur or before damaging a sufficient number of components in the safeguards systems, thereby precluding safe shutdown.

A study by United Engineers and Constructors (Reference 7.7-5) investigated the consequence of a gasline explosion at the site and cited the results of the 1965 Natchitoches, Louisiana, pipeline explosion whereby pipe missiles were found as far as 351 feet from the point of the blowout. Such missiles would pose little threat to the Unit 3 facilities which are 400 feet or farther from the gasline, or to the Unit 2 facilities which might be more vulnerable, but which are located 1,000 feet from the line and which are protected by a number of other structures.

In view of the foregoing, we can assign an annual frequency of $5.0 \times 10^{-7}$ for a gasline fire which threatens the plant and the probability of its leading to a core melt is extremely small.

### 7.7.5 STATIONARY SOURCES OF HAZARDOUS MATERIALS

Table 7.7-2 lists the types and quantities of chemicals stored at the plant and their general locations (References 7.7-1 and 7.7-6). Fuel oil is also stored onsite. However, it poses essentially no explosive hazard in countless civilian and military applications. Further, the fire hazard from this fuel is drastically reduced by the physical storage arrangements. The station does not store or use chlorine as a gaseous or liquid product.

The chemicals listed (Table 7.7-2) are stored in pressure vessels or controlled containers and are isolated or otherwise protected from direct access to the control rooms or other critical facilities. Gaseous exhaust from postulated leaks in these onsite containers is not hazardous except in the immediate proximity of the leak. Explosive energies of stored gases are protected from critical facilities by separation distances and intervening structures.

The stationary sources of potentially toxic materials offsite and within 5 miles of the plant were identified in Reference 7.7-1. These are discussed further.

### 7.7.6 ANALYSIS OF HAZARDS EFFECTS

Reference 7.7-1 identifies the chemicals which require further analysis. Others were eliminated because they are infrequently shipped, are stored in insufficient quantities so that they are not considered hazardous, or because they do not have physical properties that enable them to become a toxic gas. A summary of the remaining chemicals (mobile and stationary sources) is presented in Table 7.7-3. Analysis is in progress to determine the potential toxic effects from these chemicals. The result will be that if potential effects are significant enough to be of concern, corrective actions will be taken to reduce the hazard or effects to acceptable levels. On that basis and on the basis of the foregoing evaluations, we conclude that the effects from hazardous materials leading to core melt are extremely small.

### 7.7.7 REFERENCES


7.7-1 Consolidated Edison Company of New York, Inc., letter to NRC from John O'Toole, Enclosure 2, dated May 12, 1981.

7.7-2 Schwartz, M., U.S. Corps of Engineers, New York District, personal communication to H. F. Perla, February 1981.

7.7-3 Lave, L., and M. Kazarians, Probability of LNG Spills in Boston Harbor - A Comparison with Conventional Tanker Spills, UCLA-ENG-7866, December 1978.

7.7-4 Lawson, L., Algonquin Gas Transmission Company, Boston, MA, personal communication to H. F. Perla, February 1981.

7.7-5 United Engineers & Constructors, Inc., Plant Capability to Withstand an Explosion and Fire in a Gas Transmission Line For Indian Point Generating Station, Unit 3, April 1968.

7.7-6 Consolidated Edison Company of New York, Inc., letter to NRC from Peter Zarakas, July 1, 1980.

TABLE 7.7-1

OFFSITE RAIL/BARGE TRANSPORTATION OF HAZARDOUS CHEMICALS

| Chemical | Distance From Plant (miles) | Shipments/Year | Average Shipment Quantity (tons) |
|---|---|---|---|
| Anhydrous Ammonia | 0.9 | 48 | 64 |
| Carbolic Acid | 0.9 | 214 | 87 |
| Carbon Dioxide | 0.9 | 89 | 81 |
| Chlorine | 0.9 | 213 | 77 |
| Chlorine | 0.6 | 31 | 50 |
| Denatured Alcohol | 0.9 | 121 | 68 |
| Ethyl Acetate | 0.9 | 34 | 75 |
| Formaldehyde Solution | 0.9 | 45 | 91 |
| Hydrochloric Acid | 0.9 | 127 | 89 |
| Methanol | 0.9 | 279 | 84 |
| Petroleum Naphtha | 0.9 | 84 | 64 |
| Phosphoric Acid | 0.9 | 67 | 90 |
| Sodium Hydroxide | 0.2 | 80 | 150 |
| Sulphuric Acid | 0.9 | 70 | 76 |
| Xylene | 0.9 | 30 | 45 |

TABLE 7.7-2

CHEMICAL STORAGE AT INDIAN POINT

| Chemical | Quantity | Location at Plant |
|---|---|---|
| Carbon Dioxide (liquid) | 64,000 SCF | Unit 1 -- Service Water Pumps Area |
| Hydrogen | 23,300 CF @ 1500 psi | Unit 1 -- Service Water Pumps Area |
| | 23,300 CF @ 1500 psi | Unit 1 -- Chemical Systems Bldg Area |
| | 263 CF @ 1500 psi | Unit 2 -- PAB |
| Ammonia Hydroxide | 55 gallons | Unit 2 -- Turbine Building |
| Hydrazine | 220 gallons | Unit 2 -- Turbine Building |
| | 165 gallons | Unit 3 -- Turbine Building |
| Sodium Hydroxide | 6,000 gallons | Unit 3 -- Service Boiler Building |
| | 9,700 gallons | Unit 1 -- Nuclear Service Building |
| | 4,200 gallons | Unit 3 -- PAB |
| Sulfuric Acid | 500 gallons | Unit 2 -- Turbine Building |
| | 6,000 gallons | Unit 3 -- Service Boiler Building |
| | 500 gallons | Unit 3 -- Turbine Building |

Sources: References 7.7-1 and 7.7-6

TABLE 7.7-3

TOXIC CHEMICALS HAZARDS TO BE ANALYZED

| Chemical | Quantity Offsite (gallons) | Tons Transported/ Vehicle (avg) | Distance To Control Room (mi) |
|---|---|---|---|
| Anhydrous Ammonia | - | 64 | 0.9 |
| Benzene | 12,400 | - | 3.8 |
| Carbon Dioxide | - | 81 | 0.9 |
| Chlorine | - | 77 | 0.9 |
| Chlorine | - | 50 | 0.6 |
| Denatured Alcohol | - | 68 | 0.9 |
| Ethyl Acetate | - | 75 | 0.9 |
| Ethylene Dichloride | 7,410 | - | 3.8 |
| Hydrochloric Acid | - | 89 | 0.9 |
| Hydrogen Cyanide | 11,000 | - | 3.8 |
| Methanol | - | 84 | 0.9 |
| Toluene | 7,000 | - | 1.5 |
| Trichloroethane | 95,905 | - | 3.8 |
| Xylene | - | 45 | 0.9 |

## 7.8 TURBINE MISSILES

Turbine blades in turbine-generators could fracture and fragments could be ejected at high velocities, breaking through the turbine casing. These missiles could affect safe operation. The missile analyses which were performed for the FSAR were based upon a comprehensive study of turbine failures performed by Bush of Battelle Pacific Northwest Laboratories (Reference 7.8-1). Experience at that time indicated that the probability of a missile being ejected from the casing would be about $1.0 \times 10^{-4}$ per year. This probability for missile ejection was used in the analyses.

Currently, utilities are reanalyzing their units for potential turbine missile ejection and hits on vital equipment, based on turbine failure studies in progress by Westinghouse Corporation. In these studies, the failure mechanism has been assumed to be fatigue cracking. Recent inspections of low pressure rotors revealed the presence of stress corrosion cracking in the keyway and bore areas. This cracking mechanism is being incorporated into the calculations for the probability of a missile exiting the turbine shell. Preliminary analyses indicate that, given a frequent inspection interval for the low pressure rotors, the annual frequency of missile ejection is below $1.0 \times 10^{-4}$.

This frequency (i.e., $1.0 \times 10^{-4}$ or less per year) combined with the plant specific probabilities of the missile hitting safety related equipment results in a total hit frequency of $1.0 \times 10^{-7}$ or less. The earlier models used in the FSAR for calculating the probability of a missile exiting the turbine casing may be revised to incorporate the stress corrosion phenomena when the Westinghouse studies are completed.

### 7.8.1 REFERENCES

7.8-1 Bush, S. H., "Probability of Damage to Nuclear Components Due to Turbine Failure," Nuclear Safety, Vol. 14, No. 3, 1973.

# 7.9.1 DAMES & MOORE SEISMICITY STUDY

# Exhibit F

Exhibit F

**UNITED STATES**
**NUCLEAR REGULATORY COMMISSION**

*In the matter of*

| | | |
|---|---|---|
| ENTERGY NUCLEAR INDIAN POINT 2 L.L.C., | ) | |
| ENTERGY NUCLEAR INDIAN POINT 3, L.L.C, | ) | License No. DPR 26 and |
| And Entergy Nuclear Operations, Inc. | ) | License No. DPR 64 |
| and Entergy Northeast, Inc., | ) | |
| regarding the Indian Point Energy Center | ) | Docket No. 50-247 and |
| Unit 2 and Unit 3License Amendment | ) | Docket No. 50-286 |
| Regarding Fire Protection Program | ) | |

**DECLARATION OF ULRICH WITTE**
**REPLY TO RESPONSEs BY ENTERGY AND STAFF ANSWERING PETITION FOR LEAVE TO INTERVENE, REQUEST FOR HEARING, AND CONTENTIONS REGARDING LICENSE RENEWAL OF INDIAN POINT UNIT 3 AND UNIT 2**

My name is Ulrich Witte. WestCAN, RCCA, PHASE, and the SIERRA CLUB, and Assemblyman Richard Brodsky have retained me as a consultant and Expert Witness with respect to the above-captioned proceeding. I am a mechanical engineer with over twenty-six year's professional experience in engineering, licensing, and regulatory compliance of nuclear commercial nuclear facilities. I have considerable experience and expertise in the areas of configuration management, engineering design change controls, and licensing basis reconstitution. I have authored or contributed to two EPRI documents in the areas of finite element analysis, and engineering design control optimization programs.

I have led industry guidelines endorsed by the American National Standards Institute regarding configuration management programs for domestic nuclear power plants. My 26 years of experience has generally focused on assisting nuclear plant owners in reestablishing fidelity of the licensing and design bases with the current plant design configuration, and with actual plant operations. In short, my expertise is in assisting problematic plants where the regulator found reason to require the owner to reestablish competence in safely operating the facility in accordance with regulatory requirements. My curriculum vitae is attached hereto as Attachment A.

I submit the following comments in support of each coalition stakeholder in asserting the incomplete License Renewal Application submitted by the Applicant submitted after several attempts, and formally accepted for docketing by Staff, and published on August 1, 2008.

I note that the License Renewal Application was significantly amended again, on and submitted to the ASLB, Staff, and other parties, after an extensive 181 page amendment. It was not however, made placed in the Federal Register for public review. Change should have be noticed to all the intervening organizations, it also apparently was not.

My expertise in Configuration Management in the industry is particularly relevant to my judgment surrounding program fidelity, completeness, and compliance to federal rules. I have assisted seven plants during my tenure in reestablishing the foundational prerequisite licensing basis and design bases, together with the integration of complex programs after the Licensee lost the ability to operate in compliance with federal rules, such as 10CFR54(f), and often required more than a year to return to service. My curriculum vitae is provided in Attachment 1 to this declaration.

**CONTENTION 13: The LRA is incomplete and should be dismissed, because it fails to present a Time Limiting Aging Analysis and an Adequate Aging Management Plan, and instead makes vague commitments to manage the aging of the plant at uncertain dates in the future, thereby making the LRA a meaningless and voidable "agreement to agree."**

License renewal is be "strict design" under the rules, and as held by current precedence in renewal proceedings, can be summarized into the following four narrow areas of scope:

The Staff's well as the Applicant's response to our petition and for that matter to all of the petitions submitted, is that by "strict design," License Renewal (as codified in 10CFR54 and 10CFR51) can be simplified to address four things—and four things only:

(a) Aging of the plant structures, systems, and components will be sufficiently managed – where one cannot argue they are already addressed within the current license basis.
(b) review of time limited aging evaluations

(c) environmental impact analysis that is clearly plant specific and not generic, (for example, severe accident risk is out of scope but alternatives to severe accidents are in scope)

(d) anything else that one can prove is only possible during the renewal period but not during the current license period.

This very narrow scope is misconstrued as a structural boundary of the renewal scope in its core basis. As asserted in both the Back Ground and Summary sections of this reply actual renewal can only be legally narrowed to this points if (1) the current license basis is known, and the applicant as available incontrovertible evidence that proves compliance, (2) the present programs to be relied upon are sound, and the record provides the public as well as the Commission confidence, that rationale for extended the license term beyond the engineered design life is both safe and environmental sound.

Example after example show otherwise. Indian point was design to *suggested* criteria by a lobbying organization. Neither plant was designed or constructed to even draft design criteria, and it shows. The LRA states otherwise. See for example page 7 of Unit 3 LRA.

The results are not insignificant. Feedwater pipe bucking on Unit 2, a Steam generator tube rupture on Unit 2, fire protection program breakdowns that are substantial, and currently unresolved. Even an emergency plan is not functional after decades of wrangling between the regulator, congressional leadership, community leadership, and decades is telling. On January 7, 2008, Entergy acknowledged the existence of a credible report (see Exhibit F), where contaminates are leaking into the Hudson river principally from two leaking spent fuel pools, but not limited to other sources as described in contentions within this petition. The Report appears to assume the Hudson river water is not currently potable, and not used for drinking. However, that condition is expected to change.

These issues all point to a broken Configuration Management Program. Under item, (d) above, there appears to be no plan to correct this and this is a clear example, of "any other issue anything else that one can prove is only possible during the renewal period but not during the current license period."

For the Applicant to claim "trust me" in response after response" where specifics are required, and ambiguities are provided is a duck and run tactic. In precedence that tolerated an approach of that essentially can be summarized as "we'll figure this out later when we get a grip." As an engineer, and expert in configuration management, one can only wonder how a problematic plant can argue the most fundamental violation of contract law as acceptable and sufficient. An agreement to agree to resolve the problem later is <u>void</u>. The issues where the Applicant does this are: Flow Accelerated Corrosion, (what constitutes precise scope, including inspection of buried biping), Equipment Qualification (what and when to replace components), and reactor vessel internals analysis required for TLAA. The applicant has failed miserable on this issue already at Vermont Yankee, and this presently a significant element to renewal at Entergy's sister plant. The known problem of High Head Safety Injection System design is a clear example of TLAA scope falling short, and yet the public and the regulator is being asked to "trust Entergy." In my 26 years in assisting plants recover from being shutdown for extended periods. Trust me. Was not in any one's vocabulary. Not the rule, not the guidance, and certainly not earned by past performance. Transparency was. The LRA is NOT transparent. The recent six violations on Unit 3 continue to support the breakdown in core configuration management a t Unit 3. The OIG report regarding license renewal reinforces the breakdown. Fire protection ( in particular Hemyc wrap being installed in 1995 on Unit 3, known to be deficient within a few years. Yet was left as is, for eleven years—and is uniquely[1] pencil whipped into the condition by Entergy as not actually being a problem at. I beg to differ. The license is in current violation of the one hour rule with an unlawful "exemption" that is ungrounded and does not defend the risks to the public as acceptable. I cannot agree that the vague dates to manage the staggering number of issues with the facility back to safe operation and regulatory compliance in the future are sufficient to assert that Entergy will accomplish the core elements of renewal scope.

What is left for inference but not available for direct facial challenge is that the rule bypasses a plethora of issues that start from current unresolved problems

[1] With the exception of Entergy's James A FitizPatrick Plant which also received an exemption for a similar condition in 2006.

and are expected (by engineering rigor and not mere speculation) to either not be resolved at the end of the current license period, or more importantly, reflect a failed implementation of design criteria, operational criteria; or design basis accident mitigation that actually worsen by extending the operating license. Any topic that is addressed elsewhere is argued by Staff as out of scope—for example, emergency planning, or design basis threat. In the face of precedence that states otherwise, I believe this is fundamentally a failure by the Commission to accomplish its mandate. The physical and materiel scope of license renewal including specific plant systems, structures, components is incorrectly interpreted by the Staff—and significant areas of scope are improperly excluded.

The nexus between adequate engineering, design and operation, and maintenance of the existing plant is relevant to the predicted aging of safe operation of the extended facility. This challenge cannot be set aside – but instead must be resolved a priori to current renewal proceedings. (applicable law: precedence for this is some of this is in place from ASLB proceedings regarding VY)

First, the materiel condition of the plant matters and that depends heavily how the plant was designed, operated, modified, and maintained compliant. i.e. the efficacy of the physical plant through the past 45 years since construction needs to be provable by the docketed record including compliance to the historical and current license bases <u>by the applicant</u>. Second, the rules and case law by themselves establish the sufficiency of the license bases so as to adequately implement the congressional enacted statutes governing the protection of the health and safety of the public, as well as minimizing risk to the public assets.

The rules as codified in part 2, together with the case law are deliberate in reigning in the scope to the above four narrow areas, and it is left to the petitioner, (at least within the agency's forum for adjudication) to argue by inference the relevancy of the historical condition, accidents, design failures, insufficient corrective actions, incomplete modifications, and margin is adequate as a starting point to show that reactor, its control, and safety-related systems designed for forty years, may be safely operated for 60 years *with* substantial power up rates.

The nuclear regulatory commission's mandate is not being met by this narrow view. License Renewal proceedings as found in the hearings to date and the rules themselves, together demonstrate what is truly a stacked deck[2]. The Nuclear Regulatory Commission mandate itself is not currently implemented.[3]

In examining this contention for admissibility, we ask the Board independently ask it self the following with respect to this contention.

(1) Arguments for staying the renewal process—in spite of the Oyster creek

[2] See for example, United States Nuclear Regulatory Commission Staff Practice and Procedure Digest. Commission Appeal board and Licensing Board Decisions July 1972-January 31, 2004. Published 2005, known as NUREG-0386, Digest 13. 704 pages of mandated authoritative precedence regarding the rules provided under 10CFR2. Yet the digest contains a disclaimer that it is not necessarily correct, or complete, cautions the reader on the second page that precedent cited is current, and consistent with the new rules.

[3] See comments regarding the NRC's failure to implement is congressional mandate

precedence.

a. OIG report – the renewal process is broken.
b. Petition submitted supporting cessation of renewal proceedings until OIG renewal problems are corrected—specifically IP LRA as well as VY, Oyster Creek,
c. Vermont Governor and Vermont DPS calls for halt in renewal proceedings objection filed January 18, 2008.
d. The EPA calling for complete environmental assessment in October 2007.
e. Arguments that present new questions or contentions based upon new information (these could be submitted as a a new and distinct series of petitions)
f. December 18 changes to the LRA were material and substantial and unpublished.
g. Changes in security and confidentiality policy compels a conclusion that the LRA needs to be revised and to include areas formerly considered confidential and therefore beyond reach of public intervention. (see documents recently made public by the NRC)
h. OIG report regarding fire protection
i. Failure to incorporate DBT threat into the renewal process

(2) The physical and materiel scope of license renewal including specific plant systems, structures, components is incorrectly interpreted by the Staff—and significant areas of scope are improperly excluded. The nexus between adequate engineering, design and operation, and maintenance of the existing plant is relevant to the predicted aging of safe operation of the extended facility. This challenge cannot be set aside – but instead must be resolved a priori to current renewal proceedings. (applicable law: precedence for this is some of this is in place from ASLB proceedings regarding VY)

(3) NRC must compel the licensee to complete proper environmental impact assessments for 100's of significant changes to the facility need to be addressed. Applicable law: Environmental impact rulemaking (codification is currently in progress) to strengthen this acknowledged weakness of the rules.

I declare under the penalty of perjury that the foregoing is true and correct.

Executed this 15th day of February, 2008.

Ulrich K. Witte

State of New York )
)ss.:
County of Rockland )

SUSAN HILLARY SHAPIRO
Notary Public - State of New York
No. 02SH6060466
Qualified in Rockland County
My Commission Expires June 25, 20 11

On the 15th day of Feb., in the year 2008 before me, the undersigned, personally appeared Ulrich Witte, personally known to me or proved to me on the basis of satisfactory evidence to be the individual(s) whose name(s) is (are) subscribed to the within instrument and acknowledged to me that he/she/they executed the same in his/her/their capacity(ies), and that by his/her their signatures(s) on the instrument, the individual(s) or the person upon behalf of which the individual(s) acted, executed the instrument.

______________________________
Notary Public

# Exhibit G

# Exhibit H

Exhibit "H"

7590-01-P

NUCLEAR REGULATORY COMMISSION

Proposed License Renewal Interim Staff Guidance LR-ISG-2006-02:

Staff Guidance on Acceptance Review for Environmental Reports

Associated with License Renewal Applications

Solicitation of Public Comment

AGENCY: U.S. Nuclear Regulatory Commission (NRC)

ACTION: Solicitation of public comment

SUMMARY: The NRC is soliciting public comment on its Proposed License Renewal Interim Staff Guidance LR-ISG-2006-02 (LR-ISG) on the acceptance review criteria for environmental reports (ER) provided by applicants for reactor license renewal. This LR-ISG summarizes the Title 10 of the *Code of Federal Regulations* Part 51 (10 CFR Part 51) requirements for ERs submitted with license renewal applications (LRAs), and provides a checklist that will be used by the NRC staff to verify the completeness of these reports prior to docketing. The NRC staff issues LR-ISGs to facilitate timely implementation of the license renewal rule and to review activities associated with an LRA. Upon receiving public comments, the NRC staff will evaluate the comments and make a determination to incorporate the comments, as appropriate. Once the NRC staff completes the LR-ISG, it will issue the LR-ISG for NRC and industry use. The NRC staff will also incorporate the approved LR-ISG into the next revision of the license renewal guidance documents.

DATES: Comments may be submitted by (insert date 60 days after publication in the *Federal Register*). Comments received after this date will be considered, if it is practical to do so, but the Commission is able to ensure consideration only for comments received on or before this date.

ADDRESSES: Comments may be submitted to: Chief, Rules and Directives Branch, Office of Administration, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001. Comments should be delivered to: 11545 Rockville Pike, Rockville Maryland, Room T-6D59, between 7:30 a.m. and 4:15 p.m. on Federal workdays. Persons may also provide comments via e-mail at rgs@nrc.gov. The NRC maintains an Agencywide Documents Access and Management System (ADAMS), which provides text and image files of NRC's public documents. These documents may be accessed through the NRC's Public Electronic Reading Room on the Internet at http://www.nrc.gov/reading-rm/adams.html. Persons who do not have access to ADAMS or who encounter problems in accessing the documents located in ADAMS should contact NRC Public Document Room (PDR) reference staff at 1-800-397-4209, 301-415-4737, or by e-mail at pdr@nrc.gov.

FOR FURTHER INFORMATION CONTACT: Ms. Jennifer A. Davis, Project Manager, Office of Nuclear Reactor Regulation, U.S. Nuclear Regulatory Commission, Washington DC 20555-0001; telephone 301-415-3835 or by e-mail at jxd10@nrc.gov.

SUPPLEMENTARY INFORMATION: Attachment 1 to this *Federal Register* notice, entitled *Staff Position and Rationale for the Proposed License Renewal Interim Staff Guidance LR-ISG-2006-02: Staff Guidance on Acceptance Review for Environmental Reports Associated with License Renewal Applications*, contains the NRC staff's rationale for publishing the proposed LR-ISG-2006-02. Attachment 2 to this *Federal Register* notice, entitled *Proposed License Renewal Interim Staff Guidance LR-ISG-2006-02: Staff Guidance on Acceptance Review for Environmental Reports Associated with License Renewal Applications,* identifies the guidance for reviewing ERs received with LRAs.

The NRC staff is issuing this notice to solicit public comments on the proposed LR-ISG-2006-02. After the NRC staff considers any public comments, it will make a determination regarding issuance of the proposed LR-ISG.

Dated at Rockville, Maryland this 8th day of February, 2007.

FOR THE NUCLEAR REGULATORY COMMISSION

***/RA/***

Pao-Tsin Kuo, Acting Director
Division of License Renewal
Office of Nuclear Reactor Regulation

**STAFF POSITION AND RATIONALE FOR THE**

**PROPOSED LICENSE RENEWAL INTERIM STAFF GUIDANCE LR-ISG-2006-02:**

**STAFF GUIDANCE ON ACCEPTANCE REVIEW FOR ENVIRONMENTAL REPORTS**

**ASSOCIATED WITH LICENSE RENEWAL APPLICATIONS**

## STAFF POSITION:

The NRC staff intends to use a checklist of acceptance criteria when evaluating environmental reports submitted with license renewal applications. This guidance summarizes the 10 CFR Part 51 requirements for environmental reports submitted with license renewal applications, and provides a checklist that documents the review process used by NRC staff to verify the completeness of these reports.

## RATIONALE:

The NRC developed a checklist of the requirements in 10 CFR Part 51 to document the NRC staff's acceptance review standards regarding the information that needs to be included in an environmental report. The staff finds that the utilization of the guidance provided in the checklist will facilitate consistency and efficiency in the NRC staff's acceptance reviews of environmental reports submitted with license renewal applications.

PROPOSED LICENSE RENEWAL INTERIM STAFF GUIDANCE LR-ISG-2006-02:

STAFF GUIDANCE ON ACCEPTANCE REVIEW FOR ENVIRONMENTAL REPORTS

ASSOCIATED WITH LICENSE RENEWAL APPLICATIONS

Introduction

Each applicant for renewal of a license to operate a nuclear power plant is required to submit with its application a separate environmental report (ER) in accordance with Title 10 of the *Code of Federal Regulations* (10 CFR 54.23). As stated in 10 CFR 54.23, the ER must comply with the requirements of Subpart A of 10 CFR Part 51. The requirements governing the contents of an ER submitted at the operating license renewal stage are specified in 10 CFR 51.45 and 10 CFR 51.53(c). This LR-ISG is being proposed to document the staff's practice in performing an acceptance review of ERs submitted as part of a license renewal application.

Background and Discussion

The NRC staff routinely reviews ERs against the requirements of 10 CFR 51.45 and 10 CFR 51.53(c) as part of the acceptance review of reactor license renewal applications. Staff review guidance governing reactor license renewal environmental reviews and the preparation of environmental impact statements is provided in NUREG-1555, *Standard Review Plans for Environmental Reviews for Nuclear Power Plants, Supplement 1: Operating License Renewal.*

In conducting its acceptance review, the staff also relies on the guidance provided to applicants in Regulatory Guide 4.2, Supplement 1, *Preparation of Supplemental Environmental Reports for Applications to Renew Nuclear Power Plant Operating Licenses.* The regulatory guide provides methods acceptable to the staff for implementing the provisions of 10 CFR 51.45 and 10 CFR 51.53(c). While conformance with the suggested format of the regulatory guide is not required, use of the guide is expected to ensure the completeness of the information provided, assist the NRC staff and others in locating information, and result in more efficient and timely NRC staff review.

Proposed Action

The acceptance review checklist for ERs submitted with license renewal applications, available via ADAMS at Accession No. ML063190452, will be incorporated into the next revision of NUREG-1555, Supplement 1. The acceptance checklist is intended to be a tool to ensure efficiency and consistency in the staff's acceptance reviews and ensure that all necessary components of license renewal stage ERs are submitted in accordance with governing regulations. As noted in the checklist instructions, the absence of any of the information recommended in Regulatory Guide 4.2, Supplement 1, would not require that supplemental information be provided prior to acceptance of an application; however, applicants should expect that the absence of such information may result in more intensive environmental audit activities and/or issuance of early requests for additional information to support the staff's review. The docketing and subsequent finding of a timely and sufficient application (including the ER) does not preclude NRC reviewers from requesting additional information as a review proceeds, nor does it predict the NRC's final determination regarding the approval or denial of a license renewal application. This proposed LR-ISG is not intended to substitute or re-interpret requirements outlined in 10 CFR 51.45 and 10 CFR 51.53(c). The checklist is also expected to serve as a knowledge management tool for NRC staff members by specifying review criteria in a simplified, user-friendly format.

NUCLEAR ENERGY INSTITUTE

Project No. 690

cc:

Mr. Joe Bartell
U.S. Department of Energy
NE-42
Washington, DC 20585

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Licensing Lead - License Renewal Project
Palisades Nuclear Plant
27780 Blue Star Memorial Highway
Covert, MI 49043

# Exhibit M

Exhibit M

**UNITED STATES**
**NUCLEAR REGULATORY COMMISSION**

*In the matter of*

| | | |
|---|---|---|
| ENTERGY NUCLEAR INDIAN POINT 2 L.L.C., | ) | |
| ENTERGY NUCLEAR INDIAN POINT 3, L.L.C, | ) | License No. DPR 26 and |
| And Entergy Nuclear Operations, Inc. | ) | License No. DPR 64 |
| and Entergy Northeast, Inc., | ) | |
| regarding the Indian Point Energy Center | ) | Docket No. 50-247 and |
| Unit 2 and Unit 3License Amendment | ) | Docket No. 50-286 |
| Regarding Fire Protection Program | ) | |

**SUPPLEMENTAL DECLARATION OF ULRICH WITTE**
**REPLY ENTERGY'S RSEPONSE AND STAFF'S RESPONSE TO PETITION FOR LEAVE TO INTERVENE, REQUEST FOR HEARING, AND CONTENTIONS REGARDING LICENSE RENEWAL OF INDIAN POINT UNIT 3 AND UNIT 2**
**RE: CONTENTIONS 36**

My name is Ulrich Witte. WestCAN, RCCA, PHASE, the Sierra Club—Atlantic Chapter, and Assemblyman Richard Brodsky have retained with respect to the above-captioned proceeding. I am a mechanical engineer with over twenty-six year's professional experience in engineering, licensing, and regulatory compliance of nuclear commercial nuclear facilities. I have considerable experience and expertise in the areas of configuration management, engineering design change controls, and licensing basis reconstitution. I have authored or contributed to two

EPRI documents in the areas of finite element analysis, and engineering design control optimization programs. I have led industry guidelines endorsed by the American National Standards Institute regarding configuration management programs for domestic nuclear power plants. My 26 years of experience has generally focused on assisting nuclear plant owners in reestablishing fidelity of the licensing and design bases with the current plant design configuration, and with actual plant operations. In short, my expertise is in assisting problematic plants where the regulator found reason to require the owner to reestablish competence in safely operating the facility in accordance with regulatory requirements. My curriculum vitae is attached hereto as Exhibit O.

I submit the following comments in support of each coalition stakeholder in Contention 36 regarding Entergy's Flow-Accelerated Corrosion Program for Indian Point Units 2 and 3.

**Contention 36:**

**Entergy's License Renewal Application Does Not Include an Adequate Plan to Monitor and Manage Aging of Plant Piping Due to Flow-Accelerated Corrosion During the Period of Extended Operation**

**<u>The need for Flow-accelerated Corrosion management:</u>**

Flow Accelerated Corrosion phenomena was outside original design basis analysis, and engineering analysis did not predict the catastrophic events of 1986 and the Surry Plant, where work workers were killed, when an 18 in pipe ruptured with no prior warning. The plant was 15 years old at the time of the event. Casual relation to actual safe operation of the plant and even potential loss of control room habitably was not foreseen, when steam condensate shorted circuit cards in fire control panels, dumping the entire CO2 system, rendering it inoperable and endangering additional human life. Since CO2 is heavier than air, concentrations eventually accumulated in the plant control room. Senior Reactor Operators elected to not evacuate the control room, and begin disoriented and in some case ill from oxygen displacement by the Carbon dioxide .

**<u>The issue at Indian Point is insufficiently managed now, as it is at other Entergy Plants.</u>**

Submitted with particularity and specificity are provided here in for Unit 2. Unit 3 contains a similar historical record. The records show that the issue exists for both plants. See <u>Exhibit R</u>.

In essence, the aging management program required for license extension is predicated upon a sound, compliant and complete design basis record. Use of CHECWORKS is predicated upon the plants material conditional being monitored under the auspices of the program and benchmarked against industry trends and both cite specific and events such as ruptured pipes or unpredicted pipe thinning at other facilities. Without this, the plant's material condition, basis design assumptions required for an adequate Flow-accelerated program cannot not be substantiated.

The issue of adequate benchmarking of data is part of the larger question that Contention 36 raises. To fully address the contention, the applicant needs to establish the proposed licensing basis for management of FAC vulnerability of plant piping, as required under NUREG 1801 for each relevant system; second, provide the technical ground for basis of a program that adequately assures the plant will be safely operated and maintained regarding FAC; and finally confirmation that the program developed is fully implemented, and durable for the extended operating period.

What the record shows is the following statement by Entergy: "The FAC program that will be implemented by Entergy during the license renewal period which is the *same program* being carried out today and will meet all regulatory requirements and industry guidance" . This sweeping statement contained in the current pending LPA, is vague, and provides no engineering insight. However, the identical program is implemented at Vermont Yankee by under the same procedures. With problems. After numerous independent evaluations the identical program was found to be admissible, and the ALSB in those proceedings found the material facts in dispute geninue, and ruled against a motion for summary disposition. The hearing is scheduled for this summer.

As the expert witness corroborating with another expert, in those procedures, and the statements made in the LRA my knowledge that the programs, procedures, and industry guidance is all identical, along with the record of pipe breaks of many can be characterized as likely FAC based such as exhibit R. I cannot conclude that aging management with respect to Flow Accelerated Corrosion Program at Indian Point meets the guidance of NUREG -1801, Section XI.M.17 nor the rule.

Industry experience, heightened attention, and new guidance reflect the need to narrow the uncertainties in predicting flow accelerated corrosion. The facts are that failures associated with FAC continue to occur. For example, during the past three years, pipe thinning or failure events have occurred at Duane Arnold, Hope Creek, Clinton, Braidwood, LaSalle, Peach Bottom, Palo Verde, Palisades, Catawba, Calvert Cliffs, Kawanee, Browns Ferry, ANO, and Salem. New failures currently being investigated for failure mechanisms include Cooper, SONGS, and Nine Mile point. Some of these plants have received power uprate approvals including stretch, and MU, and are operating at increased power levels, others have EPU applications in progress.

Of particular interest in those plants that have received UPE licenses, and their failure rates after baselining the configuration geometries and wear rates post UPE. A brief review includes Hatch (2005), Clinton, Palo Verde, Dresden, Quad Cities, Surry (2006 event), and Kewaunee. Each has seen a FAC related failure after EPU.

The facts clearly point to the uncertainty in predictability—and the danger of depending on one empirical program such as CHECWORKS as a free standing singular reliable tool to avoid negative margin or pipe failure is addressed within the guidance. Industry guidance suggests an overlapping approach. For example, under NUREG 1801, the VY LPA requires addressing numerous mechanical aging programs under GALL. The FAC program is one of them and needs to address each of the following elements:

(1) Scope

(2) Preventative actions

(3) Parameters monitored or inspected

(4) Detection of aging effects

(5) Trending

(6) Acceptance criteria

(7) Corrective actions

(8) Confirmation processes

(9) Administrative processes

(10) Operating experience

Included in items (3) and (4) and (5) is the need to establish parameters, trending, and detection of aging effects. No particular number is specified for benchmarking in the NUREG, however, a firm recommendation in the NUREG is that a comprehensive baseline be established. Given that each plant has unique characteristics and operating histories this is reasonable. Separate industry guidance supports 5-10 years of data trending. See for example, "Aging management and life extension in the US Nuclear Industry" October 2006, prepared by the Chockie Group International, page 38. The outer limit of this range supports my opinion of at least 10 years for Indian Point given the extent of mismanaged pipe and equipment leakage almost from day one, and the unlawful use of suggested original design criteria from a trade organization.

I am forced to conclude that Indian point Program for FAC remains unsubstantiated as acceptable for extended operation, and based on the facts does not assure protection of the health and safety of the public.

I declare under the penalty of perjury that the foregoing is true and correct.

Executed this 15th day of February, 2008.

UKWitte

______________________________

Ulrich K. Witte

State of New York )
)ss.:
County of Rockland )

On the 15th day of Feb., in the year 2008 before me, the undersigned, personally appeared Ulrich Witte, personally known to me or proved to me on the basis of satisfactory evidence to be the individual(s) whose name(s) is (are) subscribed to the within instrument and acknowledged to me that he/she/they executed the same in his/her/their capacity(ies), and that by his/her their signatures(s) on the instrument, the individual(s) or the person upon behalf of which the individual(s) acted, executed the instrument.

______________________________
Notary Public

SUSAN HILLARY SHAPIRO
Notary Public - State of New York
No. 02SH6060466
Qualified in Rockland County
My Commission Expires June 25, 20 08

# Exhibit O

Exhibit "O"



# Ulrich K. Witte

## Summary:

Over twenty-six year's of professional experience in engineering, configuration management, licensing, regulatory compliance of large scale commercial nuclear facilities. This includes management and implementation of design change control programs, engineering standards programs, multi-department/multi-functional licensing initiatives, plant design basis and engineering process improvement programs for six energy companies operating seven nuclear power plants. Responsibilities include:

- Systems solutions to plant operations, engineering modifications, safety analyses, design changes, installation and testing, software, drawing change programs, and training. Optimized function interfaces to insure proper coordination and synchronization for cost effective and compliant operation of the facility.
- Technical support management, and issue resolution programs that identified potential hardware, operational or equipment function issues, as well as document problems, data management problems and organizational enhancements
- Engineering Change Processes from change inception to document close-out
- Multi-department Configuration Management Program including technical approach, consensus, approval, and implementation. Managed a standing Configuration Management Programs Group whose goal was to integrate ten functional areas under a corporate strategic plan encompassing two nuclear facilities.
- Vertical slice system design/operation reviews, design bases / regulatory rule reconciliation, and licensing bases reconstitution and transitioning projects
- Integration of plant equipment information systems with business processes within engineering, materials management, maintenance, and plant operations.
- Structured business process modeling. Application of functional analysis purely from a data prospective—to enhance change management, efficiency.
- Chaired ANSI certified industry guidance on cost effective, compliant, and institutionalized programs for successful configuration management enhancement
- EPRI guidance on optimizing the Engineering Change Process
- Formal training to engineering department personal with specific courses on the engineering change process, plant safety analysis, and modification testing. Trained engineering personal on the requirements of the plant wide Configuration Management Program.

## Technical Consultant

Northern Lights Engineering, L.L.C., 71 Edgewood Way, Westville, Connecticut 06515 (May 2002 –Today)

Established a consulting practice where I provided expertise in matters affecting the safe operation and regulatory compliance of commercial nuclear power facilities. This includes licensing and regulatory compliance issues, modification and implementation of industry standards, engineering design reviews, and configuration management analysis associated with an unexpected event, a design failure, or an elevated risk condition, and includes review of proposed changes to the plant operating license in preserving design efficacy.

Technical Advisor and Expert Witness to IPSEC representing WestCAN, Clearwater, the Sierra Club - Atlantic Chapter, and PHASE
Providing technical advisory, expert witness work and legal assistance in preparing and submitting petition for leave to intervene and request for hearing with contentions regarding the license renewal application by Licensee for Indian Point Nuclear Units 2 and 3. This included preparing and filing an initial petition containing 51 contentions and several other petitions regarding fire protection for Unit 3, in context with the recent EPA letter, as well as Mothers v. NRC filed in 9th circuit, and the October 31 DEC/AG letter. The work includes, separate allegations of regulatory procedural violations regarding the Thermal Shock Proposed Rule, and recent Fire Protection Exemptions that appear to clearly violate to CFR Part 2, and the Design Basis Threat rule under 10CFR73. This effort includes expert review of the Aging Review Program, in particular flow-accelerated corrosion issues, and finite element fatigue analysis reviews of susceptible components and a number of other contentions related to the safe operation of each unit beyond its 40 year license.

Technical Advisor and Expert Witness to the law firm of Shems, Dunkiel, Kassel, & Saunders, PLLC
Currently providing technical assistance in pre-filed testimony regarding Entergy Nuclear Operations application for renewing the operating license of Vermont Yankee. This includes Aging Review Program, in particular flow-accelerated corrosion issues, and finite element fatigue analysis reviews of susceptible components and a number of other contentions related to the safe operation of the plant beyond its 40 year license at 120% of originally design power

Technical Advisor, to the law firm of Leroche, Meyers, and Conswel, LLP.
Provided licensing and regulatory compliance expertise in legal claim and derivative action by the board of directors of the First Energy Corporation against its corporate officers in their role associated with the Northeast black out of August 2003, and the mismanagement of the Davis Besse Nuclear Power Plant.

Technical Advisor to the Union of Concerned Scientists
Provided technical review of UCS analysis of the Davis Besse reactor head corrosion event. This included analysis of the loss of integrity of the reactor vessel, and the immediacy of the reactor head failure.

## Senior Scientist, Dominion Resources Inc, Millstone Station

P.O. Box 128, Waterford, Connecticut 06385-0128 (December 1996 – 2002)

Project Manager, Licensing Commitments. Established the Regulatory Commitment Management Program. Developed a program that established senior management and department level control of more than 30,000 licensing commitment that was previously broken. The substantially enhanced program captured, dispositioned, consolidated, and managed implementation of docketed commitments to the NRC. Status, responsibility and clear communication were successfully implemented to allow Millstone to successfully restart Units 2 and 3.

The effort required substantial procedure revisions, customer consensus building, and integration of separate free-standing department specific database applications, as well as the station wide action item tracking system. A near term deliverable necessary for the successful restart of Unit 3 was to provide a workable, compliant and functioning regulatory commitment management program.

Project Manager, 50.54(f) Licensing Bases Transition Project. I led a team of 14 individuals to disposition and validate approximately 5100 regulatory commitments necessary for restart of Unit 3. The effort has led to a quality rate of more than 98 percent with production average of about four hours per commitment.

## Manager, Configuration Management Program, New York Power Authority:

123 Main Street, White Plains New York 10621, Nuclear Generation Department, Engineering Division
(November 1991 - November 1996)

Established the Configuration Management Program for the New York Power Authority's nuclear facilities. Included are 10 functional areas and integrated controls as authored in the corporate strategic plan. Management functions and technical skills include the following:

- Established Configuration Programs Group. This group and my position were established as a result of INPO Plant Evaluation calling for configuration management enhancement, and resolution of design control issues identified by the NRC in their DET Inspection of 1991 of the FitzPatrick Plant, as well as independent assessments. Recruited permanent staff, and supplemented the group with contracted staff on as needed basis to support both plants correcting significant technical and functional issues and being placed on the NRC's Watch List.

- Modified the engineering change process. Areas of immediate attention included the Design Control and Modification Programs, where a series of working groups were established to correct technical content and improve quality, ownership, and business efficiency of the design change process. This effort was achieved via: (1) a formal process to assess, model, and enhance the design change and modification process and interfaces to key functions; and (2) immediate changes to engineering procedures.

- Assessed and enhanced the Plant Equipment Data Base and controls for each plant. Results of the assessment indicated that the IP3 Plant Equipment Database contained significant problems with component classification, equipment type and status, maintenance history etc. Prepared and implemented a recovery plan and project team to reestablish the controls and content of database to be compliant with NRC Generic Letter 83-28 and to support the plant restart. Streamlined and enhanced the component classification process for both plants. Established controlled and non-controlled segregation of plant equipment in accordance with recent EPRI guidance.

- Automated and validated existing fragmented and corrupt sources of engineering information. These data sources were compiled, validated, and controlled and included multi-department areas such as set point controls, Electrical Cable and Raceway Information Systems for JAF and IP3, along with the fuse controls and data management.

- Developed design basis problem resolution process, "Design Document Open Item". Established methods for prioritizing, tracking and closing out design document issues. Established proper interface and control room notifications as per tech spec requirements. Provided guidance on operability determinations and reportability. Provided oversight for classifying and tracking more than 1100 open design issues for IP3 and 300 for JAF. Defended program to the NRC.
- Established working groups between Nuclear Generation Department and the corporate wide Information Management Organization. Gained management endorsement for areas of data quality improvement and automation for the Nuclear Generation Department. This led to enhanced implementation of the equipment information systems for both sites.

## Project Manager, Program to Assure Completion and Quality, Tennessee Valley Authority:

(December 1990 - March 1991) Under contract by CYGNA Energy Services to the Vice-President, Engineering and Operations Department, Watts Bar Nuclear Plant.

- Developed a comprehensive plan to measure progress and confirm quality of the in-progress design evolution of the plant. Developed a methodology for linking specific plant equipment to that equipment's respective design basis (and associated design attributes); license commitments; and numerous verification programs currently in place. The five phase program was presented to NRR in January and received approval as an activity to assist TVA in removing the stop work order on construction of the facility.

## Technical Manager, Configuration Management Program, Southern Nuclear Operating Company:

(December 1988 - November 1991). Under contract by ABB Impell and CYGNA Energy Services to Corporate Engineering Manager, Edwin I. Hatch Nuclear Plant, Georgia Power Company.

- Established and implemented the Hatch Configuration Management Program. Phase one of the effort included definition, establishment of management objectives, specification of the configuration management program scope and development of a reference manual.
- Developed and executed formal rigorous horizontal evaluations (the second phase of the project) of each relevant functional area including engineering design, implementation, plant operations and maintenance, procurement, information systems, document control and others. The program integrates functional areas across the plant, each architect engineer, and corporate (SONOPCO and Southern Company Services) organizations.
- Implemented enhancements to the program. This phase includes upgrading the design change process to achieve successful integration across organizations; stricter adherence to closure activities; and formal design engineering involvement in such activities as procurement of replacement items (equivalency). Additional controls were established such that misapplication of information obtained through informal design change processes such as the "Request for Engineering Assistance".
- Reconciling the plant's design basis. A second major activity of the program was to compile, consolidate, and ultimately, automate the plant's design basis. A major objective is to provide access and retrievability of current design basis to each of the key users of each participant organization.

- Applied Structured Business Analysis including CASE tools in the evaluation and enhancement phases. The as-found configuration management activities of all relevant processes were modeled and analyzed with this technique. Proposed enhancements are then tested on the model prior to actual implementation.
- Chaired the subcommittee for the Nuclear Information and Records Management Association which is developing a Technical Position Paper entitled, "Implementation of a Configuration Management Enhancement Program for a Nuclear Facility".

## Team Leader, NRC Safety System Functional Inspection Response Organizations:

Led the NRC Safety System Functional Inspection Response Teams for Georgia Power Company (1989), and Sacramento Municipal Utility District (1987). Assisted as team coordinator in the GPC - Plant Hatch Electrical Distribution System Functional Inspection Response Team (1991). Under contract by ABB Impell (December 1987 - November 1990) to the site Engineering Manager, Rancho Seco, SMUD. and CYGNA Energy Services (December 1990 - November 1991) to the Corporate Engineering Manager, Edwin I. Hatch Nuclear Plant, Georgia Power Company.

- In the case of GPC, the NRC SSFI resulted in validation of the in progress implementation of the Hatch Configuration Management Program, and only one violation to the licensee.
- The effort included an SSFI self-assessment as well as managing the utility through the NRC inspection.
- For SMUD, developed and executed a plan for closure of both immediate findings and long term corrective action required. Assisted in defending the plan to the NRC.
- For GPC - Plant Hatch EDSFI in June 1991. Developed and implemented an EDSFI Preparation Plan for the Engineering (both A/Es) and site organizations. This effort included management of a 27 man team preparation and inspection response team for the Hatch EDSFI.

## Deputy Mechanical Engineering Manager, Engineering Department

Under Contract to the Site Engineering Manager, Rancho Seco, Sacramento Municipal Utilities District, Rancho Seco (April 1986 - September 1987)

Managed the implementation and closure of over 400 modifications to the plant. Provided the NRC with a basis for allowing a successful restart of the facility. (January 1986 to November 1986) Impell Lead Project Engineer, Class 1 Piping and Support Recertification Effort, SMUD.

- Developed an engineering department action plan to improve technical quality, reconstitute design basis for five systems, control costs of plant modifications, and improve adherence to schedule.
- Responsible for the complete recertification of the Pressurizer Relief Line, Decay Heat System, and others. Responsible for expediting and implementing design changes as necessary through to closure. Assisted in Utility responses to NUREG-0737, and I&E 79-14.
- Upgraded the Engineering Department procedures to gain credit for the relaxation of ASME code requirements in structural damping values. Initiated the FSAR changes as well.

## Project Engineer, Fire Protection:

Under Contract to Sacramento Municipal Utilities District, Rancho Seco ( November 1984 to April 1986), SMUD Fire Protection Coordinator, Fire Protection Program

- Developed the SMUD Appendix R Fire Protection Program. Established or substantially revised 110 plant and engineering procedures including shutdown procedures on total loss of the plant's control room, technical specification surveillance procedures, fire protection system maintenance procedures, and the development of a fire protection program manual.

Successfully defended the program to the NRC during the 1985 Appendix R Inspection, with no resulting findings or open items.

## Additional Experience (6/78 through 8/84):

Senior Engineer, performed original pipe stress analysis and support placement for Duke Power's Catawba Plant. Qualified approximately 8 class one and two plant systems. (ABB Impell 6/78 - 12/79).

Non-linear finite element analysis of large diameter piping for EPRI. Analysis of production stress codes versus non-linear evaluation techniques, versus actual in situ testing of the system. Results were published in EPRI Report "Seismic Piping Test and Analysis. (ABB Impell, 1980 -1981)

As Project Engineer, directed the preparation of the annual Emergency Plan exercises for Kansas Gas and Electric Company, Union Electric Company, and Texas Utilities. In two plants, the exercise was installed on the plants simulator, and received recognition from the NRC for realism of the scenario. (ABB Impell 1982-1984).

## EMPLOYER SUMMARY:

**Northern Lights Engineering, L.L.C.** 12/2002 – current
71 Edgewood Way
Westville, CT 06515

**Northeast Utilities /Dominion Resources Inc** 12/1996 – 12/2002
(Under Contract via Cataract Inc through 9/97.)
2500 McClellan Ave.
Pennsauken, NJ 08109

**New York Power Authority** 11/1992 -12/1996
123 Main Street
White Plains, New York 10671

**Cygna Energy Services** 11/1991 - 11/1992
5600 Glenridge Drive, Suite 380
Atlanta, Georgia 30075

**ABB Impell Corporation** 6/1978 - 11/1991
333 Research Court
Technology Park-Atlanta
Norcross, Georgia 30095

**Northern Lights Engineering, L.L.C.**
**71 Edgewood Way, Westville, Connecticut, 06515**
**Ulrich K. Witte**

## EDUCATION:

University of California, Berkeley
B.A. Physics, 1983
Senior level and graduate course work in Mechanical Engineering, and Electrical Engineering

Quinnipiac University School of Law
J.D expected June, 2009

## PUBLICATIONS:

- EPRI Report Number 108736, "Guidelines for the Optimization of the Engineering Change Process," March 1994.
- NIRMA PP-03, "Position Paper for a Configuration Management Enhancement Program for a Nuclear Facility," April, 1992. Subcommittee Chair.
- EPRI Report Number 8480, " Seismic Piping Test and Analysis," 1980.

## PROFESSIONAL AFFILIATIONS AND AWARDS

American Society of Mechanical Engineers, American Nuclear Society, Nuclear Information and Records Management Association, Who's Who For Rising Young Americans.

## REFERENCES:

References available upon request.

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# Exhibit P

Entergy

**Entergy Nuclear Northeast**
Entergy Nuclear Operations, Inc.
Indian Point Energy Center
295 Broadway, Suite 1
P.O. Box 249
Buchanan, NY 10511-0249

September 1, 2005

Re: Indian Point Units No. 2 and 3
Docket Nos. 50-247 and 50-286
NL-05-094

Document Control Desk
U.S. Nuclear Regulatory Commission
Mail Stop O-P1-17
Washington, DC 20555-0001

**SUBJECT: Response to NRC Generic Letter 2004-02, Potential Impact Of Debris Blockage On Emergency Recirculation During Design Basis Accidents At Pressurized-Water Reactors**

**References:**
1. NRC Generic Letter 2004-02, "Potential Impact Of Debris Blockage On Emergency Recirculation During Design Basis Accidents At Pressurized-Water Reactors", dated September 13, 2004.
2. NL-05-023, "90-Day Response to NRC Generic Letter 2004-02, Potential Impact Of Debris Blockage On Emergency Recirculation During Design Basis Accidents At Pressurized-Water Reactors", dated February 28, 2005.

Dear Sir:

This letter provides Entergy Nuclear Operations (Entergy), Inc. response to NRC Generic Letter (GL) 2004-02 (Reference 1) for Indian Point Unit 2 and Indian Point Unit 3. The information requested by the Generic Letter is provided in Attachment 1.

Attachment 2 provides an update to commitments made by Entergy in the 90-Day response to the subject generic letter (Reference 2). No new commitments are being made in this submittal. If you have any questions or require additional information, please contact Mr. Patric W. Conroy, Licensing Manager at 914-734-6668.

I declare under penalty of perjury that the foregoing is true and correct. Executed on 9/1/2005.

Sincerely,

Fred R. Dacimo For.
Site Vice President
Indian Point Energy Center

cc: next page

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Attachment 1: Indian Point Unit 2 and Unit 3 Response to NRC Generic Letter 2004-02
Attachment 2: Indian Point Unit 2 and Unit 3 Update to Commitments made in the 90-Day Response

cc:

Mr. John P. Boska, Senior Project Manager
Project Directorate I,
Division of Licensing Project Management
U.S. Nuclear Regulatory Commission

Regional Administrator
Region I
U.S. Nuclear Regulatory Commission

Resident Inspector's Office
Indian Point IP 2
U.S. Nuclear Regulatory Commission

Resident Inspector's Office
Indian Point IP 3
U.S. Nuclear Regulatory Commission

Mr. Paul Eddy
NYS Department of Public Service

**INDIAN POINT UNIT 2 and UNIT 3**

**ATTACHMENT 1 TO NL-05-094**

# Response to NRC Generic Letter 2004-02, Potential Impact Of Debris Blockage On Emergency Recirculation During Design Basis Accidents At Pressurized-Water Reactors

ENTERGY NUCLEAR OPERATIONS, INC
INDIAN POINT NUCLEAR GENERATING UNITS 2 AND 3
DOCKETS 50-247 AND 50-286

## Response to NRC Generic Letter 2004-02, Potential Impact Of Debris Blockage On Emergency Recirculation During Design Basis Accidents At Pressurized-Water Reactors

Addressees are requested to provide the following information no later than September 1, 2005:

**Requested Information Item 2(a):**

Confirmation that the ECCS and CSS recirculation functions under debris loading conditions are or will be in compliance with the regulatory requirements listed in the Applicable Regulatory Requirements section of this generic letter. This submittal should address the configuration of the plant that will exist once all modifications required for regulatory compliance have been made and this licensing basis has been updated to reflect the results of the analysis described above.

**Entergy Response to Item 2(a):**

The recirculation functions of the Emergency Core Cooling System (ECCS) and Containment Spray System (CSS) under debris loading conditions will be in compliance with the regulatory requirements listed in the Applicable Regulatory Requirements section of the subject generic letter in accordance with the new regulatory guidance. In order to ensure compliance, Entergy has performed and continues to perform analyses to determine the susceptibility of the ECCS and CSS recirculation functions to adverse effects of post-accident debris blockage and operation with debris-laden fluids. The analyses to date conform to the greatest extent practicable to the NEI 04-07 Guidance Report methodology (NEI GR)(Ref. 1) as supplemented by the NRC Safety Evaluation Report (NRC SER)(Ref. 2). (Refer to response to Item 2(c) for further information).

The following major activities have been completed:

- Containment walkdowns and surveillances with the exception of latent debris sampling for Unit 2
- Vendor debris generation analyses
- Vendor post-accident containment water level calculations

The following activities are currently in progress:

- Formal acceptance of completed vendor calculations
- Available Net Positive Suction Head (NPSH) analysis
- Entergy review of vendor debris transport analysis
- Entergy review of vendor downstream effects evaluations
- Development of conceptual design options
- Entergy review of vendor debris head loss evaluations (sump screen surface area determinations)
- Selection of the final design

- Selection of sump screen hardware vendor

The following activities are currently in planning:

- Assessment of margin to address chemical effects
- Programmatic and procedural changes
- Confirmatory latent debris sampling for Unit 2

Based on the work performed to date, modifications will be required to both the recirculation and containment sumps and associated screens. The Unit 3 Internal Recirculation (IR) pumps will be replaced to match the Unit 2 design in order to reduce the required net positive suction head. In addition, modifications may be required in order to reduce the amount of debris migrating to the sumps. These modifications may include the addition of flow channeling including flow diversion barriers/new crane wall openings, debris interceptors, selected installation of insulation jacketing and missile/jet impingement barriers.

The recirculation sumps at both Unit 2 and Unit 3 are of a sufficient size to accommodate replacement screens with large surface areas. The containment sumps are considerably smaller, particularly for Unit 2. In order to address the issues associated with the relatively small Unit 2 containment sump Entergy is currently evaluating analysis, design and licensing basis options. These options are discussed further in the responses to Items 2(c) and 2(d)(iii).

Preliminary results indicate that the upper and lower bearings of the Internal Recirculation (IR) pumps may be affected by debris. Preliminary results also indicate that the fibrous debris that passes through the sump screens may collect to form a thin fiber bed below the core for certain primary system break locations. Resolution of these potential downstream issues may require equipment modifications and/or the use of an alternate evaluation approach as discussed further in the response to Item 2(c).

Following selection of the final design option, which will provide resolution to the above issues, detailed engineering in support of the modification will commence. This detailed engineering will include sump screen structural analysis, consistent with industry accepted practices and applicable regulatory guidance. The analyses completed to date or in process may be affected by the final design resolution of the sump screen blockage issues. These analyses will be revised as required to represent the final design.

Licensing basis changes will be required as a result of analyses or plant modifications made to ensure compliance with the regulatory requirements listed in the Applicable Regulatory Requirements section of the subject generic letter. Should a License Amendment Request (LAR) be required it will be submitted to the NRC by December 31, 2005. The potential for a LAR is further discussed in the response to Item 2(e).

**Requested Information Item 2(b):**

A general description of and implementation schedule for all corrective actions, including any plant modifications, that you identified while responding to this generic letter. Efforts to implement the identified actions should be initiated no later than the first refueling outage starting after April 1, 2006. All actions should be completed by December 31, 2007. Provide justification for not implementing the identified actions during the first refueling outage starting after April 1, 2006. If all corrective actions will not be completed by December 31, 2007, describe how the regulatory requirements discussed in the Applicable Regulatory Requirements section will be met until the corrective actions are completed.

**Entergy Response to Item 2(b):**

The response to 2(a) provided a list of completed, in progress and planned activities needed to address the subject generic letter. The following design and related actions, as determined to be required, are scheduled for completion prior to refueling outages 2R17 and 3R14 for Unit 2 and Unit 3 respectively, but not later than December 31, 2007. Currently 2R17 is scheduled for April, 2006 and 3R14 is scheduled for March, 2007.

- Available Net Positive Suction Head (NPSH) analysis
- Debris transport analysis
- Downstream effects evaluation
- Development of conceptual design options
- Determination of debris head losses (sump screen surface areas)
- Selection of the final design
- Selection of sump screen hardware vendor
- Design and structural analysis of replacement sump screens
- Design and structural analysis of debris interceptors and flow diversion barriers
- Design of missile/jet impingement barriers
- Design of insulation jacketing
- Assessment of margin to address chemical effects
- Procedural revisions and enhancements
- Programmatic revisions and enhancements

The selection of the sump screen vendor is in progress and will be completed shortly. The debris transport and downstream effects evaluations are also nearing completion. An update of these activities will be submitted to the NRC by December 15, 2005.

The replacement of the sump screens and attendant modifications are currently scheduled to be completed during refueling outages 2R17 and 3R14.

The following items have currently been identified as activities that may require additional evaluation or additional testing to confirm or validate various assumptions used in the sump evaluation methodology. These activities are discussed further in other sections of this response:

- Chemical effects testing
- Downstream effects evaluation
- Scanning Electron Microscope (SEM) test for asbestos containing thermal insulation
- Zone of Influence (ZOI) testing for qualified coatings
- Strainer debris bypass fraction test
- Strainer head loss performance test including thin bed invulnerability demonstration
- Debris interceptor performance test

The following key activities and/or predecessors that could impact final design and planned installation are:

- Chemical effects testing results
- Results of the downstream effects evaluation on the fuel and system components
- Results of evaluations associated with the Unit 2 containment sump
- Final design selection and hardware delivery

Entergy intends to complete all design, procurement, fabrication, delivery and installation of replacement sump screens and attendant modifications that will meet or exceed all applicable regulatory requirements for post-accident sump performance by startup from the 2R17 and 3R14 outages, but no later than December 31, 2007.

As noted above, a number of challenges exist with respect to the need for additional analyses, testing and key activities/predecessors, most notably issues associated with the Unit 2 containment sump related to its small size and the downstream effects evaluation for the fuel.

As indicated above, Entergy will supplement this response by December 15, 2005 to provide an updated status of the requested information.

<u>Requested Information Item 2(c)</u>:

A description of the methodology that was used to perform the analysis of the susceptibility of the ECCS and CSS recirculation functions to the adverse effects of post-accident debris blockage and operation with debris-laden fluids. The submittal may reference a guidance document (e.g., Regulatory Guide 1.82, Rev. 3, industry guidance) or other methodology previously submitted to the NRC. (The submittal may also reference the response to Item 1 of the Requested Information described above. The documents to be submitted or referenced should include the results of any supporting containment walkdown surveillance performed to identify potential debris sources and other pertinent containment characteristics.)

**Entergy Response to Item 2(c):**

Each of the containments of the Indian Point Units comprises three main floor levels: an operating floor at El. 95'; an intermediate floor at El. 68'; and a basement floor at El. 46' that contains the reactor cavity and two sumps; the recirculation sump and the containment sump. Gratings on the floors at El. 95' and 68' provide paths for the flow of water from the higher levels of the containment to the sumps.

The two sumps for each of the Units are independent of each other. The recirculation sump serves the two 100% capacity IR pumps, which are the preferred source of cooling in the recirculation phase of an accident. The containment sump serves as a backup to the recirculation sump, and feeds two 100% capacity Residual Heat Removal (RHR) pumps located outside containment. The containment sump is not placed in service unless the IR pumps, or associated flowpaths, are unavailable. The two sumps are at the same floor elevation but in different quadrants of containment.

The primary safety concerns regarding long term recirculation cooling following a LOCA are the LOCA-generated and pre-LOCA debris materials transported to the recirculation and containment sumps. This debris can result in adverse blockage effects and post-LOCA hydraulic effects, the combination of which can have an adverse effect on the long term recirculation function. An additional concern is the impact of sump screen debris bypass on downstream components in the ECCS and CSS systems, and in the reactor vessel, during long term recirculation.

Entergy has performed and continues to perform analyses to determine the susceptibility of the ECCS and CSS recirculation functions to adverse effects of post-accident debris blockage and operation with debris-laden fluids. These analyses identified those high energy lines that, if ruptured, could require the use of ECCS and CSS recirculation, the rupture locations that produce significant quantities of debris that may challenge the recirculation function, the zone within which the break forces will be sufficient to damage materials and create debris, the amount of debris generated and the characteristics of the debris. These analyses conform to the greatest extent practicable to the NEI GR (Ref. 1) as supplemented by the NRC SER (Ref. 2). Details of these analyses are provided below.

The primary contractor for these analyses is Enercon Services. Subcontractors supporting Enercon are Westinghouse and Alion Science and Technology.

Debris Sources and Generation

A review of the accident analysis and operational procedures was performed to determine the scenarios that require ECCS or CSS to take suction from the recirculation and containment sumps. It was determined that Large Break Loss of Coolant Accidents (LBLOCAs) and certain Small Break Loss of Coolant Accidents (SBLOCAs) require sump operation. Other High Energy Line Breaks (HELBs) were considered and it was determined that sump operation for these HELBs is not required. It was also determined that the HELBs that may require recirculation are located within the crane wall inside containment.

Potential debris sources that could, in the event of a high-energy line break, challenge the performance of the recirculation and containment sump screens and ultimately the ECCS and the CSS were identified. The amount of debris generated during and following a loss of coolant accident was based on the debris sources within the containment and the location and type of pipe break. The types, quantities and locations of the potential debris sources (including insulation, coatings, and dirt/dust) were identified using plant insulation drawings, specifications and/or walkdown reports and surveillances.

The Unit 2 containment walkdowns were completed in November, 2004. These walkdowns were performed in accordance with the guidance provided in NEI 02-01 (Ref. 3). A latent debris walkdown was performed in accordance with NEI GR and the NRC SER, with the exception of a sampling survey for dust, dirt, and lint. In the absence of this sample, the Unit 3 latent debris quantities were assumed to be applicable to Unit 2. This assumption will be verified during a confirmatory Unit 2 walkdown.

The Unit 3 containment walkdowns were completed in April, 2005. These walkdowns were also performed in accordance with the guidance provided in NEI 02-01 (Ref. 3). A latent debris walkdown was performed in accordance with NEI GR and the NRC SER, and included a sampling survey for dust, dirt, and lint.

Debris Generation Analysis

Break selection consisted of determining the size and location of the HELBs that would produce significant quantities of debris and potentially challenge post-accident sump performance. The debris inventory and the transport path were examined when making this determination.

In accordance with Regulatory Guide 1.82, Rev. 3 (Ref. 4) and the NEI GR guidance report, the method used for estimating the amount of debris generated by a postulated LOCA is based on a spherical zone of influence (ZOI). Thus, the evaluation of debris generation for a given break location consisted of establishing an appropriate ZOI, mapping that ZOI volume over the spatial layout of piping and components, calculating the quantity of debris source material within that ZOI, and determining the size distribution of the debris.

The spherical ZOI was truncated whenever the ZOI intersected robust barriers. The only robust barriers considered for all of the break locations were the primary shield wall, the crane wall, the operating deck, the RHR heat exchanger/ internal recirculation pump enclosure, and other robust concrete structures. No shadowing by large components within the north and south compartments inside the containment was credited.

At Indian Point Unit 2, five types of insulation were identified inside the crane wall during the containment walkdowns: Nukon® Low Density Fiberglass (LDFG), Transco Blanket (LDFG), Temp-Mat High Density Fiberglass (HDFG), Asbestos (particulate), and Reflective Metallic Insulation (RMI). For Unit 3, eight types of insulation were identified inside the crane wall:

Calcium Silicate, Nukon® (LDFG), Mineral Wool, Temp-Mat (HDFG), Asbestos (particulate), unclassified Fiberglass, Fiber Board, and RMI.

Debris sources that may dislodge and become transportable as a result of the harsh containment environment and effects of containment sprays were also evaluated. These sources include unqualified coatings, degraded qualified coatings, tags, labels, tapes, dust, and dirt. The insulation inside the containment building contains adequate covering to prevent containment spray flow or break flow from eroding insulation that is not destroyed during the LOCA event.

The specific break locations considered include breaks that: (1) generate the largest quantity of debris, (2) generate two or more different types of debris, (3) breaks in the most direct path to the sump and (4) large breaks with the largest potential particulate debris to fiber ratio. There are many breaks that could generate a small quantity of fibrous debris that would be necessary to form the theoretical 1/8" thin bed. As a result, the strainers to be designed will require a relatively large surface area with a complex geometry. Entergy plans to install replacement strainers with demonstrated invulnerability to development of a thin fiber bed.

Debris generation analyses were performed for the Baseline Analyses utilizing the debris specific ZOIs, in accordance with the NEI GR as supplemented by the NRC SER. Additionally, Analytical Refinement Analyses were performed considering ZOI size reductions and refined characterization of the generated debris. The debris generation analyses for the base and the refinement cases are described below.

Debris Generation (Baseline Analyses)

Baseline debris generation analyses were performed using the methodology, destruction pressures and ZOIs provided in the NRC SER and NEI GR. For materials for which specific data is not provided in the NEI GR, this analysis considers the destruction pressures and ZOI for the most limiting or comparable material. Additionally, the most limiting size distribution is considered for these materials.

For instance, a recommended destruction pressure and ZOI for asbestos insulation is not provided in the NEI GR. Therefore, the asbestos type insulation was assumed to have destruction properties equivalent to the NEI GR category having the lowest destruction pressure (ZOI=28.6D). The destroyed insulation inside the ZOI was assumed to fail as 100% fines.

For the baseline analyses, the large quantity of potentially adverse debris generated and the amount of debris expected to be transported to the sump has the potential to challenge the largest replacement strainers that can be located in the recirculation and containment sumps. Therefore, in order to more accurately predict a reduced amount of debris generated, analytical refinement analyses were performed.

Debris Generation (Analytical Refinement Analyses)

The quantity of transportable debris from the LOCA can be reduced by application of analytical refinements in the form of increased destruction pressures (reduced ZOI) and refined characterization of generated debris. The specific refinements, the corresponding effect on debris generation, and the specific activities required to implement these refinements are discussed below.

(a) The size distributions for LDFG and HDFG Insulation Debris were based on an Alion Science and Technology proprietary analysis that provides refinements to the NEI GR methodology for determining size distributions for fiberglass materials. NRC SER Section 4.2.4 suggests that the LOCA generated fibrous insulation debris could be separated into four distinct size classifications. The proprietary Alion analysis categorizes fibrous materials into fines, small pieces (< 6"), large pieces (> 6"), and intact pieces and are defined based on incremental destruction pressure zones.

(b) It was assumed that qualified coatings have a ZOI of 4D. This ZOI for qualified coatings is judged conservative based on the fact that the initial reactor coolant system pressure is significantly less than the pressures utilized to remove coatings using water-jet technology. In addition, industrial experience with water-jet technology to remove coatings requires application of a high-pressure jet at close proximity to the coated surface for extended periods of time. In contrast, the time period of blowdown for a PWR reactor coolant system due to a LBLOCA is on the order of 30 seconds and the break discharge pressure decreases over the duration of the blowdown period.

The 4D ZOI assumption for qualified coatings will require technical justification that may include specific coatings debris generation testing.

(c) It was assumed that asbestos insulation with jacketing has the same destruction properties as calcium silicate with jacketing. The NEI GR and NRC SER do not provide a recommended destruction pressure or ZOI for asbestos insulation. However, most commonly used asbestos insulation material is actually calcium silicate with asbestos fiber.

This assumption will require technical justification that may include verification testing (including Scanning Electron Microscope (SEM) examination) to demonstrate that the asbestos with jacketing has comparable characteristics as calcium silicate with asbestos fiber.

(d) It was assumed that all unqualified coatings, excepting inorganic zinc, outside of the coatings ZOI fail as chips. The size of chips or flakes was assumed to be equivalent to the smallest applied coating thickness. All coatings inside the ZOI and inorganic zinc outside the ZOI were assumed to have a 10 micron particle coating debris size.

A BWR Owner's Group (BWROG) report "Failed Coatings Debris Characterization" utilized autoclave test data gathered by the BWROG Containment Coating Committee to simulate LOCA exposure and gain insight into post-LOCA failure mechanisms. The result showed that all but the inorganic zinc paint failed as macro-sized pieces.

(e) It was assumed that stainless steel jacketing will be installed on insulated piping with asbestos with cloth. As stated in Item (c) above, it is expected that the asbestos insulation is essentially calcium silicate with asbestos fiber. Therefore, the ZOI for calcium silicate with stainless steel jacket was used in the debris generation analysis refinements.

This assumption requires the installation of steel jacketing on certain cloth covered asbestos piping insulation.

Debris Transport

Computational Fluid Dynamics (CFD) analyses are currently being performed to determine recirculation debris transport assessments. These analyses are being performed by Alion Science and Technology and Enercon Services.

The CFD model is used to determine the local fluid velocities and turbulence levels in the post-LOCA containment pool, as the recirculation water flows from the broken pipe and containment sprays to the sump strainers. The fluid velocities and turbulence levels are indicative of the ability of assorted sizes and types of debris to settle in the flow field. Areas with low velocities allow smaller debris sizes to settle, while larger velocities and/or turbulence levels indicate areas where debris may remain in suspension or roll along the floor and consequently, be more readily transportable to the sump.

The CFD results show that coolant discharged from the break and the containment sprays flows directly to the sumps. Any debris dispersed along the containment floor within the crane wall has a high potential for transport to the sumps. The large quantity of potentially adverse debris types and the debris expected to be transported to the sumps has the potential to challenge the largest replacement strainer that can be accommodated in the recirculation and containment sumps, for both the baseline and refinement debris generation cases.

Consequently, remedial actions to reduce the amount of debris transported to the sump may be warranted.

Debris Transport Reduction

In addition to the analytical refinements discussed above, reductions in debris transport can be achieved by plant configuration changes that minimize flow velocities and turbulent kinetic energy. The current containment layout is not conducive to debris settlement. Flow channeling, which involves diverting or distributing flows to reduce average velocities and turbulence levels offer a relatively efficient method for reduction of debris that is transported to the sumps.

A review of the containment layout offers a unique solution for debris reduction utilizing flow channeling by diverting break flows inside the crane wall through the reactor cavity/in-core tunnel and then towards the sumps. The reactor cavity/in-core tunnel offers an expansive area that produces velocities low enough to allow settlement of small and large debris pieces, free from the turbulence inducing break flow and containment spray effect. Additionally, debris entering the reactor cavity/in-core tunnel is not expected to erode due to the very low flow velocities within the in-core tunnel. Consequently, only fines and particulate matter may remain transportable.

In addition to flow channeling, debris interceptors provide a means for trapping entrained debris prior to reaching the recirculation and containment sump screens. The utilization of flow channeling through the reactor cavity/in-core tunnel, which eliminates the small and large debris pieces, requires that only fines and particulate debris be trapped using debris interceptors. If it is determined that debris source term reduction can be realized with use of debris interceptors, it is anticipated that debris interceptors may be located near the recirculation and containments sumps and outside the crane wall.

The CFD model will be revised, as required, to determine the debris transport during the detailed design phase for the replacement sump screens and associated modifications. Inputs will include the sump flows, the configuration of the flow channel, flow diverters, and the crane wall openings that are being considered in the proposed conceptual design.

Net Positive Suction Head and ECCS Pumps

For the IR and RHR pumps, a new analysis is currently in process that is expected to provide an increase in calculated NPSH margins. In order to determine the required strainer size, conservative NPSH margins limits, representing the debris head loss limits have been established. These debris head loss limit values, provided in Table 1, are expected to bound the recalculated NPSH margins.

The available NPSH values will be determined for a given containment flood elevation level for both LBLOCA and SBLOCA scenarios. In accordance with Regulatory Guide 1.82, Rev. 3 (Ref. 4), the calculated height of water on the containment floor did not consider quantities of water that do not contribute to the sump pool, nor that amount of water in enclosed areas that cannot be readily returned to the sump. In addition, conservative assumptions will be made regarding sump temperature and containment pressure conditions. It is expected that credit will not be taken for containment overpressure provided the replacement sump screens do not extend above the containment floor.

The IR and RHR pump NPSH margins will be determined for the most limiting pump flow rates corresponding to the limiting post accident system alignments. The Unit 3 IR pump NPSH margins will be based on the replacement IR pumps. In addition, the available NPSH will be calculated using the water level downstream of proposed new openings in the crane wall. The containment water level downstream of the new openings in the crane wall in the conceptual design is expected to have draw-down of approximately 2 inches at a sump flow rate equivalent to both IR pumps operating.

Debris Accumulation and Head Loss

The required strainer surface areas for the debris transported to the recirculation and containment sumps were estimated using the debris head loss limits provided in Table 1, to ensure that adequate NPSH margins are maintained. The industry accepted NUREG/CR-6224 correlation (Ref. 6) was used in these estimations.

The required Unit 2 strainer surface areas are estimated to be 1800 $ft^2$ and 1025 $ft^2$ for the recirculation and containment sumps, respectively. The corresponding Unit 3 strainer areas are 1350 $ft^2$ and 800 $ft^2$. These surface areas consider debris generation refinements and the transport model representing flow channeling through the reactor cavity/in-core tunnel, but do not include chemical effects. (See the Chemical Effects section below for how chemical effects are being addressed.)

Upstream Effects

The upstream effects evaluations include the completed containment flooding calculations and the ongoing CFD analyses that are being used to perform recirculation transport assessments. The containment flooding analysis considered holdup areas to minimize containment level for NPSH assessments. Such areas included the refueling cavity, operating floor, intermediate level, and other miscellaneous holdup volumes. The CFD methods are being used to determine the local fluid velocities and turbulence levels in the post-LOCA containment pool, as the recirculation water flows from the broken pipe and containment sprays to the sump strainers. A three dimensional (3-D) CAD model of the containment is used in the CFD analysis which is currently in progress and includes all significant features in the containment up to the post-LOCA containment flood level. The model includes all significant structures such as, concrete walls, structural steel, and large tanks & equipment that could impede or affect the flow of water to the sump.

Downstream Effects

An evaluation is currently being performed to assess the potential for wear, abrasion and debris clogging of flow restrictions downstream of the sump screens to ensure long term recirculation cooling and containment pressure and temperature control. Those flowpaths and components of the ECCS and CSS that are required to operate during recirculation are under evaluation. The evaluation is determining the susceptibility of those flowpaths, and components in those flowpaths, to wear and abrasion as well as obstruction due to debris that may pass through the recirculation and/or containment sump screens. These components and flow paths include, but are not limited to, containment spray nozzle openings, High Head Safety Injection (HHSI) throttle valves, coolant channel openings in the core fuel assemblies, fuel assembly inlet debris screens, ECCS pump seals, bearings, and impeller running clearances.

The current containment and recirculation sumps contain wire mesh screens with 1/8" x 1/8" square openings. In the evaluation, due to the large debris load, it is assumed that replacement screens having a larger surface area and 1/8" diameter circular openings would be installed. The evaluation uses debris size values from WCAP-16406-P (Ref. 5).

The IR, RHR and HHSI pump vendor is performing an evaluation of the susceptibility of these pumps to blockage and wear and abrasion effects due to the debris concentration determined to be in the recirculating fluid.

Preliminary results of the downstream effects analysis indicate that the majority of components are not susceptible to clogging or undue wear and abrasion including the RHR and HHSI pumps. However, these preliminary results also indicate that the upper and lower bearings of the IR pumps may be affected by debris. Preliminary results also indicate that the fibrous debris that passes through the sump screens may collect to form a thin fiber bed below the core for certain primary system break locations. Resolution of these potential downstream issues may require equipment modifications and/or the use of an alternate evaluation approach as discussed under Alternative Evaluation below.

Chemical Effects

In the replacement recirculation and containment sump screen designs, margin for an increased head loss due to chemical effects will be included. The technical justification for the chemical effects head loss will be based on a plant specific materials evaluation that will determine whether the joint NRC/EPRI integrated chemical effects test (ICET) parameters bound the plant conditions. If the chemical effects test conditions do not bound the plant specific conditions a plant specific evaluation may be required.

Alternate Evaluation

In addition to the evaluations reported above, the application of the methods defined in Section 6.0, "Alternate Evaluation," of Volume 1 of the NEI GR (Ref.1), considering the limitations and clarifications as approved by the NRC SER (Ref. 2), is being considered. This alternate analysis methodology allows for use of an alternate break size in design basis analyses of containment recirculation performance. As part of implementing the alternate evaluation approach, it would be demonstrated that reasonable assurance of mitigation capability is retained for break sizes between the alternate break size and the double-ended guillotine break of the largest pipe in the reactor coolant system.

This alternate analysis is being considered to address challenges associated with the small size of the Unit 2 containment sump as well as to address certain downstream effects currently under evaluation.

**Requested Information Item 2(d)**

The submittal should include, at a minimum, the following information:

(i) The minimum available NPSH margin for the ECCS and CSS pumps with an unblocked sump screen.

(ii) The submerged area of the sump screen at this time and the percent of submergence of the sump screen (i.e. partial or full) at the time of the switchover to sump recirculation.

(iii) The maximum head loss postulated from debris accumulation on the submerged sump screen, and a description of the primary constituents of the debris bed that result in this head loss. In addition to debris generated by jet forces from the pipe rupture, debris created by the resulting containment environment (thermal and chemical) and CSS washdown should be considered in the analyses. Examples of this type of debris are disbonded coatings in the form of chips and particulates and chemical precipitants by chemical reactions in the pool.

(iv) The basis for concluding that the water inventory required to ensure adequate ECCS or CSS recirculation would not be held up or diverted by debris blockage at choke-points in containment recirculation sump return flowpaths.

(v) The basis for concluding that inadequate core or containment cooling would not result due to debris blockage at flow restrictions in the ECCS and CSS flowpaths downstream of the sump screen, (e.g., a HPSI throttle valve, pump bearings and seals, fuel assembly inlet debris screen, or containment spray nozzles). The discussion should consider the adequacy of the sump screen's mesh spacing and state the basis for concluding that adverse gaps or breaches are not present on the screen surface.

(vi) Verification that close-tolerance subcomponents in pumps, valves and other ECCS and CSS components are not susceptible to plugging or excessive wear due to extended post-accident operation with debris-laden fluids.

(vii) Verification that the strength of the trash racks is adequate to protect the debris screens from missiles and other large debris. The submittal should also provide verification that the trash racks and sump screens are capable of withstanding the loads imposed by expanding jets, missiles, the accumulation of debris, and pressure differentials caused by post-LOCA blockage under predicted flow conditions.

(viii) If an active approach (e.g., back flushing, powered screens) is selected in lieu of or in addition to a passive approach to mitigate the effects of the debris blockage, describe the approach and associated analyses.

**Entergy Response to Item 2(d)(i):**

The minimum available NPSH margin for the ECCS and CSS pumps with an unblocked replacement sump screen is dependent upon the replacement sump screen designs. This submittal will be supplemented by December 15, 2005 to include these values upon completion of the design of the replacement sump screens.

**Entergy Response to Item 2(d)(ii):**

The final design of the replacement sump screens has not been completed. However, it is expected that the final design will result in full submergence of the screens following a large break LOCA. Efforts will be made to ensure full screen submergence following a small break LOCA (SBLOCA). In case of partial screen submergence during a SBLOCA, it is expected that adequate gravity flow through the debris loaded strainer media will be demonstrated. The estimated screen areas of the Unit 2 replacement sump screens are approximately 1800 $ft^2$ and 1025 $ft^2$ for the recirculation and containment sumps, respectively. The corresponding Unit 3 strainer areas are 1350 $ft^2$and 800 $ft^2$. These are the estimated surface areas, utilizing the NUREG-6224 methodology (Ref. 6), to meet debris head loss limits listed in Table 1 without inclusion of chemical effects.

**Entergy Response to Item 2(d)(iii):**

The maximum calculated head loss across the replacement screens is dependent upon the replacement sump screen designs which as indicated previously have not been finalized. However, for conceptual design purposes, the maximum head loss limits of 0.25 ft and 1.0 ft (for single IR and RHR pump operation, respectively), due to debris accumulation on the submerged sump screens, considered in conjunction with the sump temperature with the most limiting NPSH margin, require approximate screen sizes of 1800 $ft^2$ and 1025 $ft^2$ for the Unit 2 recirculation and containment sumps, respectively. The corresponding Unit 3 strainer areas are 1350 $ft^2$and 800 $ft^2$. These screen sizes should be sufficient to accommodate debris that is transported to the sumps including debris sources that may dislodge and become transportable as a result of the harsh containment environment and effects of containment sprays. Additional sump screen surface area may be required as margin to accommodate the uncertainties associated with chemical effects.

The recirculation sumps at both Unit 2 and Unit 3 and the Unit 3 containment sump are of a sufficient size to accommodate the above noted screen areas plus additional surface area for margins required for chemical effects. The Unit 2 containment sump is considerably smaller, and may not be able to accommodate a 1025 $ft^2$ screen area.

In order to address the issues associated with the relatively small Unit 2 containment sump, Entergy is currently evaluating analysis, design and licensing basis options. In terms of analysis, consideration is being given to the application of the methods defined in Section 6.0, "Alternate Evaluation," of Volume 1 of the NEI GR (Ref.1) as supplemented by the NRC SER (Ref. 2). The design options under consideration include screen designs that allow higher screen surface areas to be placed within a given volume and possibly extending the sump screens outside of the containment sump. Entergy is also evaluating the feasibility of a containment sump licensing basis change. (See the response to Item 2(e) for further information on licensing basis changes.)

Conceptual designs are under development to reduce the magnitude of debris transported to the sump thereby reducing the required surface area.

The primary constituents of the insulation debris bed that result in screen head loss for Unit 2 are Nukon®, Asbestos, RMI, Temp-Mat and Transco Blanket. The Unit 3 primary constituents are Nukon®, Asbestos, Calcium Silicate, Temp-Mat, Fiberglass, and RMI. Additional debris sources include degraded qualified coatings, qualified coatings within the ZOI, unqualified coatings, latent debris, labels and tags. As indicated in the response to 2(c), screen head loss due to chemical effects is currently in planning.

**Entergy Response to Item 2(d)(iv):**

The water inventory required for ECCS and CSS recirculation will not be held up or diverted by debris blockage at choke-points in containment recirculation sump return flowpaths. This conclusion is based on evaluations and walkdowns conducted to look for potential choke-points in the return flowpaths to the sumps. The liquid inventory holdup evaluations showed acceptable post-LOCA water levels within containment and sufficient flow is provided to the recirculation and containment sumps.

The results of these evaluations were used to establish minimum water levels used in the debris transport and head loss calculations, as well as the conceptual design efforts discussed in this submittal.

**Entergy Response to Item 2(d)(v):**

As discussed in Response 2(c), the impact of debris passing through the strainers causing blockage in downstream components is currently under evaluation. The purpose of the evaluation is to determine whether the ECCS and portions of the CSS flowpaths could become blocked due to the debris that passes through the containment and recirculation sump screens. The evaluation utilizes the methods described in proprietary WCAP-16406-P (Ref. 5) and vendor evaluations. Both particulate and fibrous debris are considered in the evaluation. A sump screen round hole size of 1/8-inch is currently used as a basis for the evaluation. The replacement sump screen hole size is expected to be 1/8-inch or smaller. Preliminary results of the downstream effects analysis indicate that the majority of components are not susceptible to blockage. However, preliminary results indicate that the upper and lower bearings of the IR pumps and fuel assembly inlet strainers may be adversely affected by the debris/fibrous material that pass through the screens.

The final results of the downstream blockage analysis will be reported to the NRC by December 15, 2005.

**Entergy Response to Item 2(d)(vi):**

As discussed in Response 2(c), the potential for excessive wear, abrasion, and plugging of close-tolerance subcomponents in pumps, valves and other ECCS and CSS components due to ingestion of debris downstream of the sump screen is under evaluation. The evaluation is using the methods described in proprietary WCAP-16406-P (Ref. 5), vendor evaluations, and an assumed circular sump screen hole size of 1/8-inch.

Preliminary results of the downstream effects analysis indicate that the majority of close-tolerance components are not susceptible to undue wear, abrasion, and plugging including the RHR and HHSI pumps. However, these preliminary results also indicate that the upper and lower bearings of the IR pumps may be adversely affected by debris.

The final results of the downstream wear analysis will be reported to the NRC by December 15, 2005.

**Entergy Response to Item 2(d)(vii):**

As discussed earlier the structural evaluation of the replacement sump screens and any associated trash racks is dependent upon the replacement sump screen design selected for installation. This evaluation will be performed once a design has been selected and will be consistent with industry accepted practices and applicable regulatory guidance.

**Entergy Response to Item 2(d)(viii):**

An active approach has not been selected in lieu of a passive approach to mitigate the effects of debris blockage.

**Requested Information Item 2(e):**

A general description of and planned schedule for any changes to the plant licensing bases resulting from any analyses or plant modifications made to ensure compliance with the regulatory requirements listed in the Applicable Regulatory Requirements section of this generic letter. Any licensing actions or exemption requests needed to support changes to the plant licensing basis should be included.

**Entergy Response to Item 2(e):**

Licensing basis changes will be required as a result of analyses and plant modifications made to ensure compliance with the regulatory requirements listed in the Applicable Regulatory Requirements section of the subject generic letter. Changes to the plant licensing basis will be performed in accordance with 10CFR50.59. Currently, Entergy does not plan to submit License Amendment Requests (LARs) or exemptions requests in conjunction with the resolution of GSI-191 for Indian Point Unit 2 or Unit 3. However, as discussed in the response to 2(d)(iii), licensing basis options associated with the Unit 2 containment sump are under evaluation due to the challenges posed by its small size. Should these evaluations determine that a LAR or exemption request is warranted, such request will be submitted by December 31, 2005.

**Requested Information Item 2(f):**

A description of the existing or planned programmatic controls that will ensure that potential sources of debris introduced into containment (e.g. insulations, signs, coatings, and foreign materials) will be assessed for potential adverse effects on the ECCS and CSS recirculation functions. Addressees may reference their responses to GL 98-04, "Potential for Degradation of the Emergency Core Cooling System and the Containment Spray System after a Loss-of-Coolant Accident Because of Construction and Protective Coating deficiencies and Foreign Material in Containment," to the extent that their responses address these specific foreign material control issues.

**Entergy Response to Item 2(f):**

Programmatic controls that will be implemented include the additional controls for qualified coatings, an insulation configuration control and inspection program and revised FME controls.

A qualified coatings program will be added to the controls already in place for the procurement, application, maintenance and assessment of qualified coatings. The inspection process currently includes a detailed visual inspection and documentation of coating status and deficiencies. The visual inspection will be augmented by the qualified coatings program.

The insulation configuration control program will be used to ensure that future potential sources of insulation debris will be controlled with respect to potential effects. The program will provide controls to maintain the inventory of insulation inside of containment such that the amount and type remains within the acceptable design margin for debris loading of the recirculation and containment sump suction strainers following a LOCA.

The revised containment FME program will ensure the containment FME programs will not introduce foreign materials that would adversely affect the ECCS and CSS recirculation functions. This program will also monitor the level of dirt/dust and latent fiber within the containment building.

## References

1. Nuclear Energy Institute Document NEI 04-07, Volume 1, Revision 0, "Pressurized-Water Reactor (PWR) Sump Performance Methodology," dated December, 2004.

2. Safety Evaluation by the Office of Nuclear Reactor Regulation Related to NRC Generic Letter 2004-02, published as Volume 2 of Nuclear Energy Institute Guidance Report (NEI 04-07) "Pressurized Water Reactor Sump Performance Evaluation Methodology," dated December, 2004.

3. Nuclear Energy Institute Report NEI 02-01, "Condition Assessment Guidelines: Debris Sources Inside PWR Containments," Revision 1, dated September, 2002.

4. Regulatory Guide 1.82, "Water Sources for Long-Term Recirculation Cooling Following a Loss-Of-Coolant Accident," Revision 3, November 2003.

5. WCAP-16406-P, "Evaluation of Downstream Sump Debris Effects in Support of GSI-191," June 2005.

6. NUREG/CR-6224, "Parametric Study of the Potential for BWR ECCS Strainer Blockage Due to LOCA Generated Debris," dated October 1995.

**Table 1 Allowable Strainer Debris Head Loss**

| Sump | Pump Alignment | Allowable Debris Head Loss |
|---|---|---|
| Recirculation | One internal recirculation pump | 0.25 ft |
| Recirculation | Two internal recirculation pumps | 1.5 ft |
| Containment | One RHR pump | 1.0 ft |

## INDIAN POINT UNIT 2 and UNIT 3

## ATTACHMENT 2 TO NL-05-094

**Update to Commitments made in the 90-Day Response to NRC Generic Letter 2004-02, Potential Impact Of Debris Blockage On Emergency Recirculation During Design Basis Accidents At Pressurized-Water Reactors**

ENTERGY NUCLEAR OPERATIONS, INC
INDIAN POINT NUCLEAR GENERATING UNITS 2 AND 3
DOCKETS 50-247 AND 50-286

| Number | Commitment | Due Date |
|---|---|---|
| 1 | Complete Indian Point Unit 3 containment walkdowns to support the analysis of susceptibility of the ECCS and CSS recirculation functions to the adverse effects of debris blockage identified in Generic Letter 2004-02. | Complete |
| 2 | Complete the analyses of the susceptibility of the ECCS and CSS recirculation functions for Indian Point Unit 2 and Unit 3 to the adverse effects of post accident debris blockage and operation with debris-laden fluids identified in Generic Letter 2004-02. | Prior to 2R17 and 3R14 |

# Exhibit Q

# UNITED STATES
# NUCLEAR REGULATORY COMMISSION

| | | |
|---|---|---|
| *In the matter of* | | |
| ENTERGY NUCLEAR INDIAN POINT 2 L.L.C., | ) | |
| ENTERGY NUCLEAR INDIAN POINT 3, L.L.C, | ) | License No. DPR 26 and |
| And Entergy Nuclear Operations, Inc. | ) | License No. DPR 64 |
| and Entergy Northeast, Inc., | ) | |
| regarding the Indian Point Energy Center | ) | Docket No. 50-247 and |
| Unit 2 and Unit 3License Amendment | ) | Docket No. 50-286 |
| Regarding Fire Protection Program | ) | |

## SUPPLEMENTAL DECLARATION OF ULRICH WITTE REPLY ENTERGY'S RSEPONSE AND STAFF'S RESPONSE TO PETITION FOR LEAVE TO INTERVENE, REQUEST FOR HEARING, AND CONTENTIONS REGARDING LICENSE RENEWAL OF INDIAN POINT UNIT 3 AND UNIT 2 RE: CONTENTIONS 22-25

My name is Ulrich Witte. WestCAN, RCCA, PHASE, the Sierra Club—Atlantic Chapter, and Assemblyman Richard Brodsky have retained with respect to the above-captioned proceeding. I am a mechanical engineer with over twenty-six year's professional experience in engineering, licensing, and regulatory compliance of nuclear commercial nuclear facilities. I have considerable experience and expertise in the areas of configuration management, engineering design change controls, and licensing basis reconstitution. I have authored or contributed to two

EPRI documents in the areas of finite element analysis, and engineering design control optimization programs. I have led industry guidelines endorsed by the American National Standards Institute regarding configuration management programs for domestic nuclear power plants. My 26 years of experience has generally focused on assisting nuclear plant owners in reestablishing fidelity of the licensing and design bases with the current plant design configuration, and with actual plant operations. In short, my expertise is in assisting problematic plants where the regulator found reason to require the owner to reestablish competence in safely operating the facility in accordance with regulatory requirements. My curriculum vitae is attached hereto as Exhibit O.

I submit the following comments in support of each coalition stakeholder in Contentions 22-25 regarding the original design, construction and operation of the plant, and their relevancy to the license renewal application as delineated in 10CFR Part 54.21, "Contents of the application,-general information" and 10CFR50.54.22 , "Contents of the application – technical information," and 10CFR54.31 "Continuation of the CLB and conditions of renewed license" as contained in the License Renewal Proceedings of Indian Point Unit 2 and 3.

**Contention:**

**The Applicant was not required to comply with the federal approved general design criteria, contained in the Code of Federal Regulations (CFR) and instead used trade guidance for Indian Point 2 and 3. as opposed to of General Design Criteria for current design, and the current operating license and with regard to the Applicant's LRA for an additional 20 years of operation**

**The design criteria based upon trade guidance, was misrepresented by the Applicant in the renewal application as conforming to draft criteria published in 1967, and then relieved of all conformance to essentially all committed design criteria under a letter published by the Office of Nuclear Reactor Regulation in 1992.**

**The historical record shows that the applicant after discovering the error, failed to remediate the violation, and the misrepresentation, and therefore, indicates a breakdown in implementing and enforcing the provisions of the Administrative Procedures Act.**

**This 40 year old design criteria problem affects both plants, and leaves Indian Point without adequate safety margins and the New York Metropolitan region without adequate assurance of protection of public health and safety**

Submitted with particularity and specificity are provided here in for Unit 2. Unit 3 contains a similar historical record. The records show that the issue exists for both plants.

In essence, the aging management program required for license extension is predicated upon a sound, compliance and complete design basis record. Without this, the plant's material condition, basis design assumptions required for license renewal cannot be substantiated by prerequisite in situ conditions of essentially all aspects of each ageing plant.

Both respondents argues the legal ground of the general design criteria. Whereas neither Staff nor Entergy takes issue with the historical events leading to our conclusion. The regulatory history regarding applicability is not contested as documented on the table beginning on page 169 of the petition. Entergy argues that we simply arrived at the incorrect conclusion. Even with Unit 3, for example, stating in Section 1.3 of the UFSAR that it complies with the GDCs, Entergy's counsel states with respect to contentions 10, 11A and 22, 23, 24, and 25 that ***neither plant is committed to the GDCs at all.***

Much on point, there is a substantial error in Entergy's response. Page 59 of the Applicant' response states the following:

> The GDC, which are contained in Appendix A to 10 C.F.R. Part 50, establish minimum requirements for the principal design criteria for water-cooled nuclear power plants. As set forth in NRR Office Instruction LIC-I00, Revision 1, *the GDC are not applicable to plants with construction permits issued prior to May* 21, 1971. The construction permits for Indian Point Units 2 and 3 were issued before that date; on October 14, 1966, and August 13, 1969, respectively. *Thus, the GDC do not apply to those plants*. [emphasis added]

This is a substantial error. The reliance of Energy and Staff of the legality of LIC 100 is misguided—the document is far from authoritative. See Exhibit W. There are literally 100s of places in the license basis where the applicant directly or by inference states that he or she intends to comply with the GDC in question so as to answer the notice, letter, order or tiered licensing document.

Several examples are provided. A very high tier document is the plant Technical Specification Manual. This is essentially the undisputed black letter set of rules that the plant must conform to operate within its license conditions, and technical limits to operational actions are required for off-normal events, or design basis accidents.

The TRM cites B 3.1 REACTIVITY CONTROL SYSTEMS, B 3.1.3 Moderator Temperature Coefficient (MTC), that ***GDC 11 is required***. GDC 11 for this application is the *final GDC dated May 21, 1971*. According to GDC 11 (Ref. 1, in the TRM), "the reactor core and its interaction with the Reactor Coolant System (RCS) must be designed for inherently stable power operation, even in the possible event of an accident. In particular, the net reactivity feedback in the system must compensate for any unintended reactivity increases."

In addition, on page 65 of the file, and The meteorological monitoring instrumentation system was installed to meet the requirements, in part, of 10 CFR 50 Appendix A (again, the TRM cites Ref.1), Title 10, Code of Federal Regulations, Part 50 Appendix A, Criterion 64, "Monitoring Radioactivity Releases." See exhibit Y

Just by making this statement in their response they essentially invalidate and discredit their entire license renewal application, and there January 22nd response.

In fact, any statement they make in the LRA, or in responses to RAIs, or legal proceeding may be interpreted as *a possible modification to the CLB.* A statement "thus, the GDC do not apply to those plants," (see page should have Staff more than just a little agitated. A second occurrence is found on Page 64, of Entergy's reply contention 11B renewal. "As a threshold matter, IPEC Units 2 and 3 are not subject to the GDC…further, to the extent WestCAN is challenging the underlying design of the facility, such matters are beyond the scope of this proceeding and are inadmissible as a matter of law." One cannot fathom that with these kinds of fundamental errors, of what design criteria the plant is required to be engineered, designed and operated to, it is beyond sound engineering, that one can somehow apply engineering analysis to any aspect of the rules of 10CFR54.

A second example is provided in Exhibit P. In this example, NRC BULLETIN 2003-02: leakage from reactor pressure vessel lower Head penetrations and reactor coolant pressure Boundary integrity is at issue. On page 4 of Entergy's response to the Bulletin (included in Exhibit M), the applicant states "Also, the information provided in Section 3, Regulatory Requirements, of MRP-48 (Reference 1) is applicable for the IP2 and IP3 RPV lower head. ***Compliance with the applicable general design criteria (GDC 14, 31, and 32) is discussed in the Updated Final Safety Analysis Reports for IP2 and IP3.***"

Control room habitability is a third example.

We stand firm that admissibility threshold is met for all six criteria. We disagree with the Applicants complaint of lack of particularity and specificity. These examples should have been ferreted out the Applicant prior to wasting so many resources in and the public health and safety at risk for so many years and not suggesting 20 more.

Essentially every other element of safety and hinges on integrity, control and management of the licensing and design basis, and compliance with the law, and lawful operation of the facility. One would think one could simply examine the SER, along with the rest of the CLB circa the original operating license granted and find transparent the records for design basis, construction, licensing conditions, maintenance and safe operation of the plant.

After careful examination of the facts, as represented in the table of events, it appears that just the opposite is true. Applicable rules as found in 10 CFR are not followed, and in fact it appears the applicant and the regulator are under "discretionary enforcement" or other unlawful bypassing of the rules such as LIC-100, the opposite routinely. Bypassing the core protection provided to the public under the Administrative Procedures Act is un acceptable.

The past and present owners of Indian Point have failed for forty years to ensure that the nuclear reactor(s) are in compliance with regulations established by the US Nuclear Regulatory Commission to ensure public health and safety.

In its application for a 20-year license extension, Entergy has misrepresented the official record of the Federal Register to give a false appearance of compliance with regulations. In fact, the reactors have been out of compliance since they were granted its original operating license 40 years ago.

The License Renewal Rule requires the applicant to identify which set of rules and regulations the reactor complies to (NRC regulations have been changed and updated several times since the 1960's.) However, the Applicant and the NRC are unable or unwilling to state which regulations are applicable to Indian Point.

The Nuclear Regulatory Commission has failed in its responsibilities by allowing Indian Point to operate under a set of "guidelines" proposed forty years ago by an industry lobbying group, but never approved by the NRC's mandatory "rule-making" process.

The results of this are painfully obvious. A plant that that experienced a design basis event tube rupture, spent fuel pools leaking, and piping leaking. Establishing and maintaining the design basis is impossible, when the core general design criteria are simply set aside.

The smoking gun is evident in the complete version of the 1968 DDFSAR. I cannot endorse relicensing the Indian Point Unit 2 facility based upon the record and the facts of the historical record up to and including the current statements contained the Applicants LRA regarding the construction, management, and safe operation of the plant being in compliance with the draft general design criteria published in the Federal Register in 1967, with the 1968 DDFSAR Report (see petition filed December 10, 2007) stating otherwise.

I declare under the penalty of perjury that the foregoing is true and correct.

Executed this 15th day of February, 2008.

UWitte

Ulrich K. Witte

State of New York )
)ss.:
County of Rockland )

On the 15th day of Feb., in the year 2008 before me, the undersigned, personally appeared Ulrich Witte, personally known to me or proved to me on the basis of satisfactory evidence to be the individual(s) whose name(s) is (are) subscribed to the within instrument and acknowledged to me that he/she/they executed the same in his/her/their capacity(ies), and that by his/her their signatures(s) on the instrument, the individual(s) or the person upon behalf of which the individual(s) acted, executed the instrument.

Notary Public

SUSAN HILLARY SHAPIRO
Notary Public - State of New York
No. 02SH6060466
Qualified in Rockland County
My Commission Expires June 25, 2008

# Exhibit R

Entergy

Entergy Nuclear Northeast
Indian Point Energy Center
295 Broadway, Suite 1
P.O. Box 249
Buchanan, NY 10511-0249
Tel 914 734 5340
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Fred Dacimo
Vice President, Operations

November 13, 2003

Re: Indian Point Units 2 and 3
Dockets 50-247 and 50-286
NL-03-178

Document Control Desk
U.S. Nuclear Regulatory Commission
Mail Stop O-P1-17
Washington, DC 20555-0001

Subject: **90-Day Response to NRC Bulletin 2003-02 Regarding Leakage From Reactor Pressure Vessel Lower Head Penetrations and Reactor Coolant Pressure Boundary Integrity**

Reference: 1) NRC Bulletin 2003-02, "Leakage from Reactor Pressure Vessel Lower Head Penetrations and Reactor Coolant Pressure Boundary Integrity," dated August 21, 2003

Dear Sir:

Pursuant to 10 CFR 50.54(f), Entergy Nuclear Operations, Inc (Entergy) is hereby providing the response to Bulletin 2003-02 (Reference 1) for Indian Point Unit 2 (IP2) and Indian Point Unit 3 (IP3). The information requested by the Bulletin is provided in Attachment 1.

The U.S. Nuclear Regulatory Commission issued the Bulletin to advise licensees that current methods of inspecting Reactor Pressure Vessel (RPV) lower heads may need to be supplemented with additional measures to detect reactor coolant pressure boundary leakage. Licensees are required to provide information regarding RPV lower head inspection programs previously implemented and plans for future inspections to address observations identified in the Bulletin. Since the next refueling outages for IP2 and IP3 are after December 31, 2003 (Fall 2004 and Spring 2005, respectively), this response is due within 90 days of the Bulletin date.

The last inspections of the RPV lower heads for IP2 and IP3 were performed during the prior refueling outages, Fall 2002 and Spring 2003, respectively. A description of these inspections is provided in Attachment 1 in response to item (1)(a) of the Bulletin. Based on recommendations developed by the industry's Material Reliability Program, Entergy has prepared an expanded inspection program for the RPV lower head. A description of the inspections planned for future outages is provided in Attachment 1 in response to item (1)(b) of the Bulletin.

The Bulletin also requires that a post-inspection report be submitted to the NRC within 60 days following restart from the next refueling outage. Entergy agrees to provide the requested information as specified in item (2) of the Bulletin.

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There are no new commitments being made in response to this Bulletin. If you have any questions regarding this submittal, please contact Kevin Kingsley at (914) 734-5581.

I declare under penalty of perjury that the foregoing is true and correct. Executed on 11/13/03

Sincerely,

Fred R. Dacimo
Vice President, Operations
Indian Point Energy Center

cc: Mr. Patrick D. Milano, Senior Project Manager
Project Directorate I,
Division of Licensing Project Management
U.S. Nuclear Regulatory Commission
Mail Stop O-8-C2
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<u>ATTACHMENT 1 TO NL-03-178</u>

# 90-DAY RESPONSE TO NRC BULLETIN 2003-02

Entergy Nuclear Operations, Inc
Indian Point Nuclear Generating Units 2 and 3
Docket No 50-247 and 50-286

# 90-DAY RESPONSE TO NRC BULLETIN 2003-02 REGARDING LEAKAGE FROM REACTOR PRESSURE VESSEL LOWER HEAD PENETRATIONS AND REACTOR COOLANT PRESSURE BOUNDARY INTEGRITY

**Requested Information Item (1)(a):**

*A description of the RPV lower head penetration inspection program that has been implemented at your plant. The description should include when the inspections were performed, the extent of the inspections with respect to the areas and penetrations inspected, inspection methods used, the process used to resolve the source of findings of any boric acid deposits, the quality of the documentation of the inspections (e.g., written report, video record, photographs), and the basis for concluding that your plant satisfies applicable regulatory requirements related to the integrity of the RPV lower head penetrations.*

**Entergy Response:**

During the most recent refueling outages for each unit, inspections were performed as an extension of actions that were taken to assess pressure boundary integrity for Alloy 600 penetrations in the RPV upper head. The scope and results of the most recent inspections are summarized below. A description of the RPV lower head penetrations and insulation configuration is also provided to support the inspection discussions provided in this response.

*Description of RPV lower heads at IP2 and IP3:*

There are 58 penetrations, nominally 1.5 inches in diameter, in the RPV lower head for the incore instrument nozzles. An Alloy 600 tube extends through each penetration and the tubes are welded at the inside surface of the lower head. Each penetration is surrounded by a ¼-inch thick weld pad at the outside surface of the lower head. Discussions with the vessel fabricator indicate that the intent of this feature was to facilitate weld repair of an incore instrument nozzle.

The RPV lower head is covered with reflective metal insulation, approximately 3 to 3.5 inches thick, and contoured to the profile of the head. This insulation is part of the overall reactor vessel insulation package and is not designed to be removable. There is a 2.5 to 3 inch diameter hole in the insulation at each penetration, resulting in a ½ to ¾ - inch annular gap between the tubing outside diameter and adjacent insulation. This gap is filled with steel wool and capped with a metal ring that is secured with four screws to the insulation package.

*IP2 Inspection During 2R15:*

The latest inspection of the IP2 RPV lower head was performed in November 2002, during refueling outage 2R15. This inspection consisted of a visual inspection, without insulation removal, performed by a VT-2 qualified individual, as well as engineering personnel. The inspection scope included the outside surface of the lower head insulation and the 58 locations where the incore instrument nozzles penetrate through the insulation.

Although the inspection identified white streaks and some brown rust streaks on the outside of the insulation, there were no signs of inservice leakage attributed to RPV lower head penetrations. The observed streaking was considered characteristic of leakage that initiated outside of the insulation. Two possible sources of this leakage were (1) refueling cavity seal leakage or (2) refueling cavity liner leakage. Based on a review of the observations, Entergy concluded that there was no evidence of pressure boundary leakage at the lower head.

Since the above inspection of the IP2 lower reactor vessel head identified no through-wall leakage it was determined that the integrity of the lower vessel head, including the Alloy 600 penetrations remained within the applicable ASME Code and other regulatory requirements identified in the Bulletin.

*IP3 Inspection During 3R12:*

The latest inspection of the IP3 RPV lower head was performed in April 2003, during refueling outage 3R12. This inspection consisted of a visual inspection performed by a VT-2 qualified individual, as well as engineering personnel, without insulation removal. The inspection included all 58 of the penetrations as well as the outside surface of the lower head insulation.

Several brown streaks were observed on the outside of the insulation, originating at the circumferential seam between the hemispherical section of the insulation and the cylindrical section of the insulation. Since this seam is located above all of the lower head penetrations, Entergy concluded that these streaks, did not initiate at any of the lower head penetrations.

In addition, brown streaks were observed in the vicinity of penetrations 1, 10, and 45 with no apparent corresponding streak path between the penetration and the circumferential insulation seam. Penetrations 1 and 10 are near the center of the reactor vessel and penetration 45 is near the periphery. Further assessment of this observation was accomplished by removing the metal ring and steel wool from penetration 45 to allow performing a Bare Metal Visual (BMV) examination of the penetration and the surrounding area of the head. Penetration 45 was selected for this examination since it was the most accessible of the three. Similarly, the insulation was removed and a BMV examination was performed for penetration 55 (located adjacent to 45) and the surrounding area of the head. These inspections confirmed that there was no evidence of leakage at the annulus around the penetrations inspected.

A chemical or isotopic analysis of the observed streaks was not practical because the streaks consisted primarily of staining, with little or no accumulated deposits available for sampling. There was no visual evidence of boron residue associated with any of the observed streaks.

The results of the inspection were documented in the procedure associated with this inspection activity and the assessment of the observed streaking was documented in Entergy's Corrective Action Program. Several photographs taken during the inspection were compared with photographs taken during previous inspections. This comparison indicated that the observed streaks appeared to be historical in nature and not the result of leakage occurring during the prior operating cycle. Based on a review of the observations, Entergy concluded that there was no evidence of pressure boundary leakage at the lower head.

Since the above inspection of the IP2 lower reactor vessel head identified no through-wall leakage it was determined that the integrity of the lower vessel head, including the Alloy 600 penetrations remained within the applicable ASME Code and other regulatory requirements identified in the Bulletin.

*Compliance with Regulatory Requirements:*

The basis for concluding that IP2 and IP3 satisfy the regulatory requirements applicable to the RPV lower head penetrations is the same as that previously stated in prior Bulletin responses regarding the RPV upper head penetrations. Also, the information provided in Section 3, Regulatory Requirements, of MRP-48 (Reference 1) is applicable for the IP2 and IP3 RPV lower head. Compliance with the applicable general design criteria (GDC 14, 31, and 32) is discussed in the Updated Final Safety Analysis Reports for IP2 and IP3. Entergy complies with the requirements of 10 CFR 50.55a through the Inservice Inspection Program and associated implementing procedures established for inspection and repair activities. The requirements of 10 CFR 50 Appendix B, Criteria V and IX involve documentation and control of special processes that are applicable to the existing inspections and new inspections being planned per the response to Item (1)(b). Compliance with these criteria is specified in Entergy's Quality Assurance Program document, which is applicable to IP2 and IP3. Criteria XIV requires measures to assure that conditions adverse to quality are promptly identified and corrected. Entergy has an established corrective action program, which includes provisions for identification and assessment of conditions adverse to quality.

**Requested Information Item (1)(b):**

*A description of the RPV lower head penetration inspection program that will be implemented at your plant during the next and subsequent refueling outages. The description should include the extent of the inspections which will be conducted with respect to the areas and penetrations to be inspected, inspection methods to be used, qualification standards for the inspection methods, the process used to resolve the source of findings of boric acid deposits or corrosion, the inspection documentation to be generated, and the basis for concluding that your plant will satisfy applicable regulatory requirements related to the structural and leakage integrity of the RPV lower head penetrations.*

**Entergy Response:**

The next refueling outages for IP2 and IP3 are scheduled for Fall 2004 and Spring 2005, respectively. Entergy is currently planning to perform a BMV inspection, 360 degrees around each of the 58 incore instrument nozzles at both units. Should unexpected obstructions or conditions be encountered during this effort, Entergy will implement the required changes to allow for a 100% BMV examination during the subsequent refueling outage, consistent with the requirements of this Bulletin. The BMV inspection would also apply to subsequent outages, unless industry experience or site-specific observations indicate the need for an alternate inspection approach.

As described in the response to item (1)(a), the area around each penetration is packed with steel wool covered by a metal cover that is screwed to the main insulation package. Entergy will remove the steel wool and metal covers from each of the 58 penetrations in order to gain access for a direct, unobstructed view of each incore instrument nozzle at the penetration through the RPV lower head. Remote visual devices may also be used to ensure a comprehensive inspection. The inspection procedures and inspector qualifications will be consistent with the requirements of ASME Section XI and EPRI recommendations (Reference 2) previously established for similar visual examinations of the RPV upper head. In addition, Entergy will monitor industry developments and inspections at other facilities through the existing operating experience program and will incorporate new information into the inspection plans, as appropriate.

Each of the 58 RPV lower head penetrations will be inspected for conditions that would be indicative of reactor coolant leakage from a through-wall defect in the incore instrument nozzle or in the J-Groove attachment weld that secures the instrument nozzle to the reactor vessel. Boron residue or other signs of leakage will be documented in Entergy's corrective action program and will be evaluated using the applicable ASME Section XI requirements. In the event that through-wall or other unacceptable defects are identified, repairs will be made in accordance with the requirements of 10 CFR 50.55(a), prior to restart from the refueling outage.

The process to be used to resolve findings will be similar to that previously established to support RPV upper head inspections, including use of industry-developed guidance (Reference 2). Operating experience from the South Texas examination will also be included if needed to assess findings from the inspection. Because of the physical configuration of the lower head, the potential for masking affects that can occur on the RPV upper head (such as conoseal leakage and material entrained by the ventilation system) will not be a factor for the RPV lower head inspection. Masking sources that could apply for the lower head inspection (refueling cavity seal or refueling cavity liner) occur at low temperature and tend to result in staining streaks on the insulation surface rather than accumulation of boron deposits. Chemical and / or radioisotopic analysis techniques may be used to help characterize the composition and source of deposits, if appropriate. The results of the inspections will be documented in accordance with the inspection procedures and resolution of findings, if any, will be documented through the Entergy corrective action program.

*Compliance with Regulatory Requirements:*

Adopting expanded inspection activities for the RPV lower head and penetrations does not adversely affect Entergy's compliance with applicable regulatory requirements. The response to item 1(a) regarding compliance with regulatory requirements is also applicable for the inspection program that will be implemented during the next and subsequent refueling outages. Conducting the planned BMV inspections, will provided additional assurance of reactor coolant pressure boundary integrity at the RPV lower head.

**Requested Information Item (1)(c):**

*If you are unable to perform a bare-metal visual inspection of each penetration during the next refueling outage because of the inability to perform the necessary planning, engineering, procurement of materials, and implementation, are you planning to perform bare-metal visual inspections during subsequent refueling outages? If so, provide a description of the actions that* *are planned to enable a bare-metal visual inspection of each penetration during subsequent refueling outages. Also, provide a description of any penetration inspections you plan to perform during the next refueling outage. The description should address the applicable items in paragraph (b).*

**Entergy Response:**

Entergy intends to perform a BMV inspection of each penetration in the RPV lower head during the next refueling outages for IP2 and IP3. However, as stated in the response to item 1(b), if unexpected obstructions or conditions interfere with completing the full inspection at that time, as planned, other actions may be taken to allow for the BMV inspection to be performed at the subsequent refueling outage. In the event that this situation develops, a discussion of the circumstances and updated inspection strategy will be included in the inspection results report discussed in Requested Information Item (2).

**Requested Information Item (1)(d):**

*If you do not plan to perform either a bare-metal visual inspection or non-visual (e.g., volumetric or surface) examination of the RPV lower head penetrations at the next or subsequent refueling outages, provide the basis for concluding that the inspections performed will assure applicable regulatory requirements are and will continue to be met.*

**Entergy Response:**

Entergy intends to perform a BMV inspection of the RPV lower head penetrations during the next refueling outage for each unit. Therefore the basis for ensuring that applicable regulatory requirements are and will continue to be met includes the performance of these inspections. In the event that inspections cannot be performed as planned Entergy will reassess the basis for concluding that applicable regulatory requirements are met, and document this reassessment in the inspection results report discussed in Requested Information Item (2).

**Requested Information Item (2):**

*Within 60 days of plant restart following the next inspection of the RPV lower head penetrations, the subject PWR addressees should submit to the NRC a summary of the inspections performed, the extent of the inspections, the methods used, a description of the as-found condition of the lower head, any findings of relevant indications of through-wall leakage, and a summary of the disposition of any findings of boric acid deposits and any corrective actions taken as a result of indications found.*

**Entergy Response:**

Entergy agrees to submit the requested information within 60 days of restart following the next inspection of the RPV lower head penetrations. These inspections are currently planned for the next refueling outages as discussed in the response to item (1)(b).

**References:**

1. EPRI Report MRP-48, "PWR Materials Reliability Program Response to NRC Bulletin 2001-01", August 2001.

2. EPRI Report 1006296, "Visual Examination for Leakage of PWR Reactor Head Penetrations on Top of RPV Head", Revision 1 dated March 2002. (or later version as needed)

OMB Control No.: 3150-0012

UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF NUCLEAR REACTOR REGULATION
WASHINGTON, DC 20555

August 21, 2003

NRC BULLETIN 2003-02: LEAKAGE FROM REACTOR PRESSURE VESSEL LOWER HEAD PENETRATIONS AND REACTOR COOLANT PRESSURE BOUNDARY INTEGRITY

## Addressees

All holders of operating licenses for pressurized-water nuclear power reactors (PWRs) with penetrations in the lower head of the reactor pressure vessel (RPV), except those who have permanently ceased operations and have certified that fuel has been permanently removed from the reactor pressure vessel.

All other holders of operating licenses for nuclear power plants will receive a copy of this bulletin for information.

## Purpose

The U.S. Nuclear Regulatory Commission (NRC) is issuing this bulletin to:

(1) advise PWR addressees that current methods of inspecting the RPV lower heads may need to be supplemented with additional measures (e.g., bare-metal visual inspections) to detect reactor coolant pressure boundary (RCPB) leakage,

(2) request PWR addressees to provide the NRC with information related to inspections that have been or will be performed to verify the integrity of the RPV lower head penetrations, and

(3) require PWR addresses to provide a written response to the NRC in accordance with the provisions of Section 50.54(f) of Title 10 of the *Code of Federal Regulations* (10 CFR 50.54(f)).

## Background

PWR RPV upper heads have a number of penetrations, including penetrations for control rod drive mechanisms (CRDMs). These penetrations are typically made of nickel-based Inconel Alloy 600. The penetrations are welded to the inside of the RPV head with nickel-based Inconel Alloy 82/182 materials. Most PWRs also have penetrations in the RPV lower heads for in-core nuclear instrumentation. The same Inconel materials are typically used in the lower head penetrations and welds. The primary coolant water and the operating conditions of PWR plants have caused cracking of nickel-based alloys in upper head penetrations through a process called primary water stress corrosion cracking (PWSCC).

As part of the response to issues associated with degradation of the RPV upper head at the Davis-Besse Nuclear Power Station, the NRC issued Bulletin 2002-01, "Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity," dated March 18, 2002. This bulletin requested information about the condition and inspections of RPV upper heads and about licensee's boric acid corrosion control (BACC) programs. The NRC subsequently issued Bulletin 2002-02, "Reactor Pressure Vessel Head and Vessel Head Penetration Nozzle Inspection Programs," dated August 9, 2002. This bulletin was issued to address staff concerns regarding the adequacy of visual examinations as a primary inspection method for the RPV upper head and RPV upper head penetrations. By NRC Order EA-03-009, dated February 11, 2003, the NRC required specific inspections of RPV upper heads, CRDM penetrations, and associated welds in addition to the inspections required by Section XI of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code (Code).

After evaluating the responses received in response to Bulletin 2002-01, the NRC staff issued requests for additional information (RAIs) to PWR licensees in order to obtain more detailed information regarding licensee BACC programs. The NRC staff summarized its review of the responses to Bulletin 2002-01 and the associated RAIs in Regulatory Issue Summary (RIS) 2003-13, "NRC Review of Responses to Bulletin 2002-01, 'Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity,'" dated July 29, 2003. The NRC noted in RIS 2003-13 that most licensees do not perform inspections of Alloy 600/82/182 materials beyond those required by Section XI of the ASME Code to identify potential cracked and leaking components. For the RPV lower head, the ASME Code specifies that a visual examination, called a VT-2 examination, be performed during system pressure testing. Licensees may meet the ASME Code requirement for a VT-2 inspection by performing an inspection of the RPV lower head without removing insulation from around the head and penetrations. It is the NRC staff's understanding that many licensees perform the ASME Code-required inspections without removing insulation and, therefore, may not be able to detect the amounts of through-wall leakage expected from potential flaws due to PWSCC or other cracking mechanisms.

The lower head and bottom mounted instrumentation (BMI) penetrations of the South Texas Project Unit 1 (STP Unit 1) RPV were visually inspected on April 12, 2003, as a routine part of the unit's refueling outage. The lower head of the reactor is surrounded by an insulating box structure with no insulation directly in contact with the lower head. The inspection was accomplished by removing three of the insulation panels forming the insulating box. Three different vantage points were used to inspect all 58 BMI penetrations in the vessel lower head. The inspection found small amounts of white residue around two of the 58 BMI penetrations (numbers 1 and 46) at the junction where the penetrations met the lower reactor vessel head. The residue at penetrations 1 and 46 was collected for laboratory analysis to determine the source of the residue material. Approximately 150 milligrams and 3 milligrams were collected from penetrations 1 and 46, respectively. The analysis of the sample for lithium demonstrated that the lithium was approximately 99.9 percent lithium-7, which indicated that the reactor coolant system was the source of the residue. The analysis of the sample for cesium indicated that the average age of the residue collected was between 3 and 5 years. The licensee for STP Unit 1 indicated that these residues were not visible during the previous inspection on November 20, 2002.

Ultrasonic inspections (using circumferential, axial, and zero degree probes) of 57 BMI penetration tubes at STP Unit 1 were completed in May 2003, along with the visual inspections of the surfaces of the 58 J-groove welds which attach the BMI penetration tubes to the RPV lower head. In addition, eddy current testing (ECT) was used to examine the J-groove weld and inside diameter surfaces of some BMI penetration tubes. Axial cracks were found in penetration tubes 1 and 46. The largest of these cracks was entirely through-wall and extended above and below the J-groove weld. No evidence of cracking was found in any other penetration. BMI penetrations 1 and 46 have been repaired. The licensee is continuing to investigate the cause of the cracks. The investigation has not, to date, identified any manufacturing practice or operating condition that is unique to the affected penetrations or to the RPV at STP Unit 1. The design of the area beneath the RPV at STP Unit 1 and the inspection methods used by the licensee enabled the discovery of the leaking penetrations. From the NRC staff reviews described in RIS 2003-13, the NRC staff concluded that leakage such as that observed at STP Unit 1 would likely not have been detected during inspections performed at many other PWRs.

Discussion

The RPV and its head penetrations are an integral part of the RCPB, and their integrity is important to the safe operation of the plant. The recent identification of cracking and leakage from two BMI penetrations at STP Unit 1 raises questions about potential degradation mechanisms which may be active in this area. In addition, licensee responses to the Bulletin 2002-01 followup RAIs raised questions about the adequacy of inspections performed by licensees to detect leakage from RPV lower head penetrations.

As indicated above, the investigation of the degradation mechanism involved in the cracking of the two penetrations at STP Unit 1 is continuing. However, an evaluation of the available information leads to several observations. First, although the root cause of the cracking experienced at STP Unit 1 is not yet understood, the investigation to date has not identified potential root causes which would be unique to the affected penetrations at STP Unit 1.

Second, the licensee for STP Unit 1 uses a method of inspecting the RPV lower head penetrations that permits visual examination of the external metal surfaces of the vessel lower head and its penetrations, unimpeded by the surrounding insulation. In comparison to the previously discussed VT-2 examinations specified in Section XI of the ASME Code, which do not require the removal of insulation and must be performed at normal operating pressure conditions once each refueling outage, the inspections conducted by the STP Unit 1 licensee are superior for the purpose of finding evidence of leakage like that observed at STP Unit 1. In fact, the NRC staff has concluded that the VT-2 examinations required by Section XI of the ASME Code would not be effective at finding deposits like those discovered at STP Unit 1.

Third, the circumstances of the STP Unit 1 findings indicate that the cracking and the onset of leakage may have occurred several years prior to the discovery of leakage. The licensee's prior inspections of STP Unit 1 lower head were capable of finding the deposits observed in April 2003. However, no evidence of leakage had been noted as the result of any inspections conducted prior to April 2003. Therefore, a one-time inspection of an RPV lower head area may not provide adequate assurance that degradation is not occurring similar to that observed in the BMI penetrations at STP Unit 1.

The small amount of leakage from the cracks discovered at STP Unit 1 did not represent an immediate safety problem due to the size and orientation of the cracks. In addition, safety systems included in plant designs and required to be available during plant operation would be able to mitigate the effects of more significant leaks, including a gross rupture of an RPV lower head penetration. Although unlikely, a significant leak from an RPV lower head penetration could introduce operational and safety concerns since it would require operation of safety systems for an extended period and complicate longer term efforts to stabilize the plant. To maintain the overall defense-in-depth philosophy incorporated into the design and operation of nuclear power plants, licensees should take appropriate actions to ensure the integrity of the RPV lower head penetrations.

The NRC staff believes it is appropriate for licensees to assess their current inspection practices to periodically ensure that there are no leaks from RPV lower head penetrations. This conclusion is based on the safety concerns associated with a significant leak from the RPV lower head and the uncertainties associated with the ability of some current inspection practices to identify cracks and resultant small leaks from RPV lower head penetrations.

Inspections capable of detecting through-wall leakage from any RPV lower head penetration, beginning at the next refueling outage, would provide additional confidence in the integrity of the RPV lower head penetrations. If visual inspections are performed to detect evidence of possible leakage, such inspections should include an inspection of 100% of the circumference of each penetration as it enters the RPV lower head.

The industry's Materials Reliability Program (MRP) has made recommendations for PWR licensees to perform bare-metal visual inspections of RPV lower head penetrations during the current or next refueling outage. The recommendations were included in a letter from Leslie Hartz, MRP Senior Representative, dated June 23, 2003 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML031920395). The MRP is an industry program, coordinated by EPRI, to address material-related issues associated with PWRs.

The NRC is aware that preexisting conditions at some facilities may prevent licensees from performing bare-metal visual inspections of some RPV lower head penetrations during their next refueling outage. For these plants, such inspections of the RPV lower head penetrations may not be possible, for example, until after plant modifications, cleaning, and completion of other tasks provide access and a clean surface for baseline and future inspections. For the plants unable to perform inspections as recommended above, additional confidence in the integrity of the RPV lower head penetrations may be obtained by licensees (1) developing an inspection plan to examine as many of the RPV lower head penetrations as is practical, and (2) taking the necessary steps to enable the performance of inspections as above for each penetration during subsequent refueling outages. In conducting inspections or other activities on the RPV lower head, licensees should recognize that entry into and work in cavities under PWR reactor vessels present very high radiation hazards. Access controls to these areas should require, among other things, close communication between plant operations and radiation protection staff on the status of the highly activated components (e.g., thimble retraction from the core into the reactor cavity) so that required reactor cavity access controls and oversight can be fully implemented before very high radiation levels are created. More information on these under-vessel hazards is provided in Appendix B of Regulatory Guide 8.38, "Control Of Access To High And Very High Radiation Areas In Nuclear Power Plants."

The NRC staff is working with the industry and other stakeholders to revise the ASME Code and NRC regulations to address inspection of RCPB locations susceptible to cracking, including RPV penetrations. These activities will not be completed for several years, so the NRC is issuing this bulletin to address the immediate concerns identified following the reviews of the responses to Bulletin 2002-01 and followup RAIs and the discovery of leaks from BMI penetrations at STP Unit 1. The NRC has posted and will continue to post information about these subjects on its Web site (www.nrc.gov).

Applicable Regulatory Requirements

The NRC has acknowledged that the existing regulatory requirements may need to be supplemented in order to ensure required inspections of RPV lower head penetrations are adequate to identify potential penetration leakage. However, several provisions of the NRC regulations and plant operating licenses (technical specifications) pertain to RCPB integrity and the issues addressed by this bulletin. The general design criteria (GDC) for nuclear power plants (Appendix A to 10 CFR Part 50), or, as appropriate, similar requirements in the licensing basis for a reactor facility, the requirements of 10 CFR 50.55a, and the quality assurance criteria of Appendix B to 10 CFR Part 50 provide the bases and requirements for NRC staff assessment of the potential for, and consequences of, degradation of the RCPB.

The applicable GDCs include GDC 14 (Reactor Coolant Pressure Boundary), GDC 31 (Fracture Prevention of Reactor Coolant Pressure Boundary), and GDC 32 (Inspection of Reactor Coolant Pressure Boundary). GDC 14 specifies that the RCPB be designed, fabricated, erected, and tested so as to have an extremely low probability of abnormal leakage, of rapidly propagating failure, and of gross rupture. GDC 31 specifies that the probability of rapidly propagating fracture of the RCPB be minimized. GDC 32 specifies that components which are part of the RCPB have the capability of being periodically inspected to assess their structural and leaktight integrity.

NRC regulations in 10 CFR 50.55a state that ASME Class 1 components (which includes the RCPB) must meet the requirements of Section XI of the ASME Code. Various portions of the ASME Code address RCPB inspection. For example, Table IWB-2500-1 of Section XI of the ASME Code provides examination requirements during system leakage testing of all pressure-retaining components of the RCPB and references IWB-3522 for acceptance standards. IWB-3522.1(c) and (e) specify that conditions requiring correction include the detection of leakage from insulated components and discoloration or accumulated residues on the surfaces of components, insulation, or floor areas that may be evidence of borated water leakage, with leakage defined as the through-wall leakage that penetrates the pressure retaining membrane. Therefore, 10 CFR 50.55a, by reference to the ASME Code, does not permit through-wall degradation of the RPV lower head penetrations. For through-wall leakage identified by visual examinations in accordance with the ASME Code, acceptance standards for the identified degradation are provided in IWB-3142. Specifically, supplemental examination (by surface or volumetric examination), corrective measures or repairs, analytical evaluation, and replacement provide methods for determining the acceptability of degraded components. Criterion V (Instructions, Procedures, and Drawings) of Appendix B to 10 CFR Part 50 states that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings. Criterion V further states that instructions, procedures, or drawings shall include appropriate quantitative or qualitative acceptance criteria for determining that important activities have been satisfactorily accomplished. Visual and volumetric examinations of the RCPB are activities that should be documented in accordance with these requirements.

Criterion IX (Control of Special Processes) of Appendix B to 10 CFR Part 50 states that special processes, including nondestructive testing, shall be controlled and accomplished by qualified personnel using qualified procedures in accordance with applicable codes, standards, specifications, criteria, and other special requirements.

Criterion XVI (Corrective Action) of Appendix B to 10 CFR Part 50 states that measures shall be established to assure that conditions adverse to quality are promptly identified and corrected. For significant conditions adverse to quality, the measures taken shall include root cause determination and corrective action to preclude repetition of the adverse conditions. For degradation of the RCPB, the root cause determination is important for understanding the nature of the degradation present and the required actions to mitigate future degradation. These actions could include proactive inspections and repair of degraded portions of the RCPB.

Plant technical specifications (TS) pertain to this issue insofar as they do not allow operation with through-wall reactor coolant system pressure boundary leakage.

Requested Information

(1) All subject PWR addressees are requested to provide the following information. The responses for facilities that will enter refueling outages before December 31, 2003, should be provided within 30 days of the date of this bulletin. All other responses should be provided within 90 days of the date of this bulletin.

(a) A description of the RPV lower head penetration inspection program that has been implemented at your plant. The description should include when the inspections were performed, the extent of the inspections with respect to the areas and penetrations inspected, inspection methods used, the process used to resolve the source of findings of any boric acid deposits, the quality of the documentation of the inspections (e.g., written report, video record, photographs), and the basis for concluding that your plant satisfies applicable regulatory requirements related to the integrity of the RPV lower head penetrations.

(b) A description of the RPV lower head penetration inspection program that will be implemented at your plant during the next and subsequent refueling outages. The description should include the extent of the inspections which will be conducted with respect to the areas and penetrations to be inspected, inspection methods to be used, qualification standards for the inspection methods, the process used to resolve the source of findings of boric acid deposits or corrosion, the inspection documentation to be generated, and the basis for concluding that your plant will satisfy applicable regulatory requirements related to the structural and leakage integrity of the RPV lower head penetrations.

(c) If you are unable to perform a bare-metal visual inspection of each penetration during the next refueling outage because of the inability to perform the necessary planning, engineering, procurement of materials, and implementation, are you planning to perform bare-metal visual inspections during subsequent refueling outages? If so, provide a description of the actions that are planned to enable a bare-metal visual inspection of each penetration during subsequent refueling outages. Also, provide a description of any penetration inspections you plan to perform during the next refueling outage. The description should address the applicable items in paragraph (b).

(d) If you do not plan to perform either a bare-metal visual inspection or non-visual (e.g., volumetric or surface) examination of the RPV lower head penetrations at the next or subsequent refueling outages, provide the basis for concluding that the inspections performed will assure applicable regulatory requirements are and will continue to be met.

(2) Within 60 days of plant restart following the next inspection of the RPV lower head penetrations, the subject PWR addressees should submit to the NRC a summary of the inspections performed, the extent of the inspections, the methods used, a description of the as-found condition of the lower head, any findings of relevant indications of through-wall leakage, and a summary of the disposition of any findings of boric acid deposits and any corrective actions taken as a result of indications found.

<u>Required Response</u>

In accordance with 10 CFR 50.54(f), the subject PWR addressees are required to submit written responses to this bulletin. This information is sought to verify licensees' compliance with the current licensing basis for the subject PWR addressees. The addressees have two options:

(1) addressees may choose to submit written responses providing the information requested above within the requested time periods, or

(2) addressees who choose not to provide the information requested or cannot meet the requested completion dates are required to submit written responses within 15 days of the date of this bulletin. The responses must address any alternative course of action proposed, including the basis for the acceptability of the proposed alternative course of action.

The required written responses should be addressed to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, 11555 Rockville Pike, Rockville, Maryland 20852, under oath or affirmation under the provisions of Section 182a of the Atomic Energy Act of 1954, as amended, and 10 CFR 50.54(f). In addition, a copy of a response should be submitted to the appropriate regional administrator.

<u>Reasons for Information Request</u>

NRC regulatory requirements and plant TS requirements preclude operation with through-wall leakage from the RCPB. Requirements in the ASME Code, NRC regulations, and plant TS are intended to make licensees perform inspections to maintain an extremely low probability of abnormal leakage, of rapidly propagating failure, and of gross rupture. The current inspection techniques used at many PWRs may not detect small leaks such as those discovered at STP Unit 1. Uncertainty exists about the root cause of the cracking and resultant leakage at STP Unit 1, and whether other PWRs with RPV lower head penetrations could have similar problems. A detailed assessment of the risks associated with this issue is hampered by the uncertainties associated with the degradation mechanisms which may be active in RPV lower head penetrations, plant conditions (especially for those plants that have not performed the recommended inspections), and the course of events given a significant leak from the lower head. Improved inspections of the RPV lower head penetrations will resolve some of these uncertainties and could identify and allow correction of conditions before they become a significant safety concern.

This information request is necessary to permit the NRC staff to verify compliance with existing regulations and plant-specific licensing bases. The information being requested by this bulletin focuses on RPV lower head penetrations in more detail than previous generic communications and, therefore, is not currently available to the NRC staff. The NRC staff will use the information to assess the acceptability of current licensee lower vessel head inspection programs to identify BMI penetration leakage, and to determine the need for, and guide the development of, any additional regulatory actions (e.g., generic communications, orders, or rulemaking) to address the integrity of the RCPB. Such regulatory actions could include regulatory requirements for augmented inspection programs under 10 CFR 50.55a(g)(6)(ii). The NRC staff will review the responses to this bulletin to determine whether the PWR addressees' inspections provide reasonable assurance that existing applicable regulations are met. If concerns are identified, the NRC staff will contact each affected addressee.

Related Generic Communications

Regulatory Issue Summary 2003-13, "NRC Review of Responses to Bulletin 2002-01, 'Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity,' July 29, 2003 (ADAMS Accession No. ML032100653)

Information Notice 2003-11 "Leakage Found on Bottom-Mounted Instrumentation Nozzles," August 13, 2003 (ADAMS Accession No. ML032250135)

Bulletin 2002-02, "Reactor Pressure Vessel Head and Vessel Head Penetration Nozzle Inspection Programs," August 9, 2002 (ADAMS Accession No. ML022200494)

Bulletin 2002-01, "Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity," March 18, 2002 (ADAMS Accession No. ML020770497)

Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants," March 17, 1988 (ADAMS Accession No. ML031130424)

Backfit Discussion

Under the provisions of Section 182a of the Atomic Energy Act of 1954, as amended, and 10 CFR 50.54(f), this bulletin transmits an information request for the purpose of verifying compliance with existing applicable regulatory requirements (see the Applicable Regulatory Requirements section of this bulletin). Specifically, the required information will enable the NRC staff to determine whether current inspection and maintenance practices for the detection of degradation of the RCPB at reactor facilities (similar to the degradation observed at STP

Unit 1) provide reasonable assurance that RCPB integrity is being maintained. No backfit is either intended or approved by the issuance of this bulletin, and the staff has not performed a backfit analysis.

*Federal Register* Notification

A notice of opportunity for public comment on this bulletin was not published in the *Federal Register* because the NRC staff is requesting information from power reactor licensees on an expedited basis for the purpose of assessing compliance with existing applicable regulatory requirements and the need for subsequent regulatory action. This bulletin was prompted by the discovery of leaks from BMI penetrations at STP Unit 1 and by the NRC staff's assessment of responses to Bulletin 2002-01. As the resolution of this matter progresses, the opportunity for public involvement will be provided. Nevertheless, comments on the actions requested and the technical issues addressed by this bulletin may be sent to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001.

Small Business Regulatory Enforcement Fairness Act

The NRC has determined that this action is not subject to the Small Business Regulatory Enforcement Fairness Act of 1996.

Paperwork Reduction Act Statement

This bulletin contains an information collection that is subject to the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 et seq.). This information collection was approved by the Office of Management and Budget, clearance no. 3150-0012, which expires August 31, 2006. The burden to the public for this mandatory information collection is estimated to average 110 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the information collection. Send comments regarding this burden estimate or any other aspect of this information collection, including suggestions for reducing the burden, to the Records Management Branch (T-6 E6), U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001, or by Internet electronic mail to INFOCOLLECTS@NRC.GOV; and to the Desk Officer, Office of Information and Regulatory Affairs, NEOB-10202, (3150-0012), Office of Management and Budget, Washington, DC 20503.

Public Protection Notification

The NRC may not conduct or sponsor, and a person is not required to respond to, an information collection unless the requesting document displays a currently valid OMB control number.

If you have any questions about this matter, please contact one of the persons listed below or the appropriate Office of Nuclear Reactor Regulation project manager.

***/RA/***
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