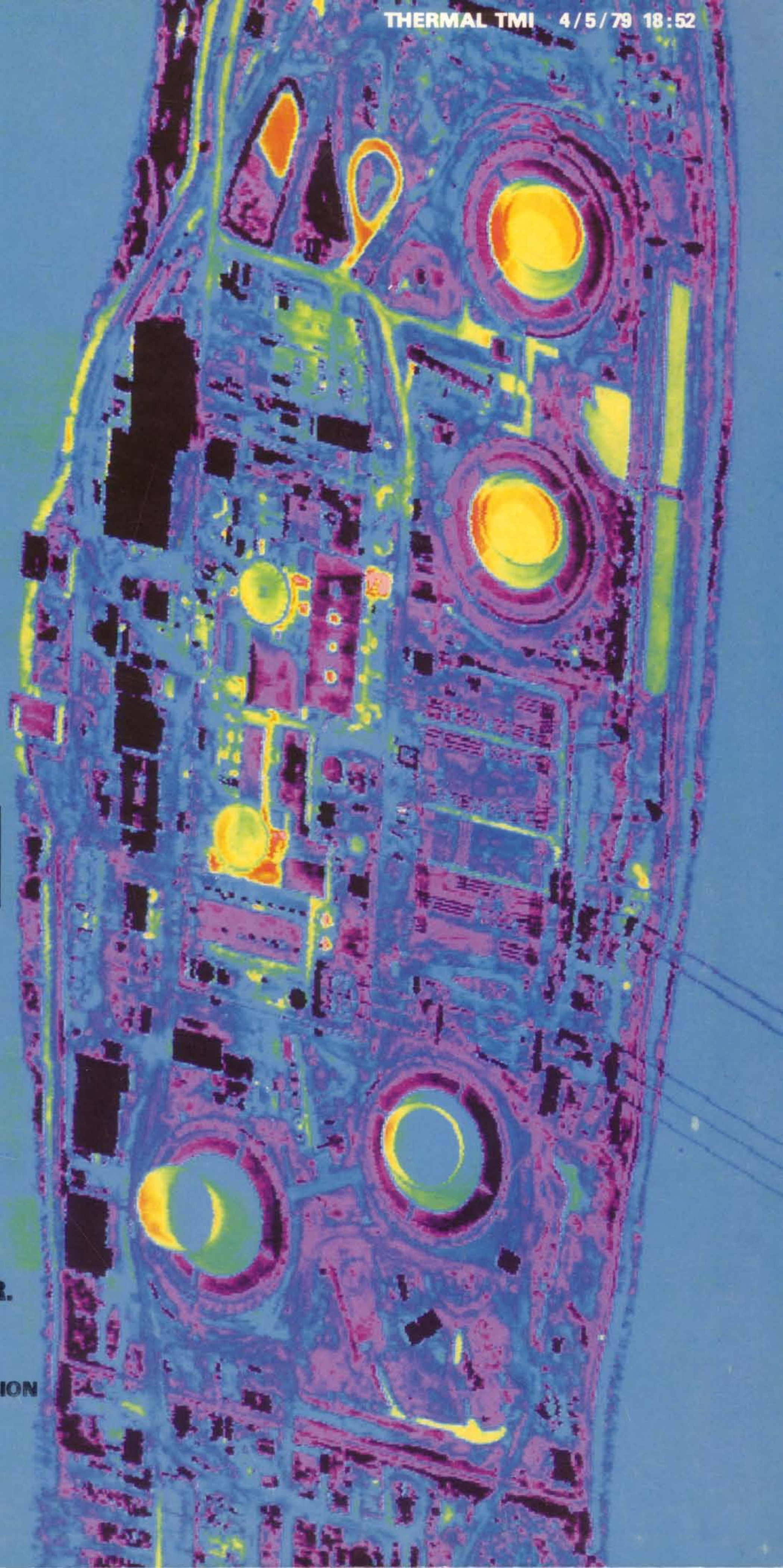

VOLUME II Part 1

three mile island

A REPORT TO THE COMMISSIONERS AND TO THE PUBLIC

MITCHELL ROGOVIN
director

GEORGE T. FRAMPTON, JR.
deputy director

**NUCLEAR REGULATORY COMMISSION
SPECIAL INQUIRY GROUP**

COVER:
A heat-sensitive DOE photograph of Three Mile Island taken on the eighth day of the accident. Yellow areas are at a higher temperature.

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VOLUME II Part I

three mile island

A REPORT TO THE COMMISSIONERS AND TO THE PUBLIC

MITCHELL ROGOVIN
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NUCLEAR REGULATORY COMMISSION
SPECIAL INQUIRY GROUP

FOREWORD

This is the second volume of the Special Inquiry Group's report to the Nuclear Regulatory Commission on the accident at Three Mile Island. The first volume contained a narrative description of the accident and a discussion of the major conclusions and recommendations.

This second volume is divided into three parts. Part 1 of Volume II focuses on the preaccident licensing and regulatory background. This part includes an examination of the overall licensing and regulatory system for nuclear powerplants viewed from different perspectives: the system as it is set forth in statutes and regulations, as described in Congressional testimony, and an overview of the system as it really works. In addition, Part 1 includes the licensing, operating, and inspection history of Three Mile Island Unit 2, discussions of relevant regulatory matters, a discussion of specific precursor events related to the accident, a case study of the pressurizer design issue, and an analysis of incentives to declare commercial operation.

Part 2 of Volume II focuses on a technical description of the accident. It includes a narrative description of the accident, a time line chronology, a discussion of radioactive releases and the radiation protection program at TMI, an assessment of plant behavior, a discussion of core damage and alternative accident scenarios, and a discussion of human factors. Much of this work relies on technical analyses performed by companies and organizations under contract to the NRC and under the direct supervision of the Special Inquiry Group.

Sandia Laboratories conducted an analysis of the early parts of the accident sequence, emphasizing thermal-hydraulics, chemical properties of the core, and interpretation of possible scenarios. Battelle Columbus Laboratories conducted an analysis of the first 16 hours focusing on alternative scenarios as well as the actual sequence. Los Alamos Scientific Laboratory and Idaho National Engineering Labs provided analysis of reactor system behavior using advanced engineering codes. These contracts were carried out under the joint direction of the NRC's Office of Nuclear Regulatory Research and the Special Inquiry Group staff. The section on Human Factors draws substantially from work performed by the Essex Corporation under contract to the NRC and monitored directly by the Special Inquiry Group. Part 2 also contains an assessment of the environmental and socioeconomic impacts of the accident. This analysis is based in large part on work done by Mountain West Research, Inc., under contract to the NRC.

Part 3 of Volume II contains descriptions and assessments of responses to the accident by (1) the utility, (2) the NRC, and (3) State and Federal agencies; an analysis of information provided to the media during the accident; and a study prepared for the Special Inquiry Group on safety management factors germane to the accident. These sections contain considerable amounts of overlapping material. However, the added emphasis is necessary to gain insight from the individual organizational focus. Part 3 also considers analyses performed under contract by the National Academy of Public Administration which provided an evaluation of organizational alternatives for crisis management.

Part 3 also contains an appendix that compares the recommendations made by the Special Inquiry Group in Volume I of this report with recommendations made by the President's Commission and by the NRR/NRC Lessons Learned Task Force.

An index for all three parts of Volume II is contained at the back of Part 3.

Although the bulk of these in-depth studies was prepared by the staff of the Special Inquiry Group, as in the case of Volume I, we must take final responsibility for the contents of this volume, and particularly for the conclusions and recommendations.

Mitchell Rogovin, Director
NRC/TMI Special Inquiry Group

George T. Frampton, Jr., Deputy Director
NRC/TMI Special Inquiry Group

January 1980

AVAILABILITY OF REFERENCES

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1. Dispositions (both those taken by the President's Commission and those taken by the Special Inquiry Group. These are indicated by name and page number.)
2. Memorandums and letters (internal, external and those received by NRC and others)
3. Interviews (These are indicated by name and page number.)
4. Regulatory Guides
5. Standard Review Plan (NUREG-75/087)
6. Technical Specifications (generic or docket specific)
7. SECY papers (NRC staff papers for Commission consideration)
8. Commission Issuances (labeled, for example, 4 AEC 768, 6 NRC 1218, where "4" is the volume number, "AEC" indicates pre 1975 issuances, "NRC" is post 1975, and "768" is the page number. These issuances present Commission opinions and decisions.)
9. ACRS transcripts and reports (Advisory Committee on Reactor Safety)
10. Docket material (for example, Docket 50-320 is Three Mile Island 2. A Docket 50 file contains all materials pertinent to a specific powerplant.)
11. Branch technical positions (from Office of Nuclear Reactor Regulation)
12. NRC contracts (for example, NRC-05-77-044)
13. NRC Inspection and Enforcement Manual
14. Commissioner speeches

15. Public Announcements
16. Board Notifications (to ASLB and participants in proceedings)
17. Transcripts of Operating License Hearings (in Docket Files)
18. Operating licenses and amendments (in Docket files)
19. NRC Management Directives (that is, Manual Chapters)
20. Transcripts of NRC Commission meetings
21. Proceedings of Atomic Safety and Licensing Boards
22. IE Circulars and Preliminary Notifications (PN)
23. Vendor and licensee topical reports (for example, B&W, Met Ed, and GPU reports)
24. NRC Inspection Reports
25. Meeting summaries
26. Plant logs, charts, data
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ERDA reports
DOE reports
Federal Energy Regulatory Commission (FERC) Dockets
Internal Revenue Service Ruling and Bulletins (com. Bul and Rev. Rul.)
Military Specifications (Mil. Spec.)
HEW reports
National Academy of Science reports
National Council on Radiation Protection (NCRP) reports
National Laboratory Reports (Savannah River Laboratory, Lawrence Livermore Laboratory)
EPA Manual of Protective Action Guides
Federal Response Plan for Peacetime Nuclear Emergencies
Federal Aviation Administration
U.S. Department of Labor
WASH reports (WASH-1400 and others)

State

D.C. Circuit Court (D.C. Cir.)
Pennsylvania Consolidated Statutes (Penn. Consol. Stat.)
Pennsylvania Supreme Court (Pa. Super. Ct.)
Pennsylvania Public Utilities Commission (PaPUC) hearings and proceedings
New Jersey Board of Public Utility Commissioners
Pennsylvania-New Jersey-Maryland (PJM) Interconnection Agreement
Ohio Public Utilities Commission (Ohio PUC) hearings
Ohio Statutes (Ohio St.)
Pennsylvania Emergency Management Agency

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The publications of the United Nations are available from that organization.

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I. PREACCIDENT LICENSING AND REGULATION BACKGROUND

A LICENSING AND REGULATION OF NUCLEAR POWERPLANTS

1. AN EXAMINATION OF THE NRC'S LICENSING AND REGULATORY SYSTEM FOR NUCLEAR POWERPLANTS FROM DIFFERENT PERSPECTIVES

Frequently many diverse perspectives contribute to a complete understanding of a particular phenomenon. The following three sections set forth different perspectives of how the regulatory process administered by the Nuclear Regulatory Commission attempts to ensure that nuclear powerplants are constructed and operated safely, and how effectively the Commission performs its functions.

The first section, "The System as Established in Applicable Statutes and Regulations," provides an overview of the licensing and regulatory process, setting forth the major substantive and procedural requirements for obtaining NRC authorization to construct and operate a nuclear powerplant and identifying the major actors in the regulatory process and the roles they play. Next, "The Commission's Assessment of the Basis for Reactor Safety" sets forth a portion of the remarks of former NRC Chairman Joseph Hendrie before a Congressional oversight committee in February 1979. As such, it constitutes the most contemporaneous public self-assessment of the operation of the regulatory process at the time of the accident at Three Mile Island. Finally, "The Licensing and Regulation System for Nuclear Powerplants: An Overview of Its Major Deficiencies in Assessing Reactor Safety" describes the major shortcomings in the present regulatory process.

Each of these perspectives provides different insights into the existing regulatory process governing the construction and operation of nuclear powerplants. Each contributes to an understanding of the context of the accident at TMI-2 and of the recommendations made elsewhere in this report.

a. The System as Established In Applicable Statutes and Regulations

Introduction

Many parties share responsibility for the safe design, construction and operation of nuclear powerplants. The Nuclear Regulatory Commission's function is to set standards for radiological safety, environmental protection, and antitrust conformity' which the applicant must satisfy to obtain a license, and to ensure the utility's subsequent compliance with those standards through audit-type inspections and other enforcement activities. The Commission must coordinate its activities with other Federal agencies which dictate environmental and health standards that the licensee must meet, and with State and local governments having regulatory oversight for nonradiological matters in plant siting, construction, and operation.

Although the NRC has plenary regulatory responsibility over all matters of radiological health and safety, the primary responsibility for the safe design, construction, and operation of a nuclear powerplant under the present regulatory system ultimately rests with the utility.[2] This division of responsibility is perhaps best illustrated by analyzing the NRC licensing process.

The Licensing Process

The NRC uses a two-step licensing approach, involving a safety evaluation and mandatory hearing prior to the issuance of a construction permit and another complete safety evaluation and a nonmandatory hearing prior to the issuance of an operating license.[3] This two-step process requires issuance of a construction permit before major work can begin on a nuclear facility and, thereafter, the grant of an operating license before the unit can actually begin producing power with nuclear fuel.

An applicant must submit information to the NRC at each stage of licensing proceedings. The Atomic Energy Act of 1954 prohibits construction on a nuclear facility without the construction permit.[4-6] If construction is completed in accordance with this previously issued permit and the completed plant meets NRC standards, an operating license will be issued.[7]

No specific nuclear powerplant design is required by the NRC; the design submitted must only conform to the statutory and regulatory standards in order to obtain approval. The General Design Criteria (GDC) set forth minimum requirements for principal design criteria found necessary in plants of similar design and location previously licensed by the Commission.[8] These criteria constitute "engineering goals" rather than "precise tests or methodologies by which reactor safety can be fully ... gauged."[9] The General Design Criteria are supplemented by the staff's Standard Review Plan and Regulatory Guides, which set forth a description of the staff's internal standards for measuring compliance with the GDC. However, neither the Standard Review Plan nor the Regulatory Guides are embodied in NRC regulations. Thus, although compliance with these interpretive materials generally can be expected to facilitate staff approval, they are not, strictly speaking, mandatory, and applicants are free to select other methods for complying with the General Design Criteria.

As part of its application for a construction permit, the utility must submit a Preliminary Safety Analysis Report (PSAR).[10] The PSAR must contain information on the site and its suitability for the proposed unit; a summary of the facility itself, including safety considerations; preliminary design information related to the NRC's General Design Criteria; the Quality Assurance Program planned to meet NRC-established requirements;" an assessment of the risks of the plant's operation to the public; identification of additional research into safety issues necessary before the design can be granted an operating license; an emergency plan to cope with emergencies; and the technical and financial qualification of the utility to build and operate the facility. In addition, the applicant must submit information to the NRC on the impact the nuclear plant will have on the environment;[12] and must advise the Attorney General of any anticompetitive impact that would be[13] created or maintained by grant of the license.

This information allows the NRC staff to evaluate the design of the plant, environmental impact that might be presented by its operation, and any relevant antitrust problems. Following a radiological safety review, the staff prepares a Safety Evaluation Report.[14] This report provides the basis for safety findings by the staff and identifies problems the NRC staff has with the proposed safety features and general plant design. The staff also prepares a Draft Environmental Statement, which is circulated for comment, revised, and converted into a Final Environmental Impact Statement in accordance with the National Environmental Policy Act.[15] The Environmental Statement describes the impact on the environment that the proposed plant would have, measures alternatives and identifies resources that woula oe lost by construction.

In addition, an analysis is made of the utility's technical and financial qualification to construct and operate the plant. The Commission's review of technical qualifications involves an analysis of the utilities' organizational structure, including the depth of its engineering and nuclear expertise. The financial analysis constitutes an effort to determine if the utility can afford to safely construct, operate, and decommission the plant at the end of its useful life.

The Atomic Energy Act requires a mandatory public hearing regarding the construction permit.[16, 17] The decision whether to grant each application is decided in an adjudicatory, evidentiary proceeding before an Atomic Safety Licensing Board (ASLB), a three-member panel consisting of an attorney serving as chairman and two technical members, which has been delegated the responsibility and authority of the Commission to make initial decisions regarding both construction permits and operating licenses. The Commission staff appears in these proceedings, even if they are uncontested, and the applicant has the burden of proof.

The difference between an uncontested and contested construction permit hearing is significant. In an uncontested hearing, the ASLB does not conduct a *de novo* review of the application; it only decides generally whether the staff's review of the applicant's proposal was adequate.[18] In a contested proceeding, by contrast, the ASLB must resolve the specific contentions raised by the parties concerning the application, although it has limited authority to consider other matters not put in issue by the parties in "extraordinary circumstances" where it determines that "a serious safety, environmental or common defense and security matter exists."[19] The NRC staff assumes the role of a party; it is given no special status or weight except as to discovery matters.

A contested hearing occurs when either the staff or intervenors oppose the grant of the license. Intervention can be granted to any person whose "interest may be affected." In addition, States or their subdivisions have a unique right of intervention under NRC regulations. They are allowed to participate fully in the hearing, to cross-examine others and present their own case, but are not required to take position on issues, as do other parties. Additionally, a person may make a "limited appearance" at a hearing and thus be granted an opportunity to address the ASLB but not to cross-examine other parties' witnesses.[20] No NRC regulation may be attacked by a party in either a construction permit or operating license proceeding, except on a successful showing by petition for waiver or exemption, that "special circumstances with respect to the subject matter of a particular proceeding are such that application of the rule or regulation ... would not serve the purposes for which [it] was adopted ... "[2t]

The change in public participation in the ASLB process is reflected by the dramatic increase in the percentage of contested hearings. During the 1960s, hearings were rarely contested and the ASLB's major function involved determinations regarding the quality of the staff's review. In the 1970s, by contrast, virtually every hearing has been contested, and the ASLB's focus has centered almost exclusively on the contested issues raised by the parties.[22]

Decisions of the ASLB normally become final Commission decisions unless appealed by a party. Even if appealed, an ASLB decision becomes final immediately unless an opposing party demonstrates good cause why it should not. By delegated authority, the Atomic Safety and Licensing Appeal Board is authorized to consider and resolve issues appealed from the ASLB by parties to that proceeding. In "extraordinary circumstances," the appeal board also may consider serious issues not raised by the ASLB in an operating license proceeding. The appeal board may certify major or novel questions of policy, law or procedure for the Commission's consideration. In addition, parties may seek to appeal issues resolved by the appeal board, and the Commission may, on its own motion, review the appeal board's actions or decisions in cases of exceptional importance. Commission review is discretionary, however, 10 C.F.R. 2.786(b)(4), and appeal board determinations not so reviewed are considered final.[23]

Each application for a construction permit or operating license must be submitted to the NRC's Advisory Committee on Reactor Safety (ACRS).[24, 17] The ACRS is a statutorily-created independent group of experts in fields relevant to reactor safety, selected by the NRC to advise in reactor safety matters. The committee's independent analysis of the safety of each proposed plant is recorded in a written letter to the NRC chairman. The ACRS views are not entered into evidence for the substance of their contents-that is, reactor safety concerns-but for the more limited purpose of demonstrating compliance with the statutory requirement that an advisory committee review has been conducted. It is for the NRC staff, intervenors or, in some cases, the Atomic Safety Licensing Board to raise any safety issues regarding the application that might be identified in the advisory committee's report.

With the grant of the construction permit, the applicant assumes the responsibility of informing the NRC of any deficiencies it finds in the design or construction of the plant or in any breakdown in the Quality Assurance Program required by Appendix B of 10 C.F.R. Any change in the "principal architectural and engineering criteria" must be authorized by amendment to the construction permit, and an application for such an amendment must satisfy the same procedural requirements and substantive standards as previously described. Since "principal architectural and engineering criteria" are nowhere described in the regulations, however, identification of the precise changes that might require an amendment to the construction permit calls for a subjective judgment by the applicant and the NRC staff.[25]

At the operating license stage, the applicant must update its Preliminary Safety Analysis Report by submitting a Final Safety Analysis Report (FSAR) providing all information obtained regarding the site since the construction permit application. The FSAR must evaluate the results of the applicant's research program to show that all safety questions unresolved at the construction permit stage have been resolved.[26] Additional information, including applicant's proposed technical specifications defining the operational and safety limitations on the plant[27] must be provided. These technical specifications are a part of any license the NRC finally grants,[28] and their violation is cause for enforcement action.

Unlike the construction permit review stage, there is no requirement of a hearing prior to granting an operating license. However, the NRC publishes notice of its intent to issue an operating license, and affords the opportunity to anyone whose interest may be affected to petition for intervention and request a hearing prior to issuing the license. If such a petition is filed, and intervention granted, an adjudicatory hearing will be held. Appeals can be taken from these hearings, and such appeals proceed through the same general appellate process as previously described.[29]

The formal system discussed above is accompanied by a substantial amount of informal consultation between the NRC staff and the applicant. From the earliest point of interest in obtaining a license, an applicant may contact the staff to obtain guidance regarding methods of procedure and the content of required submissions. Frequently, the staff will insist on changes in proposed designs or siting features in order to write a favorable Safety Evaluation Report or Environmental Impact Statement or to take other favorable action on an application. This informal negotiation process typically continues throughout the application period. For example, the staff amends the Safety Evaluation Report after its publication to include any "open" safety issues, and it currently will not, as a matter of policy, proceed to a licensing hearing without analyzing all safety issues in that report. Informal resolution of any such safety issues, and their removal from the Safety Evaluation Report, removes these matters from the contested arena unless they are raised by an intervenor. As a result of this informal process, many potential "problems" are eliminated by consultation between the staff and applicant long before the adjudicatory hearing process begins. Typically, these issues never surface again at later stages of the licensing process.

Procedural mechanics aside, the standards used by the NRC in determining whether to grant a construction permit or an operating license are different.[3] The standards for issuing a construction permit provide that the permit can be issued even without all of the technical information that will eventually be necessary for an operating license if "the principal architectural and engineering criteria" have been described, further information will eventually be supplied; research into safety issues is promised; and there is "reasonable assurance" that all safety considerations will be resolved before completion of construction and that the proposed nuclear plant "can be constructed and operated at the proposed location without undue risk to the health and safety of the public."[30]

The terms "reasonable assurance" and "undue risk" are nowhere defined, either in the statute or in the NRC's regulations, however. They are derived from the basic health standards in that Act such as "adequate protection to the health and safety of the public," no "unreasonable risk to the health and safety of the public," and the like.[28,31]

There are built-in limitations in "converting" a construction permit to an operating license. For example, issuance of a construction permit normally does not indicate approval of safety systems unless such approval has been specifically requested. NRC regulations provide, however, that the Final Safety Analysis Report must be submitted before an operating license can be granted, and the operating license is not granted unless the NRC is satisfied that the safety systems are adequate.[32] An operating license will be issued if the plant was constructed in conformance with the construction permit application, the Atomic Energy Act, and the Commission's rules and regulations; if it will operate in conformance with all of the above; and, finally, if there is reasonable assurance that the licensee's activities will not endanger the health and safety of the public. The applicant also must show his technical and financial qualification to operate the nuclear facility and must demonstrate that granting the license will not be inimical to the common defense and security.[33,34]

The operating license is good for an initial period of 40 years from the date the construction permit was issued, subject to certain implicit conditions.[35]

However, the NRC may revoke, suspend or amend the license at any time during the 40-year period.[36,37] The licensee is also subject to compliance with future rules and regulations which might be promulgated,[38,39] and the license is conditioned upon having any operators licensed by the NRC at the controls.[40] Just as the design of the plant system has to meet certain codes and standards adopted by the NRC, so must performance of those systems meet adopted codes and standards.[41] Further, new technical specifications, rules and regulations and directives can modify the operation of any specific unit.

Inspection and Enforcement

The NRC attempts to ensure compliance with the standards it has set for the design, construction and operation of the plant through inspection and enforcement. NRC regulations place a duty on the applicant to retain and make certain information available to the NRC Office of Inspection and Enforcement (IE). IE maintains regional inspection offices that conduct announced and unannounced visits to plants to ensure compliance with the license, Technical Specifications, the Atomic Energy Act, and the promulgated rules and regulations thereunder. Some plants also have "resident" IE inspectors. Finally, when requested, the holder of a construction permit or an operating license must also undertake studies and make reports to the NRC.42

Enforcement of these provisions is provided for in both the Atomic Energy Act and in NRC regulations. Sanctions include revocation, suspension or modification of a license, and the Commission is also authorized to seek injunctions in the Federal courts and to impose civil penalties for violation of license requirements. In appropriate cases, the directors of the Office of Nuclear Reactor Regulation (NRR) and Inspection and Enforcement (IE) have the authority to require immediate corrective action, subject to the right of a licensee to challenge it later.4

Responsibilities of the Utility

The licensing and regulatory process described above represents the NRC's attempt to discharge its responsibilities regarding the construction and operation of a nuclear power facility. The licensing and regulatory process places the burden on the applicant to demonstrate that the plant can be designed, constructed and operated with "reasonable assurance" that it will not endanger public health and safety or the environment. Briefly stated, the NRC is responsible for determining that there is "reasonable assurance" that the applicant will comply with its regulations and that the health and safety of the public will not be endangered by the plant's operation.

The NRC imposes substantial responsibilities on a utility when it becomes an applicant for a license or a licensee.[44] Conditions on design, construction and operation are imposed in the license or construction permit itself, as well as through the Technical Specifications. In spite of the formidable regulatory structure described above, the fact remains that the primary responsibility for the actual design, construction and operation of a nuclear powerplant rests with the applicant-the utility that seeks to sell the power to its customers. Finally, the utility has the responsibility to properly decommission the nuclear facility. This includes filing and following an NRC-approved decommissioning plan and terminating a license only with NRC approval.

Responsibilities of Nonlicensees

Generally, only licensees are legally responsible to the NRC. Reactor system vendors, architect-engineers and construction contractors are not licensed by the Commission. NRC regulations require, however, that each of these organizations report deficiencies in fabrication or construction of a nuclear powerplant.[45] In addition, the NRC's Quality Assurance Program and the General Design Criteria impose an element of indirect NRC control over these nonlicensees. The reactor system vendors, architect-engineers and construction firms may also have contractual responsibilities and may voluntarily assume responsibilities beyond those required by the Commission or other regulatory bodies.

The role of the reactor vendor is inextricably involved with NRC regulation, since no utility would purchase a system that would not pass NRC scrutiny. Indeed, most applicants look to vendors for the design material to be submitted to the NRC. The vendors' designs conform with the GDC in part because they have been modified in response to past staff evaluations of those systems in earlier licensing proceedings.

Once an order has been placed with a vendor and fabrication of the "basic components" begins, the vendor becomes subject to the provisions of 10 C.F.R. Part 21. Part 21 is based on Section 206 of the Energy Reorganization Act[46] and was designed to provide some direct control over vendors and other nonlicensees. It requires maintenance of records and reports of "defects" in fabrication, installation, or construction of a nuclear facility and its component parts.

The major review of vendor responsibility comes through the Quality Assurance Program. As discussed previously, the licensing process requires each applicant to establish a Quality Assurance Program, which must include the vendor's fabrication and testing process. The licensee is responsible for establishing a program that will ensure that the vendor will deliver a reactor system meeting NRC standards. Further, IE's Region IV office directly inspects each vendor's facilities to ensure it has a quality control program sufficient to meet NRC standards and Part 21 requirements.

Although nothing other than the quality assurance analysis and 10 C.F.R. Part 21 appears legally to bind the vendor into a relationship with either the licensee or the NRC, vendors traditionally have played an active role in the nuclear design process. If there are unresolved safety issues in a design, vendors may undertake the necessary research and make the results available to licensees, who must then convince the NRC of the system's safety. Obviously, this is to the vendor's economic advantage, because no future orders would be received for any design that could not pass NRC review.

Once an operating license has been granted for a vendor's design, the vendor's relationship with the licensee does not end. Through a system of contracts and arrangements, the vendor may continue to provide information and technical support on its units; and, as the Three Mile Island accident demonstrated, the vendor sometimes becomes actively involved in analyzing the plant's design, either for retrofitting or during an accident. Thus, vendors have some continuing obligations to the utilities that purchase their design; to the NRC which must deal with the design's generic problems; and to the public in general.

The relationship of architect-engineers and construction firms is quite similar to the reactor system vendors, although the former are perhaps less often involved in the ongoing problems of nuclear facilities. Like the vendor, the architect-engineering firm and the construction firm are indirectly regulated through the NRC's Quality Assurance Program and 10 C.F.R. Part 21. Record-keeping and reporting requirements for defects are imposed on the architect-engineer and construction contractor by Part 21 as well. Additionally, NRC regulations provide standards and specifications that certain components of the plant must meet.[41] The architect-engineer must select critical equipment, such as pumps, reactor vessels, and piping, which conform to these codes and to the General Design Criteria.

Even though the ultimate responsibility for the utility's Quality Assurance Program rests with the utility itself, its implementation may be delegated to others, including architectural-engineering or construction firms, so long as the program's results are reported to an appropriate level of utility management.[47] Appendix B to 10 C.F.R. Part 50 specifies that design, material purchased and special types of activities (such as welding) be subject to inspection and testing, and any deficiencies thus discovered must be reported to the NRC.

NRC Coordination with Responsibilities of Other Federal Agencies

Although the NRC has primary responsibility in matters of radiological health and safety, many other Federal agencies have some responsibility for the construction and operation of nuclear powerplants. These agencies generally deal with matters under statutory authority other than the Atomic Energy Act. Where there are conflicts or overlapping responsibilities, memoranda of understanding have been entered into to resolve these differences.[48]

Although there is some public confusion, the Nuclear Regulatory Commission is not part of the Department of Energy (DOE). Since the separation of the Atomic Energy Commission into the NRC and the Energy Research and Development Administration (ERDA) in 1974 effected by the Energy Reorganization Act of 1974, P.L. 93-438, 88 Stat. 1233, 42 U.S.C. 5801 et seq., the NRC has been an independent regulatory agency. ERDA became part of the DOE in 1977, Department of Energy Organization Act, P.L. 95-91, 91 Stat. 565, 42 U.S.C. 7101 et seq., and that department assumed the operation of the national laboratories which had developed and tested nuclear capabilities under both the AEC and ERDA. DOE, therefore, has inherited a great deal of expertise in nuclear matters and, in times of emergency, assists the NRC in monitoring radiation, maintaining communication and other technical support activities.

The Environmental Protection Agency has the authority to evaluate the environmental impact of thermal water pollution of a nuclear plant, and the EPA must issue a New Point Discharge Elimination System Permit before any discharge is permitted. The EPA also is responsible for setting national emission standards for radiation releases into the atmosphere, and it advises the President of the United States on matters related to radiation and the environment and has certain other responsibilities related to emergency response planning.[49] The National Environmental Policy Act requires the NRC to evaluate the impact of thermal pollution in deciding whether to issue a construction permit, and the Commission and the EPA work together in evaluating the impact of water pollution from a plant.

NRC also coordinates with the Departments of Interior, Agriculture and Commerce, and the Army Corps of Engineers, each of which may have certain concerns that may be implicated in plant siting determinations. Similarly, the Food and Drug Administration's Bureau of Radiological Health issues guidelines regarding the safe use and disposal of radioactive products, and other FDA Bureaus have responsibilities that may overlap with the NRC's in certain cases. The Occupational Safety and Health Administration of the Department of Labor has responsibilities for the safety of the work place,[50] and the Commission and the Department of Transportation and the U.S. Postal Service share responsibilities related to the transportation of radioactive materials.

NRC Coordination with Responsibilities of State and Local Agencies

The Federal Government (through the NRC) has the principal responsibility for matters of radiological health and safety associated with a nuclear powerplant.[51] In all other areas affecting nuclear plant construction and operation, States have the authority to regulate, although their authority is sometimes coextensive with Federal authority. Thus, except as noted, the full range of what is legally known as "police powers" may be exercised by the host State of a nuclear powerplant. These include fire and police protection, zoning controls and environmental limitations unrelated to radiation safety, and taxing powers.

Among these police powers is the emergency response responsibility of a State for its citizens in the event of an accident at a nuclear plant. The NRC has the lead role among Federal agencies in developing plans for radiological emergencies. (Others involved include EPA, DOE, DOT, HHS, FEMA, and HUD.) In this capacity, the NRC is charged with reviewing and concurring in State and local radiological emergency plans, and the Commission's analysis of a utility's emergency response plan submitted with its construction permit application includes an assessment of the capacity of the State and local agencies to respond. Numerous guides exist on development of these emergency plans and the Federal Government has offered substantial assistance in training local agencies.[52] NRC guides are updated to include elements which must be considered in a complete plan. By 1977 there were 70 such planning elements necessary before a plan would meet minimum NRC standards. Six States submitted successful plans in 1978. At the end of 1979, there were a total of 14 such successful State plans.[53]

In addition to emergency response planning, the NRC maintains close contacts with State agencies ors areas of potentially conflicting authority. For example, the NRC has published a guide to energy facility siting to assist the States and has entered into agreements with several States on environmental matters. Although not relevant to nuclear plants, States may be given responsibilities over small amounts of special nuclear materials by becoming an Agreement State with the NRC. Under this arrangement, NRC transfers its authority over byproduct material to the State in certain areas.

b. The NRC Assessment of the Basis for Reactor Safety

Although individual Commissioners and senior Commission staff members have testified regarding the basis for the Commission's assessment of reacfor safety,[54] the NRC as a collegial body has never issued a statement on this subject. Press and Congressional interest in the NRC's policy statement of January 18, 1979 on the Reactor Safety Study[55] apparently resulted in an attempt by the Commissioners to agree on such a statement.ss That attempt was not completely successful, however, and Chairman Hendrie testified individually as "the Chairman of the NRC" before a House Subcommittee on February 26, 1979[57] rather than as official spokesman for the entire NRC. Nevertheless, this prepared testimony is relevant to the inquiry. First, it is the most comprehensive statement on the subject by a member of the NRC and presumably represents the Commission's best effort, as of the date of the testimony, to reach collegial agreement on the subject. Moreover, because this testimony was given only a relatively short time before the March 28, 1979 incident at TM1-2, it is fair to conclude that it represented at least the Chairman's understanding of how the NRC assesses reactor safety.

The prepared testimony and the Chairman s oral testimony are printed in their entirety in the record of the Congressional hearing.ss Portions of his prepared testimony are as follows:

> I will turn now to the first topic in your letter announcing these hearings, Mr. Chairman: What is the basis for the Commission's assessment of reactor safety? The best answer to that is our re-

gulatory system, which depends upon having nuclear plants sited, designed, constructed, and operated on the basis of conservative application of sound and accepted engineering principles, on requirements for multiple and redundant safety systems, and on a set of regulatory requirements that are updated to reflect operating experience. The designers, builders, and operators of these plants are required to have quality assurance programs and their work is subjected to a continuing licensing and inspection process by the NRC. The results of the licensing and inspection process are, in turn, subject to independent review by the Advisory Committee on Reactor Safeguards and often to examination of public hearings.

We believe this regulatory system has served us well. It is a rigorous system, and appropriately so in view of the technology we regulate. It is our job as regulators to make sure that there is no undue risk from licensed facilities and, while one must acknowledge strongly held views to the contrary, over 400 reactor-years of experience to date give us some reason to believe we are on the right track.

I am going to outline the essential elements of the regulatory system which gives us our assurance of reactor safety and I will be emphasizing the strong points of that system. In doing so, I do not want to leave the impression that everything is just fine and that there are no problem areas. Like most human institutions, our regulatory system is an evolving one and it is certainly not perfect. As you know, there are a number of safety issues, some of which we touched on at your hearing last Thursday, that are in various stages of resolution and that may require changes in plant design. Steam generator tube integrity in pressurizer water reactors, hydraulic phenomena in the containments of boiling water reactors, stress-assisted corrosion in reactor primary coolant system piping, environmental qualification of safety-related electrical equipment-these are some of the safety issues listed in the report to Congress on such matters. We believe we have sufficient understanding of these issues and have taken appropriate steps in the short term to provide adequate protection of the public safety, but full resolution of them is still to come.

In other areas, we are examining many of our regulations with a view to improving and upgrading them. Part 100, our siting regulation, is an example. Like our regulations, our licensing, inspection, and safety research programs could be improved. So could the quality assurance programs of our applicants and licensees, which occasionally are found deficient in one aspect or another; and our process of reviewing and inspecting industry quality assurance programs for compliance with our regulatons could be improved. However, I think all these programs are on balance, very good and, judged against past efforts by society to control new technologies, are outstanding. But again, they are not perfect; they can and should be improved; and we are working to do just that.

Basis of Safety

The underpinning for our safety assurances is our licensing process. It provides for the issuance of construction and operating licenses only after multi-level review that includes public participation and input at its key stages. The licenses issued in accordance with this process specify the framework and necessary details of actions that designers, builders and operators of nuclear power plants must follow in order to provide assurance that there will be no undue risk to the public health and safety. Compliance with the license conditions is enforced by NRC inspectors during plant construction and operation. This system has been strengthened further with the assignment of resident inspectors at operating reactors, reactors under construction, and fuel facilities.

Licenses are issued for those nuclear power plants which, based on careful and independent reviews by the NRC staff, the Advisory Committee on Reacfor Safeguards, a Licensing Board, and if necessary, an Appeal Board or the Commission itself, are found to meet the safety criteria and standards required by our regulations. These safety standards include requirements for considerable margins between design and operating conditions and for redundancy in primary and backup equipment, in order to compensate for the fact that no body of knowledge can ever be complete enough to reduce uncertainties and risks to zero. Thus, although the operation of nuclear power plants is not risk-free, the safety objective of the NRC, as implemented through this licensing process, is to require plant builders and operators to take all those actions considered necessary to assure that the risk to public health and safety is, and continues to be acceptably small.

One of the primary tools in achieving this safety objective is that use of the defense-in-depth concept for protecting public health and safety. In its more general application, this concept calls for the incorporation of three levels of safety in nuclear plants.

The *first level* requires that measures be taken to design, build and operate a nuclear power plant so it will, with a high degree of assurance, operate without failures that could lead to accidents. The plant is designed to conservative standards so that it will be safe in all phases of operation and have a substantial tolerance for errors, off-normal operation and component malfunction.

Despite the care that is taken in design, construction and operation to avoid equipment failures or operating errors that could lead to safety problems, some failures or error must be expected to occur during the service life of a nuclear power plant. The *second level* of safety requires the provision of measures to cope with them. Protection for the reactor operating staff and the public is provided by protection devices and systems designed so that expected occurrences and off-normal conditions will be detected and either arrested or accommodated safely. The requirements for these protection systems are based on consideration of a spectrum of events that could lead to off-normal operations which the plant design must accommodate. In addition, testing programs are required to verify that the protection systems will function as designed.

The *third level* of safety supplements the first two by requiring design features and equipment to protect the public, even in the event of the occurrence of very unlikely accidents. The additional safety margins provided by these features are assessed primarily by eva!uating the response of the plant to a number of assumed accidents, involving in most instances the assumption of an independent failure of an element of the protective system simultaneously with the occurrence of the accident they are intended to control. From analyses of these postulated accidents, a number of sequences called "design basis accidents" are selected as a basis for the design of the additional plant features and equipment that are provided to further protect public health and safety. One of the third-level requirements for all nuclear plants is the emergency core cooling systems that are designed to cool the core in the event of a major instantaneous rupture of the normal plant cooling systems.

Application of the defense-in-depth concept also resulted in the provision of mutiple physical barriers between the radioactivity contained in the reactor fuel and the environment outside the plant. The fuel is contained in a sealed metal cladding; the clad fuel is contained in a heavy steel primary coolant system; and the primary coolant system is enclosed in a sealable containment building. The defense-in-depth concept is also applied widely in the design and review of many of the individual systems of the plant, leading to requirements for redundant and independent subsystems and backup systems. These requirements are embodied in NRC regulations, standards and regulatory guides that are based on sound engineering practices established over the past twenty years, and that undergo continued review and improvement as operating experience accrues. Our comprehensive research program provides the technical bases for the confirmation of NRC's safety decisions and for needed improvements.

The NRC Standard Review Plan, first published in 1975 after years of development, provides documented guidance for the staff and applicants as to current staff positions on acceptable ways to implement the regulations. It consists of over 1400 pages of detailed criteria and methods used for safety reviews and evaluations.

These comprehensive safety reviews are performed by the NRC staff during plant design, construction, and operations. Independent safety reviews are also conducted by the Commission's Advisory Committee on Reactor Safeguards, and the results of these reviews are discussed in the public hearings conducted by the Commission's Atomic Safety and Licensing Boards. The reviews are designed to assure the proper and conservative application of the Commission's regulations which implement the defense-in-depth concept. The purpose, scope, and effect of these reviews in minimizing public risk can best be shown by relating them to the siting, design, construction, and operation phases of nuclear power plants.

Siting

The principal NRC requirements for the siting of nuclear power plants are found in our regulations in 10 CFR Part 100 and its Appendix A, Geologic and Seismic Siting Criteria for Nuclear Power Plants. The siting reviews carried out by the staff in implementing this regulation, play an important role in assuring that the likelihood of severe reactor accidents due to siting considerations is very low. For example, the requirements of this regulation, supported by the independent evaluations of seismic and geologic conditions at and near a reactor site by the NRC staff and its consultants, provide the basis for establishing the seismic design parameters for a plant. The seismic design parameters are required to be conservative enough so that the likelihood of an earthquake more severe than the design basis earthquake is very low, and the possibility of a severe accident resulting from such an earthquake is even lower. Similarly, NRC regulations require that other environmental considerations that have the potential to cause a severe reactor accident, such as flooding, tornadoes, industrial accidents at nearby facilities, and overflying aircraft, be evaluated and designed against.

Design

There are many NRC regulations that require the implementation of the defense-in-depth concept in the design of nuclear power plants. These include the majority of the present 64 General Design Criteria, other Appendices of 10 CFR 50, and Section 50.55a, Codes and Standards for Nuclear Power Plants. A large amount of the effort involved in NRC design reviews is for the purpose of determining whether these requirements are being properly and conservatively implemented, and we rely heavily on these detailed design reviews for our assurance that we are achieving our safety objective.

In addition to the design reviews performed by the NRC staff, our regulations require license applicants to perform analyses of various postulated equipment, system, and personnel failures. Independent evaluations of these events on a selective basis are then performed by the NRC to assure that equipment and personnel performance under the assumed conditions are properly described and the accident consequences conservatively calculated. These independent accident analyses provide further assurances of the design adequacy of licensed nuclear power plants.

Construction and Operation

Appendix B to 10 CFR Part 50 of the NRC regulations establishes mandatory quality assurance criteria for all phases of nuclear power plant design, construction, and operation. These criteria are implemented by field reviews

Each license for operation of a nuclear reactor contains Technical Specifications, which set forth the particular safety and environmental protection measures to be imposed upon the plant, and the operating conditions that are to be met in order to assure protection of the health and safety of the public and of the surrounding environment.

The NRC's Office of Inspection and Enforcement continues its inspections during the operating life of the plant to ensure that the requirements of NRC's licenses are enforced, that problems arising in operation are well handled, and that valuable feedback from operating experience is made available to other licensees and incorporated into the safety reviews of other plants. Furthermore, NRC licenses require utilities to test important safety systems periodically and to report failures of all safety-related equipment to the NRC. I should note that we have some steps underway to improve this process of getting operating experience and testing information out to other licensees. The results of NRC inspections and reports of equipment failures are routinely made public.

The continuing review of operating experience by licensees and by the NRC staff provides another important contribution to the assurance of nuclear power plant safety. Design improvements, based on this experience, can be incorporated into new plants, and any mistakes in design and construction of operating plants can be corrected.

Even after nuclear plants begin commercial operation, they are not insulated from safety improvements. There has been a continuing NRC program of improvements in existing nuclear power plants, based on operating experience, new criteria, and better understanding of safety issues through research, testing and analysis. As the number of operating nuclear power plants has increased over the years, there has been a corresponding increase in the allocation of NRC staff resources to the inspection program and to the technical safety evaluation efforts necessary to provide continued assurance of safe operation of licensed reactors.

One of the many examples of the feedback of operating experience to upgrading of safety requirements involves fire protection. After the Browns Ferry fire in March 1975, an NRC Special Review Group was established to identify the lessons learned from this event and to make recommendations for the future. As a result, the Commission's Office of Inspection and Enforcement issued bulletins to licensees and initiated special fire protection inspections. In response, licensees instituted a number of immediate improvements in fire protection at their plants. A generic task activity was initiated by the staff to develop upgraded guidelines for fire protection in nuclear power plants. The generic task culminated in mid-1976 with the issuance of a revised Standard Review Plan section on fire protection. At that time we started a reevaluation of each operating reactor against the new guidelines and we are requiring appropriate plant modifications to upgrade fire protection. The new guidelines have been used as a basis for fire protection review for all operating license and construction permit applications under review since mid-1976.

In summary, the NRC recognizes that the operation of nuclear power plants presents some element of risk. But we believe that our process, which involves a well-developed safety approach, the specification of safety design requirements to implement that approach, and an extensive safety review, licensing and inspection process, gives reasonable assurance that risk is comparatively very small.

The safety record so far achieved in the operation of nuclear power plants gives support to the validity of the NRC approach. We have had, at this point, approximately 440 reactor-years of operation of licensed commercial nuclear plants in the United States without an accident having significant effect on the health and safety of the public. While this experience is, of course, much less than that needed to prove our belief that large reactor accidents have a low probability of occurrence, it is an encouraging record and an outstanding one for a major industrial activity.

NRC's regulatory process has relied and will continue to rely on the judgment of highly skilled engineers and scientists as the source for its safety decisions. Based on the aforementioned considerations, and without prejudice to any conclusion we might reach in any individual licensing proceeding, we believe that nuclear power plants designed, constructed, licensed to operate, and operated in accordance with our regulations and requirements present no undue risk to the public.

It would be nice to be able to say that there are absolutely no problems with respect to the safety of nuclear power plants, that perfection has been achieved, and that all risks have been eliminated. This is not the case. While we believe that nuclear power plants are adequately safe, in the ordinary sense of the word, and that the risk to the public health and safety from their operation is very small, the Commission's intention is to assure that this risk remains very small so that nuclear power can continue to represent a suitable and safe alternative for satisfying a portion of the nation's electrical energy needs.

C. The Licensing and Regulatory System for Nuclear Power Reactors: An Overview of Its Major Deficiencies in Assessing Reactor Safety

Introduction

Although the system for licensing and regulating nuclear powerplants has been heralded as one safeguarded by separate reviews by independent bodies during the various phases of the licensing process, this is a false assurance. In fact, the NRC's staff, whose resources for technical review substantially exceed those of the other reviewing bodies, decides virtually all of the safety issues that are resolved in the licensing process, and likewise determines which safety issues need not be resolved in that process. By the time the other independent bodies become involved most of those determinations have been made. Thus, as a practical matter, the review of the NRC staff's safety determinations by the Advisory Committee on Reactor Safeguards (ACRS) and the Atomic Safety and Licensing Board (ASLB) is a ritualistic process, the result of which is effectively predetermined.

The ACRS is the one body offering the potential for an independent technical review of staff safety determinations. The advisory committee's actual contribution has been disappointing, however. The end result of the ACRS' review typically is a cryptic advisory letter concluding that the plant can be constructed and operated safely if some concerns are addressed, to some degree, by some entity in the future.

The review of the ASLB also contributes little to the regulatory process. Regrettably, hearings before the board are more a legal and procedural *tour de force* than a forum for open and candid discussion. No one, not even the members of these boards, seriously contends that they contribute substantially to the quality of the technical review.

Finally, the NRC's Commissioners, who justify their isolation from the staff determinations in individual licensing cases on the ground that they may be called upon to review the ASLB's decision in the formal review process, usually decide not to grant review of plant-specific technical issues.

Thus, the existing review structure provides legal, procedural, and institutional shields to the regulatory staff, generally assuring that its actions and inactions will ultimately prevail without substantial modification or correction. The staff's determination of the acceptable level of safety typically prevails without any penetrating review and is approved by independent bodies who largely depend on the NRC staff for the information they need to appraise that very staff's judgments. Ultimately, the present review structure makes the staff's position even more impenetrable to independent review.

The present regulatory system is also characterized by substantial diffusion of responsibility and accountability. The present organization is fragmented, and little NRC attention has been given to the relationships of the various staff offices. Effective overall management controls are nonexistent, and the NRC's failure to provide general policy guidance fosters a system affording considerable amounts of unbounded, and effectively unreviewed, discretion to the staff members who make the technical engineering judgments that ultimately determine the degree of safety to be required in a nuclear plant.

The present system for licensing and regulating nuclear power reactors has consistently promised substantially more than it has delivered. This section provides a general overview of its more important deficiencies in this regard.

Practically All Safety Issues Are Resolved by the Staff

One who is neither an experienced observer nor a participant in the licensing process for nuclear power reactors might assume that the staff's resolution of most, if not all, of the important safety issues is effectively reviewed or monitored by other components of the regulatory system. This is not how the system operates in practice, however. In fact, the substance of the NRC's licensing and regulatory functions are carried out almost exclusively by a technical staff trained in various engineering and scientific disciplines relevant to nuclear power reactors. These persons review the license applications, establish the safety requirements, develop standards and recommendations, conduct inspections, take enforcement actions, and administer research programs. These persons realistically control most licensing and regulatory actions. Even where hearings must be held regarding permit or license authorizations, practically all safety decisions are made outside the formal hearing process by the regulatory staff during its lengthy application review. For all practical purposes, these decisions are routinely made by the staff without substantial oversight by anyone.

Even though an organizational analysis of the licensing function may suggest that staff safety determinations may be reviewed at various points in the regulatory process, in fact, the effectiveness of these reviews is minimal. Each of the bodies that appear to be in a position to exercise effective oversight of staff safety judgments in the licensing process-the ASLB, the ACRS, and the NRC itself-has certain limitations that have impaired its contribution to the process.

Advisory Committee on Reactor Safety

The Advisory Committee on Reactor Safety, or ACRS, is an independent, part-time, and advisory statutory committee, whose basic charter is to "review safety studies and facility license applications referred to it and ... make reports thereon, ... advise the Commission with regard to the hazards of proposed or existing reactor facilities and the adequacy of proposed reactor safety standards, and ... perform such other duties as the Commission may request."[59] In addition, beginning in 1977, the ACRS has been required to "undertake a study of reactor safety research and prepare and submit annually to the Congress a report containing the results of such study."so

The advisory committee exercises an independent review over staff licensing actions and generally reviews proposed changes in regulations and regulatory guides that are of safety significance. As part-time advisors its members cannot, and do not attempt to, duplicate in detail the staff's review in individual licensing cases. Moreover, staff regulatory actions taken outside the formal licensing process are not routinely reviewed by the ACRS.

As its title indicates, the function of the ACRS is advisory only. Thus, ACRS safety determinations or recommendations in individual licensing reviews are not regarded as substantive evidence of those particular issues or concerns in hearings before the ASLB. The ACRS determinations are entered in the hearing record simply to demonstrate the NRC's compliance with the statutory requirement of consultation with the ACRS, not for the substance of the concerns that the advisory committee may have raised. If particular issues raised by the advisory committee are not independently sponsored by one of the parties to the hearing, they are not regarded as having been put in issue, and they need not be considered by the licensing board.

The ACRS is one component in the review process that offers the potential for effective, independent technical scrutiny of the staff's positions on safety issues. The committee's review of an application and the staff's position on that application comes near the end of the staff's review of the application, after the staff has reached its position, but before the "trial" before a licensing board whose favorable decision is a necessity for the license to be issued. Unfortunately, the advisory committee's potential has not been realized.

Like the licensing and appeal boards, the advisory committee depends primarily on information furnished in the staff's Safety Evaluation Report. The product of the advisory committee's review is typically a cryptic advisory letter, generally concluding that the plant can be constructed or operated safely provided that some of the committee's concerns are addressed by someone at some undefined date. With this, the committee's involvement in the review process ends. As of March 28,1979, it is fair to say that the advisory committee, as a collegial body, had not recently criticized the quality of the technical review process, and did not aggressively assure that the NRC staff responded to its concerns. The committee seemed to share the views of the staff, and presumably the NRC, that individual licenses could be issued with a substantial number of generic issues to be decided at some future time.

Substantial dissatisfaction exists regarding the role of the ACRS and the manner in which it performs its function. In view of its limited resources, the advisory committee depends heavily on the NRC staff for information. The committee is not satisfied with the quality of the staff reports submitted to it, or the presentations of those who appear before it. The staff's performance before the committee has been unenthusiastic, if not constrained-in part because of the staff's low regard for the committee's contributions and in part because many of these same staff members recognize that they may be called to testify before the licensing board. Similarly, the ACRS is not satisfied with its relationship with the Commissioners or with the leadership exhibited by the regulatory staff. On the other hand, those who appear before the ACRS regard many of its discussions as vague and unfocused, and many of the comments offered by the committee in particular cases as largely consisting of vague generalities that contribute relatively little to the licensing process.

Atomic Safety and Licensing Boards

The Atomic Energy Act requires a public hearing before an Atomic Safety Licensing Board prior to the grant of a construction permit.[61,62]

Beyond their general responsibility to preside at public hearings on the licensing of nuclear powerplants, the ASLB's role with respect to nuclear reactor safety matters is unclear. These boards must decide the issues raised before them, but beyond this mandate, the NRC has not given the ASLB positive, unambiguous, and realistic policy directives. The NRC's emphasis instead has been on encouraging expedition and, concomitantly, on describing what the boards are not expected to do. Consequently, the boards do not, and should not be expected to, conduct an extensive review or audit of the quality of the NRC staff's safety review.

Almost without exception, the issues before a board are raised by interested members of the public who have intervened as parties in the proceeding. Boards are called upon to decide on the basis of a record made principally by the applicant, who is typically supported by the NRC staff, and by an opposing intervenor. The board itself has no responsibility to produce a record, however, and its decisional work must be based on the record produced by parties who usually are grossly mismatched in available resources, and who advocate widely divergent positions. The outcome is virtually predictable; almost without exception, the position advocated by the applicant and NRC staff ultimately prevails.

Practically all experienced observers-including most of the ASLB members who responded to a Special Inquiry Group questionnaire-believe that the formal hearings do little to enhance the quality of safety assurance for a specific nuclear powerplant. Indeed, some believe that the formal proceedings discourage applicants and the staff from dealing with all sides of controversial safety issues in their safety analyses and evaluations.

The Atomic Safety and Licensing Appeal Board

Although the NRC itself, under the law, is the final administrative decisionmaker in the licensing and regulatory process, it has delegated substantially all of that authority to the Atomic Safety and Licensing Appeal Board (ASLAB). [63] A party may seek NRC review of an appeal board decision on the ground that the decision "is erroneous with respect to an important question of fact, law, or policy," [64] and the NRC may, "in cases of exceptional legal or policy importance, review the decision or action on its own motion." In practice, however, NRC consideration of appeals from the appeal board is rare; the appeal board generally has the final word on issues raised before it.65

The NRC's failure to meet its responsibility to provide a complete and unambiguous set of regulations has exacerbated the appeal board's difficult tasks. The appeal board for years has devoted a good deal of its time and effort to interpreting the NRC's substantive regulations and their application to the facts of record. [66] The board and others have for years pointed out that many of the regulations are ineptly drafted-some to the point of being virtually incomprehensible-and that others have quite obvious gaps in them. None of these findings have resulted in any substantial overall corrective action from the NRC, however.

The Role of the Commissioners in Individual License Determinations

Although one might expect the NRC as a collegial body to play a substantial role in significant licensing determinations regarding individual plants, that is not the case. As previously indicated, NRC review of appeal board determinations in individual proceedings is not common. Ironically, however, the NRC's *ex parte* rule, designed to preserve the Commissioners' impartiality so that they can perform this appellate function, isolates the Commissioners from meaningful contact with the regulatory staff.

The Commission's ex parte rule effectively provides that after a matter has been noticed for a hearing, no Commissioner or member of his or her staff who advises in these appellate functions may consult the technical staff with respect to matters that may become relevant to the particular facility. [67] The *ex parte* rule thus erects a barrier between the Commissioners and their best source of information on licensing-the staffs of the Office of Nuclear Reactor Regulation (NRR) and the Office of Inspection and Enforcement (IE). This further isolates the Commissioners from the licensing process, and from the myriad safety determinations that are resolved at that level but do not rise to the Commission's consideration in the formal appeal process.

A Substantial Number of Licensing and Regulatory Actions Are Taken Outside the Formal License Authorization Process

The bulk of the NRC's technical resources on reactor safety issues is in its regulatory staff. The majority of safety issues are reviewed, evaluated, and have safety judgments rendered at the staff level. For cases that must go to hearing, this evaluation and judgment is reflected in the staff's Safety Evaluation Report in which the underlying reasoning and evaluations may be either sparse or omitted. Typically, that staff judgment prevails.

A substantial array of other licensing actions taken by the staff typically neither go to hearing nor receive review by anyone outside the NRR. These include:

- Granting or denying amendments to a construction permit or to an operating license;

- Determinations that proposed changes in facility design or procedures do not involve an unreviewed safety question and therefore do not require any license amendment;
- Determinations to increase or to decrease safety requirements at a particular plant;
- Determinations to apply new regulatory requirements on a plant-specific basis;
- Determinations that a safety issue is generic and therefore need not be resolved on a plant-specific basis;
- Determinations of whether a staff technical positon should be maintained if an applicant licensee seeks internal review of that position;
- Determinations that a component, system, or equipment is safety grade or non-safety grade.

In addition to these judgments related to a particular licensing process, the regulatory staff is also responsible for making safety judgments in more general areas of policy and planning. Obviously, these determinations have a pronounced impact on the safety of particular plants. These more general areas include:

- The nature and focus of the inspection and enforcement process;
- The evaluation of operational information;
- Interpretation of regulations and regulatory guides;
- The need for and allocation of resources;
- The priority for additions to, or changes in the regulations and guides.

The System Is Not Bounded by Definitive Statutory Standards or Regulatory Objectives

Two fundamental questions, which go to the heart of the NRC's regulatory responsibilities, are involved in making safety evaluations and decisions for nuclear powerplants. How much safety is needed and how much is provided? The answer to the first question-identifying the acceptable degree of risk-inescapably should be a policy decision made by the people through their elected representatives. The answer to the second entails an evaluation of the risk being taken measured against the benchmark of acceptable risk. This answer should be determined in the engineering and scientific arena by those who are responsible for making the safety evaluations.ss However, no helpful guidance has been given to staff reviewers in quantifying the level of acceptable risk by either the Congress or the NRC. The NRC's statutory mandate provides it no guidance on what level of risk Congress considers acceptable. Instead, present law charges the NRC with the responsibility to determine that its licensing and regulatory requirements "will provide adequate protection to the health and safety of the public"[28] and to "prescribe such regulations or orders as it may deem necessary" to govern any activity authorized by a license "in order to protect health and to minimize danger to life or property."[69]

However, there has been no national policy to study and compare societal risks from presently accepted means of generating electricity and no clear identification of priorities exist among the choices that can be made. Certainly this is a fundamental defect, and these basic judgments should not be left to an independent regulatory agency in the licensing of individual nuclear powerplants.

The NRC is given almost unlimited discretion to act in the licensing and regulation of nuclear powerplants within a statutory authority bounded only by the broadest of standards. This statutory approach-like the Commission's licensing and regulatory system itself-was developed during the evolutionary phase of nuclear powerplants, and has not been changed to recognize new policy issues relating to the commercial use of nuclear powerplants.

Other than repeating the regulatory truisms that "public safety is the first, last, and a permanent consideration in any decision on the issuance of a construction permit or a license to operate a nuclear facility," and that the NRC must have "reasonable assurance" that public health and safety are not endangered by its licensing actions, the Commission, as a collegial body, has given the staff essentially no substantial policy direction and guidance.[70] Thus, as of March 1979, the licensing and regulatory system operated under essentially the same general regulations, guides, and practices as it did on January 19, 1975 when the NRC came into existence. Other than structural changes in the organization as required by the Energy Reorganization Act of 1974, the existing system continued without policy directives and guidance.[71]

As a collegial body, the NRC has given the staff little guidance on what it deems to be acceptable levels of risk in nuclear reactor safety. Although millions of dollars were spent and a massive effort undertaken by the government in the Reactor Safety Study,[72] the NRC did not direct the staff to use the methods and techniques of that study to enhance reactor safety. The licensing and regulatory staff did not use these techniques to any appreciable extent prior to March 1979.[73] Similarly, after the issuance of the Lewis Report in September

1978, which **assessed** the achievements and limitations of WASH-1400, the NRC, after extensive debate to reach an acceptable collegial position, issued a policy statement that was essentially negative in tone and created a misleading picture of the Lewis Report's findings and recommendations on WASH-1400 and its Executive Summary.[55] Although the Lewis Report found the Executive Summary to WASH-1400 and the Study's absolute numerical assessment of risk deficient in important details, it unequivocally endorsed WASH-1400 techniques as an aid in technical decisionmaking.

> Fault-free/event-free analyses should be among the principal means used to deal with generic safety issues, to formulate new regulatory requirements, to assess and revalidate existing regulatory requirements, and to evaluate new designs.

The overall negative tone of the NRC's statement, and its obfuscation of what the Lewis Report criticized and what it endorsed, resulted in policy direction and guidance that seems to have had a negative impact on the quality of the licensing and regulatory system for nuclear power reactors.

As a result of the silence of Congress and the NRC, the determination of what constitutes "adequate protection to the health and safety of the public,"[28] is largely left to the individual or composite judgment of members of the staff who conduct licensing reviews; make recommendations in regulatory documents such as the staff's Safety Evaluation Reports; inspect, enforce, and establish requirements; and administer research programs. The hard truth is that there is usually no rational basis given as to the level of risk and how there is adequate protection to the public. In the absence of regulatory policies that logically flow from the establishment of an acceptable level of risk, and the use of techniques to move licensing and regulation in the direction of relative risk assessments, the staff is invariably left to apply a series of generalized "rules of thumb" that appear to be based largely on subjective evaluations, which may be neither neutral nor objective. Without this risk basis, it is difficult to construct a rational regulatory policy or to measure the effectiveness of the licensing and regulatory system.75

The Absence of Unified and Positive Management Fosters Fragmentation of Responsibility and Ineffective Coordination within the Commission and the Industry

The NRC is remote from the day-to-day operation of the licensing and regulatory system at the staff level. As a result, management of the system is largely left to the directors of the NRC's five program offices (see Appendix 1.1). Responsibilities are fragmented within those offices, and the absence of effective checks and balances within the system or any effective oversight from the outside has created and perpetuated a system in which each office attempts to look after its own interests as best it can.

The Office of Nuclear Reactor Regulation (NRR) plays the predominant, and for all practical purposes, the exclusive role in the majority of nuclear reactor safety decisions that arise during the application review and after the license is issued. However, even at the office level, it is not clear who is responsible for being office spokesman. NRR appears to speak with many voices and at many different levels on reactor safety issues. This gives outsiders the impression that confusion and uncertainty exist within the Commission on technical matters, and that the Commission overreacts in some instances but does not act as a regulator in others.

Apparently this problem is largely a reflection of the substantial fragmentation existing within the NRR. The most notable examples of this fragmencation include the following:

- Approximately 24 technical review branches scattered among the four divisions that comprise NRR, review various pieces of an application under varying review approaches that have gradually evolved over almost a decade;
- Technical branches in the Division of Operating Reactors (DOR), in which technical disciplines parallel those of other branches, primarily the Divisions of Systems Safety, and Site Safety and Environmental Analysis;
- A separate Division of Project Management (DPM) that is dependent on the technical resources in other divisions, thus introducing additional management challenges;
- Isolation of the quality assurance, technical qualifications, and operator licensing functions in the DPM-a division primarily oriented toward meeting targeted licensing review schedules;
- The initial placement of the responsibility for an operating reactor in the DPM, followed by an internal negotiation process under which that responsibility is transferred to the DOR. This fragmentation effectively removes the DOR from a position of responsibility during the important months of initial operation and creates confusion regarding who has the responsibility for evaluating relevant operational information;
- The isolation of the Technical Specifications Branch in the DOR;

- The absence of ultimate responsibility for the review of the nuclear steam supply system in its entirety by any branch or entity in the technical review area;
- The lack of responsibility for the review of the entire plant from the standpoint of systems interactions, which may be of safety significance, in any branch or entity within the NRR. [76]

Substantial interface problems exist within NRR in at least two important areas. The first area involves the transfer of lead responsibility for an operating nuclear plant from the DPM, which is primarily responsible for shepherding the application through the system, to the DOR, created in 1975 to provide attention and expertise to operating reactors. Prior to March of 1979, internal procedure and policy in this area vested the responsibility for operating reactors in the DPM for more than a year after operations began. [77] Consequently, the important Davis Besse precursor events in 1977 and the entire operating life of TMI-2 took place when responsibility for these reactors still remained in the DPM.

A second interface problem in NRR relates to the roles of the Divisions of Operating Reactors and Systems Safety. Each of these divisions has technical disciplines that for the most part are duplicative. The respective roles of these divisions, the duplication of technical disciplines in each, and the coordination of their actions on safety issues have been lingering questions never satisfactorily addressed by NRR management. [78]

The NRC has been equally unsuccessful in dealing with the fragmentation of responsibility within the industry it regulates. A nuclear powerplant is a single unit with a large number of system interactions, some of which are of safety significance. As the applicant and licensee, the utility is responsible for the proper construction and the safe operation of the plant. However, it is obvious that many others exercise substantial judgment and take significant actions that may affect the plant's safety. For example, many other entities, such as the equipment vendors, the architect-engineers, and the construction contractors, are involved in the design, construction, and manufacturing of the thousands of pieces of equipment and components for the plant.

The only direct regulatory relationship is between the NRC and the utility. The contractual relationships between the utility and the nuclear steam suppliers, the architect-engineer, the construction contractor, and others are generally entered into prior to the NRC's review of the license application and may not always be conducive to sound regulatory objectives. For example, the issue of who should bear the burden of the costs of safety changes and the possible effects of safety changes on a vendor's contracts with other utilities are realities that cannot be ignored. (See Section I.E for a detailed discussion in a different, but related, context.). With very limited exceptions, however, the NRC has no policy statement or regulation that addresses this fragmentation of responsibility and its potential consequences.

In addition to these problems of fragmentation of responsibility within particular offices and within the regulated industry itself, additional problems arise at the points where various offices and entities within the NRC interact. The NRC's Office of Inspector and Auditor's "Independent Review of the Browns Ferry Fire," states;

> One area of inquiry during this investigation was the level of the relationships between IE, Licensing, and Standards. Certain views were expressed that relations were good and on the other extreme that they were lousy. Faced with varying sentiments such as these, it is perhaps safe to say that the interface could stand improvement. Consideration should be given to the establishment of a mechanism to improve the existing interface between all elements of the Commission, and we might consider making this problem the subject of a future audit. [79]

These words apply with equal force as of March 1979.

The Offices of NRR and IE are assigned responsibilities requiring each to deal directly with licensees on safety, safeguards, and environmental matters involving the construction and operation of nuclear powerplants. IE inspects powerplants to determine compliance with NRC's requirements, applicable regulations, and the commitments NRR extracts in particular cases. The responsibilities of each office are discussed in an internal "Agreement on NRR/I&E Interface and Division of Responsibility" agreed to by the directors of these two offices (see Appendix 1.2). The principal responsibilities assigned to NRR are establishment of safety, safeguards, environmental, and antitrust criteria for license issuance; evaluation of license and amendment applications; and issuance of licenses and amendments that meet established criteria. NRR also has responsibility to evaluate the performance of licensed facilities to establish the adequacy of, or need for change in NRC requirements. The principal responsibilities assigned to IE are (1) the inspection of licensed facilities and activities to ascertain compliance with NRC requirements (2) observation and reporting on the safety of licensed activities (3) investigation of the safety of licensed activities (4) investigation of events reported and allegations received, and (5) effecting enforcement action where noncompliance with NRC requirements is identified. IE also has responsibility for evaluating licensee performance with respect to safety and safeguard matters, and for providing feedback to NRR.

The effectiveness of these offices' execution of their shared responsibilities is compromised by defects in the working relationship between the two. There appears to be neither a fertile feedback of inspection results into licensing and regulatory requirements, nor a general awareness on the part of inspectors of special matters that are of safety significance to NRR. If IE becomes involved in initial evaluations of a licensee event, at some ill-defined point the "lead responsibility" for the matter is transferred to NRR. Joint NRR/IE teams are not used to observe and evaluate significant operational events, such as initial systems testing and the ascensions to power tests, and there are no personnel rotations between NRR and IE.

Even though one of NRR's prime information sources is the inspector in the field, IE inspectors have a formidable organizational network to maneuver before the information reaches the responsible license reviewer. Division of responsibility within IE between its headquarters office and its five regional offices aggravates the problem. IE inspectors in these regional offices are the sources of information for many of the responsibilities of NRR. The interface line between these inspectors is channeled through the regional office organization and through the IE headquarters office, however, there is no direct channel between them and the technical reviewers in NRR.

In addition, the regulatory staff relies on outside contractors and consultants, to a substantial extent, to review sections of applications in the reactor area. The extent to which the staff is able to or does manage and evaluate this review work is difficult to assess. It is unclear whether this reliance on outside consultants reflects NRC constraints, staff preferences, or other motivations. In any event, this practice results in further fragmentation of the review.

The relationships among other important components of the regulatory system also require improvement. The communications between the NRC, NRR, and the ACRS are deficient. The ACRS, which has technical expertise in nuclear safety matters capable of supplementing that of NRR and which by statute has an independent advisory role in that area, is not pleased with the staff's lack of response to some of its recommendations. On the other hand, the Atomic Safety and Licensing Boards, which compared to the advisory committee have limited expertise in the area of nuclear reactor safety, could be overwhelmed by the "Board Notification Policy," which requires the staff to furnish them with a wide assortment of unevaluated or poorly evaluated information. Thus, the system is apparently placing primary oversight responsibility on licensing boards, the entity outside of NRR with little nuclear reactor safety expertise, and not on the advisory committee, the entity established by statute to provide independent and advisory expertise to the NRC on "the hazards of proposed or existing reactor facilities" and "the adequacy of proposed reactor safety standards."[59]

The precise functions of the Regulatory Requirements Review Committee (RRRC) also merit examination (see Section I.A.3.a). This committee has no charter from the NRC, is not referred to in NRC regulations, and does not operate under regulatory criteria that can be applied in practice. The RRRC is a staff institution headed and dominated by NRR. It has no permanent members and no permanent supporting staff.[80] Nevertheless, this committee is the staff organization that decides whether to impose new regulatory requirements or to relax existing ones. Once it makes that decision its task is finished, and the job of implementing its decision passes to others in NRR, who sometimes fail to implement those mandates in a timely manner.[81]

The System Does Not Assure That All Important Issues Are Identified

The licensing review and the staff's safety evaluations focus primarily on safety systems hardware and whether it complies with the design principles set forth in the General Design Criteria for Nuclear Powerplants,[8] or, in rare instances, to more specific criteria.[82] The licensing review thus largely consists of an engineering review, designed to compare a particular proposed design system against a series of established engineering criteria and performance standards. The operational side of nuclear safety-considerations such as the human element, the individual machine interface, control room design, qualifications to assume the responsibility for a nuclear powerplant, operator training, emergency planning, operating procedures, and the systematic evaluations of operational feedback information-is largely ignored in the licensing and regulation of nuclear power reactors, however.[83] As the experience at TMI-2 illustrates, these considerations can be extremely important to the safe operation of even properly designed nuclear powerplants. Even if one incorrectly assumed that the engineering review was adequate to perform the task assigned to it, the failure of the regulatory system to adequately consider and regulate these operational factors has now been recognized to be a substantial shortcoming in the existing regulatory system.

Principles That Bound the Review

The NRC's design safety review does not require consideration of all of the systems and components of the nuclear plant, but only of those deemed "safety-related." Moreover, the NRC's licensing review does not encompass a consideration of designs for prevention or mitigation of accidents involving independent failures of more than a single component or system, such as occurred during the TMI-2 accident. These and other limitations circumscribe the NRC's licensing design safety review.

Design Basis Accidents

The principal tool used by the staff for reactor safety evaluation is an analysis of a spectrum of design basis accidents. The NRC has postulated nine classes of increasingly severe accidents and occurrences. The licensing review system is intended to develop reasonable assurances that the plant's proposed design will adequately deal with eight of those categories, assuming that the probability of the most severe accidents is sufficiently remote to exclude that category from review.

The response of the reactor plant to each of these postulated events is predicted and the radiological consequences are calculated. The greatest emphasis, both in accident analysis and supporting research, has always been on assurance of the means for core cooling under all circumstances, particularly in the event of a large loss-of-coolant-accident (LOCH). Earlier safety reviews tended to emphasize the concept of a maximum credible accident, and to evaluate the adequacy of the reactor site and the integrity of its containment in judging the acceptability of its design and location. As the size of nuclear reactors increased, the potential for consequences resulting from the system's inability to deal with any of the design basis accidents also increased. However, the regulatory system has never deviated from the judgment that because the probability for the occurrence of a highly severe accident is so low, the consideration of these accidents in the regulatory process can be basically ignored. Thus, accidents of increasing consequences beyond design basis accidents, such as those leading to extensive core damage, or to core melt, are not dealt with by additional design requirements, despite their potentially awesome consequences.

The Single Failure Criterion

The single failure criterion is a term applied in systems design and analysis to define the required reliability of the systems needed for **safe** shutdown and cooling, and for mitigation of the consequences of postulated accidents. Simply stated, the single failure criterion is a requirement that a system designed to carry out a specific safety function must be capable of carrying out its mission in spite of the failure of any single component within the system or in an associated system supporting its operation. This concept has the direct objective of promoting reliability through the enforced provision of redundancy in those systems that must perform a safety-related function. Its application involves a systematic search for potential single failure points and their effects on prescribed missions in order to identify design weaknesses that could be overcome by increased redundancy, or use of alternative systems or procedures.

Application of the concept is complicated by the interrelationships between the various plant systems in a nuclear powerplant. Furthermore, there is a need to define for specific systems the events and associated assumptions that must be considered during application of the single failure criterion.

Safety and Nonsafety Systems

The staff devotes substantial effort in reviewing safety systems, but pays practically no attention to those systems deemed nonsafety. This is the practics even for equipment which is in the gray area between safety-related and nonsafety-related, such as a power-operated relief valve in the primary coolant system.[85] There is no clear definition or guidance to reviewers in determining whether equipment should be deemed to be safety- or nonsafety-related.[86] The designation of systems as safety-related or nonsafety-related is done in a somewhat arbitrary and inconsistent manner (see Section I.A.3.b). Additionally, once a system is designated as nonsafety-related, it is difficult to have the designation changed. This makes it particularly difficult for an IE inspector to effect necessary changes in systems arbitrarily defined as nonsafety. Instead, discussions between the staff and the industry have focused primarily on determining the reliance that can be placed on nonsafety grade equipment to prevent or mitigate the consequences of anticipated transients.

Staff Review of the Application

The staff does not conduct an exhaustive review of the design of a reactor. It conducts instead an audit review of the design as described in the application.

Guidance on procedures for conducting this audit review are set forth in the Standard Review Plan (SRP), issued in September 1975. The SRP has never been followed for the complete review of any application, however, and it is generally recognized that its content is of uneven quality.[87] The plan's definition and distribution of review responsibilities are not well established in several review areas, and its discussion of secondary review responsibility and review interfaces is often inadequate or missing.[88]

Distinctly different review approaches are followed by the staff in some of the different technical areas. In some areas, a technical review consists mainly of reviewing an applicant's interpretation of guides and standards. In others, the staff undertakes an indepth audit of an applicant's design, construction, procedures, and operational practices. Finally, in some other technical areas, the staff's review depends heavily on staff analyses performed independently of the applicant's analysis.[89]

The staff's review of safety systems under the SRP is done either by organizational units, such as containment systems, reactor systems and plant systems; or by technical disciplines, such as mechanical engineering, materials engineering, and structural engineering. Although systems interactions are considered in the staff's review, no entity is assigned that responsibility for the complete plant. Thus, there is no mechanism for assuring that the staff's audit review adequately considers the interaction of various plant systems, particularly with regard to whether actions or consequences in one system could adversely, affect the redundancy and independence of safety systems.90

Inspection and Enforcement

The inspection process is performed primarily by observation of licensee activities, visual inspection of hardware, and audit of records to ascertain whether the licensee is complying with applicable regulatory requirements and commitments (see Section I.B.3). The audit of documents is relied on heavily to verify compliance with quality assurance requirements. The inspection process is guided by procedures, or modules as they are called, contained in the Inspection Manual, the inspectors' analogue to the Standard Review Plan for the NRR technical reviewers of the application. The procedures relating to risk mitigating systems are generally grouped by categories used in the standard technical specifications. These systems are reviewed periodically by an inspector at some level of frequency, by varying methods, and in varying detail.

Some inspection efforts do not have direct association with plant systems, but rather with general activities such as training, which is important to safety. Some of the inspection effort also involves auditing the plant surveillance program, which has the objective of assuring the operability of accident mitigating systems. Finally, the inspection effort also involves some review of the plant's operating procedures. This review does not generally appear to involve an indepth examination of the adequacy of these procedures, however, or even those which appear to be important, such as emergency procedures. The review is primarily an accounting exercise to ensure that procedures exist which meet some minimum, but undefined, standards. Except for the resident inspector program, considerable inspection effort is devoted to document audits and to determining whether procedural requirements are being observed.

The inspectors are the NRC's observers during the power ascension tests, acceptance, and preoperational testing programs. The confidence that structures, systems, and components will perform as required is a strong function of the adequacy of these programs, second only to how well they were designed, constructed, or fabricated in the first place. Practically no standards have been developed in this area, however, and the basis for determining the amount of inspection resources allocated to different activities, such as the relative risks for the various activities, is not well defined.[91]

The NRC's Inspection and Enforcement Manual identifies the purpose of the inspection program for the operations phase of nuclear power reactors to be "to obtain sufficient information through direct observations, personnel interviews, and review of facility records and procedures to ascertain whether the licensed management control program is effective and whether the facility is being operated safely in conformance with regulatory requirements."[92] Inadequate capabilities for data analysis and for independent verification impairs the achievement of the overall goals of this program.[93]

There Is No Provision for Systematic Evaluation of Operating Reactor Experience and Related Research

The NRC's extensive reporting system, Licensee Event Report System (LERS), gathers substantial information on the operating experience at nuclear powerplants. In addition, the NRC's operational data base includes input from inspection and enforcement reports, the reporting of defects, noncompliance, construction deficiencies, and some information from foreign reactors.[94]

Even though a major purpose of obtaining this information is to identify potential safety-related problems, prior to March 1979, the NRC never established a procedure to assure that operating information is systematically analyzed and evaluated for its safety significance. To the extent that operating experience was reviewed, reviews were conducted on a random, uncoordinated basis with no assurance that major safety-related problems were identified, or that related information was disseminated to the industry and fed back into the licensing and regulation process for reactors. No attempt was made by the NRC to require the industry to conduct such evaluations, and the NRC did not inform the industry of the limitations of its own analytical and evaluation efforts. Similarly, it is uncertain to what extent the large number of technical reports developed in research programs that possess potential safety significance are routinely considered and injected into the regulatory system.

The NRC's efforts to impose requirements for information exchange within the industry are equally deficient. The nuclear industry has a system, Nuclear Plant Reliability Data System (NPRDS), for voluntarily reporting minor mishaps and components failures at operating nuclear powerplants. In his April 1977 energy message, the President of the United States requested the NRC to make that system mandatory. The NRC has not yet decided whether the benefits from a mandatory system would outweigh the additional industry burden, however, and consequently has not acted.

The "Generic" Label Is Used to Prolong the Resolution of Safety Issues

"Generic safety issues" are issues related to a particular class or type of reactor plant or design, and not just to a specific plant (see Section I.A.3.c). They are also referred to as "unresolved safety issues," although not all generic issues are related to safety matters. Until recently neither the NRC nor its predecessor made an attempt to define, categorize, or manage generic technical activities on a systematic basis. Even now, progress in this regard is disappointing.

The dichotomy between generic and plant specific safety issues leads to situations in which Atomic Safety and Licensing Boards having the responsibility for making the ultimate safety finds are made aware of, but powerless to deal with, a long list of generic issues awaiting resolution, some of which have remained outstanding for a long time. As a matter of regulatory practice, generic issues related to a particular plant are not required to be resolved prior to that plant's licensing. Thus, by being labelled generic, these issues cease to be obstacles to the licensing of specific plants. This general policy is designed to avoid undue delay in the licensing process, and to provide an element of stability in that process by assuring that issues of general applicability are resolved on a consistent and uniform basis from one plant to the next. One of the regulatory premises underlying the categorization of an issue as generic is that its safety significance does not prohibit the continued operation of the plant while the issue is being resolved.[95] Generally, this premise does not receive the scrutiny it deserves, however. Categorization of issues as generic also assured that they would be resolved, if at all, either without public participation, or if a regulation change or addition were involved, probably on the basis of an informal rulemaking proceeding. Because these issues were not deterrents to the licensing of specific plants, there was no incentive for priority attention to be given to their resolution. An examination of the numerous issues categorized as generic, however, calls that premise into serious question.

Eventually, a series of events stimulated increased staff attention to this problem. In 1976, members of the NRC's technical review staff raised 27 generic safety issues, and in 1977, the NRC instituted a program to impose management control in the area.

On November 23, 1977, the ASLAB emphasized that "unresolved" issues cannot be disregarded in individual licensing proceedings simply ly because they also have generic applicability. The board indicated that there must be some explanation in the Safety Evaluation Report why construction should be allowed to proceed in the face of an unresolved generic question. The appeal board later held that where operation of a reactor is involved, the justification for authorizing the license in light of unresolved generic issues can obviously be more difficult than at the construction stage.[97]

On December 13, 1977, the Energy Reorganization Act of 1974 was amended to include a new Section 210, "Unresolved Safety Issues Plan."[98] This statute directs the NRC to develop a plan "providing for specification and analysis of unresolved safety issues relating to nuclear reactors," and to take such action "as may be necessary to implement corrective measures with respect to such issues." Section 210 required the NRC to submit to Congress on January 1, 1978, a report on its plan for the resolution of generic issues. One feature of the submitted plan was a Technical Activities Steering whose purpose is to increase manage- Committee, involvement in and oversight of, generic techn- ment activities. Unfortunately, the NRC's actual progress in this area has been disappointing. With all of these stimuli, the NRC has reported some progress regarding the schedules and priorities for the resolution of these issues on the basis of their contribution to risk.[99] Criteria for identifying such items as the priorities for resolution of these issues, for determining when to allow construction and operation of a reactor even though outstanding unresolved generic safety issues remain, or for otherwise governing the activities of the Technical Activities Steering Committee remain either vague or nonexistent, however.

Some Important Regulations Are Inadequate

The NRC's regulations, like the focus of the staff's review, mostly set forth general criteria relating to design. The regulations are almost completely lacking in any criteria relating to the operational aspects of nuclear reactor safety. Moreover, the regulations do not contain well defined safety criteria and requirements. Many are ineptly drafted-some to the point of being virtually incomprehensible. Others appear to be of questionable merit in view of the changes that have occurred since their publication.[100] Still other regulations have quite obvious gaps. No organizational entity is charged specifically with the responsibility of assuring that the regulations are adequate, or alerting the NRC to problems in the regulations themselves. Some of the more significant examples of inadequacies in the NRC regulations follow.

10 C.F.R. Part 100-Reactor Site Criteria

The essential elements of nuclear powerplant siting policy are set forth in Part 100. These regulations were published by the Atomic Energy Commission in 1962 as an "interim guide." The authors recognized that experience with siting nuclear powerplants was at that time too limited to form the basis for a more definitive final statement.[101] Nevertheless, these 1962 "interim" regulations have not been significantly changed since that time.[102]

10 C.F.R. Part 50-Domestic Licensing of Production and Utilization Facilities: Appendix A, "General Design Criteria for Nuclear Powerplants"

The development of General Design Criteria (GDC) for nuclear powerplant construction permit applications began in 1964. The GDC were first issued for interim guidance in 1965, and were reissued in 1967. Following extensive discussion with industry representatives, 55 criteria were published as mandatory requirements in Appendix A to Part 50, which became effective on March 21, 1971. In the introduction to these criteria, the following statement is made:

> The development of these General Design Criteria is not yet complete. For example, some of the definitions need further amplification. Also, some of the specific design requirements for structures, systems, and components important to safety have not as yet been suitably defined.

These general criteria have remained essentially unchanged since that statement was made in 1971, and they have not been significantly changed since 1967. Moreover, the GDC constitute only general statements of design objectives or principles. The criteria lack any explanation of their underlying logic or discussion of their interrelationships. This shortcoming provides each staff reviewer little guidance when left with the task of deciding what the general words mean, what assumptions need to be made, and how the GDC should be applied.[103]

10 C.F.R. 50.109-"Back fitting" Regulation

These regulations provide in part that:

> The Commission may ... require the backfitting of a facility if it finds that such action will provide substantial, additional protection which is required for the public health and safety or the common defense and security.

Prior to release of this regulation in March 1970, the imposition of additional safety requirements after the issuance of a construction permit, commonly referred to as "backfitting," was handled on a case-by-case basis. In the more than 9 years that followed issuance of the backfitting regulation, these decisions continue to be made without workable backfitting criteria[104] (see Section I.A.3.a).

10 C.F.R. 50.35-Issuance of Construction Permits

The proposed "backfitting" regulation included a provision for development and use during reactor construction of a system similar to the technical specification system used for reactor operation.

This proposal was not adopted in the final rule, however. The reason given was that the "essential elements of the proposal design" in the proposed rule "require further definition involving additional study."[105] After 9 years of further study the regulations still have not been clarified in this area. Nevertheless, every construction permit contains language authorizing construction of the proposed facility "in accordance with the principal architectural and engineering criteria." Although subtle legal arguments can be made to give these words meaning, the technical reviewers lack any regulatory definition. Consequently, even though a quarter of a century has passed since the enactment of the Atomic Energy Act of 1954, there are no clear regulatory criteria as to the meaning of a construction permit, or the extent to which a construction permit holder may make changes of the plant design proposed in the application without prior NRC approval. Similarly, there are no workable regulatory criteria for the staff to follow in determining whether to require reactor "backfitting" after a construction permit has been issued.

10 C.F.R. Part 21-Reporting of Defects and Noncompliance

This regulation is ambiguous regarding important matters, such as its applicability to architect-engineers and to information originating from experience with a reactor located outside of the United States.

Proposed Annex to Appendix D to 10 C.FR Part 50

Proposed by the Atomic Energy Commission nearly a decade ago, this annex, although never officially adopted, has been followed as guidance ever since. The annex establishes classes of accidents, including the "Class 9," which is beyond the design basis spectrum of accidents. More importantly, its effect is that the consequences of such accidents are not considered in the environmental statements for land-based nuclear plants.[107]

The System Is Tasked with Major Responsibilities Other Than Nuclear Reactor Safety

The National Environmental Policy Act (NEPA), which took effect on January 1, 1970, required that nonradiological effects on the environment be considered in the licensing of nuclear power reactors. Theretofore, licensing jurisdiction was confined to radiological safety. Even under a begrudging interpretation, NEPA's extension of jurisdiction would have had a substantial effect on the licensing process. The interpretation of NEPA by the U.S. Court of Appeals for the District of Columbia in *Calvert Cliffs Coordinating Committee v. United States Atomic Energy Commission,* 449 F. 20 1109 (D.C. Cir. 1971), substantially magnified NEPA's impact on the licensing process. Among other things, the *Calvert Cliffs* decision required the cost-benefit balancing of a potentially vast number of environmental values. As a result, issues such as the need for power, choices of fuel and alternative sites, and the availability of uranium resources, now are raised in individual licensing cases. These must be evaluated, along with innumerable other environmental issues raised in the draft and the final environmental impact statements, for each plant at the construction permit and operating license stages. These new demands began during 1971 to 1974, a period when other events that had a substantial impact on the licensing process occurred, such as the beginning of opposition to the location of nuclear powerplants and the increased number of new applications for both construction permits and operating licenses, with the resulting increased demands on staff resources. (See Table I-1.)

During these years a continuing increase in the size of the technical staff occurred. Although this inquiry has not attempted to quantify the degree of the impact of *Calvert Cliffs,* the fact that a number of senior personnel who were trained and who worked in the field of nuclear reactor safety were permanently transferred to work in the environmental impact statement field suggests that it may have been significant.

Substantial prelicensing antitrust review responsibilities were also added to the system for the licensing of nuclear powerplants in the 1970 amendments to the Atomic Energy Act of 1954, including Public Law 91-560, 84 Stat., 1472. Although this law added to the overall licensing effort, it did not require that staff resources be diverted from nuclear safety review work, as did the *Calvert Cliffs* decision. On the other hand, the law imposes responsibilities on the NRC that are not at all related to the Commission's primary responsibility and capability-protection of the public health and safety from nuclear radiological hazards.

The Nuclear Nonproliferation Act of 1977[109] substantially extended the NRC's nuclear export responsibilities. The expansion by this complex and in part, inscrutable law, was not in the area of radiological health and safety, however. Although the NRC has little or no public health and safety responsibility for nuclear exports, the Nuclear Nonproliferation Act of 1977 requires its involvement in foreign nuclear commerce, nuclear weapons nonproliferation, foreign policy determinations, and other similar

TABLE I-1. Applications received during fiscal years 1967-75

	Construction Permit Applications		Operating License Applications	
Fiscal Year	Number of Applications	Number of Units	Number of Applications	Number of Units
1967	16	22	3	3
1968	18	24	3	4
1969	14	19	8	13
1970	7	12	6	7
1971	11	16	15	22
1972	5	10	2	3
1973	9	17	7	9
1974	21	42	5	8
1975	14	31	1	1

areas. These are all areas which, in large measure, the NRC is neither designed nor staffed to handle and which appear to be ill-suited for an independent regulatory body. During the first year of this Act's existence, which incidentally ended shortly before the TMI-2 accident, the NRC devoted a substantial portion of its time to these international matters.[110]

The System Promised More Than It Delivered

Over the years the system has been portrayed as one that deals with substantially more from a regulatory standpoint than it in fact does. For example, the entire area of plant operations-technical qualifications of the utility, personnel qualifications, operating and emergency procedures, and human factors-have received only superficial attention from the regulatory standpoint. This lack of attention, when coupled with fragmented safety-related responsibilities within the industry, could well have led to an excessive reliance on the NRC by utilities and others in the industry.

The present organization and vague standards almost assure that the licensing system will have deficiencies. The existing highly fragmented operation, the absence of an entity outside of the licensing and regulatory system to observe and evaluate its quality, and the broad discretion typically exercised at almost every review level, fosters divisive and parochial interests rather than a coherent regulatory system. Coupled with the almost total emphasis on the regulatory system's efficiency (i.e. "promptness") rather than its quality, these shortcomings lay the groundwork for a system that does not focus on the difficult issues and which, in the final analysis, does not offer the public the high quality licensing and regulatory system to which it is entitled.

d. Findings and Recommendations

Findings

- The Atomic Energy Act of 1954, as amended, and the Energy Reorganization Act of 1974, as amended, authorize the NRC to act with almost unlimited discretion in making substantive public health and safety, and common defense and security judgments, provided that the minimum prescribed procedures, essentially legal, are observed.
- There is a lack of policy direction and guidance from the NRC to the staff. The system does not have well defined regulatory objectives, and no "Acceptable Risk" goal has been established as policy.
- There is no regulatory yardstick either to measure existing risk, to evaluate the effectiveness of regulatory actions in decreasing risks to an acceptable level, or to assure that an acceptable risk level is maintained.
- For more than two decades, the NRC and its predecessor have licensed nuclear powerplants almost exclusively on the basis of engineering judgment.
- There is no yardstick, other than the safety record of operating plants, by which anyone can rationally evaluate either the quality or the consistency of these highly personalized judgments, or the degree of assurance of safety they provide.
- Although the NRC has broad rulemaking authority, its regulations are in many respects outdated and inadequate, as noted by its appeal board and others.
- Responsibility for substantive safety matters is fragmented within the NRC among five major offices, and is further diffused at and below the

division level within these offices, particularly in the Office of Nuclear Reactor Regulation.

- There is no unified and positive leadership or management of the internal operation of the NRC.
- The NRC does not operate as a team working together to identify and resolve difficult issues. Instead, there is an excessive and detrimental amount of parochialism.
- The NRC and its staff have almost unlimited discretion in making safety judgments provided certain ASLB findings are made. These findings can be made almost ritualistically on the basis of poorly articulated engineering judgment.
- The system focuses almost entirely on nuclear systems and equipment, and practically ignores operational areas (e.g., qualifications of utilities, procedures, systematic evaluation of operational information, human engineering, etc.). The focus on design and equipment is evident in the composition and qualifications of the regulatory staff, which is not operations oriented or experienced.
- Important participants in safety decisions (reactor system vendors and architect-engineers) are almost completely isolated from the regulatory system, except for quality assurance and deficiency purposes, although they are affected by, and may react to, the requirements the system imposes on licenses.
- The system does not assure that significant safety issues are identified through risk assessment methods and techniques. For example, the Standard Review Plan is not based on risk assessment methods, there is little focus on things such as systems interactions, safety/nonsafety grade, single failure criterion, design basis accident bounds, etc.
- The system provides no incentives to enhance safety; instead it results in acceptance of what may be the "lowest common denominator," compliance with NRC requirements.
- The system does not deal adequately with the disincentives to safety such as who will bear the economic burden if safety improvements are recommended and adopted.
- The system does not encourage and is not receptive to the ideas and suggestions of others.
- The licensing system now permits, and indeed encourages the commencement of a massive construction effort on the basis of preliminary design information (e.g., the two step licensing process, limited work authorization, and the immediate effectiveness rule). It also provides discincentives to desired regulatory goals, such as the move in the direction of standardization.
- After licensing, no regulatory criteria exist that can be applied to explain on a rational basis things such as the imposition of new regulatory requirements, enforcement actions, and postlicensing actions such as "administrative solutions" to a design flaw. This entire area is one where actions appear to be based almost completely on the judgment of senior staff officials.
- NEPA and its judicial interpretations have placed significant responsibilities on the NRC in areas other than reactor safety.
- The Congress, in the Atomic Energy Act of 1954, as amended, has placed prelicensing antitrust review responsibilities on the NRC, which have little or no relation to the Commission's primary radiological health and safety mission in the nuclear field.
- The Congress in the Nuclear Nonproliferation Act of 1977, has placed substantial international relations responsibilities on the NRC. These responsibilities have little or no relation to the NRC's primary reason for being and, it would appear, are inappropriate for an agency outside of the Executive Branch.
- In the absence of national policies on societal risks from available means of generating electricity and the fuel choices which should be made, these issues are being debated by interested members of the public in the licensing of individual nuclear powerplants.

Recommendations

- A Nuclear Reactor Safety Board should be established outside the line functions for licensing and regulation that would, among other things, exercise independent oversight of the effectiveness of the system. Another component of this oversight organization should be an Office of Public Counsel. Core of the internal oversight team: ACRS (independent and advisory); Reactor Safety Board; and Office of Public Counsel.
- A statement of regulatory objectives should be developed including policy on risk objectives and methods, to better use risk assessment techniques either qualitatively or quantitatively, in licensing and regulatory actions. The importance of WASH-1400 techniques should be emphasized through an expanded risk assessment program that provides some of the evaluative tools to determine the qualitative or quantitative relative risk significance of events or patterns of events.
- Important participants in nuclear plant design and

construction, such as the reactor system vendors and the architect-engineer, should either be licensed or made accountable by some equivalent system.

- An organization should be designated to have primary responsibility in the rulemaking area to assure that the quality of the regulations are adequate.
- The two-step licensing process as it is now used, should be abolished along with other policies (limited work authorizations and the immediate effectiveness rule), and replaced with a system that provides incentives for more design and site-related safety and environmental issues to be resolved before construction begins.
- Incentives should be established that would result in more information prior to construction, fewer unresolved issues, and less variety in the design of important systems.
- Important areas such as the backfitting of new regulatory requirements, enforcement actions, licensing operation, or permitting of continued operation with major open safety issues should be examined and prompt action taken to publish applicable regulatory criteria. Judgment needs to be exercised, but on a rational regulatory basis bounded by criteria based on the best available relative risk assessment.
- The NRC should be relieved of all responsibilities placed on it under the Nuclear Nonproliferation Act of 1977. These functions should be transferred to the Executive Branch.
- The NRC should be relieved of its prelicensing antitrust review responsibilities under the Atomic Energy Act of 1954, as amended. These responsibilities should be transferred to the Executive Branch.
- The U.S. Government, after considering and comparing societal risks from presently available means of generating electricity, should decide on the choices to be made as a matter of national policy.

REFERENCES AND NOTES

'The terms utility, licensee and applicant will be used interchangeably throughout.

[2] Nuclear powerplant licensees are subject to prelicensing antitrust review requirements in Section 105 of the Atomic Energy Act, 42 U.S.C. 2135.

[3] *Power Reactor Development Co. v. International Union of Electric Radio and Machine Workers,* 367 U.S. 396 (1969).

4Some preliminary work, such as site clearance, is permitted under a Limited Work Authorization, however. 10 C.F.R. Sec. 50.10(e).

[5] 42 U.S.C. 2131, 2235.

[6] 10 C.F.R. Sec. 50.10(b).

[7] 10 C.F.R. Secs. 50.51, 50.57.

[B] See 10 C.F.R. Part 50, Appendix A.

[9] *Petition for Remedial and Emergency Action,* 7 NRC 400, 418 (1978).

[10] See 10 C.F.R. Sec. 50.34.

[11] 10 C.F.R. Part 100; Part 50, Appendix B.

[12] 10 C.F.R. Sec. 50.30(f); 10 C.F.R. Part 51.

[13] 10 C.F.R. Sec. 50.33A.

[14] 10 C.F.R. Sec. 2.102.

[15] 42 U.S.C. Sec. 4321 *et seq.*

[16] 42 U.S.C. Sec. 2239a.

[17] 10 C.F.R. Sec. 50.58(a).

[18] 10 C.F.R. Part 2, Appendix A.

[19] 10 C.F.R. Sec. 2.760(a).

[20] 10 C.F.R. Secs. 2.714(a)(1); 2.715(a),(c).

[21] 10 C.F.R. Sec. 2.758(b).

[22] The steady increase in the number of contested hearings during this decade is documented in the NRC's Annual Report to the Congress. Each of these reports include statistics on the subject.

[23] 10 C.F.R. Secs. 2.760, 2.762, 2.764(a), 2.785, 2.785(b)(2), 2.785(c), 2.786, 2.786(a)(b), 2.786(b)(4).

[24] 42 U.S.C. Sec. 2232b.

[25] 10 C.F.R. Secs. 50.55(e), 50.35, 50.91.

[26] However, "generic" unresolved safety issues may remain outstanding at this point.

[27] 10 C.F.R. Sec. 50.36(c).

[28] 42 U.S.C. 2232a.

[29] 10 C.F.R. Secs. 50.58(b), 2.105, 2.714.

[30] 10 C.F.R. Sec. 50.35(a).

[31] 42 U.S.C. 2077c(2).

[32] 10 C.F.R. Secs. 50.35(b), 50.34(b).

[33] See 42 U.S.C. Sec. 2235.

[34] See 10 C.F.R. Sec. 50.57.

[35] 10 C.F.R. Sec. 50.51.

[38] 42 U.S.C. Sec. 2236.

[37] 10 C.F.R. Subpart B.

[38] See "backfitting," 10 C.F.R. Sec. 50.109.

[39] See "backfitting," 42 U.S.C. Sec. 2233.

[40] 10 C.F.R. Sec. 50.54W.

[42] 10 C.F.R. Secs. 50.70, 50.71.

[43] 10 C_F.R. Sec. 2.202.

[44] It might be noted in passing that large nuclear units may involve many utilities as licensees. Typically, one utility assumes the "lead role" and will be the operating utility. Although Commission regulations do not distinguish between the operating holder of an operating license and the other utilities which are also technically licensees, in past cases the NRC has granted the operating utility a license to operate the nuclear facility and to possess nuclear materials. The other participating utilities are identified in the license as simply holding a license to possess nuclear materials.

[45] 10 C.F.R. Part 21.

[48] 42 U.S.C. Sec. 5846.

[47] 10 C.F.R. Part 50, Appendix B.

These memoranda of understanding deal with relations between numerous agencies. Examples include those reached with the Environmental Protection Agency (40 F. Reg. 60115, December 23,1975; 38 F. Reg. 24936, August 21,1972); the Department of Transportation (38 F. Reg. 8466) and the Army Corps of Engineers (40 F. Reg. 37110, August 25, 1975).

[49] In emergency response planning, the EPA has assumed many of the responsibilities of the former Federal Radiation Council and in that capacity has been reviewing the Federal Radiation Protection Guides (25 F. Reg. 4402, May 18, 1960). The NRC and other member agencies of the Federal Interagency Coordinating Committee for Emergency Preparedness have commented to the EPA on proposed nuclear accident protective guides for airborne releases of radioactive gases and particulates. These guides, which are being prepared for use by State and Federal agencies in emergencies, will become part of NRC regulations once promulgated by EPA.

[50] OSHA defers to the NRC on matters of radiological health and safety, and NRC licensees are deemed in compliance with OSHA regulations by the Department of Labor.

[51] *Northern State Power Co. v. Minnesota,* 405 U.S. 1035 (1972).

[52] The NRC has offered the States planning guidance on developing emergency plans [See NUREG 75/111 (1974)] and responding to various types of accidents (NUREG-0396). The NRC has also trained State emergency response personnel in courses taught by various Federal agencies. Examples of courses which have been available include "Radiological Emergency Response Planning." This training is available to all States' personnel, not just those with plans that are concurred with by the Commission.

[53] See General Accounting Office Report EMD-78-10, "Areas Around Nuclear Facilities Should Be Better Prepared for Radiological Emergencies," March 30, 1979. It should be noted that the absence of a State approved plan as of March 28, 1979, does not preclude a utility's operating a plant there. The NRC did not, as of that date, require that each State with a nuclear plant have an approved plan, although the licensee's emergency plan, in part, relied on State and local agencies.

[54] See e.g., "Licensing and Regulation of Nuclear Reactors," Hearings before the Joint Committee on Atomic Energy, Part 1, 90th Cong., Ist Sess., 2-227 (April, May 1967); "Nuclear Reactor Safety," Hearings before the

Joint Committee on Atomic Energy, Part 1, 93rd Cong., 1st Sess., (January, September, October, 1973); and "Nuclear Regulatory Commission's Safety and Licensing Procedures," Hearing before the Committee on Government Operations, U.S. Senate, 94th Cong., 2d Sess. (December 13, 1976).

[55]"NRC Statement on Risk Assessment and the Reactor Safety Study Report (WASH-1400) in Light of the Risk Assessment Review Group Report," January 18, 1979. This statement is published in "Reactor Safety Study Review," Oversight Hearing Before the Subcommittee on Energy and the Environment of the Committee on Interior and Insular Affairs, House of Representatives, 96th Cong., 1st Sess., 115 (February 26, 1979). This document will be subsequently cited as "Reactor Safety Study Review."

[56]See Memoranda from Commissioner Gilinsky to other Commissioners, "Commission Statement on the Reactor Safety Study," January 22, 1979; from Chairman Hendrie, "Commission Statement on Nuclear Plant Safety," January 25 and 31, 1979; and from Commissioner Ahearne to Joseph Fouchard, "Commission Statement on Reactor Licensing," February 6,1979.

[57]"Reactor Safety Study Review, (at p. 4)", Oversight Hearing before the Subcommittee on Energy and the Environment of the Committee on Interior and Insular Affairs, House of Representatives, 96th Cong., 1st Sess., 115 (February 26, 1979).

[58]1d. at 90-114 of Prepared Testimony, 4-29 of Oral Testimony

[59]42 U.S.C. Sec. 2039 (Section 29 of the Atomic Energy Act).

sThe Atomic Energy Act, Pub. L. No. 95-209, 91 Stat., 1483 (1977).

[61]1f the application for a license to construct is opposed, as most have been during the 1970s by intervening parties, the ASLB must make all of the required safety findings and authorize the Director of the Office of Nuclear Reactor Regulation (NRR) to issue the construction permit. If the application is not contested, the ASLB's role is to decide "whether the application and the record of the proceeding contain sufficient information," and whether the staff's review "has been adequate to support the Director of the Office of Nuclear Reactor Regulation's proposed findings for the issuance of the construction permit" (10 C.F.R. Part 2, Appendix A V (f) and 2.104).

ASLBs also conduct the hearings on application for a license to operate nuclear power reactor, if a hearing is held. In an operating license proceeding, the ASLB determines the contested issues. The director of NRR, depending on the ASLB's resolution of the contested issues, would issue, deny, or appropriately condition the operating license [10 C.F.R. Part 2, Appendix A VIII (b)(c), 2.104(c)].

[62]42 U.S.C. Secs. 2239a, 2241 (Sections 189a, 191 of The Atomic Energy Act).

[63]See 10 C.F.R. Sec. 2.785(a).

[84]10 C.F.R. Sec. 2.786(b)(1).

[65]Even if there is no appeal, the ASLAB reviews the ASLB's decision. Any action taken by an ASLAB "shall have the same force and effect ... as actions of the Commission" subject, however, to review by the Commission [10 C.F.R. Secs. 2.785(c), 2.786(a)].

[66]See NRC, "Seminar Report on the Public Hearing Process for Nuk m Power Plants," NUREG-0545, at 76, June 1978.

[67]10 C.F.R. Sec. 2.780.

[68]Hanauer dep., Exhibit 1134.

[69]42 U.S.C. Sec. 2201i.

[70]See *Petition for Remedial and Emergency Action,* 7 NRC 400 (April 13,1978).

[71]It was not until September 1, 1978 that the Commission noted the following as requiring "further action by the staff" (Memorandum from Samuel J. Chilk, Secretary to the Commission, to Lee V. Gossick, Executive Director for Operations, "Improving the Process for Determining the Need for New Reactor Requirements ...," September 1,1978):

- How might the staff most expeditiously proceed to define in more explicit-if not quantitative-terms the criteria for deciding when a requirement is essential to safety, while still recognizing that judgment is an inherent part of such decisions?
- What needs to be done to clarify the circumstances under which economic impacts associated with new requirements can and should be taken into account and to improve the quality of value-impact analysis of new requirements?
- How should NRR decisions and the basis for new requirements best be documented and most expeditiously communicated to and implemented by those affected?
- How can the NRR process be opened to observation or participation by interested persons outside so as to improve the quaky of new requirements and the timeliness of their implementation?
- Might RRRC (Regulatory Requirements Review Committee) membership and structure be altered to more appropriately account for the extent of demands on the time of senior staff personnel and the possibility of conflicts with their other duties?
- What changes in NRR procedure might be adopted which would take better account of the concern that the precedent established by imposing new requirements in individual cases in the interim, prior to RRRC review and approval (so-called category 4) make RRRC approval and NRR adoption for generic use a foregone conclusion?
- How might NRR procedures be improved to prevent the further accumulation of generic issues and to introduce greater predictability with respect to requirements to be imposed?
- What might be done to better distinguish the basis for permitting a licensed reactor to continue operation pending implementation of a new requirement, whereas the operating license for a completed reactor may be withheld until the new requirement has been incorporated?
- How might NRR identify and eliminate elements of the Standard Review Plan, which make an insignificant contribution to overall plant safety, so that staff and industry resources can be focused on matters of most significance to safety?

The staff responded to the September 1, 1978 memorandum in an "Information Report" to the Commissioners, SECY-79-8, "Improving the Process for Determining the Need for New Reactor Requirements," January 2, 1979. However, as of March 1979, with one exception (opportunity to receive views of interested persons), these items had not been acted upon by the NRC.

[72]NRC, "Reactor Safety Study-An Assessment of Accident Risks in U.S. Commercial Nuclear Powerplants," Executive Summary, Wash-1400 (NUREG-75/014), October 1975.

[73](SECY-79-106): Memorandum from H. R. Denton, NRC, to the Commissioners, "Review of Use of WASH-1400 in Licensing Actions," February 9,1979.

[74]"The Lewis Report," NUREG/CR-0400, September 1978, Page xi.

[75]See "Federal Regulation and Regulatory Report," Report by the Subcommittee on Oversight and Investigations of the House Committee on Interstate and Foreign Commerce, 94th Cong., 2d Sess., Page 515 (October, 1976). Compare Case dep. at 227-229 and Staff Paper, SECY-79-424, "Value-Impact Guidelines," (July 2,1979).

[76]DPM was once the place in the organization where the entire plant was reviewed. The project manager then was the "Systems Interactions" reviewer. That role is no longer performed in DPM. however.

[77]Presumably, the transfers are not accepted by the DOR if, in the judgment of its management, a large number of safety issues remain unresolved. See also Vassallo dep. at 35-44 and Case dep. at 245-246.

[78]Ross dep. at 94 and Exhibit 1158.

[79]NRC Office of Inspector and Auditor, "Independent Review of the Browns Ferry Fire," NR 01A-001, at 17, August 1976

[80]Case dep. at 242.

[81]Examples of delayed implementation of the committee include Regulatory Guide 1.101 on emergency planning and Regulatory Guide 1.97 on instrumentation to monitor the course of an accident.

[82]See 10 C.F.R. Part 50, Appendix K-ECCS Evaluation Models.

[83]Hanauer dep. at 59-62.

[84]See proposed annex to 10 C.F.R. Part 50, Appendix D- NRC, *Federal Register, Vol.* 36, No. 22851, December 1, 1971.

[85]Hanauer dep. at 110-115.

8eA practical working definition is that an item is "safety-related" if its failure can lead to the release of radioactivity or if it is needed to mitigate the consequences of an accident.

[87]Vassallo dep. at 25.

[88]See Report of the General Accounting Office "Nuclear Power Plant Licensing: Need for Additional Improvements," EMD-78-29, page 22, April 26, 1978.

[89]See generally, NRC, "Nuclear Power Plant Licensing: Opportunities for Improvement," NUREG-0292, at 1-3, 2-11-12, June 1977.

[90]See Angelo dep. and attached Exhibits.

See generally, NRC, "Insights into Improving the Efficacy of Nuclear Power Plant Inspection Procedures Based upon Risk Analysis," NUREG/CR-0153, June 1978.

92 Inspection and Enforcement, U.S. Nuclear Regulatory Commission, Office of Inspection and Enforcement, Chapter 2500.

salt is difficult, under these circumstances, to evaluate the measure of the effectiveness of the inspection program and the inspection and enforcement reports it produces in identifying safety issues and in reducing reactor risk. The Division of Inspection and Enforcement itself apparently has been searching for an approach in this area. See, e.g., "Licensee Performance Evaluation," NUREG/CRO110 (Phase I), October 1978; "Licensee Performance Evaluation (Phase III), NUREG/CR-0979, August, 1979; Draft Report to IE by Teknekron Inc., "Analysis of the First Eighteen Months of Licensed Operations of Babcock and Wilcox Plants," September, 1979; and "Insights into Improving the Efficacy of Nuclear Power Plant Inspection Procedures Based upon Risk Analysis," NUREG/CR-0153, BMI-2004, June, 1978.

[94]Whether information from foreign reactors is even received apparently depends, in large measure, on agreements between our Government and the country in which the reactor is located. In some cases, this information may never be received by our Government. Moreover, even if the information is provided, its dissemination to the public may be subject to constraints imposed by the agreement between the United States and the foreign country. Insisting that the constraints be removed may result in no information being received at all, however.

[95]NRR, "Identification of Unresolved Safety Issues Relating to Nuclear Power Plants," NUREG-0510, at 4, January 1979.

986 NRC 760.

[97]8 NRC 245. The reason often given for allowing construction to proceed is that there is time to find a solution and build it into the plant's design. Thereafter, the most common reasons for allowing a reactor to operate, even though there are unresolved generic safety issues, are that a solution satisfactory for that reactor has been imposed, that a restriction on the level or nature of operation adequate to eliminate the problem has been imposed, or that the issue does not arise until the later years of plant operation.

[98]The Energy Reorganization Act, Pub. L. No. 95-209, 91 Stat., 1482 (1977).

[99]See NUREG 0410, January 1978 and NUREG 0510, January 1979.

[10]DMalsch dep. at 10-14,139-141.

[101]"Insufficient experience has been accumulated to permit the writing of detailed standards that would provide a quantitative correlation of all factors significant to the question of the acceptability of reactor sites. This part is intended as an interim guide to identify a number of factors considered by the Commission in the evaluation of reactor sites and the general criteria used at this time as guides in approving or disapproving sites."

[102]See, NRC, "Report of the Siting Policy Task Force," NUREG-0625, August, 1979.

[103]Some guidance is available in the Standard Review Plan and Regulatory Guides, but the General Design Criteria are so general that they provide a basis for a variety of interpretations that may change with time.

Case dep. at 235-236.

[105]NRC, *Federal Register, Vol.* 35, No. 5317, March 17, 1970.

[108]Angeb dep., Exhibits 1073-1078.

[107]See, NRC, *Federal Register, Vol.* 36, No. 22851, December 1, 1971. See also *Offshore Power Systems* (Floating Nuclear Plants) ALAB-489, 8 NRC 194 (1978),

reconsideration denied and cert. granted, ALAB-500, 8 NRC 323 (1978)). See also *Carolina Environmental Study Group v. A.E.C,* 510F.2d796, 798, 799 (D.C. Cir. 1975).

See The National Environmental Policy Act, Pub. L. No. 91-190, 83 Stat., 852 (1970).

See The Nuclear Nonproliferation Act, Pub. L. No. 95-242, 92 Stat., 120 (1978).

n°See "Does the Emperor Have Any Clothes," a speech by Chairman Ahearne (then Commissioner), September 11, 1979.

2. RELEVANT REGULATORY STAFF ACTIONS TAKEN OUTSIDE OF THE ADJUDICATORY PROCESS

a. Issuance of Operating License

The operating license for TMI-2 was issued on February 8, 1978.[1] Attachment 1 to the license included the technical specifications that delineated the operational requirements and limits for the facility. Attachment 2 contained a number of preoperational tests, startup tests, and other requirements that required completion by the licensee. The TMI-2 license contained a number of license conditions that required completion at some specific event or time, or at the outcome of some evaluation or proceedings.

The license was issued on the basis of the evaluation and approval of the Final Safety Analysis Report docketed in 1974 (including 62 amendments to the Report) and the environmental report as supplemented and amended (see Section I.B.1). The TMI-2 license application was managed by Light Water Reactor Branch 4, Division of Project Management (DPM). This was the first and only operating license issued through this Branch.[2]

After the license was issued, responsibility for TMI-2 was retained in DPM until August 1979.[3] Earlier attempts to transfer TMI-2 were rejected by the Division of Operating Reactors (DOR).[4] This is attributable to the lack of resources in both divisions,[5] and reflected DOR's refusal to assume responsibility for TMI-2 in view of the number of outstanding areas identified as license conditions.[6]

b. Amendments, Exemptions, and Modifications to the TMI-2 License

Amendments, exemptions, and modifications to the TMI-2 license as well as additional related staff actions are summarized below.

Amendment No. 1

In the interest of minimizing delays, technical specification requirements were waived, and hydrostatic testing of the primary coolant system was permitted at a lower system temperature prior to initial criticality. Hydrostatic testing of new pressure boundaries was required to test the pressure boundaries which resulted from plugging of steam generator tube sheets, replacement of reactor coolant pump gaskets, and installation of instrumentation in the steam generator. Requirements for hydrostatic testing are set forth in Appendix G to 10 C.F.R. Part 50. Appendix G does not, however, address testing conditions when fuel is loaded in the reactor vessel. Conformance to the technical specifications would have delayed the test until the unit had achieved operational mode 4 (hot shutdown) thereby allowing the reactor coolant conditions to meet the pressure and temperature requirements. The staff's safety analysis concluded that the fuel would not be subjected to conditions that might damage the fuel, and the testing was completed with the fuel in the vessel[7]

Amendment No. 2

This amendment removed license conditions that had been completed, revised other conditions, and added one condition. The following license conditions were satisfied and thus deleted, or were modifled to reflect agreements between the staff and the licensee:[8,9]

1. License paragraph 2.C.(3).b. The licensee had provided voltage and frequency variations resulting from a 500-kW load rejection from the diesel generators.
2. License paragraph 2.C.(3).1.1. Design details of an automatic water suppression system in each diesel generator room basement was submitted to the NRC as required.
3. Paragraph 2.C.(3).1.2. The licensee provided a firewater pipe rupture analysis and indicated that design of appropriate water spray protection would require further analysis (see 4 below).
4. Paragraph 2.C.(3).1.3. This condition was revised to assure that design of water spray protection features would be accomplished at a suitable later time and paragraph G.12. was added to the license to require installation of the automatic water suppression system.

With the exception of paragraph 2.C.(3).b, the above conditions all related to fire protection. Implementation of fire protection measures was not required until startup following the scheduled refueling outage in April 1980. This schedule appears to have been arbitrarily selected; the staff's safety analysis did not provide the basis for this or any other implementation schedule.

Authorization to Proceed to Operational Mode 4-Hot Shutdown

The licensee had completed paragraphs B.l and B.2 of Attachment 2 to license, which contained the testing requirements to be completed prior to entering mode 4. Accordingly, these paragraphs were deleted.[10]

Amendment No. 3

Amendment No. 3 reflected the fact that particular requirements had been satisfied and thus that the relevant license conditions were no longer required. These and the other revisions of this Amendment are discussed below:[11]

1. License paragraph 2.C.(3).c was deleted since the licensee had provided documentation of its proposal to permit utilization of smaller impellers in the reactor building emergency cooling booster pumps.
2. License paragraph 2.C.(3).d was deleted to reflect the licensee's provision of documentation demonstrating the adequacy of the net positive suction head for the reactor building spray pumps.
3. License paragraph 2.C.(3).e was deleted because the licensee had provided analyses defining the containment temperature response to a steam line break, and had justified the adequacy of environmental qualification temperatures of components inside containment.
4. Paragraph C.1 of Attachment 2 was revised to delete as requirements for entry into mode 2 three fuel handling system tests and to add a test of the reactor coolant waste evaporator. Technical specifications already required tests of the fuel handling equipment equivalent to those deleted here, and newly added paragraph 1 required a comparable test of the waste evaporator. Paragraph 1 was added to Attachment 2 to require this waste evaporator test. The testing procedure for the reactor coolant waste evaporator was delayed because part of the waste evaporafor was being used in TMI-1. During this time, the processing of radioactive waste for TMI-2 was performed by TMI-1. Postponement of this test permitted entry into mode 2 (startup) approximately 2 months ahead of schedule.
5. Paragraph C.5 of Attachment 2 was revised to clarify the required equipment alignment to assure that the emergency core cooling high pressure injection pumps would not empty the makeup tank in the event of a loss-of-coolant-accident. This measure was compensatory and had been required until redundant automatic makeup tank isolation valves were installed pursuant to license paragraph F.1A
6. Paragraph F.2 of Attachment 2 was revised to correct a typographical error. This paragraph, which was included as an original license condition, exempted the licensee from technical specifications for the hydrogen purge air cleanup systems. Evidently, charcoal in certain filters could not be changed to meet Regulatory Guide 1.52, Revision 1, "Design, Testing, and Maintenance Criteria for Post Accident Engineering Safety Feature Atmosphere Cleanup System Air Filtration and Absorption Units of Light-Water-Cooled Nuclear Power Plants." The exemption permitted operation until the first refueling, scheduled for April 1, 1980.

Authorization to Proceed to Operational Mode 2-Startup

A staff letter to Metropolitan Edison Company (Met Ed) authorized it to proceed to operational mode 2.[12] The licensee had completed the test requirements of paragraph C and G in Attachment 2 to the license required for startup. Completed items included test procedures, environmental-administrative procedures, various work list items, installation of makeup tank hydrogen isolation valves, and procedure revision.

Three Pump Operation

Metropolitan Edison notified the NRC by letter of March 29, 1978, of its intention to operate at power using only three of the four coolant pumps since the antirotational device had failed on the fourth pump.[13] Before the letter was sent, the reactor went critical on three pumps at reduced power, as authorized by the technical specifications. The Commission responded by requesting the licensee to analyze certain transients to document the safety margins for longer term operation.[14] Evidently, the staff determined, however, that short term operation was acceptable on the basis of similar analysis for other Babcock & Wilcox (B&W) plants because no analysis of that issue was requested.

The licensee informed the Commission on May 12, 1978 that the fourth pump had been repaired, extended operation with three pumps was not anticipated, and the operating margins need not be qualified. The Commission apparently agreed, because no NRC reply could be found in the docket files.

Authorization to Proceed to Operational Mode 1-Power Operation

By letter of April 7,1978, the Commission authorized Metropolitan Edison to proceed to power operation, because all of the items in Attachment 2 required to initiate this mode had been completed.[15] Those items were as follows:

1. Optimization of voltage levels at the safety-related bases and verification of such optimization (paragraph D.1).
2. Modification of the diesel generator air starting system to provide 10 starts (paragraph D.2).
3. Making the intermediate closed cooling water heat exchangers seismic Category I.

Relief from Testing Requirements

In response to Metropolitan Edison's request for relief from certain requirements of the inspection and testing requirements, as specified in Section XI of the ASME Boiler and Pressure Vessel Code and Addenda, the Commission granted relief pursuant to 10 C.F.R. Sec. 50.55a because "compliance would result in hardships and unusual difficulties without a compensating increase in the level of safety." The staff's safety analysis indicated that such relief was appropriate pursuant to 10 C.F.R. 50.55a(6)(i), and the relief granted encompassed the period from license issuance until the initiation of commercial operation (February 8 to December 30,1978).[16]

Amendment No. 4

As a result of two emergency core cooling system injection occurrences where sodium hydroxide was inadvertently and unnecessarily injected into the reactor coolant system, the licensee requested and received approval to change the actuation signals to the controlling value for the sodium hydroxide tank. In addition, Amendment No. 4 responded to a B&W finding that the incore nuclear detectors for indicating quadrant tilt and axial imbalance possessed more uncertainty than initially assumed. Although the staff had not fully completed its review of B&W analysis, they approved the proposed changes to the alarm setpoints for quadrant tilt limits.[17]

Amendment No. 5

Technical specifications were changed to reflect testing of the control rod handling mechanism for loads within its design specifications. The original technical specifications for determining the limiting condition for operation (LCO) required that the control rod hoist be tested with the same loading capacity as the fuel assembly hoist. The safety analysis concluded, however, that the control rod handling mechanism could be tested for different loadings than required for the fuel assembly handling mechanism, and Amendment No. 5 reflected that determination.[18]

Deletion of Pseudo Rod Ejection Test

In response to Metropolitan Edison's request to delete this test from the TMI-2 startup and test program because of unnecessary radwaste and consumption of 24 hours of time that could be used more productively,[19] the NRC eliminated this requirement.[20] The staff approved Metropolitan Edison's technical justification based on similar tests at the Davis Besse and Rancho Seco plants and verification of the prediction models based on these data. The same models were used in the safety analysis of TMI-2.

Amendment No. 6

The license was amended to permit a number of changes:[21]

1. Alternate procedures for containment air lock leak rate testing.
2. Plant operation with an increase in ultimate heat sink temperatures from 88° to 98°F. The upper limit temperature was limited to 90°F, however, until the impellers in the control building booster pumps were changed to produce more flow and, inturn, provide adequate cooling to the control building air conditioning equipment.
3. Removal of most of the orifice rod assemblies and the installation of retainers on the remaining assemblies and on the burnable poison rod assemblies. The core flow technical specifications had to increase to compensate for increased bypass flow due to removal of the assemblies and the addition of the retainers. As a result of these changes, the operating margin in flow rate between measured and technical specification requirements was reduced from 5 to 3%. The accuracy of the flow instrumentation is important to ensure this margin. The flow measurement system and its calibration was approved by the NRC based on the measurement uncertainty for the same system in TMI-1 of 1.5%, which resulted in a net operating margin of 1.5%. On the basis of this small margin, the staff probably should have required measurement of the uncertainty in TMI-2, but they did not.

4. Replacement of the 12 steam safety valves resulted from the failure of these valves to reseat during a previous transient. Twenty smaller safety valves were installed, which provided 6% more flow than the original valves.
5. An increase in the reactor coolant system low pressure trip setpoint from 1800 to 1900 psig. The reactor coolant system low pressure trip setting was changed primarily to increase operating flexibility and to reduce unnecessary high pressure injection actuation of the emergency core cooling system.
6. Miscellaneous revisions of the technical specifications to reflect correctly the rod bow penalty and the addition of allowable valves of instrumentation inaccuracies into the channel function test acceptability requirements.

Amendment No. 7

This amendment deleted environmental license conditions that had been completed by the licensee. The deletions included a creel survey and aerial remote sensing requirement. Amendment No. 7 also reflected an administrative change in the Appendix B technical specification.[22]

Amendment No. 8

This change in the technical specification permitted operation at reduced power levels with reduced reactor coolant system flow. Previously, the technical specification required design flow rate regardless of the reactor power level.[23]

Amendment No. 9

This amendment incorporated the modified Metropolitan Edison's amended physical security plan into the license.[24]

Orders for Modification of License

Orders for modification of license were issued on May 26, 1978[25] and October 13, 1978.[26] In accordance with 10 C.F.R. Part 21, on April 12, 1978, B&W reported a safety concern regarding small break loss-of-coolant-accident (LOCA) analyses to the NRC. A small break LOCA at the pump discharge with an accompanying single failure was calculated by B&W to be more limiting than the small break identified previously as the worst-case small break LOCA pursuant to the ECCS Evaluation Models set forth in Appendix K to 10 C.F.R. Part 50. After analyses and submissions by B&W and the licensee, the Commission adopted B&W's and Metropolitan Edison's proposed solution by issuing an order for modification of license on May 26, 1978, which amended the TMI-2 operating license to restrict power to 2568 MW. The other B&W plants whose operating licenses were similarly modified were Oconee 1, 2, and 3, TMI-1, Arkansas Nuclear 1, Crystal River 3, and Rancho Seco.

When it notified the Commission of the problem recognized by B&W, Metropolitan Edison indicated that authorization to operate at a power level of 2568 MW was sufficient to respond to this matter, and that no further corrective action should be required. The Commission's modifications of the TMI-2 operating license adopting this approach is questionable for reasons discussed below.

As part of its justification to operate at this reduced power level, Metropolitan Edison indicated that the control room operator was trained to recognize the symptoms and drilled to respond to a small break LOCA. Instruments indicating the pressurizer level and pressure-both nonsafety-related equipment-were identified by the licensee as the control room instrumentation to be used by the operator to ascertain the small break LOCA symptoms and thus to initiate corrective action. The licensee further indicated that no operator actions would be required if the power level was further reduced to less than 63% of full power, or 1764 MW.

The Commission's acceptance of Metropolitan Edison's justification for operation at 2568 MW was inconsistent with the general staff position that no safety credit was to be given for operator actions that are required within 10 minutes of the accident and that nonsafety grade equipment cannot be relied on to mitigate an accident. The solution advanced by the licensee and accepted by the Commission in part assumed that, within *2 minutes* of the accident, the operator would analyze his instrumentation and determine whether there was a loss of offsite power concurrent with a diesel or makeup pump failure and a small break LOCA. In the event the operator recognized such an occurrence, it was further assumed that an auxiliary operator would be directed to the auxiliary reactor building to open cross current valve between high pressure injection trains and, while in communication with the control room operator, manually open the two other valves to obtain a certain flow rate through each valve. During this time, the control room operator would be required to verify that the normal makeup valve was closed. If all this occurred, the required flows would be established within 10 minutes after the actuation signal for the emergency core cooling system.

Subsequent experience with operator reactions at TMI-2 demonstrate that these assumptions were faulty. In addition, the NRC staffs safety analysis indicated that there was some uncertainty concerning other assumptions employed in the B&W analyses. The safety evaluation stated:

> [We] [NRC staff] cannot conclude at this time that operation of TMI-2 at 2568 megawatts thermal would be fully in conformance with 10 CFR Part 50.46. On the other hand, the range of calculations now available shows that for operation of this facility at power levels up to 2568 megawatts thermal, ECCS performance calculations for the limiting small break indicate that this break has a very substantial margin on peak clad temperature below the limits of 10 CFR Part 50.46(b) if appropriate operafor action is property taken (as described above).[•0]

On October 13, 1978, the NRC issued the second order for modification which superseded its order of May 26, 1978. This second order specified that the power level could be increased to the maximum authorized reactor power level of 2772 MW. As part of the effort to justify operation at the maximum power level, changes to a previously NRC approved ECCS evaluation model were requested by B&W and subsequently accepted by the NRC; this extended the time within which operator action was initially required. Although the order stated that "continued reliance on operator action to perform the required steps to ensure plant safety on a permanent basis is undesirable ... ", the staff had not reviewed the licensee's proposal of schedule for a permanent solution, and it did not form the basis for any evaluation supporting the order. Although this second order directed the licensee to undertake ECCS modifications to eliminate future reliance on prompt operator actions in accordance with an approved schedule, it reiterated the Commission's approval of the same operator actions for mitigating the small break LOCA approved in the first order.

The permanent modifications that would eliminate prompt operator action were approved for TMI-2 on December 8, 1978.[27] These permanent modifications were scheduled to be completed during the first refueling outage scheduled for April 1980.

The same issue was considered for TMI-1. By letter of November 21, 1978,[28] the licensee requested that the NRC grant an extension of the exemption to 10 C.F.R. Part 50.46 for TMI-1 until early 1980. This extension would be one year after the scheduled refueling outage in February 1979. During this one year extension, the licensee proposed to continue to rely on operator actions as described. On March 16, 1979, NRC approved this request based on, among other considerations, the financial penalty imposed on the licensee if the modifications were performed at an earlier date than during the next refueling stage. The justification cited by the NRC for the extension included:

> The public interest is served by issuing this exemption for TMI-1 in that in the absence of an exemplion, shutdown of the facility would be required. Loss of the large block of generating capacity could adversely affect electric system reliability and thus possibly adversely affect the public.

c. **Pending Regulatory Actions**

The following technical specification change requests (TSCR) were submitted by the licensee for NRC review and approval as of March 29,1979:

- TSCR #003-re: The adequacy of patrolling fire watches vs. continuous watches.
- TSCR #006-re: Miscellaneous changes to the administration section of TMI-2 technical specifications.
- TSCR #016-re: Defeating fast transfer of station balance of plant loads upon the failure of an auxiliary transformer.
- TSCR #17-re: Operability of control rod reed switch position indicator channels.
- TSCR #10-re: Frequency for performing heat balances.

In addition, Commission had received requested submissions regarding the licensee's proposed course of action in several areas, including the following:

1. Reactor Building Purge Valve Analysis - NRC Request, 11/29/78; Met Ed Response, 3/16/79
2. Single Auxiliary Transformer-Operation NRC Request, 8/18/78 (verbal); Met Ed Response, 8/29/78
3. Inservice Instrumentation- Met Ed Submission, 7/25/79

d. Status of Pertinent Commitments to the Regulatory Staff

The following lists the status of Metropolitan Edison's commitments to provide information to the Commission and to[32] take other specified actions as of March 29,1979.

Environmental Qualification of Electrical Components-IE Bulletin 79-01

Review was completed by the licensee before March 27, 1979. The response was being prepared for submission to the NRC.

Small Break LOCA Piping Crossconnect

Work was progressing toward installation of this equipment at the first scheduled refueling outage in April 1980.

Feedwater Isolation Valves

Work was progressing toward installation of safety grade equipment at the first refueling outage. Specifically, analyses were being performed to demonstrate design adequacy. The NRC had performed a preliminary design review and had approved the design concept, but had requested the design adequacy analyses before issuing a formal design acceptance. Modification of the main steam and feedwater systems is required by paragraph 3(i) of the operating license.

Asymmetric LOCA Loads

Work was progressing toward completion of the analysis in June of 1980. B&W analyses of cavity loadings and vessel/vessel internals loading was in progress.

IE Bulletins

Work was underway to investigate the applicability of the concerns raised in IE Bulletin 79-02-"Pipe Support Base Plates" (issued March 8, 1979)-and Bulletin 79-03-"Longitudinal Pipe Welds" (issued March 13, 1979)-which were submitted to TMI-1 and TH-2. The architect-engineering firm for each unit had been instructed to investigate the extent to which IE Bulletin 79-02 applied. This investigation was underway but had not been completed. The licensee had determined that IE Bulletin 79-03 was not applicable to TMI-2, but the investigation for applicability for TMI-1 had not been completed.

Security

The TMI security plan had been approved, and work was underway to implement some security systems. However, compensatory actions approved by the NRC were in effect.

License Conditions

The TMI-2 operating license stipulated that certain items should be completed within a specified time frame. Several items had been completed before March 27, 1979, and work was continuing on the remaining items within the time periods initially set forth in the operating license. A discussion of the items that had not yet been completed follows.

The operating license required Metropolitan Edison to take the following actions before startup following the first regularly scheduled refueling:

1. Provide a second level of voltage protection for the onsite power system.
2. Modify the system design to automatically prevent load shedding of the emergency buses once the onsite sources are supplying power to all sequence loads on the emergency buses. This load shedding feature was required to have the capability of being automatically reinstated if the onsite source supply breakers are tripped.
3. Provide recommended technical specifications for items (1) and (2) specified above, including test requirements to demonstrate the full functional operability and independence of the onsite power sources.
4. Install an environmental temperature monitoring system to ensure that the environment at the location of Class IE equipment in buildings outside containment is maintained within the temperature range for which the equipment is designed to operate.
5. Submit appropriate descriptions and analyses and modify the secondary (main steam and feedwater) systems so that the consequences of a spontaneous break anywhere in a secondary system line will be mitigated only by safety grade equipment, with nonsafety grade equipment permitted to serve as a backup for the equipment. For assumed single failure of safety grade portions of the secondary systems where a break might be caused by a seismic event, Metropolitan Edison Company was required to modify the systems so that accident consequences will be mitigated only by seismic Category I components after assuming single failure in any seismic Category I component.
6. Submit and implement a response time testing program for the protection system.
7. Modify the reactor coolant pressure boundary overpressure protection system to satisfy Commission requirements regarding credit for operator action, single failure criteria, testability, seismic design, and IEEE-279 criteria, and effect on reliability of other safety systems.
8. Complete modifications necessary to achieve the capability to shut down the plant safely and independently of cabling and equipment in the cable spreading room, and add either a manually operated fixed water system in the cable spread-

ing room, or fire retardant insulation around each cable tray in the cable spreading room not readily accessible to a manual fire hose stream so that no fire would be expected to affect redundant safety trains.

9. For all fire doors, provide electrical fire door supervision with time delayed alarms in a constantly manned area, lock the doors closed, or provide acceptable hold-open features for identified doors designed to close in the event of a fire.

Attachment 2 to license required that the following activities be completed before startup after the first regularly scheduled refueling outage:

1. Provide redundant automatic safety grade makeup tank isolation valves (MU-V-12) actuated by an d engineered safety features signal.
2. Replace the charcoal in the filters in the following systems so that the requirements of the indicated Appendix A technical specifications will be met.

System	*Technical Specification*
Hydrogen Purge Air Cleanup	4.6.4.3.b.2, 4.6.4.3.c
Control Room Emergency Air Cleanup	4.7.7.1.c.2, 4.7.7.1.d
Fuel Handling Building Air Cleanup	4.9.12.b.2, 4.9.12.c

Pending such charcoal replacement, Metropolitan Edison Company has been exempted from compliance with the above technical specifications.

3. Provide an automatic water suppression system in each diesel generator room basement.

e. Findings

1. The TMI-2 license contained a number of safety-related conditions that were not required by the staff to be completed before the issuance of the operating license. Apparently no NRC criteria exist for the number or kind of outstanding issues that are permitted when a license is issued.
2. The NRC approved operator action to mitigate a small break loss-of-coolant-accident for B&W plants was questionable. The time (2 minutes) available to the operator to identify the accident is insufficient, and the information to which the operator was expected to respond is provided by nonsafety-related instrumentation.
3. The transfer of TMI-2 and other plants from the Division of Project Management to the Division of Operating Reactors is not timely. Consequently, responsibility for part of the most important operating history-preoperational and startup testing-is not vested in the appropriate NRC Division of Operating Reactors.

REFERENCES AND NOTES

[1]Three Mile Island Nuclear Station Unit 2, Facility Operating License, License No. DPR-73, February 8, 1978.

[2]Varga dep. at 19.

[3]Memorandum from D. Vassallo, NRC, to D. Eisenhut, "Transfer of THREE MILE ISLAND NUCLEAR STATION, UNIT 2 (TMI-2) to Operating Reactors," August 22,1979.

[4]Varga dep. at 31.

[5]Vassallo dep. at 38; Varga dep. at 31.

[6]Memorandum from V. Stello, NRC, to D. Vassallo, "Transfer of TMI-2 to DOR," September 26, 1978. The same responses existed for delayed transfer of Davis Besse, Unit I from Division of Project Management to Division of Operating Reactors for 18 months. Vassallo dep. at 35.

Letter from S. Varga, NRC, to J. Herbein, Met Ed, Subject: Three Mile Island Nuclear Station, Unit 2-Issuance of Amendment to Facility Operating License, dated March 3, 1978.

[8]Letter from S. Varga, NRC, to J. Herbein, Met Ed, Subject: Three Mile Island Nuclear Station, Unit 2-Issuance of Amendment to Facility Operating License, dated March 10, 1978.

[9]Memorandum from H. Denton, NRC, to Commissioner Ahearne, "Evolution of TMI-2 Operating License," July 2, 1979.

[10]Letter from R. Boyd, NRC, to J. Herbein, Met Ed, Subject: Three Wile Island Nuclear Station, Unit 2-Authorization to Proceed to Operational Mode 4, dated March 10, 1978.

[11]Letter from R. Boyd, NRC, to J. Herbein, Met Ed, Subject: Three Mile Island Nuclear Station, Unit 2-Issuance of Amendment to Facility Operating License, dated March 24, 1978.

[12]Letter from R. Boyd, NRC, to J. Herbein, Met Ed, Subject: Three Mile Island Nuclear Station, Unit 2-Authorization to Proceed to Operational Mode 2, dated March 25, 1978.

[13]Letter from J. Herbein, Met Ed, to S. Varga, NRR, Subject: Power Operation with Three Reactor Coolant Pumps, dated March 29,1978.

[14]Letter from S. Varga, NRC, to J. Herbein, Met Ed, Subject: TMI-2 Partial Loop Operation, dated May 3, 1978.

[15]Letter from R. Boyd, NRC, to J. Herbein, Met Ed, Subject: Three Mile Island Nuclear Station, Unit 2-Authorization to Proceed to Operational Mode 1, dated April 7,1978.

[16]Letter from S. Varga, NRC, to J. Herbein, Met Ed, Subject: Respond Inservice Testing Program for Pumps and Valves for Three Mile Island Nuclear Station Unit 2 (TMI-2), dated April 21,1978.

[17]Letter from S. Varga, NRC, to J. Herbein, Met Ed, Subject: Three Mile Island Nuclear Station, Unit 2-Issuance of Amendment to Facility Operating License, dated May 19,1978.

Letter from S. Varga, NRC, to J. Herbein, Met Ed, Subject: Three Mile Island Nuclear Station, Unit 2-Issuance of Amendment to Facility Operating License, dated June 5,1978.

[19]Letter from J. Herbein, Met Ed, to Director of Nuclear Reactor Regulation, NRC, Subject: Psuedo Ejected Rod Test Delection, dated May 19,1978.

[20]Letter from S. Varga, NRC, to J. Herbein, Met Ed, Subject: Deletion of Psuedo Rod Ejection Test at TMI-2, dated June 12, 1978.

[21]Letter from S. Varga, NRC, to J. Herbein, Met Ed, Subject: Three Mile Island Nuclear Station, Unit 2-Issuance of Amendment to Facility Operating License, dated August 17,1978.

[22]Letter from J. Davis, NRC, to J. Herbein, Met Ed, Subject: Three Mile Island Nuclear Station, Unit 2-Issuance of Amendment to Facility Operating License, dated September 5,1978.

[23]Letter from S. Varga, NRC, to J. Herbein, Met Ed, Subject: Three Mile Island Nuclear Station, Unit 2-Issuance of Amendment to Facility Operating License, dated December 15, 1978.

[24]Letter from S. Varga, NRC, to J. Herbein, Met Ed, Subject: Three Mile Island Nuclear Station, Unit 2-Issuance of Amendment to Facility Operating License, dated February 23, 1979.

[25]Letter from S. Varga, NRC, to J. Herbein, Met Ed, Subject: Transmitting Order for Modification of License, dated May 26,1978.

[26]Letter from S. Varga, NRC, to J. Herbein, Met Ed, Subject: Transmitting Order for Modifications of License, dated October 13, 1978.

[27]Letter from R. Reid, NRC, to J. Herbein, Met Ed, Subject: Facility Modifications to Eliminate Reliance on Operator Action Following a Small Break LOCA, dated December 8,1978.

[28]Letter from J. Herbein, Met Ed, to R. Reid, NRC, Subject: Small Break LOCA Long Term Modification, dated November 21, 1978.

[29]Letter from R. Reid, NRC, to J. Herbein, Met Ed, Subject: Three Mile Island Nuclear Station, Unit (-Issuance of Amendment to Facility Operating License, dated March 16,1979.

[30]NRC, "Modifications of Conditions of Exemptions," *Federal Register, Vol.* 44, No. 63, March 30,1979.

[31]Letter from J. Herbein, Met Ed, to M. Rogovin, NRC/SIG, Subject: Ref. NTFT M790626-01, at 7, dated July 9,1979.

[32]1d. at 10.

3. OTHER RELEVANT MATTERS

a. Regulatory Requirements Review Committee

Background

The Regulatory Requirements Review Committee (RRRC) was established in March 1974 by the Atomic Energy Commission's director of regulations to review new regulatory requirements and changes to current requirements and to determine whether, when, and where these changes in requirements should be applied.[2] This and other aspects of the Commission's regulatory program were prompted in part by industry charges that changes in regulatory requirements that were not needed for safety were being imposed by the regulatory staff without management review or control. The industry charged that this process, which was generally referred to as "ratcheting," imposed new requirements on previously approved designs and previously established licensing criteria. Industry officials also charged that the "ratcheting" process substantially contributed to the long delays in the granting of some construction permits and operating licenses. Thus the review committee was established to contribute to a more systematic approach to determining when to impose new requirements on plants at various stages in the licensing process.

In addition, other aspects of the regulatory program for controlling ratcheting included staff reorganization along technical disciplinary lines, publication of a regulatory guide for the format and content of safety analysis reports, revisions to regulatory guides for promulgating new staff positions, and the development of Standard Review Plans[3] defining all safety requirements which must be satisfied during the review process. The regulatory program objective was never intended to eliminate ratcheting. Instead, it was designed to stabilize the licensing process and to assure that any ratcheting that did occur was done with the knowledge and approval of senior management within the Commission staff. The overall objective was that the implementation of the NRC's standardization policy in conjunction with the discipline imposed by the RRRC would stabilize the designs provided by industry and the regulatory requirements established by the Commission.

The charter membership of the committee consisted of five senior management representatives of the NRC. The chairman and two of the other members were from the licensing staff, one member was the head of the inspection and enforcement staff, and the other was the head of the standards organization. The chairman and all of the members were appointed by the director of regulation. The members' participation reflected their personal views as opposed to those of their respective organizations.[4] In 1975, when the Nuclear Regulatory Commission was formed to replace the Atomic Energy Commission, the RRRC began to report to the Executive Director for Operations (EDO), and its membership increased to reflect the significant managerial and functional changes. The Offices of Standards Development and Regulatory Research had single representatives, and the Office of Inspection and Enforcement had two representatives. However, with the chairman and four other representatives, the Office of Nuclear Reactor Regulation (NRR) retained a majority of the voting members. The RRRC organization also included a SeCretary to organize and record the minutes of the meetings and a technical representative from the office of the Executive Director, both of whom were nonvoting members.[5] The voting members of the RRRC had senior management responsibilities in the NRC, and their participation in the committee was of necessity limited to attendance and some preparation for the meetings. No permanent staff was assigned to the RRRC to assist in assessing the matters under consideration or in monitoring the implementation of its recommendations when approved by the director of NRR.[6]

The recommendations of the RRRC are determined by the majority vote, based largely on informed engineering judgments of its members.[7,8] The material submitted to the RRRC for its review includes a technical description for the proposed change, a discussion of the need for the change, and the value-impact assessment which includes a recommended process for implementing the change, if approved. The value-impact assessment of new or revised requirements is prepared by the branch or groups originating the change in requirements proposed by the committee. This assessment addresses the value and impact of the requirement on the NRC, the industry, and the public from both an economic and a safety perspective.

The value-impact assessment provides a source of information in the decision process.[9] However, because of the generally poor quality of these assessments, their contribution is minimal. Determinations of the RRRC still largely reflect the individual judgment of the members, informed by general opinions, background, and knowledge they obtain from other sources. Industry has criticized these value-impact statements,[11] and the committee itself has frequently referred an issue back to the staff because of their inadequacies. Finally, although the value-impact statement contains a recommendation for implementing the issue, the RRRC does not have its own guidance or criteria available to its members to cast their votes in categorizing the issue.[8]

In reaching a decision to backfit requirements to existing plants, the RRRC relies on the criteria[4] in 10 C.F.R. 50.109, Backfitting. As a practical matter, however, this section of the regulations does not provide sufficient guidance for backfitting deck sions.[12] "Other than the hortatory feelings it creates, it's meaningless."[8] The committee does not document the guidance or criteria its members use in casting their votes. Moreover, although a summary of the meeting and the RRRC decisions was transmitted in a memorandum to the EDO, the chairman of the committee testified that he was uncertain of any action taken as a result.13

Discussion of Operation

The RRRC considers matters having a potential for substantial impact on virtually all phases of the licensing process of nuclear plants. The committee's recommendations reflect its view of how the issues, if approved by the director of NRR, should be implemented by the staff. Its implementation categories were defined for regulatory guides in 1975 in meeting number 31,[14] which subsequently was adopted for all issues considered by the RRRC.

The committee's options are to reject or defer the proposed changes altogether or to determine an implementation schedule for them. RRRC decisions to implement particular requirements rather than to reject or defer them are classified in the following categories:

Category I-Clearly forward fit only by implementing the change only on current and future applications. No further. staff consideration of possible backfitting is required.

Category II-Further staff consideration of the need for backfitting appears necessary for certain identified items of the regulatory position. A category 11 determination reflects the judgment that existing plants should be evaluated to determine their status with regard to these safety issues and to determine the need for backfitting on existing plants, designs and sites on a "case-by-case" basis.

Category III-Clearly backfit to apply the proposed change to existing plants, designs and sites. Existing plants should be evaluated to determine whether identified items of the regulatory position are resolved in accordance with the guide or by some equivalent alternative.

An issue is usually placed in category II when it cannot be clearly categorized as a category I or III. For example, if sufficient information is not available or if the benefits and requirements for certain parts of a regulatory guide cannot be ascertained, the issue is placed in category II. While this practice prevents delay in publishing the guide,[15] it also leaves its implementation to individual staff interpretations, thus creating the potential for *ad hoc* ratcheting and allowing the very kind of uncontrolled escalating regulatory requirements that the committee was created to minimize. In addition, matters involving categories 11 and III caused confusion among staff members when the manner and schedules for their implementation were taken into consideration. As a result, some category 11 items have not been implemented by the staff.[16]

Although category III mandates the backfitting of a particular requirement, there appears to be no direct relationship between a category III determination and the regulatory backfit requirement in 10 C.F.R. 50.109 that this "additional protection ... is required for the public health and safety." The absence of criteria allows considerable RRRC flexibility in judging the improvement in safety for a category III issue.[17] Furthermore, the NRR has established its own category IV classification for regulatory requirements that are considered by both an NRR division director and the office director to be of sufficient potential safety importance to warrant regulation of applicants and licensees before review by the RRRC.[18,19] These category IV requirements are to be submitted for RRRC review as promptly as practical. Obviously, this dilutes the RRRC's overall control at the ratcheting process. Because applicants theoretically cannot be required to comply with the category IV requirement if it is later deemed to be of lesser significance by the eventual RRRC decision, they generally try to avoid a timely response to a category IV requirement, hoping for an outcome more favorable to their position.

The independence of NRR in deciding to implement the committee's category requirements further dilutes the committee's authority. In some cases, the director of NRR has chosen not to implement some RRRC decisions.[20] In other cases, staff limitations have prevented implementation of other RRRC decisions,[21] which have been approved by the director of NRR.

Although the committee initially was established to maintain a stable baseline of regulatory requirements, it has evolved as the focal point for controlling racheting requirements during the licensing process.[22]

The committee's categorization of regulatory guides applies to the regulatory position section of the guide but is not published in the implementation section of the guide. The regulatory position section contains the NRC requirements and the implementation section indicates how the guide is supposed to be applied in the licensing process. However, the RRRC had decided in 1975 that the implementation section should address only the relevance of the guide to new applications. Consequently, the applicants and licensees were not apprised of the actual implementation to be effected by the staff for reviewing ongoing applications or for licensed facilities or approved designs. Representatives of the utilities and vendors complained that the staff's actions in imposing the regulatory positions did not reflect what was specified in the implementation section.[23]

In response to industry concerns that they were not afforded notice of, or opportunity to comment, or participate in the RRRC's decisions, the committee's operating procedures were changed to provide an opportunity for public input. Beginning in early 1979, the subject matters to be considered by the RRRC are published in the Federal Register and the supporting information (e.g., value-impact statements) is made available to the public. A period of time, usually 60 days, is provided for public comment. After the comment period, the RRRC considers the matter. The positions recommended by the RRRC and approved by the director of NRR are then published and an opportunity is afforded for appeal.[24] Approved RRRC recommendations are not usually effective until 30 days after they are published.

Neither the NRC nor the RRRC has established any procedures for ensuring that approved committee recommendations are implemented.[25] Generally, the NRC office involved in the decision has the responsibility for its implementation. For example, a change to a regulation is the responsibility of the director of the Office of Standards Development; a change in licensing criteria is the responsibility of the director of NRR. Because the division directors are committee members and a summary of the committee's meetings is distributed to the assistant directors of the divisions and to other NRC managers, the Commission may assume that implementation will be initiated and completed by individuals responsible for particular requirements.[26] In practice, however, the implementation of approved RRRC recommendations is far from uniform.

The first systematic program to implement approved RRRC recommendations was initiated in 1978 by the Division of Project Management (DPM), which developed a program to ensure that category II and III requirements were implemented for plants, applications, and designs within their scope of responsibility. The Division of Operating Reactors (DOR) likewise assured implementation of these requirements for all other operating plants and for plants scheduled for operation in 1978.[27] Previously, only category I issues had been implemented by the staff as additional regulatory requirements.

General implementation problems remain, however, as is illustrated by the fate of Regulatory Guide 1.97, "Instrumentation for Light-Water Cooled Nuclear Power Plants to Assess Plant Conditions During and Following an Accident." This revision to plant safety standards, which in light of the accident at Three Mile Island should be applied to existing plants, was deleted from the list of category II issues to be reviewed by the Systematic Evaluation Program branch of the DOR. According to a memorandum circulated among branch members 9 days after the accident at TMI-2, the change was not made to the NRC requirements due to a lack of implementation guidance.[28] Moreover, revisions to the safety requirements of only 11 plants (none of which is B&W design) are presently under review by the Systematic Evaluation Program.

RRRC Actions

Because the RRRC began categorizing regulatory requirements in 1975, 22 have been classified as category II (Table 1-2) and 8 as category III (Table I-3). The remaining regulatory guides and revisions and branch technical positions, some 200 in number, were classified as category I items.

A number of issues that were either classified as a category I item or were not reviewed and approved by the RRRC may warrant reconsideration in view of the accident at TMI-2. Illustrative examples of these issues are contained in Table 1-4.

Findings

1. The function of the Regulatory Requirements Review Committee is an important part of NRC's program to control the development of new regulatory requirements. Because of the need to change regulatory requirements as the technology of risk assessment and of nuclear power plant design develops, the function assigned to the RRRC is important and must be strengthened.

TABLE 1-2. List of category II recommendations

No.	Item	Subject
1	FIG 1.27, Revision 2 (1/76)	Ultimate Heat Sink for Nuclear Powerplants
2	FIG 1.52, Revision 1 (7/76)	Design, Testing, and Maintenance Criteria for Engineered Safety-Feature Atmosphere Cleanup System Air Filtration and Adsorption Units of Light-Water-Cooled Nuclear Powerplants
	NOTE: Revision 2, Category I (7/77)	
3	RG 1.59, Revision 2 (8/77)	Design Basis Floods for Nuclear Powerplants
4	RG 1.63, Revision 2 (11/77)	Electric Penetration Assemblies in Containment Structures for Light-Water-Cooled Nuclear Powerplants
5	RG 1.68, Revision 1 (1/77)	Initial Test Programs for Water-Cooled Reactor Powerplants
6	RG 1.91, Revision 1 (Draft) 12/77)	Evaluation of Explosions Postulated to Occur on Transportation Routes Near Nuclear Powerplants
7	RG 1.97, Revision 1 (8/77)	Instrumentation for Light-Water-Cooled Nuclear Powerplants to Assess Plant Conditions During and Following an Accident
8	RG 1.100 (3/76)	Seismic Qualification of Electric Equipment for Nuclear Powerplants
9	FIG 1.102, Revision 1 (10/76)	Flood Protection for Nuclear Powerplants
10	RG 1.105, Revision 1 (11/76)	Instrument Setpoints
11	RG 1.108, Revision 1 (8/77)	Periodic Testing of Diesel Generators Used as Onsite Electric Power Systems at Nuclear Powerplants
12	RG 1.115, Revision 1 (7/77)	Protection Against Low-Trajectory Turbine Missiles
13	RG 1.117, Revision 1 (10/77)	Tornado Design Classification
14	RG 1.118 (6/76)	Periodic Testing of Electric Power and Protection Systems
15	FIG 1.124, Revision 1 (1/13/78)	Service Limits and Loading Combinations for Class 1 Linear Type Component Supports
16	RG 1.130 (7/77)	Design Limits and Loading Combinations for Class 1 Plate-and-Shell-Type Component Supports
17	RG 1.137 (1/18/78)	Fuel Oil Systems for Standby Diesel Generators
18	RG 8.8, Revision 2 (3/77)	Information Relevant to Ensuring that Occupational Radiation Exposures at Nuclear Power Stations Will Be As Low As Is Reasonably Achievable
19	BTP APCSB 9.5.1 (8/76)	Guidelines for Fire Protection for Nuclear Powerplants Under Review and Construction
20	BTP MTEB 5-7 (7/77)	BWR Coolant Pressure Boundary Piping

TABLE 1-2. List of category II recommendations-Continued

No.	Item	Subject
21	RG 1.141 (Draft) (4/78)	Containment Isolation Provisions for Fluid Systems
22	SRP 5.4.7 Revision (1/78)	Residual Heat Removal System

TABLE 1-3. List of category III recommendations

No.	Item	Subject
1	RG 1.39 Revision 1	Housekeeping Requirements for Water-Cooled Nuclear Powerplants
2	RG 1.56, Revision 1 (1/78)	Maintenance of Water Purity in Boiling Water Reactors
3	RG 1.68.2 (1/77)	Initial Startup Test Program to Demonstrate Remote Shut-down Capability for Water-Cooled Nuclear Powerplants
4	RG 1.99, Revision 1, (4/77)	Effects of Residual Elements on Predicted Radiation Damage to Reactor Vessel Materials
5	RG 1.101, Revision 1 (3/77)	Emergency Planning for Nuclear Powerplants
6	RG 1.114 Revision 1 (11/76)	Guidance on Being Operator at the Controls of a Nuclear Powerplant
7	RG 1.121 (8/76)	Bases for Plugging Degraded PWR Steam Generator Tubes
8	RG 1.127 Revision 1	Inspection of Water-Control Structures Associated with Nuclear Powerplants

TABLE 1-4. Illustrative examples relevant to the TMI-2 accident

1. Regulatory Guide 1.97, Revision 1 - *Instrumentation for Light Water Cooled Nuclear Powerplant Conditions During and Following an Accident.*

   This was categorized as Category II for operating plants.

2. Revisions to Reactor Systems Branch Technical Position - "Reactor Coolant Systems Overpressurization Protection."

   RRRC recommended giving credit for operator action and did not require mitigating equipment to be "safety related." It was not required to be backfitted to operating plants.

3. Regulatory Guide 1.7, Revision 2 - *Control of Combustible Gas Concentrations in Containment Following a Loss-of-Coolant Accident.*

   This guide and associated change to 10 CFR 50 was categorized as Type 1 - no backfit. Provisions would require measurement, mixing, and dilution of atmosphere.

4. Regulatory Guide 1.141 (for comment) - *Containment Isolation Provisions for Fluid Systems.*

   Categorized as a Type II. It would include requirements for diverse actuation signals for containment isolation, leak testing, and valve position indication in control rooms.

TABLE 1-4. Illustrative examples relevant to the TMI-2 accident-Continued

5. Revision to Branch Technical Position, RSB-5-1 - "Design Requirements of the Residual Heat Removal System."

   Categorized as Type II. It would eliminate susceptibility of operating reactors to single failures in the Residual Heat Removal System.

6. Regulatory Guide 1.101, Revision 2 - *Emergency Planning for Nuclear Power Plants.*

   Revision 2 was not considered by RRRC (insignificant changes). Revision 1 to the guide was Category II. The original regulatory guide was a Category III.

7. Amendment of 10 CFR 50 to require *Periodic Updating* of *FSAR's* (2/27/76).

   Referred back to staff for additional clarification and definition. Requirement has not been subsequently considered.

8. Regulatory Guide 1.105, Revision 2 - *Instrument Spans and Setpoints.*

   Revision 2 to the guide was categorized as Type II in December 1976. Revision 1 was categorized as Type I in June 1976 although instrumentation out of conformance to Technical Specifications Limits was the most frequent abnormal occurrence between 1972 and 1973.

9. Evaluation of Technical Competence of Utility Applicants.

   Issue was referred back to the staff without discussion in 1974. This issue has not subsequently been considered.

10. Regulatory Guide 1.63, Revision 2 - *Electrical Penetration Assemblies in Containment Structures for Light Water Cooled Nuclear Power Plants.*

    Categorized as Type II. The requirement would assure that containment leak design rate is not exceeded during a LOCA.

11. Regulatory Guide 1.52, Revision 2 - *Design, Testing and Maintenance Criteria for Engineering* Safety *Feature Atmosphere Cleanup* System *Air Filtration and Adsorption Units of Light Water Cooled Nuclear Power Plants.*

    Revision 1 was categorized as Type 11. Revision 2 was characterized as Category I. Requirements contribute to meeting GDC 19 and 61 of Appendix A to 10 CFR 50.

12. Regulatory Guide 1.118, Revision 1 - *Periodic Testing of Electric Power and Protection Systems.*

    Categorized as Type I - forefit only. Sets forth requirements for testing of protection systems which perform safety-related functions.

13. Regulatory Guide 1.33, Revision 1 - *Quality Assurance Program Requirements* (Operation).

    Categorized as Type I - forefit only. Guide addresses acceptable quality assurance practices to meet the requirements of Appendix B to 10 CFR 50.

14. Regulatory Guide 1.143 (for comment, July 1978) - *Design Guidance for Radioactive* Waste *Management* Systems, *Structures, and Components Installed in Light Water Cooled Nuclear Power Plants.*

    Categorized as Type I - forefit only. Originally considered by RRRC in 1974. Industry resistance delayed the initial publication of the Guide. As an alternate, the RRRC recommended a Branch Technical Position. The applicants may appeal the requirement.

2. Few RRRC decisions have been implemented on other than a category I basis, requiring "forward fitting."

3. The RRRC's categorization of regulatory requirements, guides, etc., has been predominantly based on engineering judgments. Categorization criteria for classifying the issues with respect to their relevance to safety and risk does not exist.

4. The NRC does not have a mechanism or responsible organization to ensure that RRRC decisions are implemented.

b. Quality Assurance

The Introduction to Appendix B of 10 C.F.R. Part 50 defines quality assurance as:

> [A]ll those planned and systematic actions necessary to provide adequate confidence that a structure, system, or component will perform satisfactorily in service. Quality assurance includes quality control, which comprises those quality assurance actions related to the physical characteristics of a material, structure, component, or system which provides a means to control the quality of the material, structure, component, or system to predetermined requirements.

The NRC regulations require that applicants establish a Quality Assurance (QA) Program for the design, fabrication, construction, and testing of the structure, systems, and components of the facility that is adequate to satisfy the minimum requirements of Appendix B of 10 C.F.R. Part 50, "Quality Assurance Criteria for Nuclear Powerplants and Fuel Processing Plants," and that this program be presented in the Preliminary Safety Analysis Report (PSAR), as specified in 10 C.F.R. 50.34(a)(7). Similarly, 10 C.F.R. 50.34(a)(3) requires compliance with Appendix A to that same Part, "General Design Criteria for Nuclear Powerplants," for the principal design criteria, and 10 C.F.R. 50.34(b)(6) requires that the Final Safety Analysis Report (FSAR) include information concerning managerial and administrative controls to assure safe operations, and also refers to Appendix B for the minimum acceptance requirements.

As indicated above, Appendices A and B of Part 50 establish requirements related to quality assurance for plant design and operation. The first five criteria of Appendix A constitute the overall requirements for the General Design Criteria. Criterion 1, "Quality Assurance and Records," requires quality standards for structures, systems, and components "important to safety" commensurate with the importance of the safety functions they perform. Although definitive guidelines are not established to delineate the safety importance contributed by the various systems and structures, this criterion generally requires that all equipment and structures in a nuclear powerplant performing a safety function be subjected to some appropriate quality assurance standard.[2s]

Appendix B contains 18 criteria that are applied to the design, fabrication, construction, and testing of safety-related structures, systems, and components of the facility as well as to the managerial and administrative controls to ensure safe operations. Unlike the requirements of Criterion 1 of Appendix A, which apply to all functions that are "important to safety," the QA program required by Appendix B affects only the safety-related functions and equipment of the facility operation[30] thus presenting classification problems discussed below.

As an applicant and, thereafter, a licensee, the utility is responsible for the establishment and execution of the Quality Assurance Program. The NRC's requirements for the program are also imposed on nuclear steam system suppliers (NSSS), architect-engineers, and other subtler suppliers of equipment,[31,32] although the NRR reviews only the QA programs for the principal suppliers.[33] In addition, IE inspects many of the licensees' vendors through the Licensee Contractor and Vendor Inspection Program described below in the section on "Implementation of QA Programs."

The Standard Review Plans 17.1, "Quality Assurance During the Design and Construction Permit Phase,"[34] and 17.2, "Quality Assurance During Operations Phase,"[35] contain the scope of review and acceptance criteria for the NRC's approval of quality assurance programs. These Standard Review Plans refer to a number of regulatory guides that provide guidance to the applicant for complying with the criteria of Appendix B. At least 18 regulatory guides addressing various aspects of a QA program exist, most of which endorse industry standards. For example, numerous standards developed by the American National Standards Institute (ANSI), identified in Series N45.2-1971, "Quality Assurance Program Requirements for Nuclear Powerplants,"[36] and in Series N18.7-1976, "Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Powerplants,"[37] are endorsed as QA practices acceptable to the NRC for construction and operational phases, respectively. Additional guidance to applicants for the design and operation of nuclear powerplants is provided in other Commission publications, including:

1. Guidance on Quality Assurance Requirements During Design and Procurement Phase of Nuclear Powerplants.[38]
2. Guidance on Quality Assurance Requirements During the Construction Phase of Nuclear Powerplants[39]
3. Guidance on Operational Quality Assurance Requirements During the Operations Phase of Nuclear Plants[40]

The review conducted by the Quality Assurance Branch (QAB) in NRC's Division of Project Management is limited to an evaluation of the description of the applicant's QA program in the PSAR and FSAR, and an assessment of whether that program complies with the 18 criteria of Appendix B.[41] However, no attempt is made by the QAB to determine how or to what extent the QA programmatic requirements are applied. This determination is left to the discretion of the applicant,[42] who is responsible for identifying safety-related items,[43] determining the extent that QA requirements are applied to these items, identifying the activities to which Appendix B applies,[44] and imposing QA requirements on its contractors and vendors.[32] The majority of the applicant's QA programs are found in its implementation procedures, which are not even submitted to the NRC for review or approval. These implementing procedures, which constitute several volumes of documents, are retained by the utility.[45]

The QAB does not review the applicant's procedures that implement its QA program.[46] Review of implementation is the responsibility of IE. However, IE does not review the substance of the utility's procedures to determine their adequacy or to give NRC approval. The IE review assumes that the utility's procedures for implementing its QA program are adequate, and simply attempts to determine whether they are being followed.

Deficiencies in the regulations governing QA requirements have been identified in the past by both NRR and IE personnel.[47] For example, NRC regulations do not require the QA program to be included as a condition of the license pursuant to 10 C.F.R. 50.54. Consequently, the licensee can make changes to its QA program and implement procedures without NRC review and approval unless the changes involve an "unresolved safety issue" pursuant to 10 C.F.R. 50.59.[48] The staff has attempted to compensate for this deficiency by obtaining licensee commitments to comply either with Regulatory Guide 1.33, "Quality Assurance Programs Requirements for Operation,"[49] or with industry standard ANSI N18.7, "Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Powerplants,"[37] which include some of the activities in the QA program. However, a "commitment" is not a regulatory requirement and is not necessarily enforceable.[50] These commitments are not binding, therefore NRC approval is not required to cancel or change them.[51]

Another deficiency is the lack of specific criteria for preventive and corrective maintenance programs, surveillance testing, and other operational activities for ensuring the quality of these activities. For example, the failure of circuit breakers for certain safety-related equipment has been attributed to inadequate preventive maintenance programs and suggests a generic weakness. This problem is compounded by the lack of specific qualification requirements and certification of personnel performing these activities, which the NRC staff recently has certification sought to correct by recommending licensing or

Although the requirements of Appendix B are sufficiently broad to adequately address most aspects of acceptable quality assurance programmatic requirements, one important shortcoming of the regulatory program arises from the absence of a definition of "safety-related," a concept central to the entire structure. Although Appendix B contains numerous references and applications of "safety-grade equipment," "safety-related equipment," and "equipment required for safety-related functions," NRC regulations contain no definition of "safety-related" or comparable terms. No other general regulatory guidance for defining or applying these terms is found and NRC staff members have different interpretations of these terms.[55] Failure to define "safety-related" has restricted the scope of the NRC's quality assurance programs.[56] Identification of particular "safety-related" structures, components, and systems is the responsibility of the applicant utility. The absence of definitional guidance supports the applicant's narrow interpretation and, correspondingly, decreases the staff's ability to insist that a particular system or function is "safety-related."

This lack of clarity has generated staff disagreement concerning the identification of equipment to which Appendix B should be applied and concerning the differences and similarities between Appendix A, which applies to components that are "important to safety" and require a graduated quality standard, and Appendix B, which imposes a higher quality standard on the systems and functions to which it applies.[55] This disagreement has frustrated efforts to formulate a regulatory guide for implementing Appendix B.[57]

The NRC has not encouraged industry development of a classification system of nuclear facility equipment and systems. The chairman of the ANS-50 Ad Hoc Committee for ANSI Standard "Equipment Classification for Light Water Reactor Powerplants" indicated that the NRC opposed such a standard and would not provide an NRC representative to the committee. The chairman further indicated that he understood that the NRC considered Regulatory Guide 1.26, "Quality Group Classifica-Lions and Standards for Water-, Steam-, and Radioactive-Waste-Containing Components of Nuclear Powerplants," [58] and Regulatory Guide 1.29, "Seismic Design Classification," [n9] to adequately classify systems and thus opposed further efforts.

The necessity of providing definitions for determining the applicability of Appendix B was noted as early as 1972.[60] Currently, however, the only regulatory guide that specifically identifies the equipment governed by Appendix B is Regulatory Guide 1.29, which defines seismic category I equipment and requires that all such equipment be identified in section 3.2.2 of the PSAR and FSAR. The determination whether other systems, equipment, or functions should meet Appendix B requirements is made by the applicant. Items that the applicant considers governed by Appendix B are listed by the applicant in section 17.2 of its PSAR or FSAR, which is the primary review responsibility of the QAB. This list, commonly referred to as the Q-list, identifies systems in general. All of the components of these systems are not safety-related equipment, however.[61] For example, although the auxiliary feedwater system was identified on the Q-list for TMI-2, the control component of that system was not considered safety-related and thus not subject to QA requirements. The interface between safety and nonsafety equipment is determined by the applicant and not reviewed and approved during the NRC review. The QAB does not review individual Q-lists to determine their adequacy or acceptability because of a lack of technical competency in the review area.[62]

The QAB recently initiated a new practice to help to ensure the completeness of the list of quality assured equipment. The new QAB practice requires that each technical branch review and approve items on the Q-list that are in their assigned primary review area of responsibility.[63]

The NRC staff position regarding nonsafety-grade equipment has been that it should not contribute to either the mitigation or aggravation of the performance of the safety grade equipment during a transient or accident.[84] However, some staff actions have been to the contrary. Credit, both implied and explicit, has been given for nonsafety-grade equipment such as pressurizer relief valves, pressurizer level instrumentation, pressurizer heaters, refueling water tank level instrumentation, steam generator level instrumentation, control systems, incore instrumentation, turbine bypass valves, and diesel generator support systems to mitigate a transient or to provide process control information to initiate operator action.[65] Although this equipment is important to safety, it normally would not appear on the Q-list, and the NRC lacks specific design criteria for it. Assessment of the staffs current practice of relying on nonsafety grade equipment for the mitigation of the severity of anticipated operational transients may lead to a change in staff policy resulting in additional requirements in the future. The licensing boards were notified of this possible change the day after the TMI-2 accident.[ee]

Crediting nonsafety-grade equipment to the performance of a safety-related function also is clearly contrary to Criterion 29 of Appendix A, "Protection Against Anticipated Operational Occurrences," and 10 C.F.R. 50.55a. Criterion 29 requires that protection and reactivity control systems be designed to ensure "an extremely high probability of accomplishing their safety function." The NRC has established no design criteria for nonsafety-grade equipment. The reliability of this equipment has not been evaluated by the staff, and the single failure criterion is not applied to nonsafety equipment.[67] Section (h) of 10 C.F.R. 50.55a requires that proteclion systems meet the appropriate edition of the Institute of Electrical and Electronics Engineers (IEEE) Standard, "Criteria for Protection Systems for Nuclear Power Generating Stations (IEEE-279)." However, the criteria of this standard normally are imposed only for the primary reactivity control system (reactor protection system) and the engineered safety features systems, which are clearly safety-related systems.

Electrical systems and equipment and instrumentation are complex, and this equipment is one of the major contributors to the safety of nuclear powerplants. Classification of this equipment has been recognized as a problem area within NRC since 1974.[88] An IE regional office branch chief indicated that the classification of electrical systems has been one of the most neglected areas, and this area of neglect has permitted safety-related equipment to escape QA requirements. The branch chief identifled the following electrical equipment systems that perform a safety-related function, but fail to appear on Q-lists: the process computers and support equipment used to compute safety limits as defined in the technical specifications, control systems, air systems serving safety-related instrumentation and valves, and instrumentation and monitoring systems. These systems had not been reviewed as safety related before March 28,1979.[69]

The scope of safety-related electrical systems is delineated in Standard Review Plan 7.1, "Instrumentation and Controls, Introduction." These systems are divided into three categories: Basic safety systems that perform a protective function, auxiliary supporting systems that enable these basic safety systems to operate, and other systems important to safety. The latter category was further defined to include:

> [T]hose systems which operate to reduce the probability of occurrence of specific accidents, or to maintain the plant (including other safety systems) within the envelope of operating conditions postulated in the accident analyses as being required to assure full protection capability.

Although this definition is broad enough to require all electrical systems to be designed according to the requirements of Class 1-E, for example, IEEE-296 Standard, single failure criterion, and seismic and environmental qualifications, industry opposition successfully has prevented such a classification by the NRC.[71]

Both the NRC and industry recognize the need to establish a graded classification of electrical systems commensurate with their importance to safety.[72] To date, Appendix A has not been implemented and no regulatory guide or branch technical position addressing a graded classification and requirements for such instrumentation or electrical equipment exists. Therefore, electrical equipment is subjected to either the full measure of QA requirements if it is safety-related, or to none at all.

The IEEE Standards Committee has been drafting a standard regarding' the design criteria for safety-related surveillance instrumentation (other than Class 1-E) that have been required by the operator during normal operating and shutdown conditions of nuclear powerplants since 1974. A representative from NRR cast a negative ballot vote on the proposed standard in 1977.[73] The Office of Standards Development subsequently was requested by NRR to develop a regulatory guide to establish criteria for the design of systems other than Class 1-E,[74] but manpower limitations have prevented progress in the development of this guide.[75]

Reliability of equipment, namely, predictability that it will function when needed, is specifically omitted from the NRC QA requirements.[76] In lieu of quantitative reliability criteria, the NRC applies the single failure criterion to achieve reliability. Stephen Hanauer, currently Assistant Director for Plant Systems, NRC Division of Systems Safety, identified the lack of NRC quantitative reliability criteria for safety-related systems as a problem in 1975.[77] The shortcoming of the NRC's current approach was expressed in his recent deposition:

> The Single Failure Criterion is an approach to reliability requirements, grossly oversimplified, which provides a certain degree of reliability such that the failure of any single component will not fail the function of the system.
> However, it is applied to systems of vastly different reliability with the result that systems complying in every respect with the Single Failure Criterion can have greatly different reliability, and that the specification of the Single-Failure Criterion does not provide a well-defined level of reliability.[78]

Similar criticisms have been advanced by others. For example, one of the recommendations of a report on the NRC Quality Assurance Program conducted by Sandia Laboratories in 1977 addressed the need for the addition of reliability analyses in the QA program.[79] Other recommendations have been made to the NRC to incorporate formal reliability safety practices[80] The NRC did not apply reliability techniques to safety analyses of the feedwater systems until after the TMI accident, however.[81]

Implementation of QA Programs

Assessing the adequacy of Quality Assurance Programs for nuclear powerplants, the present director of NRR concluded that the requirements of Appendix B, guidance presented in regulatory guides, the NRC-endorsed ANSI standards, and the SRPs 17.1 and 17.2 are sufficient to ensure their quality.[82] He acknowledged, however, that proper implementation may be lacking. The director recognized the lack of inspection and enforcement manpower to police QA implementation. The IE inspection program uses a sampling system for verifying implementation of the licensee's QA program. The elements of the QA program to be inspected are identified in chapter 3500 of the IE Inspection Manual[83] This chapter is divided into modules, which contain inspection procedures and include the requirements to be inspected by the NRC inspectors. The IE is responsible for reviewing implementation procedures for the utility's QA plan as described in the PSAR or FSAR. However, as previously indicated, the procedures are neither reviewed for adequacy nor approved by IE.

The Q-Iist is not specific regarding numerous inspection items related to equipment.[84] Therefore, quality assurance is difficult, and more information is needed to determine whether the item is acceptable or an item of noncompliance or deviation. The IE regional offices have noted their concerns regarding inadequacies of the QA program as approved by NRR in various memoranda.

In general, when requested by IE headquarters, interpretations and additional requirements have been provided by NRR.[85] However, the process is a cumbersome one. When an inspector needs clarification or an enforcement position for an inspection issue, the normal operating procedure is to address the concerns through his management to IE headquarters,[86,87] which evaluates the request and either resolves it or refers it to NRR.[87] Joel Kohler, a Region III reactor inspector, testified that IE headquarters:

> [I]s totally useless from a technical standpoint. The technical guidance that we (inspectors) get from OIE headquarters is worthless. They do not have the final word; NRR does. And it is just a waste of time in the chain of command.[87]

Moreover, the response does not necessarily include any affirmative action. For example, Boyce Grier, Director of IE Region I, requested a clear definition of the need for application of QA measures to assure that consumables meet standards in Criterion VIII of Appendix B, "Identification and Control of Materials, Parts, and Components." The memorandum noted that enforcement of this criterion was not possible because of the nonspecificity of NRR approved QA plans.[88] The response from IE headquarters indicated that no action was warranted because a regulatory guide that would address applicability of Appendix B was being drafted.[89] To date, none has been issued.

Another more relevant example is a request by James O'Reilly, former Director of IE Region I, that IE issue a bulletin concerning incorrect positioning of safety-related valves.[90] Although the evaluation by IE headquarters concluded that the eight abnormal occurrences cited in the justification of this request were of safety significance, IE also determined that the proposed bulletin did not meet the criteria for bulletin issuance, therefore it was not issued.[91] The issue identified by the Region I Director is related to Appendix B Criterion 10, "Inspection and Test Control," to make certain that the test activities are performed thereby ensuring satisfactory equipment performance in service. This same issue was identified in the Reactor Safety Study as an important potential contributor to risk.[92]

Finally, in response to a regional office request for an interim definition of "safety-related" to resolve an open inspection item, Francis Nolan, IE staff member, provided the requested definition.[93] This definition was not promulgated throughout IE. Moreover, NRR was not requested to concur with the definition, which had the potential of being used as acceptance criterion by IE, while not being used by NRR in approving the QA program.

In addition to inspecting the licensee's Quality Assurance Program, IE also inspects some of the licencee's vendors' QA programs. The Licensee Contractor and Vendor Inspection Program (LCVIP) addresses the offsite inspection of manufacturing activities for components supplied to the licensee by contractors and vendors;[94] chapter 2700 of the Inspection and Enforcement Manual contains the inspection procedures for NRC inspection.[95] IE Region IV office is responsible for implementing the LCVIP. Approximately 24 inspectors are responsible for inspecting nearly 250 vendors listed in the Licensee Contractor and Vendor Inspection Status Report (White Book).[96] Approximately 180 of these vendors are inspected annually. Formal criteria do not exist for the selection of vendors to be inspected. Vendors listed in the White Book are chosen from a larger number of suppliers of safety-related products because they are believed to be more significant regarding safety than other components.[97] Major vendors are inspected more frequently than subtier vendors.

Norman Mosley testified that the LCVIP is understaffed and greater effort should be devoted to expanding it. Efforts to expand the program were resisted by the Office of Manpower and Budget, which believed that the program should be abolished[98]

Inspections for the principal vendors (e.g., NSSS, fuel manufacturers) are based on the QA programs that have been approved by NRR through the review of vendor topical reports or the utility's program described in section 17 of the PSAR or FSAR. Other vendors are inspected according to QA programs that have been accepted by their customers and by programs approved by the American Society of Mechanical Engineers. Appendix B criteria are used to judge the acceptability of the vendors' QA programs.[97] In 1974-75, licensees' vendors were encouraged to submit topical reports describing their QA programs for NRR review. This practice subsequently was discouraged because the topical reports failed to meet the criteria, such as requirements that an organization must be an applicant, licensee, nuclear steam system supplier, or fuel manufacturer for the NRC topical report program.[99]

Because the NRC regulations do not apply directly to licensees' vendors and contractors, they are not subject to enforcement actions delineated in chapter 0800 of the IE Manual and no penalties can be imposed. However, the vendors and contractors have voluntarily corrected deficiencies identified by the IE inspections.

The QA programs are contributors to the "defense-in-depth" concept.[100] Because most equipment is designed, fabricated, and tested off site it appears that licensees' vendor's QA programs, at least the major ones, are as important as the licensees' programs and should be reviewed, approved, and inspected according to Appendix B criteria. In addition, an NRC-approved vendor QA program would reduce the number of different QA programs of a vendor required by various utilities employing his services.[101] Such a program would standardize the QA programs and include Appendix B requirements.

Impacts of Quality Assurance Related Criteria to TMI-2 Accident and Recovery

The programmatic requirements of Appendix B are sufficiently broad to encompass equipment performance and plant operation and their failures before, during and after the accident at TMI-2. It is difficult to assess the role of the QA program regarding this accident, however. Other equipment present at TMI-2, which performed satisfactorily, were safety-related but had not been required to meet NRC's quality assurance requirements. Although this mitigating equipment probably will be classified as safety-related and required to meet Appendix B standards in the future,[102] it was not designed, fabricated, or tested pursuant to Appendix B standards, and its success cannot be attributed to the NRC's QA program. Moreover, the deficiencies in the plant's status or condition could be attributed either to the lack of adequate implementation of applicable QA requirements or to the failure to require the equipment or personnel action to be subject to NRC's QA requirements at all. The following discussion lists a number of deficiencies at TMI-2 and how they can be related to inadequate quality assurance or quality control requirements.

Emergency Feedwater Block Valves Closed

Failure to verify that these valves were open after surveillance testing could be attributed to failure of the quality assurance requirement regarding the inspection of activities to ensure that the evolution from a surveillance mode to an operational mode or from a "locked-out" to operational status is accomplished in conformance to procedures. In addition, contrary to Criterion XI, "Test Control," the procedures for the surveillance tests for the auxiliary feedwater system did not include provisions for ensuring that the technical specification requirements for limiting conditions for operations were met. Regulatory Guide 1.33, "Quality Assurance Program Requirements (Operation)," requires that the results of completed procedures be routinely reviewed by onsite operating administration. Evidently, such an audit was not completed.[103] Furthermore, the operating personnel's failure to recognize that the valves were inoperative could be attributed to improper implementation of the "tag-out" system indicating operating status, which is governed by Criterion XIV, "Inspection, Test, and Operating Status."

Condensate System Malfunctions

The deficiencies in this system include a clogged condensate polisher, inadvertent closure of polisher outlet valves, and failure to remotely open the bypass valve. Surveillance requirements for the condensate system are not included in the technical specifications. The system is identified in the Q-list for TMI-2, however, and at least part of the system meets the requirements of Appendix B. These deficiencies could be related to the lack of frequency with which the system is tested or to the inadequacy of the test procedures to ensure that the system will perform satisfactorily in service pursuant to Criterion XI, "Test Control," of Appendix B. In addition, the lack of specific Appendix B requirements for preventive or routine maintenance or qualification of the personnel performing the maintenance may have contributed to the accident.

Reactor Coolant System Leakage

The pressurizer relief valve was leaking at a rate that exceeded the technical specification limit for unidentified leakage rate.[103] The pressurizer relief valve was not identified as safety-related and thus was not subject to Appendix B requirements. This valve was part of the pressure boundary and was designed and constructed according to ASME codes. However, because it was not identified as safety-related, the electrical control system and instrumentation were not Class 1-E.

Findings

1. The NRC lacks definitions for "safety-related" as applied to equipment, systems, structures, and so forth necessary to ensure that Appendix B quality assurance standards are implemented consistently. The consequence has been an ad hoc, uncontrolled application of safety-related requirements to equipment outside the reactor protec-

tion system and the engineered safety features systems.

2. The NRC has no criteria for quality assurance standards for components commensurate with their safety function as required by Criterion 1 of the General Design Criteria, Appendix A.
3. Appendix B lacks explicit criteria for maintenance and other operations and certification of personnel performing these activities.
4. The NRC lacks quantitative reliability methodology in QA program requirements and safety analyses evaluations.
5. Sections 17.1 and 17.2 of the Standard Review Plan lack acceptance criteria and review procedures for the list of items that conform to Appendix B standards.
6. The Quality Assurance Program is not a condition of the operating license.
7. Some of the TMI-2 plant deficiencies can be related to inadequate quality assurance or quality control requirements.

c. Generic Issues

Background

Generic issues are general technical matters relating to safety, safeguards, or environmental aspects of nuclear powerplant design, construction, or operation that are applicable to all or a subset of all plant types. Most generic issues are identified in the review of individual applications. However, because generic issues are not limited to a specific plant, they are not handled as part of an individual licensing case. Categorization of an issue as generic is typically delays its resolution. Because these issues are treated on a general basis and are not regarded as impediments to individual plant licensing, little incentive exists for their prompt resolution.

Impetus for addressing generic issues comes primarily from the Advisory Committee on Reactor Safeguards, which since 1972 has identified these issues during its review of utility applications to construct or operate nuclear powerplants. The advisory committee also serves as the primary impetus for their resolution; typically when "they [ACRS] quit asking questions we [NRR] quit answering them."[105] Moreover, the advisory committee deems a generic issue to have been "resolved" when it has been addressed in a regulatory guide, the Standard Review Plan, an industry standard, or branch technical positions. The advisory committee's definition of the "resolution" of a generic issue does not consider its implementation, and the committee does not follow up on "resolved" generic issues to determine whether or how they are being implemented by the NRC staff[108]

Historically, the debate over generic issues has generated considerable disagreement over the precise number of issues that existed. In 1975 the NRC's Technical Safety Activities Report identified 225 technical safety activities warranting consideration[107] These, in turn, were grouped according to areas of review in which the generic item should be addressed, such as reactor safety, engineering, site safety, containment safety, and were categorized in terms of the priorities for their consideration and resolution[108] A year later, during hearings before the Joint Committee on Atomic Energy, this list was reviewed and was characterized by the NRR as not representing "a list of safety concerns that must be resolved to assure the basic safety of continued operation of reactors. Rather, they deal with more precisely defining the safety margins in the plant."[109]

In January 1976, allegations by a departing NRC staff member before the Joint Committee on Atomic Energy[110] concerning the NRC's reactor safety review process resulted in the identification of 24 safety issues that he felt needed to be resolved before the Nation proceeded with commercial nuclear power. Again, the NRC's response to these allegations was to assert that none were technical issues that had not been adequately considered by the staff.[111] During the same hearings, three General Electric (GE) employees identified 52 additional and similar safety concerns[112] related primarily to boiling-water reactors (BWR). The Commission's evaluation of these issues concluded that they, however, "provided no new insights into any reactor safety issue."[113]

Later that year a number of NRR staff members posed another 27 problems whose priority, progress, or resolution was, in their opinion, unsatisfactory[114] The director of NRR concluded that 26 of the 27 issues raised did not warrant revisions to any of its existing licenses, or changes in current staff priorities regarding the resolution of the issue.

Congress obviously was not satisfied with the NRC's treatment of the generic issues problem. In 1977, it amended the Energy Reorganization Act of 1974 to include a new Section 210, which instructed the Commission to develop a systematic means of identifying and dealing with generic issues:

> The Commission shall develop a plan providing for specification and analysis of unresolved safety issues relating to nuclear reactors and shall take such action as may be necessary to implement corrective measures with respect to such issues. Such plans shall be submitted to the Congress on or before January 1, 1978 and progress reports shall be included in the annual report of the Commission thereafter[115]

As a result, the Commissioners directed NRR to institute a program to define, categorize, and manage generic technical activities on a systematic, integrated basis. This program was reported by the NRC in its 1978 annual report to Congress.[116] A Technical Activities Steering Committee, comprised of members of upper level NRC management, was established to manage this program. The committee initially considered over 355 generic issues, and reduced that number by combining identical and similar issues and eliminating those deemed to require policy decisions rather than a generic technical solution. By May 1977, the committee had identified, and categorized 133 generic tasks.

The steering committee additionally established the following priorities for the resolution of these issues:

Category A-Generic technical activities judged by the staff to warrant priority attention in terms of manpower and funds, either individually or combined, to attain early resolution. These matters include issues whose resolution could (1) provide a significant increase in assurance of the health and safety of the public or (2) have a significant impact upon the reactor licensing process.

Category B-Generic technical activities judged by the staff to be important in assuring the continued health and safety of the public but for which early resolution is not required and for which the staff perceives less significance than category A matters in relation to safety, safeguards or the environment.

Category C-Generic technical activities judged by the staff to have little direct or immediate safety, safeguards, or environmental significance, but which could lead to improved staff understanding of particular technical issues or refinements in the licensing process.

Category D-Proposed generic technical activities judged by the staff not to warrant the expenditure of manpower or funds because they have little or no importance to (1) the safety, environmental, or safeguards aspects of nuclear reactors or (2) to improving the licensing process can be attributed to the activity.

The steering committee established task plans to resolve only category A issues.[117] Although task problem descriptions have been published for the remaining categories, no plan for their resolution has yet been established.[118]

In a letter transmitting the "NRC Program for the Resolution of Generic Issues Related to Nuclear Power Plants" to Congress, the NRC pointed out that its program was considerably broader than that required by Section 210, and thus that its future annual reports would focus on the kinds of "unresolved safety issues" referred to by that statute, which, by definition, are the most significant subset of generic licensing issues. The steering committee subsequently developed the following definition of an "unresolved safety issue" in preparation for the Commission's 1979 Annual Report to Congress:

> An Unresolved Safety Issue is a matter affecting several nuclear power plants for which it is likely that actions will be taken to (1) compensate for a possible major reduction in the degree of protection of the public health and safety, or (2) provide a potentially significant decrease in risk to the public health and safety.[119]

Using this definition and techniques such as probabilistic risk assessment,[120] the steering committee identified 14 generic issues that met its definition[121] and thus that should be reported to Congress. The steering committee then submitted a draft of the Annual Report to the Commissioners for approval[122], which was discussed in a public meeting between the staff and Commissioners. During that meeting, four of the five Commissioners expressed dissatisfaction with the steering committee's definition.[123] Concern was expressed that the definition must be compatible with the continued operation of existing plants. The Commissioners thus requested the staff to revise its proposed definition which was changed to read as follows in the NRC's 1979 report to Congress:

> An Unresolved Safety Issue is a matter affecting a number of nuclear power plants that poses important questions concerning the adequacy of existing safety requirements for which a final resolution has not yet been developed and that involves conditions not ff likely to b[124] acceptable over the lifetime of the plants aected .

The Commission's 1979 report also added three generic issues to the list proposed by the steering committee, raising the total number of "unresolved safety issues" to 17.

Limited manpower and funding have resulted in continuing staff efforts to prioritize generic issuea in order to assign available resources for their resolution. Accordingly, the steering committee rated the issues it had by assigning points to each generic task plan. Prior to the point assignment, some task plans were combined with others,[125] resulting in a total rating of 124 task action plans.

The steering committee's ranking of the generic task plans, which was endorsed by the director of NRR, dictated where available resources should be expended.[126] For example, those ranked in the top

20 including the 17 issues identified as "unresolved safety issues" in the Commission's 1979 report to Congress, were deemed to be priority items warranting the commitment of sufficient resources to assure their resolution in a timely manner. Nineteen task action plans were established for these 17 issues. The steering committee also recommended that expenditures of resources and manpower on the 80 least pressing projects be halted. Finally, it was suggested that the other 24 tasks could be assigned resources at the discretion of the NRR division director in his area of responsibility.

Although the precise number of generic issues has fluctuated as some are redefined or recategorized and others identified for the first time in licensing actions or elsewhere, some progress has been made in this area. Mike Aycock, the Secretary to the Technical Activities Steering Committee, indicated that three category A generic issues were completed during 1978. Former NRC Chairman Hendrie has recognized the need to review the generic issues problem.[127] Still, actual progress in this area has been limited. This remains an area requiring substantially more attention and progress than it has received to date.

Impact of Generic Issues on Licensing Process

The NRC staff has determined that the construction and continued operation of nuclear powerplants without resolution of generic issues does not present an undue risk to public health and safety. This judgement is shared by the Advisory Committee on Reactor Safeguards and the Atomic Safety and Licensing Board.[128] Thus, while the licensing boards have considered generic issues in their hearings, such as the hearing on TMI-2,[129] North Anna Units 1 and 2,[130] and River Bend Units 1 and 2,[131] these unresolved matters have not deterred their licensing actions.

In response to a question by the Joint Committee on Atomic Energy whether there is any limit on the number or type of unresolved safety issues that should be permitted to remain unresolved at any one time before nuclear powerplant operation should be curtailed, the ACRS responded:

> The important word in the preceding question is type rather than *number*. Most unresolved safety issues may be classified into the following categories of increasing significance beginning with those of low consequences:
>
> (1) Conditions with potential for degrading system safety but for which it is judged that further theoretical and/or experimental evaluation will demonstrate no safety significance;
>
> (2) Conditions of minor safety significance resulting from marginal engineering practice;
>
> (3) Conditions having known safety significance but which have a low probability of occurrence and marginally acceptable consequences (approaching but less than 10 CFR 100 limits);
>
> (4) Conditions that could lead to low probability accidents of serious consequences whose correction would require extensive evaluation or possible substantial plant modifications, but where the delay in implementing correction can be justified on grounds of improbability for a limited period of delay;
>
> (5) Conditions leading to events having a high probability of occurrence and possibly serious consequences whose correction should occur prior to plant operation, but where consequences can be acceptably mitigated by a decrease in power or other operational restrictions until corrective modifications are completed or where the occurrence likelihood is reduced by other means.
>
> Instances of conditions falling into the first three categories can be numerous without creating significant jeopardy to public safety.
>
> Only a few items in Category 4 would be tolerable at any one time because the cumulative effect would be unacceptable.
>
> A limited number of items in Category 5 might be tolerable for varying periods of time depending upon the degree to which (a) operational restrictions can effect a reduction in the event probability to a tolerable level or (b) surveillance can provide an acceptable means of mitigating risk.
>
> A full quantitative basis for making judgements regarding the type and number of unresolved safety issues which are acceptable is difficult to develop but should be pursued. In the current approach, major dependence is placed upon reaching a conclusion through engineering judgements that the overall risk from the plant would not be significantly increased by the existence of the unresolved safety issues in question .w

The continued existence of unresolved safety issues in the regulatory process has been justified by the NRC's qualitative judgment that the likelihood of significant consequences associated with postulated hypothetical accidents related to these issues is sceptably small for continued licensing activities.[133] In the past, the Reactor Safety Study[92] has been referred to as confirmation that the design of each licensed plant provides reasonable assurance that its operation does not present an undue risk to the public health and safety.[134] More recently, however, a number of problems with the application of the Reactor Safety Study in the licensing arena have been identified. These are well documented in the Lewis study[135] and include adequacy of the study's data base, the validity of its assumptions, inability to verify results, the inability to quantify all contributors to risk, the value-impact of risk reduction, etc. As a result of the Lewis study, the NRC revised its policy regarding the Reactor Safety Study.[136] Consequently, the application of the Reactor Safety Study's numerical categorization of absolute risk no longer serves as a basis for regulatory decisions, and the safety significance of generic issues is now judged on a relative risk basis.[120]

Generic Issues Related to the Three Mile Island Accident

The Special Inquiry Group's (SIG) consideration of generic issues related to the accident at Three Mile Island sought to identify some illustrative examples which had the potential to prevent or alter that course of events. As will be noted, a number of issues discussed herein have not been categorized as generic issues by the NRC. Moreover, because no one knows how or when issues recognized by the NRC as generic will be resolved, how or when they might be implemented, or how they might have impacted the relevant human factors contributing to TMI-2, the undertaking presented here is a highly speculative endeavor.

Instrumentation to Detect Gross Fuel Failures

This issue, identified in 1972 by the ACRS,[137] deals with the establishment of instrumentation criteria to detect severe fuel damage (e.g., melting); the staff has completed work concerning limited fuel damage only. This item does not appear on the present NRC generic issue list.

Interruption of ECCS After LOCH

This issue arises in conjunction with the generic issue "Loss of Offsite Power Subsequent to Manual Safety Injection Reset Following a LOCA (Loss of Coolant Accident)."[138] In 1976, the Advisory Committee recommended that further studies of the probabilities and consequences of such an event be made by staff.[139] To some extent, the staff has addressed the aspect of the original issue of emergency core cooling system reset following loss of offsite power. The **issue** has not appeared on any advisory committee generic list, however, and the staff has never required that an emergency core cooling system design be capable of withstanding an interruption over a prolonged period of time and still meet the relevant safety performance criteria.[140-142]

Human-Machine Interfaces

This issue was identified by Stephen Hanauer in 1975[143] and by the resigned GE employees in 1976.[144] The advisory committee recommended evaluation of existing operator training and testing procedures to demonstrate that existing programs are effective. The committee noted the lack of a feedback system to incorporate the experience of operating plants in the preparation of operating and training prpcedures at other plants, and recommended that the NRC give increased attention to operator understanding and implementation of emergency procedures.[145] In 1978, the advisory committee recommended that *high* priority be given to the research program for man-machine interfaces; that the Commission explore advantages and disadvantages of computer controlled automation; and that a systematic review of operational experience and accidents in U.S. and foreign plants be undertaken.[146] These general issues do not appear on any NRR generic list, however, and work on the possibly related Task Activity B-17, "Criteria for Safety-Related Operations" which would address time criteria for safety-related actions has been suspended.[126]

Instrumentation to Follow the Course of an Accident

The purpose of such instrumentation is to ensure that appropriate parameters are monitored during an accident so that operators will have sufficient information available to mitigate its consequences. The advisory committee has emphasized the need to establish requirements for such instrumentation to the NRR staff since 1969.[147] The issue was identified by the Technical Steering Activities Committee as Generic Task A-34, "Instrumentation for Monitoring Radiation and Process Variables During Accidents." However, the advisory committee considered the issue to be "resolved" with the publication of Regulatory Guide 1.97, "Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant Conditions During and Following an Accident," even though this regulatory guide has not been implemented in any operating plant[148] and the industry has evidenced considerable resistance to its implementation.[149] As a result, neither the steering committee nor the Commission regarded this to be an "unresolved safety issue," and it was not included in the Commission's Report to Congress, even though the Commission was told that the issue could be critical to reducing the hazards associated with an accident.[150]

Systems Interactions

This issue addresses the effect of one system failure on another system (common cause failures) and constitutes a combination of a number of related generic issues, such as nonrandom failures, control system failures, nuclear steam system-balance-of-plant interfaces, and interaction between control and protection systems.

System interaction was identified as an issue of concern as early as 1974.[151] Although not identified by the NRC staff as an "unresolved safety issue," it was added to the list of such generic issues by the Commissioners prior to the transmission of the NRC's Report to Congress in 1979.[124] It is identified as an unresolved safety issue for Generic Task Force A-17, "System Interactions in Nuclear Power Plants."[125] However, because of resource limitations, this issue only addresses pressurized-water reactor (PWR) transients and not accidents.

Operator Error and Actions

These issues were broadly addressed by allegations of the resigned GE employees in 1976.[144] Specific areas of identified concern included design of control rooms, control room simulators and procedural requirements. Task Action Plan B-17 "Criteria for Safety-Related Operator Action," has been halted due to its low priority ranking by the Technical Activities Steering Committee.[126] Human error is not included in the NRC accident analyses evaluation[152] and based on the TMI-2 accident, this issue requires immediate attention by-the NRC in its safety analyses of transients and accidents.

Containment Isolation

In 1976, a former NRC employee criticized the Commission for its failure to deal with the isolation of low pressure systems connected to the primary coolant system.[153] Initiating signals for containment isolation has not been a generic issue, however. The advisory committee considered the need for diverse signals to initiate containment isolation for Westinghouse plants, but not for Babcock & Wilcox and other vendors.[147] The Commission staff acknowledged lack of diverse signals for B&W equipment in 1976,[154] and indicated in a 1978 meeting with Metropolitan Edison that "operating procedures will have to be revised to show manual closure of the containment isolation valves is required after accident."[155] The staff's position requiring "diversity in the parameters sensed (i.e., types of isolation signals) for the initiation of containment isolation" was expressed in Regulatory Guide 1.141, which is to be implemented on a case-by-case basis in accordance with a determination by Regulatory Requirements Review Committee.

Noncondensibles in the Reactor Coolant System

Though not identified as a generic issue, the production of noncondensible gases in a loss-of-coolant-accident was discussed as early as 1968 in various advisory committee meetings concerning hydrogen from failed fuel and nitrogen from accumulator tanks.[147] Noncondensible gases affect the natural circulation capability of the primary coolant system and provide the potential for local core blockage resulting from a gas bubble. To date, however, neither the NRC nor vendors' analyses have addressed the effects of noncondensible gases during a LOCH.

Hydrogen Control in Containment

This has never been considered a generic issue. Concerns expressed by the advisory committee in 1967[147] resulted in inerting some boiling-water-reactor (BWR) containment atmospheres, although no pressurized-water reactor (PWR) containments are inerted. Regulatory Guide 1.7, "Control of Combustible Gas Concentrations in Containment Following a Loss-of-Coolant Accident," Revision 2, was revised in November 1978, and categorized by Regulatory Requirements Review Committee as a requirement that should be imposed only on a prospective basis. Several pressurized water reactors depend on purging to control hydrogen gas concentration. A proposed amendment to 10 C.F.R. 50 to require inerting of containment atmospheres and standards for combustible gas control systems were published in November 1978.[156]

Qualification of Equipment

This was identified as Issue 25[157] during the 1976 staff discussion of generic safety issues. Thereafter, two applicable Task Activities-A-21, "Main Steamline Break Inside Containment" and A-24, "Qualification of Class I-E Safety Related Equipment"-reported on this issue.[158]

In response to a petition from the Union of Concerned Scientists, IE requested licensees to review qualification of equipment;[159] the issue was identified as an "unresolved safety issue," in the Commission's 1979 Report to Congress. In March 1979, the ACRS declared the issue "resolved," however, because critical components were covered by Regulatory Guides 1.40,1.63, 1.73 and 1.89 and IEEE

Standards[108] 382-1972, 383-1974, 317-1972, and 323-1974. This issue has not been resolved by NRC.

Capability of Hermetic Seals on instrumentation and Electrical Equipment

The Commission's failure to deal with this issue was the subject of one of the critical allegations made by the resigned GE employees in February 1976[144] The advisory committee subsequently identified this as a generic issue in April 1976. The relevant task force, Task Activity C-1, "Assurance of Continuous Long-Term Integrity of Seals on Instrumentation and Electrical Equipment," has been suspended, however.[126] The extent that the failure of hermetic seals inhibited recovery from the TMI-2 accident cannot be determined until they can be examined inside containment.

Single Failure Criterion and Reliability

In a memorandum to Commissioner Gilinsky in 1975, Stephen Hanauer stated that the "NRC has not established quantitative reliability criteria for safety-related systems."[143] Similarly, one of the allegations raised by the resigned GE employees was the Commission's lack of reliability data on systems.[144] This issue was included among the list of generic issues that certain Commission staff members claimed[114] were not receiving sufficient attention in 1976. The single failure criterion is related to several other generic issues such as passive failures, definition of safety-related equipment, systems interactions, nonrandom failures, and operator error. This issue was not included in the NRC generic list, but is accepted by the NRC staff as a satisfactory alternate to quantitative reliability analyses.[160] Moreover, the criterion is applied to only the safety related components and systems. Presently, emergency core cooling system reliability is addressed in Task Activity C-11. Expenditures[142] on both these tasks, however, have been halted.

Systematic Review of Normal Plant Operation and Control

Although this was identified as an issue[114] of concern by a critical NRC staff report in 1976, no positive efforts were initiated to include the safety significance of control systems in the NRC review process. This issue has since been marginally addressed as part of Generic Task A-17, "System Interactions in Nuclear Power Plants." The NRC generic list does not include this issue, however, and control systems[161] have not been reviewed in detail by the NRC staff.

Findings

1. Lack of NRC priority to address generic issues has resulted in resolution of only two "unresolved safety issues," and neither of these have been implemented. Most NRC efforts on generic issues have been expended on prioritizing the list of issues for the allocation of limited resources.
2. Responsibility for resolving generic issues and then implementing the resolution is widely dispersed throughout the NRC, primarily in various areas within NRR.
3. Generic issues as conditions with a schedule for completion have not been identified in construction permits or operating licenses. Consequently, there is no impetus or incentive to effect their resolution.

d. Technical Qualifications

Background

Section 182 of the Atomic Energy Act of 1954, as amended, provides that each applicant for a license:

> [S]hall specifically state such information as the Commission, by rule or regulation, may determine to be necessary to decide such *of* the technical ... qualifications *of* the applicant . . . as the Commission may deem appropriate *for* the license.[162]

NRC regulations, in turn, require that the NRC find the applicant to be technically and financially qualified prior to the issuance of a construction permit or an operating license. The regulation governing the issuance of an operating license requires that the Commission find that "[t]he applicant is technically and financially qualified to engage in the activities authorized by the operating license[163] in accordance with the regulations in this chapter." The regulation covering construction permits requires that the permit be subject[164] to the same conditions as an operating license. In addition, the regulations reiterate these conditions as a common[165] standard for licenses and construction permits.

The technical information required for the Commission's finding that the applicant is technically qualified must be included in the applicant's Preliminary Safety Analysis Report (PSAR) submitted as a part of the construction permit application, and in the Final Safety Analysis Report (FSAR)[166] submitted with the operating license application.

The regulations require that the FSAR include additional information related to the applicant's organizational structure not provided at the construction permit stage, including the following:

> The applicant's organizational structure, allocations or responsibilities and authorities and personnel qualifications requirements.[167]

> Managerial and administrative controls to be used to assure safe operation. Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants" sets forth the requirements for such controls for nuclear power plants . . . . The information on the controls to be used for a nuclear power plant "shall include a discussion of how the applicable requirements of Appendix B will be satisfied.1

NRC regulations also require that each applicant for a license authorizing operation include its proposed technical specifications which, among other things, provide for administrative controls, defined by the regulations to consist of:

> [T]he provisions relating to organization and management, procedures, recordkeeping, review and audit and reporting necessary to assure operation of the facility in a safe manner.[169]

This information is evaluated by the Quality Assurance Branch (QAB) of the NRC's Division of Project Management, whose review is based on the acceptance criteria set forth in the Standard Review Plan (SRP).[170] In some instances, the Standard Review Plan itself contains criteria for particular issues.[171] The SRP also refers to other documents for guidance. For example, the SRP refers to the "Standard for Administrative Controls for Nuclear Power Plants" for guidance on requirements relating to operating organizations, rules of practice, and onsite review criteria.[172] The AEC's "Utility Staffing and Training for Nuclear Power" offers additional guidance as to the requirements acceptable to the staff for management and technical support organization.[173] Qualifications for the applicant's personnel also are contained in Regulatory Guide 1.8, "Personnel Selection and Training"[174] which, in turn, refers to the "Selection and Training of Nuclear Power Plant Personnel," published by the American National Standards Institute,[175] and to the previously mentioned "Utility Staffing and Training for Nuclear Power".[176]

Notably absent from all of these documents are any qualitative guidelines or detailed regulatory criteria by which the various technical qualifications should be assessed.[177,178] Similarily, a definition for "technical qualifications" is lacking. Frederick Allenspach, who is the only NRC reviewer assigned responsibility for review of an applicant's technical qualifications, provided his understanding of these concepts:

> I think it's one in which the applicant has established an appropriate organization with adequately defined responsibilities, with people technically qualified to implement those responsibilities to carry out their responsibilities in design, construction, and operation of the facility.he

Key plant staff is reviewed in considerable detail, including the organization, numbers of people assigned to each position, the qualification requirements for each position and the actual qualifications of key personnel assigned to the plant staff.'[80] This review focuses on the actual qualifications of key management and professional personnel as reflected in their individual resumes, but only on the more general qualification requirements for other personnel, such as technicians, maintenance and repairmen. Key personnel include the radiation protection manager, members of the Plant Operations Review Committee, nuclear engineers, plant superintendents, and shift foremen. Plant staff are identified by position and their qualification requirements are usually contained in the technical specifications of the operating license.

After the NRC review of the technical qualifications of key personnel during the operating license review, the licensee thereafter may change these individuals without NRC review or control. Thus, in essence, the NRC approves the functions of the position rather than license an individual for that position[181] Moreover, the review of the applicant's technical qualifications to conduct operations as set forth in section 13 of the Standard Review Plan does not include all important personnel who potentially contribute to the applicant's overall technical qualification capability. For example, qualifications of quality assurance personnel and testing personnel are addressed in other review areas of the SRP.[182]

The Quality Assurance Branch examination in approving the plant operating staff in SRP 13.1.2 includes the position titles, operator licensing requirements, and the numbers of operating personnel assigned per shift. Qualifications of testing personnel involved in the initial test program are addressed in section 14 of the Standard Review Plan and not usually reviewed by the same Commission staff person who reviews the applicant's organization and staff for technical capability.[183] Because the QAB has the responsibility to review the initial test pro grams, informal discussions involving the qualifications of test personnel and other plant staff occasionally transpire between branch members.[184] Finally, IE only verifies that the individual's experience and qualifications meet the general qualification requirements of the position which have been identified by the licensee and approved by NRR.

A review of an applicant's technical qualifications does not include requirements that relate to applicant experience in either the design, construction, or operation of nuclear powerplants;[185] nor does the review cover the applicant's capability to perform routine and emergency operations of the nuclear powerplant.[186] Although some Commission staff members have recommended that past performance in operating a nuclear power facility be made an explicit and important consideration in the evaluation of an applicant's technical competence, their superiors in the staff did not concur in these recommendations.[187] Similarly, the applicant's capability to respond to an emergency situation was not considered prior to March 29, 1979, although the NRC is now evaluating licensee's capability to cope with operations during an accident. This assessment, however, is vested elsewhere in the review process. Finally, until recently the technical qualifications review has not explicitly considered the qualifications of the architect-engineer, the nuclear steam system supplier, or other contractors and consultants employed by the applicant to execute its responsibilities. However, a recent revision to the Standard Review Plan includes more definitive review responsibility with regard to qualifications of these personnel [0]

Although the NRC must make a finding that the applicant is technically qualified to engage in the design, construction and operation of nuclear powerplants, neither the basis for this determination nor the assignment of responsibility for making it are well defined.[191] The QAB provides the principal input into the Safety Evaluation Report regarding the technical qualifications of the applicant based on the review of the applicant's organization structure in[19] chapter 13 of either the PSAR or the FSAR. However, this review is quite narrow in scope by comparison to the regulatory requirements and the comprehensive finding made by the Commission in the Safety Evaluation Report. The licensing project manager "as a matter of course" makes the final overall judgmental determination that the applicant is technically qualified, using the QAB input for technical qualifications and Quality Assurance Programs, other review inputs, and his own judgment[177,193] based on his interactions with the applicant. No guidance or acceptable criteria are available to guide the project manager in this finding, however.[194,195]

As a result of Atomic Safety and Licensing Board deliberations concerning the staff's determination of an applicant's technical qualifications, efforts were initiated in December 1978 to develop a more systematic approach to evaluate applicants' qualifications.[190,196] However, efforts by the QAB to establish a formal procedure to provide a more substantial basis for determining technical qualifications have not been successful.[194] QAB recommended that procedures be formalized to include IE input to the project manager and that the project manager be assigned the responsibility for making the finding that the applicant is technically qualified. QAB further recommended the project manager's responsibilities be addressed in the Licensing Project Manager Handbook.[197] To date, these recommendations have not been implemented by the DPM.[198]

Technical Qualification Review of Metropolitan Edison Company

The review of the technical qualifications of Metropolitan Edison Company to operate TMI-2 apparently was not performed according to the Standard Review Plan. This can be attributed to the NRR revision to office letter number[9,200] which directed the staff not to document the deviations from the Standard Review Plan for TMI-2 and other plants. The specific acceptance criteria used in the review of TMI-2 were nonetheless the same as those contained in the Standard Review Plan, because the SRP reflected past review practices regarding requirements for the plant staff, such as Regulatory Guide 1.8 and ANSI Standards N18.7 and N18.1. The qualifications of the architect-engineer and vendors were not, however, reviewed.[201]

Frederick Allenspach, who has reviewed approximately 40 applications to evaluate the applicant's technical qualifications, compared Met Ed favorably to other applicants. As he stated to the SIG:

> I think in general I would have rated this home office probably average to above, and their plant staff, I think would be superior, superior to most staff[2]

Findings

1. Although the NRC must make a finding that the applicant is technically qualified to engage in the design, construction, and operation of nuclear powerplants, acceptance criteria and assignment of responsibility within NRC are not well defined.

2. The applicant's experience or past performance in the design, construction or operation of nuclear powerplants is not explicitly considered by the NRC in its evaluation of the applicant's qualifications.
3. The applicant's technical qualification is based in part on the qualifications of key individuals identified in the plant staff organization. The NRC does not review or approve the personnel changes for these key positions after the license is issued, however.
4. The review of plant staff qualifications that contribute to the overall technical qualifications of the applicant is dispersed among several NRC review disciplines.
5. The capability of the applicant to respond to an emergency situation was not considered as part of the NRC review of technical qualifications prior to the TMI-2 accident.

REFERENCES AND NOTES

'the director of regulation reported directly to the Commission and was responsible for the regulation of commercial nuclear facilities. The directors of the major offices reported to the director of regulation and not to the Commission. Currently the major office directors report to the Commission.

[2]Information Report to the Commissioners from L. M. Muntzing, "Regulatory Program for Minimizing and Controlling Ratcheting," SECY-R-74-95, December 19, 1973; Information Report to Commissioners from L. M. Muntzing, "Regulatory Requirements Review Committee," SECY-R-74-132, March 5,1974.

[3]NRC, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants-LWR Edition," NUREG-75/087.

[4]Case dep. at 226.

[5]Varga dep. at 6, 70; Hanauer dep. at 92.

[6]Case dep. at 242.

[7]1d. at 227.

[8]Varga dep. at 27.

[9]Case dep. at 229.

[1]OVarga dep. at 28.

"Case dep. at 228.

[12]/d. at 236.

[13]Varga dep. at 239.

[14]1d. at Exhibit 1004.

[•5]!d. at 40.

[16]1d. at 39.

171. at 43.

[18]14. at 56.

[19]Information Report to the Commissioners from H. Denton, "Improving the Process for Determining the Need for New Reactor Requirements," SECY-79-8, January 2, 1979. (Hereafter referred to as SECY-79-8).

[20]Case dep. at 230, 239.

21 Information Report to the Commissioners from H. Denton, "Improving the Process for Determining the Need for New Reactor Requirements," SECY-79-8, January 2,1979.

[22]Letter from E. G. Case to S. D. Freeman, Subject: Response to Freeman Letter of March 8, 1978 to Chairman Hendrie, dated April 8,1978; Varga dep. at 14.

[23]Varga dep. at 58.

[24]1d. at 57.

[25]Case dep. at 230.

[28]Varga dep. at 21.

[27]Memorandum from R. Boyd, NRC, to H. Denton, "Implementation of New Regulatory Requirements Recommended by RRRC and Approved by the Director, NRR," February 10, 1978.

[28]Memorandum from D. K. Davis, NRC, to Systematic Evaluation Program Branch Members and D. Ziemann, "Incorporation of Regulatory Requirements Review Committee Category 2 and 3 Items into Systematic Evaluation Program Review," April 6, 1979.

[29]Haass dep. at 36, 40.

[30]Haass dep. at 39; Gilray dep. at 52.

[31]Haass dep. at 20.

[32]

[33]Gilray dep. at 52.

[34]Gilray dep. at 82.

NRC, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Powerplants-LWR Edition," NUREG-75/087, Section 17.1.

[35]1d. at Section 17.2.

[36]"American National Standard Quality Assurance Program Requirements for Nuclear Powerplants," ANSI N45.2-1971.

[37]"American National Standard Administrative Controls and Quality Assurance for the Operational Phase of Nuclar Powerplants," ANSI N18.7-1976/ANS-3.2.

[38]U.S. Atomic Energy Commission, "Guidance on Quality Assurance Requirements During Design and Procurement Phase of Nuclear Powerplants," Revision 1, WASH-1283, May 24, 1979.

[39]U.S. Atomic Energy Commission, "Guidance on Quality Assurance Requirements During the Construction Phase of Nuclear Power Plants," WASH-1309, May 10, 1974.

[40]U.S. Atomic Energy Commission, "Guidance on Operational Quality Assurance Requirements During the Operations Phase of Nuclear Powerplants," WASH-1284, October 1973.

[41]Gilray dep. at 40, 56.

[42k1] at 45.

[43]Haass dep. at 28.

"Id. at 63.

[45]Ruhlman dep. at 9.

[48]Gilray dep. at 46; Haass dep. at 7.

[47]Ruhlman dep. at 19; Gilray dep. at 75.

"is is in contrast to operator requalification programs, Appendix A to 10 C.F.R. Part 50, "Safeguards Contingency Procedures," Appendix C to 10 C.F.R. Part 73, and reactor containment leakage testing procedures, Appendix J to 10 C.F.R. Part 50.

[49]NRC, Regulatory Guide 1.33, "Quality Assurance Program Requirements (Operation)," Revision 2.

[50]Ruhlman dep. at 59, 99.

[51]Ruhlman dep., Exhibit 1034, Enclosure 8.

[52]Haass dep., Exhibit 1088; Letter from H. Denton, NRC, to Commissioner Kennedy, Subject: "Preventive Maintenance," dated August 8,1979.

53 Qualifications of personnel who perform these maintenance and other activities are addressed in ANSI N18.1-1971, "Training of Nuclear Power Plant Personnel," and ANSI N45.2.6-1973, "Qualifications of Inspection, Examination and Testing Personnel for the Construction Phase of Nuclear Powerplants".

[54]Memorandum from W. Ruhlman, NRC, to J. O'Reilly, "Recommendations for Changes in IE Programs," June 29, 1979.

[55]Haass dep. at 30; Gilray dep. at 53.

[58]Eisenhut dep. at 80 (Pres. Com.); Ruhlman dep. at 35.

[57]Haass dep., Exhibit 1089: Memorandum from W. Haass, NRC, to W. Morrison, "QAB Comments on Proposed Regulatory Guide 1.XXX (RS-704-4)," July 24, 1979.

[58] NRC, Regulatory Guide 1.26, "Quality Group Classifications and Standards for Water-, Steam-, and Radioactive-Waste-Containing Components of Nuclear Powerplants," Revision 3.

[59] NRC, Regulatory Guide 1.29, "Seismic Design Classification," Revision 3.

[60] Memorandum from F. Kruesi, NRC, to L. Rogers and J. O'Leary, "Applicability of 10 CFR 50 Appendix B," August 15,1972.

[e1] Haass dep. at 50; Gilray dep. at 51.

[82] Gilray dep. at 42.

[63] Haass dep. at 53, Exhibit 1090, Memorandum from H. Denton, NRC, to Commissioner Kennedy, "Quality Assurance Programs for Nuclear Powerplants," April 16, 1979. Before February 1979, staff practice by the review branches had not been to provide to the QAB a list of safety-related equipment originating in their areas of review. Consequently, it is not clear whether the Q-lists were reviewed in detail. Haass dep. at 45.

[64] Ross dep. at 90.

[85] Examples of the practice are contained in 1) the Ross deposition, Exhibit 1156, Memorandum from D. Ross, NRC, to D. Vassallo, "TMI-2 Input to SETC Supplement No. 2," February 6, 1978, and Exhibit 1157, Enclosure: Memorandum from D. Vassallo, NRC, to E. Christenbury, "Board Notification-Nonsafety-Grade Equipment to Mitigate Transient (BN-79-12)," March 29, 1979; and 2) by Issue I, "Treatment of Non-safety Grade Equipment in Evaluations of Postulated Steamline Break Accidents in U.S. Nuclear Regulatory Commission," Staff Discussion of 15 Technical Issues Listed in Attachment to November 3, 1976 Memorandum for Director, NRR to NRR Staff, NUREG-0318, November 1976.

[66] Ross dep., Exhibit 1157.

[67] NRC, Information Report from E. Case to the Commissioners, Subject: "Single Failure Criterion, SECY-77-439," dated August 17, 1977.

[6B] Telephone Interview with Thomas Ippolitto.

[89] Memorandum from H. Denton, NRC, to J. Ahearne, "Safety Implementation of Control Systems and Plant Dynamics," October 22,1979.

[70] NRC, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Powerplants-LWR Edition," NUREG-75/087, at Section 7.1.

[71] Telephone Interview with Rodney Satterfield, Chief, Instrumentation and Control Systems Branch, NRC, Division of Systems Safety.

[72] Memorandum from R. Tedesco, NRC, to G. Arlotto, "Request for Development of Regulatory Guide for Class 2E Systems," May 20, 1977; Memorandum from G. Arlotto, NRC, to R. Tedesco, "Development of Regulatory Guide for Class 2E Systems," May 20,1977; Draft Paper Submitted Informally to NRC, "Safety Classification of Electrical Safety-Related Systems in Nuclear Powerplants," Combustion Engineering, 1974; Letter from R. Salvatorie, Westinghouse Electric Corporation to V. Stello, Jr., Subject: Criteria for Safety-Related Electrical Equipment for Nuclear Power Generating Stations, Westinghouse Electric Corporation NS-RS-279, July 3, 1974.

[73] Memorandum from R. Tedesco, NRC, to G. Arlotto, "Comments and Ballot P-466, Criteria for the Design of Safety-Related Surveillance Instrumentation (SRSI) in Power Generating Stations," February 26, 1977.

[74] Memorandum from R. Tedesco, NRC, to G. Arlotto, "Request for Development of Regulatory Guide for Class 2-E Systems," May 20, 1977.

[75] Telephone Interview with Wilbur Morrison, Chief, Engineering Methodology Standards Branch, NRC Division of Engineering Standards.

[78] Gilray dep. at 94.

[77] Hanauer dep., Exhibit 1135, Memorandum from S. Hanauer to Commissioner Gilinsky, "Technical Issues," March 13, 1975.

[78] Hanauer dep. at 50.

[79] Haass dep. at 120.

[80] "Technical Staff Analysis Report on Quality Assurance," President's Commission on the Accident at Three Mile Island, October 1979, p. 17.

[81] NRC, "Generic Evaluation of Feedwater Transients and Small Break Loss-of-Coolant Accidents in Westinghouse Designed Operating Plants", NUREG-0611 (to be published).

[82] Haass dep. at 54.

[83] NRC, Manual Chapter 3500, "(Quality Assurance,)" Enforcement and Inspection Manual, 8 volumes.

[84] Telephone Interview with Eldon Brunner, Chief, Reactor Operations and Nuclear Support Branch, NRC Region I Office of Inspection and Enforcement; Ruhlman dep. at 34 and 53.

[85] Telephone Interview with Harold Thornburg, Director, NRC Division of Reactor Construction Inspection, IE.

[88] Ruhlman dep. at 27.

[87] Kohler dep. at 65.

[88] Memorandum from B. Grier, NRC, to H. Thornburg, "Applicability of Appendix B to Safety-Related Consumables," October 5, 1977.

[BS] Memorandum from J. Sniezek, NRC, to B. Grier, "Applicability of Appendix B to Safety Related Consumables," December 8, 1977.

[90] Memorandum from J. O'Reilly, NRC, to H. Thornburg, "Proposed Bulletin-Incorrect Positioning of Safety-Related Valves," March 21, 1975.

[91] Memorandum from J. Crews, NRC, to H. Thornburg, "Proposed Bulletin-Incorrect Positioning of Safety-Related Valves," April 6, 1975.

[92] NRC, "Reactor Safety Study-An Assessment of Accident Risks in the U.S. Commercial Nuclear Powerplants," Executive Summary, WASH-1400 (NUREG-75/014), October 1975.

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[94] This program is described in Inspection and Enforcement Manual Chapter 2700, "Licensee Contractor and Vendor Inspection Program," Commission Information Letter, "Licensee Contractor and Vendor Inspection Program," SECY 77-64, February 2,1977; Commission Information Letter, "Letter to OMB Concerning NRC's Licensee Contractor and Vendor Inspection Program," SECY 78-495, September 8, 1978; and "Report of a Study of the Licensee Contractor and Vendor Inspection Program (LCVIP)", NUREG/CR-0217, July 1978.

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[88] Mosley dep. at 190.

[99] Skovholt Interview Memo (Sept. 27, 1979).

[100] Haass dep. at 12.

[1o1] Gilray dep. at 86.

[102] NRC, "TMI-2 Lessons Learned Task Force Final Report," NUREG-0585, at A-14, October 1975.

103 Letter from V. Stello, NRC, to Metropolitan Edison Company, Subject: Investigation Report Number 50-320/79-10, dated October 25,1979.

[104] Memorandum from M. Aycock et al., NRC, to B. Rusche, "Task Force Recommendations Related to the Development of a Program Plan for the Management of NRR Technical Activities," March 15,1977.

[105] Transcript of Public Meeting, "Discussion of SECY-78-616-Reporting the Progress of Resolution of 'Unresolved Safety Issues' in the NRC Annual Report," December 12, 1978.

[108] Letter from M. Carbon, ACRC, to J. Hendrie, NRC, Subject: Status of Generic Items Relating to Light-Water Reactors: Report No. 7, dated March 21, 1979. This letter contains a relatively current list of resolved and unresolved generic issues which have been addressed by the ACRS.

[107] Note from R. Heineman, NRC, to Multiple Addresses, NRC, "Technical Safety Activities Report-December 1975," January 5, 1976.

108 The categories established for these items were as follows:

> *category* A-Technical safety activities currently receiving attention which have an important impact on the licensing review process.
>
> *category* B-Technical safety activities identified as requiring NRR attention, but for which review has not been initiated because of manpower limitations or because information is not available.
>
> *category* C-Technical safety activities planned for the future that would improve the quality of the review or facilitate the review process.

[109] Hearings Before the Joint Committee on Atomic Energy, Congress of the United States, "Investigation of Charges Relating to Nuclear Reactor Safety," Volumes 1 and 2, (February 18, 23, 24 and March 2, 4, 1976) at 1065.

[110] Id. at 97.

[111] 1d. at 1052.

[112] 1d. at 494.

[113] *1d* at 1494.

[114] NRC, "Staff Discussion of 15 Technical Issues Listed in Attachment to November 3, 1976 Memo from Director, NRR to NRR Staff," NUREG-0138, November 1976: NRC, "Staff Discussion of Twelve Additional Technical Issues Raised by Responses to November 3,1976 Memorandum from Director, NRR to NRR Staff," NUREG-0153, December 1976.

[115] 42 U.S.C. Sec. 5850.

[118] NRC Report to Congress, "NRC Program for the Resolution of Generic Issues Related to Nuclear Power Plants," NUREG-0410, January 1978.

[117] NRC, "Task Action Plans for Generic Activities," November 1978.

[118] NRC, "Generic Task Problem Descriptions: Category B, C, and D Tasks," NURGEG 0471, June 1978.

[119] Memorandum from E. Case, NRC, to Multiple Addressees, "Summary of Technical Activities Steering Committee Meetings 12 and 13, November 2 and 13, 1978," January 10,1979.

[120] Summary Report on a Risk Based Categorization of NRC Technical and Generic Issues, (DRAFT), Probability Analysis Staff, 1978.

[121] Hanauer dep. at 143.

[122] Commissioner Action Request from H. Denton to the Commission, "Reporting the Progress of Resolution of 'Unresolved Safety Issues' in the NRC Annual Report," SECY-78-616, November 27, 1978.

[123] Transcript of Public Meeting, "Discussion of SECY-78-616-Reporting the Progress of Resolution of 'Unresolved Safety Issues' in the NRC Annual Report," at 128, December 12, 1978.

[124] NRC, "Identification of Unresolved Safety Issues Relating to Nuclear Power Plants," NUREG-0510, January 1979.

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[127] Transcript of Public Meeting, "Discussion of SECY-78-616-Reporting the Progress of Resolution of 'Unresolved Safety Issues' in the NRC Annual Report," at 56, December 12, 1978.

[128] Hearing Before the Joint Committee on Atomic Energy, Congress of the United States, "Investigation of Charges Relating to Nuclear Reactor Safety," Volumes 1 and 2 (February 18, 23, 24 and March 2, 4, 1976) at 1067-1068.

[129] Proceedings of the Atomic Safety and Licensing Board in the Matter of Metropolitan Edison Company, et al., pp. 1316-1351, May 18,1977.

[730] Atomic Safety and Licensing Appeal Board Decision in the Matter of Virginia Electric and Power Company, 8 NRC 245 (1978), August 25, 1978.

[131] Atomic Safety and Licensing Appeal Board Decision in the Matter of Gulf States Utilities Company, 6 NRC 760 (1977), November 23,1977.

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133, at 1063.

[13] *Id.* at 1066.

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[136] Memorandum from S. J. Chilk to L. V. Gossick, "Staff Actions Regarding Risk Assessment Review Group Report," January 18,1979.

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[138] NRC, "Staff Discussion of 15 Technical Issues Listed in Attachment to November 3, 1976 Memo from Director, NRR, to NRR Staff," NUREG-0138, at Issue 4, November 1976.

[139] Hearings Before the Committee on Government Operations, United States Senate, "Nuclear Regulatory Commission Safety and Licensing Procedures," (December 13, 1976) at 260.

[140] Memorandum from W. Butler, NRC, to D. Eisenhut, "Review of I&E Inspections of Operating PWRs Related to the Follow-up Actions Identified in NUREG-0138 Issue No. 4, "Loss of Offsite Power Subsequent to Manual Safety Injection Reset Following a LOCA," December 29, 1977.

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[145] Letter from D. Moeller, ACRS, to M. Rowden, NRC, "Report on the Review of Statements by Messrs. Bridenbaugh, Hubbard, Minor and Pollard," May 19, 1976.

[146] NRC, "1978 Review and Evaluation of the Nuclear Regulatory Commission Safety Research Program," Advisory Committee on Reactor Safeguards, NUREG-0496, December 1978.

[147] Letter from M. Carbon, ACRS, to M. Rogovin, TMI/SIG, "Response to Request for Information, dated June 29,1979," dated July 25,1979.

[148] Memorandum from H. Denton to Commissioner Ahearne, "Instrumentation to Follow the Course of an Accident," September 4,1979.

[149] Transcript of Public Meeting, "Discussion of SECY-78-616-Reporting the Progress of Resolution of 'Unresolved Safety Issues' in the NRC Annual Report," at 80, December 12,1978.

[150] Id. at 82.

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[154] Memorandum from J. Shapaker to R. Tedesco, NRC, "Proposed Position on B&W Containment Isolation System," June 22,1976.

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[160] Information Report from E. Case to the Commissioners, "Single Failure Criterion," SECY-77-439, August 17,1977.

[161] Memorandum from H. Denton, NRC, to Commissioner J. Ahearne, "Safety Implications of Central Systems and Plant Dynamics," October 22,1979.

[162] Atomic Energy Act of 1954, 42 U.S.C. Sec. 2232.

[163] See, 10 C.F.R. Sec. 50.57(a)(4), "Issuance of Operating License."

[164] See, 10 C.F.R. Sec. 50.55(c), "Conditions of Construction Permits."

[165] 10 C.F.R. Sec. 50.40(b).

[166] See, 10 C.F.R. Secs. 50.34(a)(9), (b)(7): "Contents of Applications; Technical Information."

[167] 10 C.F.R. Sec. 50.34(b)(6)(i).

[168] Id. at (b)(6)(ii).

[169] 10 C.F.R. Sec. 50.36(c)(5).

[170] NRC, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Powerplants-LWR Edition," NUREG-75/087

[171] The following sections of the Standard Review Plan set forth criteria relevant to technical qualifications assessments: Section 13.1.1, "Management and Technical Support Organization"; Section 13.1.2, "Operating Organization"; and Section 13.1.3, "Qualifications of Nuclear Plant Personnel."

[172] "American National Standard for Administrative Controls for Nuclear Power Plants," ANSI N18.7-1972, at Sections 3.3, 4.5, 5.1.

[173] U.S. Atomic Energy Commission, "Utility Staffing and Training for Nuclear Power," WASH-1130, at Section IV-A, June 1973.

[174] NRC Regulatory Guide 1.8, Rev. 1-R, "Personnel Selection and Training."

[175] "American National Standard Requirement for Selection and Training of Nuclear Power Plant Personnel," ANSI N18.1-1971.

[176] NRC, "Utility Staffing and Training for Nuclear Power," WASH-1130, at Section IV-13,June 1973.

[177] Vassallo dep. at 72.

[178] Vassallo dep., Exhibit 1023.

[179] Allenspach dep. at 10.

[180] Id. at 13.

[181] Changes to the plant organization must be approved by the NRC. Allenspach dep. at 39-40, 45 and 55.

[182] Grier dep. at 30.

[183] Allenspach dep. at 83; Haass dep. at 99.

[4] Allenspach dep. at 84.

'Allenspach dep. at 31, 62-65.

seVassallo dep. at 73, 78; Haass dep. at 81.

[187] Allenspach dep. at 63; Exhibits 1057 and 1059.

'WHaass dep. at 81-82.

mAllenspach dep. at 85.

VOVassallo dep., Exhibit 1023.

*'Vassallo dep. at 71-73.

[192] Allenspach dep. at 17.

'Allenspach dep. at 41; Haass dep. at 72, 77.

[194] Allenspach dep. at 20.

Vassallo dep. at 73; Haass dep. at 73.

The licensing board considered the technical qualification of Boston Edison Company (Pilgrim 2).

[97] Allenspach dep., Exhibits 1054 and 1064.

'Haass dep. at 74; Allenspach dep. at 23, 28.

*OVassallo dep. at 25.

[20] OMemorandum from B. Rusche to NRR Division Directors, NRC, Subject Revised Procedure for Documentation of Deviations from the Standard Review Plan, dated January 31, 1977.

[201] Allenspach dep. at 85.

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B LICENSING AND OPERATING HISTORIES

1. LICENSING HISTORY OF TMI-2

a. Introduction

This portion of the Special Inquiry Group Report is a summary analysis of the licensing history of the TMI-2 project. A background description of the regulatory institution in which the licensing reviews took place is included in order to provide additional insights into the events that did or did not occur.

Following this introduction, an initial summary, reviews the overall chronology of the licensing of both TMI-1 and TMI-2, which are nearly identical plants and adjacent to one another on the same island in the Susquehanna River.

Section I.B.1.c presents a summary of the TMI-2 construction permit review, set against a historical background description of the structure of the licensing staff and the evolution of the licensing process up to that time. The construction permit review was completed in approximately 1'/z years during a period of rapid expansion of the nuclear industry and the agencies designed to regulate it. Safety criteria have only been partially developed and are still evolving. Staff and the Advisory Committee on Reactor Safeguards reviews are also described in this section and several of the issues covered in those reviews are discussed. In addition, the TMI-2 public hearing process at the construction permit (CP) stage is described. We see in this section that all concerns raised (some of which, such as small break analyses and emergency planning, would later become significant with respect to the TMI-2 accident) were ultimately decided favorably by the regulatory bodies involved, and the construction permit was issued.

The postconstruction permit review period, some 41/2 years in duration, is described in Section LB.1.d and includes a summary of the licensing organization's activities. Since the Atomic Energy Commission (AEC) licensing staff's interaction with the TMI-2 project was only intermittent during these years, and important regulatory events were reshaping the review process, some of these events are briefly mentioned. In addition, some of the difficulties inherent in the conduct of the postconstruction permit licensing review are discussed.

The operating license review period is presented in Section I.B.1.e. During this time the Atomic Energy Commission was abolished and the regulatory staff was restructured into the Nuclear Regulatory Commission. A later expansion of the licensing staff was designed in part to incorporate the feedback of operating experience into new or modified licensing requirements.

An overall operating license review summary stresses the role of the ACRS and the Atomic Safety and Licensing Board. The operating license issued for TMI-2 is discussed to show that it contained a large number of safety-related work items that had to be completed and approved by the NRC prior to becoming an effective full power license. This is not unusual in NRC practice, and does not, of itself, imply that important safety issues are avoided by the issuance of a license. But the issuance of a license does realign work priorities within the NRR and leads to some diffusion of the clear lines of project management responsibility and authority extant prior to issuance of a license.

The final portion of Section I.B.1.e examines the conduct of the review with respect to several safety issues of significance to the TMI-2 accident. The issues discussed generally show how Met Ed met the staff's requirements at the time of the review. However, these requirements or the procedures to ensure compliance with them were inadequate to guarantee that the TMI-2 accident would not occur.

Section I.B.1.f concludes this historical overview with findings and recommendations presenting some points that do not necessarily correspond to specific parts of the preceding sections. The points are the product of both this particular phase of the SIG's investigation and of the consultation with many people who participated and assisted in this inquiry.

b. Summary of Licensing Events-TMI-2 and TMI-1

In May 1967, Met Ed applied to the AEC for a license to construct and operate the first unit, TMI-1, at a site on Three Mile Island in the Susquehanna River, about 10 miles southeast of Harrisburg, Pa. TMI-1 is jointly owned by Met Ed, the Jersey Central Power and Light Company (JCPL), and the Pennsylvania Electric Company, which are named as licensees.

The plant was to use a 177 fuel assembly Babcock and Wilcox (B&W) nuclear steam supply system (NSSS) identical to those proposed by Duke Power Company in their December 1966 application to construct the Oconee 1 and 2 reactor plants. Three other applications docketed in 1967 proposed to use the same B&W NSSS.

An unexpected spate of reactor plant applications were submitted to the AEC in 1966 and 1967, as 30 additional new applications were docketed than the total for the previous 12 years. A table showing some data for plants that have been licensed to use B&W reactors is shown in Appendix I.3. As this table indicates, prior to the series of reactors typical of the TMI design, the only B&W commercial power reactor licensed to operate was Indian Point 1, which could produce only about one-fourth the thermal power of the 177 fuel assembly design and was a considerably different reactor system design.

After the AEC staff review and a public hearing before an ASLB in April 1968, the Commission issued a provisional construction permit for TMI-1 on May 18, 1968. In March 1970, Met Ed filed a Final Safety Analysis Report as a prerequisite to obtain an operating license for TMI-1. Following staff review and a public hearing lasting 3 days in November 1973, an operating license was issued for TMI-1 in April 1974.

In April 1968, JCPL submitted an application for a nuclear plant to be located adjacent to the existing Oyster Creek 1 in Ocean County, New Jersey. In March 1969, JCPL and Met Ed, as co-owners of this plant, jointly submitted an amendment to that application indicating a site change to the site where TMI-1 was under construction. In 'January 1971, the Pennsylvania Electric Company was added as a co-owner of the facility. It and JCPL each owned 25% of the facility and Met Ed owned the remaining 50%. The proposed plant was designated TMI-2 and was to be located adjacent to TMI-1. This plant was very similar to the TMI-1 plant, in using a B&W nuclear steam supply system essentially identical to that already under construction for the TMI-1 unit.

The AEC reported the results of its review of the TMI-2 construction permit application in a Safety Evaluation Report dated September 5, 1969. Following a public hearing, Provisional Construction Permit No. CPPR-66 was issued for TMI-2 on November 4,1969.

The applicant docketed the FSAR for TMI-2 on April 4, 1974. The NRC, newly created by the Energy Reorganization Act of 1974, assumed the regulatory functions and personnel of the AEC and became functional in January 1975. Staff review resulted in a September 1976 release by NRC of a Safety Evaluation Report related to the operation of TMI-2.

At the time the Safety Evaluation Report was released several issues remained to be resolved. In September and October 1976, the NRC staff and the applicant met with the ACRS to review the application, and the ACRS issued a letter report to the Commission on October 22,1976. The Commission staff issued two supplements to the Safety Evaluation Report in March 1977 and February 1978, indicating the resolution of all matters pertinent to licensing the plant to operate.

Petitions to intervene in the operating license review which began in April 1974 were received, and the Commonwealth of Pennsylvania requested to participate as an interested State. In July 1974, the ASLB designated to rule on intervention requests granted the Commonwealth's request as well as the joint intervention request of two local environmental interest groups. This set the stage for a public hearing on the operating license application, a proceeding not required at the operating license stage absent intervention.

The hearing on reactor safety issues conducted during 1977 resulted in an initial decision on December 19, 1977, that authorized the director of Nuclear Regulation:

> mo continue in effect the construction permit of . . ., and to make such additional findings on uncontested issues as may be necessary to the issuance of a full-term operating license for that unit consistent with the terms of this Initial Decision'

Following the resolution of several outstanding safety matters, the NRR issued Facility Operating License No. DPR-73 for TMI-2 on February 8, 1978. Simultaneously, Supplement No. 2 to the Safety Evaluation Report was issued documenting the resolution of all identified safety issues. As with other operating licenses issued at that time, resolution in some cases required plant operational limitalions, which were included as conditions in the license calling for certain preoperational tests, startup tests, and other items. Some conditions required further NRC approval before progressing through various operational modes needed to reach full power.

c. TMI-2 Construction **Permit Review-May** 1968 to November 1969

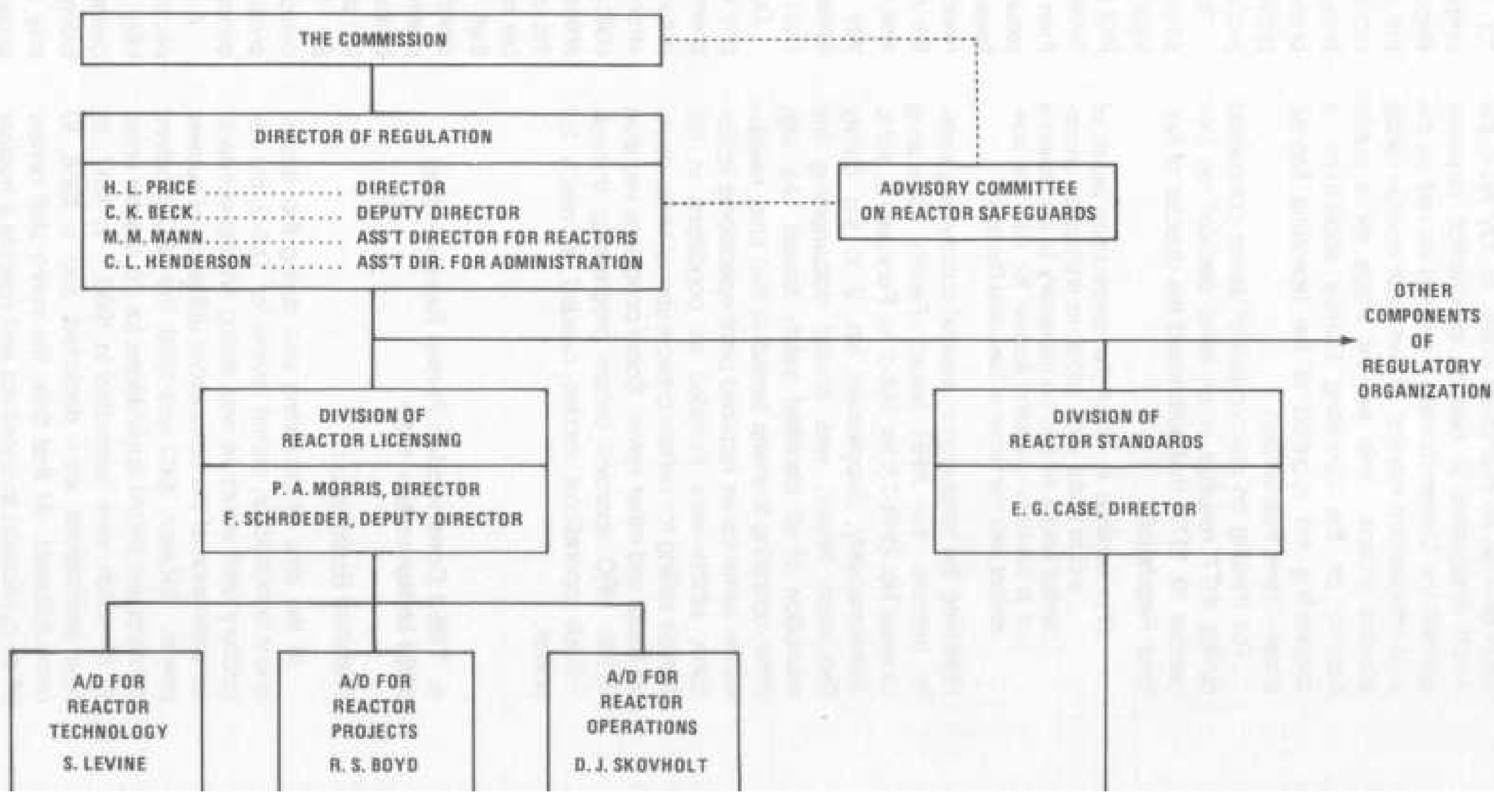
Historical Background

At the time of docketing and during the subsequent construction permit review for TMI-2, the regulatory staff structure was facing an unprecedented expansion of the commercial utilization of nuclear power. Between 1962 and 1966, the AEC received construction permit applications for 26 reactor units, 15 of which were submitted in 1966.[2] In 1967, 18 new applications were docketed, and in 1968, 10 more followed. At that time, the entire staff review of an application to construct and operate a nuclear powerplant was conducted within two groups known as the Division of Reactor Licensing (DRL) and the Division of Reactor Standards (DRS) (see the organization chart in Figure I-1). An application was assigned to a licensing project manager in one of the several reactor project branches in DRL. Then, as now, the project branch was responsible for managing and coordinating the staff review, preparing and issuing the staff's Safety Evaluation Report, and for representing the staff before both the ACRS and the ASLB. At that time, however, more of the technical review was conducted by the project manager and his associates. Specialist branches in DRS were used when necessary to provide a depth of expertise not available in the project management organization.

Because the review process was not as formally structured as it is today, more of the technical review responsibility could be retained within the project management group, and usually was. Both the scope and depth of the review were more limited than the reviews conducted today, however. As a result, reviews were completed within a year by fewer staff members than participate in more recent reviews. The technical assistance obtained during the review from DRS, as well as from within DRL, was from assistant directorates for reactor technology and reactor operations, groups parallel to the assistant directorate comprising the reactor projects branches.

During this same period, the regulatory philosophy was undergoing changes. Up to 1966, the AEC premised its regulatory requirements on an approach to safety that focused on the provision of a strong steel containment around the reactor and a policy of remote location away from populated areas. The Commission's strategy was to confine the consequences of a postulated maximum credible accident rather than to guarantee prevention of that accident. The safety philosophy was developed during the early years of commercial power reactors when 100 MW electric plants were typical. By 1966, only six commercial nuclear electric plants were in operation, all at 265 MW or less. By 1967, however, reactor plants were being designed to produce 800 to 1000 MW, thereby greatly increasing the potential consequences of a serious accident.

A commonly accepted definition of risk is an expected loss, quantitatively expressed as the probability of a postulated accident times the consequences of that accident. The risk of a serious accident was certainly increasing rapidly, if considered only from this viewpoint. Simple containment of the larger amounts of energy and stored radioactivity that could be released from the larger reactor designs was becoming more difficult to guarantee by analysis. Designs began to include additional backup systems, such as the emergency core cooling system, to mitigate the consequences of large loss-of-coolant-accidents.


THE COMMISSION
DIRECTOR OF REGULATION
H. L. PRICE .... DIRECTOR
C. K. BECK................ DEPUTY DIRECTOR
M. M. MANN............... ASS'T DIRECTOR FOR REACTORS
C. L. HENDERSON .... ASS'T DIR. FOR ADMINISTRATION
ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
OTHER COMPONENTS OF REGULATORY ORGANIZATION
DIVISION OF REACTOR LICENSING
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DIVISION OF REACTOR STANDARDS
E. G. CASE, DIRECTOR
A/D FOR REACTOR TECHNOLOGY
S. LEVINE
A/D FOR REACTOR PROJECTS
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A/D FOR REACTOR OPERATIONS
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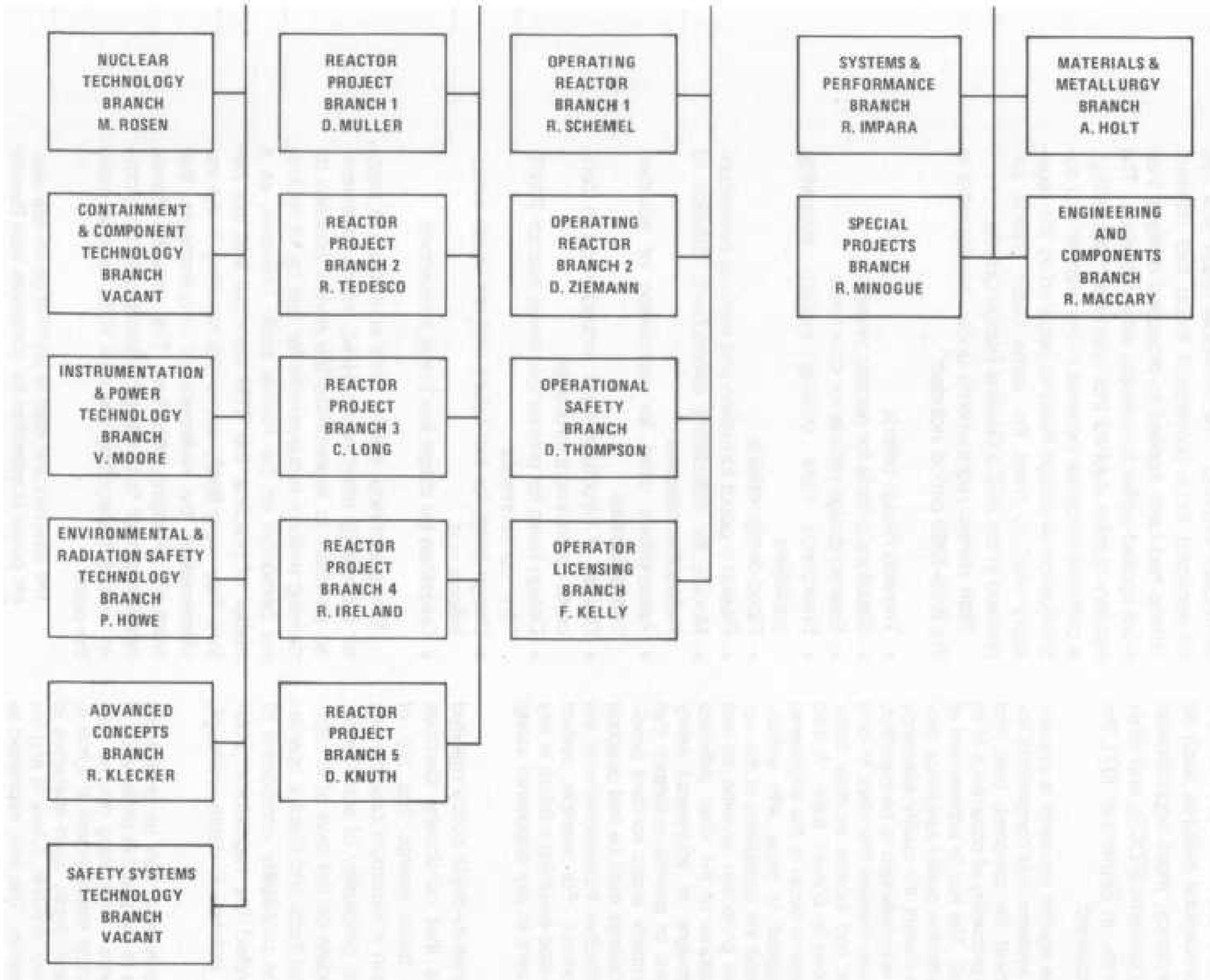

FIGURE I-1. Organization Conducting Licensing Reviews in October 1968

The report of a task force headed by William Ergen of the Oak Ridge National Laboratory issued in late 1967 moved the AEC toward a safety philosophy that demanded increased consideration of accident prevention as well as mitigation. However, this changed philosophy led to a considerably more complex set of regulatory requirements, including a variety of design and procedural features such as quality assurance, redundancy, more sophisticated emergency core cooling systems (ECCS), and other engineered safety features. In September 1971, the director of Regulation explained:

> The principal defense against accidents *is* prevention. All structures, systems, and components important to safety must be designed, built, and operated so that the probability of occurrence of an accident is very small. The key to achievement of this objective is an effective quality assurance program.... However excellent the quality assurance program, it must be acknowledged to be imperfect. Protective systems are installed therefore to deal with such transients and failures as may occur despite all that is done to prevent them. A third echelon of the defense in depth is the engineered safety features designed to cope with unlikely failures that go beyond the capabilities of the accident prevention and protection systems, as well as highly unlikely failures of the other defenses themselves. The designs of engineered safety features are evaluated to provide assurance that they *will* function properly under accident conditions. Each line of defense must be well designed and executed for effective implementation of the defense-in-depth concept. For example, system performance is evaluated assuming a failure of any single active component in any engineered safety feature.

The shift to this defense-in-depth policy resulted in a regulatory process that continually identifies new, additional design basis events that are of lesser consequences than a maximum credible accident, but have a higher probability of occurrence. The lack of a clear mandate on the level of acceptable risk, or the analytical tools and reactor operating data to establish the probability component of risk, considerably magnified the regulator's problems in pursuing the defense-in-depth concept, however:

> In principle, defense-in-depth can be proliferated endlessly, analogous to the possible proliferation of design basis accidents. Diminishing returns from such proliferation dictate establishment of a limit to the required defense-in-depth, again analogous to the distinction between 'credible' (Class 3) and 'incredible' (Class 4) events. This limit, expressed as either a requirement for depth of defense or an array of credible events for which protection is required, is one of the most difficult technical safety issues to resolve. As usual, the lack of knowledge regarding probabilities is responsible for the difficulty. Judgment is rendered on an inadequate basis, and therefore is subject to change as additional knowledge is gained.[3]

The same situation exists in 1979. Thus, during 1967 and in the years following, regulatory acceptance criteria for many basic licensing issues were continually evolving. The inevitable result was that an applicant for a powerplant found that different criteria had been applied to proposed designs than were applied earlier to evaluate similar designs. The industry quickly dubbed this approach "ratcheting", a continual stepwise increase in the number and sophistication of design features required by the regulatory staff to meet the same basic criteria expressed in the AEC's General Design Criteria.

Staff review requirements under development in the 1968-1969 period included:[4]

- Tornado design criteria
- Structural criteria for nuclear vessels
- Seismic design criteria for structures
- Emergency core cooling system evaluation guidelines
- Flood design criteria
- Fission product formation and removal evaluation
- Models for calculating atmospheric diffusion of radioactive releases
- Assumptions used for calculation of accident consequences
- Design of structural steel embedments in concrete containment structures
- Design basis for pressurized-water reactor (PWR) "dry" containments
- Design basis for fuel failure and rod worth calculations, and
- Guidelines for steam line break evaluations.

These technical issues were addressed in reactor technology memoranda (RTM), which represented an effort to systematize the review process by defining uniform requirements for use by all technical personnel on the review staff. However, as a matter of practice, the RTM were put into use before they were finally approved, resulting in the implementation by reviewers of requirements that were still changing with time. This was the classic development of "ratcheting." Statements from cover memos transmitting the new RTM for use make the point:

> The attached first draft of an RTM on off-site electric power is submitted for comments from Reactor Technology. We *will informally test the positions proposed* in the draft *in our next several-case evaluations.* **The results of trial usage and** RT comments *will* be factored into the second draft.[5] (Emphasis added.)

Furthermore:

> The enclosed document sets forth design criteria for PWR dry containments. These criteria were developed by a DRS-DRL team. The Director, DRS, concurs with the criteria. The Director, DRL, has directed that the criteria be used by DRL on a trial basis ' across the board.' Copies of the criteria will be distributed to all division technical **personnel** for this purpose. [6]

The Construction Permit Review

The construction permit review of the TMI-2 application was assigned in early 1968 to Licensing Project Leader Ray Powell, a member of Reactor Projects Branch No. 2. Powell's branch chief was Robert Tedesco. An initial plan for the review was approved and implemented in June 1968 (Figure I-2). A chronological summary of the construction permit review as actually conducted was included in the September 1969 Safety Evaluation Report by the staff and is reproduced in Figure 1-3.

During the staff's construction permit review, written requests for information were sent to the applicant on three occasions in 1968. The staff met with applicants' representatives 12 times during 1968 and 1969, prior to an ACRS subcommittee's consideration of the application on June 26, 1969 and the committee's consideration on July 10, 1969.

The October 18, 1968 staff requests for information included a request for a description of ECCS performance for postulated piping breaks of less than 0.4 square feet in area. The applicant had proposed that the ECCS be initiated by a low reactor coolant pressure (1800 psig) or alternatively by high containment pressure (4 psig). The staff was concerned, however, that for some small breaks the system's response might be delayed by a slower reactor depressurization. The applicant provided the results of analyses to demonstrate that the containment high pressure signal for the emergency core cooling system's initiation provided adequate backup protection for postulated reactor coolant pipe rupture areas down to 0.022 square feet. This is still larger than an open pressurizer relief valve, which is about 0.007 square feet. The staff later concluded that the applicant's design was acceptable.

By June 20, 1969, both the staff review and the applicant's responses were considered adequate to support an evaluation report addressed to the ACRS. [8] This type of report was the current licensing practice and constituted a summary of the staff's review; this report, written exclusively for the ACRS, had been prepared prior to the meeting in which the ACRS would review with applicant and staff the application for a construction permit. An internal staff memorandum to Peter Morris, then Director of the Division of Reactor Licensing, stated that resolution of the remaining matters could be deferred until after the issuance of the construction permit because, "[t]hey are either (1) items of a general nature generic to this class of reactor plant or (2) additional information not yet available is necessary to resolve these matters on a quantitative basis." [9] The matters highlighted in this memorandum included ECCS signal diversity, the applicant's commitments concerning control of hydrogen concentration in containment, and a staff requirement that the applicant submit plans for inservice inspection within approximately 6 months of construction permit issuance. Following an initial meeting with an ACRS subcommittee on June 26, 1969, the subcommittee members indicated additional matters that they felt might be addressed at the committee meeting scheduled for July 10, 1969. Among these were the site emergency plan and the instrumentation that would be supplied to assure that ECCS operation could be monitored following an accident to

At the ACRS meeting on July 10, 1969, the committee discussed the application with representatives and consultants of both JCPL and Met Ed, General Public Utilities Corporation (GPU), B&W, Burns and Roe, Inc., and the AEC regulatory staff. Following this meeting, the ACRS reported to the AEC chairman that it believed that, if due consideration was given to certain concerns, the TMI-2 plant could be constructed with reasonable assurance so that it could be operated without undue risk to the health and safety of the public." The committee's letter reiterated several, but not all, of the concerns identified elsewhere in the report of this inquiry, but in each case found that the matter could be resolved during construction of the plant.

Staff concerns which became committee concems included the applicant's plans to cope with potential hydrogen concentration in the containment, and questions regarding instrumentation connections designed to preserve the independence of protection and control systems. The committee also expressed concern about the integrity of the postaccident cooling system throughout the course of an accident. The focus of its concern was not on the specification of ECCS performance requirements as a function of the type of break, however, but rather that the ECCS would function for extended time in the accident environment. Significantly, the ACRS also called for a study of the possible consequences of hypothesized failures of protective

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Application and PSAR filed	April 29, 1968
Meeting to establish review plan	May 28, 1968
Issue Division of Reactor Licensing review plan	June 5, 1968
Preliminary report to ACRS submitted	May 29, 1968
First meeting with applicant and designer	June 11, 1968
ACRS briefing and technical meeting for grouted tendons presentation by applicant	June 13, 1968
Draft of Reactor Technology and consultant's questions	July 29, 1968
Reactor Technology and Reactor Operations questions due	July 29, 1968
Division of Reactor Licensing questions to applicant submitted	August 9, 1968
Applicant's response to Division of Reactor Licensing questions	August 30, 1968
Consultant reports (drafts) received	August 30, 1968
Technical meeting to settle problem areas resulting from consultants' reviews	September 1968
Final consultant reports received	September 20, 1968
ACRS Subcommittee meeting at site	October 1968
Reactor Technology and Reactor Operations ACRS report sections due	November 1, 1968
ACRS report to ACRS	December 20, 1968
ACRS meetings	January 2 & 3, 1969
Completion of Safety Evaluation	January 1969
Pre-Hearing	January 1969
Hearing	February 1969
Issuance of construction permit	February 1969

* MEMORANDUM, PETER MORRIS, DIRECTOR, DIVISION OF REACTOR LICENSING, TO MULTIPLE ADDRESSEES, "REVIEW PROGRAM AND ASSIGNMENTS FOR OYSTER CREEK UNIT NO. 2, DOCKET NO. 50-320," JUNE 10, 1968.

FIGURE 1-2. Schedule for Oyster Creek Unit 2 (Docket No. 50-320)*

April 29,1968	Application filed with three volumes Preliminary Safety Analysis Report (PSAR) for Oyster Creek Site
May 24,1968	Amendment No. 1 filed (clarification of Oyster Creek Unit 2 core power level and net electrical output)
June 11, 1968	Initial meeting with applicant (Jersey Central Power & Light Company) to review design
June 13, 1968	Meeting with staff and ACRS to review grouted tendon test program
July 1, 1968	Amendment No. 2 filed (grouted tendon test program)
August 16,1968	Meeting with applicant to review site and design criteria
August 27, 1968	Meeting with applicant to discuss seismic criteria, grouted tendons, liner design, instrumentation and quality assurance program
September 3, 1968	Amendment No. 3 filed (response to staff's request concerning reanalysis of probable maximum hurricane flood height)

FIGURE 1-3. TMI-2 Chronology of Review. Taken from safety evaluation by the Division of Reactor Licensing, U.S. Atomic Energy Commission, in the matter of Metropolitan Edison Company and Jersey Central Power and Light Company, Three Mile Island Nuclear Station Unit 2, Dauphin County, Pa. Docket No. 50-320, September 5, 1969

November 4,1968	Amendment No. 4 filed (response to staff's request for additional information dated September 19,1968)
November 8, 1968	Grouted tendon tests performed by Stressteel Corporation for applicant (witnessed by staff)
November 29,1968	Amendment No. 5 filed (response to staff's information request dated October 18, 1968)
December 10, 1968	Meeting with applicant to discuss iodine removal capability
January 15, 1969	Meeting with applicant to discuss change of plant site from Oyster Creek to Three Mile Island site and effects of change on plant design
February 14, 1969	Meeting with applicant to discuss grouted tendon surveillance program and quality assurance program
March 10, 1969	Amendment No. 6 filed (response to staff's request of October 18, 1968 plus complete PSAR revision changing plant site to Three Mile Island site)
March 17,1969	Amendment No. 7 filed (response to several matters raised in meetings with the applicant)
April 16,1969	Amendment No. 8 filed (revision and additional information regarding diesel load and size and containment pressure test)

FIGURE I-3-Continued

May 1, 1969	Applicant's request for exemption to permit construction of tendon access gallery submitted
May 7,1969	Amendment No. 9 filed (change of responsibility for design and construction to Metropolitan Edison Company)
May 13,1969	Meeting with applicant to discuss instrumentation and controls circuits
May 22,1969	Supplemental information relating to public need for exemption request submitted
June 16,1969	Meeting with applicants to discuss flood protection requirements
June 26, 1969	ACRS Subcommittee meeting with staff and applicant
June 27, 1969	Request for exemption to construct tendon access gallery granted
July 9,1969	Meeting with applicants to review applicant's design margins for grouted tendon prestress system
July 10,1969	Review by ACRS
July 17,1969	ACRS letter to Chairman Seeborg on Three Mile Island Nuclear Generating Unit No. 2

FIGURE 1-3-Continued

systems during anticipated transients, including steps required to limit the consequences. The staff's formal and publicly available Safety Evaluation Report of September 5, 1969,[12] issued several months after the committee meeting, included both the ACRS letter to the AEC and a summary of the staff and applicant plans to comply with the committee's recommendations during construction of the plant and during the operating license review of the plant.

In addition to design and analytical technical issues, the staff review at the construction permit stage included consideration of the applicants' technical qualifications to design and build TMI-2, the proposed Quality Assurance Program, and the applicant's plans for the conduct of operations at TMI-2. These matters also were reported in the staff's Safety Evaluation Report. The staff's finding that the applicant was technically qualified was based on an evaluation of information supplied by the applicant. The co-owners of the proposed plant, Met Ed and JCPL, had described how they were owned by GPU, a holding company that owned two additional utility companies. GPU also owned and operated the Saxton Research and Experimental Nuclear Unit. GPU had formed a Nuclear Power Activities Group to provide direct technical assistance to the nuclear project managers of its subsidiary companies. The TMI-2 project director for Met Ed was the vice president and chief engineer in the Met Ed Company. In addition, at that time a boiling water nuclear powerplant owned by JCPL, Oyster Creek Unit 1, was nearing operational status, and the TMI-1 plant, also owned by Met Ed, status, then under construction. The key participants involved in the TMI-2 project during 1969 are listed in Table 1-5.

Staff evaluation of the applicant's quality assurance plans was based on Met Ed's description of its commitments to certain actions and organizational structure. These Met Ed plans were measured against the staff's proposed Amendment to 10 C.F.R. 50, Appendix B, concerning quality assurance requirements, dated April 17, 1969, and found acceptable. The applicants' preliminary plans regarding plant operations were examined in the areas of personnel training, administrative controls, review and audit of operations, and the emergency plan. The staff's finding that these plans were adequate at the construction permit stage was based on the similarity of these plans to those for TMI-1 that had been found to be acceptable at the construction permit stage approximately 1 year earlier.

Following the Safety Evaluation Report issuance, a public hearing was held in Middletown, Pennsylvania, on October 6, 1969. No petitions for leave to intervene were filed with the ASLB and the only parties to the proceeding were the applicant and the staff. The staff, over the signature of the director of regulation, had already published both its proposed findings in the case and a proposed provisional construction permit with the Notice of Hearing in the *Federal Register*.[13] In accordance with the Commission's rules of practice, the board was to consider whether the application and the record of the proceeding contained sufficient information, and whether the staff's review had been adequate to support the proposed findings and the proposed provisional construction permit. An area resident presented a limited appearance statement expressing concern relating to protection of the facility from aircraft using the nearby Olmstead State Airport. Thomas M. Gerusky, a representative of the Pennsylvania Department of Health, stated that mutually satisfactory programs relating to radiological health and emergency procedures had been established in cooperation with the applicants and the U.S. Public Health Service.

On October 31, 1969, the ASLB issued its initial decision on the matter of TMI-2. The board found that the staff's review had been adequate to support both the proposed findings and the proposed provisional construction permit (see also the summary of adjudicatory proceedings in this report). Relevant findings of fact in the hearing, paraphrased from the initial decision (see Appendix 1.7), were as follows:

- The applicants and staff had identified specific issues warranting research and development efforts necessary to develop the final design of the facility. The areas of research and' development included analyses or tests on core thermal and hydraulic design, fuel-rod clad failure, internal vent valves, once-through steam generator, blowdown forces on reactor intervals, chemical spray system, and the effects of radiolysis. A schedule for furnishing information prior to completion of construction of the proposed facility was established by the parties to the hearing.
- The applicants had established a comprehensive Quality Assurance Program consistent with the intent of the AEC's proposed Appendix B to 10 C.F.R. Part 50.

The ASLB thus instructed the director of regulation to issue a provisional construction permit to JCPL and Met Ed. On November 4, 1969, Provisional Construction Permit No. CPPR-66 was issued. The Atomic Safety and Licensing Appeal Board examined the record of the proceeding and affirmed the decision of the ASLB in a memorandum

TABLE 1-5. TMI-2 projects organization

Organization	Function
Metropolitan Edison Company Jersey Central Power & Light Company	Co-owners
Burns & Roe, Inc.	Architect-engineer
Metropolitan Edison Company	Responsible for design, construction, and operation
United Engineers & Constructors	Construction Manager
Pickard & Lowe Associates	Design consultant
Babcock & Wilcox	Nuclear steam supplier
MPR Associates	Provide quality assurance assistance
GPU Nuclear Power Activities Group	Technical assistance
Schupack & Associates	Structural consultant
Gilbert Associates, Inc.	Architect-engineer, cooling towers and switchyard and aircraft design consultants

issued November 25, 1969. The Commission took no further action, and the construction permit decision became the final and official Commission action effective December 11, 1969.

d. The Postconstruction Permit Review Period, 1969-74

Met Ed encountered delays in the construction of TMI-2 (discussed later in this section) and did not submit its application for an operating license until February 1974. In the several years following the issuance of the construction permit in November 1969, the regulatory process continued to grow in the number and complexity of safety matters which were of concern to the regulatory staff. (The licensing organization during this period is described in Appendix 1.4.)

Following the 1969 construction permit issuance for TMI-2, reactor designs continued to evolve, as the number of reactor plant applications increased rapidly, continuously outpacing the staff's ability to collect, evaluate, and utilize plant operating experience in the licensing process. (As noted in Appendix 1.4, an Office of Operations Evaluation was established for this purpose in April 1972.) Protection of the environment emerged as a dominant national issue, culminating in the National Environmental Policy Act (NEPA) of 1969 and the Water Quality Improvement Act. This environmental legislation resulted in additional demands on both the users and the regulators of nuclear power. While the new environmental issues of thermal pollution and low level radiation effects did not directly influence radiological safety reviews, the additional scope of staff effort required for a given application to construct a plant presented increased management challenges to the regulatory agency.

In May 1971, the AEC reported the results of a reduced scale test of an emergency core cooling system conducted at its Idaho test facility. Although the test apparatus differed from a real ECCS in important ways, the test results unexpectedly cast doubt on the efficacy of such systems, and within a month the AEC issued emergency Interim Acceptance Criteria to assure safe operation of the ECCS if called upon. The adequacy of the ECCS immediately became an issue in construction permit and operating license hearings generally, and in the TMI-2 system in particular.

Met Ed was requested by a letter dated August 13, 1971 to provide information to show that the ECCS proposed for TMI-2 would meet the AEC criteria using a suitable evaluation model. The model was to be developed by Babcock and Wilcox, working directly with the AEC. The letter asked that the information be submitted with an application for an operating license, which at that time was not anticipated for at least another year. Met Ed was advised that if they submitted the material earlier, "we will review it in accordance with the priorities that exist at that time..."

However, the TMI-1 project was under operating license review at this time (since March 1970) and the TMI-1 design incorporated the same B&W nuclear steam supply system. Met Ed addressed the ECCS interim acceptance criteria on the TMI-1 application, where their submittal was reviewed and reported in the staff's Safety Evaluation Report issued for TMI-1 on July 11, 1973. This report covered the consequences of postulated small breaks in the reactor coolant system, and found that the ECCS would provide adequate protection for small breaks in the reactor coolant system. The smallest break examined in the evaluation was a 0.04-square foot break in the reactor coolant pump suction piping, larger than an open pressurizer relief valve, which would be an approximately 0.007-square foot orifice. The work done on the TMI-1 project was later confirmed in the TMI-2 operating license review.

On July 15, 1970, the director, Division of Reactor Licensing, notified Met Ed that the AEC would require, at the time of filing the Final Safety Analysis Report, information to support the staffs preparalion of an environmental impact statement for the TMI site. The information required was outlined in the letter. In a subsequent letter to Met Ed dated September 3, 1971, the director of regulation advised that in the Calvert Cliffs decision of July 23, 1971, the U.S. Court of Appeals for the District of Columbia had required a revision in the AEC's policy for implementing NEPA, and enclosed the effective "interim" policy. The environmental review was, in accordance with staff practice, conducted independently of the radiological safety review, which was at this point essentially quiescent for the TMI-2 project. In December 1972, the AEC staff issued a Final Environmental Statement reflecting the completion of the environmental review for both TMI-1 and TMI-2.

Also during this period, the groundwork was being laid for issuance of improved regulatory staff guidance to applicants regarding the criteria for radiological safety reviews. As a result of the regulatory staff reorganization of March 1970, the internal guidance termed reactor technology memoranda became publicly available as safety guides developed by the Division of Reactor Standards. As Harold Price, the Director of Regulation, explained to the AEC Commissioners in a memo concerning the issuance of safety guides:

> There is a need for an expeditious means of providing additional guidance to applicants on the acceptability of proposed design features... We believe such safety guides have the potential for reducing the present uncertainties in the licensing process and also have the potential for reducing regulatory staff and ACRS workload on individual cases since less review of individual designs will be required 14

The memo proposed issuance of the first three guides, and listed several others that the staff was working on.

In June 1970, there were no approved AEC General Design Criteria as part of the regulations, although a set of such criteria had been proposed for inclusion in 10 C.F.R. 50 in July 1967. Prior to issuance of the GDC, the purpose of the new Safety Guides was, as expressed in an Appendix to the Price memo to the Commissioners in June 1970, to "make available to the industry solutions that are acceptable to the regulatory staff and the Advisory Committee on Reactor Safeguards on certain safety issues." Safety guides continued to be developed (they later became regulatory guides) and became one of the several instruments used to express the technical review staff's interpretation of the GDC. The GDC were finally issued as Appendix A to 10 C.F.R. 50 in February 1971. The criteria, although generalized statements, clearly represented the essence of staff past practice and focused on matters of principal safety significance that had evolved through regulatory actions since the mid-1960s.

With the exception of the new ECCS requirements and the new NEPA requirements, both of which were issued to Met Ed with instructions to consider no later than the time of application for an operating license, no items having later significance to the TMI-2 accident arose through 1971.

Construction continued for both units at Three Mile Island, and in March 1972, GPU met with the staff to inform them that the operating license application for TMI-2 would be submitted in September or October 1972, and that plant construction was about 25% complete, with fuel loading scheduled for early 1975.

Two separate events in 1972 led to the identitication and the regulatory staff's articulation of specific safety design criteria that were not identified prior to that time. First, a leak in a large nonsafety-related expansion joint at the Quad Cities plant in Iowa resulted in water damage to equipment that would be important in safe plant shutdown. Accordingly, Met Ed and other applicants were informed in September of the necessity to consider the potential for damage to safety equipment by failures of nonsafety equipment.

The second event was an anonymous letter to the ACRS raising questions about the safety of certain pipe locations at the Prairie Island plant in Minnesota. The writer was concerned that ruptures in main steam or feedwater lines, outside of the containment, could damage adjacent equipment or structures necessary to mitigate the consequences of the pipe rupture. The ACRS brought the matter to the attention of the staff, which, after reviewing the Prairie Island design, decided that changes were necessary and that all plants should be examined to ensure that adequate protection was provided. Met Ed was notified in December that a response would be required.

In August 1973, Met Ed was informed that a change in the regulations governing operator licensing would require inclusion of a description and plans for implementation of an operator requalification program in the operating license application. Prior to 1973, licensed operators were required to renew their licenses every 2 years, but could obtain renewal simply by showing that they had performed the duties for which they were licensed and that their current employer had continuing need of their services as licensed operators. No retraining or requalification had been necessary. The requalification requirements embodied in the regulations effective on September 17, 1973, 38 Fed. Reg. 22221 (1973), are presently still in effect.

The three issues described above were presented to Met Ed (at different times) with the request that a response be provided within 30 days, without regard to when Met Ed might submit their operating license application. This staff practice was typical of that time and is also used today. Selected "generic" issues identified by the staff and considered sufficiently important to warrant immediate notification of each applicant by letter are to be responded to promptly by the 'applicant even if outside the context of an ongoing construction permit or operating license review. The applicant's response to the staff request is then reviewed. On the other hand, the periodic but unsolicited submittal of final design data to the NRC by an applicant constructing a nuclear powerplant is not necessarily reviewed after its submittal prior to formal application for the operating license.

Before May 1973, when the deputy director for reactor projects issued a "Project Managers Handbook," there was no comprehensive, formally structured approach to the role of project management in the various phases of the staff review of an application. The postconstruction permit (post-CP) period in particular was an ad hoc activity relative to the more structured process during the construction permit or operating license review stages.

The project management of post-CP applications was intended to include the project manager's followup to resolve those matters documented in the Safety Evaluation Report or the public hearing record as items remaining to be resolved after the permit was issued. Even so, once the CP was issued and the applicants' resources were heavily committed to final design engineering and plant construction, resolution of these matters often was delayed due to changed priorities. Several factors contributed to this phenomenon.

Unless specifically documented in the construction permit as a "condition" of the permit's validity, no penalty to any party would result from deferral of the post-CP matter until the operating license review. Early resolution of the matter prior to the operating license review would usually benefit only the permittee by providing a perceived certainty that an acceptable solution had been obtained and that, as a result, his resource expenditures were defined and fixed. For the staff, this earlier resolution meant a decision taken at an unnecessarily early time, thus possibly foreclosing future decision options which might be indicated by additional information obtained later. As a result, these matters generally were regarded to be of lower priority by the technical managers that allotted staff technical review resources. Staff review schedules for these matters were normally long, and expanded if an applicant delayed his response to a staff information request.

The post-CP project, "inactive" relative to an ongoing CP or operating license review, was more likely to be reassigned among the available project managers during staff personnel and organization changes. The project could also be transferred among project management branches, further diluting management continuity. Such changes also tended to diminish the perceived importance of vigorous pursuit of post-CP issues over periods of months and sometimes years.

A number of post-CP requirements were identified in the staff's Safety Evaluation Report for TMI-2, including the following:

- Further review of the applicant's status reports on development of the inservice inspection program
- Review of the final design for aircraft protection
- Further review of the Quality Assurance Program and
- Continued review of all ACRS recommendations, during construction

Except for the aircraft crash issue which was resolved for the operating license for TMI-1, the document record of TMI-2 licensing activities does not indicate that these matters were pursued with Met Ed during the construction period prior to the start of the operating license review. The aircraft crash issue was reopened after additional data on airport use became available (see Appendix 1.7).

Although systematic problems existed in efficiently resolving matters carried over from the CP review into the post-CP period, the permittee and staff generally agreed on the substance of and need for the issues that had been identified but not resolved during the construction permit review.

Two other kinds of post-CP issues were not so defined, presenting additional stumbling blocks to early resolution. These were the issues that arose after the construction permit was issued. Neither the AEC nor the NRC has developed a systematized, procedurally controlled method of conclusively acting either on changes proposed by applicants during the post-CP period or on new regulatory requirements arising after the CP issuance that might be required of these permittees. There are legal and technical difficulties inherent in interpreting "principal architectural and engineering criteria," which form part of the basis for the construction permit issuance and cannot be changed by the permittee without a construction permit amendment. On the other hand, staff imposition of new requirements on permittees is legally constrained by 10 C.F.R. 50.109 which states that "the Commission may... require the backfitting of a facility if it finds that such action will provide substantial additional protection which *is required* for the public health and safety... " (Emphasis added.) Backfitting is defined in the regulation as the addition, elimination, or modification of structures, systems or components of the facility after the construction permit has been issued.

In practice, these two types of issues have only affected staff interaction with permittees during the period from issuance of the construction permit to the applicant's submittal for an operating license. Regulatory staff evaluation of changes identified to the staff by an applicant during the post-CP period is often not completed until the operating license review. This is particularly true of complex issues that involve controversy between staff and applicant. But the consequences of this practice, in terms of public risk, could be significant. It is probable, if not certain, that staff requirements specified during an operating license review, requiring hardware changes (backfitting) in designs fixed by the applicant several years before, may be less technically sophisticated (and more costly) than if the applicant had been required to implement a staff position at the time during construction when the modification or addition could have been incorporated more readily.

The Regulatory Requirements Review Committee[15] was established in early 1974 to create a permanent management committee with responsibility for assessing the need for each new proposed safety requirement and for making specific decisions regarding the imposition of each requirement. (Additional discussion of this committee is presented in Section I.A.3.a.) The committee would consist of senior management representatives of the technical review divisions and the reactor project management division. As originally intended, the committee would "review significant new regulatory requirements or changes that provide significant relief from existing requirements, and to decide whether, when and to what plants these changes should be applied."

From the beginning, however, a program for implementation of new requirements, once accepted, proved difficult to specify with clarity. Until September of 1975, decisions on new requirements documented in RRRC meeting summaries usually stated that the new requirement would be effective at some future date, or at the earliest, "immediately," a term interpreted to apply to all applications currently in process and to any future applications, but not to require immediate modification of plants where the CP had been issued. At least twice[1fi] prior to July 1975, the committee instructed the staff to develop or implement a comprehensive program for resolving the matter of "backfitting" new or existing requirements to operating facilities licensed prior to the development of the requirement. No such program was implemented, however. The summary of the 31st meeting, issued September 24, 1975, announced that the RRRC would in the future categorize its decisions and clearly delineate which of the newly approved requirements would be required to be "backfied" to all plants, whatever their status of construction or operation. There was still no management approved program to assure that staff action was completed to effect the prompt implementation of each new "backfit" issue on the operating plant to which the issue would apply, however, and this situation prevailed through the time of the TMI-2 accident in March 1979.

In early 1973, the AEC licensing project manager for TMI-2 had reported to his management that the TMI-2 Final Safety Analysis Report would be submiffed in July 1973. This expectation was not met, and on October 26, 1973, Met Ed formally requested an extension of the dates set forth in the construction permit as the estimated earliest and latest dates for completion of construction. The proposed new dates were to be May 1, 1976 and May 1, 1977, 4 years later than originally planned. Met Ed's stated reasons for the delay included unforeseen delays in engineering and procurement, additional engineering required to revise the FSAR to meet the new AEC Safety Analysis Report guide and its subsequent Revision 1 (October 1972), difficulties in construction, difficulties in financing, additional work necessary to meet the recent AEC Interim Acceptance Criteria for ECCS, the need for additional restraints on high energy systems outside containment, and delays resulting from a decrease in the construction force to assure more effective quality control. The staff recognized the Met Ed delay and in a letter of November 8, 1973, the director of regulation urged that Met Ed submit their operating license application about 24 months before the scheduled fuel loading date for the plant. This set the date for submittal of the operating license application at about May 1974.

Meanwhile, two reactor units similar to the TMI units received operating licenses during 1973. Oconee 1 and 2, constructed and operated by the Duke Power Company, started operation on Lake Keowee in South Carolina. The TMI-1 plant received an operating license in April 1974. Oconee 3, also at the Lake Keowee site, began operation in July 1974.

e. The Operating License Review period-January 1974 to February 1978

Summary

On February 15, 1974, Met Ed submitted the application for an operating license for TMI-2. This included the FSAR and other general information as required by 10 C.F.R. 50.34. The FSAR was organized in accordance with the staff's guidance contained in the "Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants," Revision 1, dated October 1972. The new licensing project manager, who had been assigned in October 1972, met with the technical reviewers assigned to the acceptance review for the project to brief them on their responsibilities.[17] This part of the review process is designed to yield conclusions, based on a few hours of work by each reviewer, covering the completeness of the information supplied by the applicant. The project manager advised the reviewers of staff and ACRS concerns arising from the CP review, findings during onsite inspections during construction, testimony at the CP hearings in 1969, and potential new requirements developed by the staff during the years since the issuance of the CP.

On March 19,1974, the staff met with representatives of Met Ed, Babcock & Wilcox, General Public Utilities, Burns and Roe, and Gilbert Associates to discuss the results of the completed acceptance review, and to inform Met Ed of the additional information required to complete the FSAR as necessary for the staff to begin the operating license review. The application with Amendment 13 to the FSAR was accepted and docketed for operating license review on April 4,1974.

A staff review schedule was established, based on an operating license issuance within 24 months. This schedule was not met, however. The minimum operating license review schedule for any plant is set by plant construction progress, since an operating license (OL) cannot be issued until construction is certified as complete.[18] Like most OL applications, the TMI-2 application was docketed much earlier than necessary to complete the review before the plant was ready to load fuel. Staff experience has shown that as delays in plant completion are encountered, applicants' responses to staff concerns also are slowed, which in turn can result in further schedule delays in staff actions. Of the 46 months between the April 1974 docketing of the OL application and its issuance in February 1978, about 12 months were attributed to construction delays, six months to Met Ed licensing delays, and four months to staff delays.[18]

By August 21, 1974, the first round of staff questions had been sent to Met Ed. This standard question and response method of review continued for another 25 months until the staff's issuance of the Safety Evaluation Report in September, 1976. Another new Licensing Project Manager, Harley Silver, was assigned in May 1975.[19]

The Safety Evaluation Report issuance was impeded both by staff delay in preparing questions and evaluating responses, and by Met Ed delay in responding to questions. Met Ed also encountered delays in plant construction. As a result, in early 1976 a number of unresolved issues remained between the applicant and staff.[20] In May 1976, Met Ed was predicting that the plant would be ready for fuel loading in July 1977,[21] which would have been the earliest time that an operating license was needed.

At this time, in a letter to Met Ed,[22] the NRC project management branch chief responsible for the TMI-2 review presented a revised schedule for completing the Safety Evaluation Report and taking the project to ACRS review. This schedule assumed completion of the ACRS review by August 20, 1976. After still further schedule delays during

1976, however, the ACRS review was concluded in October 1976. (See the discussion in the following section entitled "The Role of the Advisory Committee in Reactor Safeguards (ACRS) in TMI-2 Licensing."). During 1977 and early 1978, additional delays in resolving outstanding issues further delayed issuance of the operating license until February 1978. While hearings before the Atomic Safety and Licensing Board continued throughout 1977, they were not the pacing event because an initial decision was issued during December 1977.

During the operating license review, a number of events took place which could have left their mark on the TMI-2 operating license review, the general conduct of the licensing process, or its organizational elements. Some of these events were:

- The creation of the Regulatory Requirements Review Committee in early 1974
- The creation of the NRC in January 1975
- The issuance of the Standard Review Plan in November 1975 (**see** Appendix 1.5)
- The reorganization of the Office of Nuclear Reactor Regulation in December 1975 (**see** Appendix 1.4)
- The issuance of the second through the sixth ACRS Generic Issues letters[23]
- The issuance of 61 new regulatory guides and 74 revisions to issued guides
- A Congressional inquiry into staff regulatory practice in 1976, precipitated by safety issues raised by NRC staff members
- The staff's continuing struggle to implement the Standard Review Plan, and the ultimate rejection[24] of any attempt to "backfit" the acceptance criteria to a number of plants in the licensing process, including TMI-2

The public hearing process began soon after the ACRS review was completed in October 1976. The public hearing was precipitated by the granting of an intervention request made by the Citizens for a Safe Environment and the York Committee for a Safe Environment as joint petitioners. The Commonwealth of Pennsylvania was also granted permission to participate as an interested State.

In accordance with the Commission's rules, the ASLB confined its hearing to the matters placed in controversy by the parties. Several board hearing sessions were held during the period of March through July 1977. Issues argued during the hearings involved the following:

- The environmental impact of thermal releases
- The biological survey performed by the applicant's consultant
- The design of the cooling towers for earthquake or tornado resistance
- The applicant's cost-benefit figures used to justify the need for the nuclear plant
- The capability of containment structures and other buildings to withstand aircraft impact
- The environmental radioactivity monitoring program
- The flood protection system
- The warnings and evacuation plans of both the applicant and the Commonwealth of Pennsylvania
- Gaseous radioactivity releases during normal operation
- The effect on local water quality of chlorine discharge from the plant circulating water system and
- The effect of cooling tower plumes on the gaseous effluent from the plant

The ASLB initial decision issued on December 19, 1977, 6 NRC 1185 (1977), authorized the director of the NRR to "make such additional findings on uncontested issues as may be necessary to the issuance of a full-term operating license for that unit, consistent with the terms of this Initial Decision." The joint intervenors moved to stay the order on the basis that the environmental review of the nuclear fuel cycle had not correctly dealt with the effects of radon (Rn-222) releases generated in the course of the mining and milling of uranium. The appeals were denied by both the Atomic Safety and Licensing Appeal Board (ALAB-456, January 27, 1978) and the Commission (order issued March 2, 1978). An operating license was issued on February 8, 1978. Legal maneuvering by the intervenors was continued in the case; the hearing record was ultimately reopened, and litigation continues to this day. (Additional information on the ongoing hearing process is summarized in the section entitled "The Hearing Phase of TMI-2 Licensing," under Section I.B.1.e.)

The Role of the Advisory Committee on Reactor Safeguards (ACRS) in TMI-2 Licensing

The documented ACRS review of the TMI-2 project at the operating license stage is contained in three documents, the transcripts of subcommittee and committee meetings,[25] and the subsequent letter summary report to the NRC chairman by the ACRS chairman (see Appendix 1.6). The ACRS discussed the Met Ed application with representatives of and consultants for the applicants, General Public Utilities Service Corporation, the Babcock and Wilcox Company, Burns and Roe, Inc., and the NRC staff. At that time, the application, which had been reported on in the staff's Safety Evaluation Report, was represented in part by the applicant's FSAR as amended through Amendment No. 44. The operating license was ultimately issued based on the FSAR through Amendment No. 62.

The ACRS letter noted several topics that the committee concluded needed more work by the applicants or the NRC staff or both. Some of these topics had more relevance to the TMI-2 accident than others, but on each topic, the committee's comments were more characteristic of earnest advice to be followed in the indeterminate future than of strong recommendations which must be carried out as a condition of a favorable ACRS report to the Commission. A sampling of these comments from the TMI-2 letter, but typical of ACRS letters on all projects, follows:

- This ... should be reviewed and evaluated by the NRC staff prior to operating at up to full power ...
- The committee wishes to be kept informed.
- This issue should be resolved in a manner satisfactory to the NRC staff.
- The committee recommends that (staff and applicant) ... continue to strive for an early resolution of this matter in a manner acceptable to the NRC staff.
- The committee believes that appropriate test procedures to confirm ... should be developed.
- The committee recommends that further review be made ...
- The committee recommends that studies be made ...
- The committee recommends that, prior to commercial power operation of TMI-2, additional means ... should be in hand in order to provide improved bases for timely decisions ...
- The committee believes that the applicants and the NRC staff should further review ... for measures ... and that such measures should be implemented where practical.
- Those (generic) problems should be dealt with appropriately ... as solutions are found.

The committee's conclusion on the review was as follows:

> The Advisory Committee on Reactor Safeguards believes that, if due regard is given to the items mentioned above, and subject to satisfactory completion of construction and pre-operational testing, there is reasonable assurance that Three Mile Island Nuclear Station, Unit 2 can be operated at power levels up to 2772 MWt without undue risk to the health and safety of the public.

Thus, although the committee expressed a number of reservations in a general way, it recommended no explicit restraints or conditions on the issuance of an operating license. The committee found that, subject to certain "satisfactory completion," there was "reasonable assurance" that TMI-2 could be operated safely.

The adequacy of the emergency core cooling system was not a specifically reported concern, and the ACRS apparently recognized and accepted, without prejudice, that the staff and applicant were still involved in work to complete the Met Ed justification of the ECCS design. As reported elsewhere in this licensing summary, the staff and Met Ed interaction concerning ECCS matters extended through 1977 and even during 1978 after an operating license had been issued.

Generic issues noted by the ACRS included some of the matters which later proved to be significant in the TMI-2 accident. As generic issues, however, these were by definition to "be dealt with appropriately ... as solutions are found." Issues having TM!-2 accident significance were:

- Behavior of reactor fuel under abnormal conditions
- Instrumentation to follow the course of an accident
- Maintenance and inspection of plants

The 14 issues raised by the ACRS were addressed by the staff in the March 1977 Supplement No. 1 to the Safety Evaluation Report. All but five issues were considered closed out in Supplement No. 1. Of the remaining five, the staff closed out all but one in their Supplement No. 2 issued in February 1978 concurrently with the issuance of the operating license. The remaining issue involved the scheduled implementation of required plant improvements to assure that staff requirements for fire protection would be met. The operating license was conditioned to require that these improvements be completed prior to startup following the first regularly scheduled refueling outage.

In the 15 months between the ACRS review and issuance of the operating license, the staff declared 17 plant specific issues other than those raised by the ACRS to be resolved through staff and applicant interaction. The FSAR was formally changed 18 times. Nevertheless, in February 1978, five remaining issues required specific conditions in the license. Although the ACRS received copies of all correspondence on the docket, and theoretically could have intervened with additional direction or advice at any time, it was not involved in the review and approval of any of these matters. The ACRS review was formally concluded in October 1976.

The Hearing Phase of TMI-2 Licensing

Construction of TMI-2 was authorized in November 1969 by an initial decision of the ASLB after a hearing in which there was no opposition to the plant.[26] On May 20, 1974, the Atomic Energy Commission provided opportunity to interested persons to request intervention and a public hearing on the proposed operation of TMI-2. The joint intervenors presented numerous contentions which alleged various inadequacies relating to protection of the public health and safety and the environment.[27]

Two of the joint intervenors' contentions were:

> The environmental radioactivity monitoring program of the Applicant's is inadequate to accurately measure the dose delivered to the public during normal and accident conditions. Only active, real-time detectors can determine what the actual dose rate is. Furthermore, an array of offsite detectors could greatly aid in possible evacuation plans. No operating license should be granted until the Applicants provide a network of active radiation monitors.

> The warning and evacuation plans of the Applicants and the Commonwealth of Pennsylvania are inadequate and unworkable. The plans assume that all local and State officials involved are on 24-hour notice and can be contacted immediately. They further assume that all people notified will promptly react and know how to respond and are trained to do so. They also assume that the public which has been assured that accidents are 'highly unlikely' or 'highly improbable' will respond and allow themselves to be evacuated. No operating and evacuation plans are shown to be workable through live tests.[28]

The joint intervenors offered no extensive expert testimony on these issues, however, and the licensing board rejected both as nonsupportable. Basing its rejection of the radiation monitoring contention on the testimony of witnesses offered by the NRC regulatory staff and the applicant, the licensing board said:

> With respect to the ability of active, real-time detectors to aid in evacuation plans, such detectors would again be of little or no value. Instrumentation used to determine the severity of an accident, and the need for any offsite emergency action, is located on site and is monitored from the reactor control room.

> In summary... , the Board finds that the radiological effluent and environmental monitoring programs as proposed by the Applicants and approved by the Staff are adequate to measure and evaluate normal radioactive effluent releases... and that active, real-time detectors would add nothing to the present capability. We further find that the response or effectiveness of both in-plant instrumentation and offsite personnel in the event of an accident would not be aided or improved by such detectors...[29]

The joint intervenors did not appeal the licensing board's decision on this issue.

The licensing board, in rejecting the joint intervenors' contention on the inadequacy of emergency planning, found:

> [T]hat the record supports the conclusion that [this Contention], in its entirety, is without merit, and that the Staff has properly assessed the adequacy and workability of the emergency response. We also find the emergency and evacuation plans to be both adequate and workable.

The capability to successfully use the originally approved emergency plan was challenged by the joint intervenors in the operating license hearing. Witnesses testified on behalf of the staff, the applicants, and the Commonwealth of Pennsylvania. This contention was the only one for which the Commonwealth presented prepared testimony and submitted proposed findings, and it adopted the applicant's proposed favorable findings as its own.[31] The intervenors presented no prefiled testimony, but conducted extensive cross-examination and submitted proposed findings on this issue.

The intervenors challenged several assumptions that they considered crucial to successful action in accordance with the plan. These challenged assumptions were:

- That appropriate State and local officials are available to be contacted any time they are needed
- That such personnel, upon being notified, will know the right thing to do and will do it promptly because they have been so trained
- That any members of the public that should be evacuated will respond appropriately and will permit themselves to be evacuated despite the lack of drills or tests of the public response

The board found that the preponderance of evidence supported all of the above assumptions, and that the emergency and evacuation plans were both adequate and workable.

board's decision on emergency planning to the

Atomic Safety and Licensing Appeal Board. Relying on the record produced before the licensing board, the appeal board rejected all of the intervenors' arguments.[32] The ASLAB's holding confirmed the evidentiary deficiency in the joint intervenors' case, and also found that:

> [E]xisting Commission regulations do not require consideration in a licensing proceeding of the feasibility of devising an emergency plan for the (in the event of an accident) of persons located outside of the low population zone.
>
> It is true that, for reasons which need not be discussed here, the applicants and the staff nevertheless looked into the possible need for protective measures within a 5-mile radius of the reactor- and the intervenors were permitted to cross-examine on the evidence presented in this regard. It scarcely follows from this fact, however, that the question of emergency planning at still greater distances from the LPZ boundary had to be explored at the Intervenors' instance.
>
> The requirements for evacuation planning are rooted in 10 CFR Part 100, and that Part 100 assumes releases of radiation based upon a hypothetical major accident 'that would result in potential hazards not exceeded by those from any accident considered credible.' Thus, what accidents might conceivably occur at the particular plant in question is irrelevant to planning for emergency evacualion; that is based solely on the Part 100 hypothetical accident and the assumed releases of radioactivity resulting therefrom3

Not discussed at the hearing was the NRC program to review and concur in radiological emergency plans prepared by State governments, or the existence or status of any such plan for Pennsylvania. The Commonwealth had been requested by the NRC in 1975 to submit a State plan for review.[34,35] However, at the time of the accident, the Commonwealth did not have an NRC approved radiological emergency plan.[36] As far as can be determined, the Commonwealth never submitted a Pennsylvania Radiological Emergency Response Plan to the NRC for review in response to the 1975 request, even though a recent General Accounting Office (GAO) report[37] indicated that such a plan existed or was being prepared.

A significant issue throughout the TMI-2 licensing proceeding (as well as for that of TMI-1) has been whether the public is adequately protected against the hazards of an airplane crash into the plant.[38] The board agreed that additional evidence must be taken on the probability of heavy aircraft crashes into the plant, with one member dissenting, in part, on the grounds that the operating license should have been suspended pending decision on this issue.[39] This matter had not been resolved as of March 28, 1979. (Extracts from important board decisions have been reproduced in Appendix 1.7.)

The TMI-2 Operating License

The TMI-2 operating license issued on February g 1978 contained numerous conditions and includan Attachment 2 specifying required preoperational and startup tests which could not be started until many other specifically identified work items were completed "to the Commission's satisfaction." The authorized event sequence of initial fuel loading, cold shutdown, initial criticality (startup), and power operation required written authorization from the NRC prior to each new step in the sequence.

The TMI-2 license provides that

> Metropolitan Edison Company is authorized to operate the facility at a core power level of 2772 megawatts thermal. Prior to attaining that power level, Metropolitan Edison Company shall comply with the appropriate conditions identified in Paragraph (3) below and complete the preoperational tests, startup tests and other items identified in Attachment 2 to this license in the sequence specified. Attachment 2 is an integral part of this license.

The "Paragraph (3)" and "Attachment 2" referred to describe many incomplete work items in systems and components clearly important to safety. The practical result of this approach is that the license, publicized as an authorization to operate at full power for 40 years, is actually only a permit to load fuel and go to cold shutdown. Following that, an extensive remaining technical effort, including interaction with the NRC staff, is still required to get the plant to a full power operational status. As of September 1978, approximately 14 major work items remained to be completed. TMI-2 did not reach full power operational status until November 1978.

From the time of the operating license issuance, the TMI-2 plant was officially an "operating reactor" as far as the NRC licensing process was concerned. According to standard licensing process practice, the organization nominally responsible for operating reactors does not usually accept responsibility for the newly licensed "operating" plant at that time. In this case, TMI-2 did not become the responsibility of the NRR's Division of Operating Reactors even though the TMI-1 reactor, in operation since 1974, was already so assigned. When the TMI-2 accident occurred in March 1979, formal responsibility for the plant remained with the Division of Project Management.

This delay is largely attributable to the reluctance of the DOR to accept responsibility for a plant when a significant number of safety issues still remain unresolved. Asserting this reluctance, the division refused to accept responsibility for TMI-2 in September of 1978,[40] and formal responsibility was not transferred to the DOR until August 22, 1979.[41] The project management responsibility for all of the B&W operating reactors other than TMI-2 was with the Operating Reactors Branch No. 4 in DOR.[42]

The licensee's first contact point with NRC is Inspection and Enforcement,[43] which determines whether additional NRC help is needed to resolve a particular matter. This is an important change from the way the review process works prior to license issuance, when the assigned project manager for the DPM is the principal NRC contact with Met Ed. During the period between February 1978 and March 1979, several licensing actions took place. (These actions are described in Section I.A.2.)

Operating License Review Issues Having TMI-2 Significance

The licensing of a nuclear plant entails NRC staff judgments on a large number of radiological safety issues. The following review focuses on several specific issues relevant to the TMI-2 special inquiry.

Site Selection

At the time the Three Mile Island site was selected for Unit 1, five sites had been considered by the then joint applicants, Met Ed, JCPL, and Pennsylvania Electric Company.[44] The alternative site evaluation was done in 1965 and 1966, prior to a CP application in May 1967. The sites considered were:

1. Three Mile Island
2. Gilbert Station site on the Delaware River in New Jersey
3. Portland Station site on the Delaware River in Pennsylvania
4. Monocacy site on the Schuylkill River, south of Reading Pennsylvania
5. Berne site on the Schuylkill River, north of Reading

All of the considered sites were roughly equivalent in their distance from population centers, a major consideration. Foundation conditions, including exposure to seismic disturbances, likewise did not significantly vary at these sites. The ultimate selection of TMI-1, intended to be operating by 1973 or 1974, was based on the following considerations:

1. Availability and cost of cooling water
2. Transmission investment and transmission losses
3. Cost of site and site preparation
4. Construction labor rates and productivity

Studies for siting the nuclear unit that eventually became TMI-2 began in 1967, and this unit was to begin operation at about the same time as TMI-1, 1973 or 1974. Of the six sites considered in the region, Oyster Creek, New Jersey was initially selected, largely because of the local need for additional generation capacity and the associated transmission cost savings attendant to plant construction in that area. However, Met Ed re-examined the siting issue in 1968 and decided that the TMI site had certain economic advantages over Oyster Creek based on a planned 1973 operating date. In December 1968, the decision was made to construct a second unit at TMI.

Offssite Radiological Impacts

Met Ed analyzed and reported on a number of accidents and anticipated transients in its Final Safety Analysis Report. The staff selected certain of these analyses as representative of events for which the offsite dose consequences would be conservatively greater than the other accident sequences analyzed by Met Ed. For these selected sequences the staff independently calculated the potential consequences.

The radiological consequences of selected "design basis" accidents were examined by the staff in two kinds of review activities. One was the radiological safety review, concerning the maximum dose that an individual would receive while standing on either the plant exclusion boundary or the edge of the defined low population zone. A second review presented the results of similar analyses in terms of both the dose to an individual on the plant boundary and the integrated dose to the total estimated population within 50 miles of the site.[46] In each of these reports, the staff found that the calculated doses, which were considered to be either realistic or very conservatively calculated for the specific accidents analyzed, represented very low and acceptable risks to the public. The staff's Safety Evaluation Report stated that the calculated potential offsite doses due to design basis accidents were less than the offsite dose guidelines of 10 C.F.R. 100. Thereafter, in section 7.0 of the supplement to the Final Environmental Statement the staff reported that the estimated integrated exposure of the population within 50 miles of the plant from each postulated accident would be orders of magnitude smaller than that from naturally occurring radioactivity.

No hypothetical sequences of failures more severe than the postulated "design basis" accidents were considered because their probability of occurrence was thought to be sufficiently low to preclude consideration. The staff's environmental statement explicitly embodied this approach, referring to guidance issued by the Commission in the form of a proposed annex to Appendix D, 10 C.F.R. Part 50,[48] which has never officially been made a part of the regulations. From the time of its 1971 publication to this date, this proposed annex has constituted the highest level and most recent document promulgated by the NRC explaining what a Class 9 accident is and why such accidents are to be excluded from consideration in the licensing process:

> The occurrences in Class 9 involve sequences of postulated successive failures more severe than those postulated for establishing the design basis for protective systems and engineered safety features. Their consequences could be severe. However, the probablity of their occurrence is so small that their environmental risk is extremely low. Defense in depth (multiple physical barriers), quality assurance for design, manufacture, and operation, continued surveillance and testing, and conservative design are all applied to provide and maintain the required high degree of assurance that potential accidents in this class are, and will remain, sufficiently remote in probability that the environmental risk is extremely low. For these reasons, it is not necessary to discuss such events in applicants' Environmental Reports.

Thus all persons or groups necessary to approving the operating license for TMI-2 tacitly accepted that the conservatively calculated doses reported in the Safety Evaluation Report, being within 10 C.F.R. Part 100 guidelines for the postulated accidents examined, were in fact the necessary and sufficient demonstration of an acceptable level of risk from accidental releases of radioactivity. Further, each of the accident sequences evaluated was based on the staff's "single active failure" criteria, which did not include assumptions of personnel actions that could or would degrade emergency cooling functions in the reactor coolant system or secondary system, or both. Figures 1-4 and 1-5 show the offsite dose consequences as reported in the staff's Final Environmental Statement and SER. Finally, even though the TMI-2 project had been excepted from adherence to the Standard Review Plan used in staff reviews after 1975, the offsite dose consequence analyses and results therefrom met the staff guidelines and acceptance criteria as contained in the staff Standard Review Plan in February 1978.

Emergency Core Cooling System

The Met Ed Final Safety Analysis Report incorporated, by reference, B&W topical reports BAW-10104, "B&W's Evaluation Model," and BAW-10103, "ECCS Analysis of B&W's 177-FA Lowered Loop NSS." The evaluation model required by Appendix K to 10 C.F.R. 50 was documented in BAW-10104. BAW-10103 described the application of the model to evaluate the consequences of a range of sizes of hypothetical pipe breaks in order to analytically demonstrate compliance with 10 C.F.R. 50.46.

In the September 1976 Safety Evaluation Report, the staff stated:

> The emergency core cooling system for Three Mile Island Unit 2 complies with 10 CFR Part 50.46 and 10 CFR Part 50, Appendix K, and is acceptable, pending completion and review of the issues identified in our review of BAW-10103 (request for additional small and transition break analyses), and verification that these are applicable to Three Mile Island Unit 2. These analyses are expected to be submitted by December, 1976.

The staff reviewed additional analyses submitted by B&W in December 1976, and approved B&W's small break analyses for their 177 fuel assembly, lowered loop steam design, on February 18, 1977. Although several calculational model changes were reported by B&W after February 1977 and were subsequently approved by the staff, the small break analyses completed prior to February 1977 were shown to be acceptably conservative. The final Safety Evaluation Supplement No. 2, issued February 1978, stated that "studies of the spectrum of breaks have been completed and are in accordance with the emergency core cooling system acceptance criteria, and are acceptable."

The smallest break postulated by B&W at that time was 0.04 square feet at the reactor coolant pump suction. B&W concluded that:

> [F]or breaks less than or equal to 0.04 square foot, the HPI [high pressure injection] alone is capable of matching decay heat boiloff and maintaining a liquid inventory sufficient to preclude any temperature excursions.[49]

Significant assumptions made for this analysis included the continued operation of at least one of two redundant HPI systems, a reactor coolant pump trip and coastdown coincident with reactor trip, and the availability of the auxiliary feedwater system. None of these conditions were met during the TMI-2 accident.

Still further changes in small break analyses were reported by B&W and resolved with the staff during 1978, after TMI-2 licensing. The 1978 revisions in the detailed justification of emergency core cooling system performance for the smallest break did not change the conclusion reached earlier, that a 0.04-square foot break would not result in any significant fuel element cladding temperature increase. The revised calculations, approved by the staff, showed that after 50 minutes, the HPI flow would exceed the fluid mass loss due to boil off through the break, and that prior to 50 minutes the fluid mixture level would not drop below the top of the core. Again, a key assumption in the analysis, but not realized in the TMI-2 accident, was that ECCS flow from at least one HPI pump would be continuously available from the time of its automatic initiation.

During 1976, 27 separate generic safety issues were raised by several NRC staff members who felt that the staff's consideration of these issues was deficient. These issues became the subject of extensive discussions in various settings, including the ACRS and Congressional Committees. The issues were not discussed in the staff technical review as reported in the Safety Evaluation Report of September 1976 or its two subsequent supplements of March 1977 and February 1978. Each of the issues was addressed in staff testimony introduced in the public hearing held on the TMI-2 project, and for each issue, the staff found that operation of TMI-2 could be authorized.

One of the 27 issues relevant to the TMI-2 accident concerned the potential consequences of an interruption in design ECCS flow within a few minutes after its automatic initiation. As originally described by a staff member, the interruption in flow was possible because operators in some plants were required to reset the safety injection signal 2 minutes after the occurrence of the signal. Reset is the manual cancellation of the safety injection logic signal, which causes power to be supplied to engineered safety features loads, including the ECCS and related support systems. While reset does not of itself turn off the ECCS loads (pump, valve, and fan motors) which are already drawing power, a subsequent loss of offsite power would require prompt operator action to manually restart them. This is because the automatic control logic for startup of emergency diesel generators would cause sequential loading of normal shutdown cooling loads (not ECCS loads, in the absence of the safety injection signal) in some designs, and no loads at all in some other designs.

In considering this issue, the ACRS concluded that a loss of offsite power subsequent to the safety injection signal should be considered in accident analyses whether or not the safety injection signal could be reset, because in either case a delayed loss of offsite power would cause some interruption of ECCS flow while electrical loads were being transferred to the diesel generator.51 Until this time, the staff had postulated in the design basis analyses that offsite power was lost coincident with a loss-of-coolant-accident. All of the discussions that took place on this matter focused on the design basis large-pipe break LOCA, but not on small break analyses. For the large LOCA, the break and the safety injection signal occur almost simultaneously because of the very rapid depressurization, whereas for the small breaks the safety injection signal itself could be delayed, and was for approximately 2 minutes in the TMI-2 case. The effect of later ECCS interruption on the smaller break accidents is unknown.

While the ACRS noted that the consequences of interruption in ECCS flow should be examined because at that time it was seen that an offsite power loss could cause the interruption, another cause of interruption is now obvious-if permitted by design and encouraged by procedures and training, an operator may erroneously reduce or terminate ECCS flow in the first crucial minutes of a depressurization event, such as occurred at TMI-2 for what amounted to a very small break.

The NRC's conclusions reported in November 1976, prior to ACRS review, were:52

1. Inspection and Enforcement (IE) would review operating pressurized water reactors to assure that all safe shutdown loads would automatically be picked up following an operator action to reset the safety injection signal.
2 IE would also examine emergency procedures to be followed in the event of a LOCH to assure that the procedures do not permit safety injection reset earlier than 10 minutes following the accident signal, unless such action was shown to be necessary in the interest of safety.
3. There was no basis for changes in current operating licenses or for changes of staff priority in considering the issue.

The staff testified at the TMI-2 hearing on May 18, 1977, concerning each of the 27 issues, that no major change in regulatory requirements was necessary to assure the health and safety of the public. Concerning Issue No. 4, "Loss of Offsite Power Subsequent to Manual Safety Injection Reset Following a LOCA," the following testimony was given:

> This issue applies in general to Westinghouse plants; it is not applicable to Three Mile Island Unit 2. This plant design does not require system SIS (safety injection signal) reset to permit further operator action. Control is retained of individual components. After a postulated loss of offsite power following a LOCA, as long as the actuating signal exists, ECCS loads would be automatically sequenced onto the emergency diesels. (Emphasis added.)

CLASSIFICATION OF POSTULATED ACCIDENTS AND OCCURRENCES
(FROM FINAL ENVIRONMENTAL STATEMENT, DECEMBER 1972, SECTION VI)

CLASS	AEC DESCRIPTION	APPLICANT'S EXAMPLE(S)
1	TRIVIAL INCIDENTS	NONE
2	SMALL RELEASES OUTSIDE CONTAINMENT	SPILL IN SAMPLE HOOD
3	RADWASTE SYSTEM FAILURE	INADVERTENT RELEASE OF WASTE GAS DECAY TANK
4	FISSION PRODUCTS TO PRIMARY SYSTEM (BWR)	NOT APPLICABLE
5	FISSION PRODUCTS TO PRIMARY AND SECONDARY SYSTEMS (PWR)	ONE DAY OPERATION WITH PRIMARY SYSTEM LEAK TO REACTOR BUILDING NORMAL OPERATION WITH STEAM GENERATOR TUBE LEAK AND RELEASE FROM CONDENSER
6	REFUELING ACCIDENTS	DROP OF FUEL ASSEMBLY OR DROP OF HEAVY OBJECT ON FUEL ASSEMBLY
7	SPENT FUEL HANDLING ACCIDENT	DROP OF FUEL ASSEMBLY
8	ACCIDENT INITIATION EVENTS CONSIDERED IN DESIGN BASIS EVALUATION IN THE SAFETY ANALYSIS REPORT	UNCOMPENSATED OPERATING REACTIVITY CHANGES STARTUP ACCIDENT ROD WITHDRAWAL ACCIDENT COLD WATER ACCIDENT LOSS OF COOLANT FLOW ACCIDENT STUCK-OUT, STUCK-IN, OR DROPPED CONTROL ROD ACCIDENT LOSS OF ELECTRIC LOAD ACCIDENT STEAM LINE FAILURE STEAM LINE LEAKAGE STEAM GENERATOR TUBE FAILURE ROD EJECTION ACCIDENT LOSS OF COOLANT ACCIDENT WASTE GAS TANK RUPTURE
9	HYPOTHETICAL SEQUENCES OF FAILURES MORE SEVERE THAN CLASS 8	NONE

FIGURE 1-4.

SUMMARY OF RADIOLOGICAL CONSEQUENCES OF POSTULATED ACCIDENTS

(SINGLE UNIT ONLY)

CLASS	EVENT	ESTIMATED FRACTION OF 10 CFR PART 20 LIMIT AT SITE BOUNDARY *	ESTIMATED DOSE TO POPULATION I N 50 MILE RADI US, MAN-REM
1.0	TRIVIAL INCIDENTS	**	**
2.0	SMALL RELEASES OUTSIDE CONTAINMENT	**	**
3.0	RADWASTE SYSTEM FAILURES		
3.1	EQUIPMENT LEAKAGE OR MALFUNCTION	0.073	10
3.2	RELEASE OF WASTE GAS STORAGE TANK CONTENTS	0.29	40
3.3	RELEASE OF LIQUID WASTE STORAGE TANK CONTENTS	0.003	0.47
4.0	FISSION PRODUCTS TO PRIMARY SYSTEM (BWR)	**N.A.**	N.A.
5.0	FISSION PRODUCTS TO PRIMARY AND SECONDARY SYSTEMS (PWR)		
5.1	FUEL CLADDING DEFECTS AND STEAM GENERATOR LEAKS	**	**
5.2	OFF-DESIGN TRANSIENTS THAT INDUCE FUEL FAILURE ABOVE THOSE EXPECTED AND STEAM GENERATOR LEAK	.002	0.23
5.3	STEAM GENERATOR TUBE RUPTURE	0.096	13
6.0	REFUELING ACCIDENTS		
6.1	FUEL BUNDLE DROP	0.015	2.1
6.2	HEAVY OBJECT DROP ONTO FUEL IN CORE	0.26	36
7.0	SPENT FUEL HANDLING ACCIDENT		

FIGURE I-4-Continued

CLASS	EVENT	ESTIMATED FRACTION OF 10 CFR PART 20 LIMIT AT SITE BOUNDARY *	ESTIMATED DOSE TO POPULATION IN 50 MILE RADIUS, MAN-REM
7.1	FUEL ASSEMBLY DROP IN FUEL STORAGE POOL	0.01	1.3
7.2	HEAVY OBJECT DROP ONTO FUEL RACK	0.038	5.3
7.3	FUEL CASK DROP	**N.A.**	**N.A.**
8.0	ACCIDENT INITIATION **EVENTS CONSIDERED** IN **DESIGN BASIS** EVALUATION IN THE SAFETY ANALYSIS REPORT		
8.1	LOSS-OF-COOLANT ACCI-DENTS		
	SMALL BREAK	0.16	40
	LARGE BREAK	1.2	1000
8.1(a)	BREAK IN INSTRUMENT LINE FROM PRIMARY SYS-TEM THAT PENETRATES THE CONTAINMENT	N.A.	**N.A.**
8.2(a)	ROD EJECTION ACCIDENT (PWR)	0.12	100
8.2(b)	ROD DROP ACCIDENT (BWR)	**N.A.**	**N.A.**
8.3(a)	STEAMLINE BREAKS (PWR's-OUTSIDE CONTAINMENT)		
	SMALL BREAK	<0.001	<0.1
	LARGE BREAK	<0.001	0.13
8.3(b)	STEAM LINE BREAKS (BWR)	**N.A.**	**N.A.**

*REPRESENTS THE CALCULATED FRACTION OF A WHOLE BODY DOSE OF 500 MREM OR THE EQUIVALENT DOSE TO AN ORGAN.

**THESE RELEASES WILL BE COMPARABLE TO THE DESIGN OBJECTIVES INDICATED IN THE PROPOSED APPENDIX I TO 10 CFR PART 50 FOR ROUTINE EFFLUENTS (I.E., 5 MREM/YR TO AN INDIVIDUAL FROM EITHER LIQUID OR GASEOUS EFFLUENTS).

FIGURE I-4-Continued

15.3 RADIOLOGICAL CONSEQUENCES OF ACCIDENTS

15.3.1 GENERAL

AS NOTED IN THE SAFETY EVALUATION REPORT, WE HAD PREVIOUSLY CONCLUDED THAT WITH A CONTAINMENT LEAK RATE OF 0.13 PERCENT PER DAY AND A DOSE REDUCTION FACTOR OF 6.6, THE OFFSITE DOSE GUIDELINES OF 10 CFR PART 100WOULD BE MET.

WE HAVE REVIEWED THE REVISED SPRAY ADDITIVE SYSTEM DESCRIBED IN SECTION 6.2.3 OF THIS SUPPLEMENT, AND CONCLUDE THAT THIS SYSTEM, ALTH000H SLIGHTLY LESS EFFECTIVE FOR IODINE WASHOUT THAN THE SYSTEM ORIGINALLY PROPOSED IN THAT IT DOES NOT REMOVE THE ORGANIC FORM OF IODINE, RESULTS IN A SUFFICIENTLY RAPID ABSORPTION OF THE DOMINANT ELEMENTAL FORM TO MEET THE OFFSITE DOSE GUIDELINES OF 10 CFR PART 100WITH A CONTAINMENT LEAK RATE OF 0.13 PERCENT PER DAY. TABLE 15.1 HAS BEEN COMPLETED TO SHOW THE POTENTIAL OFFSITE DOSES RESULTING FROM THE POSTULATED LOSS-OF-COOLANT ACCIDENT.

15.3.2 DESIGN BASIS ACCIDENT ASSUMPTIONS

IN THE SAFETY EVALUATION REPORT, WE HAD NOT COMPLETED SUBPARAGRAPH 4 OF THIS SECTION COVERING ASSUMPTIONS DEALING WITH IODINE REMOVAL. BECAUSE THE APPLICANT HAS NOW PROVIDED AN ACCEPTABLE SPRAY ADDITIVE SYSTEM, THESE PARAMETERS ARE LISTED BELOW.

4. IODINE REMOVAL BY THE CONTAINMENT SPRAY SYSTEM WAS BASED ON:

SPRAYED CONTAINMENT VOLUME	1.764×10^{6} CUBIC FEET
UNSPRAYED CONTAINMENT VOLUME	3.950×10^{5} CUBIC FEET
MIXING RATE BETWEEN SPRAYED AND UNSPRAYED REGIONS	2.0 TURNOVERS OF UNSPRAYED VOLUMES PER HOUR PLUS 18 000 CUBIC FEET PER MINUTE
IODINE REMOVAL COEFFICIENTS	
ELEMENTAL	10.0 HOURS^{-1}
ORGANIC	0
PARTICULATE	0.4 HOURS^{-1}
ELEMENTAL IODINE DECONTAMINATION FACTOR	100

FIGURE 1-5. Accident Analyses (From Safety Evaluation Report, TMI-2, Supplement 1, March 1977)

POTENTIAL OFFSITE DOSES DUE TO DESIGN BASIS ACCIDENTS

ACCIDENT	TWO HOUR EXCLUSION BOUNDARY (610 METERS)		COURSE OF ACCIDENTS LOW POPULATION ZONE (3218 METERS)	
	THYROID	WHOLE BODY	THYROID	WHOLE BODY
	(REM)	(REM)	(REM)	(REM)
LOSS-OF-COOLANT	280	8.2	108	2.1
POST-LOCA HYDROGEN PURGE DOSE			<1	
FUEL HANDLING	46	3		<1
STEAM GENERATOR TUBE RUPTURE	6	<1		
STEAM GENERATOR TUBE RUPTURE WITH IODINE SPIKE	76	<1		
STEAM LINE BREAK	2	<1		
LOSS OF OFFSITE POWER	<1	<1		
LOSS OF OFFSITE POWER WITH COINCIDENT IODINE SPIKE	1	<1		
GAS DECAY TANK RUPTURE	NEGLIGIBLE	6	NEGLIGIBLE	<1
ROD EJECTION**				
CASE 1	24	< 1	11	<1
CASE II	102	2	19	<1

**ACTUAL ROD EJECTION DOSES WILL NOT EXCEED THE DOSES FOR CASE I (RELEASES THROUGH THE CONTAINMENT) OR CASE II (RELEASES THROUGH THE SECONDARY SYSTEM).

FIGURE 1-5-Continued

Notwithstanding this disclaimer of the issue's relevance to TMI-2, further work was done to assure that all pressurized water reactor facilities had written procedures describing all necessary operafor actions to sustain operation of the emergency diesel generator, ECCS, and related engineered safety features after a loss of offsite power following a LOCA, and **subsequent to a safety** injection signal reset.

A March 19, 1979 memorandum from IE to the Division of Operating Reactors[53] stated that of 46 operating pressurized-water reactors inspected (including TMI-1 and TMI-2), 30 were found either not to need any corrections because of inherent design features, or already to have adequate procedures, and 16 were found to require procedure revision. All deficient procedures were said to have been corrected by December 31, 1978. However, an examination of emergency procedures effective on March 28, 1979 (see Section II.C.1 of this report) indicates that, for a small break LOCA in particular, the TMI-2 procedures include (1) an explicit direction to bypass (reset) the safety injection system signal, and (2) a caution to restore, by manual action after loss of offsite power, only the reactor building isolation and cooling functions, not any safety injection function.

A curious factor relative to this issue is the well known and accepted staff review practice within the Division of Systems Safety generally to refuse to give credit in safety analyses for operator actions needed earlier than 10 to 20 minutes following a LOCA.[54] Allowing an operator to electively terminate ECCS injection flow within the first 10 minutes "if necessary for safety" is inconsistent with this practice. One might question the decision to allow any elective degradation of design flow during a time of great demand on the operator's decision-making capability (increasing the potential for error), if that is not necessary to safety. On the other hand, if it is necessary to safety, allowance of the manual action would appear to be in direct conflict with established regulatory practice disallowing *required* manual actions early in an accident sequence.

The regulatory staff's evaluation of whether licensees are justified in concluding that prohibiting safety injection system reset for 10 minutes is not in the best interest of safety is still underway. Work on other matters considered of higher priority has displaced any progress on this part of the issue since gathering responses from a number of licensees in late 1977. Regarding the ACRS concern about the loss of power at any time subsequent to ECCS initiation (even without any adverse operator action), again no further staff analysis has been reported. The ACRS concern has, since March 1978,[55] been classed as a generic issue to be managed by the Technical Activities Steering Committee. The matter now is the responsibility of the Unresolved Safety Issues Task Force.

Onsite Radiological Protection

Met Ed had proposed ventilation systems designs acceptable to the staff as of the time of the Safety Evaluation Report issuance in September 1976. The staff agreed in the Safety Evaluation Report that the systems were designed to assure that personnel are not exposed to normal or abnormal airborne concentrations exceeding those in 10 C.F.R. Part 20 by (1) maintaining air flow from areas of low radioactivity potential to areas of high radioactivity potential (2) preventing recirculating air in the auxiliary and fuel buildings (3) maintaining a negative pressure in the auxiliary and fuel buildings with respect to the atmosphere and (4) periodically purging the containment structure with outside air through high efficiency particulate air and charcoal filters.

When the operating license was issued in February 1978, an exemption from NRC requirements on the quality of the charcoal in the fuel handling building air cleanup system was allowed until the first regularly scheduled refueling outage, at which time the charcoal was to be replaced. This had been requested by Met Ed on the basis that the initial loading of charcoal had been specified and purchased prior to a revision in NRC requirements (Regulatory Guide 1.52, Revision 1, July 1976), and that laboratory testing of the charcoal indicated filtration efficiency only slightly less than the new NRC requirement. The exemption was granted by citing in the operating license the specific sections of the technical specifications which would be exempted. However, an additional section was erroneously cited which exempted the requirement to test the charcoal after each 720 hours of use. This error was the apparent result of incomplete checking by qualified NRC technical personnel of a "last minute" change incorporated within a day or two of the issuance of the operating license on February 8, 1978. The resultant elimination of the requirement to periodically test the charcoal, which did not quite meet standards at installation, set the stage for the undetected degradation of the charcoal that probably did occur. The charcoal adsorber was important for removal of radioactive iodine from the fuel handling building and auxiliary building atmospheres.

Following the operating license issuance, modifications in the heating and ventilating systems of the fuel handling building and auxiliary building, discussed in more detail in the IE investigation into TMI-2,[56] resulted in continuous flow through these filters. The staff originally approved the filters, system design, and operational surveillance procedures on the basis that the filters would normally be bypassed and would be used only when needed to filter air expected to contain some radioactive iodine. The staff was not informed of the design change by Met Ed, and the filter charcoal was not tested between March 1978 and March 29, 1979. It is concluded (see Section II.B.2) that the operating history of the filters significantly degraded the removal efficiency of the carbon filter material prior to the TMI-2 accident.

Instrumentation to Monitor the Course of an Accident

At the issuance of the Safety Evaluation Report in September 1976, the postaccident monitoring instrumentation was considered an open issue only because of the lack of justification that the instrumentation would survive a design basis earthquake. This concern was subsequently reported resolved in Supplement No. 1, issued in March 1977, and Supplement No. 2 of February 1978. The staff accepted the Met Ed proposals on the basis of (1) an analytical verification of structural integrity, (2) the potential availability of backup information from portable equipment, and (3) the similarity of the instruments to other seismically qualified components. No evaluation of the equipment with respect to postaccident environment design criteria was reported.

Equipment qualification for the postaccident environment in general was and is a continuing and controversial design issue. Postaccident environmental criteria have for several years been selected conservatively to envelope those conditions expected within containment following the design basis LOCA events analyzed in the applicant's Safety Analysis Report. Design basis accidents have by definition precluded core damage greater than that expected in the large-pipe break LOCK This predicted environment has included radiation levels characteristic of relatively much less core damage and radioactivity released to the containment than occurred at TMI-2. Staff review responsibility, vested primarily in the electrical instrumentation branch and the technical specifications development group, was exercised in the TMI-2 review only to the extent of assuring that certain plant or system variables were selected for monitoring, that the appropriate instruments would have assured safety-grade power sources, and that the systems were expected to survive postulated accident environments to provide information to plant operators. Installed postaccident monitoring instrumentation and the availability of that instrumentation for TMI-2 was documented in Tables 3.3-10 of the technical specifications[57] which is reproduced here as Figure 1-6.

The issue of postaccident monitoring also arose during the late 1976 consideration of the 27 issues raised by staff members. Issue No. 21, "Instruments for Monitoring Both Radiation and Process Variables During Accidents,"[58] reflected the staff position that radiological effluent and area monitoring are not relied on as a primary means of coping with postulated accidents. Testimony on the 27 generic issues at the TMI-2 operating license hearing reiterated the staff position, and stated that there were no radiation monitoring systems at TMI-2 that were required to automatically activate emergency equipment to mitigate the consequences of the LOCA. This was based in part on the assumption that the safety features actuation system would initiate containment isolation on the detection of a 4-psig pressure in the containment. The testimony stated that:

> [T]he staff determined that gaseous release from the reactor containment would be isolated from the environment by the action of the Safety Features Actuation System and that there would be no flow of containment gases through either the reactor containment purge monitor or through the plant vent monitor.

As the TMi-2 event would later demonstrate, the staff's position quoted above is an example of the problems inherent in its focus on the large break LOCA event which would have quickly pressurized the containment sufficiently to cause isolation. At TMI-2, the 4-psig containment pressure, which was the only signal that would isolate the containment, was not reached for about 4 hours after the accident, partly because of manual actions taken by the operators to activate the building's self-contained cooling and ventilation system. During that time some 8000 gallons of reactor coolant water (that had been released through the pressurizer relief valve) and contained gases were inadvertently transferred out of containment.

The staff's Standard Review Plan had since November 1975 specified criteria that required diverse containment isolation signals. But TMI-2, as an operating license application that was docketed pri-

INSTRUMENTATION

POSTACCIDENT INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.3.6 THE POSTACCIDENT MONITORING INSTRUMENTATION CHANNELS SHOWN IN TABLE 3.3-10 SHALL BE OPERABLE.

APPLICABILITY: MODES 1, 2, AND 3.

ACTION:

A. WITH THE NUMBER OF OPERABLE POSTACCIDENT MONITORING CHANNELS LESS THAN REQUIRED BY TABLE 3.3-10, EITHER RESTORE THE INOPERABLE CHANNEL TO OPERABLE STATUS WITHIN 30 DAYS, OR BE IN HOT SHUTDOWN WITHIN THE NEXT 12 HOURS.

B. THE PROVISIONS OF SPECIFICATION 3.0.4 ARE NOT APPLICABLE.

SURVEILLANCE REQUIREMENTS

4.3.3.6 EACH POSTACCIDENT MONITORING INSTRUMENTATION CHANNEL SHALL BE DEMONSTRATED OPERABLE BY PERFORMANCE OF THE CHANNEL CHECK AND CHANNEL CALIBRATION OPERATIONS AT THE FREQUENCIES SHOWN IN TABLE 4.3-10.

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FIGURE 1.6. TMI-2 Postaccident Instrumentation (From TMI-2 Technical Specifications)

TABLE 3.3-10

POSTACCIDENT MONITORING INSTRUMENTATION

INSTRUMENT	MINIMUM CHANNELS OPERABLE
1. POWER RANGE NUCLEAR FLUX	2
2. REACTOR BUILDING PRESSURE	2
3. CORE FLOOD TANK LEVEL	1/TANK
4. REACTOR COOLANT OUTLET TEMPERATURE	2
5. REACTOR BUILDING DOME RADIATION MONITOR	1
6. RC LOOP PRESSURE	2
7. PRESSURIZER LEVEL	2
8. STEAM GENERATOR LEVEL/STARTUP	1/STEAM GENERATOR
9. STEAM GENERATOR LEVEL/OPERATING	1/STEAM GENERATOR
10. BORATED WATER STORAGE TANK LEVEL	1
11. HIGH PRESSURE INJECTION FLOW	11LOOP
12. LOW PRESSURE INJECTION FLOW	1/LOOP
13. REACTOR BUILDING SPRAY PUMP FLOW	1
14. STEAM GENERATOR PRESSURE	1/STEAM GENERATOR

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FIGURE 1-6-Continued

or to January 1, 1977, was specifically exempt from the Standard Review Plan.[59] Even so, Met Ed did agree to install a reactor building dome radiation monitor (see Figure 1-6), although the monitor was not part of the containment isolation system.

Other instrumentation that either was or would have been particularly valuable for monitoring the course of the accident is also not required by the licensing process. This includes direct measurement of reactor core coolant temperatures, for which 52 thermocouples were available in 52 of the TMI-2 reactor fuel assemblies, and a direct measurement of reactor vessel water level, which is not available on any pressurized-water reactor. General Design Criterion 13 of 10 C.F.R. Part 50 requires instrumentation to "monitor variables over their anticipated ranges for normal operation, ... and for accident conditions as appropriate to assure adequate safety." This was not interpreted by the licensing staff to require either direct reactor vessel water level measurement or incore (vessel) thermocouples.

The ACRS had raised the issue of water level instrumentation with the staff and B&W during its review of the B&W standard nuclear plant design (BSAR-205).[60] B&W's position, unchallenged by the NRC staff, was that the pressurizer level indication and other available reactor-coolant-system measurement instrumentation provided were adequate for the trained operator to take effective action to correct a decreasing liquid level in the reactor coolant system. The subsequent ACRS letter report to the Commission on BSAR-205 recommended that "a study be made of the merits of including instrumentation to sense the water level in the reactor pressure vessel."[61] This was a matter of generic interest to the ACRS and later became part of the staff's generic effort on all "instruments for monitoring radiation and process variables during accidents," discussed in the following paragraphs.

The provision of adequate instrumentation to follow the course of an accident has for years been a controversial generic issue among the NRC, the ACRS and the regulated industry. Basic issues have included the plant variables to be measured, the kinds of information needed about those variables, the instrument operating ranges necessary to adequately sense and display the variables throughout the predicted durations of the accidents, and the criteria, methods, and objectives of environmental qualifications testing for verification of the instruments.

Because of the technical complexity of the issues in controversy, and NRC's unwillingness or inability to explicitly define what minimum requirements were necessary to protect the public health and safety, the regulated industry periodically argued, with partial success, that at least some of the NRC's requirements were excessive, unworkable, or both. Beginning as early as 1969, the ACRS has called for an assessment and subsequent action by the staff on this instrumentation issue.[62] The NRC issued Regulatory Guide 1.97 on this topic in December 1975, then revised that guide in August 1977, but efforts to obtain industry implementation of the guide were unsuccessful due to the applicants' opinions that more definitive NRC direction was needed on acceptable methods. of compliance.[63] Further directions for implementing the guide were to be developed under the NRC's Program for the Resolution of Generic Issues mandated by Section 210 of the Energy Reorganization Act of 1974. At about the same time the August 1977 Revision 1 of the guide was issued, the generic task plan to implement the guide was approved as Task A-34, "Instruments for Monitoring Radiation and Process Variables During Accidents."[64] The approved problem description for that task indicated the depth of the lack of consensus on most of the specifics of the issue, even though a regulatory guide had already been issued:

> To develop criteria and guidelines to be used by applicants, licensees and staff reviewers to support implementation of Regulatory Guide 1.97, Revision 1 (Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant Conditions During and Following an Accident).
>
> Such criteria and guidelines would provide specific guidance on functional and operational capabilities required of the various classes of instruments, including in-plant and ex-plant instruments. Where such guidance cannot be provided, the rationale to be applied to derive requirements for specific situations will be provided.

Progress was made during 1978 under this task plan and was reported on March 28, 1979,[65] with the recommendation that Generic Task Activity A-34 be considered completed. Reactor vessel coolant level was only one of more than 37 plant operating parameters considered and determined to be of importance, but for which backfitting of monitoring instrumentation on operating plants would not be justified.

The TMI-2 accident gave impetus to a reconsideration of the generic issue, and the later work is summarized in a recent memorandum to Commissioner Ahearne. The current plan for resolution calls, in part, for another revision to the Regulatory Guide and for "prompt implementation by the Office of Nuclear Reactor Regulation on all operating plants and plants under construction."[66]

Emergency Plan

The licensing requirements regarding emergency planning are described in 10 C.F.R. 50 Appendix E, and center on the development of an acceptable plan for actions to be taken in the event of declared emergencies at the plant site. The plan involves the cooperation of certain State and local government agencies, which the NRC secures at the time of emergency plan approval by obtaining written documents from appropriate State and local agencies indicating their intent and capability to act when notified of an emergency at the plant site.

Apart from such documented intent to cooperate and provide appropriate services, NRC regulations prior to March 28,1979 did not require that the NRC approve the emergency plan of any organizational entity other than the applicant. State and local governments are not required to have nuclear emergency plans.67

The staffs review of the Met Ed emergency plan was summarized in section 13.3 of the Safety Evaluation Report in September 1976. The staff concluded that the plan met the requirements of 10 C.F.R. 50 Appendix E, that it was responsive to the specific requirements of the staff, and that it provided a basis for an acceptable state of emergency preparedness.

Staff review of the Three Mile Island emergency plan started with the plan for TMI-1. The staff's Safety Evaluation Report of July 11, 1973, for the operating license review of TMI-1 reported that the emergency plan was acceptable. The criteria used by the staff were those found in Appendix E to 10 C.F.R. Part 50, supplemented by a guidance document entitled, "Guide to the Preparation of Emergency Plans for Production and Utilization Facilities," dated December 1970. A revised emergency plan for the Three Mile Island site (to be effective during emergencies initiating at either TMI-1 or TMI-2) was submitted with the TMI-2 Final Safety Analysis Report in May 1974. The staff review of this plan was completed in August 1975 and reported in the staff's Safety Evaluation Report for TMI-2 dated September 1976. This review was conducted at the same time the initial Standard Review Plan was under development. The Standard Review Plan was published in November 1975. The criteria in effect for the TMI-2 review were nearly equivalent to those issued in section 13.3 of the Standard Review Plan.[68]

The initial version of Regulatory Guide 1.101, "Emergency Planning for Nuclear Power Plants," was also published for comment in November 1975. The criteria found in Annex A of this guide are substantially equivalent to those found in Appendix A of the Standard Review Plan. Assimilation of public comment on the Regulatory Guide resulted in publication of Revision 1 in November 1977. Regulatory Guide 1.101 was declared by the Regulatory Requirements Review Committee to be sufficiently important to safety as to be applied to all plants, whether already operating or not.[69] However, as has been noted earlier in this report, the RRRC decisions did not explicitly define when a new requirement must be met by a licensee. In this case, the NRC decided to impose the newer requirements on licensees only when the licensee proposed a revision to its emergency plan.[68]

Met Ed submitted such a proposed revised plan to the NRC in Amendment No. 65 to the FSAR dated May 11, 1978. As reported in an internal NRC staff memorandum,[70] this revised plan was found to be deficient with respect to the criteria of Regulation Guide 1.101, Revision 1. This memorandum recognized that the emergency plan was considered to apply to the entire Three Mile Island site, encompassing the operations of both TMI-1 and TMI-2. Nevertheless, Met Ed was never requested to consider and resolve the deficiencies due to internal administrative delay resulting from split responsibility within NRR for the TMI-1 operating unit (Division of Operating Reactors) and the TMI-2 under operating license review (Division of Project Management). Met Ed records show that the plant operating personnel modified emergency procedures based on the revised plan (unapproved by NRC) submitted in Amendment 65 to the FSAR. However, no basis for the licensee approval of the revised plan was found in plant records, as is required by the plant technical specifications, sections 6.5.1.6, 6.5.1.7, and 6.8.

The implementation of the emergency plan was a matter of controversy in the operating license hearing. (This is discussed in "The Hearing Phase of TMI-2 Licensing," under Section I.B.1.e.)

Control Room Design Requirements

The NRC review of electrical instrumentation and controls focused on the evaluation of systems and components associated with reactor plant control, and even more narrowly, specifically with those systems and components associated with safety-related functions. Generally, GDC 13 and 19, sections 7 and 8 of the Standard Review Plan, and a number of related regulatory guides that were developed beginning in the early 1970s have not considered the integration of the control systems at the operator-control interface to provide for efficient, safe utilization of the controls by one or more operators. The TMI-2 control room design, now known to have been deficient in certain human factor aspects, was not evaluated with regard to those factors during either the construction permit or operating license reviews. This topic is discussed at length in the Human Factors section (see Section II.E) of this report.

Emergency Feedwater System

Staff review of the Met Ed operating license application led to some changes in this system design.[71] The design changes were all intended to make the system less vulnerable to piping or equipment failures. The first set of inquiries to Met Ed in August 1974 included this position statement by the Instrumentation and Control Systems Branch:

> We have concluded from the information presented in the FSAR concerning the Auxiliary Feedwater System (AFS) that this system is essential to plant safety and must be capable of satisfying its functional requirement after sustaining a break in its piping inside containment and a single electrical failure. We will require that the instrumentation, control, and electrical subsystems associated with the AFS be designed to conform to IEEE Std 279-1971 and IEEE Std 308-1971.[72]

The term auxiliary feedwater system used by Met Ed is synonymous with emergency feedwater system used by the staff.

Other requirements were also complied with by Met Ed during the review to assure that total reliance was not placed on the "nonsafety grade" integrated control system and the air supply system, which provided power for some diaphragm operating valves. By September 1976, the only qualification on the staff's endorsement of the emergency feedwater system was that it was subject to final review of the steam line break analysis. At that time a potential controversy existed between the staff and Met Ed over the need for, and quality of, automatic termination of both main and emergency feedwater flow in the event of a steam line break.

The staff expected no particular problem in achieving a resolution of the then open issue at the October 1976 meeting of the ACRS. The committee recognized this and merely asked to be kept informed.[73] During 1977, the 27 issues raised by individual staff members (and which resulted in the publication of NUREG-0138 and NUREG-0153) included one entitled "Treatment of Non-Safety Grade Equipment in Evaluation of Postulated Steam Line Break Accidents." Discussion of this issue with Met Ed led to a resolution by the time of the public hearing[50] in May 1977. As presented by the licensing project manager at the hearing, the resolution was that the applicant had "submitted a program indicating his plans to comply with the staff position."

At the license issuance in February 1978, the staff concluded that TMI-2 could be licensed to operate even though Met Ed had not yet installed systems (including the emergency feedwater system) that would mitigate the consequences of a steam line break using only safety grade equipment. However, the staff documented its review[74] of the consequences of both steam and feedwater line breaks, with no credit given for the operation of the nonsafety grade equipment available, and concluded that operation for the first fuel cycle would be acceptable. This conclusion is included as a condition in the operating license:

> Prior to startup following the first regularly scheduled refueling outage, Metropolitan Edison shall do the following:
>
> Submit appropriate descriptions and analyses and modify the secondary (main steam and feedwater) systems so that the consequences of a spontaneous break anywhere in a secondary system line will be mitigated only by safety grade equipment, with nonsafety grade equipment permitted to serve as a backup for the assumed single failure of safety grade equipment. For those portions of the secondary systems where a break might be caused by a seismic event, Metropolitan Edison Company shall modify the systems so that accident consequences will be mitigated only by seismic Category I components after assuming single failure in any seismic Category I component.[7]

Another aspect of the emergency feedwater system performance approved by the staff during the operating license review was the controls and instrumentation for the system. The block valves for the system which were closed in the TMI-2 accident and prevented the delivery of water to the steam generators have no automatic control. The overall emergency feedwater system itself is not actuated or controlled by the safety features actuation system. Actuation of the system was designed to occur on loss of main feedwater pumps, loss of all four reactor coolant pumps, loss of power, or by manual operation. Steam generator level was designed to be controlled by the integrated control system through throttling of the diaphragm operated emergency feedwater flow valves.

The staff's review and approval as reported in the Safety Evaluation Report did not extend to verification of Met Ed's assurance that the manually controlled block valves in the emergency feedwater flow lines would be open when flow was required. However, the plant technical specifications did have requirements on the "operability" of the emergency feedwater flow paths.[76] The NRC has since found that Met Ed violated these requirements regarding the emergency feedwater isolation valves.[77]

Technical Specification

The technical specifications which are incorporated in an operating license are based on the requirements of 10 C.F.R. Part 50.36. They are generally developed in parallel with the staff's safety review effort leading to the issuance of the staff's Safety Evaluation Report. Because the as-built condition of equipment is often important to the final selection of safety limits and limiting control settings, the final work on establishing the technical specifications is usually done in the last year before issuance of an operating license. In the case of TMI-2, work started with the staff's transmittal to Met Ed of a set of standard technical specifications for B&W reactors in fate 1975. Over the next 2 years an interchange of correspondence and several meetings with the staff yielded the final set of specifications that became Appendix A to Operating License No. DPR-73 for TMI-2.

Technical specifications standardized in format and content were developed several years ago for each of the light-water reactor nuclear steam system suppliers. In October 1974, the D.C. Cook Station, Unit 1 was the first plant licensed utilizing the standard technical specifications. Since that time all facility operating licenses issued have incorporated standardized technical specifications. These licensees have included three B&W reactors-Crystal River Unit 3, Davis Besse Unit 1, and TMI-2.

Standard Review Plan section 16.0 gives a general statement concerning the intent to use standardized technical specifications that meet the requirements of 10 C.F.R. 50.36, and briefly states that "generic standard technical specifications" have been developed but are subject to revision and that the latest revision is available from the NRR. No details of the structure or content of the Standard Technical Specifications (STS) are given within the Standard Review Plan nor are any acceptance criteria prescribed as in other Standard Review Plan sections. As a result, the STS are a governing document unto themselves, existing as the most official available NRC staff interpretation of what is necessary to comply with 10 C.F.R. 50.36.

Development of the detailed standard technical specifications during an operating license review is the primary responsibility of the STS group, which is composed of technical specialists working within the Division of Operating Reactors. The licensing project manager within the Division of Project Management retains overall responsibility for completion of the project review, but in the preparation of technical specifications, the project manager interacts with the STS group within DOR rather than directly with the technical review specialists within the Division of Systems Safety. The STS group, however, appoints one person within that group to be responsible for preparing the specifications and coordinating the efforts of the various technical specialists involved. A "proof and review" copy of the technical specifications is circulated to all review organizations and comments are solicited, but formal, documented concurrence is not required. Consequently, last minute changes in technical specifications, just prior to license issuance, involve a significantly higher risk of error. Such errors did occur in the TMI-2 technical specifications, as described in an earlier section entitled "Onsite Radiological Protection.

Applicant Technical Qualifications and Organization

The staff's review and evaluation of the Met Ed organizational structure and of the technical qualifications of the organizational entity is documented in the Safety Evaluation Report sections 13 and 14. The regulatory criteria and authority for examination of an applicant's technical qualifications is found in 10 C.F.R. 50.34(a)(9) and (b)(7). The regulatory criteria were further developed by additional information in October 1972 in the Regulatory Guide 1.70, "Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants," Revision 1, which in about two pages described the types of information that a prospective licensee should supply in an applicant's Safety Analysis Report to "indicate generally how the applicant intends to conduct operations, and to assure that the licensee will maintain a technically competent and safety-oriented staff." No specific requirements are cited.

The Standard Review Plan sections 13.1.1, 13.1.2, and 13.1.3 elaborate on what the acceptance criteria might be, but does so with reference to WASH-1130 and ANSI N18.1-1971, indicating that those standards are "generally acceptable" or contain provisions that the applicant "should meet or exceed." While the Standard Review Plan was not formally required for the TMI-2 review, the staff's review and evaluation in the Safety Evaluation Report indicated that ANSI N18.1-1971 was complied with regarding selection and training of personnel. The staff declared in the Safety Evaluation Report in October 1976 that the overall organization structure was "satisfactory to provide an acceptable operating staff," and that the applicant had "the necessary resources to provide offsite technical support for the operation of the facility." In accordance with the staff's general practice, there was no reported evaluation by the staff of the management plans or controls to effectively utilize the offsite technical resources when needed.

The Advisory Committee on Reactor Safeguards' review in October 1976 resulted in an explicit, narrowly drawn comment by the committee:

> The management organization proposed by the Applicants to delineate the safety related responsibilities of the offsite and onsite personnel of the Three Mile Island Station left open questions as to how these responsibilities are to be discharged during normal working hours and during evening, night, and weekend shifts. This matter should be resolved to the satisfaction of the NRC Staff.

This comment developed from information brought up by the staff at the full ACRS meeting of October 15, 1976.[78] Met Ed had submitted new organization charts in September 1976 which caused the staff's Quality Assurance Branch reviewers to be concerned about the priority given to allocations of technical support personnel assigned to support both TMI units at the site. Organization charts submitted in September 1976 showed the same technical support groups reporting to both unit supervisors simultaneously. Following the ACRS meeting, additional questions were asked of Met Ed.[79] The concerns that surfaced at the October 1976 ACRS meeting were resolved to the staff's satisfaction[80] by Amendment Nos. 52, 54, and 55 to the FSAR and the resolution was reported in Supplement No. 2 to the Safety Evaluation Report, which was issued in February 1978. The discussion in that supplement did not explicitly address the concerns expressed in the ACRS letter of October 26, 1976.

It should be noted that the ACRS comment discussed above was the only critical result of the committee's review of the Met Ed organization and technical qualifications, despite a wide ranging discussion of that subject at the full committee meeting. The NRC staff has recognized the inadequacy of its review process in this area for some years, as shown by the exhibits in the Allenspach deposition,[81] but has not given the matter sufficient priority to accomplish systematized improvement in the process from approximately 1974 to this date. (Technical qualifications as treated in the licensing process are further discussed in Section I.A.3.d of this report.) While changes have been designed and evaluated by appropriate management officials, the licensing staff is generally unaware of the more recent criteria and requirements so that implementation is largely an ad hoc activity that is not yet ensured on any given project.

Combustible Gas Control

It is well established that the TMI-2 plant systems designed to cope with free hydrogen inside containment were inadequate during the course of the accident. Met Ed provided a thermal recombiner located outside the containment and attached to the containment by 4-inch piping. This system was designed to circulate containment atmosphere through the recombiner at about 60 standard cubic feet per minute (the containment free volume is about 2 million standard cubic feet) and to maintain the containment hydrogen concentration below 4% hydrogen by volume.

The system design was based on hydrogen generation rates far lower than were experienced in the TMI-2 accident, and in particular for less total hydrogen evolving from the reaction between steam and the zirconium alloy cladding on the fuel rods in the reactor core. The staff's licensing criteria effective in September 1976 were based on Regulatory Guide 1.7, Revision 1, which referenced the General Design Criteria and other appropriate sections of 10 C.F.R. Part 50, and led to staff approval of Met Ed's design basis hydrogen generation predictions.[82] These predicted conditions were simply not representative of the much greater amount of hydrogen produced in the first several hours of the TMI-2 accident, because of the extensive core damage and zirconium-oxygen reaction of what is now thought to be over 50% of the fuel cladding. As a result of the large amount of hydrogen generated and released to the containment volume, a rapid pressure rise, now thought to be due to a rapid hydrogen burn, occurred approximately 9 hours and 50 minutes after the accident.[83] Since the accident, the NRC has recognized[84] the need to reconsider the design bases with respect to hydrogen production and control.

Quality Assurance

In the Safety Evaluation Report of September 1976, the staff found that:

> [T]he applicant has described an acceptable Quality Assurance organization which has sufficient authority and independence to permit effective implementation of their Quality Assurance program without undue influence from costs and schedules.

> We therefore conclude that the Quality Assurance program is acceptable for control of the quality-related activities during the operational phase of the Three Mile Island Nuclear Station, Unit 2.

The staff's review was reported to be based on the criteria of Appendix B to 10 C.F.R. 50 and a number of regulatory "guidance" documents, including:

- WASH-1284: Guidance on Quality Assurance Requirements During the Operations Phase of Nuclear Power Plants
- WASH-1309: Guidance on Quality Assurance Requirements During the Construction Phase of Nuclear Power Plants
- WASH-1283: Guidance on Quality Assurance Requirements During the Design and Procurement Phase of Nuclear Power Plants

In addition, the Safety Evaluation Report stated that Met Ed's demonstrated capability to implement satisfactorily the QA program on TMI-1 was further assurance that it could and would carry out the QA program for TMI-2 satisfactorily.

The NRR is assigned the responsibility for determining that an applicant has adequate QA program plans and the organizational structure necessary to carry out those programs. The office of IE has the responsibility to evaluate and report on the applicant's implementation of the program. The interface between these offices is another area in which good interoffice working relationships, comprehensively designed and implemented NRC procedures, and, above all, dedicated and determined NRC management is critical to the Commission's mandated objective of ensuring that an applicant executes an adequate quality program. Met Ed's program implementation was periodically checked by field inspections from the time of construction permit grant in 1969. However, as has been noted by other reviewers,[85] and described in other sections of this report, both the NRC and its predecessor, the AEC, have focused quality assurance on those portions of the plant considered "safety-related" and have ignored, or at least accorded much less significance to, the interactions of nonsafety systems and nonsafety-related procedures, controls, and organizations with activities clearly important to nuclear safety objectives. (Further discussion of the meaning and application of the term "safety-related" is found in Section I.A.3.b of this report.)

The regulatory staff's *licensing* responsibility, as discharged totally within NRR, was focused essentially only on the Met Ed descriptions of its programs and organization as presented within the FSAR and the plant technical specifications. The implementation of these programs through plant operating procedures was left to IE. Thus, any deficiencies in quality assurance as practiced by Met Ed were not likely to be discovered and were not discovered by NRR in the licensing process leading to an operating license issuance. However, the point is not merely that had the condensate polishing system, or the pressurizer relief valve, or the various emergency procedures been engineered and checked to higher quality standards, the TMI-2 accident would not have occurred. The existing QA program must be expanded within NRR and effectively coordinated with the NRC inspection entities to assure that an applicant is initially qualified and remains qualified to hold an operating license.

Pressurizer and Pressurizer Controls

This area of technical review provides an example of the lack of mutual understanding on the part of the NRC staff and the applicant concerning which systems are important to plant safety and which systems should be required to meet NRC standards such as redundancy, diversity, the single failure criteria, and seismic load resistance. In its final approval of the TMI-2 design, the staff considered the matter of pressurizer control only to the extent necessary to say that detailed schematic drawings of the control circuitry had been reviewed.[86] No criteria or conclusions were reported.

In discussing the systems required for safe shutdown, Met Ed stated that pressurizer controls were required to ensure the capability of controlling reactor coolant pressure.[87] Perhaps significantly, Met Ed did not consider the pressurizer heaters to be a member of the group called pressurizer controls, because in this context Met Ed described only the spray valve control and the relief valve control. Because the controls are described with those other systems required for safe shutdown, it may not have been considered that the pressurizer heaters would be needed during a process which should require only excess heat *removal.* Achievement of "safe shutdown" (reactor 1% subcritical, system pressure and temperature within technical specifications) was defined as a separate and apparently lesser safety requirement than the reactor shutdown achieved completely automatically by the reactor protection system designed to meet the full "safety-related" criteria.

The Met Ed justification for the "safe shutdown" system controls not being designed to full "safety-related" electrical criteria (IEEE Standard 279 requirements) was that the "safe shutdown" systems are not protection systems like the reactor protection system (RPS) or the safety features actuation system (SFAS). In this case, the line between safety-related and nonsafety-related was drawn by Met Ed at the boundaries of the RPS and SFAS systems, and that distinction was accepted by the staff. The TMI-2 event and studies following it have shown that more sophisticated analyses of the need for the pressurizer control system during expected transients, particularly those involving loss of offsite power, are necessary. The licensing process during the TMI-2 operating license review did not recognize the need for the features now seen necessary, because the accident and transient assumptions evaluated simply did not reveal the need for systems and controls other than those provided by the reactor protection system and the engineered safety features actuation system.

f. Findings and Recommendations

Findings

Design Basis

1. Safety objectives in the General Design Criteria and other Title 10 regulations are too subjective and imprecise to be effectively applied by engineers and scientists.
2. The standard format and content of Safety Analysis Reports (Regulatory Guide 1.70) and the Standard Review Plan identify and structure a review which is inadequate in depth to prevent or mitigate the consequences of a TMI-2-type accident.
3. The distinction in the review process between safety-related and nonsafety-related equipment or systems led to the staff's ignorance of the importance of malfunctions in certain "nonsafety equipment."
4. Operator training, plant emergency operating procedures, control room design, applicant technical qualifications, plant technical specifications, and quality assurance are areas for which there are inadequate regulatory requirements or an inadequate management of the review process, or both.
5. The continuous increase in the number and cost of regulatory requirements, applied without a clearly discernible technical rationale, has frustrated the industry, leading to an unsafe attitude that "we'll give NRC what they ask for and not one bit more."

The Process

1. Regulatory stability, in terms of organizational control of the development and implementation of new or modified requirements, has not been achieved through the activities of the Regulatory Requirements Review Committee.
2. The process does not adequately control the need and justification for backfitting in accordance with 10 C.F.R. 50.109.
3. Coordination is lacking between the Division of Operating Reactors and the Division of Project Management in the critical period between operating license issuance and transfer of the project to the Division of Operating Reactors.
4. The public hearing process does not reveal or explore the merits of much of the safety review that is resolved between staff and applicant prior to the hearing.

TMI-2 Review

1. The staff technical management failed to effect prompt (several months) resolution of the matter of appropriate emergency core cooling system cut-off by an operator. The matter was raised as a generic issue in November 1976 by a dissenting staff member, and surfaced again in Davis Besse and other B&W plant transients in 1977 and 1978, events which occurred either during the operating license review for TMI-2 or prior to the TMI-2 accident.
2. The staff did not respond to licensee's change in emergency plan after the operating license was issued.
3. An operating license was issued on February 8, 1978 without the documented concurrence of the staff responsible for technical specifications.
4. The operating license issued contained an error in technical specifications that gave the licensee an exemption from periodic testing of the capability of carbon filters in the auxiliary building.
5. The TMI-2 review, with a few exceptions, was in accord with staff practice during the period April 1974 through September 1976.
6. Met Ed did not report on the safety significance of equipment modification, after operating license issuance, that resulted in continuous airflow through carbon filters during normal operation instead of using them only postaccident. The result was "poisoning" of filter carbon before it was needed after the accident.

7. B&W consistently told staff and ACRS that reactor vessel water level instrumentation was not necessary. The staff and ACRS response, during the TMI-2 review, was acquiescence, if not agreement.
8. The staff failed to implement Regulatory Guide 1.101 on emergency planning on Met Ed, which had been declared by the Regulatory Requirements Review Committee to be a backfit measure.

Recommendations

1. Rational risk objectives should be established and approved by Congress. NRC must present these objectives to the regulated industry and the public through a rational policy that will generate acceptance, respect, and cooperation from all parties.
2. Current requirements should be reevaluated using the best available risk assessment techniques, with the purpose of meeting specific risk objectives. New or modified requirements should be expressed in the Standard Review Plan as the minimum acceptance criteria required for public health and safety at a given time.
3. An explicit rationale, which is as quantitative and objective as possible, should be established for the evaluation of proposed new safety requirements against the criteria "substantial additional protection required for public health and safety."
4. New requirements should be implemented in a staged, controlled process that provides for holding plant designs standard over significant periods of time.
5. An organizational element charged with continuing responsibility to carry out recommendations 2, 3, and 4 above should be established.
6. The existing design basis accident concept should be enlarged to a greater defense-in-depth, to include sequences based on assumptions of at least one random failure, an additional equipment unavailability due to a maintenance fault, and one human error in operation.
7. The hearing process should be modified either to increase the technical content of the deliberations for the public benefit, or alternatively, and also for the public benefit, to eliminate an essentially wasteful expenditure of public resources.
8. The comprehensive analysis and application of operating plant experience to the development of new or modified regulatory requirements should be assured.
9. An NRC internal Quality Assurance Program should be established to ensure that the licensing process is conducted in accordance with Commission approved standards.
10. The Standard Review Plan should be expanded and developed in areas of operator training, plant emergency operating procedures, control room design, applicant technical qualifications, plant technical specifications, and quality assurance. Similarly, actions should be taken to ascertain that the licensing organization is adequate to execute the expanded review.

REFERENCES AND NOTES

16 NRC 1185 (1977), included in Appendix 1.7.

[2]Hearings Before the Joint Committee on Atomic Energy, U.S. Gong., 1st Sess. (April 4, 6, and 20, and May 3,1967) at 303-307.

[3]P.A. Morris and S.H. Hanauer, "Technical Safety Issues for Large Nuclear Power Plants," Fourth United Nations International Conference on the Peaceful Uses of Atomic Energy, at 207, September 1971, Geneva.See Exhibit 1044, Hanauer dep.

[4]Memorandum from R. DeYoung, USAEC, to P. Morris, "RTM and TAR Status Report," April 2,1969.

[5]Memorandum from V. Moore, USAEC, to S. Levine, "Reactor Technology Memorandum (First Draft) - Off-Site Electric Power," February 28, 1968.

[6]Memorandum from R. DeYoung, USAEC, to R. Boyd and D. Skovholt, "Design Basis Criteria for Pressurized Water Reactor Dry Containments, January 3, 1969," February 19,1969.

[7]Between April 1968 and May 1969, Jersey Central Power & Light Company took full responsibility for the design and construction of the facility, and the AEC licensing staff dealt exclusively with JCPL. By Amendment 9 to the Preliminary Safety Analysis Report (May 7, 1969) the responsibility for design and construction was transferred to the Metropolitan Edison Company. The Pennsylvania Electric Company's Purchase of a 25% ownership interest in 1971 did not change this responsibility, which continued to be that of Metropolitan Edison.

[8]NRC, "Report to ACRS-Three Mile Island Unit 2," June 20,1969.

[9]Memorandum from R. Tedesco, USAEC, to P. Morris, "Report to ACRS on Three Mile Island," June 16, 1969.

[10]Memorandum from R. Powell, USAEC, to R. Boyd, "ACRS Subcommittee Meeting for Three Mile Island Nuclear Power Plant Unit 2," July 17, 1969.

"'Letter from S. Hanauer, USAEC, to G. Seaborg, Subject: Report on Three Mile Island Nuclear Station Unit 2, dated July 17, 1969.

12 Safety Evaluation by the Division of Reactor Licensing, U.S. Atomic Energy Commission in the Matter of Metropolitan Edison Company and Jersey Central Power and Light Company, Three Mile Island Nuclear Station Unit 2, Dauphin County, Pennsylvania, September 5, 1969.

[13]NRC, *Federal Register, Vol.* 34, No. 13708,1969.

14 Memorandum from H. Price, USAEC, to Commissioners Seaborg, et al., "Issuance of Safety Guides," June 25, 1970.

[15]U.S. Atomic Energy Commission Information Report to Commissioners, "Regulatory Requirements Review Committee," SECY-R-74-132, March 5, 1974.

16 Memorandum from E. Case, USAEC, to L.V. Gossick, "Regulatory Requirements Review Committee Meetings," June 28, 1974 (Meeting No. 4) and September 19,1974.

[17]Washburn dep. at 9, 10.

[18]Note from H. Berkow, NRC, to Chairman Hendrie, "Schedule Performance Evaluation," January 31,1979.

[19]Silver dep. at 65 (Pres. Com.).

[20]Memorandum from H. Silver to Technical Review Branch Chiefs, "TMI-2 SER Open Items," March 16, 1976.

[21]Letter from W.T. Gunn, GPU Service Corporation, to USNRC Directorate of Regulatory Operations, Subject: Submittal of Schedular Information (TMI-2), dated May 6, 1976.

[22]Letter from K. Kniel, NRC, to Met Ed, dated May 12, 1976.

[23]See Section I.A.3.c for further discussion of generic issues.

[24]Memorandum from B. Rusche, NRC, to Division Directors, "Revised Procedures for Documentation of Deviations from the Standard Review Plan," January 31, 1977.

[25]ACRS Subcommittee Meetings Transcripts (September 23-24, 1976) and the 198th General Meeting of the ACRS Transcript (October 15,1976).

[26]4 AEC at 283, November 12,1969.

[27]See *Petition for Intervention by Citizens for a Safe Environment, of Harrisburg, Pennsylvania, and the York Committee for a Safe Environment, of York, Pennsylvania,* June 18, 1974. These organizations were the Joint Intervenors. The petitions are on file in Licensing Docket No. 50-320.

[28]6 NRC at 1201, 1203 (December 19, 1977).

296 NRC at 1201-1202.

3D6 NRC at 1206.

316 NRC at 1203.

[32]8 NRC at 9,14, 25 (July 19,1978).

[33]8 NRC at 23.

[34]Letter from H. Brown, Office of International and State Programs, to E. Kline, Lieutenant Governor, Pennsylvania, Subject: Radiological Emergency Response Planning, dated May 9, 1975.

[35]Letter from E. Kline to H. Brown, dated May 21, 1975.

[36]Fourth Report by the House Committee on Government Operations, "Emergency Planning Around U.S. Nuclear Powerplants: Nuclear Regulatory Commission Oversight," 96th Gong., 1st Sess., dated August 8, 1979, at 31.

[37]GAO Report No. EMD-78-110, dated March 30, 1979, at 42.

[38]8 NRC at 25.

398 NRC at 48-49 and 295 (September 15,1978).

[40]Memorandum from S. Varga, NRC, to Distribution List, "Transfer of TMI-2 to DOR," September 19, 1978.

[41]Note from V. Stello, Jr. to D. Vassallo, "Transfer of TMI-2 to DOR," September 26, 1978.

[42]Reid dep. at 9.

[43]/d. at 15.

[44]AEC Directorate of Licensing, "Final Environmental Statement Related to Operation of TMI Nuclear Station, Units 1 and 2," Section XI, December 1972.

[45]The results of this review are described in Chapter 15 of the staff's "Safety Evaluation Report, related to operation of Three Mile Island Station, Unit 2," NUREG-0107, September 1976, and Supplement 1, undated.

[46]AEC, "Final Environmental Statement, Three Mile Island Station, Unit 2," December 1972.

[47]AEC, "Final Supplement to the Final Environmental Statement," December 1976.

[48]10 C.F.R. Part 50, Proposed Annex to Appendix D, "Discussion of Accidents in Applicants' Environmental Reports: Assumptions," Federal Register, 36 FR 22851, and Statement of Consideration, 39 FR 26279.

[49]Babcock & Wilcox Company, "ECCS Analysis of B&W's 177-FA Lowered Loop NSS," BAW-10103, Revision 3, at C-7, July 15, 1977.

[50]Transcript of TMI-2 Operating License Hearing (May 18, 1977) at 1322.

[51]NRC, "Report of the Advisory Committee on Reactor Safeguards on Selected Safety Issues Related to Light-Water Reactors," Issue No. 4, December 12,1976.

[52]NRC, "Staff Discussion of Fifteen Technical Issues Listed in Attachment to November 3, 1976 memorandum from Director, NRR, to NRR Staff," NUREG-0138, November 1976.

[53]Memorandum from N. Mosely to V. Stello, "Emergency Operating Procedures Governing S1S Reset at Operating PWR's-Memorandum dated June 28, 1978," March 19, 1979.

[54]NRC, "TMI-2 Lessons Learned Task Force Status Report and Short-Term Recommendations," NUREG-0578, at 18, July 1979.

[55]Memorandum from R. Boyd to E. Case, "Proposed Technical Activity," March 3,1978.

[56]NRC, "Investigation into the March 28, 1979, Three Mile Island Accident by Office of Inspection and Enforcement," NUREG 0600, at 11-1-28, August 1979.

[57]Appendix A to Operating License No. DPR-73, February 8, 1978, at 3/4-40.

[58]NRC, "Staff Discussion of Twelve Additional Technical Issues Raised by Responses to November 3, 1976 Memorandum from Director, NRR, to NRR Staff," NUREG-0153, December 1976.

[59]Memorandum from B. Rusche, NRC, to R. Boyd, et al., "Revised Procedure for Documentation of Deviations from the Standard Review Plan," January 31,1977.

[60]Transcript of the 208th General Meeting of the ACRS (August 11, 1977) at 98-106.

[81]Letter from M. Bender, ACRS, to Chairman Hendrie, Subject: Report on Babcock-205 Standard Nuclear Steam System, dated August 18, 1977, Appendix D in "Safety Evaluation Report Related to the Preliminary Design of the BSAR-205 Standard Design," NUREG=0433, Docket STN 50-561, May 1978.

[62]Letter from M. Carbon, ACRS, to M. Rogovin, NRC/SIG, Subject: Significant Recommendations by ACRS in 14 Specific Areas on Non-B&W Plants, dated July 25,1979.

[63]Memorandum from R. Minogue, NRC, to H. Denton, "Instrumentation to Follow the Course of an Accident," at 2, August 17, 1979.

[84]NRC, "NRC Program for the Resolution of Generic Issues Related to Nuclear Power Plants," NUREG-0410, January 1978.

[65]Memorandum from R. DeYoung, NRC, to R.J. Mattson, R.S. Boyd, V. Stello, E.G. Case, "Draft Report of Completion of Generic Activity A-34," March 28,1979.

[66]Memorandum from H. Denton, NRC, to Commissioner Ahearne, "Instrumentation to Follow the Course of an Accident," September 4, 1979.

[87]Report to Congress by the Comptroller General of the U.S., "Areas Around Nuclear Facilities Should Be Better Prepared for Radiological Emergencies," GAO Report No. EMD-78-110, at 14,16; March 30,1979.

[68]Hearings Before the Subcommittee on Nuclear Regulation of the Committee on Environment and Public Works, U.S. Senate, 96th Cong., 1st Sess., (April 10, 23, and 30, 1979) Part I at 200-202.

[69]Memorandum from E.G. Case, NRC, to L.V. Gossick, "Regulatory Requirements Review Committee Meeting No. 34, August 15,1975," August 22,1975.

[70]Memorandum from G. Knighton, NRC, to R. Reid, "Three Mile Island Site Revised Emergency Plan," November 1, 1978.

[71]NRC, "Safety Evaluation Report for TMI-2 at the Operating License Stage," NUREG-0107, Sections 1.6, 7.4.1,10.5, September 1976.

[72]Letter from K. Kniel, NRC, to R.C. Arnold, Met Ed, Subject: Further Requirements for Licensing of Three Mile Island, Unit 2, dated August 21,1974.

[73]Letter from D. Moeller, ACRS, to Chairman Rowden, Subject: Report on Three Mile Island Nuclear Station, Unit 2, dated October 22,1976.

[74]NRC, "Safety Evaluation Report Supplement No. 2," NUREG-0107, Sections 15.2.2, 15.3.1, 15.3.2, February 1978.

NRC, "TMI-2 Operating License No. DPR-73," February 8,1978.

[76]NRC, "TMI-2 Operating License No. DPR-73," at Appendix A; Technical Specifications at 3/4.7-4, 5.

[77]Letter from V. Stello, NRC, to R.C. Arnold, Met Ed, Subject: Investigation Report Number 50-320/79-10, dated October 25, 1979.

[78]Allenspach dep. at 73 and Exhibit 1062 at 345-350.

[79]Memorandum from C.J. Heltemes, NRC, to S. Varga, "Three Mile Island Unit 2, Conduct of Operations," December 2, 1976.

[80]Memorandum from D.J. Skovholt, NRC, to D.B. Vassallo, "Three Mile Island, Unit No. 2 Safety Evaluation Report, Conduct of Operations," May 6,1977.

[81]Allenspach dep. at 73 and Exhibit 1062 at 345-350.

[82]Met Ed, "Final Safety Analysis Report, Three Mile Island Nuclear Station-Unit 2," Vol. 4, Figure 6.2-34, Amendment 14.

[83]NRC, "Investigation into the March 28, 1979, Three Mile Island Accident by Office of Inspection and Enforcement," NUREG-0600, at 1-4-47, August 1979.

[84]NRC, "TMI-2 Lessons Learned Task Force Status Report and Short-Term Recommendations," NUREG-0578, at A-23, July 1979.

[85]The President's Commission on the Accident at Three Mile Island, "Technical Staff Analysis Report Summary," at 18-1, October 31, 1979.

[86]NRC, "TMI-2 Safety Evaluation Report," NUREG-0107, Section 7-4, October 1976.

[87]Met Ed, "Final Safety Analysis Report, Three Mile Island Nuclear Station-Unit 2," Vol. 5, Section 7.4.1.1.6, Amendment 58.

[68]NRC, "TMI-2 Lessons Learned Task Force Status Report and Short-Term Recommendations," NUREG-0578, at A-1, July 1979.

2. OPERATING HISTORY OF THREE MILE ISLAND NUCLEAR STATION

Three Mile Island Unit 1

An operating license for TMI-1 was issued on April 9, 1974. Initial criticality was achieved June 5, 1974; initial electrical power generation occurred on June 9, and commercial operation was declared on September 2, 1974. Based on the review of License Event Reports and Monthly Operating Reports, TMI-1 experienced at least 10 reactor trips, instances in which all control rods are inserted simultaneously into the reactor core stopping the nuclear reaction, during the first year of operation. The following is a yearly summary of the operating history of TMI-1.

June 5, 1974 Through December 31, 1974

After the unit began commercial operation there were only two outages. The unit operated near full power continuously during September through December. The following lists contain the occurrences reported during the period of June to December 1974.

Date	Event
7/12/74	Reactor trip due to faulty relays on turbine generator. Duration, 8 hours.
7/13/74	Reactor trip due to feedwater flow oscillation. Duration, 8.1 hours.
7/14/74	Reactor trip due to technician error. Duration, 30.7 hours.
8/3/74	Reactor trip due to operational error. Duration, 11.6 hours.
8/13/74	Reactor trip scheduled as part of test program. Duration, 244.3 hours.
8/26/74	Manual shutdown to repair steam and feedwater leaks. Duration, 47.8 hours.
3/30/74	Reactor trip due to turbine trip and operator error. Duration, 29.7 hours.
10/20/74	Scheduled outage to repair leaking pressurizer relief valves. Duration, 248.5 hours.
11/7/74	Manual reactor shutdown to repair control rod drive motor. Duration, 97 hours.

January 1, 1975 Through December 31, 1975

There were 13 forced and 3 scheduled outages in 1975. Of these 16 outages, 11 were caused by equipment failure, 3 were performed for maintenance, and 2 resulted from operational errors. The TMI-1 unit had a favorable unit availability factor of 82.2% and capacity factor[2] of 77.3%.

Date	Event
1/23/75	Human error resulting in turbine-reactor trip. Duration, 40 hours.
3/30/75	Faulty relay resulting in turbine-reactor trip. Duration, 14 hours.
4/5/75	Rod drop and manual shutdown resulting from a faulty cable connector. Duration, 214 hours.
5/9/75	Instrumentation malfunction led to turbine-reactor trip. Duration, 9 hours.
5/22/75	Power reduction due to problems in an electrical power transformer. Duration, 16 hours.
5/25/75	Motor shaft sheared on decay heat pump. Unit manually shut down for repair of pump and scheduled control rod interchange. Duration, 421 hours.
6/18/75	Instrument error led to load reduction and reactor trip. Duration, 20 hours.
6/25/75	Reactor trip due to rod drop resulting from an electrical connector problem. Duration, 27 hours.
7/27/75	Power reduction for repair of feedwater pumps. Duration, approximately 4 days.
9/7/75	One day power reduction to verify vibration of main reactor coolant pump.
9/26/75	Manual shutdown to repair coolant pump. Duration, 266 hours.
10/16/75	Manual shutdown to repair control rod drive stator. Duration, 94.4 hours.
11/12/75	Manual shutdown to repair control rod drive mechanism for the second time. The outage was extended to repair turbine control valve. Duration, 303 hours.
12/16/75	Manual shutdown to repair makeup valve. Duration, 104 hours.

January 1, 1976 Through December 31, 1976

The major outage during 1976 was for scheduled refueling and maintenance, and was extended for repairs to other equipment. During calendar year 1976 there were four outages; one was because of operator error and the others equipment failure. As a result, the unit availability factor was reduced to 65.4% and the unit capacity factor to 60.3%.

Date	Event
1/16/76	Manual shutdown of the reactor to repair control rod drive mechanism. Duration, 46 hours.
2/20/76	Refueling. Duration, 1,532 hours.
3/3/76	Refueling outage extended because of problems with fuel handling equipment. Duration, 48 hours.

3/15/76 Extended outage to remove damaged surveillance specimen holder tubes. Duration, 720 hours.

5/27/76 Reactor trip due to operator error. Duration, 7 hours.

11/5/76 Manual shutdown for scheduled repair of decay heat valve and pipe in riverwater system. Duration, 683 hours.

January 1, 1977 Through December 31, 1977

The second refueling and maintenance outage took place during 2 months beginning March 18, 1977. Because the unit operated uninterrupted for 6 months, the unit availability factor increased to 80.9% and capacity factor increased to 76.2%.

Date	Event
2/5/77	Power reduction to repair turbine test tubing. Duration, 7 hours.
3/18/77	Refueling and maintenance. Duration, 1,394 hours.
9/16/77	Initial outage was by manual shutdown to correct problems in the demineralizer in order to reduce conductivity in the secondary fluid system. The outage was extended to repair reactor coolant pump motor and generator ground. Total outage, 261 hours.
11/14/77	Reactor trip due to failure of integrated control system.

January 1, 1978 Through December 31, 1978

The third refueling and maintenance outage for TMI-1 began March 18, 1978, and lasted 2 months. The year reflected a good operating history, compared to the previous year, and resulted in slight increases in the percentages of unit availability to 85.1% and capacity to 79.1%.

Date	Event
3/8/78	Refueling. Duration, 1,086 hours.
9/22/78	Manual shutdown to repair seal fracture on reactor coolant pump. Duration, 214 hours.
11/15/78	Power reduction to correct electrical problems on turbine control system. Duration, 14 hours.

January 1, 1979 Through February 17, 1979

Full power operation was maintained until shutdown for refueling on February 17, 1979. TMI-1 was on hot-shutdown status at the time of the TMI-2 accident.

Three Mile Island Unit 2

The NRC issued an operating license for TMI-2 on February 8, 1978. The license identified a number of preoperational tests, startup tests and other items to be completed by Met Ed within specified time frames. As a result of a mechanical failure in one of the reactor coolant pumps, the initial testing program was performed with one pump out of service for the period March 14 through May 17, 1978. The technical specifications permitted three pump operation, however, and the initial criticality was achieved on March 28, 1978, approximately 2 months sooner than if four pumps had been used.

From February 1978 to March 1979, TMI-2 experienced at least 20 reactor trips, approximately one-third of which originated in the condensate and feedwater system. In addition, four transients resulted in the actuation of the ECCS high pressure injection system. Table 1-6 contains a chronology of the TMI-2 operating history.

The major outage for TMI-2 was necessary in order to replace all of the main steam safety valves. These valves were the first of a kind design and failed to reset after lifting. This outage lasted about 5 months, beginning in April 1978. The second longest outage resulted from rupture of the atmospheric dump valve bellows and lasted approximately 2 weeks during January 1979.

Comparisons to Other Plants

Table 1-7 presents a comparison with other plants by number of Licensee Event Reports (LERs) filed with the NRC for the year of operation after the license was issued. This table provides some qualitative correlations between TMI-2 and other B&W plants and other two unit sites using equipment supplied by other pressurized-water-reactor vendors. In addition, a comparison of the LERs on PWRs nuclear steam suppliers for 1975 through 1978 is provided in Table 1-7. The comparisons, although not definitive with respect to underlying causes, indicate that the performance for TMI-2 and other B&W plants is average for PWR vendors. The director of IE Region I office considered Met Ed's performance as average compared with other licensees in his region.[3]

During its year of operation, TMI-2 had four events which resulted in actuation of the emergency core cooling high pressure injection system and the injection of borated water into the primary coolant system. The ACRS task force evaluating Licensee Event Reports[4] reported 40 inadvertent ECCS actuations in PWRs from 1976 through 1978. Actua-

TABLE 1-6. Chronology of TMI-2 operating experience

Date	Event
2/8/78	Operating License issued.
3/14/78	Began three-pump operations. Lost one pump due to mechanical failure.
3/28/78	Initial criticality.
3/29/78	Reactor trip. Pressurizer relief valve open. ECCS actuation. Shutdown (zero power) duration, 57.6 hours.
4/1/78	Reactor trip due to instrument failure indicating loss of second pump in coolant loop. Duration, 182.9 hours.
4/18/78	Reactor trip due to noise spike. Duration, 7.6 hours.
4/19/78	Reactor trip due to loss of feedwater due to personnel error performing maintenance on feedwater pumps. Duration, 7.9 hours.
4/20/78	Reactor trip due to spurious high flux spike. Duration, 6.0 hours.
4/23/78	Reactor trip caused by spurious signal. Five main steamline safety valves fail to close, and the ECCS was actuated. Design error of the valves necessitated replacement of all steamline safety valves, requiring shutdown until September 17, 1978. Metropolitan Edison removed orifice rods and installed retainers on burnable poison rods during this outage.
9/18/78	TMI-2 generated power for the first time.
9/19/78	Manual reactor trip. During test procedure of shutdown outside control room, feedwater valve closed and reactor did not trip when turbine tripped. Duration, 6 hours.
9/20/78	Reactor trip due to loss of one main feedwater pump. Duration, 9.2 hours.
9/21/78	Reactor trip due to control problems with feedwater pump. Duration, 8 hours.
9/22/78	Manual reactor shutdown for scheduled testing of main steam safety valves. Duration, 92 hours.
10/5/78	Extended outage due to Conax connector problems on steam generator. Duration, 181 hours.
10/13/78	Hot standby for 4 hours to repair turbine generator.
10/14/78	Two reactor trips due to feedwater pump problems. Duration, 13.7 hours.
10/17/78 10/20/78 10/21/78	Reduced power for total of 7.7 hours due to problems in the main generator relay, which prohibited synchronization with power grid.
10/28/78	Manual reactor shutdown in order to repair turbine. Duration, 90.1 hours.
10/29/78	During reactor shutdown a rachet trip of Group 5 control rods occurred. After trip, three rods were stuck at the 5% withdrawn positions.
11/3/78	Reactor trip due to loss of feedwater. Personnel error resulted in loss of power to condensate polishing valve.
11/7/78	Reactor trip due to loss of feedwater. Pressurizer level indicated below zero, and the ECCS was actuated. Feedwater system was found to be contaminated with oil. Duration, 594.6 hours.
12/2/78	Reactor trip due to loss of feedwater pump. Duration, 1.7 hours.

TABLE 1-6. Chronology of TMI-2 operating experience-Continued

Date	Event
12/2/78	Reactor trip during recovery from loss of feedwater. Duration, 4.8 hours.
12/2/78	Reactor trip due to personnel error resulting in excessive feedwater resulted in ECCS actuation. Duration, 28.3 hours.
12/16/78	Reactor trip due to mechanical failure in feedwater pump. Duration 146 hours.
12/28/78	Manual reactor shutdown to repair a number of steam leaks.
12/30/78	Hot standby for 3 hours to repair steam leak in turbine. Unit achieved 80% power and declared in commercial operation at 11:00 p.m. Unit maintained 82% power after 6:30 a.m. on December 31, 1978, until second heater drain pump could be returned to service.
1/2/79	Turbine taken off line to repair hydraulic leak. Duration, 11.5 hours.
1/5/79	Rod drops due to blown fuse. Automatic power reduction and then power escalation.
1/14/79	Reactor manual shutdown to repair leaking pressurizer instrumentation isolation valves.
1/15/79	During startup, reactor tripped due to loss of power to pressurizer. Outage extended to repair atmospheric dump bellows and a number of pressurizer instrumentation valves. Duration, 425.9 hours.
1/31/79	Unit returned to service.
2/6/79	Feedwater pump trips twice with automatic power runback to 55%.
2/10/79	Reactor maintained at 13% power during 13.2 hour outage to repair turbine leaks.
3/6/79	Turbine generator trip followed by reactor trip. Duration, 16.5 hours.
3/7/79	Unit operated near 97% power until loss of feedwater trip on March 28, 1979.

tions required by depressurization and other transients, which were not inadvertent, were not addressed.

A request to the NRR for information allowing a comparison of the number of TMI-2's safety injection events to those of other operating plants revealed that such information was not available and that a two-man-month effort would be required to obtain such information. Consequently, no data were provided, and the SIG was unable to make this comparison. This lack of operational information is significant, demonstrating that a major deficiency in NRC activities is the lack of a structured, systematic and coordinated process for collection, review, and evaluation of operational data. [5]

TMI-2 Plant Status on March 28, 19796

Operating Status

The plant status prior to 4:00 a.m. on March 28, 1979, was as follows:

Power Level-97.928% full power (872 MWe).

Rod Positions-Rod Groups one through five were fully withdrawn, groups six and seven were 95% withdrawn, and group eight was 27% withdrawn.

Pressurizer-

Level-229 inches
Spray-Spray valve open
Heaters-Energized in manual control
Leakage-Through one of the safety valves (RC-RIA or RC-121B)
Header temperature-190°F.

The leakage noted above could have been through pressurizer relief valve. The temperature indication is on header from all three valves.

Primary Coolant Systems-

Loop A
Pressure-2165 psig
Flow-68.484 MPPH (Million Pounds per Hour)
Temperature-Hot Leg-606°F
Cold Leg-558°F

TABLE 1-7. Comparison of licensee events

Plant	*Time Period*	*Component Failure*	*Defective Procedures*	*Design/ Fabrication Error*	*External Cause*	*Other*	*Personnel Error*	*Totals*
B& W								
TMI-1	*3/28/78-03/28/79*	*9*	*1*	*3*	*0*	*5*	*4*	*22*
TMI-2	*3/28/78-03/28/79*	*13*	*5*	*14*	*0*	*10*	*10*	*52*
CE								
Calvert Cliffs-1	*12/01/76-12/01/77*	*43*	*8*	*4*	*1*	*38*	*14*	*108*
Calvert Cliffs-2 (11/76)`	*12/01/76-12/01/77*	*67*	*1*	*6*	*1*	*14*	*12*	*101*
W								
D. C. Cook-1	*03/10/78-03/10/79*	*22*	*5*	*8*	*0*	*12*	*17*	*64*
D. C. Cook-2	*03/10/78-03/10/79*	*39*	*5*	*19*	*1*	*21*	*28*	*113*
Two Unit Stes								
*TMI-1 (6/74)**	*01/01/78-01/01/79*	*54*	*24*	*33*	*12*	*24*	*30*	*117*
Calvert Cliffs 1 (10/74)"	*01/01/78-01/01/79*	*146*	*17*	*16*	*8*	***69***	*42*	*298*
D.C. Cook 1 (1/75)`	*01/01/78-01/01/79*	*100*	*21*	*25*	*8*	*45*	*56*	*255*

*Represents date unit achieved criticality

TABLE 1-7. Comparison of licensee events-Continued

B&W Facilities-One-Year Period Immediately Following License Issuance

Plant	Time Period	Component Failure	Defective Procedures	Design/ Fabrication Error	External Cause	Other	Personnel Error	Totals
Arkansas 1		4	2	3	19	21	2	51
Crystal River		34	7	7	3	35	16	102
Davis Besse		51	14	18	4	21	22	130
Oconee 1		11	7	4	0	1	11	34
Oconee 2		7	6	1	0	2	9	25
Oconee 3		12	2	7	0	0	12	33
Rancho Seco		9	5	4	1	0	11	30
TMI-1		27	18	20	5	5	11	86
TMI-2		13	5	14	0	10	10	52

Number of LERs per Operating Plant:

	1975	*1976*	1977	1978
Babcock & Wilcox	46.7 (6)*	30.3 (6)	23.7 (6)	45.4 (8)
Combustion Engr.	41.8 (4)	46.4 (5)	64.1 (7)	46.4 (8)
Westinghouse	25.0 (17)	31.3 (19)	40.1 (22)	39.2 (23)
All PWRs	32.3 (27)	33.6 (30)	42.1 (35)	42.6 (39)
All BWRs	43.9 (22)	52.6 (23)	52.8 (25)	46.8 (25)

*Numbers in parentheses represent number of operating plants. Some information from Reference 8.

Loop B

Pressure-2148 psig
Flow-69.72 MPPH
Temperature-Hot Leg-606°F
Cold Leg-557°F
Activity-Beta/Gamma-0.3783 Ci/ml
Leakage-0.4 gpm
Letdown flow-70 pgm
Boron Concentration-1027 ppm

Reactor coolant makeup pump (MU-P-1B) was in service providing makeup and reactor coolant pump seal flows.

Secondary Coolant System-	*Steam Generator A*	***Steam** Generator B*
Loop Feedwater	5.7459 MPPH	5.7003 MPPH
Operating Level	56%	57.4%
Startup Level	158.8 inches	163.4 inches
Steam Pressure	910 psig	889.6 psig
Feedwater Temperature	462.7°F	462.7°F
Steam Temperature	595°F	594°F

Steam Generator Feedwater Pumps (FW-P-1A and FW-P-1B) were in service, condensate pumps (CO-P-2A, CO-P-18) were in service.

Genera! Plant Parameters

Borated Storage Tank Level-55 feet
Borated Storage Tank Temperature-68°F
Reactor Building Pressure-0.1 psig
Reactor Building Temperature-124°F (average)

Core Flood Tanks	A	B
pressure (psig)	595	600
level (feet)	13	13
isolation valves open		

Reactor Building Sump-On March 17, 1979, the sump pump had started seven times and had discharged approximately 1,468 gallons.

The most relevant activity just prior to the accident was an effort to unclog the transfer line from one of the condensate polishing vessels. This effort had been going on for approximately 11 hours, and supposedly had led to water entering the instrument air line. The polisher valves closed and the condensate pump (CO-P-1A) tripped. Although the check valve between the condensate polisher and service air system was frozen in the open position, the water still would not have had a path to the instrument air system except that the instrument air and station air systems were connected. Evidently, because the instrument air system lacked adequate capacity, the station air system was interconnected. There were at least two previous occasions during which water had contaminated the air system.[8]

Another deficiency in the plant status at the time of the accident was a wiring error in the control circuitry for the condensate pumps and the condensate booster pumps.[9] This error caused the condensate pump to trip when the condensate booster pump tripped. The condensate pump trip resulted in the feedwater pumps' trip.

Other deficiencies in the plant status relevant to the accident have been described in detail previously and are identified here for completeness:

1. Leaking pressurizes relief-safety valves[8]
2. Leaks in the makeup and letdown systems[8]
3. Lack of containment isolation actuation upon safety injection signal[10]

Equipment Status

Table 1-8 contains a list of activities and connected systems between TMI-1 and TMI-2 on the day of the accident. The extraction system was being supplied by TMI-2 to TMI-1; demineralizer water was being supplied by both units; and the condensate return system was being supplied by TMI-1 to TMI-2. Neither the shared activities nor the systems appear to have had any detrimental effect on the TMI-2 accident. Table 1-9 lists the equipment which was out of service on March 28, 1979. None of these outages violated the technical specifications for limiting conditions for operation.

Findings

1. Based on the number of LERs, the performance of TMI-2 and other B&W plants is average compared with other pressurized water reactor vendors.
2. The director of IE Region 1 considered the performance of the Metropolitan Edison Company to be average as compared with other licensees in his region.
3. TMI-1 reported fewer licensee events during the first year of operation than other two unit sites supplied by other PWR vendors that were selected for comparative purposes.
4. TMI-2 reported fewer licensee events during the first year of operation than did TMI-1.
5. TMI-1 has operated since 1974 without significant operational problems.
6. NRC lacks a structural, systematic and coordinated process for collection, review, evaluation and feedback of operational data.

TABLE 1-8. Connections and shared activities between TMI-1 and 2

Shared Activities

Security-Common site protection force and protected area.

Fire Suppression Water System-Common system for both Unit 1 and Unit 2.

Radwaste, So/id-Radwaste solidification done in Unit 1.

Industrial Waste *Treatment* System

Paging System-Common page system.

230-kV Substation-Offsite power for both units provided via common 230-kV substation.

River Water Chlorinator-Common system to chlorinate each unit's control room.

Meteorological Tower-Common tower reading in each unit's control room.

River Water Discharge Canal-Common discharge to river from each unit's mechanical draft cooling tower.

Primary Sampling Room-Common room for sampling Unit 1 and Unit 2 primary samples.

Connections

Extraction Steam System-Either unit can supply other unit with extraction heating.

Demineralized Water System-Supplied by Unit 1.

Condensate Return System-Condensate return connection if extraction steam is supplied.

Turbine Lube Oil Storage System-Common storage and makeup capability.

Radwaste Liquid System-Cross-connected to transfer liquids between the units.

Instrument Air System-Not normally open.

Domestic Water System-Supplied by Unit 1.

HVA C Fuel Handling Building- Common building, each unit's area with its own heating, ventilation and air conditioning.

TABLE 1-9. Equipment out of service on March 27 and 28, 1979

1. Chlorine Evaporator (CL-2-1)
2. Condensate Flow Transmitter (CO-FT-070)
3. Clearwell Tank (WR-T-2)
4. Mechanical Room Fan Coil Unit (AH-C-24)
5. Soil Exhaust Pre-filter (AH-F-27)
6. Feedwater Heater 3A Sight Glass
7. Temporary Sodium Hydroxide Pump (WT Caustic Tank)
8. Heater Drain Pump B (HD-P-1B)
9. Reactor Building Normal Cooling (RB-21 A-2)
10. Heater Drain Valve (HD-V-65B)
11. Control Building Fan Coil Unit (AH-C-52B HTR)
12. Control Building Fan Coil Unit (AH-C-52D)
13. Evaporative Cooler (RB-L-183)
14. Mechanical Draft Cooling Tower Fan 2-3
15. Makeup Skid Acid Block and Bleed Valves (r8, 9 & 10)
16. Heater Drain Limit Switch (HD-LS-327) on Heater Drain Tank (HG-T-1)
17. Main Steam Thermostat (MS-U-32B) on Turbine Bypass Line
18. Reactor Coolant Hot Leg Drain (RC-U-4)
19. Fire Door Between Auxiliary and Fuel Storage Buildings
20. Ammonia Pump A (AM-P-1A)
21. Breaker 24 (spare) 2-4V Vital Power Supply
22. Auxiliary Building Sump Tank (WDL-T-5)
23. Sodium Thiosulfate Tank (DH-T-3)
24. Makeup System Pressure Transmitter (MU-2-PT)

REFERENCES AND NOTES

[1]Availability factor is defined as:

$$\frac{\text{Hours generator on line}}{\text{Gross hours in report period}} \times 100$$

[2]Capacity Factor is defined as:

$$\frac{\text{Net electrical power generated}}{\text{Authorized net MWe (892 MWe) x gross hours in report period.}} \times 100$$

[3]Grier dep. at 81.

[4]NRC, "Review of Licensee Event Reports 1976-1978," Advisory Committee on Reactor Safeguards, NUREG-0572, September 1979.

[5]Memorandum from D. Davis, NRC, to L. Gossick, "Task Force Report on Operational Safety Data Analysis and Evaluation," May 15, 1979.

[6]Letter from J. Herbein, Met Ed, to M. Rogovin, NRC/SIG, Subject: Response to Letter from Special Inquiry Group (NTFTM 780626-01), dated June 26,1979.

[7]Interview of G. Lehmann (Interview No. TM-294).

[8]NRC, "Staff Report on the Generic Assessment of Feedwater Transients in Pressurized Water Reactors Designed by the Babcock & Wilcox Company," NUREG-0560, May 1979.

[9]Interview of G. Lehmann (Interview No. TM-294) at 23.

[10]Letter from J. Hendrie, NRC, to Chairman Kemeny, Subject: President's Commission on the Accident at Three Mile Island (Response to Questions by the Commission), dated June 25,1979.

3. INSPECTION HISTORY AT THREE MILE ISLAND (TMI) SITE

Introduction

The IE Region I office has been responsible for inspecting the TMI site during both the construction and operation of TMI-1 and TMI-2. The construction permits for TMI-1 and TMI-2 were issued on May 18, 1968 and November 4, 1969 and the operating licenses were issued on June 24, 1974 and February 8, 1978, respectively.

The IE office compiled an inspection history of the TMI site.' This history was limited to the period from June 1975 to March 1979 for convenience, and was based on the information readily available in a computer data system. The information presented in the IE history includes a tabulation of inspections, but not a detailed evaluation of the inspection reports. For the given period, 136 inspections were performed for TMI-2. A total of 41 noncompliances were found, including 7 deficiencies and 34 infractions. For TMI-1, inspections identified, a total of 95 noncompliances: 42 deficiencies and 53 infractions were identified.

Noncompliances, deficiencies, and infractions are defined in the IE Inspection Manual, chapter 0800.[2] A noncompliance is defined as a failure to comply with regulatory requirement. Items of noncompliance are categorized by IE according to their severity. In decreasing order of severity, noncompliances include violations, infractions, and deficiencies. A violation is an item of noncompliance having the substantial potential of exceeding a safety limit. An infraction is an item of noncompliance that results in a reduction of preventative capability or causes, contributes to, or aggravates an incident or occurrence. A deficiency is an item of noncompliance in which the threat to the health and safety of the public is remote and which can be corrected without undue expenditure of time or resources. The majority of TMI-2 noncompliances were related to administrative procedures and occurred during the construction phase. Most of these concerned the quality assurance area. Health physics was the most frequent noncompliance for TMI-1. A comparison of TMI enforcement actions with those of other pressurized reactor units is contained in Table 1-10.

IE initially attempted to evaluate the regulatory performance of licensees in two ways. First, operating plants were evaluated on the basis of numbers and types of noncompliance and Licensee Event Reports for each. Second, IE inspectors were asked to provide subjective evaluations of the safety of each operating plant ranging from "acceptable" to "exceptional." This evaluation rated TMI-1 better than 12 of 15 plants in Region 1.[4] However, because this evaluation was completed in 1978, TMI-2 was not included.

Unfortunately, efforts to evaluate the performance of licensees generally have not been put to effective use by the NRC. The purpose of the appraisal system has been to remove some of the abstract judgment and place the licensee evaluations on a more consistent and defendable basis. The licensee appraisal system also has sought to identify those licensees who have demonstrated poorer performances so that IE resources can be directed toward upgrading the licensee performance. These objectives have not been realized, however. IE resources have continued to be devoted arbitrarily to some plants more than to others.[5]

Inspection of TMI-2

The inspection reports for the period August 1977 through February 1979 were also reviewed by the SIG to identify issues that might be related to the TMI-2 accident. These reports contain notes on problems identified by the licensee and by the inspectors, tests observed or reviewed by the inspectors, and general observations by the inspectors concerning the design and operation of the plant. Unfortunately, most of the discussions in the inspection reports are quite brief and preclude an evaluation of either the depth of inspector review or

TABLE 1-10. Comparison of enforcement actions

Unit	6-12/1975 INF*/DEF*	1976 INF/DEF	1977 INF/DEF	1978 INF/DEF
TMI-1	2/16	20/12	22/7	9/7
TMI-2	6/10	5/1	9/3	14/3
PWR A	N/A	13/13	18/11	10/9
PWR B	N/A	29/10	21/15	6/8
PWR C	N/A	10/10	23/17	18/8
PWR D	N/A	12/10	13/11	9/9

*Infractons/Deficienc es

the underlying factors contributing to the inspector's concern. The information contained in these reports is of such a general, cursory nature that it frequently is inscrutable. For example, although approximately one-half of the inspector's time is spent on record reviews the reports do not reflect the detail of the review or even delineate the dates on which specific records are reviewed.

Table I-11 presents a summary of inspection report items illustrative of issues that could relate to the accident. Two of the three most relevant examples are the inspections performed in early December 1978 which reviewed, to some extent, the procedure and test results of the emergency feedwater-system valve lineup verification and operability tests, and the surveillance procedures for the emergency feedwater-pump functional and valve operability tests. However, the extent or detail of the review is not known, and therefore, we could not ascertain whether the feedwater block valves were considered during the inspection.

A third relevant example is the inspector's observation of the generator trip test on January 12,1979. The final data from the test were not evaluated to determine whether the pressurizer electromagnetic relief valve operated properly or if the actuating system conditions meet the acceptance criteria of the test. Although the relief valve closed, it is not known whether the test data indicated a potential operating problem. The inspection reports indicated that no discrepancies were found.

In the final analysis, the degree of relevance of these inspections to the accident is unknown. For those inspections where inspectors' concerns were identified, it cannot be determined how or to what extent their concerns were or could have been resolved, either to prevent the accident or change its course.

The inspection reports were also reviewed to identify the open or unresolved inspection items on March 29, 1978, which could be relevant to the accident. These are summarized in Table 1-12. The open items are certainly important to safety, but their relevance to the accident has not been determined.

Review of Plant Procedures

The IE inspections generally include a sample review of how procedures are implemented, results of these procedures, and administrative controls over them. IE does not review the procedures, however, for the purpose of approving their adequacy or certifying NRC approval. In fact, Norman Moseley, the former Director of Region II, told the Commissioners that "we [IE] always tell the licensee that our review of procedures is specifically not to approve the procedure, but rather to test for the effectiveness with which they review it." Victor Stello, the IE Director, agreed that approval of procedures is not given during inspections.[8] Because neither NRR nor IE approves licensees' procedures, the NRC does not approve or review in detail any of the numerous procedures used to operate the plant during testing programs or during normal or emergency operations. Nor does the NRC administer managerial control over processes, such as quality assurance, emergency plans, containment integrity, and fire protection.

As a result of inadequate performance by reactor operations and support staff, IE issued IE Circular 76-07 in December 1976.[9] The circular instructed licensees to ensure that the plant staff complied with safety procedures and that the staff be made aware of safety-related incidents that have occurred at that facility or at similar facilities. In addition, licensees were requested to review the administrative controls for plant operating procedures, such as signoff, tag out procedures, and checklists. No request was made that licensees ensure that their procedures were accurate or adequate for their intended purpose.

The drafting, review, and approval of procedures for TMI-2 were accomplished by Met Ed with assistance of "rental" engineers from B&W and Nuclear Utility Services, an outside consultant.[10] NRC's role consisted of limited auditing of TMI-2 procedures on a "sampling basis" to ensure that "their technical content was adequate to assure satisfactory performance of intended functions" and that "their format was in accord with ANSI N18.7 and the licensee's administrative contracts."[11]

Development of Operating Procedures for B&W Plants

The following discussion provides additional information on the methods used to draft, review, and approve plant procedures. The information is based on our review of the operation of Davis Besse. On the basis of the SIG review of precursor events, this discussion appears to be applicable to all B&W plants.

Plant procedures are written by the station staff using the plant's technical specifications and draft procedures (more recently referred to as Plant Operating Specifications[12]), prepared by B&W. Although procedures of other operating plants have been obtained in the past, they have proven to be of limited interchangeability because of differences in

TABLE 1-11. Summary of IE inspection reports

	Date	*Report Number*	*Inspector*
1.	October 24, 1972	50-320/72-05	Folson

In a letter to IEHQ (dated October 24, 1972) the Region I Reactor Construction Branch Chief noted that the licensee was continuing to have problems'implementing a definitive quality assurance program. This problem was also noted in an inspection report dated May 23, 1972 (50-320/72-01).

2.	April 27, 1973	50-320/73-02	

The inspector noted that the NP-1 Partial data sheets for the 2'/2 inch core spray and the 10 inch pressurizer surge line piping were signed off by a State of Ohio inspector as conforming to the ANSI B31.7 piping code. The data sheets contained no evidence that they were also in conformance with the Pennsylvania Special Standard WC-1891 as required by the PSAR.

3.	April 16, 1975	50-320/75-03	Folson

The licensee reported finding a number of defective cast stainless steel socket weld valves, most of which were check valves (2 inches or smaller). A total of 34 valves, most of which were in the radwaste system, were rejected. The vendor was Crane Company.

4.	July 16, 1974	50-320/74-04	Folson

A random selection of drawing on several stick files by the inspector showed that 21 percent of the drawings had been superseded. A similar situation was reported in August 1972.

5.	Feb. 18, 1976	50-32/76-01	Narrow

The inspector noted that the surge line was installed as shown in FSAR Figure 5.1-5 and B&W Drawing No. 141562.

6.	March 18, 1976	50-320/76-03	Fasano/Canter

The inspector noted that Reg. Guide 1.63 states that a Turbine Trip test from 100 percent power is applicable to PWRs. The licensee had chosen to perform the trip at 40 percent. The inspector noted that the NRC had concurred with the licensee's position.

7.	May 25, 1976	50-320/76-07	Canter

The inspector provided a detailed discussion on remotely operated valves which may become submerged following a postulated LOCA and ECCS actuation. Some deficiencies in valve location were noted.

8.	June 28, 1976	50-320/76-08	Narrow

The inspector observed that the Isometric Piping Drawing for a section of the Pressurizer Relief Valve discharge piping had been notated to reflect a recent change in the applicable code classification from N-2 (USAS B31.7 Nuclear Power Piping) to SC (USAS B31.1 Pressure Piping).

9.	April 12, 1977	50-320/77-10	Fasano

The inspector noted that the licensee was conducting a review of Unit 1 problems for applicability to Unit 2. The inspector had numerous observations concerning the resolution of many of these issues. None of them had specific applicability to this inquiry.

10.	May 18, 1977	50-320/77-15	Narrow

Resolution of Noncompliance 320/74-04: Stress analysis of Main Steam and Pressurizer relief valve piping. The inspector reviewed Report No. 7.00.006, Rev. 1, "Pressurizer Relief Valve Discharge Piping Stress Analysis" by Burns & Roe, dated March 21, 1977. No deficiencies were noted.

TABLE I-11. Summary of IE inspection reports-Continued

	Date	*Report Number*	*Inspector*
11.	May 23, 1977	50-320/77-16	Fasano

Resolution of Noncompliance 320/77-09-01 failure to establish document measures and failure to correct adverse conditions concerning quality as soon as practicable. The inspector noted that the issue had been resolved.

12.	June 16, 1977	50-320/77-32	Fasano

The inspector witnessed the check of the pressurizer code safety relief valve setting. No deficiencies were noted.

13.	June 29, 1977	50-320/77-24	Donaldson

Partial Resolution of Unresolved Item 76-18-01: Training program for offsite agencies. The inspector discussed with the licensee the emergency plan training program for various offsite agencies. The item remained unresolved pending review of the completed program.

14.	June 29, 1977	50-320/77-24	Donaldson

The inspector, licensee and representatives of four offsite agencies met to discuss offsite agency support. The organizations represented were: Dauphin County Office of Civil Defense, Pennsylvania Bureau of Radiological Health, Milton S. Hershey Medical Center, and Londonderry Township Fire Department.

The inspector verified that the licensee had coordinated pertinent aspects of the Station Emergency Plan development with these agencies and then discussed the anticipated nature and scope of the support planned.

15.	June 29, 1977	50-32/77-24	Donaldson

The inspector discussed the licensee's planned licensee and offsite agency training program to be implemented under the Station Emergency Plan.

16.	August 11, 1977	50-32/77-26-05	Conte

The inspector noted that some procedural errors found by the inspector should have been identified and corrected by the licensee's review and approval program. The inspector also expressed concern that approved procedures not reviewed during the inspection would exhibit similar problems.

17.	August 11, 1977	50-320/77-26-13	Conte

The licensee intended to use Preventive Maintenance Check Sheets. The inspector commented that the check sheets had no provisions requiring an operational test prior to returning the system to service.

18.	August 5, 1977	50-320/77-28	Rebelowski

The inspector noted that the licensee had completed the testing of the pressurizer code relief.

19.	August 4, 1977	50-320/77-28-06	Rebelowski

The licensee stated that there was a possible design deficiency relating to the design of the reactor coolant pump seals and their cooling water supply. The seals were not designed to accept the transient associated with station blackout.

20.	August 15, 1977	50-320/77-31	Plumlee

The inspector noted that the respiratory protection program was acceptable except that employees were not specifically evaluated as to their physical and psychological fitness for work requiring the use of respiratory protection equipment. The licensee acknowledged the deficiency and the inspector did not classify this as an Unresolved Item.

TABLE 1-11. Summary of IE inspection reports-Continued

	Date	Report Number	Inspector
21.	Sept. 21, 1977	50-320/77-32	Kellogg

The inspector witnessed the test of the 2B Emergency Feedwater Pump Functional Test. No inadequacies were identified.

22	Sept. 21, 1977	50-320/77-32	Kellogg

The inspector noted that the licensee had experienced problems with the reactor-coolant pumps (RCP); RCP-2A dropped off line after startup, probably due to a phase overload and RCP-2B developed an oil leak. The inspector reviewed accummulated data for the RCPs. No additional problems or deficiencies were noted.

23.	Sept. 29, 1977	50-320/77-34	Kellogg

During testing of main steam safety relief valves, one valve remained open for an extended period cf time. The inspector noted that the licensee's action to reseal the valve was timely. The inspector also noted that 8 of the 12 valves tested failed to meet acceptance criteria. Setpoint adjustments and retest was planned but there was no follow-up by the inspector.

24.	January 16 1978	50-320/77-42	Kellogg

The inspector reviewed the Generator Trip Test procedure. The procedure controls the response after a generator loss of load from full power. This information was used to verify adequate NSSS design and control system performance. No inadequacies were noted.

25.	Feb. 27, 1978	50-320/78-07	Kellogg

Resolution of 320/76-00-02 and 320/76-09-01. The inspector reviewed a test demonstrating that the response times of the Engineered Safety Systems were within the requirements of the proposed facility Technical Specifications.

26.	Feb. 27, 1978	50320/78-07	Kellogg

Partial Resolution of 320/77-40-02. The volute seals on all four RCPs were replaced and tested. Testing at normal temperature and pressure remains.

27.	Feb. 27, 1978	50-320/78-07	Kellogg

The inspector verified that there are plant procedures providing alternate methods for accomplishing an orderly plant shutdown and cooldown in case of loss of normal coolant supply system. No deficiencies were noted.

28.	Feb. 27, 1978	50-320/78-07-03	Kellogg

The inspector noted that testing associated with the Feedwater Latching System was incomplete.

29.	Feb. 27, 1978	50-320/78-07-05	Kellogg

The licensee noted deficiencies associated with control room status-board position indications for various safeguards components.

30.	Feb. 27, 1978	50-320/78-08	Bares

The inspector reviewed the environmental monitoring program and concluded that the licensee could implement the required radiological environmental monitoring program for Unit 2.

31.	March 7, 1978	50-320/78-09	Kellogg

Resolution of Unresolved Item 320/77-24-01 Adequacy of Station Emergency Plan. The inspector reviewed the Station Emergency Plan and its implementing procedures to verify that adequate preparedness would be implemented by the plan and its procedures. The inspector concluded that the plan covered all aspects of an emergency.

TABLE I-11. Summary of IE inspection reports-Continued

	Date	Report Number	Inspector
32.	March 29, 1978	50-320/78-10	Markowski

The inspector found some incorrectly stored out-of-calibration torque wrenches. He noted "This finding constitutes one example of an item of non-compliance with the requirements of 10 CFR 50, Appendix B, Criterion V and the licensee's administrative procedures."

33.	March 30, 1978	50320/78-12	Narrow

This report includes an investigation of an allegation by a welder that he had been required to install an anchor plate in the core flood tank without following proper procedures. The welder stated that this was a single isolated occurence. The allegation was substantiated.

34..	April 24, 1978	50320/78-15	Haverkamp

The inspector reviewed the emergency safeguards actuation that had occurred on March 29, 1978. After a loss of power to the 2-IV bus, a reactor trip had occurred and the pressurizer electromagnetic relief valve (EMOV) opened The event led to a position indication (energized solenoid) in the control room. A subsequent memorandum was written to CIE headquarters for an assessment of the fact that the EMOV was not safety-related.

35.	May 31, 1978	50-320/78-17	Haverkamp

The inspector reviewed Metropolitan Edison Company's letter to NCR:NRR dated May 5, 1978 which included results of B&W's most recent calculation concerning a small break LOCA at TMI. The inspector discussed the LOCA response actions with selected operators and verified their understanding and knowledge of the procedures. Extensive procedural changes had been made as a result of the B&W analysis.

36.	August 24, 1978	50-320/78-24	Haverkamp

The main steam line safety relief valves were determined to have excessive blowdown characteristics.

37.	August 24, 1978	50-320/78-24	Haverkamp

The inspector reviewed LER 78-26/36 dated May 2, 1978. A reactor coolant system wide range pressure transmitter had failed due to moisture-induced short circuiting in the transmitter terminal box.

38.	August 24, 1978	50-320/78-24	Haverkamp

The inspector reviewed LER 78-27/1T dated May 2, 1978 concerning an error in the small break LOCA safety analysis.

39.	Sept. 21, 1978	50320/78-28	Haverkamp

The inspector reviewed Updated LER 78-33/1T dated July 31, 1978 concerning a reactor trip followed by RCS depressurization and NaOH injection due to a steam generator safety valve which had not resealed properly.

40	November 8, 1978	50320/78-32	Haverkamp

Resolution of Noncompliance 320/78-26-01 concerning failure to update emergency procedures The inspector noted that quarterly surveillance of emergency monitoring kits now includes verification that the information book in each kit includes up-to-date procedures.

41.	Nov. 30, 1978	50320/78-33	Haverkamp

The inspector reviewed the report of an emergency safeguard actuation which had occurred on November 7, 1978, while at 92% power. A heater drain tank low level alarm ultimately resulted in loss of the 113 feedwater pump. Eventually this led to a reactor trip and a safety injection. During the transient the pressurizer level decreased below zero.

TABLE I-11. Summary of IE inspection reports-Continued

	Date	*Report Number*	*Inspector*
42.	Dec. 4-8 and 12-14, 1978	50320/78-36	Haverkamp

The inspector reviewed a sampling of test results for procedures Emergency Feed System Valve Lineup Verification and Operability Test and from the Turbine Driven E.F. Pump Operability Test for the period July 20-December 2, 1978. The purpose of the review was to verify that operations were in conformance with Technical Specifications. No discrepancies were found.

43.	Dec. 12-14, 1978	50-320/78-37	Foley/Caphton

The inspector reviewed Unit 2 Surveillance Procedure, "Motor Driven Emergency Feed Pump Functional Test and Valve Operability Test" and verified that all pumps were covered by the procedure. A sampling of completed test results was reviewed. No unresolved items were identified.

The inspector reviewed the locked valves in the emergency feedwater system to verify they were locked in the required position. No discrepancies were found.

44.	January 9, 1979	50-320/78-36	Haverkamp

The inspector expressed concern over the apparent degradation in proper radiation protection control during the preceding weekend. The inspector noted that the conditions resulted from a combination of inadequate training and insufficient designation of responsibilities.

45.	January 9, 1979	50-320/78-36	Haverkamp

The inspector noted several examples of improperly or inadequately completed operating procedures. Most of them were cases of not initialing a step as being completed. However, in one case the inspector noted that a value lineup had not been fully completed.

46.	January 12, 1979	50-320/78-39	Bettenhausen

The inspector witnessed the generator trip test. The generator trip was followed by a turbine overspeed trip and a runback in the reactor power to 15%. The inspector noted that the following test parameters could not be ascertained to meet acceptance criteria on the basis of preliminary raw data:

- RCS pressure at which the pressurizer spray valve opens or shuts
- RCS pressure at which the pressurizer electromagnetic relief valve opens or shuts
- Reactor power runback rate
- Main steam safety valve lift pressure.

No items of noncompliance were noted.

TABLE 1-12. Summary of unresolved inspection issues as of March 29, 1978

	Date	Report Number	Inspector
1.	Feb. 22-24, 1978	50-320/78-10	Markowski/Beckman

The inspector noted that the licensee had not complied with the requirements of ANSI N45.2.9, "Requirements for Collection, Storage and Maintenance of Quality Assurance Records for Nuclear Power Plants." This issue was outstanding before the operating license was issued on February 8, 1978. Issue is still unresolved.

2.	Oct. 16-20, 1978	50-320/78-32	Haverkamp

It was noted in one unresolved item that management had not given final approval to test results for a number of startup test procedures. The power ascension testing proceeded to the 75% power level but without final approval of the test result at the 15 and 40% power level plateaus. The inspector also identified, as an unresolved item pending license review, the need to include administrative controls for installation of gagging devices on safety or relief valves to be installed during modifications. Design review of the decay heat and building spray valves has not been completed by the licensee, and in the event of a major break in the nuclear services river water piping, these valves would be subject to simultaneous flooding.

3.	Dec. 4-8 and 12-14, 1978	50-320/78-36	Haverkamp

The inspector noted a number of improperly or inadequately completed operating procedures which are still open items. Some of the more relevant incomplete procedures were the emergency feedwater valve lineup, reactor building purge and purification valve lineup, pressurizer operation, makeup and purification system valve lineup, and safety features actuation systems.

The inspector noted several examples of improper implementation of Technical Specification surveillance procedures. An item of noncompliance was issued concerning containment isolation valve verification inside containment. The valves are required to be verified as closed during cold shutdown.

4.	Dec. 12-14, 1978	50-320/78-37	Foley

The inspector found that the licensee's valve testing procedures did not appear to address the testing requirements for valves with fail-safe actuators. Licensee was to incorporate these valves into the testing procedures. Action has not been completed.

5.	Dec. 28-29, 1978	50320/78-39	Bettenhauser

The inspector was to review final data obtained during a generator trip test from 96% power during a subsequent inspection. System conditions for pressurizer operations were included in the data obtained during the test. See inspection summary number 46 in Table 2. Issue is still on the inspection open list.

procedural philosophy from utility to utility and differences in the plant systems.[13]

The draft procedures provided by B&W are prepared by the Customer Services Group with technical assistance from other groups.[14] These guidelines include outlines of specific operating and emergency procedures as well as warranty criteria (e.g., water chemistry on the secondary side must meet certain standards).[15] Once these draft procedures are received by the utility, they must be supplemented with specific plant information. In addition, the utility is free to make any changes it considers appropriate."[6] With the exception of some startup and test procedures, there is no systematic review of these actual plant procedures by B&W. Only when requested by the utility to review a specific procedure does B&W make any formal or informal review of these procedures.[17]

We found no indication that plant procedures are formally or informally reviewed within the NRR and the only review conducted by the NRC is that done by IE. Principal inspectors and specialists may be assigned to review plant procedures as part of various inspection modules. For example, during the preoperational inspections, 60 to 70% of the procedures are reviewed.[18] However, this review seems to focus primarily on verifying that required procedures exist and have been reviewed by appropriate utility personnel.[19,20] A small percentage of the procedures (possibly as small as 1%) is reviewed by the inspectors for technical content. In addition, although IE has advocated that the utilities walk through each procedure, this practice has not been adopted by all utilities. The inspector does not always walk through the procedure to determine what the operator may see or do.[20] Accordingly,

were physically impossible to perform as written. 21

Once the plant becomes operational, the inspectors review approximately a third of the plant operating and emergency procedures each year.22 During this review, more attention may be given to their technical content. The procedures are also informally reviewed by the utility engineering group, which comments on problems they discern.23

As a result of this system, procedures vary considerably in format, content, and quality. Utilities do not effectively use the "debugged" procedures developed by other utilities, and numerous changes frequently are required during the first few years of operation.[24]

Similarly, operating experience is not effectively incorporated into plant procedures. B&W reviews site problem reports that document events occurring at specific plants and can provide guidance to the utilities through site instructions.[25] However, the ineffectiveness of this feedback mechanism is demonstrated by the fact that the Customer Services Group, which is responsible for the preparation of draft procedures, did not review the September 24, 1977, incident at Davis Besse (see Section I.C) to determine if, as a result of that incident, any changes were required in the draft procedures.[26]

Moreover, B&W did not receive and thus did not review the change to the Davis Besse small break LOCA procedure that discouraged operators from securing high pressure injection during a small LOCA.[26,27] In the meantime, the utility made a change to its small-break LOCA procedure while B&W was agonizing over the advisability of recommending a similar change (see Kelly/Dunn Memoranda, Section I.Q. Neither party knew of the other's actions.[28]

The principal means by which operating experience is factored into the plant procedures is through the efforts of the station staff. One of the action items that could result from an accident at a plant would be a procedural change, a change prepared by a member of the station staff and forwarded to the Station Review Board. On the basis of their recommendation, the station superintendent would make the decision whether to approve the change.[29] By using essentially the same procedures, information about incidents at other plants could be evaluated for changes in plant procedures.

Sources of such information are rather limited but include the following:

- Information from suppliers, such as B&W, Bechtel and others
- Selected Licensing Event Reports received from groups such as Edison Electric Institute (utilities do not receive the bulk of LERs from other plants)
- Bulletins and other publications from the NRC
- NRC monthly computer summaries of LERs (These summaries seldom provide enough information to make a procedural change, which usually requires direct contact with the plant involved, however.)
- B&W superintendent's group meetings

Most of this information requires considerable insight and analysis before changes are recognized and developed, and changes are certainly sporadically applied with varying degrees of success from plant to plant.

Technical specifications also play an important role in the development of plant procedures. The technical specifications for a plant are issued by the NRC as an appendix to the operating license. However, these technical specifications are normally prepared by the vendor and submitted for approval by the utility as part of its operating license application. Within the B&W organization, the technical specifications are prepared by customer services and licensing groups, with the latter having the lead responsibility. Although the technical specifications serve as part of the basis for eventual plant procedures, there does not appear to be any systematis effort by B&W to ensure that the B&W draft procedures and the proposed technical specifications, also provided by B&W, are consistent.[31] Consistency is left to the utility.[32] B&W normally does not even see the actual plant procedures, and obviously cannot review them for consistency with the technical specifications.

Within the utility the technical specifications are the responsibility of the company's power engineering group.[23] When needed, changes are made as follows:

1. A facility change request is proposed by the power engineering group or the station staff
2. A review is made by the station staff and the Station Review Board
3. A review and safety analysis is prepared by power engineering
4. A review is made by the company Nuclear Review Board
5. A request is sent by power engineering to NRC for review and approval

When a change is approved, it is the responsibility of the station staff, including the Station Review Board, to ensure that it is accomplished. [29]

Findings

1. The inspection reports did not reveal any major deficiency in the licensee's performance which clearly contributed to the accident.
2. The inspection reports lack sufficient detail to ascertain either the underlying reasons for inspectors' concerns and factors leading to noncompliance.
3. NRC approval is not required for any plant procedures.
4. There is no NRC requirement that the vendor review the utility's operating and emergency procedures to ensure that they are in accordance with the basic assumptions of the plant design.
5. Operational information is not integrated into plant procedures.
6. Schedules are not established for the resolution of important safety problems noted during inspections.

REFERENCES AND NOTES

[1] NRC, "History of Inspection at the THREE MILE ISLAND SITE," September 1979.

[2] NRC, Inspection and Enforcement Manual, 8 Volumes.

[3] Miscellaneous Documents (Untitled) from Office of Inspection and Enforcement Files, March 28,1979-May 11, 1979.

[4] Letter from W. Paton, NRC, to Atomic Safety and Licensing Board Panel and Atomic Safety and Licensing Appeal Board Panel, Subject: Board Notification-License Regulatory Performance Evaluations, dated February 1979.

[5] Mosley dep. at 196-197.

[6] Grier dep. at 74.

[7] Memorandum from D. Stemberg, NRC, to K.V. Seyfrit, "Three Mile Island 2-Pressurizer Relief Valve Control System," March 31, 1978.

[8] NRC Commission Meeting Transcripts (October 23, 1979) at 130. Memorandum from D. Sternberg, NRC, to K. V. Seyfrit, "Three Mile Island 2-Pressurizer Relief Valve Control System," March 31,1978.

[9] NRC, IE Circular 76-07, "Inadequate Performance by Reactor Operating and Support Staff," December 18, 1976.

[10] President's Commission on the Accident at Three Mile Island, "Report of the Office of Chief Counsel on the Role of the Managing Utility and its Suppliers," at 930, October 31,1979.

"*Ad.* at 95.

[12] Hallman dep. at 39.

[13] Murray dep. at 71.

[14] Hallman dep. at 41.

[15] Dunn dep. at 67.

[16] Faist dep. at 45.

[17] Walters dep. at 32.

[18] Knop dep. at 61, 63.

[19] Kohler dep. at 73.

[20] Tambling dep. at 92.

[21] Knop dep. at 67.

[22] Knop dep. at 59.

[23] Miller dep. at 55.

[24] Kohler dep. at 75.

[25] Walters dep. at 29.

[26] Hallman dep. at 50.

[27] Dunn dep. at 69; Waiters dep. at 31.

[26] Hallman dep. at 52.

[29] Murray dep. at 64.

[30] *1d.* at 66.

[31] Walters dep. at 32-33.

[32] Taylor dep. at 61.

C PRECURSOR EVENTS

1. OVERVIEW AND GENERAL DESCRIPTION

The experience of the nuclear power industry and the NRC with accidents and episodes presaging the Three Mile Island (TMI) accident was of particular interest to the Special Inquiry Group. Several such events occurred during the preceding 8 years in connection with plants other than the TMI installations. One problem at TMI-2 was also a possible precursor to the March 28,1979 accident.

The history of the industry was reviewed to determine (1) if it contained useful foreknowledge of the March 28, 1979 problems at TMI, (2) whether the information was effectively evaluated and disseminated, and (3) whether that information was ultimately effectively utilized.

Initially, the Special Inquiry Group planned to investigate all potential precursor events to determine their relevance and significance and how they were handled. However, as work progressed we realized that there were a number of additional events and issues that although they did not appear to be significant, might have yielded information that would substantiate the observations we made as a result of our review of the precursors that we did investigate. These events were not addressed because the resources required to investigate these peripheral issues were not justified by the expected return. Therefore, the precursors discussed in this report are best described as a representative sample of all the precursor events associated with the accident at TMI-2. We believe that this sample accurately reflects the ways that these events and issues have been handled.

The more significant precursor matters examined begin with a 1971 letter to the Atomic Energy Commission from H. Dopchie of Belgium (see Section I.C.5) which noted a problem with pressurizer level after a small-break loss-of-coolant accident (LOCA) from the pressurizer steam space of a Westinghouse pressurized water reactor. In 1974, such an event occurred at a Westinghouse reactor (NOK-1) at Beznau, Switzerland (see Section I.C.6).

In 1975, the Nuclear Regulatory Commission published a report of a detailed 3-year study, variously known as "WASH-1400," "The Reactor Safety Study" or "The Rasmussen Report", which attempted to measure the risks in the operation of nuclear reactors; small-break loss-of-coolant accidents and small releases of radioactivity were included (see Section I.C.7).

In September of 1977 the Davis Besse nuclear powerplant of the Toledo Edison Company, designed by Babcock & Wilcox (B&W), had a transient that was very similar to the TMI-2 accident (see Section I.C.9).

At the same time, at the Tennessee Valley Authority (TVA), Carl Michelson, a nuclear engineer and a consultant to the NRC's Advisory Committee on Reactor Safeguards (ACRS), raised to his TVA superiors some long-considered concerns about the susceptibility of Babcock & Wilcox designed plants to very-small-break loss-of-coolant accidents (see Section I.C.8). TVA submitted the Michelson report to Babcock and Wilcox for analysis in April of 1978. A handwritten copy had been given informally in the fall of 1977 by Michelson to Jesse Ebersole, a close personal friend and a member of the ACRS. Ebersole, in the process of preparing questions that were eventually sent to Portland General Electric Company about its Pebble Springs, Oregon, plant, used Michelson's report as the basis for a question about operator interpretation of pressurizer level in a B&W plant during a loss-of-coolant accident (see Section I.C.11).

At Babcock & Wilcox Company Nuclear Power Generation Division headquarters, a concern arising out of the incident in September 1977 at the Davis Besse plant prompted Engineer Joseph J. Kelly (in the Plan Integration Section) on November 1, 1977, and Bert M. Dunn, (Chief of the Emergency Core Cooling Systems Analysis Branch) on February 9, 1978 to urge their management to revise guidance concerning operator instructions on stopping the high pressure injection pumps during accidents (see Section I.C.10).

At the NRC, perhaps as a outgrowth of the composite impact of the September 1977 Davis Besse incident, the Michelson report, and Ebersole's Pebble Springs questions, Sanford Israel of the Reactor Systems Branch of the Office of Nuclear Reactor Regulation prepared a note signed on January 10, 1978, by his Branch Chief, Thomas M. Novak, concerning pressurizer design in B&W plants. The note urged that reviewers verify that operators of future plants be provided adequate information about procedures for terminating high pressure injection flow (see Section I.C.13).

In March 1978, D. M. Sternberg in Region I, Office of Inspection and Enforcement (IE), reported to K. V. Seyfrit in IE Headquarters that TMI-2 had experienced a blowdown (after a reactor trip) on March 29, 1978 because a pressurizer pilot operated relief valve (PORV) opened after a loss of control power (see Section I.C.15).

An event on March 20, 1978 at the Ranch Seco nuclear powerplant near Sacramento, California, involving loss of power to some nonnuclear instrumentation, prompted concerns at B&W about the necessity for operator education on procedures to follow when such loss of instrumentation occurs. B&W wrote to all its site operations managers (except TMI) that "pressurizer level *and RCS pressure* assure that the Reactor Coolant System is filled..."' (emphasis added). (See Section I.C.14)

At NRC's Region III, James C. Creswell, Reactor Inspector, who was an inspector for Davis Besse, developed a series of concerns, six of which he submitted on January 8, 1979, through channels for review by the Atomic Safety and Licensing Board and some of which he personally laid before Commissioners Bradford and Ahearne in March of 1979 (see Section I.C.12).

Figure 1-7 is a graphical representation of the significant precursor milestones. Figure 1-8 is a graphical representation of the organizational relationship of NRC employees who were directly involved with precursor events or issues.

This chapter reviews these events in detail and gives the Special Inquiry Group's conclusions and recommendations.

2. CONCLUSIONS AND RECOMMENDATIONS

1. The nuclear industry and the NRC had little or no concern about what the operators saw during a transient and what they did as a result. Actual plant operating and emergency procedures were not reviewed in any systematic fashion by the NRC or by the vendor. Incidents were assessed almost entirely from the perspective of the hardware with little concern about what the operator saw or did.

   In the design of equipment, much consideration is given to why a piece of equipment will not perform an anticipated function, (e.g., why a valve will not open when it should). However, little consideration need be given to why a piece of equipment might perform a function when passivity is expected. For equipment, this emphasis is proper because a piece of equipment is more likely to fail to perform a required function, than to activate and perform a function for no apparent reason. This logic has been erroneously applied to the operator. However, people by nature are not passive. The operators have shown a strong willingness to become actively involved in operating the plant following an incident. Once the operators decide that they are going to take an active role in a particular event, they have shown themselves to be very persistent and innovative in finding a way to get a certain function done. However, defining all of the reasons why an operator might initiate an action has received much less attention than it should have received during the design and licensing of nuclear powerplants. Therefore, with machines, the concern is that the machines will not perform when they should; but with operators, the concern should be that the operator will perform when they should not.

   In the past, the operators have been essentially ignored by the NRC and by the plant designers. On the other hand, incidents such as

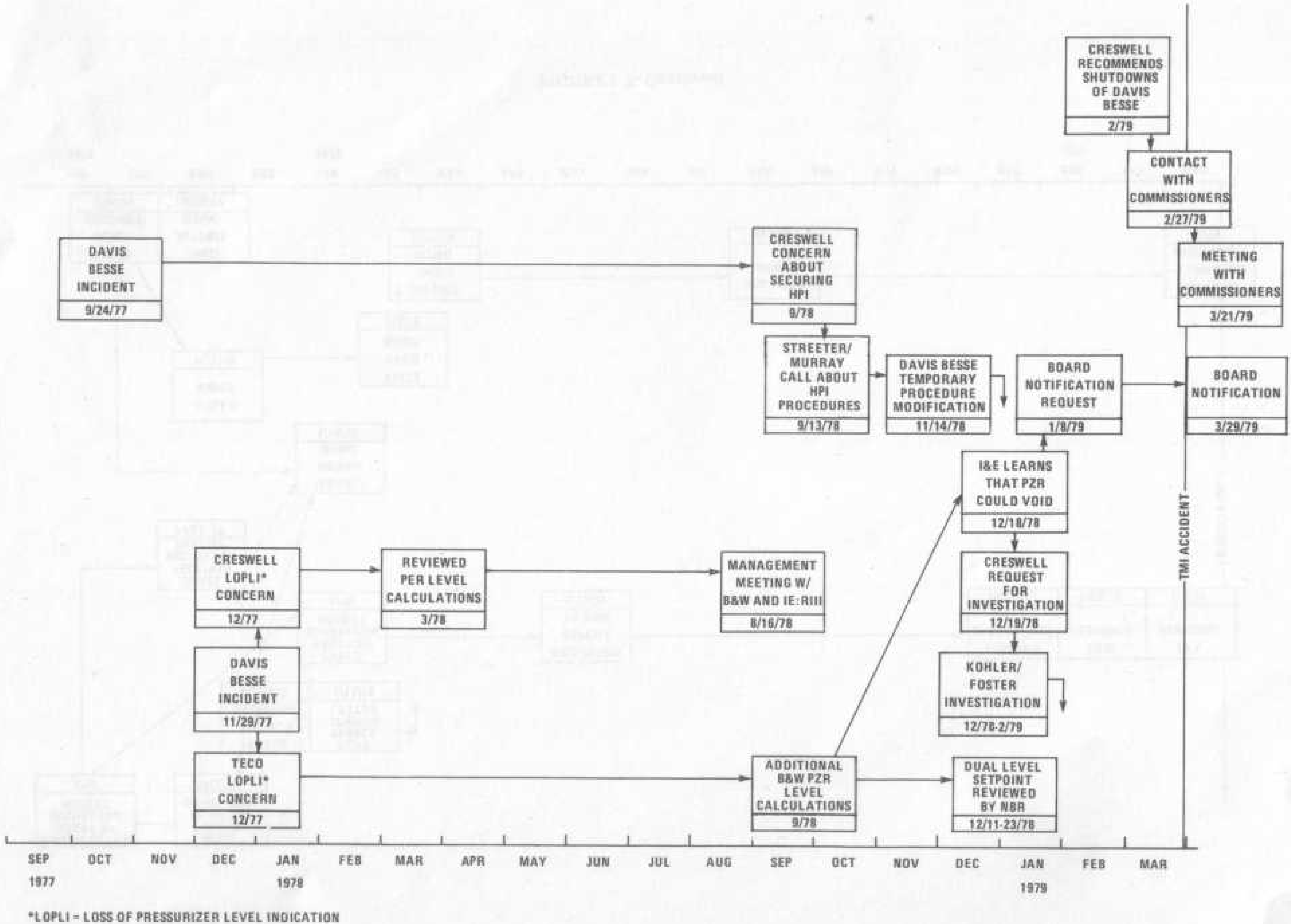

FIGURE I-7. Time Sequence of Precursor Events

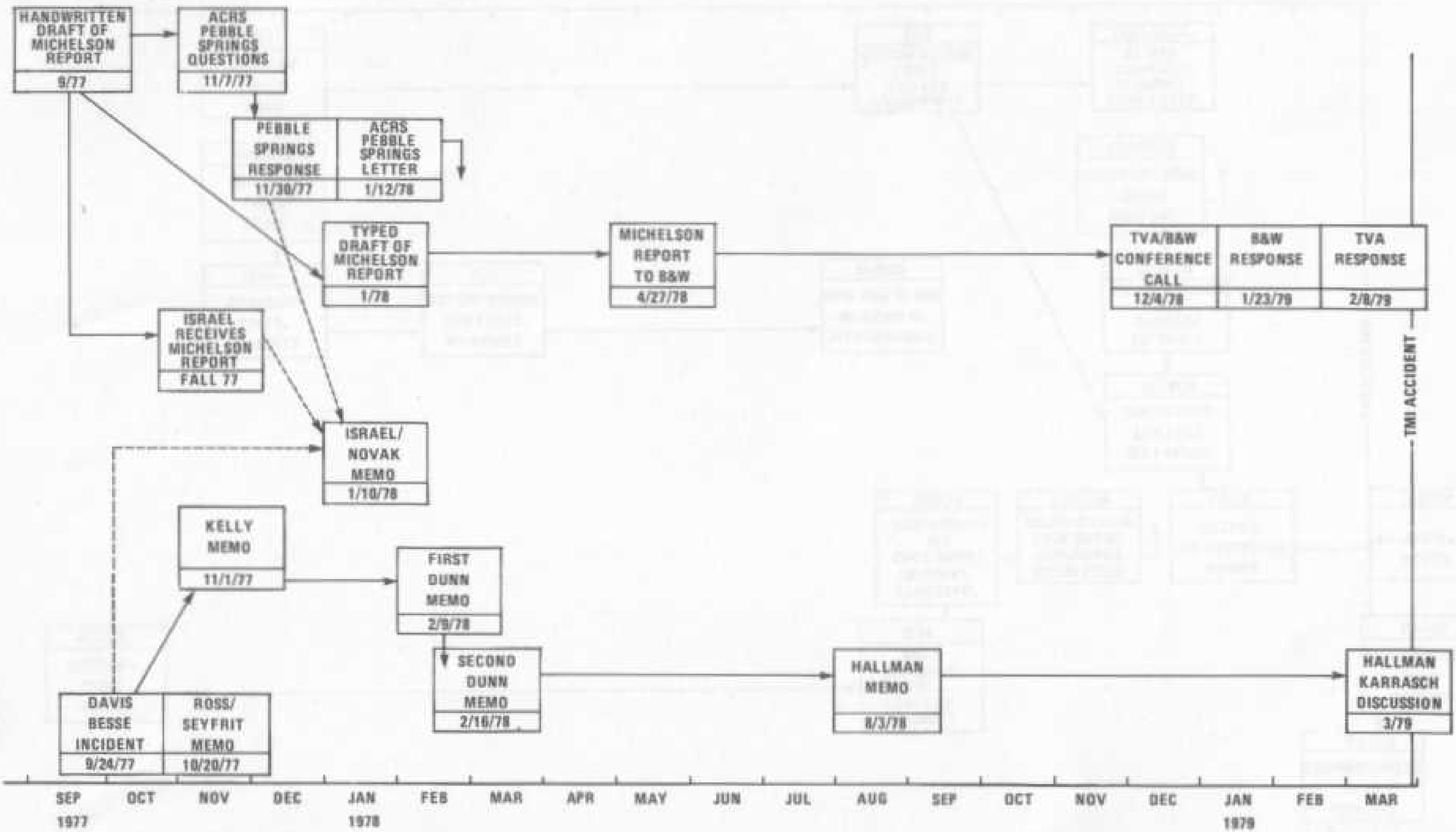

FIGURE I-7—Continued

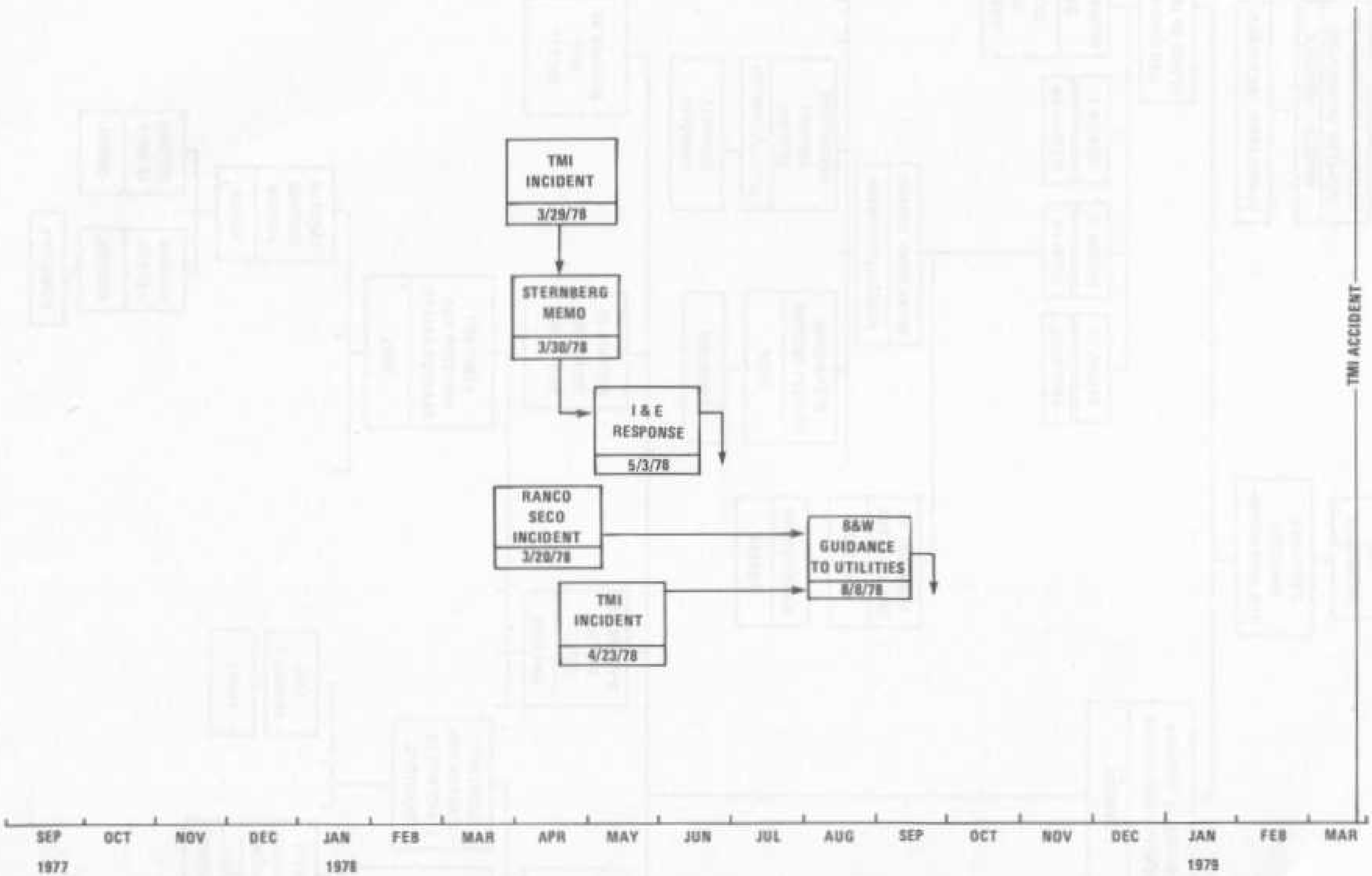

FIGURE I-7—Continued

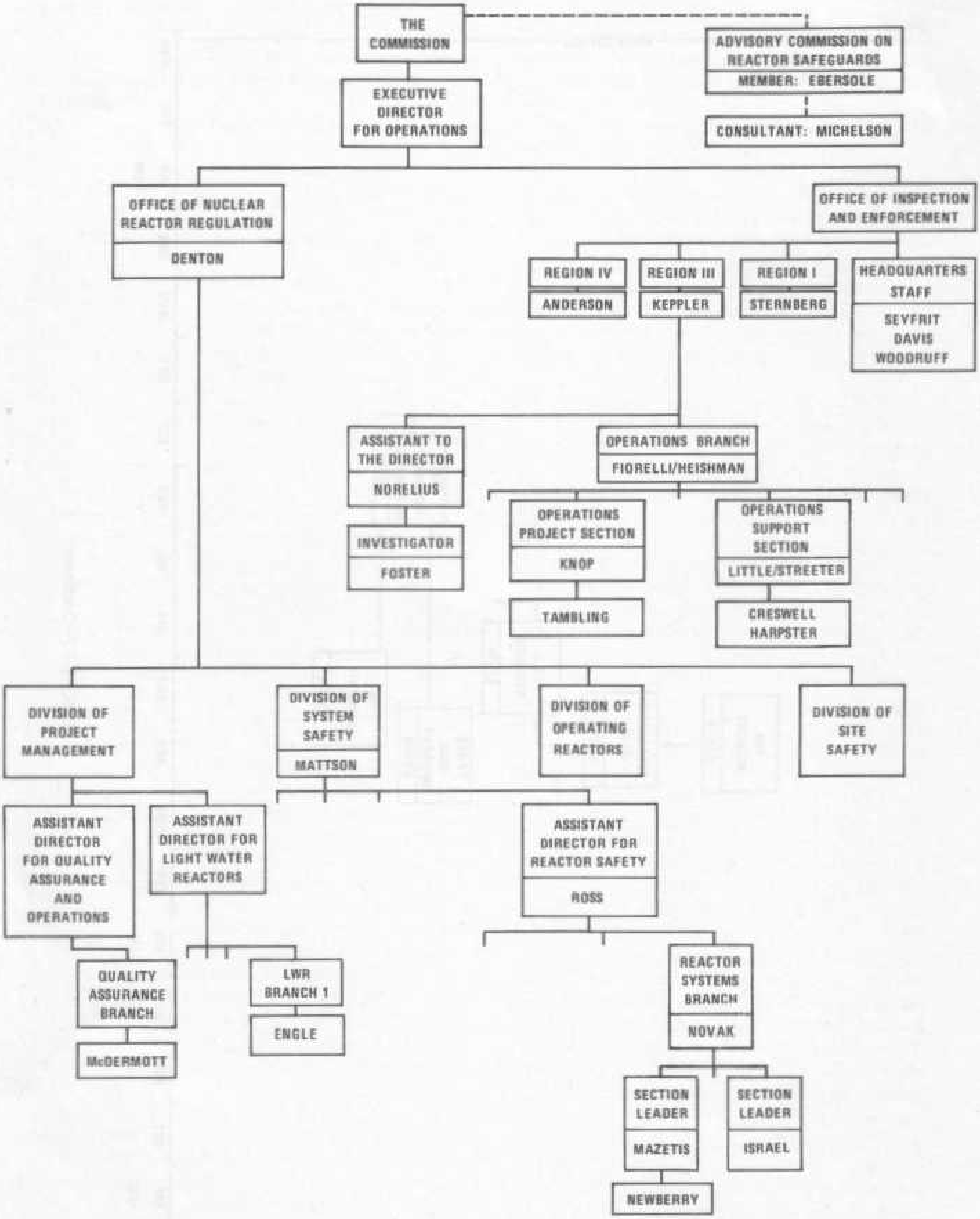

FIGURE I-8. Organizational Relationships of NRC Employees in Precursor Events the one that occurred at Davis Besse on September 24, 1977 make it quite clear that operators do not consider themselves to be passive observers during an incident. The operators are an active component. Moreover, they can and do intervene in the automatic features of the plant as well. Such intervention may be right or very wrong.

If it is decided that the operators should play an active role in mitigating and minimizing the consequences of an accident, then they must be included as an integral part of the design and analysis of the overall system. *The operator is one of the most significant safety-related systems,* and he deserves as much attention in the design and regulation as other significant safety systems.

To simply say that the operators should be better trained is not enough. The entire accident analysis of each nuclear power plant *must be redone, including back fitting to operating plants,* because one of the most important safety systems (i.e., the operator) has been almost totally ignored. Given the ability and the willingness of operators to intervene in the mitigation of an accident sequence, *analysis of the response of a plant during an accident is significantly flawed because it ignores what the operator might do.*

If it is decided that the operators should not actively participate in the mitigation of an accident, then administrative and physical prohibitions must be instituted to prevent all operator actions during an accident. It is not valid to assume that the operator will be a force for good when his participation is needed, and then pay no attention to the demonstrated fact that his participation can be a significant force for harm when it is not desired (i.e., you can't assume that he will start the pump when he should, unless you also assume that he will stop the pump when he should not).

2. The NRC and the nuclear industry must broaden their analyses of the response of plants during actual incidents. The past emphasis of such analyses has been on specific hardware problems. This has been particularly true during the assessment of the generic implications of various incidents. For example, the generic implications of the September 24, 1977 incident at Davis Besse were dismissed by many of the parties involved because the PORV at Davis Besse was designed by one manufacturer while the PORVs at other B&W plants were designed by a different manufacturer. This rationalization ignored the obvious fact that PORVs can fail regardless of who manufactures them and, therefore, the incident at Davis Besse was applicable, at a minimum, to all pressurized water reactors (PWRs) that have relief valves from the pressurizer.

   This hardware orientation can also be seen in the analysis of specific events. The emphasis of most of the parties involved in these events has been on what specific piece of equipment failed and why it failed. Although this is obviously an important consideration, an equally important consideration which has been almost totally overlooked in the past is the evaluation of the overall response of the plant, including the operators. This analysis should include comparison of the actual performance of the plant compared to the predicted response and an assessment of reasonable "what if" scenarios. To simply say that we did not have fuel damage so everything must have gone according to design is not a valid analysis. If someone with the authority to take corrective action had assessed the September 24, 1977 incident at Davis Besse and asked, "What if the plant had been at a higher power history?" and/or "What if it had taken the operators longer to identify and isolate the stuck open PORV?" that person would probably have concluded that an accident very similar to TMI, with similar unacceptable consequences, would have resulted. A few individuals asked these "what if" questions following the Davis Besse incident; however, it is obvious that most, if not all, of the parties involved were not sensitive to the significance of these questions and, as a result, essentially ignored the answers.

   It must be emphasized that simply improving the analysis of equipment problems is not enough. The entire industry and the NRC must broaden their review of operating experience to include an assessment of the overall scenario and the lessons that can be learned from each accident.

3. An NRC mechanism must be set in place to winnow through the mass of material on operational experience coming in to the NRC in order to recognize events, reports, and responses of significance. It seems clear that this should not be a compartmentalized effort. One unit adequately staffed as a full-time oversight and "think tank" body is called for. It should not be advisory; it should have the function of making findings and mandating solutions subject to review by the ultimate governing body of the NRC.

   In order to improve the depth perception of this process, it is important that concerned offices within the regulatory agency be required to submit analyses of events in their area of responsibility. The utilities, the vendors, and architect-engineers should be integrated into this analysis process. To the extent possible, divergent viewpoints, be it from the IE Regions, from the utilities, from the vendors, or from architect-engineers should be encouraged and even provoked. Multidiscipline and multiorganizational views should be insisted upon to insure against the limiting effect of parochialism.

Whether a unit such as we are proposing should have a permanent staff or a rotating staff, or a combination is a difficult choice. The experience with a permanent staff suggests that permanence makes for fixed thinking patterns. It would, accordingly, be advisable to staff an evaluation unit with a limited permanent staff to provide continuity and a rotation of technicians assigned to this group for a minimum of 2 and a maximum of 3 years. Assignment should be perceived by management as a recognition of superior performance.

The appropriate spectrum of engineering and scientific disciplines to be represented on the staff would presumably be what has been found necessary to conduct the substantive activities of the present NRC with an emphasis on generalists rather than experts in very narrow engineering disciplines. To these disciplines it is imperative to add human engineering specialists to fill the gap which the Special Inquiry found to be glaring. The relationship of man to machine, both in the design and in the operation of the machine, has not been addressed at any point in the nuclear power system in any proportion to the importance of human participation.

By way of comparison and contrast, the Task Force Recommendations on Operational Data Analysis and Evaluation for Nuclear Power Plants (SECY-79-371 dated May 13, 1979) proposed, among other options, a full-time agency group reporting to the Executive Director for Operations. This has been approved by the Commissioners as of July 12,1979. This group is, as proposed in SECY-79-371, an agency-wide office to be staffed on "a rotational assignment basis" with "an oversight/peer review role." The group will supervise the operational data analysis review groups of the several program offices of the NRC. It is to be the "focal point for interaction with both the ACRS Subcommittee and any industry groups dedicated to operational data analysis and evaluation." Its end function is to develop recommendations and provide guidance. Although we have not reviewed and do not necessarily endorse all aspects of this office, we have observed that one part of the mission of this newly established Office of Operational Data Analysis is unlike the office suggested in this recommendation. The new Office does not have binding fact finding and effective directory authority. Such an office, it is submitted, should have the power to mandate solutions. Absent such power, the new office will likely become aimless and its analyses will be ignored with impunity. It will be an ivory tower depending entirely on the authority of its opinions in an environment peopled by line specialists who are jealous of their own opinions, skills, and prerogatives. We recommend that in its area of responsibility the recommendations of this office shall be followed unless the Commissioners or the director of the applicable program office direct otherwise. This directory authority should be added to the charter of the Office of Operational Data Analysis.

4. Numerous groups within and among the NRC and the various industry organizations (e.g., vendors, utilities, architect-engineers) have been isolated from each other as a result of physical, geographical, and organizational separation. This problem has manifested itself in a number of ways, including a lack of acceptance of personal responsibility to ensure that concerns that are raised are subsequently resolved, and a failure to communicate concerns from one part of the organization to other parts of the organization. This failure to communicate applies equally within the various organizations (e.g., within t; ¡r NRC) and also between the larger organizations involved (e.g., between NRC and B&W).

For the matters that we reviewed, this problem was particularly evident in the functioning of IE headquarters. In almost every case where an attempt was made to pass concerns or information from IE field personnel to other parts of the NRC, or from NRC technical reviewers to IE field personnel; this effort was thwarted, either accidently or intentionally, by the technical programs personnel in IE headquarters (see Sternberg memo, Section I.C.15; Ross-Seyfrit note, Section I.C.9; ACRS briefing on the September 24, 1977 Davis Besse incident, Section I.C.9).

We found this insulation to be a significant problem that contributed to the failures observed in every precursor event we investigated. A superficial solution is to recommend massive reorganizations of the various groups involved. However, although reorganization may be a part of the solution, it will not alone solve the problem. We found that simply changing blocks and lines on an organization chart will not ensure that a critical piece of information or a critical insight will get from the person who has it to the person who can use it. In addition, developing procedures that require that everything be documented and distributed to everyone will not solve the problem and will only result in the proliferation of an overwhelming mass of paperwork that will actually inhibit the flow of important information. This problem is compounded by the fact that a piece of information may not be recognized as important until it is viewed in hindsight, or it may be important only to the recipient not the sender.

We were unable to define specific recommendations to eliminate this problem, although we are certain that reorganization and emphasis on increased documentation alone will not solve the problem. We therefore recommend that each group involved develop (with a great deal of assistance from consultants in the area of organizational communications) a program to reduce the insulation and lack of effective communications that currently exist. The following measures which tend to affect the problem are recommended as a minimum:

- Selection of management dedicated to insuring against insulation and isolation and conversely actively devoted to communication and interchange of information.
- An incentive program for identification and exchange of safety information, with monetary and honorary awards through salary increases, cash prizes, promotions, and public recognition.
- Regular interchange conferences with broad agendas including industry and NRC delegates.
- Interorganizational training on communications.

5. Quite apart from the evaluation body at NRC Headquarters, improvement in the Inspection and Enforcement activities in the Regions could flow from a policy of encouraging inspectors to look beyond the inspection module of the moment. Just as NRR should not use the Standard Review Plan as a barrier to thought, neither should IE use inspection modules. Each inspection should be an occasion to comment on the general state of affairs at the particular plant (e.g., cleanliness, the observable managerial activity, evident personnel ability, training problems, the overall competence level of the utility). At present, Inspectors are under direction to spend 15% of each inspection on generalized inspection. In practice, this seems to be accomplished as a timesheet entry without substance. To fulfill the promise of 15%, or to accomplish the general state-of-affairs observations here proposed, the management of the Regions and Headquarters must provide real impetus and leadership to ensure effective performance by the inspectors, and inspectors in turn must be trained and encouraged to make the state-of-affairs analysis.

   The resident inspector concept is currently being implemented at an increasing number of plants. The obvious benefits are greater familiarity with the plant and its operators. In addition, unannounced inspections can be increased without the drawbacks of finding key personnel missing and activities going on which are inappropriate to module requirements. Whether the resident inspector becomes too familiar and fraternal with the plant's staff is an issue that must be closely monitored and dealt with when problems arise. Rotation of the resident inspector, audit of his work by his superiors, and careful selection of the inspector can guard against these hazards. In general, however, the resident inspector program seems worthwhile.

6. Systematic regional evaluation and analysis of event and incident reports would be desirable. At present, for example, in Region III the project inspector assigned to a particular nuclear plant is expected to review its Licensee Event Reports. Too often these are so numerous that they preclude his careful attention. To correct this problem a permanent unit within each Region should be charged with this review and evaluation task. It should report to the IE headquarters, to other concerned offices at NRC Headquarters and to whatever "think-tank" evaluation unit is set up. The obvious advantage would be that of being able to provide Headquarters the view of events from the vicinage; the nuts and bolts perspective.

7. The Office of Inspection and Enforcement has displayed a strong tendency to defer to previous safety analyses that had been performed by NRR, without making an effort to determine if the analyses and the underlying assumptions were correct. This is a particular problem when prior analyses are used as an excuse to ignore legitimate concerns, when someone suggests that an analysis is not complete or correct, or when operating experience suggests that an analysis is not complete or correct. An example of this can be seen in the area of safety-related versus nonsafety-related systems. IE has a very small

role, if any, in determining which systems are safety-related and which systems are not. However, this determination plays a very large role in the inspection policies and practices used by IE.

These problems are due, to a large extent, to the physical and organizational separation that exists between IE and NRR. We recommend that this separation be reduced by integrating IE and the Division of Operating Reactors into a single group.

8. We found no indication of any specific effort to suppress the specific information contained in Creswell's board notification request or to limit its distribution (see Section LC.12). In fact, NRR significantly expanded the list of licensing boards to which the material was eventually sent. Although it appears that most of the steps in this laborious process are necessary, the time required to complete each step should be drastically reduced. Requirements for the maximum number of working days that a board notification request can be held at each step in the process (3 working days would not be unreasonable) should be established and strictly enforced.

9. Simplified event-tree and fault-tree analyses techniques, similar to those described in the Reactor Safety Study (WASH-1400), should be used to evaluate each nuclear powerplant proposed *or currently in operation,* to identify and, where practical, correct weaknesses in design and in operational procedures.

10. Event-tree and fault-tree analyses techniques should be used by the NRC as one of the major inputs to the assignment of priorities and allocation of resources to various reactor safety issues.

11. Perceived higher priority work was frequently cited as a reason for not completing various tasks or assigning these tasks a sufficiently low priority that they were not completed in a timely manner. The Special Inquiry Group was not able to determine whether this reason was in fact a real justification or whether it was simply a rationalization by various individuals for not doing tasks that they did not desire to do. Better management control over the priority of assigned work should be implemented. Explicit decisions should be made about what work will *not be done.*

12. During the review of the various precursor events, the Special Inquiry Group looked for and expected to find a significant amount of antagonism between the NRC and the nuclear industry. However, very little evidence of such antagonism was found. In addition, a tendency was expected on the part of the utilities and the vendors to address only those safety issues that had been raised initially by the NRC. Again, very little reflection of this tendency was found, and in fact several examples were noted where representatives of utilities and vendors had, on their own initiative, raised concerns that they felt were relevant to the safe operation of the plants (e.g., the Kelly-Dunn memoranda, the dual level set point at Davis Besse, the Michelson report).

3. RELEVANCE OF PRECURSOR EVENTS

Two issues can be considered with respect to the handling of precursor events. First, if lessons had been learned and applied, how might the actual accident at TMI been reduced or avoided; and second, how does the handling of a precursor reflea on the overall performance of the utility-vendor-regulator system.

The first issue is itself made up of two questions:

- Should additional guidance or information have been made available to the operators if a certain precursor had been handled differently?
- Would the operators at TMI have responded differently during the accident on the basis of that guidance or information?

The answer to the first question is certainly, yes. Precursors such as the Kelly-Dunn memoranda or the Michelson report should have produced guidance that, *if it had been used,* would have prevented the extensive core damage that occurred at TMI.

Unfortunately the answer to the second question can never be known for certain. It is impossible to determine if one additional piece of information integrated with the massive amount of data already available to the operators at TMI would have caused them to diagnose the problem properly and take appropriate actions to prevent the severe consequences that occurred. However, when one looks at the fact that the massive amount of significant, meaningful information that should have indicated to the TMI operators that the actions being taken were incorrect, and one realizes that this bulk of information was essentially ignored one must conclude that any additional guidance produced as a result of any of the identified precursors might have been equally ignored.

This conclusion does not, however, detract from the fact that the second issue, how the precursors were handled by the licensee-vendor-regulator system, is inherently significant.

4. DEPOSITIONS

For the most part, the testimony given by the witnesses deposed on precursor matters dealt with recollections ranging from 6 months to several years. These lapses of time have caused some proportionate loss of remembered detail. Furthermore, the supervening impact of TMI-2 and the multiple investigations that it precipitated, have made recall a difficult sorting problem. They may, in addition, have imparted to testimony either defensive bias or even slight distortions. The Special Inquiry Group kept these witness frailties in mind when the material from depositions was evaluated and used.

5. DOPCHIE LETTER-APRIL 27, 1971

As early as April 27, 1971, a concern associated with the potential impact of a loss-of-coolant accident from the steam space in the pressurizer came to the AEC from overseas. A letter from H. Dopchie, Directeur of the Association Vincotte (an organization doing technical evaluation of nuclear reactor issues under contract with the Belgium government), asked, "whether the U.S.A.E.C. has ever investigated the consequences of a rupture or valve opening or failure to close affecting the vapor space of a Westinghouse pressurizer."[2] In this letter, Dopchie went on to note that, "the difficulty occurs because the pressurizer water level would rise due to boiling in the core hence neither the low level signal nor the associated safety injection signal would be actuated."[3] (Westinghouse plants use a safety injection system which is functionally the same as the high pressure injection system on B&W plants.[4] For consistency, "high pressure injection system" will be used to refer to the Westinghouse system.) On early Westinghouse designs, high pressure injection actuation required both low reacfor coolant system pressure and low pressurizer level. Dopchie did note that high pressure injection would eventually be initiated by a high containment pressure signal. However, he concluded that this signal could be delayed because the release from the relief valves would be directed to the quench tank and not directly to the containment.

Dopchie subsequently sent a letter to the AEC on June 25, 1971,[5] that reflected that he had himself resolved many of the questions that he raised in his initial letter. For example, he stated that for a small break (one of less than 2 inches in size) the operator has at least 30 minutes to take action and for larger leaks (2 to 6 inches) the high containment pressure signal should actuate high pressure injection. However, in this discussion he did not describe what would cause the operator to take action. In his letter he did note two remaining problems: (1) must a leak larger than 6 inches be considered; and (2) was there a need to find a supplementary signal to close the containment ventilation and pressure equilization ducts.

The AEC responded to Dopchie's letter in a letter dated September 13,1971.[6] In this reply it was concluded that containment pressure and containment activity signals provided a sufficiently diverse and redundant signal for high pressure injection actuation.

Dopchie responded to this in a letter dated October 14, 1971. He raised the additional issue that this incident could be different if it were to occur while the plant was in a hot standby condition, when the containment might be in a purged condition.

By memo dated November 8, 1971,[8] Clifford Beck, the recipent of the letters from Dopchie, provided information concerning this issue to members of a Task Force which we believe to be the ECCS Analysis Task Force within the NRC. In his memo, Beck concluded that Dopchie had raised a-safety issue which had not been fully realized by the AEC. In addition, he noted that the NRC reply of September 13, 1971 did not satisfactorily resolve these questions. However, he did not describe why he felt the response was deficient. In this memo, Beck went on to state that Richard DeYoung had presented the problem to Westinghouse, but that a suitable solution had not yet been developed.

The AEC responded to Dopchie's October 14, 1971 letter in a letter dated September 28, 1972.[9] In this reply, the AEC concluded that based on Westinghouse analyses of this transient, the core would not become uncovered and that this issue did not appear to be a significant problem.

This matter was discussed with Westinghouse. Although some individuals at Westinghouse recall discussions of Dopchie and his concerns in 1971, a search of Westinghouse files subsequent to the TMI accident has produced no documentation of this contact. It is not known precisely what aspect of Dopchie's concerns were discussed or what conclusions, if any, were reached. It should be noted that at about the same time that Dopchie raised his concerns, Westinghouse was performing an analysis of small loss-of-coolant accidents from the steam space in the pressurizer. This analysis showed that pressurizer level increased during such events (as described by Dopchie). However, Westinghouse did not consider this to be a problem because the operators had over 50 minutes to manually initiate high pressure injection (see Section I.C.6 for additional discussion of this analysis). It is not known what role Dopchie's concerns played in the initiation of this analysis, or how much of this analysis, if any, was discussed with the AEC as a result of Dopchie's concerns.[10,11]

Specific Conclusions

1. As early as 1971, a concern had been raised about the response of pressurizer level during a small loss-of-coolant accident from the top of the pressurizer. Although this concern was raised in the context of a Westinghouse design and in relation to the potential for misleading the automatic initiation signal for high pressure injection on that design, it is conceivable that additional analyses of this issue might have provided some insight into the fact that operators might also misinterpret pressurizer level during such an event.
2. There is no indication that any consideration was given to the operator interpretation of pressurizer levels during this type of transient and lessons were not learned as a result of the concerns raised by Dopchie.

6. BEZNAU INCIDENT-AUGUST 20, 1974

On August 20, 1974, an incident occurred at the NOK-1 nuclear powerplant in Beznau, Switzerland that bears some similarity to the accident that subsequently occurred at Three Mile Island. (This incident has come to be known as the Beznau incident. The reactor, although located in Beznau, Switzerland, is named "NOK-1." There is no "Beznau Reactor.") The NOK-1 plant was designed by Westinghouse. The design is similar to nuclear powerplants that were built by Westinghouse in the United States.

The particular incident in question began with the reactor operating at 100% power. A trip of one of the two turbine generators occurred. As a result, the reactor coolant system temperature and pressure increased rapidly and both PORVs opened. One PORV failed to close and a subsequent depressurization of the reactor coolant system occurred. The reactor tripped on low pressure as a result of this depressurization. As pressure continued to decrease, steam formed in the reactor coolant system hot leg and pressurizer level began to rise. It eventually increased past the 100% point and remained offscale for 3 to 5 minutes. The operators were able to identify that the PORV was open in approximately 2 to 3 minutes and shut the isolation valve (there is no indication of what caused the operators to realize in such a short period of time that the PORV was open). After the PORV was shut, the pressurizer level fell rapidly as the steam bubbles in the reactor coolant system collapsed. Finally, approximately 12 minutes into the incident, the pressurizer level reached the 5% point and high pressure injection was initiated.

In this particular design, a coincident initiation was required for high pressure injection actuation. This initiation required *both* a low reactor coolant system pressure and a low pressurizer level. Therefore, because the pressurizer level went offscale high due to void formation in the reactor coolant system, the pressurizer level did not decrease initially and did not cause high pressure injection to begin until 12 minutes into the incident.

The incident was analyzed by a team from Westinghouse's Brussels, Belgium office and a report prepared. This report was distributed to various individuals in the Westinghouse domestic reactor offices in Pittsburgh, Pa. The analysis indicated that all existing protection systems had performed properly.[12]

This conclusion was based in part on an analysis of a small LOCA from the steam space in the pressurizer which had been performed in 1971. This analysis showed that during such an event, pressurizer level would rise and prevent automatic initiation of high pressure injection.[13] The analysis also showed that the operators had approximately 50 minutes to manually initiate high pressure injection before core damage would begin.[14] Westinghouse concluded that this amount of time (20 minutes is normally considered an adequate period for an operator to take required manual actions) and the indication available to the operator (Westinghouse plants have, among other indications, direct indication of the PORV position) were sufficient to provide adequate protection.[15] This conclusion was substantiated by the fact that the operators at Beznau isolated the PORV in 2 to 3 minutes.

It should be noted that prior to the TMI accident, Westinghouse guidance to utilities concerning small LOCA procedures did not provide specific warnings that pressurizer level might increase during such an event. The Westinghouse operator training program included a stuck-open PORV and the operator was instructed how to recognize this event. However, the Westinghouse simulator did not indicate a rising pressurizer level, but only indicated a more slowly decreasing level.[16]

The results of the 1971 anaylsis had been documented to the AEC in the Safety Analysis Report (Amendment 1 dated October 1972) for the RESAR-3 standard plant.[17] Although this report did not specifically state that the pressurizer level would increase during such an event, it did state that for breaks in the 2- to 6-inch range, high pressure injection might not result. The report also noted that a delay of high pressure injection of more than 50 minutes would not result in core uncovering.

Beginning with RESAR-3, the standard Westinghouse design was changed to require only low pressure to initiate high pressure injection. This change was primarily the result of operating experience which indicated that spurious actuation of high pressure injection would not be a problem if the coincident pressure and level requirement was eliminated. Westinghouse considered changing older designs, but decided that because of the time and indication available to the operator, backfitting of this change was not required. [18]

The original report of the Beznau incident was not submitted to the AEC at the time that it was prepared because the plant had responded as expected. The NRC eventually became aware of the incident at Beznau during discussions with Westinghouse employees following the TMI accident. The NRC subsequently obtained from the Swiss government the Westinghouse report and another report prepared by the Swiss. Paradoxically, however, because of the current regulatory requirements with respect to proprietary information, the Swiss government was able to designate this information as proprietary which would have prevented the dissemination of the details of this event to the public. In fact, it was initially intended that the only reference that would be made in any public NRC documents with respect to the Beznau incident, was a statement that had been approved by the Swiss government. This statement said, "We are aware of one incident at a foreign reactor designed by Westinghouse which occurred a number of years ago in which a PORV was challenged during a turbine trip transient and failed to reclose when pressure decreased. The failure to close was detected in a few minutes by the operators who immediately isolated the valve by closing the blocked valve in series with the PORV. This action terminated the incident. The failure to reclose was due to the rupture of the cast iron frame between the valve operator and the valve body which was caused by a water slug hitting the valve. The source of the water slug was the loop seal located between the pressurizer and the relief valve. Investigation of this event identified the cause of the valve failure to be design error which, we understand, has been subsequently remedied." [19] There is no indication in this statement that pressurizer level failed to decrease and that high pressure injection was inhibited as a result of the response of the plant. It was only after the inappropriateness of the withholding of this information from the public, was raised by a number of individuals, including members of this Special Inquiry, that the proprietary restrictions were removed.

After the accident at TMI, Westinghouse provided guidance to plants that still have the coincident low pressurizer/low pressurizer level high pressure injection. This guidance pointed out that during small LOCAs from the pressurizer, there may be a problem with pressurizer level hanging up. By letter dated April 10, 1979, [20] Westinghouse informed the NRC that they had advised utilities that the problem could exist and they were recommending that the operators be specifically instructed to monitor pressure and manually initiate high pressure injection if pressure dropped below the actuation point.

Specific Conclusions

1. An incident occurred at the NOK-1 nuclear plant in 1974 that demonstrated the phenomenon of increasing pressurizer level during a small loss-of-coolant accident from the steam space in the pressurizer. This phenomenon was subsequently observed at the Davis Besse plant in September 1977, and during the TMI accident. In the specific case of the Beznau incident, the high pressurizer level caused the high pressure injection to fail to initiate. At Davis Besse and TMI, the high pressure injection system initiated but was subsequently stopped because the operators erroneously interpreted the high pressurizer level.
2. The relevant phenomenon (i.e., increasing pressurizer level during a small LOCA from the pressurizer steam space) had been previously identified by Westinghouse. Therefore, the plant responded as expected. The implications of this phenomenon but not the phenomenon itself, had been reported to the AEC prior to the Beznau incident. It is not known how clearly the AEC recognized this phenomenon as a result of this matter. However, it does appear that the AEC was never explicitly informed that for older Westinghouse designs (i.e., prior to RESAR-3) operafor action was required during a small LOCA from the steam space in the pressurizer. As a result, it was not possible for the AEC to incorporate the lessons that might have been learned from this incident into the licensing of Westinghouse plants or PWRs in general.
3. Because of the restrictive nature of the current regulations with respect to proprietary information received from foreign governments, it is very possible that the information contained in the Beznau report would not have become part of the public record even in light of the TMI accident. However, it must be recognized that

there is a trade-off between restrictive proprietary information provisions that allow a foreign government to provide information that will subsequently not become part of the public record; and the fact that if foreign governments can no longer provide this information with confidence that it will not become public, they will refuse to provide the information in the future.

7. REACTOR SAFETY STUDY (WASH-1400)-OCTOBER 1975

In 1975 the NRC published the results of an extensive three year study which attempted to quantify the risks associated with operation of a nuclear reactor. The report was formally titled, "The Reactor Safety Study."[21] It has also come to be known as "WASH-1400" or "the Rasmussen Report."

WASH-1400 is a precursor to the accident at TMI for a number of reasons.

First, WASH-1400 identified the category of small-break LOCAs as one of the most significant contributors to the risk from nuclear reactor operation.[22,23] Of particular concern was the smallest class of reactor coolant system breaks (½ inch to 2 inches effective diameter) which included a break equivalent to the stuck open PORV at TMI (approximately 1 inch effective diameter). This dominance of very small LOCAs over larger LOCAs was found even in the most serious (with respect to radioactivity releases from the containment) categories of accidents identified in WASH-1400. For example, the probability of the most serious category of accident assessed in WASH-1400 being initiated by a very small LOCA is 50 times greater than the probability that it would be initiated by a large LOCA.[24] This dominance was due primarily to the fact that small pipes are considerably more common than large pipes, and large pipes are installed using stricter codes and requirements.[25]

Despite this emphasis in WASH-1400 on the significance of small LOCAs, the NRC continued to place a great deal of emphasis in the licensing process and in research allocations, on large LOCAs.[26] Had the emphasis been shifted to these very small LOCAs, it is possible that a better understanding of the subsequent events at Davis Besse (September 24,1977) and at TMI might have been developed.

Second, WASH-1400 emphasized that small releases of radioactivity resulting from various plant accidents are much more likely than large catastrophic failures releasing large quantities of radioactivity. For example, the least severe category of accident consequences (category 9), which includes the level of releases that occurred at TMI,[27] was found to be over 400 times more likely than the most severe category (e.g., category 1).[28]

As a result of this conclusion, the NRC should have recognized that these less severe accidents deserved a significant emphasis in the regulatory process because the probabilities indicated that an event of this type would occur in the coming years. As has been shown by the accident at TMI, increased emphasis should have been placed on emergency planning and dissemination of information during such high probability but low consequence events. This is particularly true when one recognizes that although the radioactivity released during these events did not produce a significant physical health effect, the psychological stress caused by these events may well have been significant.

Third, the event-tree and fault-tree analysis techniques used in WASH-1400 were shown to be an excellent technique for analyzing the relative significance of various safety issues. These techniques were sufficiently well developed to be used as a guide for selecting the issues that were most relevant to safety and deserving of a high priority. In addition, these techniques could identify weaknesses in the existing design and operating procedures that require improvement. In fact, during the WASH-1400 analysis, a significant weakness in the design of one of the two plants used as the basis for the analysis was identified and subsequently corrected.[29] This weakness had not been identified by the conventional design and licensing process.

Although the NRC staff and the nuclear industry have used the event-tree and fault-tree analysis described in WASH-1400 to a limited extent, this quantitative technique has not been used extensively to assess specific plant designs or the relative priorities of reactor safety issues. Instead, the staff has relied on more qualitative decision criteria such as engineering judgment and deterministic decision making. It can be argued that it is impractical to use the techniques described in WASH-1400 because of the time and expense required. However, Rasmussen has testified that one can learn about 90% of the information acquired during the Reactor Safety Study for a tiny fraction of the total effort expended by Rasmussen's group. He pointed out that much of the effort expended during the study was used to see if an exhaustive study would provide different answers than a cursory, simpler study. The conclusion was that one can learn a great deal from rather simple and much less exhaustive analyses.[30]

Fourth, many of the parts of the actual event that occurred at TMI were described in the various scenarios that were analyzed in WASH-1400. The

TMI accident began as a transient event. During the initial stages of the accident, the scenario closely followed a loss of main feedwater and subsequent loss of auxiliary feedwater scenario described in WASH-1400. The WASH-1400 scenario included a recognition of the possibility that a PORV could open and fail to close, a malfunction which occurred at TMI. In the same vein, one of the transients considered as a separate initiating event was an accidental opening of the pressurizer safety or relief valve. The open PORV is, moreover, the same size as the very small LOCAs assessed in WASH-1400. WASH-1400 did not, however, consider the possibility of the operators stopping or reducing high pressure injection flow, which was the most significant contributor to the severity of the consequences of the accident at TMI. [31]

In response to the comments made on WASH-1400 by a number of sources, and particularly Congressman Udall, Chairman of the House Committee on Interior and Insular Affairs, the NRC established the Risk Assessment Review Group in July 1977. The purposes of this one year review of WASH-1400 were to:

- Clarify the achievements and limitations of WASH-1400.
- Assess the peer comments thereon, and responses to those comments.
- Study the present state of such risk assessment methodology.
- Recommend to the Commission how (and whether) such methodology can be used in the regulatory and licensing process. [32]

The results of this assessment were published in September 1978 as a report titled, "Risk Assessment Review Group Report. (NUREG/CR-0400)." [33] This report has come to be known as "the Lewis Report."

Among the several conclusions reached by the Lewis Report were the following:

- WASH-1400 was a conscienious effort to apply the methods of fault-tree/event-tree analysis to an extremely complex system.
- WASH-1400 contained a number of sources of conservatism and nonconservatism in the probability calculations which were difficult to balance. The report concluded, however, that although the Review Group was unable to determine whether the overall probability of a core melt was too high or too low, they were certain that the error bands were understated.
- The methodology used in WASH-1400 was sound and should be developed and used more widely under circumstances where an adequate data base exists coupled with sufficient technical expertise to develop credible subjective probabilities. Even when only bounds for certain parameters could be obtained, the method was still useful if results were properly stated. The report noted that although the NRC had moved somewhat in the direction of using the methodologies described in WASH-1400, a faster pace was recommended.
- WASH-1400 was inscrutable and it was very difficult to follow the detailed thread of any calculations through the report. In particular, the Executive Summary was a poor description of the contents of the report, should not have been portrayed as such, and had lent itself to misuse in the discussion of reactor risks.

The Commissioners reviewed the results described in the Lewis Report and on January 18, 1979 issued an "NRC Statement on Risk Assessment and the Reactor Safety Study Report (WASH-1400) in Light of the Risk Assessment Review Group Report." [34]

The Commission noted that although the Review Group praised the study's general methodology and recognized its contribution to assessing the risks of nuclear power, the Review Group was critical of the Executive Summary, the procedure followed in producing the final report and the calculations in the body of the report. The statement was essentially negative in tone thus creating a misleading picture of the Lewis Report's findings and recommendations on WASH-1400 and its Executive Summary. Although the Lewis Report found the study's absolute numerical assessment of risk and the Executive Summary to be deficient, it unequivocally endorsed WASH-1400 techniques as an aid in technical decisionmaking:

> Fault-tree/event-tree analyses should be among the principal means used to deal with generic safety issues, to formulate new regulatory requirements, to assess and revalidate existing regulatory requirements, and to evaluate new designs.

The negative tone of the Commission's statement and its confusion about what the Lewis Report criticized and what it endorsed is puzzling. This collegial action resulted in perceived policy direction and had a negative impact on the quality of the licensing and regulatory system.

Specific Conclusions

1. WASH-1400 is a precursor of the TMI accident to the extent that it highlights the dominance of very small LOCAs over large LOCAs. However, the NRC staff has continued to place disproportionate emphasis on the less significant large LOCAs in the licensing process and

research allocation. It is not possible to determine what effect, if any, an increased emphasis on very small LOCAs, which include the stuck open PORV that occurred at TMI, might have had on the accident at TMI.

2. Fault-tree and event-tree analysis techniques described in WASH-1400 are an effective methodology for identifying weaknesses in particular designs and for assigning priorities and resources to various reactor safety issues. The NRC staff did not attempt to use these techniques to the extent warranted.
3. The actual analyses conducted during the Reacfor Safety Study were not particularly relevant to the human error aspects of the TMI accident that directly contributed to the severe consequences.
4. The NRC seemed unable to digest WASH-1400 and put its methodology to work. NRC's response was to commission one study after another.

8. MICHELSON REPORT-SEPTEMBER 1977

In September 1977, Carl Michelson, an employee of the Tennessee Valley Authority (TVA) and a consultant to the NRC Advisory Committee on Reactor described (ACRS), prepared a report in which he described some issues concerning the response of B&W 205-fuel-assembly pressurized water reactors during very small-break loss-of-coolant accidents. Michelson wrote the report as the culmination of lengthy consideration of such very small breaks, including considerable discussion with Jesse Ebersole, a member of the ACRS. Michelson had become concerned that the information available from the nuclear steam supply system vendors was not adequate, and that the models used to predict the behavior of small breaks were not valid predictors of the response of very small breaks. This report, "Decay Heat Removal Problems Associated with Recovery from a Very Small Break LOCH for B&W **205-Fuel-Assembly PWR,"** [35] is dated September 1, 1977. This report was handwritten.

The very-small-break LOCH described in this report (i.e., break size less than 0.05 square feet) was defined as one in which the steam generator must remove a significant portion of the decay heat, or else reactor coolant system repressurization occurs. The report raised numerous issues and conterns, including:

- Depressurization rates are slow and might lead to inadequate makeup rates from the high pressure injection pumps.
- Transition from natural circulation to pool-boiling may be a problem because of the time delay incurred while waiting for the water level in the U-bend region of each hot-leg pipe and in the steam generator tubes to drain to the secondary side water level.
- Isolation of breaks would remove the break as a source of decay heat removal without assurance that some other effective means of decay heat removal could be reestablished.
- During refill accumulation of noncondensible gases could prevent reestablishment of natural circulation.

The report noted that, if repressurization occurs, relief through the pressurizer safety valves would constitute a path for decay heat removal. However, these valves are not qualified for two-phase flow, and during this scenario the operator would be unaware of what is happening to the reactor vessel level. The report also noted that pressurizer level in the indicating range is not necessarily an indication that adequate core coverage is being achieved.

Adding to these concerns was an uncertainty associated with unknown vessel level and the adequacy of emergency operating instructions and operator training for this event.

The very small break postulated for this report was assumed to be located at the top of the cold-leg pipe. However, the break location was not thought to be a major influence.

The report also raised the possibility that the pressurizer surge line loop seal had the potential for inhibiting steam entry into the pressurizes.

The handwritten draft contained a brief reference to operator interpretation of pressurizes level: "Note, the presence of a pressurizes level is not an indication that adequate core coverage is being achieved." The discussion of pressurizes level and operator actions based on pressurizes level was greatly expanded in a subsequent draft.

Michelson gave a copy of the draft report to Jesse Ebersole to enable Ebersole to get more information about small breaks by asking some questions during the ACRS review of the Pebble Springs application. Michelson had been a close personal friend of Ebersole for many years and had worked for him in various capacities over approximately 20 years while Ebersole was employed by NA. (Ebersole retired from NA and joined the ACRS in 1976.) Ebersole had encouraged Michelson to become a consultant to the ACRS in areas of nuclear systems analysis and nuclear plant security.

Ebersole used the Michelson report in two ways. First, it was the basis for some questions raised by the ACRS and eventually asked of Portland General

Electric Company (the applicant) as part of the review of the Pebble Springs application (see Section I.C.11). Second, Ebersole informally passed the report on to Sanford Israel, a first-line supervisor in the NRC Office of Nuclear Reactor Regulation, with whom he had formally and informally discussed small-break LOCAs for many years. Ebersole gave Israel the report in the context that, although he (Ebersole) believed that the report described a problem, Israel could pursue the matter at his own volition.ss It should be noted that Michelson did not formally submit the report to the ACRS, and Ebersole did not formally submit it to the NRC. Michelson has testified that he did not submit the report formally because, although he felt strongly enough about it to make sure that other people were aware of his concerns, he did not feel so strongly as to believe the matter had to be forced.[39] Ebersole testified that he could have formally submitted the report to the NRC for review, but he did not do so because he did not know if the issues raised constituted a critical safety issue.[40]

Upon receiving the report, Israel reviewed it briefly, but did not read it in its entirety. He reviewed the report to determine if it contained any new information and concluded that it did not. Shortly after receiving the report, Israel was aware that B&W had made a presentation dealing with small-break LOCAs in response to the question asked by the ACRS as part of the review of the Pebble Springs application. Because he did not receive any more feedback from the ACRS he assumed that they were satisfied by the Pebble Springs response and he did not think about the issue any further.[41]

Israel has testified that he did not focus on the specific concern raised in the report associated with operator interpretation of pressurizer level. However, Israel believes that the Michelson report may have played a role in his eventual preparation of a memo concerning the question of the loop seal design of the surge line in B&W reactors (see Section I.C.13). Furthermore, Israel continued the distribution of the report by giving a copy to Gerald Mazetis, another first line supervisor in the NRC Office of Nuclear Reactor Regulation, and Mazetis briefly reviewed it. Mazetis, too, did not see anything in the report that caused him to take action.42 However, it appears that neither Israel nor Mazetis ever reviewed the paper in detail, and their involvement with it ended at this point.[43,44] Michelson testified that he never received a response from the NRC concerning his report, but was not concerned because he was assured that the NRC had his material.[45]

In January 1978, Michelson completed a revised typewritten draft of his report[4]g which included more analytical calculations and expanded several of the discussions. Michelson provided a copy of this draft report to Ebersole, but apparently the typewritten draft was not given to anyone at the NRC. The introduction to the expanded version stated:

> This report gives an account of some initial considerations of a class of very small-break LOCAs (probably less than or equal to 0.05 ft^2) for a B&W 205-fuel-assembly PWR which may have an associated decay heat removal problem.[47]

This introductory summary also stated:

> Also of concern is the possibility of break isolation by operator action resulting in repressurization and slug or two-phase flow through a pressurizer safety valve. These uncertainties may reflect on the adequacy of proposed emergency operating procedures and operator training for a very small break LOCA.[48]

Of particular interest to this Special Inquiry is Section 4.6 of the revised report which discussed the subject of pressurizer level indication. This discussion had not been included in the earlier handwritten draft. This new section stated:

> If the break is at the top of the pressurizer steam space, a rapid pressurizer refill can occur. During the transition to pool-boiling and while in pool-boiling, the level should stabilize even though the core may be uncovered. Therefore, pressurizer level is not considered a reliable guide as to core cooling conditions. No other primary side level indication is provided.[49]

This section also stated:

> A similar problem with pressurizer level indication is found in Section 4.5 relative to HPI pump trip. A full pressurizer may convince the operator to trip the HPI pump and watch for a subsequent loss of level. Although this response appears desirable, a full pressurizer may not always be a good indication of high water level in the reactor coolant system. For instance, the steam bubble which is trapped in the pressurizer may be vented by actuation of the pressurizer vent valve due to high pressure developed in the reactor vessel top plenum or by operator action. The vent valve will subsequently close, but the pressurizer may be filled solid with a subcooled liquid. The loop seal configuration of the pressurizer surge line allows the pressurizer to remain filled as the reactor coolant system water level drops until system pressure is below **saturation** pressure of the pressurizer liquid inventory. This may take a long time, if system pressure is set by a requirement to remove some of the decay heat to the steam generator at 1270 psia. Thus, a full pressurizer is not considered a reliable indication for prescribing certain operator actions such as HPI pump trip.[50]

Michelson considered whether the report should be provided to the NRC under the provisions of 10

C.F.R. Part 21. However, he concluded that he could not clearly identify this item as reportable because it was sufficiently tentative to permit sending it to B&W for comment before formally submitting it to the NRC.[51] Michelson forwarded his report to B&W for review, by letter from D. R. Patterson of TVA to James McFarland of B&W dated April 27, 1978.[52] This letter stated that increased ACRS interest in, and questions concerning, very small-break LOCA's had prompted NA to take a closer look at this problem.

Michelson testified that he made reference to the ACRS concerns (which were actually a result of his report, not a cause of it), and to the possibility of additional questions during the review of NA's Bellefonte application to encourage timely consideration by B&W. He has testified that he expected a reply in no less than 3 to 4 months.[-r3] The NA letter related further that the enclosed report was a preliminary draft study that reflected NA's initial thoughts and concerns and requested that B&W review this work and give its views. NA requested that, after B&W had reviewed this study, a conference call be arranged to discuss the matter with B&W and TVA, and a meeting be scheduled to examine the entire issue of very small breaks.

The letter did not indicate that a written response was desired or required. The central concern addressed in the cover letter involved the fact that a number of possible situations existed that might impede decay heat removal. For example:

- A steam bubble could form at the top of the hot leg which would interrupt natural circulation.
- Transition from natural circulation to pool-boiling could be a problem because of the time delay while waiting for the steam generator tubes to drain down (it is noted that this could result in system repressurization).
- Refill of the system might not restore natural circulation if sufficient noncondensible gases are present.

Other concerns noted in the cover letter were:

- The operator might isolate the leak and remove it as a source of decay heat removal.
- The code safety valves on the pressurizer are not qualified for the passage of two-phase fluid.
- Pressurizes level is not a correct indicator of water level over the reactor core.

The TVA cover letter closed with the following statement:

> We assume that the situations and concerns which have been identified above and in the attached draft study have been considered in your own in-house LOCA analysis work. Your more detailed transient calculations based on realistic system and core thermal-hydraulic models would be an appropriate verification that no serious problems exist.[54]

The Michelson report was initially received by Robert Lightle, Associate Project Manager at B&W, who immediately forwarded it to Bert Dunn, Unit Manager, and Robert Jones, Senior Engineer, in the ECCS Analysis Group.

To place the report in perspective, Lightle testified that B&W had received approximately 10000 letters from NA since B&W began work on the Bellefonte project in 1970. Approximately 6000 letters originated in the engineering group in Knoxville, of which Michelson is a member. The remainder came from the materials engineering group in Knoxville and the contract group in Chattanooga. About 7000 to 8000 letters raised a question or concern that NA wanted B&W to address. Of these, approximately 2000 were associated with plant safety.[55] The Michelson report was one of those 2000 letters.

Lightle also testified that B&W's scheduling of work requested by a customer was based on the need for the results to meet a specific licensing or construction milestone, insistence by the customer that a specific task be completed, or both. The response to the Michelson report was not perceived as directly affecting any milestones, although it might have indirectly affected the Safety Analysis Report scheduled for completion in early 1979. Lightle did not feel that NA pushed for completion of this review. Although Michelson recalls requesting several times of his supervisors that B&W be contacted concerning a response,[57] recalls only a single call concerning the report prior to November 1978.[58]

Jones recalls receiving the report in May 1978. His recollection is that he scanned it and considered it to be too detailed to review immediately because of higher priority work. Although the very small breaks described in the report had not been specifically analyzed, he believed that they had been reviewed from the standpoint of being bounded by the analysis of larger small breaks. Jones also felt that, while the report described some valid concerns, it did not raise any new or unique issues.[sa]

On the basis of Jones' initial appraisal that there was not anything particularly alarming, he and Dunn decided that the review of the report could wait and could be completed on a more leisurely schedule. The high priority work that Jones had been working on when the Michelson report was received was completed in August or September of 1978. Work on the Michelson report was, nonetheless, still delayed because of higher priority work that had been put off during the earlier efforts. In September, Jones did reread the report, but found it difficult to determine how to respond.

Elsewhere in the B&W organization, James Taylor of B&W's Licensing Branch also received a copy of the report. He referred it to Henry Bailey of his staff. Bailey reviewed the report and prepared a memo on May 25, 1978 which concluded that the phenomena described would all occur while the core remained covered. However, he also noted that, "A more valid concern may be the subject of operator action and the potential for erroneous pressurizer level."[61] He concluded that, "Bert Dunn plans to start looking at the report next week to see what's there and to consider what action or investigation should be pursued (if any)."[62]

In the fall of 1978, Michelson became increasingly concerned because he had not received a response from B&W. He placed increasing pressure on the personnel at NA who were in contact with B&W to attempt to get the review completed. Finally, in December 1978, a conference call was arranged and included a number of people from both B&W and NA. The bulk of the conversation (which lasted approximately 1 ½ hours) involved Michelson and Jones discussing their positions on the analysis of small breaks.

Michelson's concern centered on whether or not B&W had performed calculations to determine if the core stayed covered for breaks under 0.05 square feet. Jones countered that, although specific calculations had not been performed, extrapolation of data from larger small breaks indicated that keeping the core covered was not a problem. He also pointed out that the NRC had verbally accepted this conclusion that smaller breaks were not a problem. Michelson then asked that B&W identify areas where their results differed from his results, and since B&W's calculations were more sophisticated than TVA's, to inform NA of their errors. Lightle pointed out that to give such an answer would require a detailed calculation on the part of B&W, and Jones added that he did not feel that such an effort was warranted.

Michelson then asked that B&W reply to his earlier letter, describing how they had replied to the NRC with respect to the very small breaks (less than 0.05 square feet) but not by doing any actual additional analysis. B&W asked that NA provide a written description of their remaining concerns to focus the issues. This one-page summary[63] of the issues was prepared by Michelson, and forwarded to B&W by telecopy. This document states, in part, "When replying to our letter, please specifically address the following statement of the problem."[64] This summary statement then listed a number of matters not relevant to this Special Inquiry. It should be noted that the list did not include the issue of pressurizer level indication and possible operator action as a result of high pressurizer level indication. The summary concludes, "Please indicate which portions of your reply are based on analysis and indicate their availability to NA and the NRC."[65]

Jones prepared a response to Michelson's report and forwarded it to NA by letter dated January 23, 1979.[66] Jones stated in his response that his understanding of the concerns addressed was:

> (1) How is decay heat removed? (2) Will system repressurization occur? If so, could a smaller case be a worse break? (3) If the operator isolates the break, will system repressurization occur? If so, will the pressure relief valves be subject to slug or two-phase flow?[67]

Jones' response related that, although repressurization may occur, he disagreed that repressurization could cause a faster depletion of inventory from a very small break when compared to a larger small break without repressurization. He used what he described as a volume balance technique to explain his reasoning. (Volume balance is a technique for understanding how the system responds and for doing hand calculations. Computer models are used by B&W to analyze specific break sizes and locations. These computer models use more complex and mathematically rigorous relationships.)

In addition, he agreed that two-phase flow through the safety valves may occur, but he argued that even if they are damaged by that flow, such an accident had been evaluated in the Final Safety Analysis Report and found not to be a problem.

Jones also addressed the concern about operator interpretation of pressurizer level. In his response, he stated:

> As far as the appropriateness of the operator using pressurizer level indication to trip the HPI, B&W agrees that the level indication is not a reliable indication of the state of the RCS [reactor coolant system]. However, use of the pressurizer level indication, along with system temperature and pressure measurements to ensure that the system is still in a substantially subcooled state will provide sufficient guidance for operator action.[68]

Jones did not feel that the problem of operators securing high pressure injection pumps based on pressurizer level alone was a particular concern because he believed that supplemental guidance had been provided to the operators as a result of memos proposing further guidance, written by Keiy and Dunn earlier in 1978[69] (see Section I.C.10).

Dunn testified that in the course of reviewing Jones' work, he recognized Michelson's concern about operator interpretation of pressurizer level, but believed that the issue had already been resolved because of the guidance that he thought had been sent to all operating B&W plants in response to his memos. Therefore, he believed that this concern had already been resolved for operating plants. Dunn also felt confident that, although Joseph Kelly (see Section I.C.10) had not seen the Michelson report, he would ensure that new designs would be responsive to the concerns expressed by Michelson with respect to operator interpretation of pressurizer level.

When Michelson received Jones' response, his impression was that B&W had not understood his concerns. He sent a letter to B&W pointing out that use of a volume balance was not consistent with physical law and that some statements in B&W's response contained inconsistencies with respect to the application of the volume balance technique. This letter, dated February 8, 1979,71 acknowledged receipt of the B&W letter and stated, "TVA will require the following clarification and additional explanation to complete its review... "72 This clarification was associated with the volume balance technique used by B&W. The letter requested a response by March 15, 1979. Because of higher priority work, Jones did not respond to this second letter prior to the accident at TMI.

After the accident at TMI, Taylor of B&W forwarded a detailed analysis of the Michelson report to the NRC in May 1979.73 The cover letter forwarding the analysis concluded that all of the concerns raised in the Michelson report had been addressed within the B&W evaluation mode. The report also addressed the specific question of operator interpretation of pressurizer level and stated:

> Pressurizer level is not a good indication of primary system liquid inventory. No operator action should be based on that signal alone. It is quite possible to have a smaller break causing a slow loss of RCS [reactor coolant system] inventory and eventual voiding of the reactor core while maintaining a reasonable pressurizer level if high pressure injection is terminated prematurely. The only positive indication of reactor vessel liquid inventory is a subcooled indication of all RCS [reactor coolant system] pressure and temperature indicators excepting those in the pressurizer. This point is considered and demonstrated within the evaluation model particularly for breaks which occur in the pressurizer itself. a

Furthermore, in a letter dated May 24, 1979,75 from Roger Mattson of the NRC to Henry Myers, a special consultant to the House of Representatives Subcommittee on Energy and the Environment, Mattson stated that the key conclusions of the NRC staff evaluation of the Michelson report include:

> (1) The overall small breaks was shown to behavior be for the the most plants part, consistent with the behavior as predicted by Michelson and, within the expected accuracy the B&W analysis substantiated Michelson's hand calculation results. (2) This behavior did not result in unacceptable consequences and the core is not calculated to uncover for the small break accident scenarios postulated by NA (Michelson).76

However, it should be noted that the technical evaluation contained in Michelson's report (excluding the concern about operator actions based on pressurizer leveQ has little direct impact on the accident that occurred at TMI-2. Michelson's analysis is based on a 205-fuel-assembly B&W design, but the TMI-2 plant is a 177-fuel-assembly B&W design. Michelson has testified that, even if B&W had done an extensive analysis and had done everything that he could reasonably have expected to be done with respect to his concerns about small break analyses, such action would not have had any significant impact on the accident at TMI because of the differences between the 205-fuel-assembly plant that he analyzed and TMI-27

Specifically, TMI and the other 177-fuel-assembly plants are less susceptible to the problems raised by Michelson because the auxiliary feedwater is sprayed into the top of the steam generator; whereas on 205-fuel-assembly plants the auxiliary feedwater enters at the bottom of the steam generators. This difference greatly reduces the time required for transition from natural circulation to pool-boiling. However, the concern about operator interpretation of pressurizer level is directly applicable to the TMI accident. Jones agreed in his testimony that, even in hindsight, the only part of the Michelson report that applies to the TMI accident is the comment about operator interpretation of pressurizer level.78

Specific Conclusions

1. The technical issues raised in the bulk of the Michelson report are still a matter of controversy. B&W still contends, on the basis of extensive analyses performed after the TMI accident, that their method of analyzing very small-break LOCAs is valid and that such accidents are bounded by the small-break analyses that they had performed before the accident at TMI. Michelson still contends that his comments as they are applied to the B&W 205-fuel-assembly design, are still valid and unresolved.

2. The bulk of the technical discussion contained in the Michelson report, particularly with respect to the issue of repressurization and increased discharge through a very small break, did not directly apply to TMI because TMI is a 177-fuel-assembly plant and the analysis was based on a 205-fuel-assembly plant.
3. The handwritten draft report prepared by Michelson and subsequently informally provided to the NRC contains a very limited discussion of opera-for interpretation of pressurizer level. On the other hand, the typed draft contains a lengthy discussion of the response of pressurizer level during such a transient and the subsequent operator actions that might result because of this indication. For example, comments such as, "A full pressurizer may convince the operator to trip the HPI pump and watch for subsequent loss of level,"[79] are included in the typed draft, but not included in the handwritten draft.
4. Michelson and Ebersole were painfully naive to believe that a handwritten draft report, informally handed to a first-line supervisor within the NRC, would receive anything more than a cursory review. The lack of followup by Ebersole after he forwarded the report to Israel exacerbated the problem of this report not being given extensive consideration by the NRC.
5. B&W response to the Michelson report was excessively slow. However, this slow response was due primarily to the fact that B&W believed that the technical issues raised in the report were not significant and were already adequately addressed in earlier analyses, and that the bulk of their effort was associated with explaining why the concerns raised in the report were not significantissues.
6. With respect to the issue of operator interpretation of pressurizer level, B&W felt that this issue had been resolved by the additional guidance that Kelly, Jones, and Dunn all mistakenly believed had been sent to the various utilities as a result of the Kelly-Dunn memos.
7. Although Michelson was (and still is) a consultant to the ACRS, he did not provide the Michelson report to Ebersole, a member of the ACRS, because of this formal relationship (i.e., the report was not submitted to the ACRS). Michelson and Ebersole had been close personal friends long before either of them became associated with the ACRS. It was in this context of personal friends who shared a common interest (i.e., small-break LOCAs) that the Michelson report was given to Ebersole.

9. DAVIS BESSE-SEPTEMBER 24, 1977

An incident occurred at the Davis Besse Nuclear Power Station on September 24, 1977, that bears a strong resemblance to the subsequent accident at TMI-2. The incident began at 9:34 p.m. while the plant was operating at 9% power with one effective full power day of operation. The incident was initiated by a spurious half-trip of the steam and feedwater rupture control system. This trip stopped the feedwater flow to the No. 2 steam generator which caused the level in the steam generator to decrease. At 1 minute and 16 seconds after the spurious half-trip, a full trip was initiated as a result of low level in the No. 2 steam generator. This full trip isolated the main feedwater flow to the other steam generator and initiated auxiliary feedwater flow. However, the No. 2 auxiliary feedwater pump turbine did not come up to full speed because of binding of the turbine governor. This situation resulted in no auxiliary feedwater flow to the No. 2 steam generator. At approximately the same time that the full trip of the steam and feedwater rupture control system occurred, the pilot operated relief valve (PORV) opened as designed. However, due to a missing relay in the control circuit, the valve rapidly cycled open and shut, and eventually failed in the open position.

The full trip of the steam and feedwater rupture control system also shut the main steam isolation valves. As a result of the loss of cooling to the reactor coolant system, the reactor coolant system temperature increased, which in turn caused pressurizer level to increase sharply. At 1 minute and 47 seconds the operator manually tripped the reactor because of high pressurizes level.

The tripping of the reactor, the open PORV, and the injection of cold auxiliary feedwater to the No. 1 steam generator caused reactor coolant system temperature and pressurizer level to decrease. At this point, the operators were verifying proper operation of various safety features and responding to numerous alarms that were received in the control room. The alarms were received so rapidly that the implications of each alarm could not be analyzed in detail. The difficulties were further compounded by the fact that the operators did not immediately realize that the incident had been initiated by a malfunction of the steam and feedwater rupture control system.[80]

As pressure continued to decrease, it eventually reached 1600 psi (at approximately 3 minutes), at which point the safety features actuation system actuated. The actuation caused containment isolation and initiated high pressure injection flow. The containment isolation shut the vent on the quench tank, which received the discharge from the open PORV. As a result, the pressure increased in the quench tank and caused the rupture disk to blow. The operators realized that the rupture disk had blown. However, they thought that, at most, the PORV had stayed open slightly longer than normal; they did not realize that the PORV was still stuck open.

The operators did have the computer printout of temperature at the outlet of the PORV available; however, they did not use that information because the alarm printer was too far behind.[81] The only other indication of the PORV position was from the control power signal for the solenoid, and that erroneously indicated that the valve was shut.

At approximately 4'/z minutes pressurizer level stopped decreasing and began to increase as a result of the influence of the high pressure injection pumps. However, reactor coolant system temperature and pressure continued to decrease. At approximately 6 minutes, the operators stopped the high pressure injection pumps because pressurizer level had returned to normal and, in fact, had increased above the initial level.[82] Securing the high pressure injection was consistent with the plant's emergency procedures, which stated in Emergency Procedure 1201.06.2, Section 2.4.3, "Note that as RCS [reactor coolant system] pressure is decreased, the HPI [high pressure injection] must be throttled to maintain pressurizer level."S[3] However, the action of stopping high pressure injection was inconsistent with the plant operating procedures, specifically Plant Procedure 1101.01.2, Section 1.1.3, Item 6, which states:

> Reactor coolant system pressure must be maintained above the pressure that would allow the formation of a steam bubble at the highest point of the 36-inch reactor coolant piping. 84

In hindsight, some of the operators were amazed that they stopped high pressure injection based on pressurizer level indication alone, because they realized that the plant was approaching saturation conditions. They can only attribute this action to the confusion that existed in the control room. 85

Pressurizer ievel began to decrease after the high pressure injection system was stopped because of the continuing decrease of reactor coolant system temperature. At 7 ½ minutes into the incident, saturation pressure was reached in the reacfor coolant system and boiling began. The void formation in the reactor coolant system caused expansion of the water and an increase in pressurizer level. At this point, the operators were still involved with responding to alarms and checking proper operation of systems. However, they began to realize that the plant was not responding as they had expected, particularly in light of the fact that pressure had continued to decrease. Some of the operators thought initially that this pressure decrease might be caused by overcooling of the reacfor coolant system caused by the injection of cold water into the No. 1 steam generator,[86] however, others realized that they were losing reactor coolant system water. At approximately 9 minutes, pressure stabilized at 900 psi and pressurizer level was offscale high. The operators found this combination very confusing, but they realized that the system was saturated, and that the pressure was remaining constant and the pressurizer level was high as a result of the boiling in the reactor coolant system.[87, 88] At approximately 9 minutes and 20 seconds, the operators tripped one reactor coolant pump in each loop to reduce the heat input to the system. Only in retrospect did the operators realize that securing pumps to reduce heat input was not consistent with their concern that pressure decrease might be due to overcooling. 89

Reactor coolant system pressure remained constant for approximately the next 13 minutes, while at the same time pressurizer level remained offscale high. At approximately 22 minutes, the operators received a high containment pressure alarm. This alarm, coupled with an instrument reading of 3 psig, caused one of the operators to finally realize that a leak was occurring from the reactor coolant system. This fact, as well as earlier information about the quench tank rupture disk blowing and other matters indicated to him that the PORV was open, and he immediately shut the block valve. Shutting the block valve while the makeup pumps were running caused a repressurization of the system. This repressurization collapsed the steam bubbles that had formed in the reactor coolant system, and pressurizer level rapidly decreased. Because of this decrease, the operators manually restarted the high pressure injection pumps.

Approximately 1 hour after the incident began, the operators had increased reactor coolant system pressure above saturation and had returned pressurizer level to normal. As a result, they secured the high pressure injection system a second time. At this point, the plant was essentially in a stable condition.

Response to the Incident

NRC Office of Inspection and Enforcement, Region 111

The NRC Office of Inspection and Enforcement (IE), Region III in Chicago was first notified of the incident by telephone at 8:45 a.m. on Sunday, September 25, 1977, the day following the event. The event was perceived by the Region III personnel as being a very severe transient, but, because the plant was in a safe condition, it was decided that it was not necessary to send someone to the site immediately.[91] The Principal Inspector for the Davis Besse plant, Thomas Tambling, was scheduled for a training session during the week following the incident, so another inspector, Terry Harpster was sent to the plant on Monday, September 26.

The purposes of Harpster's trip to the plant were to determine if the plant was in a safe shutdown condition, determine all the relevant parameters during the transient, ensure that proper analysis of the transient was conducted,[92] and define actions necessary before any further plant operation.[93] Harpster's review, which lasted approximately 1 week, raised several concerns that were subsequently related to Tambling. These concerns included the operator response during the transient; evaluation of the pressure excursion, including boiling effects in the core and the effects of boiling on the fuel; and a possible problem with the high pressure injection system due to the fact that the operators were not sure if high pressure injection had gone into the core.[94]

Harpster's concern about operator response centered on the fact that the operators had not had adequate training to recognize the problem with the steam and feedwater rupture control system, particularly because this system was unique to Davis Besse. Harpster was also concerned about the failure of the operators to integrate plant parameters (e.g., their reliance entirely on pressurizer level). However, he did not voice this second concern because the emphasis of his work and his major concerns were associated with plant physical problems.[95] Harpster also considered the generic implication of this incident; however, he thought it unreasonable to conclude that a similar transient could occur elsewhere because of the mechanical failures involved and the fact that the steam and feedwater rupture control system that initiated the incident was unique to Davis Besse.[96] Harpster was subsequently involved in a training session for various reactor inspectors and staff personnel at Region III. This session included a discussion of the chronology of events, the initiating sequence, the operator response, and the various equipment malfunctions.

On September 30, 1977, an immediate action letter[97] was issued by Region III as a result of the September 24, 1977 incident. Among other things, this letter required an evaluation of the pressure excursion including boiling effects, to ensure that boiling did not cause damage to the reactor coolant system. IE practice and policy required that this evaluation be completed before the plant was returned to mode 4 (hot shutdown).[98,99]

When Tambling assumed responsibility for the investigation, his primary concern was resolving specific items in the immediate action letter.[100] Tambling was aware that void formation had occurred in the reactor coolant system, but he viewed it principally as a potential equipment problem associated with vibration of the reactor coolant pumps and potential fuel damage. Tambling did not realize that void formation had caused the pressurizer level to increase; consequently, he believed that the operator action of securing high pressure injection was appropriate in view of the fact that pressurizer level had returned to the operating range.[101] Tambling also considered the generic implications of the incident. However, he concluded that no generic issues were associated with the incident because the pilot operated relief valve (PORV) that had failed open had been designed by one manufacturer, and the valve in other B&W plants was designed by a different manufacturer.[102] In addition, the fact that the relay in the PORV control circuit was missing was considered a plant problem and would not be expected to occur at other facilities.[103]

At the conclusion of his inspection, Tambling requested that the licensee prepare a supplement to the initial Licensing Event Report (LER NP-32-77-16)[104] that would include the analyses that Tambling had already reviewed at the site. This material (LER NP-32-77-16 Supplement)[105] was forwarded to the Region III office on November 14, 1977, as a part of the report that is required within 90 days following such incidents.

The results of Tambling and Harpster's investigation were documented in an Inspection Report (No. 50-346/77-32) dated November 22, 1977.[106] This report describes the incident as a sudden depressurization and notes several conclusions that are relevant to this Special Inquiry: (1) the operators had problems discovering that the PORV was open because of lack of direct indication of the valve's position, and therefore, Toledo Edision installed indications of position of the PORV pilot valve; (2) the PORV control circuit was not safety-related and not covered by the quality assurance program for safety-related components; and (3) B&W had analyzed the incident and found that it was within the scope of the generalized depressurization transient previously analyzed. As a result of this inspection, no items of noncompliance associated with the incident were noted.

This concluded Region III involvement with this incident until concerns about this incident were raised by James Creswell, Region III Inspector. These concerns are discussed in detail in Section I.C.12 of this report.

NRC Office of Nuclear Reactor Regulation

The NRC Office of Nuclear Reactor Regulation (NRR) also became involved with the investigation of this incident. Leon Engle, the Licensing Project Manager for Davis Besse, was notified of the event by the Office of Inspection and Enforcement. However, because IE did not request assistance, Engle concluded that active involvement by NRR was not yet required.[107] At the same time, the Division of Systems Safety within NRR also became aware of the event, and a factfinding group headed by Gerald Mazetis was sent to the plant. Engle, Mazetis, and several other representatives of the Division of Systems Safety met with representatives of the utility, B&W, and Region III at the site on September 30, 1977.

Engle collected data from the incident and, after returning to Washington, plotted this data (see Figure 1-9). Although the data plots revealed that steam formation had caused the pressurizer level to increase, Engle did not consider this finding to be significant. He also realized that the operators had secured the high pressure injection system before isolating the leak. However, he did not focus on whether or not this action was proper because he considered operator action to be a responsibility of IE.[108] His primary concern was the fact that a relay such as the one that was found missing in the PORV control circuit could be removed from a system without anyone's knowledge. He believed that little action could result from this concern because the system was not considered to be a safety system. He was also concerned that the investigation was being conducted unsystematically because of the number of groups involved and the lack of coordination. He informed his supervisor of this concern, but nothing was done.110

After his review, Mazetis prepared a handwritten trip report" in which he noted that saturation pressure was reached during the event and that the operators secured high pressure injection when they observed an increasing pressurizer level. In this informal report, he related several issues and concerns, including: (1) there were endless speculations associated with this event, and (2) the licensee should address the dynamic effect of vapor formation in the reactor coolant system during the transient, particularly because it was associated with reactor coolant pump cavitation and seal effects. This informal report may not have been distributed to anyone. Mazetis has testified that he did not consider these concerns to be any more significant than other safety concerns that came up daily.n[2]

On October 3, 1977, Mazetis gave a briefing to representatives from the Division of Systems Safety and IE including Roger Mattson, the Director of the Division of Systems Safety, and Karl Seyfrit, the Assistant Director, Division of Reactor Operations Inspection in IE. The general characteristics of the transient were discussed, as was the plot of pressurizer level, reactor coolant system temperature, and reactor coolant system pressure, prepared by Engle (Figure 1- 9). The conclusion of this meeting was a decision by Seyfrit and Mattson that IE would maintain lead responsibility for the investigation.[n3]

Subsequently, Mazetis prepared a note dated October 20, 1977, from Denwood Ross of NRR to Seyfrit.[n4] The note described some areas of interest to the Division of System Safety that he believed should be addressed in the Toledo Edison Company formal report of the incident. One concern stated:

> The operator's role in participating in the event should be related. For example, the manual actions associated with the control *of* level in steam generator No. 2 should be described. The operator's decision to secure high pressure injection *flow* based on pressurizer level indication should be explained."[5]

Seyfrit does not recall whether he received this note; however, he believes that if he had received it, he would have called Region III or sent a copy of the report to the people conducting the investigation in Region III[116] Testimony by Region III personnel and a review of the Region III files failed to produce the document or any recollection on the part of Region III personnel concerning the issues raised by this document. The meeting on October 3, 1977, and the October 20, 1977 note appear to be the only forums in which the concerns raised by NRR personnel would have been forwarded to the IE inspectors conducting the investigation. The October 20, 1977 note apparently ended the Division of Systems Safety involvement.

R.J. McDermott of the Quality Assurance Branch in the Office of Nuclear Reactor Regulation also conducted a review to determine if deficiencies in the licensee's quality assurance program or test program had caused or contributed to the transient. In a memo dated October 6, 1977,[117] McDermott noted that the emergency core cooling system had initiated at 1600 psig, that pressure reached as low as 800 psig, and that boiling occurred in the reactor coolant system. He did not comment on these facts. He noted that he did not have sufficient information to reach a conclusion, but that he had re-

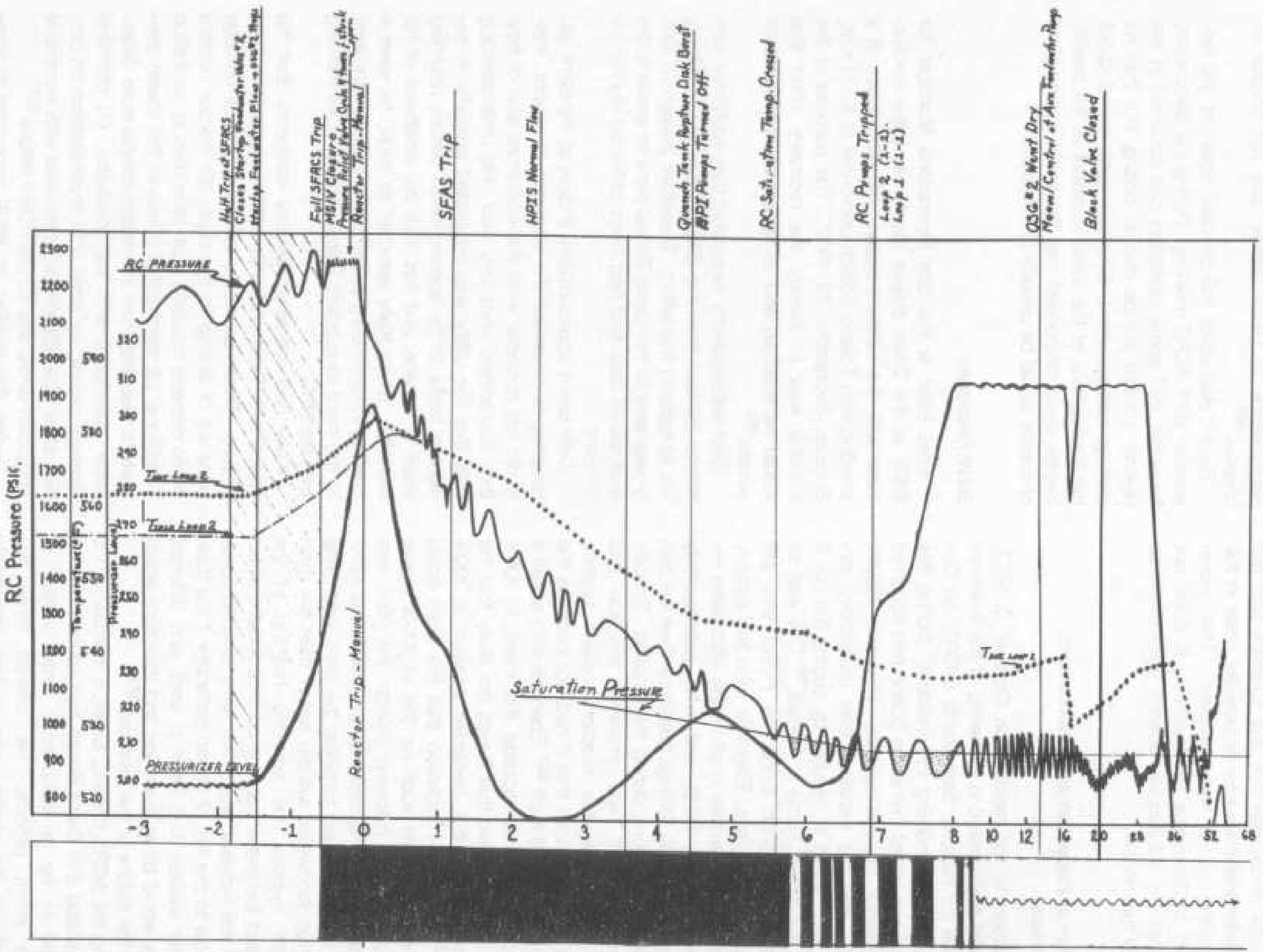

FIGURE I-9. Davis Besse, Unit 1, Reactor Trip From ~9% Full Power at 9:36 p.m., September 24, 1977 quested additional information from the IE inspector. On October 20, 1977, McDermott wrote a memo in which he concluded that the licensee had not been able to determine why or how the relay in the PORV control circuit was removed. This memo concluded McDermott's involvement. It does not appear that any subsequent actions were taken as a result of this review.

NRC Office of Inspection and Enforcement, Headquarters

In addition to the meeting on October 3, 1977, Karl Seyfrit participated in a briefing of the Advisory Committee on Reactor Safeguards (ACRS) on October 7, 1977 concerning this incident. During this briefing, it was noted that some boiling had occurred in the reactor coolant system. However, Seyfrit concluded that the transient was completely terminated after about 15 minutes by putting the No. 2 auxiliary feedwater pump in manual.[119] This was an interesting observation since the PORV was still stuck open at this time. Ebersole, who had already received the handwritten draft of the Michelson report (see Section I.C.8) and who subsequently prepared the Pebble Springs questions (see Section I.C.11) asked questions during this briefing. Specifically, he asked if high pressure injection had pumped water into the reactor coolant system. Seyfrit's response was that it had not because the operator had turned it off.[120] Ebersole also asked if it was planned to extrapolate the event to 100% power. Seyfrit stated that it was not likely that the plant could be in this particular position at 100% power.[121] Seyfrit's conclusion that the plant could not have a transient such as this at 100% power was based on the following points: the plant was operating by dumping steam to the condenser rather than using the main turbines; the plant was using the startup feedwater system rather than the main feedwater system (the spurious half-trip of the steam and feedwater rupture control system which initiated the incident would not have isolated feedwater flow to the No. 2 steam generator if the main feedwater system had been in use); and different systems would be in operation and therefore would change the nature of the transient.[122]

During the ACRS briefing, Seiss, a member of the ACRS, stated that Davis Besse had submitted what appeared to be an abnormally large number of licensee event reports. He offered three hypotheses; (1) the number was, in fact, abnormally large for a plant startup; (2) the number was typical of plants during a startup; or (3) Davis Besse personnel had a different interpretation of what should be reported. Seyfrit stated that the answer was a combination of all three; but, he concluded that the performance at Davis Besse was not unique or unusual.[123]

Seyfrit discussed this incident again at the November 1977 ACRS meeting. During the discussion, he noted that some cavitation had occurred in the reactor coolant pumps due to boiling, but that no damage had occurred. Ebersole again asked about the implications of the same accident at full power. Seyfrit again responded that the same combination of events would be unlikely at full power.[124]

B& W Response

Fred Faist is the Site Operations Manager for B&W at the Davis Besse plant. His initial involvement with the incident began with attendance at a meeting with Toledo Edison personnel at 10:00 a.m., Sunday, September 25, 1977. The purpose of the meeting was to identify the recovery effort that would be required and to review the sequence of events.[125]

Faist subsequently requested that additional personnel be sent from the B&W offices in Lynchburg, Va. to support this effort. Therefore Joseph J. Kelly was sent to the Davis Besse plant to assist in the analysis of data that had been collected during the incident.

Kelly spent approximately 2 days at the plant, attempting to determine the sequence of events. Kelly did not consider what the operators saw or how they interpreted what they saw. His understanding was that the utility was interested primarily in assigning tasks to be accomplished before returning plant to service, and this was the emphasis of his work.[126] When Kelly returned to B&W, he gave a briefing in Lynchburg to people who were later sent to the plant to support Toledo Edison in its meeting with the NRC.

Kelly had identified several concerns that he raised with Faist and with B&W personnel in Lynchburg. These concerns included: (1) fuel damage because of boiling in the core; (2) reactor coolant pump damage resulting from operation at saturation conditions; (3) mechanical stress to the steam generators resulting from increased temperature difference associated with lost insulation; (4) chemical damage caused by boric acid crystallization on carbon steel pipe; (5) stress associated with excessive cooldown rates; and (6) the PORV failure.[127]

During the briefing of B&W personnel in Lynchburg, Kelly discussed with Bert Dunn and Robert Jones of the B&W staff a concern associated with the steam formation in the reactor coolant system.

Dunn resolved Kelly's concern about boiling and the possibility that it would damage the core, but raised a new concern about the operators incorrectly securing high pressure injection.[128,129] This led Kelly to prepare a memo concerning the guidance provided to operators associated with securing high pressure injection[130] (see Section I.C.10).

Faist also worked on the recovery effort following the incident. Some concerns that he identified include the following:

- The alarm on one high pressure injection leg cleared, but the operators did not see flow indication in that leg. (Faist believes that this occurred when the operators manually initiated high pressure injection,[131] but others believe that this occurred when high pressure injection initiated automatically early in the incident.)
- Michael Derivan, the shift foreman in the control room during the incident, was confused by the fact that pressure decreased while pressurizer level increased. However, Faist testified that he did not consider the possibility that other operators might subsequently be confused.[132]

Faist has testified that he had discussed the operation of high pressure injection during the incident with Dunn and Jones of B&W, and they concluded the high pressure injection should not have been turned off because of the possibility that it would not restart correctly if it were needed later in the incident.[133] However, it does not appear that Faist did anything as a result of this discussion.

Faist prepared a Site Problem Report (No. 372)[134] He has testified that he tried to describe the hardware problems that had occurred and the sequence of events, as opposed to opinions and interviews with personnel.[135] Therefore, he did not record the fact that the operators were confused by the indication that they saw, nor did he report that the operators secured high pressure injection incorrectly. He simply noted that the operators had secured high pressure injection.

In the Site Problem Report, Faist also pointed out that the steam and feedwater rupture control system actuation did not trip the reactor. Toledo Edison opposed installing such a trip because they wanted to keep the steam and feedwater rupture control system and the reactor protection system separate. Toledo Edison personnel believed that the reactor protection system would trip the reactor when required. Faist did not consider the generic implications of the need for a similar anticipatory trip, based on loss of feedwater, on other B&W plants.[136]

Toledo Edison

The involvement of Toledo Edison management began during the actual incident. Terry D. Murray, the Assistant Station Superintendent (Murray became the Station Superintendent in November 1977), was at the plant when the incident occurred. Murray arrived in the control room shortly after the operators manually tripped the reactor and he remained there throughout the incident. After Murray was confident that the plant was stabilized in a normal hot shutdown condition, he telephoned the station superintendent to inform him of the incident.[137] Murray did not contact the NRC at this time.[138]

On Sunday morning, September 25, 1977, a meeting of station staff and support personnel was held to: review the details of the incident; identify issues that required additional investigation; and develop a plan to correct physical damage that occurred inside the containment.[139] Shortly before the group convened, the NRC was contacted.

The principal concerns that came out of this inhouse conference were of potential damage to reactor coolant pumps and to the fuel because of void formation in the reactor coolant system; thermal stress of the reactor coolant system; mechanical damage inside containment; and the cause of the sticking of the PORV.[140]

Two or three weeks after the initial meetings concerning the incident, the personnel who were in the control room met with a group of consultants to the president of Toledo Edison. During this conference the operators discussed the information available in the control room.[141,142] It was observed during the discussion that a common thread in these events was the operator's inability to recognize small LOCAs.[143] At least one of the operators also stated that his training had not prepared him for this event because he had never seen a leak where pressurizer level increased.[144] It does not appear that any actions were taken as a result of this meeting. In addition, this was the only time that the operators were asked to describe the difficulty they had in determining what was happening during the event.[145]

Specific Conclusions

1. The incident that occurred at Davis Besse is almost an exact copy of the accident that subsequently occurred at TMI. The reasons that Davis Besse did not sustain the severe core damage that resulted at TMI are that the Davis Besse

plant had been operating at a very low power level and had a very low power history, and the operators at Davis Besse were able to identify and isolate the open PORV in 20 minutes as opposed to 2 hours at TMI. If it had not been for these fortuitous conditions, it is very likely that the incident at Davis Besse would have been as severe as the subsequent accident at TMI-2.

2. Numerous groups were involved with the review of the incident at Davis Besse; a team from the Office of Nuclear Reactor Regulation, an individual from B&W in Lynchburg, two inspectors from the Office of Inspection and Enforcement, and plant personnel. Unfortunately, their efforts were not coordinated, and consequently the concerns raised by individuals were never exchanged among the members of the organizations. For example, the concerns raised by Mazetis in the Office of Nuclear Reactor Regulation that subsequently were forwarded to the Office of Inspection and Enforcement as the Ross-Seyfrit note were never forwarded to the IE inspectors actually conducting the investigation. Similarly, the concerns raised by Kelly that resulted in the Kelly-Dunn memo were never forwarded to anyone outside of the B&W organization. Because of this fragmented investigation, there was never a cross-pollination of ideas, which might have resulted in a realization of the significance of some of the individual concerns.

3. All of the review groups overemphasized equipment. The reviewers tended to disregard the generic implications of the incident at Davis Besse by simply arguing that the specific pieces of hardware were different in other plants. This argument was proposed in spite of the fact that similar pieces of equipment with comparable probabilities of failure and similar failure modes were installed on other B&W plants and, in some cases, on all pressurized water reactors.

4. The people directly involved with the investigation made no significant effort to assess the scenario from the perspective of speculative analysis. Little consideration was given to what would have happened if the plant had been at a higher power level or a higher power history, or if it had taken the operators longer to identify and isolate the stuck-open PORV.

5. The information concerning the incident that occurred at Davis Besse was not effectively distributed to other B&W utilities, specifically to Metropolitan Edison. However, this is due primarily to the fact that the people directly involved with the investigation of the incident did not identify the significant issues associated with the incident that should have been identified, and they dismissed the generic implication of the incident by their emphasis on the equipment failures rather than an emphasis on the overall scenario that occurred.

6. In reviewing the incident at Davis Besse, one can see several indications that the PORV was open and that the reactor coolant system inventory was decreasing. With the benefit of hindsight the operators' actions appear to include a number of errors. These errors include stopping the high pressure injection pumps as the reactor coolant system approached saturation conditions and the delay in closing the PORV block valve.

Study of the behavior of highly trained people under emergency conditions suggests that such people rarely make simple blunders in the operation of systems. Such people typically are highly disciplined; trained to follow procedures carefully; trained to avoid improvisation; and intensely aware of rules and constraints. Compared with the average person, they rarely make tactical errors in the sense of accidentally turning the wrong knob. Nevertheless, such trained people sometimes do make errors in emergencies. To distinguish these from the ordinary kind of errors, we may call these "strategic" errors. In an emergency such people recognize that something is wrong and that some action must be taken. They conceive a model or scenario for what is happening. They follow procedures or reaction strategy which they believe is applicable to the scenario. Studies also show that once a scenario is conceived and a reaction strategy undertaken, there is a tendency not to seek or perceive additional data which contradict the original scenario. There is a psychological phenomenon called "cognitive dissonance" which makes the mind tend to reject data in conflict with the original hypothesis. [146]

After an incorrect scenario is conceived, an entire pattern of actions can be taken which in retrospect are blunders. This phenomenon can be seen to a limited extent during the September 24, 1977 incident at Davis Besse, and to a much greater extent during the TMI accident. However, it does not appear that this phenomenon has ever been addressed in the design or licensing of nuclear powerplants. The implications of this phenomenon are considerable since it implies that any sequence of actions by an operator, no matter how ill advised it may seem to a dispassionate observer, (i.e., the designer) may in fact be a creditable event that must be considered in accident analyses.

10. KELLY-DUNN MEMORANDA-NOVEMBER 1, 1977

Joseph Kelly of the B&W staff in Lynchburg, Va., was sent to the Davis Besse plant to assist Fred Faist, the B&W Site Operations Manager, in determining the sequence of events. Kelly's conclusions were given previously in Section I.C.9.

Upon returning to Lynchburg, Kelly discussed the impact of steam formation in the reactor coolant system with Robert Jones [who subsequently became involved with the review of the Michelson report (see Section I.C.8)] and Bert Dunn of the B&W staff (see Figure 1-10 for the organizational relationships that existed). Dunn indicated that he did not consider steam formation to be a particular problem, but he did believe that the operators had terminated the high pressure injection system prematurely. He pointed out that he could develop scenarios in which the operators could have engendered serious consequences by securing high pressure injection when they did.[147,1as]

Kelly did nothing officially about Dunn's concern until he learned of a subsequent incident at Davis Besse on October 13, 1977 in which the operators prevented high pressure injection initiation. Because of this second example of what he considered to be improper operator action, Kelly wrote a memo dated November 1, 1977.[149,150]

Before writing this memo, Kelly talked to the simulator instructors at B&W and they stated that they did not understand why the operators reacted as they had. They stated that the operators had not been trained to secure high pressure injection unless reactor coolant system temperature had stabilized, reactor coolant system pressure was increasing, and pressurizer level was in the indicated band.[151]

Kelly's November 1 memo noted that during the September 24, 1977 incident, "the operator stopped HPI when pressurizer level began to recover, without regard to primary pressure"[152] with the result that boiling occurred in the reactor coolant system. Concerning the October 23, 1977 incident he wrote, "the operator bypassed High Pressure Injection to prevent initiation, even though reactor coolant system pressure went below the actuation point."[153] Because some accidents require continuous operation of high pressure injection, Kelly wondered what guidance, if any, should be given to the customers on when they could safely secure the high pressure injection system. He recommended some guidance that he considered to be appropriate. This proposed guidance stated:

> (a) Do not bypass or otherwise prevent the actuation of high/low pressure injection under any conditions except a normal, controlled plant shutdown.
> (b) Once high/low pressure injecton is initiated, do not stop it unless; T_{AVE} is stable or decreasing and pressurizer level is increasing and primary pressure is at least 1600 psig and increasing.[154]

This memo was sent to a distribution list of seven individuals in the management of the B&W organization in Lynchburg. Kelly has testified that the purpose of the memo was to raise an issue and initiate a dialogue because, although he had not reviewed the guidance, if any, that was being given at that time,[55] he felt uncertain, on the basis of the actions of the operators at Davis Besse, that B&W was giving the operators adequate guidance. The only response that Kelly received to his memo was a handwritten memo[156] from Frank Walters dated November 10, 1977.

Walters testified that he was not actively involved with the review of the September 24, 1977 incident at Davis Besse and, after receiving Kelly's memo, he conducted a superficial review of the Site Problem Report. He did not realize that steam had formed in the reactor coolant system, or that the high pressure injection system started automatically and was subsequently stopped by the operators during the initial parts of the transient. He now asserts that, in reviewing the transients, he thought that Kelly was referring to a sequence of events that began approximately 30 minutes after the incident began. During this sequence the operators manually started high pressure injection after they had shut the PORV block valve and then stopped high pressure injection when the plant had stabilized. He believed these actions were appropriate and saw no reasons for Kelly's concerns. Moreover, he felt that if Kelly's guidance was sent to the operators, there would be possible problems with the plant going solid and potential failure of the safety valves to reset, which would cause a loss-of-coolant accident.[157]

After reviewing the incident in more detail during the deposition conducted as part of this Special Inquiry, Walters agreed that the securing of high pressure injection by the operators during the initial phase of the transient was improper. He now feels that Kelly's concern about preventing similar improper operator action in the future is more significant than his concern about the plant going solid if high pressure injecton is allowed to continue to operate.[158]

As a result of his original review of Kelly's memo, Walters also believed the wording of the guidance proposed by Kelly was too complicated for the operators to understand and remember. He prepared a response on November 10, 1977, in which he stated that the operators at Toledo Edison responded correctly in view of their training. During

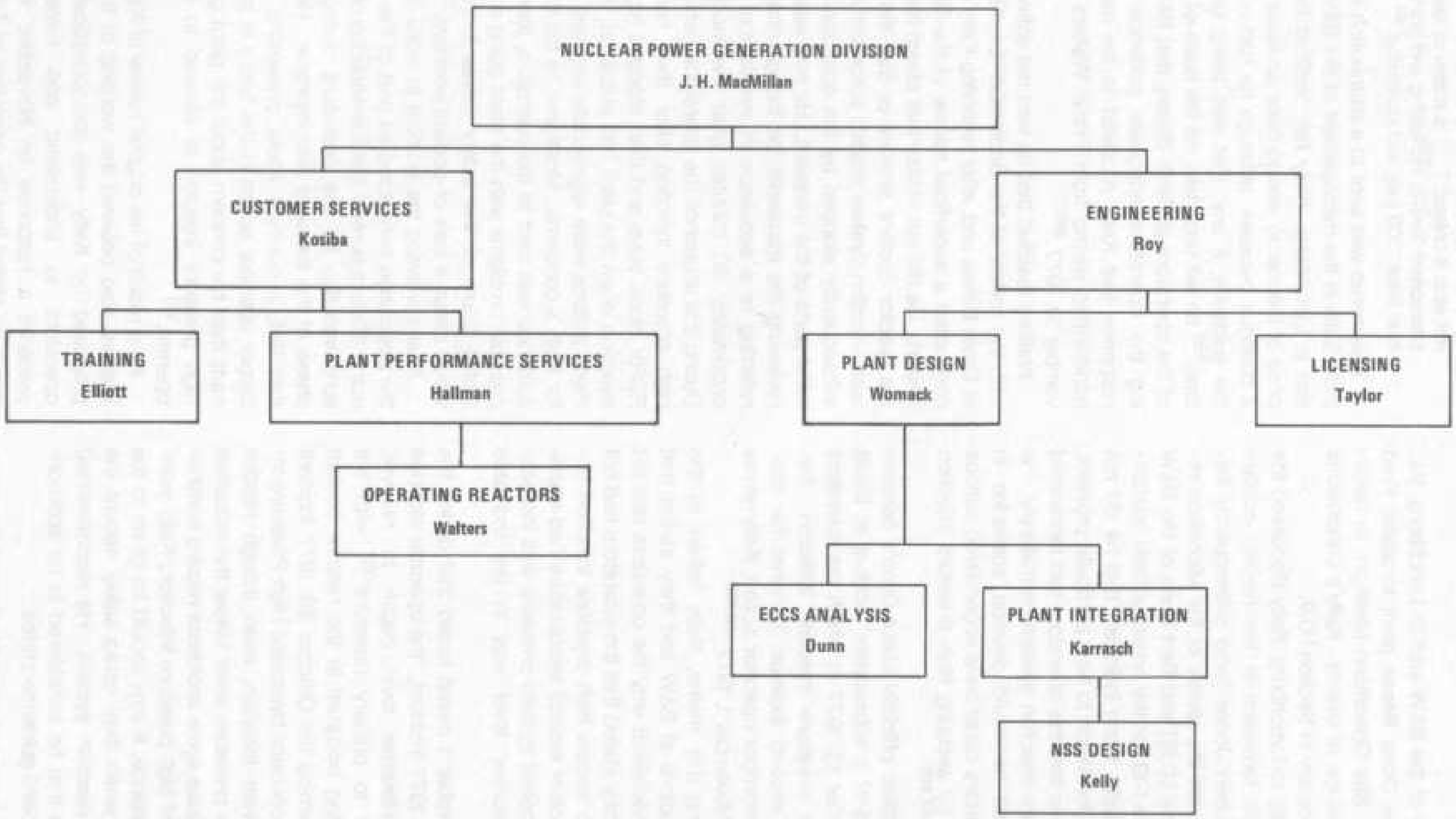

FIGURE I-10. B&W Organizational Relationships the incident at Toledo Edison there was no loss of coolant of magnitude and, in Walters' opinion, the operators would not be right to place the reactor coolant system in a solid condition every time the high pressure injection pumps initiate.

In addition to being confused by Walters' response, Kelly was troubled because he had not received a response from anyone other than Walters. However, he made no attempt to contact any of the individuals involved and he did not contact Walters. Instead he went to Dunn and recommended that Dunn write a memo escalating the issue[159]

Dunn's involvement had begun a month and half earlier when he attended the presentation given by Kelly. Dunn believed that the plant had responded as expected, but that the operators should not have secured high pressure injection when they did. He had discussed this matter with Kelly and Robert Jones and this discussion was the basis for Kelly's memo. Dunn and Kelly realized that little happened as a result of Kelly's memo.

In fact, Dunn believed that attention was not being paid to his concerns, and that this lack of action was

which Walters was a member. However, Dunn did not contact anyone to see why action was not being taken[160] Instead, he prepared a memo dated February 9, 1978,[161] and sent the memo to James Taylor. The memo was addressed to Taylor because Dunn felt that it may have involved a safety concern. Dunn has testified that he was prepared to write a preliminary safety concern notification in accordance with B&W procedures for formally raising safety concerns had he not subsequently been satisfied that his informal memorandum had worked[162] Such a preliminary safety concern would have been sent to Taylor for resolution.

Dunn's memo began with the statement, "This memo addresses a serious concern within ECCS Analysis about the potential for operator action to High Pressure Injection following the initial stage of a LOCA."[163]

Dunn continued,

> [T]he direct concern here rose out of the recent incident at Toledo. During the accident the operator terminated high pressure injection due to an apparent system recovery indicated by high level within the pressurizer. This action would have been acceptable only after the primary system had been in a subcooled state. Analysis of the data from the transient currently indicates that the system was in a two phase state and as such did not contain sufficient capacity to allow high pressure injection termination. This became evident at some 20 to 30 minutes following termination of injection when the pressurizer level again collapsed and injection had to be reinitiated. During the 20 to 30 minutes of noninjection flow they were continuously losing important fluid inventory even though the pressurizer indicated high level. I believe it is fortunate that Toledo was at an extremely low power and extremely low bumup. Had this event occurred in a reactor at full power with other than insignificant bumup, it is quite possible, perhaps probable, that core uncovery and possible fuel damage would have resulted. (Emphasis added.)

Dunn's memorandum stated that "the incident points out that we have not supplied sufficient information to reactor operators in the area of recovery from a LOCA."[165] Dunn also provided some specific recommendations for changes to the guidance to the licensees to be used in preparing operating procedures. This guidance recommended that operating procedures be written to allow for termination of high pressure injection only under the following two conditions:

> (1) Low pressure injection has been actuated and is flowing at a rate in excess of the high pressure injection capability and that situation has been stable for a period of time (10 minutes). (2) System pressure has recovered to normal operating pressure (2200 or 2250 psig) and system temperature within the hot leg is less than or equal to the normal operating condition (605"F to 630"F). *6

When Taylor received Dunn's memo, he referred the matter to the Customer Service Group which he felt could more appropriately respond to such a concern.[167] D.F. Hallman received the memo in Customer Service and referred the issue to Walters for resolution. Walters had the same reaction to Dunn's memo that he had to Kelly's memo. He was uneasy about the operators' understanding of the guidance proposed by Dunn, and the possibility of the plant going solid .[166]

Walters asked Gaslow of his staff to talk to Dunn about rewording the precaution to make it easier for the operators to understand. Gaslow contacted Dunn, and they developed a wording that was mutually acceptable. After his meeting with Gaslow, Dunn prepared a second memo to Taylor dated February 16, 1978.[169] In this memo, Dunn referenced his earlier memo and stated that Customer Services had recommended the following procedure for terminating high pressure injection following a LOCA:

> (1) Low pressure injection has been actuated and is flowing at a rate in excess of high pressure injection capability and that situation has been stable for a period of time (10 minutes). Same as previously stated. (2) At X minutes following the initiation of the high pressure injection, termination is allowed provided the hot leg temperature indication plus appropriate instrument error is more than 50'F below the saturation temperature corresponding to the

> reactor coolant system pressure less instrument error. X is a time lag to prevent the termination of the high pressure injection immediately following its initiation. It requires further work to define its specific value, but it is probable that 10 minutes will be adequate. The need for the delay is that normal operating conditions are within the above criteria and thus it is conceivable that the high pressure injection would be terminated during the initial phases of a small LOCA.

Dunn also noted in the memo that he found this scheme to be an acceptable method of preventing long-term problems. Kelly and Dunn have both testified that they believed that the issue had been resolved and that as a result of his February 16, 1978 memo the appropriate guidance would be forwarded to the utilities.[171,172] However, Walters did not consider that the issue was settled because the revised wording only resolved his doubts about the clarity of the guidance and did not resolve his concern about potential problems associated with going solid. He asked Gaslow to talk to Dunn again to resolve this second matter. However, because of higher priority work, this meeting never occurred.[173]

In August 1978, Walters wrote a memo[174] asking that Plant Integration resolve his concern. The memo was signed by Hallman, was addressed to Bruce Karrisch of Plant Integration, and included Dunn's February 9 and February 16 memos as references. The memo stated, "References 1 and 2 (attached) recommend a change in B&W's philosophy for HPI [High Pressure Injection] System use during low-pressure transients."[175] The memo also noted that the references suggest the possibility of uncovering the core if present HPI policy is continued. The memo went on to say that Nuclear Service (i.e., Customer Service) believed that the recommended change could cause the reactor coolant system, including the pressurizer, to go solid. The memo suggested that the following questions be evaluated:

> (1)... the pressurizer goes solid with one or more HPI pumps continuing to operate, would there be a pressure spike before the reliefs open which would cause damage to the RCS [Reactor Coolant System]. (2) What damage would the water surge through the relief valve discharge piping and quench tank cause?[176]

Hallman concluded the memo with the statement "We request that Integration resolve the issue of how the HPI system should be used. We are available to help as needed."[177]

Although Dunn was included on the distribution of this memo[140] he has testified that he does not recall receiving it. His explanation for this disparity is that either he did not actually receive the memo or, if he received it, he did not recognize its significance.[178]

Karrisch's involvement with this matter began with attendance at the briefing given by Kelly. However, Karrisch does not remember the details of the incident. In addition, although Kelly works for Karrisch and included him on the distribution for his November 1, 1977 memo, Karrisch does not recall receiving it. He also does not recall seeing either of Dunn's memoranda which were attached to Hallman's memo. Karrisch does recall receiving Hallman's memo and he recalls noting the two specific questions that were asked, specifically the questions associated with the pressure spike and with the water surge. However, he did not notice that the memo requested that he, representing Plant Integration, resolve the issue of how the high pressure injection system should be used.[179]

Karrisch recalls sending the memo to someone for action, but he cannot remember whom. After the TMI accident, he talked to the two people to whom he would have sent the memo, and they do not recall seeing it. Karrisch was contacted several times by Hallman concerning the memo, and in early 1979 Karrisch again reviewed the memo himself. At this time he again did not realize that the memo requested that he resolve the broader issue of how high pressure injection should be used, but only noted the two specific questions concerning the implications of the plant going solid. He did not review the two memos from Dunn that were referenced in the Hallman memo.[180]

When he did undertake the review of the Hallman memo in early 1979, Karrisch recalled work that had been done in the fall of 1978 as part of the analysis of the generic issue associated with anticipated transients without scram (ATWS). As part of this study, considerable work had been done regarding the implications of expected water surges through the safety valves. This work had shown that even though the safety valves and associated piping were not qualified for water relief, water relief was an acceptable condition for those valves.[181] Therefore, Karrisch did not see any difficulty associated with the two specific questions raised by Hallman's memo. He responded verbally to Hallman in February or early March of 1979 in a very short and informall discussion.[182,183] Karrisch believed that Hallman acknowledged that he (Karrisch) had answered Hallman's questions.[184]

Hallman recalls receiving a response from Karrisch to the effect of, "I don't think there is a problem." Later he realized that this response could be interpreted in one of two ways: (1) issuing the guidance proposed by Dunn was not a problem; or (2) Dunn's concerns were not valid and therefore, the guidance did not need to be issued. Hallman then tried to contact Karrisch but was unsuccessful before the accident at TMI.[185]

Although Kelly who started this whole sequence, works for Karrisch, Kelly was not involved or made aware of this exchange.[186,187]

Hallman has stated that in the course of his review of this issue, he thought that Kelly and Dunn were simply concerned that the operators had not raised reactor coolant system pressure high enough before securing HPI. He did not realize that the operators secured high pressure injection on the basis of high pressurizer level caused by boiling in the reactor coolant system. He has stated that if he had recognized this fact he probably would have escalated the issue to his superiors and pressed Karrisch harder to resolve it.[188]

The strong wording used by Dunn should have impressed Hallman with its significance; but apparently it did not. Considering this strong wording in Dunn's memo, it is hard to understand how the realization described above would have caused more aggressive pursuit of this issue.

It must be emphasized that Kelly, Dunn, and Jones have testified that they did not realize that this exchange between Hallman and Karrisch was taking place. The three subordinate engineers have all testified that it was their understanding that, following the February 16, 1978 memo from Dunn to Taylor, fhe appropriate guidance was mutually acceptable to all of the parties involved and would be shortly sent to the utilities. It was not until after the accident at TMI-2 that they found that this guidance had not been sent.[189-191]

Specific Conclusions

1. Kelly and Dunn identified issues that, had they been resolved, would have provided pertinent, meaningful guidance to the operators at TMI-2 and might have prevented them from taking the actions that ultimately resulted in substantial damage.
2. A lack of communication may have existed between Kelly and Dunn on the one hand, and various members of the Customer Services Group at B&W on the other. As a result, a crucial misunderstanding regarding precisely what operator actions had caused Kelly's and Dunn's concerns may have developed and was never resolved. Consequently, representatives of the Customer Service group and the Plant Integration Group continued to debate the merits of the operator actions, when, in fact, it appears they may have been talking about two entirely different sets of operator actions.
3. On one occasion, Dunn and a representative of the Customer Service group, did meet to discuss the concerns, and Dunn understood that the problems had been resolved. After the accident at TMI-2, Dunn found that these problems had not been resolved and that the guidance he proposed had not been forwarded to the utility. A significant point is that Kelly, Dunn, and Jones all mistakenly believed that in early 1978, the guidance that they had proposed had been sent to the utilities. It was not until after the accident at Three Mile Island that they found out that this was not correct, and that the guidance had never been sent.
4. An additional breakdown of communications occurred between the Customer Services Group and the Plant Integration Group. Customer Services forwarded a memo, unknown to Kelly and Dunn, to Plant Integration requesting that the concerns about the plant going solid and the overall issue of how the high pressure injection system should be operated be resolved. This resolution never happened, and no evidence exists as to whom the memo was sent for action. Eventually, Karrisch in Plant Integration did resolve the two specific questions about the implications of the plant going solid. However, he did not communicate this resolution to Customer Services effectively. At no time did Karrisch realize that he had been asked to review the overall operation of the high pressure injection system and therefore, he did not provide a response concerning this issue. Furthermore, he apparently did not recognize that the issue that he had been asked to resolve had been initiated by one of his employees (Kelly) and Kelly was ever aware that Karrisch had been asked to resolve his concern.
5. The Special Inquiry concludes that the failure of B&W to provide the guidance recommended by Kelly and Dunn was primarily the result of a gross failure by several individuals, including Kelly and Dunn, to communicate effectively, and ineffective management practices that resulted in this issue not being adequately addressed. No evidence of a conscious effort to suppress the concerns raised by these engineers was found.

11. PEBBLE SPRINGS ACRS QUESTIONS-NOVEMBER 1977

In November 1977 Jesse Ebersole of the NRC Advisory Committee on Reactor Safeguards (ACRS) prepared a set of 26 questions that were eventually forwarded to the Portland General Electric Company for response during the ACRS review of the Pebble Springs application. Three questions are relevant to this Special Inquiry because they were either related to the TMI accident or they were based on the Michelson report, which Ebersole had received in September 1977, or both (see Section I.C.8). These questions were forwarded to the NRC staff by a memo dated November 7, 1977.[192] The memo forwarding these concerns began with a statement that, "attached are questions raised by an ACRS member, to which the Pebble Springs subcommittee would like written responses prior to the ACRS full Committee review of that project."[193]

The first.question that is relevant to this Special Inquiry was based on the Michelson report. The question, number 6, stated:

> Does applicant know that time-dependent levels *will* occur in pressurizer, steam generator and reactor vessel after a relatively small primary coolant break which causes coolant to approach or even partly uncover fuel pins? *What does operator do in respect to interpreting level in pressurizer?* [Emphasis added.]
>
> During primary system refill from high pressure injection pumps there is some period when neither condensation nor natural convection is present to effect heat transport to secondary side. How is transition to natural convection *without assistance from primary coolant pumps obtained*.[194]

The second question based on the Michelson report is question 12, which stated:

> What is status of investigation of merits of a primary vessel coolant level indication system for use in post LOCA cooling for small breaks?[195]

The third relevant question is not directly related to the Michelson report but is related to the accident at TMI. This question, number 26, asked:

> Considering such matters as (1) offsite power failure, (2) condenser vacuum failure, (3) spurious main feed water valve closure (see Item 21 preceding) and recent incidents of failures in auxiliary feed water system it appears that, single failure criteria notwithstanding, at least short term failures of the auxiliary feed water system must be considered to estimate the needed availability of such system.
>
> What, for instance, would be the peak primary system pressure, consequences to primary coolant system safety and relief valves and rate of primary coolant loss following failure of the Auxiliary Feedwater pumps when needed?196

These questions were initially distributed to the NRC staff by the Division of Project Management in NRR with a request that written responses be provided to the licensing project manager no later than November 30, 1977, for possible incorporation into a formal reply.197,198

It was subsequently decided that rather than having the staff prepare responses, the questions would be forwarded to the applicant for the Pebble Springs license, Portland General Electric Company. **The questions were sent to Portland General Electric** by letter dated November 21, 1977.[199] The responses to the questions, which were prepared by B&W for Portland General Electric Company, were provided to the staff for subsequent forwarding to the ACRS by letter dated November 30, 1977.[200]

These responses, which total approximately 52 pages, (less the 10 pages required to restate the questions) were prepared in less than 10 days. The response relative to question 6 included approximately three pages that detailed how the reactor coolant system would react during the transients described. This analysis concluded that uncovering of the core would not take place, and therefore the issue was not a problem. The pressurizer is not mentioned in this response, and the question relating to "What does operator do in respect to interpreting level in pressurizer?"[201] was not addressed.[202]

Bert Dunn of B&W, who prepared the response to question 6, testified that he had had a continuing discussion of these general issues associated with small breaks with Ebersole. In his approach to question 6, he attempted to respond to his understanding of Ebersole's general concerns, rather than responding to the specific questions asked. He did not realize that he had not responded to one of the questions, the question associated with operator interpretation of pressurizer level.[203]

Dunn also testified that he did not connect Ebersole's question about operator interpretation of pressurizer level with the issues that he and Kelly had raised about securing of high pressure injection by the operators during the Davis Besse incident on September 24, 1977[204] (see Section I.C.10).

When the questions and responses were received from B&W through Portland General Electric Company, they were reviewed by Scott Newberry of the NRC's Reactor Systems Branch. He testified that he perceived that he was responsible to be familiar with the material and to discuss the responses at the ACRS meeting. He did not review the response to question 6 in detail because he felt that any questions associated with small breaks would be addressed by Sanford Israel (also of the NRC's Reactor System Branch), who was the staff member who customarily responded to questions about small-break LOCAs.[205]

With respect to the other questions that are relevant to this Special Inquiry, the response to question 12 stated:

> B&W is no longer considering the use of primary vessel coolant level indication systems. Present analyses show that adequate system protection is provided by existing equipment and sensor design. For the specific case of small breaks in the primary **system, please note** *the* **response of Question** *6.*[206]

For question 26, the answer concluded that the Pebble Springs design complied with the latest NRC requirements. However, a preliminary analysis of the event sequence assuming that all feedwater was lost simultaneously was provided. The significant points in this scenario were as follows: at approximately 10 seconds into the event the pressurizer begins to relieve decay heat by way of the safety valves; at approximately 2 minutes the reactor coolant system expansion causes the pressurizer to become water solid; at approximately 10 minutes the high pressure injection initiates as a result of high containment pressure; and at approximately 45 minutes high pressure injection heat removal equals decay heat removal. However, boiling does occur in the core, but stops before the end of the postulated scenario (i.e., at approximately 45 minutes). A coolable geometry is maintained throughout and the long term cooling is provided by the high pressure injection system. [207]

After the responses from Portland General Electric were received, a meeting was held within the NRC to decide on the staff's position. A firm technical stand was not taken because the applicant's analysis was not provided in detail; therefore, the staff felt it could not review the work in detail. The staff did not feel that they had the responsibility to review the responses to the same extent as if the questions had been originated by the NRC staff rather than by the ACRS. Furthermore, some of the questions went beyond what the staff would normally require in its review (e.g., more than a single failure). [208] Consequently, the responses were forwarded to the ACRS without comment.

The responses were subsequently discussed at a full ACRS committee meeting in January 1978. During this meeting, Ebersole noted that the parties involved had done a good job and had been responslue to the questions asked. [209] A lengthy discussion of the various questions was conducted which included specific reference to question 6. Ebersole again raised the issue of how the operators would interpret pressurizer level. The initial argument was that this subject would be covered in their training. However, Ebersole stated that he thought this event would not be accurately simulated by the simulator used for operator training. This assertion was not challenged by any individual at the meeting. No subsequent discussion of this issue was conducted, [210] and the meeting proceeded to the next question.

The NRC representatives involved with this ACRS meeting generally do not recall the discussion of operator interpretation of pressurizer level. Their overall impression was that the ACRS discussion did not raise any concerns. In addition, they presumed that the response satisfied Ebersole, so they did not carry the issue any further. Because the emphasis of the NRC review is on design of systems, the reviewers normally do not review what the operators see or do, and are generally not concerned with how the operator would interpret certain plant conditions. [212] This situation may explain why the NRC staff did not recognize this issue.

Representatives of B&W were also in attendance at this ACRS meeting, but the concern about operafor interpretation of pressurizer level was not identified by B&W's internal review of issues raised during ACRS meetings as an issue requiring further analysis. This oversight is probably due to the fact that throughout the licensing process, the emphasis at B&W has also been on the design analysis and engineering aspects. Items related to the operator and the operating procedures do not get the same level of attention within B&W as items related to system design. [213]

Ebersole testified that he realized during the ACRS meeting that he had not received an answer to his question about operator interpretation of pressurizer level. He did not make a major issue of this fact. He took comfort in the fact that he had exposed the issue to all the participants at the ACRS meeting. Furthermore, he knew that Michelson was pursuing the matter separately with BMW [214]

As is its normal practice, the ACRS in January 1978 wrote a letter to the Chairman of the NRC describing its review of the Pebble Springs application. [215] This letter did not cite any of the 26 questions or responses as outstanding items requiring additional review. The letter did cite the Portland General Electric response as a reference and noted that the 26 questions had been raised by Ebersole and responded to by Portland General Electric. The letter also noted that Steve Varga of the NRC staff had said that the NRC found nothing in the responses to alter the staff's conclusions. [216]

The Atomic Safety and Licensing Board for Pebble Springs also raised the issue of the ACRS questions in a prehearing conference on April 12, 1978. A specific question was:

> Has the staff reviewed the November 30, 1977 applicant's response to a series of questions raised by the ACRS? Are there any unresolved questions at this time? Can construction proceed pending a resolution? Are all of them included in the staff's list of unresolved items? [217]

In its reply, the NRC staff stated that they had reviewed the applicant's responses and found nothing that would change the evaluation as recorded in the Safety Evaluation Report and the four supplements. The staff noted that the majority of the questions had sought additional clarification of specific items of interest, and some posed assumptions and scenarios that exceeded those criteria necessary for the protection of the health and safety of the public. The staff concluded that they agreed with the applicant that the system was designed in accordance with NRC requirements. Finally, the reply to the licensing board noted that the January 12, 1978 letter from the ACRS indicated that the Committee was satisfied with the applicant's responses including additional information provided by the staff and applicant at the Pebble Springs ACRS review meeting.[218]

Specific Conclusions

1. Two of the three questions that are relevant to this Special Inquiry, were prepared as a direct result of Ebersole's review of the Michelson report (see Section I.C.8).
2. Although the questions were specifically addressed to the staff, the staff chose to send the questions to the utility for response. The utility subsequently sent the questions to B&W, and B&W eventually prepared the response that was forwarded to the ACRS.
3. Question 6 was actually a collection of several questions. B&W attempted to respond to their overall perception of Ebersole's concern about the small-break LOCAs rather than trying to respond to the specific questions that were asked in question 6. Consequently, one question, "What does operator do in respect to interpreting levels in pressurizer?" was not recognized by B&W and was not answered. This deficiency was not noted by either the applicant (Portland General Electric Company) or by the NRC staff in their review of the responses.
4. Ebersole discerned that the question about operator interpretation of pressurizer level had not been answered in the formal response provided. Therefore, he asked a related question during the ACRS full committee meeting on Pebble Springs. Ebersole still received an unsatisfactory response, but he did not pursue the matter because he felt that he had adequately exposed the issue in the written questions and in the ACRS full committee meeting.
5. The NRC staff and the B&W staff that attended the meeting did not identify the issue of pressurizer level and operator interpretation as warranting additional evaluation. Thus, this concern ended at this point and was never subsequently raised.
6. The ACRS letter for Pebble Springs cited the responses prepared by B&W as a reference. However, the responses were not mentioned in the body of the ACRS letter, and no indication was given that any of the issues raised, either in the questions or in the responses, required further evaluation.

12. CRESWELL CONCERNS-DECEMBER 1977

Throughout 1978 and 1979, an IE Region III inspector, James Creswell, raised concerns associated with the Davis Besse nuclear powerplant that had some relevance to the accident at TMI-2. Creswell's involvement with Davis Besse began in August 1977. He was assigned to inspect the facility during startup and was subsequently assigned to inspect its power ascension program. Creswell, however, was not the Principal Inspector for Davis Besse at any time. The portion of Creswell's involvement with Davis Besse that is relevant to this inquiry began following an incident at Davis Besse on November 29,1977.

While preparing for a test with the plant operating at 40% power, the operators plugged a reactimeter patch panel into the plant's instrumentation system. Because of a short circuit in the panel, the unit demand signal was shorted and produced an erroneous demand signal of 62.5%. Power started to ramp from 40% to 62.5%, but the reactor tripped as designed at 50% power. When the reactor tripped, the turbine automatically tripped. Because of an error in the plant procedure, the operator tripped the generator output breakers. The generator output breakers would have tripped automatically 30 seconds after the turbine tripped. Because the output breakers were manually tripped rather than automatically tripped, house power loads were not automatically transferred to offsite power. This situation resulted in a total loss of ac power in the station, which tripped the reactor coolant pumps and started the diesels. One diesel operated properly but one tripped on overspeed. After the reactor coolant pumps stopped, the plant was cooled using natural circulation. Subsequently, power was restored and the plant was returned to normal operation.

This incident was reviewed by the NRC Office of Inspection and Enforcement, the B&W organization, and the Toledo Edison organization. The B&W personnel at the plant described the event in Site Problem Report No. 396.[219] However, no significant issues were raised. Toledo Edison's principal concerns centered on the error in the procedure that allowed the operator to trip the generator output breakers rather than waiting for the automatic trip, and on the reason for the failure of the diesel generator. In IE Inspection Report 50-346/77-34,[220] the conclusions were that (1) the incident was caused by a short in the patch panel; (2) the loss of offsite power was due in part to procedure inadequacy and operator error; (3) the diesel generator tripped on overspeed; and (4) the temperature-pressure transient was reviewed by B&W who concluded that it was bounded by existing analyses.

In December 1977, Toledo Edison raised the possibility that the November 29 incident might be used in place of a required natural circulation test. This possibility was considered by B&W; however, B&W concluded that the data were incomplete and they could not approve the transient as a satisfactory test of natural circulation.[221]

Toledo Edison subsequently requested that the NRC consider the possibility of using the data from the November 29th event in place of the natural circulation test. A meeting was held with the NRC on February 7, 1978 to discuss this issue. Toledo Edison argued that although the data did not specifically meet the requirements of the natural circulation test, the 3 days at low power required to conduct the test were not justified by the benefits to be gained because the elevated steam generators at Davis Besse would produce more flow than that observed at an earlier natural circulation test at the Oconee Plant.[222] In a letter from the NRC on February 16, 1978[223], the conclusion was that the natural circulation test must be run at Davis Besse, but Davis Besse was allowed to proceed to 100% power with the condition that the test be conducted within 120 days.

Because of the Toledo Edison request, the Principal Inspector for Davis Besse, Thomas Tambling, asked Creswell to go to the site and review the data to determine what the IE Region III position was with respect to its adequacy. When Creswell arrived at the site, he requested the plot of various parameters during the transient and found that a plot of pressurizer level was not provided. He requested that plot and subsequently received it. This plot showed that pressurizer level had gone offscale low for some period of time during the event. Consequently, he asked that calculations be done to determine the minimum pressurizer level that existed during the incident because he was concerned that possibly the pressurizer had emptied during the event. In early March 1978 he received calculations from Toledo Edison that indicated that the pressurizer had not completely emptied and that the actual level in the pressurizer was 9 inches below the lowest range of the pressurizer level indication (this lowest level indication is approximately 75 inches above the bottom of the pressurizer).

Creswell was concerned that the pressurizer level decrease would necessitate securing the heaters in the pressurizer and this action would make pressure control in the reactor cooling system more difficult. Moreover, the loss of level indication would make it difficult for the operators to determine the reactor coolant system inventory, and the actual emptying of the pressurizer would result in void formation in the reactor coolant system.[224]

Creswell was also concerned that under worse conditions, the results of this particular transient could have been more severe. The specific conditions that he believed could exacerbate the situation were: (1) both auxiliary feedwater pumps should have come on simultaneously during the incident (one auxiliary feed pump did not come up to full speed because of mechanical failure in the governor and therefore did not inject cold water into one of the steam generators for several minutes during the actual event) (i.e., the incident would have been more severe if the plant had responded as designed); (2) the plant could have been at a higher power level, a situation that would have caused a greater amount of decay heat to be put into the reactor coolant system; and (3) the steam generator safety valves that normally lift during an event such as this could have caused the steam generator pressure to decrease even further (such a decrease would result in a greater cooldown of the reactor coolant system and a greater contraction of the reactor coolant system inventory).[225]

Creswell reported his conclusions in an Inspection Report (No. 50-346/78-06) dated April 20, 1978.[226] He concluded that the November 29 event did not meet the requirements for natural circulation and noted that NRR had reviewed this issue and agreed by letter dated February 16, 1978. He also noted that pressurizer level indication had gone offscale low for approximately 5 minutes. He stated that the licensee later provided an analysis that showed that the pressurizer level fell to approximately 9 inches below the lowest level indication. Creswell continued to pursue the issue of pressurizer level because of his concern that the transient might have been worse under different conditions and because he was not sure whether the incident had been conservatively bounded by existing analysis.[227]

While Creswell was discussing this issue with Toledo Edison, additional discussions of this issue were carried on between Toledo Edison and B&W and internally within both organizations. As early as November 1976, B&W had forwarded a letter[228] to Davis Besse that included specific recommendations for avoiding pressurizer offscale-low indication. These recommendations included (1) raising the nominal pressurizer level, (2) readjusting the steam generator safety valve blowdown, and (3) raising the pressurizer low level alarm. Following the incident on November 29, 1977, Toledo Edison had begun to address possible actions that could be taken to prevent the loss of pressurizer level during such an event. One possibility, leaving the makeup pumps on during a loss of offsite power, was recommended in a memo dated December 16, 1977.[229] That memo also noted that B&W had been consulted with respect to this matter to determine if Toledo Edison was maintaining too high a level in the steam generators. This memo also made an interesting observation that at no time during the event did steam generator pressure go high enough to lift the steam generator safety valves. This comment is inconsistent with discussions elsewhere that excessive blowdown by the steam generator safety valves caused the overcooling and contraction of the reactor coolant system and the excessive reduction of pressurizer level. Internal B&W memos, including one dated February 10, 1978,[230] noted that decreasing pressurizer level offscale low was indicative of steam generator level increases due to auxiliary feedwater. This memo described this effect as undesirable and noted that conversations with Fred Miller of Toledo Edison indicated Toledo Edison's desire to have this situation corrected.

In late 1977, Toledo Edison revised its operating procedures on the basis of natural circulation test results and instructed the operators to maintain the steam generator level at 35 inches. In late 1978, however, B&W recognized that this corrective action was improper. Toledo Edison's desire to reduce steam generator level for maintenance of indicated pressurizer level conflicted with B&W's need to maintain a steam generator level of at least 120 inches because that was the lowest level that B&W felt could be maintained based on the small-break LOCH analysis. By memo dated November 28, 1978,[231] Toledo Edison notified IE Region III that they had identified the procedure change that could have led to steam generator level in violation of the small-break LOCA analysis. Specifically, Emergency Procedure 1202.26 directed the operator to take action to maintain steam generator level below 120 inches even if a small break occurred. This memo noted that a procedure was being revised. This fact was also reported to IE Region III in LER 78-115 dated December 8, 1975.[232]

The eventual solution to this problem of low pressurizer level was a dual level setpoint that would maintain 35 inches in the steam generators during events other than a LOCA and 120 inches during a LOCH. B&W and Toledo Edison agreed that the proposed solution would allow safe operation without safety analysis violations.[233] This solution was formally submitted to the NRC (NRR) by letter dated December 11, 1978.[2]

During this period, Creswell continued to pursue his concern about loss of pressurizer level. In a memo from Creswell to his supervisor, John Streeter, dated August 14,1978,[235] Creswell recommended that during a subsequent meeting between the Davis Besse management and the IE Region III management, an issue that should be discussed was the need to complete technical evaluations in a timely manner. As a specific example, Creswell cited the loss of pressurizer level conditions discovered early in 1978.

During this period, B&W was conducting additional analyses to address the issues of loss of pressurizer indication and voiding of the pressurizer. In a report dated August 31, 1978, "Dynamic Performance of the Pressurizer During Reactor Trip at Davis-Besse 1,"[236] the conclusions were that the loss of pressurizer level indication would occur if the steam generator pressure decreased to 950 psig, and the emptying of the pressurizer would occur if steam generator pressure decreased to 850 psig. However, the report noted that the minimum expected steam generator pressure for future reactor trips would be 980 psig. This minimum pressure was higher than the pressure experienced during the November 29, 1977 event because the steam generator safety valves had been adjusted to a higher minimum pressure as a result of that event. This report indicated that during the November 29 event, the level in the pressurizer was 32 inches below the lowest level indication, which was considerably below the original estimate of 9 inches below the lowest indication. However, this level was still 43 inches above the bottom of the pressurizer.

The report stated that, to limit steam generator pressure during this event, the rate of fill of the steam generators with auxiliary feedwater must be controlled by the operator. The maximum fill rate should be limited to 850 gallons per minute instead of the existing 1200 gallons per minute that occurred during the November 29 event.

Creswell discussed these analyses with Toledo Edison on September 8, 1978.[237] Creswell noted several matters based on these analyses. First, he was concerned because the minimum pressurizer level during the November 29 event was found to be not 9 inches but 32 inches below the lowest level indication as a result of new calculations; and second, he was concerned that the people performing these calculations seemed to be unable to predict the actual minimum pressurizer level accurately. He also felt that the analysis should have assumed no makeup flow because makeup flow would be lost in a loss of offsite power.[238] These revised calculations were subsequently prepared and given to Creswell during an inspection beginning on October 31, 1978.[2]

Because of his review and interest in the November 29 event and his concern about voiding of the pressurizer and saturation conditions in the reactor coolant system, Creswell attempted to determine if any events had occurred at Davis Besse in which voiding or saturation had actually occurred.[24o] In late summer of 1978, Creswell reviewed the analyses of the September 24, 1977 incident at Davis Besse (see Section I.C.9) during which saturation conditions had occurred in the reactor coolant system. Creswell noted that the operators had secured the high pressure injection pumps while the loss-of-coolant accident continued. He considered this operator action to be improper, and he discussed this matter with several people, including Fred Miller of Toledo Edison's engineering staff, and Streeter, his supervisor at IE Region 111.241

This problem of the operators securing the high pressure injection was documented in Inspection Report No. 50-346/78-27 dated October 25, 1978, which was based on an inspection by Creswell on September 5-8,1978.[242] In this report it was noted that the licensee was reviewing the operator action of blocking the safety features actuation system logic and securing high pressure injection before discovering the cause of the loss of reactor coolant.

Apparently Miller and Streeter shared his concerns. Miller and Streeter separately discussed this matter with Terry Murray, the Station Superintendent at Davis Besse.24a,[244] Initially, Murray did not agree that the operators had performed incorrectly, and he argued that their actions were proper because pressurizes level was increasing. However, after some discussion it was decided that a change in the procedures for operation of the high pressure injection system at Davis Besse should be made. This change was subsequently reviewed by the Site Review Board on September 15, 1978, and the deck sion was made to change the procedure.245 A Temporary Modification Request for Emergency Procedure 1202.06, Section 2.4.3, was subsequently approved by Toledo Edison on November 14, 1978[246] This change included a note which stated, "Prior to securing high pressure injection, insure that a leak does not exist in the pressurizer such as a safety valve or an electromagnetic relief value stuck open."[247] These changes were reviewed by Streeter and Creswell,[248,249] and the wording was subsequently modified based on additional recommendations by Creswell and Streeter. By January 1979 the wording of this note had evolved to read:

> NOTE: Prior to securing HPI, insure that a leak does not exist in the pressurizer such as a safety valve or an electromagnetic relief valve stuck open. A minimum decay heat flow of 2800 gpm is required prior to securing HPI. If the leak has been isolated, the HPI Pump can be shutdown after RCS ppump r increases above the shutoff head of the

Unlike other B&W plants which have HPI pumps with a shutoff head above the safety valve set point, the shutoff head of the HPI pumps at Davis Besse is approximately 1700 psig.

Although the issue was resolved at Davis Besse, the generic implications of this issue were never addressed. There is no evidence that any of the parties involved proposed that the amplification in the Davis **Besse** procedure should be referred to other utilities, to B&W, or to the NRC headquarters.

Creswell continued to be actively involved in his separate concern about low pressurizer level during the November 29, 1977 event. In early December 1978, in a phone conversation with a Toledo Edison staff member, Streeter was informed that under certain worst-case conditions it was possible to cornpletely void the pressurizer during a loss of feedwater event. This information was contrary to Streeter's and Creswell's perception of previous statements by Toledo Edison to the effect that, under worst-case conditions, the pressurizer could not void during a severe cooldown event.251,252 Because of this new information, Creswell prepared a memo Streeter to Streeter's supe2 sor, Gaston Fiorelli,through , dated December 19, 1978, in which Creswell stated his concern about the performane of Davis Besse because of the possibility of voiding the pressurizes and noted that this new information raised the spector of an unreviewed safety issue. He requested that an investigation be conducted. The memo stated:

> I feel that the NRC should conduct a thorough investigation of this matter to determine when the issue of pressurizer voiding was first identified, who identified it (B&W or TECo) and if the issue was property reported per the requirements of Part 21. In addition, the licensee's performance regarding any corrective action associated with the issue should be examined in light of regulatory requirements.[254]

In a separate memo to Streeter on the same date,[255] Creswell noted that it still required an inordinate amount of time for Davis Besse to complete technical evaluations, and that this lack of timely evaluation could result in unsafe operation. Creswell recommended in this memo that a course of action be developed to resolve this problem and it be conveyed to Toledo Edison. Streeter requested on December 20, 1978[256] and Creswell provided on January 29, 1979,[257] a list of specific examples documented in inspection reports of failures on the part of Toledo Edison to provide timely evaluation of technical issues.

Streeter subsequently initiated an investigation of Creswell's concerns and assigned Joel Kohler and James Foster from IE Region III to conduct the investigation. Creswell had indicated to Streeter that he wanted to participate actively in the investigation.[258] Streeter has testified that he decided, however, that he wanted a more objective review of the issues by individuals who had not been actively involved in earlier reviews.[259]

At the same time, Toledo Edison and the NRC Office of Nuclear Reactor Regulation had been discussing a dual level setpoint that was designed to minimize or prevent problems with loss of pressurizer level indication and voiding of the pressurizer. The dual level setpoint was formally proposed to NRR in a letter dated December 11, 1978.[2] The letter concluded that the proposal did not involve an unreviewed safety question because the 120-inch steam generator level was only required for a small-break LOCA, and the 35-inch steam genera-for level was required to maintain pressurizer level indication during transients in accordance with General Design Criterion 13.

The information provided by Toledo Edison to the NRC concerning the dual level setpoint was supplemented by an additional analysis provided in a letter dated December 22, 1978.[261] This supplemental analysis included a consideration of the transient resulting from the inability of the operator to control steam generator level at 35 inches. This December 22, 1978 letter concluded that, during a loss of offsite power with no makeup flow, the pressurizer level would be slightly above the outlet to the surge line; however, during a loss of feedwater, the pressurizer would empty and the high pressure injection system would initiate.[262] The supplemental analysis stated that any steam voids that entered the reactor coolant system would not collect and no flow blockage would occur because forced flow would continue. This letter concluded that there were no unreviewed safety questions associated with this issue.[263]

At a conference call on December 23, 1978, representatives of the NRR, IE, B&W, and Toledo Edison concluded that no fuel damage would result from the issue raised in this matter. Therefore, they concluded that this matter did not constitute an unreviewed safety question.[264]

Although there is considerable confusion as to exactly what was reviewed and what was concluded by NRR, it would appear that within IE it was believed that NRR considered that voiding of the pressurizer during overcooling events was not a problem.[265,266]

This perception does not appear to be entirely consistent with NRR's actual conclusions. Seymour Weiss, whose branch in the Division of Operating Reactors (NRR), reviewed the dual level setpoint, has testified that if it had been at all conceivable that the licensee could empty the pressurizer, that would have constituted an unreviewed safety issue. However, Weiss has also testified that it was his understanding that although there would be a loss of level indication with the dual level setpoint installed, the pressurizer would not empty. He has also testified that his branch reviewed the analysis supporting this conclusion and found it to be correct.[267] It would therefore appear that NRR Gonsidered voiding the pressurizer to be an unreviewed safety issue but in the case of Davis Besse and events such as the November 29, 1977 incident, this was a moot point because of the proposed dual level setpoint.

On January 8, 1979, Creswell prepared a memo in which he requested that information be conveyed to licensing boards for certain plants (Midland and Davis Besse) still under licensing review.[268] Several issues were raised in this request. The issue relevant to this Special Inquiry stated:

> Inspection and Enforcement Report 50-346/78-06 documented that pressurizes level had gone offscafe for approximately five minutes during the No- 29,1977 loss of offsite power event. There are some indications that other B&W plants may have problems maintaining pressurizer level indications during transients. In addition, under certain conditions such as loss of feedwater at 100% power with the reactor coolant pumps running the pressurizer may void completely. A special analysis has been performed concerning this event. This analysis is attached as Enclosure 1. Because of pressurizer level maintenance problems, the sizing of the pressurizer may require further review. Also noted offsca le(le than event was the fact that Tom went le (less han 520°F). In addition, it was noted that the makeup flow monitoring is limited to less than 160 gallons per minute and that makeup flow may be substantially greater than this value. This information should be examined in light of the requirements of General Design Criterion 13.m

Creswell has testified that he requested this board notification in the hope that either the licensing board or a technically competent intervenor group would pick up on the issues that he had raised and address them in the forum of a licensing board hearing.[270] These matters were subsequently reviewed by IE, which decided that they did not warrant reporting to the licensing board.[271] However, Creswell insisted that the matter be referred to the licensing board[272] and, in accordance with IE procedures, the matter was forwarded on March 29, 1979, the day following the TMI accident.[273]

Tracing the path of Creswell's board notification begins with his preparation of the Board Notification request on January 8, 1979. IE Region III forwarded the request to IE headquarters by memo dated January 19, 1979.[274] This memo noted that IE Region III did not know the significance of the information as it may have affected staff positions, but they believed that NRC policy required that the information be forwarded to appropriate licensing boards.[275] By memo dated February 28, 1979, Norman Moseley (IE headquarters) informed Dudley Thompson (IE headquarters) that based on his preliminary evaluation, including discussions with Creswell, the items in Creswell's request did not meet the criteria for board notification. Despite this, Moseley noted in his memo that IE Manual, chapter 1530 required that the information be forwarded to the licensing boards if, as was the case here, the originator of the request persisted in his desire to have the material forwarded. Moseley also agreed to provide a written evaluation of the items contained in the request within 7 days.[276] By memo dated March 1, 1979, Thompson forwarded the request to Domenic Vassallo (NRR, Division of Project Management) for determination of the applicability of the items contained in the request. Vassallo forwarded the package to Edward Christenbury (NRC, Office of the Executive Legal Director) in a memo dated March 6, 1979.[277] Vassallo noted that the material should be forwarded to the licensing boards immediately, to be followed later by any technical analysis that became available.

Vassallo also recommended that the original list of boards to which Creswell requested that the package be sent (i.e., Davis Besse and Midland), be expanded to include other B&W plants (i.e., Erie, Greene County, Pebble Springs, TMI). The package was received by Joseph Scinto (OELD) on March 6, 1979. Because of higher priority work, however, the matter was not reviewed until March 21, 1979. On March 23, 1979, Creswell called Scinto to inquire about the status of the request. As a result of this call and discussions at a subsequent staff meeting, Scinto decided to forward the package to the licensing boards as soon as possible. The preparation of the package for distribution to the licensing boards, including the extensive service list associated with each of these cases, required approximately one week.[278] Consequently, the material was eventually sent to all of the parties involved on March 29, 1979.[279]

Considering that Creswell's request passed through at least five different individuals in three different NRC Offices, and considering that none of these individuals appeared to consider the matter to be particularly significant or time sensitive, it is not surprising that it took almost 3 months for Creswell's board notification to reach the licensing boards. This is not to say that this labored journey through the system is acceptable; however, the fact that it did continue to move through the system does appear to indicate that there was no specific effort to suppress the material contained in the board notification.

Part of the material eventually sent to the licensing boards, was an evaluation by the IE headquarters' staff of each issue raised by Creswell.[280]

With respect to the item that is relevant to this Special Inquiry (i.e., loss of pressurizer level low), the evaluation noted that the event had been reviewed by NRR with no unreviewed safety questions remaining. The IE evaluation concluded that the fact that T_{cold} went offscale low was not a problem because of the wide range of instrumentation provided, and makeup flow instrumentation was not a deviation in the General Design Criteria because lack of indicated flow above 160 gallons per minute was not a significant factor. The IE evaluation concluded that loss of pressurizer level indication low could be considered to be a deviation from General Design Criterion 13. However, the evaluation stated that providing level indication that would cover all anticipated occurrences might not be practical. The evaluation also noted that the Davis Besse Final Safety Analysis Report discussion of General Design Criterion 13 listed the pressurizer level instrument, but did not mention loss of pressurizer level indication during transients. The memo concluded that this apparent omission in the Safety Analysis Report would be the subject of further review.[281]

While Creswell prepared this board notification, Kohler and Foster continued their investigation of Creswell's concerns. They met with Creswell on December 29, 1978 and again on January 29, 1979 in an effort to clarify Creswell's concerns. Kohler and Foster have both testified that they found it difficult to communicate with Creswell and could. not determine precisely what it was that he wanted them to investigate.[282,283]

On the other hand, Creswell testified that Kohler and Foster did not have the technical expertise in B&W system interaction to understand his concerns completely. They discussed both the issue of loss of pressurizer level indication and voiding of the pressurizer. Creswell believed that they understood the loss of pressurizer level indication issue, but he was not confident that they understood the more complex voiding issue. In addition, although he did not request that Kohler and Foster conduct a technical evaluation of the B&W analyses, he has testified that he would have expected that such an evaluation would be performed.[284]

Kohler and Foster have testified that they believed that their principal responsibility was to determine if a timely evaluation of this matter had been performed by B&W. They believed that the technical issues associated with loss of pressurizer level indication and voiding of the pressurizer had been resolved by the NRR during December 1978. Therefore, they limited their investigation primarily to the issue of the timeliness of the evaluation of loss of pressurizer level indication.[285,286]

Foster and Kohler went to the Davis Besse plant to meet with B&W and Davis Besse personnel. They also went to B&W offices in Lynchburg, Va., for a meeting on February 14, 1979, to discuss the concern associated with loss of pressurizer level indication.[109] During this meeting, Kohler and Foster were provided with a letter from B&W to Arkansas Power & Light Company, dated April 3, 1975,[287] in which B&W analyzed an event during which there was a momentary loss of pressurizer level indication following a reactor trip. The letter concluded that maintaining reactor coolant system pressure above 1500 psig by automatic high pressure injection actuation would ensure that the reactor core remains covered. A qualitative analysis in the letter indicated that even if the pressurizer emptied, reactor coolant system pressure would drop to saturation (1000 to 1300 psig) and high pressure injection would initiate.

Kohler and Foster were also given information that indicated that B&W had informed Davis Besse by letter dated November 22, 1976,[2] that a loss of pressurizer level indication was a possible result of the operation of the plant. The letter included a specific recommendation to adjust the steam generator safety valve blowdown point. This recommendation had not been implemented at Davis Besse prior to the November 29, 1977 incident, but was implemented subsequently.

Other information given to Kohler and Foster indicated that Toledo Edison had begun investigating corrective actions to minimize the possibility of losing pressurizer level indication as early as February 1978.[289]

Donald Anderson of the IE Region IV office also participated, to a limited extent, in the Lynchburg meetings. Anderson has testified that, during a break in the meeting, he had a private conversation with Kohler and Foster, during which Kohler stated that Creswell was a troublemaker and they (Kohler and Foster) were there to "shut him up."[290] Kohler has testified that although he does not recall making the comment, he does not deny that he could have made such a comment. However, he has testified that if he made such a comment it was in the context that they were there to resolve Creswell's concerns one way or another, without any prejudgments about whether his concerns were valid.[291] Foster also did not recall the specific comment, but he agreed with Kohler that if such a comment was made, it was in the context that they would either prove that Creswell's concerns were not valid or collect the evidence required to substantiate his concerns formally.[292]

Foster and Kohler concluded that Toledo Edison and B&W had performed a timely evaluation and they concluded that the evidence indicated that Toledo Edison had contacted B&W shortly after the incident to determine if corrective actions could be taken to minimize the possibility of losing pressurizer level indication, and B&W had performed an analysis of a loss of pressurizer indication (at Arkansas Nuclear One in 1975) before the incident occurred at Davis Besse on November 29, 1977.[293] These conclusions were documented in Inspection Report No. 50-346/79-06, dated April 25, 1979.[294]

Kohler and Foster had two meetings with IE management upon returning to the regional office. The first meeting on March 5, 1979 was held primarily to give IE management the initial conclusions resulting from the investigation. A subsequent meeting on March 16, 1979 included Creswell. The purpose of the second meeting was to determine whether any items of noncompliance were associated with the issues investigated. The conclusion was that no items of noncompliance were associated with the issues investigated, although some concerns were discussed with the licensee at a subsequent management meeting.

Kohler and Foster felt that Creswell was disappointed that they had not found something of more substance in their investigation. Creswell questioned several things that Foster did not consider to be within the scope of the investigation.[295]

Apparently the slow response by Toledo Edison to Creswell's concern, which led to his frustration associated with this issue, was caused by a combination of several factors: Toledo Edison did not consider Creswell's concern to be a significant safety issue, but primarily an operational inconvenience;[296] and there was considerable tension between Creswell and people at Toledo Edison due to a failure to communicate.[297]

During this same time period, Creswell had also become concerned about the overall operation of the Davis Besse facility. He had become convinced that Davis Besse should be shut down because of the weakness of the Davis Besse management. Because of these more general concerns, Creswell decided that it was necessary to contact the NRC Commissioners directly in accordance with the Commission's "open door" policy. Therefore, he contacted Commissioner Bradford on February 27, 1979[298] and Commissioner Ahearne on March 12, 1979.[299]

Shortly after his phone conversation with Commissioner Ahearne, Creswell forwarded a large package of material documenting his concerns to Commissioner Ahearn's office. In a summary, Creswell listed several issues relevant to this Special Inquiry. These include: (1) evidence that the B&W reactor design provides significantly less protection than other PWR designs (Creswell cited the Rancho Seco March 20, 1978 incident (see Section I.C.14) and the Davis Besse November 29, 1978 incident (see Section I.C.15) as examples);[300] (2) numerous significant operator errors had occurred at Davis Besse (Creswell cited the September 24, 1977 incident at Davis Besse as an example because the operators shut off the emergency core cooling system during a LOCA);[301] and (3) serious questions about conformance of B&W reactor design with several general design criteria (specifically, with respect to Criterion 13, Creswell cited the November 29, 1977 event as an example because pressurizer level indication was lost for 5 minutes).[302]

Creswell met with Commissioners Ahearne and Bradford and members of their staff on March 21, 1979 in Bethesda, Md. and recommended that Davis Besse be shut down.[303] The Commissioners did not wish to reach a conclusion about the merits of Creswell's concerns until they had heard the other side of the story.[304] However, they realized that Creswell was sincere in his concerns and that he had come to them because he had a technical disagreement with his management. They also realized that he was concerned that his emphasis of these issues was adversely affecting his career.[305] On March 29, 1979, Commissioner Ahearne sent a memo" to Harold Denton, Director of the Office of Nuclear Reactor Regulation, and to Davis of the Office of Inspection and Enforcement, requesting a status report on various issues associated with Davis Besse. These issues were based on the concerns raised by Creswell.

Commissioners Bradford and Ahearne have testified that they planned to request that the IE Performance Appraisal Team be sent to Davis Besse as soon as possible to assess the performance of that facility.[307] The Commissioners have testified that they proceeded in a less than direct manner so as not-to publicize the fact that Creswell had talked with them, in order to protect him from any potential reprisals.[308,309]

Creswell also discussed the issue of shutting down Davis Besse with James Keppler, the IE Region III Director, on March 22, 1979. At this meeting, he recommended that the Davis Besse plant be shut down because of their poor management organization and performance.[310,311] Keppler felt that this action was premature until less drastic courses of action had been used to improve the performance at Davis Besse. He believed that, for example, more frequent and higher level management meetings, such as those that had been used at Commonwealth Edison concerning the Zion plant, might be used to improve the performance at Davis Besse.[312] However, Creswell did not expect that this type of action would be effective because the issues that had been discussed with Davis Besse at previous management meetings had not, in his opinion, been satisfactorily resolved.[313,314]

These meetings with Keppler and with Commissioners Ahearne and Bradford essentially completed Creswell's involvement with these issues prior to the TMI accident. After the accident at TMI, Davis Besse was the subject of the extensive review and analysis associated with the lessons learned from the TMI accident, and the assessment of the potential impact of continued operation of all B&W reactors.

Specific Conclusions

1. The thrust of Creswell's concerns pertained to a technical issue, loss of pressurizer level low in B&W plants, as illustrated by a November 29, 1977 transient at Toledo Edison's Davis Besse reactor, that was not directly related to the accident at Three Mile Island on March 28, 1979. It was this issue that Creswell persisted in having submitted to the licensing boards. In the course of pursuing these concerns at Davis Besse, Creswell also recognized that operator action terminating HPI during a separate transient at Davis Besse on September 24, 1977, had been improper. This latter operator action terminating HPI was a precursor of the TMI-2 accident.
2. During the September 24, 1977 incident at Davis Besse, the operators secured high pressure injection 4 to 5 minutes into the transient because

of high pressurizer level. Creswell reviewed this action in September 1978 during his review of the November 29, 1977 Davis Besse transient. He correctly viewed the action as improper. As the result of the efforts of Creswell and his immediate superior, Streeter, revised procedures for operators at Davis Besse were developed in November 1978 by Toledo Edison to prevent premature termination of HPI. Neither the matter of this operafor error nor the change in the operators' instructions at Davis Besse were reported to NRC Headquarters as a generic problem by Creswell or by the IE Region III management or flagged for other plants. Creswell did cite the improper operator action in material he submitted to Commissioners Ahearne and Bradford, not as an outstanding issue but as an illustration of what he felt was the incompetence of the utility at Davis Besse. The aspect of the September 24, 1977 transient that was a precursor of the TMI-2 accident, improper operator action terminating HPI, was not the focus of Creswell's presentation to the Commissioners. He did not identify this particular operator error to the Commissioners as a potential generic problem, but only as an isolated error.

3. Creswell did focus on the safety implications of loss of pressurizer level low during overcooling transients. It is still a matter of technical controversy whether loss of pressurizer level indication and voiding of the pressurizer are significant safety issues. In any event, neither situation occurred at TMI-2 during the March 28, 1979 transient, which involved pressurizer level indication offscale high and a full pressurizer resulting from entirely different phenomena. In other words, the concern about pressurizer level falling too low was not directly related to the misleading pressurizer level high that played an important role in the TMI-2 accident. The two concerns are distinctly different. Creswell himself has testified that he does not consider the issue of low pressurizer level during the November 1977 event and the issue of operator actions during the September 1977 event to be directly related.
4. With respect to Creswell's efforts to present his concerns about loss of pressurizer level low and about the competence of Toledo Edison's management at Davis Besse to his own management, the licensing boards and to the Commission we conclude:
   - Despite the fact that Creswell's management disagreed with the substance of his concerns, there was no effort to suppress or restrict Creswell's board notification request. All of the procedures were followed which permit an individual to bring such a concern to the boards in the face of management's disagreement with such concerns.
   - The inability of the parties involved to resolve Creswell's concerns short of escalation to the licensing boards and to two Commissioners was the result of a technical dispute, exacerbated by personality conflicts and difficulties in communications.
   - Although the steps in the processing of board notifications are probably appropriate, the time for each step should be drastically reduced. A maximum number of working days to accomplish each step (3 to 5 seems sufficient) should be fixed and enforced.

13. ISRAEL-NOVAK NOTE-JANUARY 10, 1978

On January 10, 1978, Sanford Israel of the Reactor Systems Branch, NRC Office of Nuclear Reactor Regulation, prepared a note[315] to the members of the branch for signature by the Branch Chief, Thomas Novak. The note stated that loop seals in the pressurized surge line were used in some plant designs, particularly B&W designs. Although these seals are not considered to be a problem during ordinary situations, under certain conditions such as an accident where significant voids are formed in the reactor coolant system, the result could be a two-phase mixture in the pressurizer that was not at the highest temperature in the reactor coolant system. Under these circumstances, additional loss of reactor coolant system inventory or shrinkage in the reactor coolant system might not be indicated by pressurizer level.

The note pointed out that the situation had already occurred at Davis Besse when a relief valve stuck open (see Section I.C.9). The note also provided a limited technical discussion of how this manometer effect would function in the loop seal of the surge line. The note concluded that,

> Although the safety analyses do not require determination of the makeup system, operators would control makeup flow based on the pressurizer level as part of their normal procedures. As a result, under certain conditions where the pressurizer could behave as a manometer the operator could erroneously shut off makeup flow when significant void occurs elsewhere in the system or loss of inventory is continuing.

Two courses of action were recommended: (1) "the basis for the design requirement be studied carefully for all CP [construction permit] reviews with the object of determining if the loop seal can be eliminated," and (2) "for OL [operating license] reviews procedures should be reviewed to ensure adequate information before the operator terminates makeup flow."[317]

Israel has testified that he cannot recall precisely why he wrote the note but he cited three possible reasons, individually or in combination: (1) the response of pressurizer level to voids formed in the reactor coolant system during the incident at Davis Besse on September 24, 1977 (see Section I.C.9); (2) the draft Michelson report that he had received (see Section I.C.8); or (3) the response to the Pebble Springs questions that had been reviewed by his branch (see Section I.C.11).[318]

The note was not sent to the NRR Division of Operating Reactors (DOR), which had technical review responsibility for plants already in operation. Israel has testified that he had not paid much attention to the distribution of the note and was aware of no set policy in this area. His recollection is that the fact that the note was not sent to DOR was not the result of a conscious decision.[319]

Although this note was written before the operating license for TMI-2 was issued, Israel testified that the active review of the TMI case had been completed in this area and, therefore, he would not have expected the note to be implemented on TMI-2.

Israel did not, at the time, consider this subject a serious problem, and the note was simply a reminder to the individuals in the Reactor Systems Branch to evaluate this issue on the cases that they reviewed. He still does not believe that the concern relates directly to the early phases of the accident at TMI-2 because the loop seal was not what caused the pressurizer level to increase initially.[320] Later in the TMI-2 accident, when the pressurizer level remained high despite the fact that the reactor coolant system was essentially filled with steam, the manometer effect described by Israel could have occurred.

Novak believed that the issue was significant enough to be brought to the attention of the reviewers and he therefore agreed that a "review reminder" such as this note should be prepared. This "review reminder" was essentially investigatory, and after more information was obtained from case reviews, a decision could be made whether this matter should be pursued further. He has also agreed that the matter was not referred to DOR because no one considered whether the note should be sent to DOR.

The only case under active review where the note could have been applied before the TMI-2 accident was the Midland operating license application. However, requests for additional information sent to the applicant after the note was prepared do not include any questions that could have resulted from this note. The reviewer involved, Scott Newberry, testified that he does not know why the questions were not sent, although he does recall receiving the note. The only explanation that he can provide is that either "it fell through the crack," possibly because it had to do with operating procedures which were not normally reviewed, or he decided to wait until a later stage of the review process, possibly because the operating procedures had not yet been written for Midland.[321] Therefore, it appears that no action was taken with respect to the concerns described in this note, and that the material was never reviewed to determine if additional guidance should be provided to the licensees for plants already in operation.

Specific Conclusions

1. We could not determine why Israel wrote the note. Apparently the reason was some combination of the incident that occurred at Davis Besse on September 24, 1977; the handwritten draft copy of the Michelson report that was provided to Israel by Ebersole; or the questions that were asked during the ACRS review of the Pebble Springs operating license application.
2. The technical content of the Israel-Novak note did not describe the phenomenon that caused the reactor operators at Davis Besse, and subsequently at TMI-2, to secure high pressure injection. However, the note did describe a phenomenon that may have caused the pressurizer to remain full of water during the latter stages of the TMI accident when the reactor coolant system was essentially completely converted to steam.
3. No actions were taken within the Reactor Systems Branch, the branch to which the note was addressed.
4. The note was not sent to the Division of Operating Reactors for evaluation of its applicability to operating plants, apparently because of an oversight, rather than the result of any conscious decision not to send it.

14. RANCHO SECO-MARCH 20, 1978

On March 20, 1978, an incident occurred at the Rancho Seco nuclear powerplant when an operator dropped a light bulb into an instrument panel, short-ing out a nonnuclear dc power supply. This short caused a reactor trip and a rapid cooldown at approximately 300°F per hour. This rapid cooldown was greater than the cooldown rate limits permitted in the technical specifications for the plant. Furthermore, the loss of the dc power supply caused the loss of approximately two-thirds of the temperature, pressure, flow, and level signals available to the operator in the control room. During the incident, high pressure injection actuated at 1600 psig which maintained pressure above 1400 psig.

The event was reviewed by B&W and by the Sacramento Municipal Utility District (SMUD) and it was determined that the plant could return to power and that no significant damage had occurred.[322] However, the NRC staff noted that although no structural damage occurred, if the plant had operated for a longer time with the associated irradiation of the reactor vessel, more significant damage was possible as a result of brittle fracture associated with the rapid cooldown rate. The conclusions were that positive steps should be taken to prevent transients of this kind, and that the generic implications of the transient be promptly reviewed. This review was initiated in a memo from Darrell Eisenhut of the NRR staff to Victor Stello of the NRR staff, dated March 30, 1978.[323]

SMUD pointed out an additional problem, namely, that the incident had resulted in a loss of a significant amount of instrumentation, and consequently, the operators were hampered in their attempts to respond to the incident. This problem was caused not only by the erroneous indications observed by the operators, but also by the fact that the equipment responded in some cases to the erroneous signals that were received as a result of the loss of power. The operators found it difficult to determine which of their indicators were valid and which were incorrect.[324]

This incident was also reviewed by IE, and a formal transfer of lead responsibility was executed on April 25, 1978,[325] transferring responsibility for several issues from IE to NRR. The issues raised in this transfer included: (1) review of the power supply to nonnuclear instrumentation to determine whether design changes were necessary; (2) review of the advisability of automatic initiation of auxiliary feedwater flow by a safety features actuation system signal; and (3) evaluation of the susceptibility of B&W plants to other initiating events or failures that could produce similar cooldown transients. This transfer of lead responsibility did not address the issue of the operator interpretation of indication or the availability of indication to the operators.

On June 20, 1978, a meeting held at Rancho Seco included representatives from NRR and from SMUD to discuss the cooldown transient. One purpose of the meeting was to determine whether other failures or initiating events could cause a similar transient. Conflicting reports exist concerning whether an additional failure mechanism was identified. One summary of the meeting indicated that none of the attendees postulated another mechanism or failure that would initiate a similar transient.[326] However, another summary of the same meeting stated, "The final item on the agenda was a discussion of other possible mechanisms for causing a severe cooldown transient. Depressurization due to a faulty electromatic relief valve [PORV] or safety valve was the only possibility discussed."[327]

Regardless of what was actually decided at the meeting, because of perceived higher priority work, further action on this entire issue was suspended after this meeting, and no additional actions were taken on any of the issues addressed in the transfer of lead responsibility.[328,329]

As already noted, B&W had also reviewed this incident and, on August 8, 1978, sent a letter to each of the Site Operations Managers (except at TMI-2) for subsequent forwarding to B&W plants. This letter discussed the severe thermal transient that had occurred at Rancho Seco and also discussed the substantial loss of nonnuclear instrumentation associated with the loss of electrical power. The letter observed further that need for a careful evaluation of operator training and emergency operating procedures for any loss of nonnuclear instrumentation. The letter emphasized that the operator's response should be keyed to certain variables if a loss of normally available instrumentation occurs. The specific variables cited as significant were (1) pressurizer level, (2) reactor coolant system pressure, (3) steam generator level, and (4) steam generator pressure. The letter stated, "The pressurizer level and reactor coolant system pressure assure that the reactor coolant system is filled; the steam generator level and pressure assure adequate decay heat removal."[330]

As stated earlier, this letter was sent to all B&W utilities except Metropolitan Edison, the operator of TMI-2. The reason this letter was not sent to TMI is that an earlier incident had occurred at TMI on April 23, 1978, and it was thought by B&W that this issue had been discussed with TMI in sufficient detail that it was not necessary to send them the letter. However, no specific documentation concerning these discussions was found. Another reason for not sending the letter to TMI was that the TMI integrated control system involved in the response to the erroneous indication was different from the system installed at Rancho Seco.[331] If this letter had been sent to TMI-2 it might have resulted in operator training that emphasized the need to consider reactor coolant system pressure, and not just pressurizer level, when attempting to determine reactor coolant system inventory.

Specific Conclusions

1. The incident itself was not a direct precursor of the TMI-2 accident (i.e., the incidents themselves are not similar).
2. A letter was prepared and forwarded to various B&W utilities. The letter discussed the fact that reactor coolant system pressure and pressurizer level were the measures of reactor coolant system inventory. Had TMI-2 received this letter, it might have resulted in additional emphasis and training at TMI-2 with respect to the fact that pressurizer level alone was not an accurate indication of reactor coolant system inventory. The letter was not forwarded to Metropolitan Edison, however, because B&W concluded that the issues contained in the letter had been discussed with them during the review of a similar incident which had occurred at Three Mile Island on April 23, 1978. This discussion is not, however, a matter of record at either B&W or Toledo Edison.

15. THREE MILE ISLAND-MARCH 29, 1978/STERNBERG MEMORANDUM-MARCH 31, 1978

On March 29, 1978, a reactor trip occurred at TMI-2 as a result of the loss of a vital bus. Power to the vital bus was lost because of the tripping of the alternate power supply during a test. This loss of power caused the PORV to fail open on loss of power to the control bistable, causing a depressurization of the reactor coolant system. Furthermore, the high pressure injection system initiated. The depressurization was stopped after about 4 minutes by reenergizing the vital bus from its alternate power supply.

The utility noted that there was a problem associated with this incident because the PORV opened (rather than closed) on loss of power to its control bistable. In a Startup Problem Report dated March 30, 1978,[332] the utility suggested either changing the valve to fail shut or providing an indication on the control panel that the valve had an open signal.

This matter was reviewed by B&W and the conclusions were that B&W agreed with the concept of having the valve fail shut on loss of nonnuclear instrumentation, and that the indication of the PORV position should be provided in the control room; however, this indication was to come from the power to the-solenoid -

This issue was also reviewed by the architect-engineer, and an engineering change memo was initiated on April 6, 1978. The engineering change memo provided for an indication in the control room of power to the solenoid. The memo initially included a provision for changing the PORV to fail shut on loss of power; however, that provision may have been subsequently deleted because it was not required for proper system operation.[335] Whether the PORV was eventually changed to fail shut on loss of control power was not determined. Burns and Roe also concluded that, even though it would require a change to the Final Safety Analysis Report, the change was not an unreviewed safety question.[336]

These actions were subsequently reported to the IE Region I office by Metropolitan Edison in a letter dated June 27, 1978.[7] This letter concludes that reactor coolant system pressure reached as low as 1173 psig during the event and that (1) the control signal should be changed to cause the valve to fail shut on loss of control power, and (2) position indication for the PORV should be provided in the control room.

During this period, Daniel Sternberg of the IE Region I office also became concerned as a result of this incident. Sternberg was the Acting Branch Chief for the IE branch responsible for TMI-2. He prepared a memo to IE Headquarters, dated March 31, 1978, in which he noted that the March 29, 1978 incident resulted in a blowdown because the PORV opened on a loss of electrical power to the control bistable. Although Sternberg acknowledged that the valve was not safety-related, he stated:

> It is requested that the adequacy of the design approach (i.e., valve failing open on loss of control power) be reviewed on an expedited basis for B&W facilities in general and Three Mile Island in particular -

Sternberg has testified that he was concerned because the PORV failed open on the loss of a single power supply, and this failure resulted in an initiation of an unannunciated loss-of-coolant accident. Sternberg believed that his ability to correct problems such as this was significantly impaired since the item was not defined as a safety-related component.[341] Nonetheless, he thought that the issue should be addressed. He also testified that he would have recommended that the matter be referred to NRR for review, but he had been told earlier in his career in IE Region I not to make such recommendations because such decisions were the prerogative of IE headquarters.[342]

Sternberg received a response from IE headquarters signed by Karl Seyfrit on May 3, 1978.[3] The response, which was prepared by Roger Woodruff, stated:

> The request is based on failure of the valve in the open position. Failure in this position is covered in Section 7.4.1.1.6 of the FSAR. We conclude that additional review is not warranted.[344]

Section 7.4.1.1.6 of the FSAR, titled "Pressurizer Control," states, "In the event that the relief valve were to fail in the open position, pressure relief could be controlled by cycling (open and close) the relief isolation valve."[346]

Woodruff did not contact anyone in NRR about this matter because he thought that the issue had already been reviewed by NRR. Furthermore, he did not think the valve should be safety-related because the code safety valves, which provide relief protection if the PORV fails to open, are safety-related.[346]

Sternberg has testified that he accepted the response as adequate because someone had reviewed the issue and decided that it was not a problem. However, he would have preferred to see an analysis of the implications of a valve that can cause a small loss-of-coolant accident by failing open on a loss of control power. Because of perceived higher priority work, however, Sternberg did not pursue the issue after he received the memo from IE headquarters.[347]

Although Seyfrit did not personally review the matter in detail, he thought that because the issue was addressed as part of the application, and that application had been reviewed by NRR previously, the design was acceptable.[348]

Specific Conclusions

1. The memo is a precursor to the TMI-2 accident because it refers to an incident that occurred at TMI (March 29, 1978) during which a PORV failed in the open position creating a small LOCA. Although this failure, was due to a loss of control power, it had the same effect as the failure, for whatever reason, a year later.
2. A reexamination by NRR of the adequacy of the design of the TMI-2 PORV, might have precipitated an assessment of the implication of a stuck-open PORV, or might have provided the impetus for an adequate PORV position indication in the control room. Such a reexamination never occurred.

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[107] Engle dep. at 13-16,18.

[108] 1d. at 65-66.

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"'Old. at 18, 28, 35-39.

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'''3 1d at 15-16.

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[115] /d. at 1.

[116] Seyfrit dep. at 15.

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[116] Memorandum from R. J. McDermott, NRC, to D. J. Skovholt, "Reactor Coolant System Depressurization Event at Davis-Besse-2," October 20,1977.

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[120] 1d. at 347-348.

[121] 1d. at 350.

[122] Seyfrit dep. at 34-35.

[123] 210th Advisory Committee on Reactor Safeguards Transcripts (October 7,1977) at 249-350.

[124] 211th Advisory Committee on Reactor Safeguards Transcripts (November 3, 1977) at 174-184.

[125] Faist dep. at 8.

[126] Kelly dep. at 11-12, 24.

[127] Id. at 14-15.

[128] 1d. at 20-22.

[129] Dunn dep. at 23-24.

[130] Kelly dep. at 29-30, 33.

[131] Faist dep. at 10-11.

[132] 1d. at 21.

[133] Id. at 24-26.

[134] Babcock & Wilcox, "Toledo Edison Company Site Problem Report-SFRCS Trip/Reactor Trip/Coolant Spill," SPR No. 372 (November 1977).

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[136] *14.* at 31-33.
[137] Murray dep. at 7-21.
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[139] *1d.* at 21.
[140] *Id.* at 24.
[141] 1. at 32-34.
[142] Derivan dep. at 44.
[143] /d. at 47.
[144] 14. at 47.
[145] at 44, 49.
[146] "Cognitive Dissonance and the Accident at Three Mile Island," p. 1, *The Energy Daily*, October 11, 1979.
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[148] Dunn dep. at 23-25.
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[156] Memorandum from F. Walters, Babcock & Wilcox, to J. J. Kelly, "High Pressure Injection During Transient," November 10, 1977.
[157] Walters dep. at 9-14, 22.
[158] 11. at 10-14.
[159] Kelly dep. at 39-40.
[160] Dunn dep. at 29.
[161] Memorandum from B. M. Dunn, Babcock & Wilcox, to J. Taylor, "Operator Interruption of High Pressure Injection," February 9,,1978.
[162] Dunn dep. at 29-30.
[163] Memorandum from B. M. Dunn, Babcock & Wilcox, to J. Taylor, "Operator Interruption of High Pressure Injection," February 9,1978, at 1.
[164] at 1.
[165] 1d. at 1.
[166] 1d. at 2.
[167] Taylor dep. at 16-17.
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[169] Memorandum from B. M. Dunn, Babcock & Wilcox, to J. Taylor, "Operator Interruption of High Pressure Injection," February 15, 1978.
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[171] Kelly dep. at 42-43.
[172] Dunn dep. at 34, 36.
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[174] Memorandum from 0. F. Hallman, Babcock & Wilcox, to B. A. Karrasch, "Operator Interruption of High Pressure Injection (HPI)," August 3, 1978.
[175] /d.
[176] 1d.
[177]
[178] Dunn dep. at 35.
[179] Karrasch dep. at 9-12,14-16.
[180] 1d. at 14-17.
[181] Id. at 20.
[182] Id. at 20, 22.
[183] Hallman dep. at 25-29.
[184] Karrasch dep. at 22.
[185] Hallman dep. at 25-29.
[186] Karrasch dep. at 23.
[187] Kelly dep. at 45.
[188] Hallman dep. at 30-31.
[189] Kelly dep. at 43-44.
[190] Dunn dep. at 34, 36.
[191] Jones dep. at 52-53.
[192] Memorandum from R. Muller, NRC, to C. Stahle, Pebble Springs Nuclear Plant, "ACRS Questions RE Pebble Springs Review," dated November 7,1977.
[193] Id. at 1.
[194] 14. at 2-3.
[195] /d. at 5.
[196] 14. at 10.
[197] Memorandum from S. A. Varga, NRC, to All Divisions of Systems Safety Branch Chiefs, "ACRS Questions on Pebble Springs," November 15, 1977.
[198] Memorandum from S. A. Varga, NRC, to Site Analysis Branch Chiefs in Division of Site Safety and Environmental Analysis, "ACRS Questions on Pebble Springs," November 17,1977.
[199] Letter (and attached document) from J. L. Williams, Portland General Electric Co., to S. A. Varga, NRC, Subject: Responses to 26 Questions Raised by the ACRS on the Pebble Springs Application, dated November 30, 1977.
[200] 14. at cover letter.
[201] Memorandum from S. A. Varga, NRC, to Site Analysis Branch Chiefs in Division of Site Safety and Environmental Analysis, "ACRS Questions on Pebble Spring," November 17, 1977.
[202] Letter (and attached document) from J. L. Williams, Portland General Electric Co., to S. A. Varga, NRC, Subject: Responses to 26 Questions Raised by the ACRS on the Pebble Springs Application, dated November 30, 1977.
[203] Dunn dep. at 54-55.
[204] 1d. at 56.
[205] Newberry dep. at 4-7.
[206] Letter (and attached document) from J. L. Williams, Portland General Electric Co., to S. A. Varga, NRC, Subject: Responses to 26 Questions Raised by the ACRS on the Pebble Springs Application, dated November 30, 1977, at 24.
[207] 1d. at 51-52.
[208] Novak dep. at 48-52.
[209] NRC Meeting of the Advisory Committee on Reactor Safeguards (January 6,1978) at 201, 236.
[210] 1d. at 246-247.

[211] Israel dep. at 5.

[212] Newberry dep. at 11-12.

[213] Taylor dep. at 31-35.

[214] Ebersole dep. at 31.

[215] Letter (and attached excerpts from minutes of the 213th ACRS Meeting, January 5-7, 1978) from S. Lawroski, NRC, to J. M. Henry, NRC, Subject: Report on Pebble Springs Nuclear Plant, Units 1 and 2, dated January 12, 1978.

[216] Id. at 19.

[217] Filing of NRC Staff's Responses to Board Questions During the Pebble Springs Pre-Hearing, Conference Held on April 12, 1978, Before the Atomic Safety Licensing Board, at 7, dated May 25, 1978.

[218] Id. at 7.

[219] Letter from L. Roe, TECO, to R. Reid, NRC, Subject: Forwards Analysis Supporting Continued Operation of Subject Facility with Dual Level Control Steam Generators, dated December 11, 1978.

[220] NRC Inspection Report of inspection conducted by T. N. Tamblin at Davis Besse Nuclear Power Station, Unit 1, December 16, 1977.

[221] Memorandum from C. W. Tally, Babcock & Wilcox, to M. E. McAlpine, TECO Site Operations, "Analysis of Natural Circulation Transient Data," December 21,1977, at 1-3.

[222] Meeting summary from L. Engle, NRC, to TECO, Davis Besse Nuclear Power Station Unit No. 1 (DB-1), "Summary of Meeting on Natural Circulation Tests," February 14, 1978, at 1-2.

[223] Letter from R. S. Boyd, Office of Nuclear Reactor Regulation, to L. E. Roe, TECO, Subject: Natural Circulation Test-Davis Besse, Unit No. 1, dated November 29, 1977.

[224] Creswell dep. at 14-16.

[225] Id. at 18-19.

[226] NRC Inspection Report of inspection conducted by J. S. Creswell at Davis Besse Nuclear Power Station, Unit 1, April 20, 1978.

[227] Creswell dep. at 18-19.

[228] Letter from R. J. Baker, Babcock & Wilcox, to J. G. Evans, Davis Besse Nuclear Power Station, Subject: Recommendations for Avoiding Pressurizer Off-Scale Indications, dated November 22, 1976.

[229] Memorandum from C. R. Domeck, Davis Besse Nuclear Power Station, to E. C. Novak, Davis Besse Nuclear Power Station, "Davis-Besse Nuclear Power Station, Unit No. 1, Summary of a November 29, 1977 Incident," December 16, 1977.

[230] Memorandum from C. W. Tally, Babcock & Wilcox, to R. P. Williamson, Babcock & Wilcox, "SPR 396," February 10, 1978.

[231] Memorandum from T. Murray, TECO, to T. Tambling, NRC, November 28, 1978.

[232] Letter from T. D. Murray, TECO, to J. G. Keppler, NRC, Subject: Reportable Occurrence 78-115 Davis-Besse Nuclear Power Station, Unit 1, Date of Occurrence: November 27,1978, dated December 8, 1978.

[233] Memorandum from Cartin, Babcock & Wilcox, to B.A. Karrasch, Babcock & Wilcox.

[23.1] Letter from L. Roe, TECO, to R. Reid, NRC, Subject: Forwards Analysis Supporting Continued Operation of Subject Facility with Dual Level Control Steam Generator, dated December 11, 1978.

[235] Memorandum from J. S. Creswell, NRC, to J. F. Streeter, NRC, "Information for Management Meeting at Davis-Besse," August 14, 1978.

[236] R. W. Winks, Babcock & Wilcox, "Dynamic Performance of the Pressurizer During Reactor Trips at Davis-Besse 1," August 31, 1978.

[237] NRC Inspection Report of inspection conducted by J. S. Creswell of Davis-Besse Nuclear Plant, Unit 1, October 25, 1978.

[238] Creswell dep. at 24-25.

[239] NRC Inspection Report of inspection conducted by J. F. Streeter, J. S. Creswell, and J. D. Smith, of Davis Besse Nuclear Power Station, Unit 1, February 7,1979.

[240] Creswell dep. at 95.

[241] Creswell dep. at 97.

[242] NRC Inspection Report of inspection conducted by J. S. Creswell of Davis-Besse Nuclear Plant, Unit 1, October 25,1978.

[2°] Summary of telephone conversation between J. Streeter, NRC, and T. Murray, TECO, Subject: Operation of High-Pressure Injection During September 24, 1977 Event," at 1, September 13, 1978.

[244] Miller dep. at 19.

[245] Summary of telephone conversation between J. Streeter, NRC, and T. Murray, TECO, Subject: Operatic,, of High-Pressure Injection During September 24, 1977 Event," September 13, 1978, at 2.

[246] Davis Besse Nuclear Power Station, Unit 1, Temporary Modification Request, dated November 26,1978.

[247] Id. at 1.

[248] NRC Inspection Report of inspection conducted by J. F. Streeter, J. S. Creswell, and J. D. Smith, of Davis Besse Nuclear Power Station, Unit 1, February 7,1979.

[249] Streeter dep. at 15-16.

[250] "Davis-Besse Nuclear Power Station, Unit No. 1, Emergency Procedure EP1202.06, Loss of Reactor Coolant and Reactor Coolant Pressure," at 4.

[251] Creswell dep. at 26.

[252] Streeter dep. at 29, 35, 38.

[253] Memorandum from J. S. Creswell, NRC, to G. Fiorelli, NRC, "Concern Regarding Voiding of Pressurizer at Davis-Besse 1," December 19, 1978.

[254] Id. at 1.

[255] Memorandum from J. S. Creswell, NRC, to J. F. Streeter, NRC, "Technical Evaluations, Davis-Besse 1," December 19,1978.

[256] Memorandum from J. F. Streeter, NRC to J. S. Creswell, NRC, "Technical Evaluation, Davis-Besse 1," December 20,1978.

[257] Memorandum from J. S. Creswell, NRC, to J. F. Streeter, NRC, "Technical Evaluations, at Davis-Besse 1", January 29,1978.

[258] Creswell dep. at 31-32, 59.

[259] Streeter dep. at 52.

[260] Letter from L. Roe, TECO, to R. Reid, NRC, Subject: Forwards Analysis Supporting Continued Operation of Subject Facility with Dual Level Control Steam Generators dated December 11, 1978.

[261] Letter from L. Roe, TECO, to R. Reid, NRC, Subject: Additional Safety Evaluation of Transient Resulting from

Inability of Operator to Control Steam Generator Level of 35 Inches," dated December 22, 1978.

262 Id. at 9.

263 Id. at 9.

264 Streeter dep. at 32-33.

265 Creswell dep. at 62-64, 175-176.

266 NRC Inspection Report of inspection conducted by J. F. Streeter, J. S. Creswell, and J. D. Smith, of Davis Besse Nuclear Power Station, Unit 1, February 7, 1979.

267 Weiss dep. at 9-12, 25, 37.

268 Memorandum from J. S. Creswell, NRC, to J. F. Streeter, NRC, "Conveying New Information to Licensing Boards-Davis-Besse Units 2 & 3 and Midland Units 1 & 2," January 8, 1979.

269 Id. at 2.

270 Creswell dep. at 178-179.

271 Memorandum from N. C. Moseley, NRC, to D. Thompson, NRC, "Notification of Licensing Boards (AITS F30468H2)," February 28, 1979, at 1.

272 Id. at 1.

273 NRC Board Notification, March 29, 1979.

274 Memorandum from J. G. Keppler, NRC, to N. C. Moseley and H. D. Thornburg, NRC, "Recommendation for Notification of Licensing Boards and Requests for Technical Assistance (AITS F30468H2)," January 19, 1979.

275 Memorandum from N. C. Moseley, NRC, to D. Thompson, NRC, "Notification of Licensing Boards (AITS F30468H2)," February 28, 1979.

276 Memorandum from D. Thompson, NRC, to D. B. Vassallo, NRR, "Information for Board Notification-Davis-Besse Units 2 & 3 and Midland Units 1 & 2," March 1, 1979.

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278 Note from J. F. Scinto, NRC, to E. S. Christenbury, OELD, Subject: Processing of Board Notices, dated April 5, 1979, at 1-2.

279 NRC Board Notification, March 29, 1979.

280 Memorandum from N. C. Moseley, NRC, to D. Thompson, NRC, "Notification of Licensing Boards," March 28, 1979.

281

282 Foster dep. at 15, 40.

283 Kohler dep. at 17, 47, 64.

284 Creswell dep. at 52-57.

285 Foster dep. at 7, 26, 29, 53.

286 Kohler dep. at 20, 33-35, 46.

287 Letter from J. D. Phinney, B&W, to W. Cavanaugh, III, Arkansas Power and Light Co., Subject: Arkansas Nuclear One-Unit One Pressurizer Level Setpoint B&W Reference NSS-8, dated April 3, 1975.

288 Letter from R. J. Baker, Jr., B&W, to J. G. Evans, Davis Besse Nuclear Power Station, Subject: Recommendations for Avoiding Pressurizer Off-Scale Indications, dated November 22, 1976.

289 Memorandum from C. W. Tally, B&W, to R. P. Williamson, B&W, "SPR 396," February 10, 1978.

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291 Kohler dep. at 55-57.

292 Foster dep. at 49-50.

293 NRC Inspection Report of inspection conducted by J. E. Foster and J. E. Kohler, at the Davis Besse Nuclear Power Station, Unit 1, April 25, 1979, at 10-12.

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295 Foster dep. at 22-23.

296 Memorandum from J. S. Creswell, NRC, to G. Fiorelli, NRC, "Concern Regarding Voiding of Pressurizer at Davis-Besse 1, December 19, 1978, at 23-24.

297 Kohler dep. at 60-62.

298 Bradford Interview Transcript at 128 (Pres. Com.).

299 Ahearne Interview Transcript at 48 (Pres. Com.).

300 Memorandum from J. S. Creswell, NRC, to J. F. Ahearne, NRC, "Summary of Concerns," undated, at 1, 4-5.

301 Id. at 1, 6.

302 Id. at 1, 10-11.

303 Creswell dep. at 184.

304 Ahearne Interview Transcript at 49 (Pres. Com.).

305 Bradford Interview Transcript at 131-133 (Pres. Com.).

306 Memorandum from J. F. Ahearne, NRC, to H. Denton, NRR, and J. Davis, IE, "Status Report on Davis-Besse Unit No. 1," March 29, 1979.

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308 Ahearne Interview Transcript at 52 (Pres. Com.).

309 Bradford Interview Transcript at 130 (Pres. Com.).

310 Keppler dep. at 26-29.

311 Creswell dep. at 188.

312 Keppler dep. at 26-27.

313 Creswell dep. at 201-205.

314 NRC Inspection Report of inspection conducted by R. C. Knop and T. N. Tambling at Davis Besse Nuclear Power Station Unit 1, September 21, 1978.

315 Letter from T. M. Novak, NRC, to RSB Members, Subject: Loop Seals in Pressurizer Surge Line, dated January 10, 1978.

316 Id. at 1.

317 Id.

319 *Id.* at 10.

320 Id.

321 Newberry dep. at 17-22.

322 Letter from J. T. Janis, B&W, to R. J. Rodriguez, Sacramento Municipal Utility District, Subject: Rancho Seco Nuclear Generating Station-Unit No. 1, Evaluation of NSS Cooldown Transient, dated March 23, 1979, at 1.

323 Memorandum from D. Eisenhut, NRC, to V. Stello, Jr., "Rancho Seco Nuclear Generating Station-Evaluation of the NSS Cooldown Transient," March 30, 1978.

324 Letter from J. J. Mattimoe, Sacramento Municipal Utility District, to R. H. Engelken, NRC, Subject: Operating License DPR-54, Reportable Occurrence 78-1, at 3, dated March 31, 1978.

325 Transfer of Lead Responsibility from K. V. Seyfrit, DROI, IE, to B. K. Grimes, NRR, "Rancho Seco Non-Nuclear Instrumentation Power Supply and Auxiliary Feedwater Initiation," April 25, 1978, Serial No.: IE-ROI: 78-04.

MMeeting Summary from G. B. Zweitig, NRC, "Cooldown Transient of March 20, 1978," (June 20, 1978) dated July 13,1978, at 3.

[327] Memorandum from R. Lobel, DOR to P. S. Check, "Summary of Meeting Held at Rancho Seco Nuclear Powerplant on June 10, 1978 to Discuss a Recent Cooldown Event," at 6, July 31, 1978.

[328] Telephone logbook of F. Hebdon, NRC; entries for calls to R. Lobel, NRR, July 9, 1979.

[329] 1d., entries for calls to G. Zweitig, NRC, July 10, 1979.

[330] Letter from I. D. Green, B&W, to T. D. Murray, Davis Besse, Subject: SMUD Rapid Cooldown Transient, dated August 9, 1978, at 2.

[33] Taylor dep. at 58.

[332] Metropolitan Edison Company, "Three Mile Island Nuclear Station GPU Startup Problem Report," Docket 50-320, March 30,1978.

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[334] Burns and Roe, Inc., TMI Unit No. 2, Engineering Change Memo, dated April 6,1978.

[336] 1d. at 1.

[338] TMI Nuclear Station-Unit ##2, Burns and Roe Nuclear Safety Review, dated April 14, 1978.

[337] Letter from J. G. Herbein, Metropolitan Edison Company, to B. H. Grier, Subject: Special Report Concerning the TMI-2 ECCS Actuation of March 29, 1978, dated June 27,1978.

"Memorandum from D. M. Sternberg, NRC, to K. V. Seyfrit, "Three Mile Island-Pressurizer Relief Valve Control System (AITS #F14674H2)," March 31,1978.

3391d.

[34°] Stemberg dep. at 6.

[341] 1d. at 19.

[342] *14.* at 40-44.

[343] Memorandum from K. V. Seyfrit, NRC, to E. J. Brunner, "Three Mile Island Unit No. 2/Pressurizer Relief Valve (AITS F14674H2)," May 3,1978.

3"Id.

[345] Final Safety Analysis Report (FSAR), Three Mile Island- Unit 2, Vol. 6, Sec. 7.4.1.1.6.

[34] sWoodruff dep. at 8.

[347] Sternberg dep. at 48.

[348] Seyfrit dep. at 42-43.

D PRESSURIZER DESIGN AND PERFORMANCE: A CASE STUDY

The pressurizer is a steel cylinder with hemispheres welded on either end. It is attached to the reactor coolant system by a pipe, as shown in Figure I-11. The purposes of the pressurizer are to maintain system pressure and to absorb system volume changes during transients. Heaters near the bottom of the pressurizer heat the water so that a steam bubble Is maintained in the top of the vessel. This bubble serves as a cushion. The cushion can be enlarged by additional heating, to force water out of the pressurizer and back into the reactor coolant system, thus increasing system pressure. By cooling the pressurizer steam, the bubble is shrunk, and system pressure is decreased. Figure 1-12 illustrates the pressurizer.

The pressurizer also has a water level indicator that shows the level of the boundary between the water and the bubble. Operators commonly use the pressurizer water level indicator to tell them about water level in the entire primary system. Under normal circumstances, if there is some level indication in the pressurizer, the rest of the system should be full of coolant; if the pressurizer level disappears (goes below zero), there may be no way to determine how much water is in the system or even whether the reactor core is covered with coolant water.

In reading the information that follows, the reader should keep in mind that pressurizer level indication can tell the operator something about (1) pressure in the reactor coolant system; (2) reactor coolant inventory (how much water is in the system); and (3), in some instances, whether boiling is taking place in the reactor. A basic design concept of a pressurized water reactor is that sufficiently high pressure is maintained in the primary system so that boiling does not take place in the reactor during reactor trips.' During loss-of-coolant accidents, boiling may occur for some period of time. Rowever, safety systems, such as high pressure injection pumps, are designed to activate automatically and cool the reactor core.

Pressurizer level can respond in a number of ways during transient conditions (such as reactor trips and accidents). During the initial phase of the TMI-2 accident, for example, it first moved upward, then downward, and then upward again. The first upward movement was in response to the "bottling up" of heat in the reactor. As temperature climbed in the reactor, the water expanded and increased the level in the pressurizer. The level then dropped when the reactor scrammed, and reduced the generation of heat by over 90%, causing the reactor coolant to shrink, and temperature and pressure to

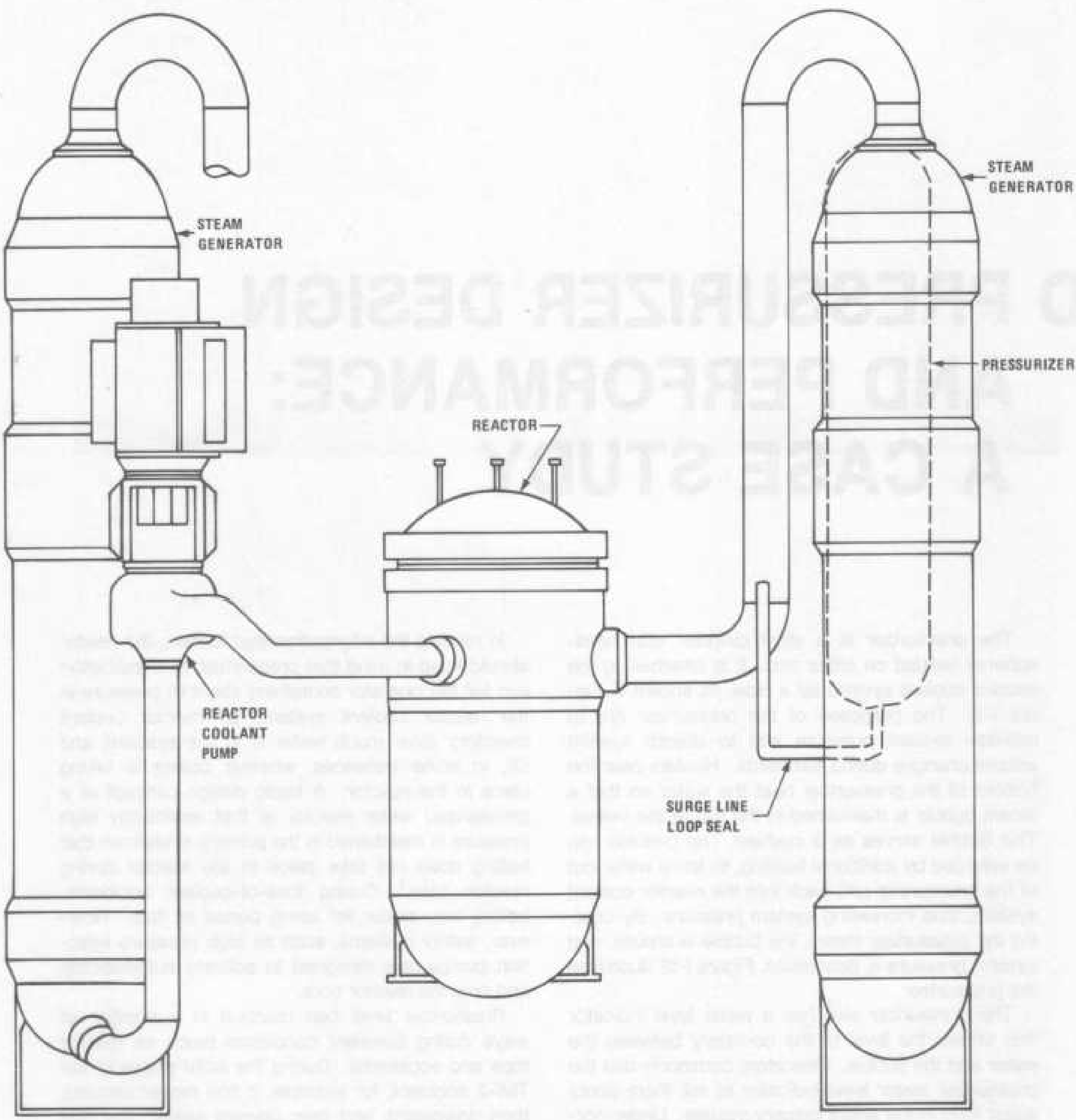

FIGURE I-11. Pressurizer Surge Line Loop Seal Arrangement

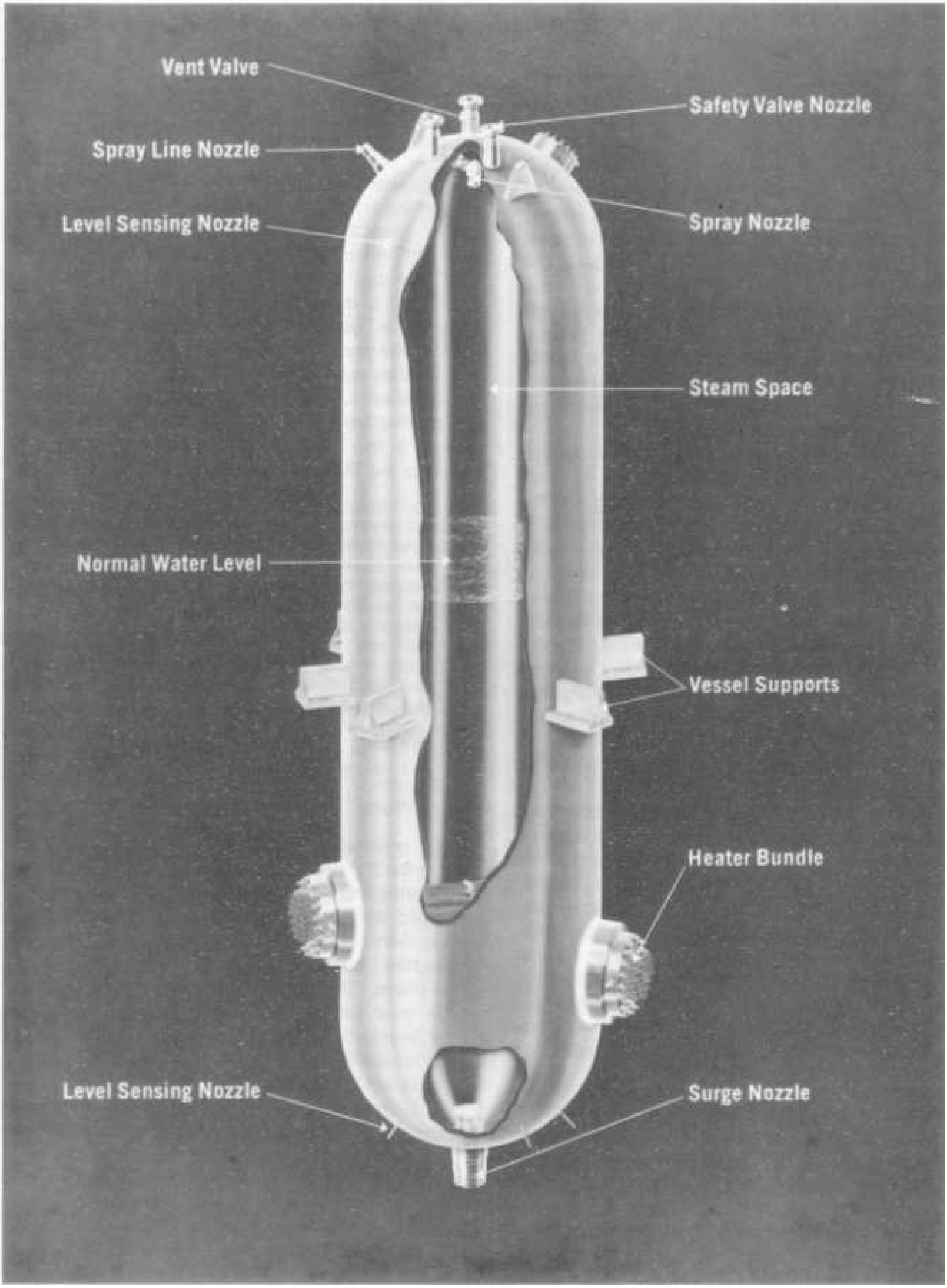

FIGURE 1-12. The Pree:urizer

sharply reduce. When the operators observed the declining level they responded immediately by stopping the normal letdown flow of water out of the reactor and increasing the makeup flow of water into the reactor. The level rose again (as the operators expected), but then something highly unusual happened. The level did not stop rising, but continued increasing until it indicated to the operator that the pressurizer was completely full of water. The operators throttled the high pressure injection (which had come on automatically) in the belief that less, not more, water was needed in the primary system. Though they did not realize it, the stuck-open relief valve in the top of the pressurizer was permitting coolant to flow through the pressurizer and out of the system.

The main effect of the pressurizer level indication during the Three Mile Island accident, then, was that its increasing misled operators into thinking that the reactor coolant system was full of coolant, when in fact it was not. The accident demonstrated, among other things, the extent to which operators had been trained to key on pressurizer level to tell them when to initiate various manual actions. In fact, the operators' decision at Three Mile Island to throttle high pressure injection showed the extent to which they were accustomed to seeing this emergency safety system actuate during the anticipated operational transients and that they were conditioned to turn it off when the anticipated transient appeared to have run its course.

Much of the following discussion addressing pressurizer level pertains to what happens during a *normal reactor trip,* not an accident like Three Mile Island involving a stuck-open valve. During a normal trip, the pressurizer level moves up, then down, and then up again, but stops going up before the pressurizer becomes full of water. The main area of interest in this discussion is the *downward* movement in the cycle, what happens when the pressurizer level goes low. Three concerns may be encountered when the level drops, depending on how far it goes:

1. The level may go down to the point at which the pressurizer heaters cut off. This action removes the heat source that can be used, either automatically or manually, to compensate for pressure decreases.
2. The level drops further to the point at which the level indicating instrumentation cannot show the operator where the level of water is in the pressurizer; that is, the level reads zero.
3. The level drops further and the pressurizer empties. If pressure drops low enough, boiling may occur in the reactor coolant system, affecting the removal of heat from the reactor, the operation of the reactor coolant pumps, and eventually the fuel itself.

Pressurizer level indication is therefore a serious issue of importance to the operator's knowledge of reactor coolant system conditions. According to John W. Anderson, Arkansas Nuclear One (ANO) Plant Manager, "As far as the PSC [Plant Safety Committee] is concerned, when all pressurizer level indication is lost then there is no way to know whether the core is covered with water and therefore, a safety question exists." [2]

Ed Frederick, a control room operator who was manipulating the makeup and high pressure injection controls in the TMI-2 control room during the initial stages of the TMI accident, testified:

> Specifically on the pressurizer, you often find yourself working very hard to maintain yourself within those limits, even on a simple reactor trip. It will take several manual actions to maintain, for instance, the minimum 100-inch figure for keeping the heaters covered. Much of the reactor trip procedure is devoted to pressurizer level control, so I can't really think of anywhere that we purposely ignore this or try to exceed it and/or let it be exceeded because they are so important to the plant, pressure control....
>
> Q: So you obviously ... are concerned with pressurizer level not going down?
>
> A: Right .... [3]

The pressurizer at TMI-2 is a standard B&W design for 177 fuel assembly plants first developed for Oconee 1 and 2 plants in 1967. [4] (B&W diligently searched for the design calculations but could not locate them.) Figure 1-13 illustrates the location of pressurizer level instrumentation taps for various B&W plants. The location of these taps controls the range over which the operator can monitor the water level in the pressurizer. Figure 1-14 schematically represents the location of heater bundles for the standard 1500-cubic foot pressurizer.

Past performance at B&W plants has revealed problems with the maintenance of pressurizer level. [5]

Some of these problems have resulted from malfunctions of the main steam safety relief valves or turbine bypass valves during loss-of-feedwater transients. The main steam safety relief valves on a B&W facility are designed to open during a normal loss-of-feedwater transient, because of a reduction of heat removal capacity on the secondary side of the steam generator. This reduction of heat removal capacity causes elevated secondary tempera-

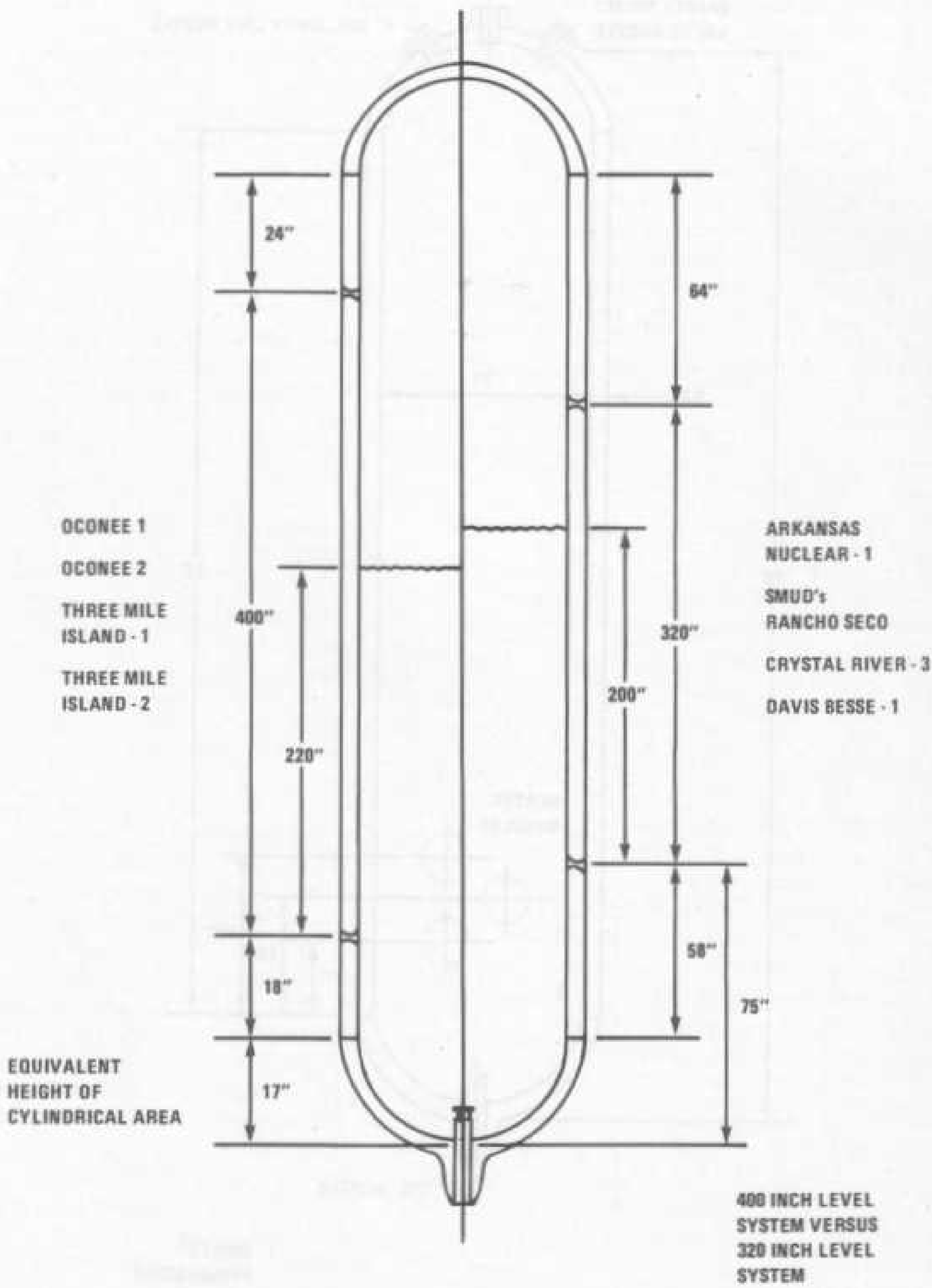

FIGURE I-13. Pressurizer Level Tap Location

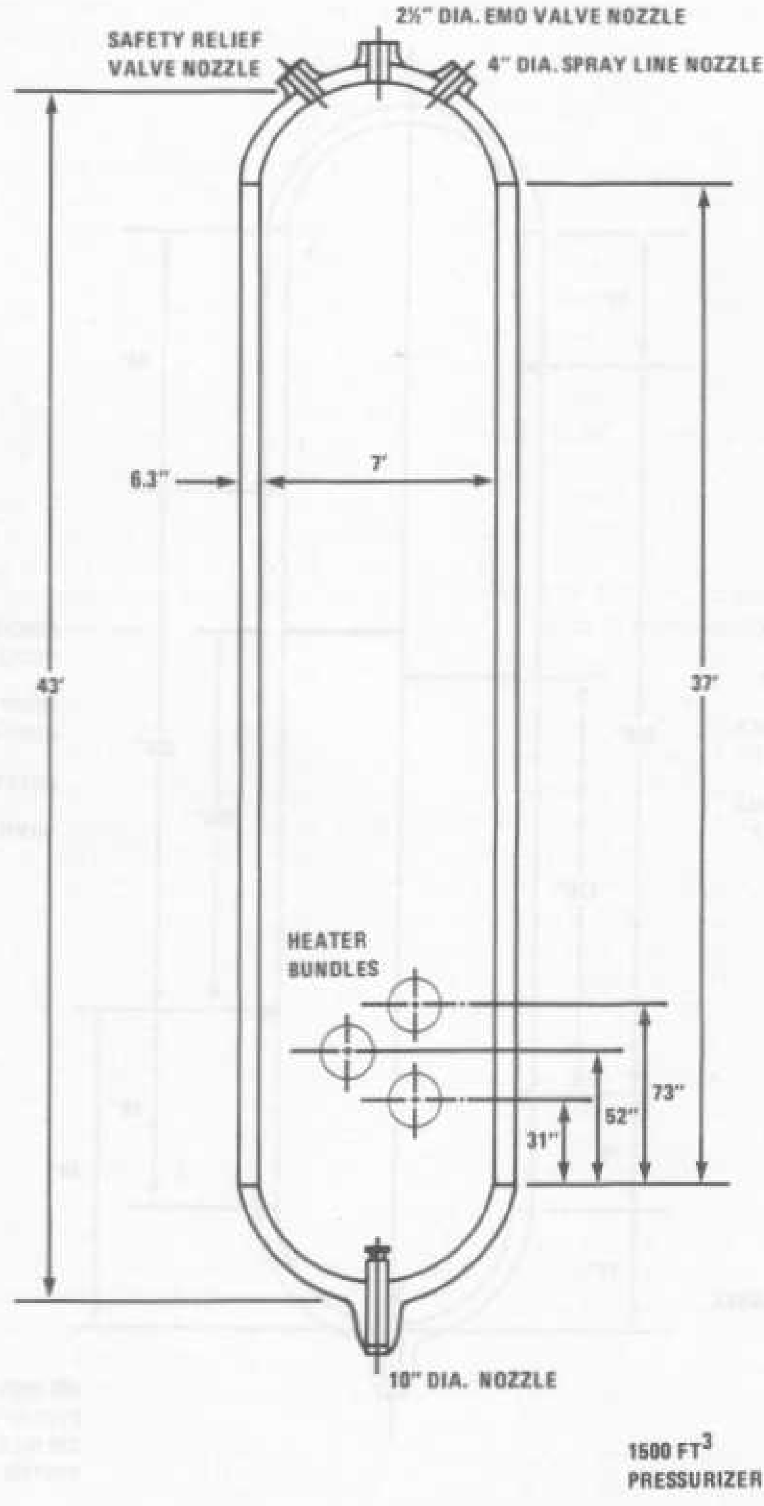

FIGURE I-14. Pressurizer Heater Bundle Location tures and thus causes pressures that exceed the safety relief valve setpoints. So the B&W design results in a more frequent challenge to the valve than other PWR designs do.

Main steam safety relief valves have a history of malfunctions. These valves are not classified as safety related, so they are not subject to the controls of the nuclear quality assurance program. While such valves have been used in fossil fuel plants for many years, the restrictive requirements for pressure control in nuclear plants tax the capability of these valves to perform satisfactorily.

One such malfunction occurred on April 23, 1978, at Three Mile Island, Unit 2. During a reactor trip, five main steam safety relief valves, after opening during a loss-of-feedwater transient, failed to close properly. As a result, the steam generators continued to steam directly to the atmosphere, removing more heat from the primary system than was intended. The overcooling of the reactor coolant caused shrinkage and loss of pressure level indication; that is, the level indication went to zero.

In a report submitted to the NRC, Met Ed stated that the high pressure injection system (HPI) was automatically actuated as the reactor coolant pressure dropped.[6] The report further indicated that the HR was bypassed within 6 seconds of its actuation. The bypassing took place while indicated pressurizer level was zero. Later in the event, high pressure injection was again initiated. A B&W study performed on the event concluded that the pressurizer never emptied. The B&W report also stated: "It appears that only the operator's timely initiation of HPI prevented this from occurring ...."[7] Subsequent calculations indicated that the core remained covered with water during the transient. However, boiling was concluded to have occurred.[8]

The following sections describe the design of the pressurizer; relate a history of correspondence and events, including two NRC inspections, which illustrate how problems with the pressurizer were identified and addressed; summarize this history; and set forth conclusions and recommendations.

Review of the B&W Pressurizer Design

The B&W design document, "Design and Performance Analysis-Pressurizer," which details how the pressurizer was designed and defines the conditions under which it was intended to function, states: "The pressurizer is an integral component of the primary system. Its function is to maintain system pressure within system design values and to absorb system fluid volume changes during all normal and abnormal transients."

Step 3 of the procedure (Section IIIA), which deals with minimum pressurizer level, is as follows:

> Set the pressurizer minimum level (volume) at the higher of:
>
> a. 150 cu ft, or
> b. the volume in the pressurizer lower head up to the tangent line.
>
> The level should not drop below this point during or after a reactor trip.[9]

The volume in the pressurizer lower head is not more than 56.8 cubic feet.[10] Therefore the minimum level (volume) for the purpose of this calculation is 150 cubic feet. This volume corresponds approximately to a level of 30 inches above the juncture of the lower head and the cylindrical body of the pressurizer. For an Oconee or TMI pressurizer, in which the lower tap for the pressurizer level indicator instrumention is located 18 inches above the juncture of the lower head and cylindrical body, a minimum indicated level of approximately 12 inches should result during or after a reactor trip. However, the lower tap at the Arkansas Nuclear One (ANO-1) plant is located 58 inches *above* the juncture. Thus, at ANO-1, at the limit of the design, the operator would **see** level indication at zero, but the *actual* level would be 28 inches *below* the bottom tap.

To determine the maximum outsurge (flow of water out of the pressurizer during a trip or transient), the B&W design document advises:

> Obtain the maximum outsurge. The outsurge is associated with a reactor trip from full power. The reactor coolant system temperature will drop from the reactor coolant system temperature at full power to the temperature corresponding to the turbine bypass set point ....n

This definition of maximum outsurge, which is associated with the minimum permitted pressurizer level during a transient, assumes that the maximum temperature change experienced from a trip at full power is governed by the bypass valve set point. The assumption does *not* take into account possible additional temperature changes caused by turbine bypass valve malfunctions, secondary safety relief valve malfunctions, or feedwater system malfunctions.

To locate the level taps, step 14 (Section IIIA) of the B&W analysis states:

> Set the location of pressurizer level indication taps by the following criteria:
>
> a. The lower level taps must be below the minimum pressurizer level to avoid loss of indication during the design outsurge.

b. The upper level taps must be above the maximum pressurizer level to avoid loss of indication during the design insurge.12

The design document also requires a check of the computed PZR (pressurizer) volume by comparing the step 14 criteria with pressurizer level response to certain transients as calculated by two computer programs. Documents examined in this investigation reveal that at least one of those programs was never certified as required by B&W design requirements; that is, validated by comparison against actual operating experience in at least three different applications.[13]

As the lower level taps for the ANO-1 series pressurizer were located above the minimum pressurizer level as defined in procedure step 3 (Section IIIA), as pointed out above, they were located contrary to the design requirements. A B&W engineering change authorization document specifically states that the tap location was changed to save $18 000 in the cost of welding.[14]

Similarly, there *was* an analysis available to B&W indicating that in event of a stuck-open pressurizer relief valve-such as'at TMI-the *upper-level* pressurizer taps might be covered, either in the TMI/Oconee or the ANO-1 pressurizer. On October 16, 1973, R. Jones, B&W ECCS Engineer, obtained the results of a CRAFT (Version 2) calculation (a type of computer analysis) performed to analyze the stuck-open safety valve transient.[15] The results of this analysis were provided to the NRC in a response to question 15.11 for the PSAR for the Bellefonte application, dated November 1, 1973. The question requested the following information: "Provide in Section 15.1.13 a discussion of the events following the opening of a pressurizer safety valve as required in the October 1972 Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants."

The response stated in part: "[A]t 166 seconds, the flow increases sharply as a two-phase fluid is being leaked through the safety valve rather than steam." Figure Q15.11-5, titled "Inner Vessel Liquid Volume for a Pressurizer Safety Stuck Open," was attached to that response. This figure showed voiding in the reactor vessel occurring within 200 **seconds of the safety valve failure. The volume of** fluid in the reactor vessel would indicate significant flow of reactor coolant to the pressurizer.

Had B&W compared the results of the CRAFT calculation to the pressurizer design requirements, they would have noted that the upper level taps would have been covered during the stuck-open safety valve transient; that is, that pressurizer level indication would have been at its maximum (offscale high). However, the pressurizer design document does *not* require that an analysis of pressurizer performance be performed under stuck-open safety valve conditions.

History of Pressurizer Level Problems

On August 13, 1974, a generator breaker trip test was performed at TMI Unit One. During this test, pressurizer level fell to approximately 40 inches. The pressurizer heaters cut off at 80 inches, thereby reducing pressurizer pressure. During a B&W presentation to the customer on September 4,1979, J. G. Herbein, Plant Superintendent, stated that there were two areas of operation that required improvement: first, during a reactor trip the pressurizer level should not fall as low as it did, and second, during a turbine trip from 100% power the reactor should not trip.[16]

It was further noted in the resulting Site Problem Report that the plant might further depressurize and high pressure injection might be initiated. The low pressurizer level during the transient was initially attributed to the turbine bypass valves staying open longer than necessary, but was later attributed to overfeeding with feedwater.[17]

On August 29, 1974, R. C. Luken, Plant Integration, B&W, raised the question of the effect on pressurizer response of turbine bypass valve matfunction in a memorandum to B. A. Karrasch, Control Analysis, B&W. (B&W diligently searched for this referenced memorandum but could not locate it.) In a September 18, 1974 memorandum, Karrasch noted to Luken that, "Depending upon the conditions of the makeup system, the pressurizer and surge line could be emptied causing the reactor coolant system pressure to drop to hot leg saturation pressure and possibly violate fuel compression limits." Karrasch further stated, "The current Control Analysis workload would preclude an analysis of this type before the first quarter of 1975."[18]

Karrasch then turned his attention to pressurizes level indication. He wrote:

> Mr. Burris has recently conducted a survey of the pressurizer level tap locations for all the 177 FA plants. The lower tap on the Toledo (Davis Besse) **pressurizer is 40" above the normal tap location and will result in loss of pressurizer level** *indication* during a normal reactor trip. Even though adequate level exists, the loss of level indication is probably not acceptable to the customer and should be investigated before plant startup.

Karrasch then described three options to "solve this potential problem with indicated pressurizer level." First, the plant could operate safely at a higher operating level except possibly for ATWS (anticipated transients without scram). Second, the tap could be lowered 40 inches. Third:

> Change nothing and inform the customer that he will lose indicated pressurizer level following a normal reactor trip transient (I believe this will be unacceptable to the customer). We may be able to show that with proper use of the makeup and letdown valves, and using Oconee, TMI and Arkansas data, that the pressurizer level will not be lost following a reactor trip. This would also require analysis and at best may show that the indicated pressurizer level will stay just on scale for the assumed conditions. 19

In a September 24, 1974 memo, E. R. Kane, Reactor Performance Service, B&W, notified J. N. Kaelin, the B&W Site Operations Manager at Arkansas Nuclear Unit One, of the pressurizer level problem. Kane wrote:

> Evaluation of data from Oconee Units I and II and TMI-1 reveals the possibility of an extremely large and rapid decrease in pressurizer level during RC pressure transient following reactor trips. TMI-1 experienced a drop t ~ 3" during the Generator Trip Test from 100% F.P0

He continued:

> Because the upper and lower pressurizer level taps at Arkansas are forty (40) inches below and above, respectively, the upper and lower taps at TMI-1, the possibility exists that level indication will be lost completely following a significant RC pressure transient. For this reason, it is recommended that the pressurizer level control setpoint be increased by 30" to 210" with an operating band of ±15 inches. Since pressurizers at other B&W plants have level taps locations identical to Arkansas, the performance of the plant during a reactor trip from 40% FP is vitally important for evaluating proposed corrections to this problem. Please forward pertinent reactimeter data (particularly, pressurizer level and RO pressure) to Lynchburg as soon as possible after the trip.20

In a September 26, 1974 memorandum to J. Anderson, ANO Plant Manager, Kaelin recommended increasing operating level in the pressurizer21 and notified him that the pressurizer level taps were 40 inches higher and lower than at TMI and Oconee.

On October 2, 1974, G. H. Miller, Chairman of the ANO Plant Safety Committee (PSC) forwarded the minutes of a committee meeting that took place on October 2, 1974 to J. Anderson. The minutes state:

> The PSC feels this (increasing level to 210 inches) is an unreviewed safety question since no analysis appears to have been conducted to verify [that] the pressurizer will not go solid during a load rejection without reactor trip, thus also causing a potential loss of pressurizer level indication. The PSC recommends that B&W be requested to justify the location of the low level tap at ANO based on Three Mile Island, Unit 1 and Oconee I and 11.22

Anderson forwarded the PSC concerns in a memorandum to W. Cavanaugh, Manager, Nuclear Services, Arkansas Power and Light (AP&L), dated October 15,1974.23

On October 18, 1974, AP&L responded to the B&W recommendations to increase the pressurizer level. Cavanaugh noted:

> We have subsequently learned that, during the same transient [Generator Trip] at TMI-1 the pressurizer level first increased by 60 inches. Applying this 60 inch rise to the proposed maximum operating level of 225 inches, the level would reach 285 inches. This is within 5 inches of a previous B&W recommendation for an administrative reactor trip at 290 inches and approaches loss of indication high conditions.24

Cavanaugh stated that the recommendation to increase pressurizer level could not be implemented because:

> 1. No analysis has been provided to AP&L to verify that this change will not cause the pressurizer to fill solid resulting in loss of level indication during a load rejection without a reactor trip.
> 2. No analysis results have been provided which indicate that the accident analysis contained in the FSAR would not be affected. Parameters affected would include (1) additional mass released due to increased Reactor Coolant System (RCS) volume, and (2) time for pressurizer to fill solid.
> 3. Basing the recommendation on a transient including one turbine bypass valve partially stuck open is not valid since the turbine bypass system is non-Q and more than one valve may stick open resulting in a more severe transient.
> 4. Explain the reason for the difference in the location of the level tap at ANO versus TMI-1 and Oconee 1, 2 and 3.25

In the meantime, correspondence between B&W and AP&L was going back and forth about acceptance criteria for the pressurizer level in reactor trip tests.

Kaelin, B&W, wrote AP&L's Anderson a memorandum on October 29, 1974, about changing these acceptance criteria on pressurizer level. He said a recent reactor trip test had resulted in failure to meet these criteria. Kaelin stated that the pressurizer heaters would cut off during reactor trips because the pressurizer was not designed to keep them covered. He also noted that the location of the level taps ensured a sufficient volume of reactor coolant in the pressurizer at 0 inches indicated and that a steam bubble still existed when the level was 320 inches indicated. He continued, "The acceptance criteria [in the test] ... should be revised to apply only to normal pressurizer system operation (prior to reactor trip) and another acceptance criteria of 0 to 320 inches indicated, be established for the transient associated with a reactor trip."[26]

On November 1, 1974, R. F. Rogers, a Reactor Inspector assigned to Region II, filed the following report after reviewing a turbine-reactor trip test performed at ANO-1:

> Two acceptance criteria were not satisfied in the performance of this test. Paragraph 8.1.01/002 requires that high pressure injection not be initiated and Paragraph 8.2.01/003 requires that pressurizer level remain between 40 inches and 300 inches. High pressure injection was manually initiated due to decreasing pressurizer level while the actual level reached approximately 31 inches. The corrective action listed in the test document for these deficiencies *indicate that none is possible* and that these deficiencies *are characteristic of the primary system.* (Emphasis added.)

This test was approved for final acceptance by the station superintendent on Form A-16, Test Endorsement Record, on October 4, 1974. This form states that all deficiencies and discrepancies have been cleared and all acceptance criteria have been met.

> In discussions with licensee [ANO] representatives, the inspector was shown a letter from Babcock and Wilcox, dated October 29, 1974, which provided technical justification for a lower pressurizer level limit and recommended that the licensee revise its acceptance criteria as presently stated in this test. This had not been done. Inability to meet test acceptance critera in the power ascension test program must be fully documented and evaluated prior to final acceptance by the plant superintendent. This evaluation and acceptance must be completed for this test and will remain an unresolved item.[27]

The ANO Test Working Group that reviewed startup test results, met on November 20, 1974.[28] They reviewed the test deficiencies observed during the turbine reactor trip test. They resolved these deficiencies using the following rationale:

1. Regarding the acceptance criterion that high pressure injection not being initiated, they concluded that since it was actuated manually instead of automatically, the acceptance criterion was met.
2. They stated that reactor coolant temperatures were lower than designed because of equipment malfunctions.
3. Regarding the acceptance criterion that pressurizer level not go below 40 inches during the test, they noted that the ANO pressurizer lower level taps were 40 inches above other comparable B&W plants, and further, that the only limit on pressurizer level should be that it remain onscale (greater than 0 inches) to assure that water remains in the pressurizer and that the reactor core is not uncovered.

In the next inspection report, NRC's ANO-1 Project Inspector, M. L. Kidd, resolved the unresolved issue reported by Rogers. He wrote:

> The documentation regarding inability to meet certain acceptance criteria in TP 800.14, "Turbine/Reactor Trip Test," at forty percent power did not fully justify acceptance of the results. (RO Report No. 50-313/74-14, Details II, paragraph 2.a). On November 11, 1974, further explanation as to why the test results were acceptable was entered into the test summary. This additional justification was reviewed and accepted by the Test Working Group on November 20,1974.
>
> Regarding Criterion 8.1.01.002 which required that high pressure injection (HPI) not be initiated, it was explained that this referred to automatic initiation of HPI due to low reactor coolant system pressure. The fact that HM was manually initiated (starting of a makeup pump) due to low pressurizer level did not detract from the test results .[29]

On November 18,1974, a reply from Baker (B&W) answered the October 18, 1974 letter from Cavanaugh (AP&L), in which Cavanaugh had rejected B&W's recommendation to solve the pressurizer level problem by increasing the normal operating level from 180 inches to 210 inches. That suggestion was now withdrawn and Karrasch's third alternative-"do nothing"-was adopted with an additional suggestion for quick operator response in the event of a reactor trip. Baker stated:

> The B&W recommendation to increase the normal operating pressurizer level from 180 inches to 210 inches was intended to be a temporary measure to preclude possible loss of *indicated* pressurizer level following a reactor trip. Operating data from Oconee and TMI shows that the pressurizer level may approach a zero indication at Arkansas following a reactor trip, depending upon initial conditions of the pressurizer, the primary makeup and purification system response and the steam relief system response. Based upon a TMI concern that their indicated level might be lost for various conditions following a reactor trip, we assumed Arkansas would have the same concern and recommended the level setpoint increase to minimize the probability of this occurrence. After plant startup testing and with data in hand from several reactor trips, the recommendation would then have been reevaluated. Further evaluation of the increased level setpoint has resulted in a revised B&W position, and we now feel that the original 180 inch pressurizer level setpoint should be retained and the previous recommendation be disregarded. Actual reactor trip transients at Arkansas will still enable us to evaluate the pressurizer level response and even if *indicated* level is lost momentarily, the actual level will still be available to maintain RC pressure, which is the parameter of interest. We would suggest that the operators be instructed to secure letdown flow and increase makeup flow immediately follow-

ing a reactor trip to help maintain the ;iressurizer level; these actions are being taken at Oconee and TMI.[30]

During December 1974, pressurizer level indication was lost during a trip from 100% power.[31]

On December 6, 1974, Cavanaugh replied to G. M. Olds, Senior Project Manager, B&W:

> [You] withdrew your recommendation to increase the normal operating level from 180 inches to 210 inches indicated level to preclude possible loss of indicated pressurizer level following a reactor trip. However, that letter did not address the fact that ANO-1 lower level tap is 40 inches above the tap on Oconee and Three Mile Island.[32]

Cavanaugh then pointed out that the FSAR showed an erroneous location for the level tap and that a reactor trip from 75% full power (FP) resulted in loss of indication for 45 seconds. He further explained that following trips from 100% FP, the level indication could be lost in excess of 1 minute.

On December 11, 1974, D. A. Reuter, Licensing Engineer, AP&L, wrote Cavanaugh about future test requirements:

> I can also find no unreviewed safety question involved in reducing the acceptance limit on the pressurizer level, but did have some questions on the pressurizer level instrumentation as noted in reference 5 [memo, Cavanaugh to Olds, December 6, *1974]*. These questions do not, however, directly affect the acceptance criteria on lower limits and thus I concur with this change.33

On December 12, 1974, a telephone conversation was held among Baker, Cavanaugh, and Reuter. B&W had no documentation regarding this telephone conversation. Statements by W. Cavanaugh,[34] J. Anderson,[35] and D. Reuter[36] indicate either that the reason for the tap change cannot be recalled or that a satisfactory explanation for the tap change was not received.

In response to a Special Inquiry Group (SIG) request, B&W furnished the file copy of the December 6, 1974 memorandum from Cavanaugh to Olds. This memorandum includes a handwritten note associated with the initials R.P.W. (Assumed to be those of R.P. Williamson, since he was on the distribution list). The note states, regarding item 1 (FSAR Figure 4-6): "This is probably generic on 177 F.A. (Fuel Assembly) Plants ... NSS 8-14." NSS 8-14 refers to the contract numbers for ANO, Oconee 3, Rancho Seco, Midland 1 and 2, and Davis Besse 1. In addition, we reviewed the FSAR copy maintained by the NRC Licensing Project Manager, G. Vissing, for data pertinent to pressurizer level instrumentation. Table 7-11 in the FSAR lists the range of the pressurizer level instrumentation as 0 to 400 inches. This information is contrary to the actual 320-inch range. Cavanaugh has said that his FSAR also indicates 0-400 inches as opposed to 320 inches.[37]

On January 22, 1975, Cavanaugh wrote Anderson:

> On the matter of changing the acceptance criteria on reactor trip to [greater than] 0 [inches] level indication on the pressurizer [versus greater than] *40* [inches), B&W said that this change was due to the difference in lower level tap location between Oconee and ANO-1. B&W further stated that the acceptance criteria could be that the HPSI actuation setpoint on the RCS pressure is not reached. Thus, if we lost level indication during a test, we could justify the results as acceptable based on the RCS pressure during the transient.[3B]

On February 3, 1975, G. Miller (AP&L) forwarded to Anderson the minutes of a PSC meeting that took place on January 28, 1975. The minutes noted that: "Committee reviewed letter NDC 2183 [memo, Cavanaugh to Anderson, January 22, 1975], Pressurizer Level Setpoint and did not concur with loss of indication statement. Committee views this as an unreviewed safety question."[39]

On February 6, 1975, Anderson responded to Cavanaugh's January 22 memorandum as follows:

> Below are comments on above named subject, as listed by the Plant Safety Committee. I concur with P.S.C.
>
> Paragraph 1 [memo, Cavanaugh to Anderson, January 22, *1975]* states that we have no problems on loss of level indication in the pressurizer as we still have RCS pressure indication. The PSC does not agree because we have never been shown that just staying above the HPSI [HR] setpoint *(1500* psig) ensures that the Rx [Reactor] core is covered with water. As far as the PSC is concerned, when all pressurizer level indication is lost then there is no way to know whether the core is covered with water and therefore, a safety question exists-which 2s unreviewed and probably not easily solved

On March 3, 1975, a memo from Cavanaugh to Govers, Service Project Engineer, B&W, addressed this concern about voiding in the reactor coolant system. The memo refers to the December 12,1974 telephone conversation by stating:

> [I]t was pointed out by B&W that there is no operational problem as long as the pressure is staying away from the automatic HPSI actuation setpoints; that manual HPSI [HPI] initiation is not required as long as a *RCS* pressure indication is available in the control room; and that the pressurizer is sized to maintain *RCS* pressure even if the level indication is lost. B&W further stated that the acceptance criteria on pressure following a reactor trip could be that the HPSI [HPI] actuation setpoint is not reached. In order for us to evaluate the above information, we request that you provide us with information showing that staying above the HPSI [HPI] setpoint (1500 psig) ensures that the reactor

core remains covered with water. This is necessary in completing our review of the deletion of manual HPSI initiation from the procedures following reactor trip which has an impact on the number of HPSI [HPI] transients during plant life.[40]

In the meantime, AP&L's Safety Review Committee (SRC) had also reviewed the pressurizer level setpoint and concluded that it was *not* an unresolved safety question-the opposite of the *PSC's* conclusion. On March 3, 1975, the Safety Review Committee met to consider this difference of views. The committee's minutes record:

> Follow
> January minutes. The PSC reviewed letter NDC 2183 [memo, Cavanaugh to Anderson, January 22, 1975], Pressurizer Level Setpoint, and determined it to constitute an unreviewed safety question. The SRC had previously reviewed this letter and found it to not constitute an unreviewed safety question. Since there had been little communication between any PSC members and SRC members on this matter, there was some confusion about it. More information will be gathered and presented at the next SRC meeting.[41]

The SIG reviewed the subsequent SRC meeting minutes for March 7, 1975. There was no mention of pressurizer level indication. The SRC meeting minutes for March 17, 1975, *do* record that the SRC reviewed the March 3, 1975, PSC minutes, but no reference *is* made to the disposition of the *PSC's* concern about pressurizer level indication. On April 3, 1975, B&W responded to AP&L's request for an analysis in a memo from J.D. Phinney, Manager, Operating Plant Services and Maintenance, to Cavanaugh. It stated:

> Even though the pressurizer water outsurge during system cooldown will allow system pressure to fall below 2155 psig, data from reactor trips at B&W's operating plants shows that the RC pressure remains well above 1500 psig. With the RC cooldown established by means of the turbine bypass valves' pressure setpoint, RC pressure will not drop to 1500 psig unless the pressurizer is completely drained. If the pressurizer were to drain completely, RC pressure would drop rapidly to the saturation pressure for the hottest water remaining in the RC system. The temperature of this water would be between 550F and 579F with a resulting RC pressure of 1010 psig to 1300 psig. This resulting pressure *band* if the pressurizer were to empty following a reactor trip is well below the 1500 psig HPSI automatic initiation setpoint. Thus 1500 psig is an adequate low pressure setpoint for ensuring that the reactor core remains covered with water.[42]

On April 15, Cavanaugh (AP&L) informed Anderson (AP&L):[41]

> Attached is reference 3 [letter, Govers to Cavanaugh, March 3, 1975], from B&W which provides their answers to PSC comments on loss of level indication in the pressurizer following a reactor trip. From that letter, it can be seen that as long as water remains in the pressurizer the core will remain covered and the HPSI [HPI] setpoint will not be reached. If the pressurizer empties, HPSI [HPI] will be automatically initiated due to the rapid pressure drop mentioned in their letter.[43]

On April 30, 1975, after the PSC had reviewed the April 15, 1975 memo, Anderson replied to Cavanaugh:

> It is agreed that staying above the 1500 psig setpoint ensures that the Rx core is covered with water. However, since the pressure should stay above 1500 psi until the pressurizes is emptied and then *immediately* drop to well below the 1500 psig setpoint, it is too late for proper corrective action since the steam bubble would then be drawn into the Reactor Vessel. Once level indication is lost, there is no way for the operator to know where the Pressurizer level is until an immediate drop in pressure indicates that the pressurizer is dry or until its level increases (due to HP injection and T_{we} leveling out) to the point of being on scale again.
>
> There is an alternative, which the PSC has recommended that Operations use in the event of a Reactor Trip. (Actually this technique has been required on all Rx trips to date.) This is to initiate High Pressure Injection manually as soon as possible following confirmation of a Reactor Trip. This technique can ensure that Pressurizer level will not drop below its indication range provided HPI is initiated early enough following the trip. There is a problem with this, however, in that according to B&W the HPI nozzles at the point of entry to the RCS have a design life of only 40 cycles (temperature transient). Although this number does not appear in the FSAR, AEC Question 4.1 shows an allowable 480 transients for the HPI System. Even at 480 cycles this is only 12 trips per year for 40 years and experience indicates that we will probably have more than 12 trips in an average year.
>
> I request that the SRC review the PSC's recommendation to manually initiate HPI upon confirmation of Reactor trip and that Nuclear Service personnel communicate with B&W to determine if 40 cycles is, in fact, the design life for the HPI nozzles. Please forward your recommendations as early as possible.[44]

In May 1975, pressurizer level indication was lost following a reactor trip from 100% power.

Phinney (B&W) visited the ANO site during May

Anderson, the Plant Manager. He recorded that:

> Loss of pressurizer level indication on unit trip, although may be technically justifiable, certainly is not desirable. The 40 cycle limitation on HP injection on top of this further complicates the problem. AP&L is currently deciding if this condition is a significant design deficiency, reportable to the NRC. I [Phinney] indicated to Mr. Anderson that B&W has stated our position and that additional work on our

> part would be considered enhancement and we would consider such additional work under the Master Services Contract. There are some things which can be done such as analysis to increase the number of allowable HP Inj. [injection] cycles or changing level taps and instrumentation. I [Phinney] understand there is a pressure tap on the surge line.[45]

On June 10, 1975, Cavanaugh (AP&L) contacted D. J. Stokes, Bechtel Project Manager, to request an analysis for actuating the standby makeup pump to automatically supply additional flow to prevent low pressurizer level.

On July 9, 1975, E. H. Smith, Bechtel Project Engineer, responded to Cavanaugh's request. He stated that the requested analysis showed that simply starting a second pump would probably not provide sufficient flow to keep pressurizer level on scale. By adding a valve, sufficient flow could be obtained, but electrical circuitry for the makeup pumps would be complex and would require extensive amounts of new cable.

He summarized: "In view of the above we recommend correcting the pressurizer level instrumentation rather than starting the second makeup pump "[47]

On July 24, 1975, R. Govers (B&W) forwarded to Cavanaugh a report which elaborated on the subject of pressurizer level. This report was prepared by R. W. Winks, B&W Control Analysis Engineer. Govers wrote: "Although the above reference [memo, Govers to Cavanaugh, April 3, 1975] pointed out that the loss of pressurizes level indication does not constitute an unsafe condition, we are providing in the attached report specific recommendations for maintaining pressurizes level indication above zero inches."~

Winks referred to two requests in his report:

> Arkansas Power & Light Company has requested that B&W define what recommended actions should be taken to ensure that the indicated level of the pressurizer does not drop below zero inches on future major plant transients. An additional request was made for B&W to clarify transient pressurizer system performance presented in the Reactor Coolant System Functional Specification i4[8]comparison with actual pressurizes performance9

In response to the first request, Winks recommended that the code steam safety valve be readjusted so that the minimum steam pressure remained greater than 980 pounds per square inch in the steam generator. Additionally, he advised AP&L to check the calibration of their pressurizer level signal processing system. Regarding initiating high pressure injection, Winks said that the operator should no longer start the makeup pump, which is connected to the normally unused injection nozzle, whenever RC pressure decreases below 1800 psig or pressurizer level approaches a zero indication. Winks commented that starting a second makeup pump would have a small impact on pressurizer level. He also recommended setting the pressurizer level setpoint at 190 to 195 inches.

In response to AP&L's second request Winks wrote:

> A review has been conducted of the pertinent sections of the B&W Reactor Coolant System Functional Specification for ANO-1 as requested by AP&L. It was their concern that actual pressurizer system performance did not agree with that stated in the above document and B&W should clarify any discrepancies.[50]

Regarding the applicability of design to the ANO operation, Winks continued:

> The graphs of predicted system behavior for each transient were developed using a B&W hybrid analog-digital computer simulation of the Arkansas Plant. The simulator was subjected to a large number of severe transients specifically to be conservative for subsequent design stress analyses on RCS components and the transients were not designed to accurately represent actual plant performance.[51]

Winks then referred to the three analyzed transients which he considered to be pertinent. The most germane transient was the turbine trip followed by a reactor trip. The B&W analysis predict- that reactor pressure would level off at 1700 pounds per square inch and pressurizes level would reach a minimum at 50 inches. Winks wrote that the feedwater flow modeling was "unlike the actual sudden decrease and rapid increase in feedwater flow generally occurring at the plant."[52] At no point in his description of the system design did Winks mention the "Design and Performance Analysis-Pressurizer" (previously described), although there was an oblique reference to the individual component functional specifications.

On August 5, 1975, Cavanaugh wrote D. J. Stoker, Project Manager, Bechtel Power Corporation: "We have reviewed your reference letter concerning the increase of makeup flow to prevent pressurizes low-level during a reactor trip. Based on Bechtel's conclusion, we have determined that the problems of piping, valves, and electrical circuitry needed to accomplish additional make-up are more complex than we can justify without more plant data."[53] Cavanaugh then requested that Bechtel investigate and complete a proposed design to extend the range of existing level instrumentation by means of a tap on the surge line.

On the same day, Anderson wrote to Cavanaugh, commenting on Winks' recommendations. Regarding adjustment of the code steam safety valves, he said:

> We concur that it would be nice that T_{81e} not fall below 548°F. We do not concur that this can be accomplished solely by resetting our main steam safeties. Further, we believe that the blowback of the main steam safeties has been optimized through several attempts at resetting the amount of blowback in the early phases of ANO-1's startup test program. It is possible that some drift has occurred since the last setting; but since resetting of blowback is largely a trial and error process, it is likely that an attempt at change might worsen rather than improve the present blowback.
>
> The B&W letter fails to relate differences in F.W. flow following the two trips discussed. It has been noted that excessive F.W. flows following a trip can drive T_C down just as effectively as lowering turbine header pressure.
>
> It is felt that the ICS system design, which allows a runback of F.W. after trip at normal tracking rate (20°%/min.), is a major contributor to the excessive shrink noted in our system. Even though the main and to-load block valves trip closed rapidly on a trip, far too much F.W. flow is driven through the full-open S.U. valves which will not modulate to old to-level limit on the OTSGs until the F.W. demand signal is run back to below the to-level limit value. This does not occur until 4 minutes following the trip. Excessive F.W. flow also creates excessive blow time of the M.S. safeties, which tends to lower their lift and reset points.
>
> The Operations group suggests that the S.U. control valves be placed in manual and reduced to 10% demand (after the main F.W. blocks are opened in the course of plant startup). If a trip occurs, the F.W. flow will decrease at whatever rate the main and to-load blocks will travel closed down to the minimum pre-set value. Hopefully this would provide data to demonstrate our contentions. A long-term solution, such as instantaneous ICS runback on Rx trip, could then be pursued.[54]

With respect to pressurizer level instrumentation, Anderson told Cavanaugh: "As pointed out, these differences could be due to F.W. flow differences between the two trips."[54] He said that the plant staff had rejected the idea of starting an additional makeup pump as a solution: "We disagree; we do not want an unnecessary E.S. actuation to the same extent as some don't want the unnecessary HPI nozzle thermal cycles. See note below."[54] He also rejected increasing normal pressurizer level: "We wholeheartedly disagree; this would eliminate any possibility of surviving load rejection, or loss-of-pumps runbacks."[54] Anderson concluded: "If operations were provided with wider range pressurizes level indication, the standby E.S. pump wouldn't be started."[54]

On September 8, 1975, E. H. Smith, Bechtel Project Engineer, wrote Cavanaugh.[55] He enclosed drawings for the level transmitter modification to relocate the lower level tap in the surge line and said that construction would start upon Cavanaugh's approval.

On October 1, 1975, E. H. Smith, again contacted Cavanaugh regarding the proposed modification. He wrote that further analysis had disclosed a problem:

> Specifically the results of our analysis indicate that, during the transient associated with reactor trip, velocities in the pressurizer surge line may exceed 50 feet per second. These velocities would significantly affect the performance of the instrument, causing it to give erroneous information.

Smith further mentioned Bechtel's investigation of alternate methods for solving the problem.

On November 6, 1975, R. A. Govers (B&W) wrote Cavanaugh expanding B&W's recommendation to reduce the decrease in pressurizer level in a post-reactor trip condition.[52] Govers recommended that the response of the turbine bypass valves and feedwater system be investigated further. Govers noted: "Further improvements to the ANO-1 feedwater system can probably be made in the areas of optimized tuning or equipment enhancements. This should be pursued on a priority basis. B&W is prepared to assist AP&L in this investigation as a task under the Master Services Contract."[57]

On December 10, 1975, Smith wrote Cavanaugh on the level transmitter modification. Again, a modification was proposed that would provide erroneous indication, but Bechtel commented that the transmitter would indicate very closely the minimum pressurizer level. Smith went on to say:

> During the meeting [November 20, 1975] you indicated to us that the main object is to establish the elevation of the lowest point of the surge. This information is required in order to ascertain that the pressurizer level does not drop low enough as to result in steam binding of the reactor vessel. If the level stays within the PZR [pressurizer] vessel, as expected by B&W, and as would be deduced from the original curve, we believe that the suggested solution is adequate to confirm B&W's information and to establish the lowest point elevation.[SS]

On January 5,1976, Cavanaugh wrote Anderson:

> We have received a proposal from Bechtel to measure pressurizer level below the present range of our level indicators. This proposal states that during a rapid level change the indicator would give erratic indication. However, during a downsurge the indication would be lower than the actual condition such that conservatism would exist in the instrument.[59]

Cavanaugh then asked Anderson to evaluate the proposal.[59]

On February 17, 1976, Luken (B&W) wrote Cavanaugh:

> At a recent meeting with representatives of AP&L to discuss problems in plant response to large

upset transients, AP&L indicated a desire to change the turbine bypass and steam code safety relief valve setpoints for ANO-1. Presently, interaction between these valves results in unsatisfactory utilization of the turbine bypass valve relief capacity, thereby requiring the steam safety valves to relieve steam for a longer period of time. This overheats the valve seats lowering the safety valve reseat pressure and results in cycling which over cools the reactor coolant system [0]

Govers then suggested that the setpoint changed on the bypass valves and that the pressure setpoint be changed on some of the code safety relief valves.

On October 21,1976, B. F. Hill, B&W Plant Equipment Services, sent a memo to R. J. Baker, E. L. Logan, and C. E. Mahaney so that they could apprise Crystal River, Midland, and Davis Besse personnel of the pressurizer offscale indication problem. Hill noted: "The 177 fuel assembly plants with the pressurizer level indication range of only 320 inches are susceptible to below zero level indications on reactor and turbine trips and load rejection transients." He recommended increasing the operating pressurizer level from 180 inches to 200 inches noting: "Any additional increase in level will be in conflict with the assumptions employed in the Anticipated Transient Without Scram study for the NRC." He also recommended readjusting the safety valve blowdown noting:

> The amount of blowdown of the steam safety relief valves has been assumed to be 5% or approximately 50 psi for the safety valves with the lowest setting (1050 psig). Measured steam line pressures at operating plants of this type indicate that the actual blowdown is about 7% or 75 psi and even as large as 8.5%. The minimum reactor coolant system average temperature following a reactor trip should not decrease below 548"F and the minimum steam generator discharge pressure should exceed 975 psig at the same time [s1]

Recapitulation and Analysis

A concern about preventing pressurizer level indication from going too low was expressed by Metropolitan Edison to B&W as a result of a genera-for breaker trip test at TMI-1. B&W Lynchburg personnel evaluated this concern and noted that under certain circumstances the pressurizer might be voided altogether. They also realized that the problem of pressurizer level going too low, as it did at TMI-1, might be more pronounced at certain other B&W plants, including ANO-1 and Davis Besse, where the lower tap was 40 inches higher than at TMI-1. A B&W official (Karrasch) proposed three alternatives to deal with the latter problem: lower the tap; raise the normal operating level of the pressurizer so that the level would have further to fall in the event of a transient; or do nothing and tell the customers that even if level indication were lost, level would still be sufficient. He noted that the third alternative would probably not be acceptable to the customers.

B&W notified AP&L of the level indication problem. The mention of possible pressurizes voiding was not passed along. B&W's notification included a recommendation to increase the operating level. AP&L's Plant Safety Committee then evaluated the recommendation and determined that the change had not been analyzed to their knowledge, that conditions could be worse than those assumed in B&W's letter, and that loss of pressurizer level indication *high* might result from the change in operating level. It is interesting to note that AP&L apparently was unaware that the level tap had been moved up until they received this B&W notification on September 26, 1974, because the FSAR showed an erroneous location for the level tap. (The range of the pressurizer level instruments was also erroneously listed in the FSAR.) AP&L has told the SIG that they did not conduct QA audits directed toward the design or fabrication of the pressurizer level instrumentation, and that upon discovery of the reduced level range of the pressurizer level indicator, they did not review B&W's documentation on the subject.[62]

After receiving the AP&L evaluation, B&W withdrew its recommendation for increasing the operating level. B&W at this point did not acknowledge the possibility of pressurizer voiding, but rather, stated that level would be available, even if indication was lost, to maintain pressure. B&W then recommended instructing the operators to take immediate corrective action following a reactor trip by increasing makeup flow.

A technical support inspector from Region II noted the low pressurizer level problem during his review of test acceptance criteria for minimum level. Documentation reviewed by him indicated no corrective action was possible to address the low pressurizer level test deficiency. It should be noted that the testing was performed under conditions (manual initiation of HPI) that resulted in higher pressurizer levels than would be experienced without operator actions. The inspector also noted that the plant superintendent had already approved testing that pointed out the deficiency. AP&L then received a recommendation from B&W to change the test acceptance criteria. AP&L reviewed and approved these test acceptance criteria changes, approving operator actions to address the deficiency. In the next inspection report, the NRC project inspector closed out the item. The inspector noted that one of the test acceptance criteria apparently had not been met because the high pressure injection had come on, but he accepted the utility's explanation that since high pressure injection had been initiated *manually* rather than automatically, the test was accepted.

The Plant Safety Committee (PSC) again reviewed the loss of pressurizer level issue, and again classified it as an unreviewed safety question. The plant superintendent noted that the issue probably was not easily solved. He further noted that B&W had stated that the pressurizer was sized to maintain RCS pressure even if the level indication was lost, but that it had never been shown to AP&L by B&W that even if this occurred, the reactor core would definitely stay covered. AP&L requested an evaluation to assure that if pressure dropped but stayed above the high pressure injection setpoint, core uncovery would not result.

The Safety Review Committee (SRC) had previously reviewed Cavanaugh's memo to Anderson, dated January 22, 1975, and found that the deficiency did *not* constitute an unreviewed safety question. The SRC then reviewed the PSC decision that there *was* an unreviewed safety question and cited confusion about the issue. The confusion apparently resulted from little communication between the PSC and SRC. Although there was a statement in the SRC minutes that more information would be gathered and presented at the next SRC meeting, there was no mention of the issue in the minutes of the next meeting.

B&W responded to the request for further evaluation by stating that the pressure could drop, but would stay well above the high pressure injection setpoint. B&W reported that if the pressurizer voided, core exposure would not occur because pressure would drop rapidly to below the HPI setpoint and HPI would actuate automatically, providing more water to the core. The concern about pin compresssion limits being exceeded as the result of bypass valve malfunction, previously raised by Luken, was not addressed. Neither were the effects of saturation on system performance or operator response addressed.

Section II, step 15 of B&W's design document, "Design and Performance Analysis-Pressurizer," provides that: (1) the lower level indication tap must not be uncovered; (2) the resulting pressure must not be less than the high pressure injection setpoint plus 100 pounds per square inch; and (3) if the pressurizer heaters are uncovered, the addition of makeup water to cover the pressurizer heaters should not cause the reactor coolant system pressure to decrease to less than the high pressure injection setpoint plus 50 pounds per square inch. Thus B&W's response was not consistent with its own design criteria.

The PSC then proposed that HPI be initiated manually following a reactor trip, but observed that such a procedure created a problem with stresses in the HPI piping.

AP&L Plant Superintendent Anderson then discussed the issue with a B&W representative visiting the plant and told him that AP&L was considering whether the loss of pressurizer level indication was a significant design deficiency. The B&W representative stated that additional work on the subject by B&W would result in additional charges.

B&W conducted a study of the pressurizer level problem at ANO-1. This report compared performance at ANO-1 and TMI-1. The report made recommendations to AP&L to limit the cooldown of the primary system. B&W had been asked to conduct a review of their design requirements versus the operating experience at ANO-1, but in fact the analysis they performed stressed the difference in the way the plant was analyzed as compared to what was experienced in operation.

The AP&L plant staff reviewed the B&W recommendations made in the above referenced report and rejected them, adding: "If operations were provided with wider range pressurizer level indication, the standby (HPI) pump wouldn't be started."

AP&L contacted their architect-engineer, Bechtel Power Corporation, and asked Bechtel to evaluate increasing the makeup capacity to prevent low level during a reactor trip. This evaluation was done and submitted to AP&L. AP&L rejected this course because of Bechtel's description of the "complexity" of the modification. Bechtel was then asked to modify the pressurizer level instrumentation to increase its range. Drawings were prepared, but this modification was never implemented.

A meeting was held between AP&L and B&W to discuss changes that would improve the pressurizer level problems. It was finally decided to adjust the setpoints on the bypass valves and safety valves.

Two years after the loss of indication problem was identified, B&W initiated recommendations to the Crystal River, Midland, and Davis Besse facilities to address the issue.

Conclusions

1. Operating experience in B&W plants demonstrated that the system had been designed so that a system component, the pressurizer, was not capable during certain anticipated operating tran-

sients of maintaining reactor coolant system pressure at a level that would prevent the reactor from tripping or the emergency core cooling system from automatically coming on, or both.

2. Design changes in tap locations that were inconsistent with B&W's own design criteria were made to the component at some plants in order to save money. It appears that these savings were trivial in view of the limited number of plants involved and the engineering costs associated with the change. This change worsened the human factors relationship between operators and the equipment by causing pressurizer level indication (which operators rely upon to assure themselves that the reactor core is covered with coolant) to be lost for a substantial period of time during anticipated operational transients. Apparently, the system's performance during operational transients was not examined to determine the effect of this change prior to the change being implemented.
3. In these plants, manual actuation of the emergency core cooling system or some other operator action was required to compensate for the component's limitations.
4. B&W was reluctant to accept its customer's initial conclusion that the level indication problem was a safety issue, not just an operational inconvenience. The supplier maintained that the problem did not constitute an unreviewed safety question, and repeatedly tried to convince the customer that additional operator action or changes in other parts of the system should be relied upon, rather than a design change. The matter was eventually resolved by making changes elsewhere in the system.
5. The issue of the solution to the component limitation was discussed and ultimately resolved at ANO largely outside the review process of the NRC.

Recommendations

1. Systems controlling pressurizer level for anticipated operating transients should be distinctly and separately operated from systems designed to supply cooling water for loss-of-coolant accidents. Systems designed for loss-of-coolant accidents should be designed to actuate in response to breaks in the reactor coolant system and should be designed to operate unabated until their function is served.
2. The NRC should consider reviewing acceptance criteria for startup tests performed and comparing them to design requirements as required by design documents, to determine whether similar component limiations exist.
3. Instrumentation should be installed to provide a clear indication to the operator of water level in the reactor vessel.
4. The NRC should review the B&W pressurizer design in greater detail to determine whether equipment modifications (for example, greater makeup capacity) are needed. (See also the recommendation in Section II.C.1.b.)
5. The NRC should review the reliability of secondary equipment (main steam safety valves, bypass valves, and feedwater systems) and determine whether existing equipment is acceptably reliable.

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E INCENTIVES TO BEGIN "COMMERCIAL OPERATION"

1. INTRODUCTION AND CONCLUSIONS

One goal of the Special Inquiry Group (SIG) was to determine "...the extent to which financial or tax considerations influenced conditions in the plant in any way that might have contributed to the accident...."[1] This report discusses those considerations that are more commonly known as the "rush to 'commercial operation.'"[2] At the same time, it attempts to examine the implications of this investigation for the regulation of nuclear powerplants.

The Allegations

The national media, approximately 1 week after the March 28, 1979, accident at Three Mile Island (TMI), reported what was believed to demonstrate a rush to commercial operation. For example, *The Washington Star* began an article with the statement:

> Metropolitan Edison Co.... was able to save millions of dollars in Federal taxes by beginning commercial operation of its [TMI] reactor No. 2 just two *days* before the end of last year.
>
> That savings... has raised questions as to whether the reactor was *unduly rushed into operation.*[3] (Emphasis added.)

The Washington Star article also referred to the Pennsylvania Public Utilities Commission's (PaPUC) approval of a $49 million rate increase for Metroplitan Edison (Met Ed), noting that a portion of that represented rate recognition of TMI reactor No. 2 (TMI-2).[3]

In its April 6, 1979, edition, *The Washington Post* reported on a press conference held by the Ralph Nader organization, Public Citizen, Inc., at which it was charged that "Metropolitan Edison has reaped huge tax benefits *by pushing TMI-2 into service* before the end of 1978.[4] (Emphasis added.) *The Washington Post* article quoted Public Citizen as alleging that "the decision to put the unit into commercial operation was an economic decision that disregarded a troubling record of mechanical malfunctions."[4]

At the Public Citizen news conference on April 5, 1979, that organization released a 24-page study entitled, "Death and Taxes: An Investigation of the Initial Operation of Three Mile Island No. 2."[5] The paper, written by three attorneys from different Nader organizations, concluded: "There is substantial evidence to suggest that the safety and reliability of TMI-2 were far from assured when the unit was placed in commercial operation at 11:00 p.m. on December 30, 1978, but that the companies nonetheless placed the unit in service at that time in order to realize significant tax benefits." [5]

At the press conference, Public Citizen also released copies of a four-page letter sent to President Jimmy Carter over the signature of Ralph Nader and five others. The letter, copies of which were distributed to chairmen of certain congressional committees, repeated the allegations of the "Death and Taxes" paper.

Methodology

In investigating this allegation of "rush to commercial operation" in depth, the Special Inquiry Group decided on the following approach: First, an attempt would be made to identify all relevant incentives [6] that existed for General Public Utilities (GPU) in putting TMI-2 into "commercial operation" in 1978. Second, an investigation would be conducted to determine what action GPU took in constructing and testing TMI-2 so as to enable its completion before the end of 1978. Finally, the ultimate question would be addressed: Was the safety of Unit 2 compromised by any "rush" that was identified?

The report is structured to answer three questions that followed from this methodology: (1) Were there incentives for completing TMI-2 before December 31, 1978? (2) Was deliberate action taken to enable that completion? (3) Was the safety of TMI-2 compromised by this action? A summary of the conclusions prefaces the report.

However, this report is focused as much on the generic *implications of* the investigation for the nuclear industry as on the precise question of any TMI-2 rush. These implications suggest the need for a better understanding and a stricter regulation of the relationship between financial incentives and nuclear safety. Any attempt to read either the TMI-2 investigation or the implications separately will not assist in a full understanding of the issues involved.

Conclusions

1. Incentives did exist for completing all work and testing on TMI-2 and declaring that unit to be commercial on or before December 31,1978.
2. Actions were taken at TMI-2 indicating that there were time considerations which were linked to financial incentives. However, these actions affected primarily self-imposed company criteria, and no adjustment of NRC-mandated safety criteria took place.

   An inference that these actions were taken *in order to* obtain the incentives referred to in conclusion 1 can be derived from the fact that corporate officials charged with completion of TMI-2 were directly informed of those incentives and their relationship to a December 31, 1978 completion date.
3. Given the assumption that compliance with the regulatory program of the NRC indicates safe construction and operation of a nuclear facility, actions taken at TMI-2 to obtain certain financial incentives *did not* compromise the safety of TMI-2. This is a recognition of the fact that no violations of NRC regulatory standards during the period from the granting of an operating license to commercial operation of TMI-2 were detected. For those individuals unwilling to accept the above assumption, the question of whether the actions taken affected the safety of TMI-2 is unanswerable.

   Without NRC criteria, there is no definition of "safe enough" against which to judge the adjustments that were made in the TMI-2 timetable. To establish a standard that equates the fact that the accident occurred with "compromised safety" imposes an impossible *post hoc* standard upon licensees.
4. This investigation indicates that neither the financial incentives associated with construction of a nuclear powerplant nor the impacts of those incentives on safety are fully recognized by Federal or State regulatory bodies. Consequently, regulatory requirements may create incentives which could compromise a utility's commitment to nuclear safety.

2. INCENTIVES FOR COMPLETING ALL WORK AT TMI-2 BEFORE THE END OF 1978

Turning to the first question of incentives, an attempt was made to fully explore each reason that may have existed for completing all work (declaring the unit in commercial operation) at TMI-2 before December 31, 1978. The first two major financial incentives-rate recognition and tax benefits-are treated at some length. Other, lesser incentives are also discussed in an attempt to present a full picture of the situation facing GPU at that time.

a. Rate Recognition of TMI-2

One of the incentives for putting TMI-2 into commercial service before the end of 1978 that the Special Inquiry Group investigated was the utility rate treatment consequences.[8] To fully understand this aspect of the inquiry and its findings, a brief review of the fundamentals of rate regulation is necessary.

The three operating companies of GPU-Met Ed, Pennsylvania Electric Company (Penelec), and Jersey Central Power & Light (JCP&L)-are all regulated utilities.[9] On the retail level, Met Ed and Penelec are subject to the jurisdiction of PaPUC, as their service areas lie within the Commonwealth of Pennsylvania. JCP&L, however, is regulated by the New Jersey Department of Energy, Board of Public Utilities (NJBPU), because it serves customers within that State.[10] Because all three GPU companies are involved in interstate power transactions," they are also subject to the regulation of the Federal Energy Regulatory Commission (FERC), an agency of the U.S. Department of Energy.[12]

Leaving aside the broad authority of these economic regulators until later in this report, the primary duty of each of these bodies is to regulate the rates the GPU companies charge their customers to prevent exploitation of the "natural monopoly" utilities have in certain markets. The guiding principle in that regulation, as stated in the Pennsylvania statutes, is to "provide for a just and reasonable return on the fair value of the property used and useful in the public service...."[13]

Giving definition to that principle involves a fairly complex process, but the essential point is that the utility generally does not by its own decision raise its rates. Under the Pennsylvania scheme, the utility notifies PaPUC of its intention to revise its rates and then files a new tariff to accomplish that goal.[14] PaPUC then has the authority to suspend the effectiveness of the rate request for 7 months while it investigates the "justness and reasonableness" of the rate request[15] PaPUC may then hold a hearing and, if it finds the proposed rates to be unjust or unreasonable, it may then determine rates it considers "just and reasonable" and "fix the same by order to be served upon the public utility ...."[16]

Part of the determination of the justness and reasonableness of the proposed rates is an examination of the rate base: that property the company claims is "used and useful in the public service."[17] A new generating facility, such as TMI-2, would not be earning "a just and reasonable return"[18] for the investors until PaPUC found it to be "used and useful in the public service."[19]

Determining the value of the used and useful property is also a matter for PaPUC determination. Pursuant to a Uniform System of Accounts,[20] utilities are allowed to capitalize the cost of borrowing money to build a generating plant.[23] This component of the final costs of a unit, called allowance for funds used during construction (AFUDC), can amount to a substantial portion of the final cost of a unit, especially toward the end of a project. Customers pay a "rate of return" on this capitalized debt cost, just as they do on the concrete and equipment of the facility.

As previously noted, the term "commercial operation" has a number of meanings. When expressed as "declaration of commercial operation," it is indicative of a utility accounting change that has ratemaking consequences. It is at that declaration that a new generating facility stops accruing AFUDC and is placed in the "plant in service" account on the utility's books.[22] The regulatory impact of that shift is that the utility then looks to the State Public Utility Commission (PUC) to provide a rate of return on a plant now claimed to be "used and useful in the public service."

The risk nature of this declaration of commercial operation should be obvious. There may be a considerable delay between the declaration-the end of accruing AFUDC-and the first payment by customers toward a "used and useful" plant. During this period, the utility is neither capitalizing the ongoing costs, obtaining a rate of return on its investment, nor recouping the normal operating and maintenance expenses associated with the unit.[23] This period can be referred to as a "regulatory gap." The goal of the utilities, clearly, is to minimize its length; that is, it is advantageous for utilities to seek to declare a unit to be in commercial operation (with its associated accounting changes) as close as possible to that time in which final PUC action will bring rate relief.[24]

The gamble in declaring a plant in commercial operation is not eliminated, however, simply by prompt PUC action. If a serious problem with the plant should develop following this declaration, the shareholders might be exposed to the costs of curing the problem. Since AFUDC had stopped, such repair work could not be capitalized into the value of the project for ultimate recovery from the ratepayers, absent some further PUC action.[25]

As can be seen, AFUDC provides something of a safe harbor for earnings, which utilities are reluctant to leave until the smooth waters of a rate increase are in sight. This security of capitalizing all costs while minimizing risks causes regulators to be wary of the device. As discussed in detail below, challenges are often made to the amount of AFUDC claimed by a company in a unit. These challenges are based on the premise that the company should have completed the project sooner, reducing AFUDC, and thereby reducing the valuation of the property upon which ratepayers will be forced to pay a rate of return.

From a regulatory perspective, this is the importance of commercial operation. It was the possibility of challenges to the timing of its declaration of TMI-2 as being in commercial operation that caused the GPU companies to be very specific in defining when that declaration would occur for TMI-2.26,27 As will be discussed below, the GPU Service Corporation (GPUSC) even established formal procedures for making the declaration.28 More importantly, Met Ed had numerous contacts with PaPUC in which it made certain representations, linking the declaration of commercial operation of TMI-2 to completion of the test program at the unit.

Met Ed recognized that the standard for declaring TMI-2 in commercial operation was going to be scrutinized even in PaPUC R.I.D. (Rate Investigative Docket) 434, a proceeding in which TMI-2 was not allowed in rate base. On February 17, 1978, the administrative law judge (ALJ) there heard oral argument concerning the appropriate criteria for a declaration of commercial operation.29 PaPUC itself heard oral argument on the matter on May 10, 1978.29

At a June 23, 1978, annual review meeting with GPU officials, members of PaPUC apparently raised the issue again, now looking toward the new filing (R.I.D. 626), which again proposed including TMI-2. In a letter dated August 11, 1978, William Kuhns, GPU Chairman of the Board, wrote to the chairman of PaPUC and stated that the criteria for determining when a plant would go into commercial operation "is not a matter of formula but is a matter of reasonable judgment based on a consideration of all the pertinent facts."30 Some of the prerequisites cited by Kuhns were that (1) tests had been run to demonstrate that "the plant as constructed is capable of providing the service intended," (2) startup testing and evaluation had progressed to the point where portions of the unit were made available to the pool for system dispatching, and (3) the plant was capable of producing sufficient energy "for use by the ratepayers."31

Special emphasis seems to have been placed on the test program requirement. Kuhns noted that the required tests were sometimes necessary to "assess the operational acceptablility of major items of plant equipment and such tests have been the basis for acceptance and supplier payments."31 Kuhns also noted that these operational tests "include a number of performance tests to be successfully completed before the Operating Permit [sic], issued by the Nuclear Regulatory Commission, can become effective for full power operation."31

Kuhns then referenced an earlier letter to the chairman of PaPUC from GPU President Herman Dieckamp, in which Dieckamp communicated the problems GPU was having in the startup and test program at TMI-2.32 In sum, Kuhns said:

> What this boils down to is that, under your Commission's Uniform System of Accounts, a generating unit must be transferred from CWIP to plant in service when, after a reasonable testing period, it is ready for service even if there are some clean-up construction activities remaining.33 (Emphasis added.)

Meanwhile, the Met Ed rate proceeding (R.I.D. 626) was still before an administrative law judge. On August 30, 1978, the judge asked the parties to develop and transmit suggested criteria for determining when a nuclear facility is "in commercial service."34 Met Ed responded with an exhibit, submitted by Robert Arnold, Vice President of Generation, that incorporated Section 14.1 of the NRC-mandated Final Safety Analysis Report (FSAR).35,36 Arnold's covering statement stated: "Schedule 14.1 describes the test program which must be completed prior to unrestricted operations."37

The final item in this sequence of Met Ed communications regarding the meaning of commercial operation, was a letter dated November 30, 1978 from William Kuhns to the New Jersey Department of Energy, Board of Public Health (NJBPU). Kuhns wrote, "Due to the extensive interest shown by the [Pennsylvania and New Jersey] Commissions in the status of Three Mile Island Nuclear Station Unit 2, particularly as to when the unit will be ready to be placed in commercial service, we are providing an updated status on the unit."38 The status according to Kuhns was that "[t]he full load generator trip will mark completion of a start-up and test program which has applied to all unit structures, systems and components necessary to conduct commercial operations. ...We believe that completion of this program will provide assurance that the unit is capable of producing significant energy and is then ready to be placed in commercial service."38

Dieckamp summed up this history of communications on the subject of "commercial service:"

> I doubt that the declaration of the commercial in service date of a particular generating unit has ever received as much attention from so many sources as was the case for TMI-2. We have sought to make clear that our view of the appropriate time for the declaration was the successful completion of a long series of tests.... Those tests were outlined in a 25-page Exhibit No. E-21 presented by Mr. R. C. Arnold in R.I.D. 62639 (Emphasis added.)

However, no matter how many communications passed between GPU and the PUCs on this topic, Met Ed's position remained the same: TMI-2 would not be declared in commercial operation before all FSAR-identified startup tests had been completed. In Arnold's words: "We believe that under normal conditions completion of this test program is a prerequisite for declaration of commercial operation. We think it provides assurance that the plant is capable of producing significant energy and is ready to be placed in commercial service."[40]

We have called this linking of the test program and the commercial operation of TMI-2 a "commitment" made by GPU to PaPUC (and others). It should be noted that, although some GPU officials would agree with that characterization,[41] others insisted on distinguishing these "communications" as not being commitments because the latter term "tends to carry with it some kind of an implication that something would ... flow from the failure to have made the report."[42] Semantics aside, the linking of the FSAR test program and the commercial inservice date of TMI-2 is an important issue in this investigation. It must be recognized that without this *voluntary* commitment, there is no PUC requirement that all FSAR tests be completed before a declaration of commercial operation.[43]

A final point that should be noted regarding rate regulation goes to neither law nor accounting, but to the current regulatory system. Whether appointed or elected, public utility commissioners do not gain widespread approval by increasing rates. There is also a desire on the part of PUC staffs, charged with representing the public interest, to closely monitor the practices and claims of utilities. Along with the new offices of the consumer advocate, the PUC staff constantly challenges the utility to demonstrate that it is entitled to its claimed rate relief. The effect and potential consequences of this regulatory environment are discussed at length below, but the key point is that utility decisionmaking takes place in an environment of oversight and competing demands.

With that understanding of the regulatory process and its pitfalls, this report turns to TMI-2 and the attempts of the GPU companies to achieve recognition for the unit in their respective rate bases. The processes in both Pennsylvania and New Jersey, as well as proceedings before FERC, must be examined.

Both Met Ed and Penelec had sought inclusion of TMI-2 in their respective rate bases long before a declaration of commercial operation was made on December 30, 1978. In (PaPUC docket number) R.I.D. 434, Met Ed had convinced the administrative law judge hearing the case to allow $165 931000 to be included in its rate base as representing the cost of TMI-2. The basis of the argument accepted by the judge was that the plant was going to be "used and useful" within the test year under consideration. Therefore, the company should be allowed to earn a rate of return on that investment as of the date it goes into commercial operation. On exception of the PUC staff and the Pennsylvania Consumer Advocate, the commissioners rejected this approach, ordering instead that Met Ed institute a separate proceeding when it was ready to include TMI-2 in its rate base.[45]

This would necessitate a reexamination (retrospectively) as to whether the unit was "used and useful." The consumer advocate even proposed a month trial period following the declaration of commercial operation before PaPUC would decide whether TMI-2 was "used and useful."[46]

Penelec similarly sought inclusion of TMI-2 in its rate base in a February 1, 1977, filing. Using the same future test year as had Met Ed in R.I.D. 434, Penelec argued that it should be allowed $64151000 as its 10% portion of TMI-2.[47] At this time, Penelec was projecting that TMI-2 would become operational May 31, 1978. In its rate case it was using a future test year,[48] which ran through December 31, 1977. The administrative !aw judge who heard the initial Penelec request decided that this "post future test year adjustment" (that is, the inclusion of TMI-2 in the rate base on the assumption that Penelec would meet its scheduled operation date) was proper. PaPUC summarized the findings below:... they [the ALJs] found no reason to exclude from rate base that property which is projected to be in service within a short period after the Commission's Order here is entered."[49]

The consumer advocate and PUC staff took exception to the administrative law judge's finding, and the full commission agreed with their objections. The Pennsylvania commission said:

> We do not believe that, as an integral part of this rate proceeding, Penelec should be given authorization to increase rates at some indefinite future time. Instead ... the better procedure ... would be to have the company make a separate filing to reflect its increased revenue requirement resulting from the commercial operation of TMI-2.[5"]

Meanwhile, JCP&L was having similar problems before NJBPU commissioners.[51] Having proposed a test year ending March 31, 1977, JCP&L was forced to concede that TMI-2 would not be in commercial operation until "spring of 1978."[52] JCP&L then joined the other parties in its rate proceeding in agreeing "that it would be appropriate to determine the company's revenue requirements associated with TMI-2 in the context of the overall results of operation during a more current test year."[52]

NJBPU then ordered one-half of JCP&L's investment in TMI-2 to be shifted from the proposed utility plant in service account to the construction work in progress (CWIP) account, where it would be allowed to earn AFUDC from that date.[53] At the same time the NJBPU ordered the Hearing Examiners Office to begin a phase II proceeding to examine the "more current test year" data that would involve TMI-2.[54]

In summary, all three GPU operating subsidiaries had tried before TMI-2 was declared to be in commercial operation to have the unit included in their respective rate bases. All had been rebuffed by the commissions in Pennsylvania and New Jersey, despite the variety of arguments used by the companies.

However, the financial condition of Penelec caused that company to file for a rate increase even before its 1977 filing (R.I.D. 392) had been decided by the PaPUC. On April 28, 1978, more than a month before PaPUC refused recognition of Penelec's share of TMI-2 in the rate base of R.I.D. 392, Penelec filed a tariff that would increase retail base rates by $75.4 million.[55] Using a future test year that ended December 31, 1978, Penelec again included TMI-2 in its rate base.[55] At this time, Penelec was predicting that TMI-2 would go into commercial operation on May 30,1978.[56]

The basis for Penelec's quick refiling was stated by PaPUC in its order as being "anticipated deterioration in earnings ... attributed to the expected increase in capital, operating and maintenance costs of the placement in service of the Three Mile Island Unit No. 2... nuclear unit, the Homer City Unit No. 3 ... coal fired generation plant, and the Homer City coal-cleaning plant."[57] On January 26, 1979, PaPUC allowed Penelec to increase revenues by $64272000.[58] That amount was calculated on a rate base of $1350000000-$175841000 (13%) of which represented Penelec's ownership of 25% of TMI-2.[58,59]

Acting on PaPUC's advice in R.I.D. 434,[60] Met Ed filed a new tariff for PaPUC's approval on June 30, 1978.[61] At that time, Met Ed was predicting that TMI-2 would be in commercial service on September 1, 1978.[62] Of the $86 802 000 increase in revenue sought by Met Ed, $68820000 represented "revenue requirements for Met Ed's fifty percent ownership of Three Mile Island Unit No. 2...."[63]

In R.I.D. 626, Met Ed proposed a test year ending March 31, 1979.[64] Despite prior arguments in the proceeding by the Pennsylvania Office of the Consumer Advocate,[65] no one questioned the propriety of including the vast majority of TMI-2 in Met Ed's rate base in the proceeding.[66] Indeed, by the time of the drafting of the final PaPUC order, the commission could point to the fact that "Three Mile Island Unit No. 2 ... went into service December 31, 1978."[67] On March 31, 1979, PaPUC granted Met Ed a revenue increase of $49178 000 on Pennsylvania jurisdictional operations.[68] This figure was calculated on a total rate base of $1160000000, which included TMI-2.

In New Jersey, phase II of the JCP&L proceeding was decided on January 31, 1979.[69] The hearing examiner noted that TMI-2 did not go into commercial service as expected in "the Spring of 1978."[70] However, since JCP&L had "waived the statutory limit on the suspension period until after TMI-2 was placed in commercial service,"[71] and that had now occurred, it was desirable to act on the matter. NJBPU granted JCP&L a $33.8 million increase in retail rates, which reflected, among other things, the addition to the "utility plant in service" account of $163 853000 for JCP&L's 25% share of TMI-2.[72]

As previously noted, the State commissions do not have jurisdiction over interstate power sales.[73] To obtain rate increases for such interstate transactions (so as to reflect the placing into service of TMI-2), the GPU operating companies filed proposed rate increases with FERC. On July 18, 1978, Penelec filed for an increase of $7 587 000 from its 1 partial and 11 full requirements (wholesale) customers.[74] The Penelec case proposed a test year ending June 30, 1979 and an effective date for the rate increase of August 16, 1978.[74] Pursuant to the Federal Power Act, FERC suspended the effective date of the rate increase to December 1, 1978. At that time, Penelec would be allowed to collect its increase, subject to ultimate refund should FERC rule that those rates were unreasonable.[75] This proceeding was still awaiting a FERC decision at the time this report was written.[76]

Similarly, Met Ed filed on November 13,1978.[77] It sought a $4 772 496 increase from its five full and one partial requirements customers.[77] Met Ed used a test year ending December 31, 1979, and proposed an effective date for the rate increase of January 12, 1979.[77] As is typically the case, FERC suspended the rates for 5 months, to June 13, 1979.[78] This proceeding, too, is pending before FERC.

Finally, on December 18, 1978, JCP&L filed for an increase of $2136 351 to its all-requirements customers.[79] Using a test year beginning January 31, 1979, JCP&L sought an effective date of February 19, 1979.[79] FERC suspended that until July 17, 1979, at which time the increases would go into effect, subject to refund.[80] As with the other TMI-2 related cases, this matter is still awaiting a final decision by FERC. Although portions of the proposed rate tariffs of the GPU companies have gone into effect[81] whether those companies will retain the approximately $14.5 million of increases sought has not been decided.

In sum, the GPU operating companies achieved rate increases of approximately $165 million in 1979.[82] Although many factors were involved in these increases, to a large extent they reflect the addition of TMI-2 to the companies' rate bases and associated regulatory treatment.[83]

However, only a small percentage of these increases accrued to the shareholders of the companies as a return on their investment.[84] In other words, the $165 million should not, *ipso facto,* be seen as an incentive for rushing TMI-2 into commercial operation before the end of the year, 1978. Rather, to determine if the regulatory process was an incentive for declaring TMI-2 to be commercial by the specific date of December 31,1978, one must examine what effect there would be on the pending regulatory proceedings had that date not been met.

Throughout the previous discussion, there has been an attempt to record the test year in each regulatory proceeding. A test year is a period of time for gathering data relative to a particular utility's si-

rates[85] When inflation was low, the typical approach was to use an "historical" test year. That is, the actual history of the utility would be examined and future needs (revenue, rate of return) would be determined. However, with rising inflation and longer regulatory proceedings, the historical test year data was out of step with a utility's needs by the time a decision was made. Hence, many PUCs now allow a utility to use a "future" test year in which the utility predicts its condition at some year ending in the future and regulators attempt to determine its needs on the basis of this future-looking data. The goal, apparently, is to coordinate test year and final action such that the granted rate increases reflect a company's picture at that time-and not some past data.[86]

If a company seeks to present data regarding its situation that falls outside the test year, it risks the danger that regulators will not hear that evidence.87 If this item is a significant matter in the utility's rate planning, such a disallowance could be damaging.

In the cases pending before various regulatory bodies involving TMI-2, 1979 future test years are found in the Met Ed PaPUC proceeding (March 31, 1979), the Met Ed FERC proceeding (December 31, 1979), the Penelec FERC proceeding (June 30, 1979), and the JCP&L FERC proceeding (January 31, 1979).[88] In the NJBPU proceeding, although a March 31, 1977 test year was applicable to the phase I proceeding, a "later test year with corresponding adjustments of other specific data will be used for Phase II."[89] In other words, by stipulation in New Jersey, the exact end of the test year was not an issue; it was to be made to correspond to the commercial operation date of TMI-2.[90]

The Penelec PaPUC proceeding also used a future test year ending on December 31, 1978.[91] Of course, when Penelec filed for increased rates on April 28, 1978, it was predicting that TMI-2 would be in commercial operation on May 30, 1978.[92] Thus, the GPU operating companies at this time apparently expected TMI-2 to be included in the rate bases of the then-pending proceedings, as its commercial operation date was within the relevant test years.

However, a number of problems[93] caused the predicted commercial operation date of TMI-2 to slip substantially, and the 1978 test year in the Penelec case became significant to GPU. As GPU President Herman Dieckamp told the President's Commission on the Accident at Three Mile Island:

> December 30 tended to be a significant date in terms of having the plant in service during what, under utility regulation, is called the 'test year.' That is the time period during which costs and expenses and investment are all normalized in order to determine the rates that will be used in charging to the customers. The test year tends to be significant because of *things that occur outside of the test year, it offers a legal opportunity to exclude those costs.*[94] (Emphasis added.)

In this explanation, Dieckamp did *not* distinguish between the Penelec case-the only proceeding in which this test year problem could be an issue-and all other GPU proceedings.

Similarly, Robert Arnold did not distinguish between Penelec's situation and the other operating companies' rate proceedings. Focusing on the same point as Dieckamp, Arnold said in a deposition that the test year problem was an incentive to be commercial in 1978. He explained:

> [As] I understand it, that [being commercial in 1978] would remove, as a matter of contention, whether or not subsequent rates, which we had not received at the end of 1978, could properly reflect TMI-2 ... I think it was our position that it could still be included in the calculation of the appropriate rates but the incentive from the company standpoint-the only incentive that I know of-to have it commercial by the end of the year was that it removed that as an issue before the PUC.[95]

In sum, company officials arguably believed, as they worked toward completing commercial operation at TMI-2 in 1978, that such completion would eliminate an argument before PaPUC. In not stressing the fact that this was an issue only in the Penelec case, what the officials seem to suggest is a least-common-denominator type of planning. That is, although Penelec owned only 25% of TMI-2, and although the other operating companies (and Penelec at FERC) would not be risking test year arguments, if the plant came into commercial operation in 1979, it was Penelec, the operating company with the most exacting requirements, that concerned officials. The goal, it could be said, was to declare TMI-2 commercial in 1978 to avoid this test year argument.

That this type of reasoning is not entirely logical has been pointed out by GPU officials since the accident. It would be a very narrow argument to insist that Penelec's $175 million investment in TMI-2 should not be considered in setting the utility's rates because the plant went into commercial operation on some day in January 1979, rather than before December 31,1978.[97] In fact, it would have been a difficult argument for PaPUC to accept in light of the persistent history of the GPU companies in seeking to achieve rate base recognition of TMI-2. Had it accepted the argument, it almost certainly could have expected another rate filing.

Furthermore, planning the commercial operation date on the basis of the Penelec test year end date of December 31, 1978, might not even make financial sense. Speculating on that possibility, GPU Treasurer John Graham said that it would appear that the advantage of collecting 3 more months of AFUDC (until the Met Ed test year date of March 31, 1979) would outweigh the possibility of future litigation to contend denial of TMI-2 in the Penelec rate base because it fell outside the test year.[98,99]

Nonetheless, the fact remains that TMI-2 was declared in commercial operation on December 30, 1978-1 day before the end of the Penelec test year. Thus, the potential for argument on this score was eliminated.[100]

Beyond this specific desire on the part of GPU to avoid an argument concerning the Penelec test year, there were several other pressures on GPU to complete the project as soon as possible. That is, there were a number of regulatory devices that, although not linking a declaration of commercial operation to 1978 per se, made any earlier completion advantageous. These are examined as part of the collection of regulatory incentives.

Generally, all of these pressures flow from the accounting change that accompanies a declaration of commercial operation. As previously discussed,[101] that declaration shifts a new generating station out of the CWIP account (with its accompanying accumulation of AFUDC) into the plant in service account (with its accompanying regulatory gap until the commissions find the unit "used and useful"). Regulators have an obvious incentive to limit the amount of AFUDC that is capitalized into the final cost of a unit. Such a limitation reduces the rate base value of the project and directly reduces the rates that the customers must pay on the shareholder's investment.[102]

Specifically, FERC attempts to limit accumulation of AFUDC during the test phase by specifying in Instruction 9D of its Uniform System of Accounts[103,104] that "The utility shall furnish the Commission with full particulars of and justification for any test or experimental run extending beyond a period of 120 days for nuclear plant...."[105] In other words, if a utility tests a nuclear unit for a period greater than 120 days following initial synchronization[106] the utility must explain why that has happened. The goal is to prevent a utility from abusing the test period and its corresponding accrual of AFUDC.[107] The penalty for running over the 120-day period, apparently, is the possible disallowance of that portion of AFUDC associated with the longer-than-specified test period. Further, FERC could require the utility to alter its books to reflect this reduced "cost" of the completed project.[109]

In the case of TMI-2, as discussed more fully later in this report, GPUSC was unable to complete the testing at the unit within the 120-day period following initial synchronization on April 21,1978.[110] Instead, when GPU realized the repair of the main steam relief valves would certainly push them past a 120-day test program, GPU Comptroller Edward Holcombe wrote to the FERC chief accountant. Holcombe asked FERC to ignore the initial synchronization of April 21 and instead allow a 120-day test period to begin at the resynchronization following repair of the steam valves.[111] By telephone, the head of the FERC Division of Audits replied to Holcombe that, although FERC would not allow restarting the test period, there was precedent for allowing a plant to test for a period greater than 120 days "if there were good and sufficient cause for that."[112]

GPU was proceeding, in other words, with the "exposure" that FERC could eventually deny a portion of AFUDC associated with a test period that ran longer than 120 days. Each day beyond that period before commercial operation created an incremental increase in that exposure.

Whether GPU officials were concerned with the possibility of FERC disallowance because of Instruction 9D is difficult to determine. Robert Arnold said he was unaware of FERC ever denying an extension of the test program schedule.[113] Similarly, Holcombe said that, although there was some exposure from this issue, it was similar to that involved any time a new unit is placed in commercial operation.[114] In addition, he was confident that the test problems would convince FERC of the need to go beyond the 120-day period.[114]

In fact, GPU did not file a report with FERC **ex**plaining the longer than 120-day test period at TMI-2.[115,116] Holcombe explained that at the time this report would have been prepared, the March 28, 1979, accident occurred.[117] That report has now been filed, and FERC is presumably examining the record to see if the extension of the test program was justified.

On the basis of past arguments, GPU could also reasonably have been concerned in 1978 with arguments before the State Commissions that portions of AFUDC should be disallowed for other reasons. In October 1978, the accounting firm of Touche Ross & Company prepared a report for the New Jersey Department of Public Advocate, which analyzed a construction "slow down" at TMI-2 during 1977 because of a "cash flow" problem within GPU.[118] It was the conclusion of that report that the final cost of TMI-2 and its associated charges to ratepayers would be higher because of the construction delays.[119-121] The Touche Ross report was used by the consumer advocates in both New Jersey and Pennsylvania to argue for reducing the amount of AFUDC calculated into the cost of TMI-2.[122]

From GPU's perspective, the possibility that such an argument might be successful was a matter of concern. This concern was not mitigated by the fact that an argument of disallowing AFUDC as punishment for an intentional delay had been unsuccessful in past cases.[123] In those cases, PaPUC had decided that there was no evidence of intentional delay. Obviously, one means of limiting the potential for these arguments was simply to minimize the time in which AFUDC was collected. As GPU Treasurer John Graham said:

> I guess given that context of the Touche Ross Report there was the potential for someone to make an attack on the time in the fall and winter of 1978 on the AFC [AFUDC] and I guess the loner you accrued AFC the more potential developed.)[4]

Whether it was caused by an intentional slowdown, defective valves, or something else, it would be to the advantage of GPU to minimize the accrual of AFUDC from a regulatory standpoint-even though there might be advantages to GPU in the "safe harbor" previously discussed.[125]

AFUDC could also be challenged on specific utility decisions. For example, the failure of the main steam relief valves was attacked before PaPUC as an example of poor management decisionmaking.[126] The Pennsylvania Office of the Consumer Advocate argued that $12.2 million should be disallowed from the proposed rate base, so that the shareholders (as opposed to the ratepayers) would bear the cost of the failure.[127] Such an argument was not unique; the valuation of TMI-1 was similarly reduced by the cost of replacing faulty concrete pourings.[128] Hence, any delay or any malfunction placed regulatory pressure on GPU to minimize the problem and the time it took to develop a cure. Otherwise, the potential for disallowance of a portion of AFUDC existed in the pending regulatory proceedings. To prevent these arguments or the lengthening of the regulatory gap, GPU had an incentive to complete TMI-2 as soon as possible. This is not inconsistent with a December 31,1978 target date.[129]

An additional possible regulatory incentive existed for completing TMI-2 before December 31,1978: the desire to maintain good relationships with the various regulatory authorities themselves. Regulated utilities deal in a long term relationship with PUCs and FERC. For that reason, GPU may have been anxious to maintain good relationships with these commissions.

This situation is especially true for PaPUC, which was perceived by GPU as being a "more formal" regulatory body.[130] In the specific case of TMI-2, recall that GPU had committed itself to completion of the specified test program before declaring the unit in commercial service.[131] Had time required GPU to declare the unit commercial before all tests had been completed[132] to meet a December 31, 1978 deadline,[133] GPU could have counted on possible antagonism from PaPUC or its staff.

In addition, GPU was attempting to create a favorable impression before PaPUC in its adversary proceedings. Knowing that the commercial operation of TMI-2 had become a significant issue in its second 1978 proceeding (R.I.D. 626), Met Ed quickly alerted by telegram the other parties (the staff, the Office of the Consumer Advocate, et al.) that TMI-2 had gone into commercial operation while they were writing their final briefs.[134] The record in R.I.D. 626 had been specifically left open to receive evidence on the commercial operation of TMI-2.[135] Met Ed presumably wanted to be able to point to such operation at the final oral arguments scheduled before PaPUC in the proceeding.[136] However, another malfunction in early January prevented such a statement.[137]

The point is that for the sake of appearances and relationships with PaPUC, it would have been advantageous for GPU to have TMI-2 in commercial operation by the end of 1978. This would enable it to (1) comply with the previous commitment to

PaPUC and escape future technical arguments and (2) make assertions at final argument in the rate case that would have been more difficult otherwise. As with the other incentives identified in this section, it is difficult to determine whether these were concerns of GPU officials. Dieckamp has said they would have been consistent with the kind of factors GPU would recognize.[138]

Reviewing all of the incentives identified in this section, it must be concluded that there were regulatory advantages for GPU in completing TMI-2 as soon as possible. Minimizing the possible arguments for AFUDC disallowance, attempting to retain good relationships with the regulators, and improving the ongoing rate proceedings were goals that were assisted by completion of the unit. However, the only regulatory incentive that can be identified as being linked to completion of the unit by December 31, 1978, is that previously noted: the 1978 test year in the Penelec case.[139] Whether that incentive alone would be sufficient to tempt a utility away from its planned course of action requires evaluation on the part of the reader. The contention of the SIG is that, in conjunction with the incentives discussed in the following sections, the Penelec test year reinforced pressures to complete the unit in the shortest possible time. It could, indeed, have had an impact on GPU planning and operation.

b. Tax Ramifications of Placing TMI-2 in Commercial Operation in 1978

A second major incentive for declaring TMI-2 to be in commercial service in 1978 is alleged to have been the tax treatment that follows from that decision.[140] The starting point to determine the impact of this incentive is to review the tax law as it would have been known to GPU in 1978.

The Internal Revenue Code provisions of interest here are the investment tax credit (ITC) and depreciation allowance sections of the Code.[141] The ITC is designed to provide incentives for businesses to invest in new plants and equipment. The goal is to stimulate the return of capital to a business both to upgrade the efficiency of the process and to provide a boost for the economy.[142] The depreciation allowance is simply a recognition that the value of an asset deteriorates over time. A business taxpayer, therefore, is allowed to deduct from its tax base a portion of the value of the asset each year as compensation for this "wear and tear."[143]

This concept of depreciation as an expense of doing business is normally taken on a straight-line basis. While the tax laws recognize this method of calculating depreciation, it also recognizes so-called "accelerated methods," by which a business can depreciate an asset over a shorter useful life (i.e., at a greater amount per year) than it would be allowed to under the straight-line method. One function of the accelerated methods of depreciation is to provide the same incentives as the ITC: to encourage businesses to constantly upgrade their production capabilities with new equipment. If a business meets the criteria established by Congress and the Internal Revenue Service (IRS), it is entitled to the credit and deduction.

Utilities, however, do have special tax problems. Because they are regulated, special attention is paid to the question of who benefits from tax advantages.[144] For example, PUCs sometimes attempt to "flow through" the depreciation deduction utilities receive under so-called accelerated methods.[145,146] In some ways, such regulation defeats the apparent intention of Congress in providing the advantages to begin with; a utility subject to a flow through order would not have the additional capital ,provided for by accelerated depreciation to finance new construction. In some provisions of the Code, Congress has intentionally drafted the law such that attempts by PUCs to flow through tax advantages will prevent the utility from using that method of accounting.[147] Hence, there will be nothing to flow through.

Utilities also have special provisions in the tax laws themselves. For example, section 46 limits the qualified investments upon which a utility can claim ITC.[148] Other provisions limit the percentage credit on those investments by utilities.[149] While exact figures are not crucial, the concepts and criteria for obtaining these benefits are important.

Section 46 (as in effect in 1978) allows a business to receive a 10% credit on the value of certain qualified investments (to a maximum of $25 000 and a percentage of the investment).[150] A qualified investment is defined by section 46 as a percentage of the property "placed in service by the taxpayer during such taxable year."[151] (Emphasis added.) Section 167 allows depreciation treatment for "property used in the trade or business, or of property held for the production of income."[152] (Emphasis added.) It is apparent that both of these provisions require that an investment or asset be more than merely existing; it must be involved in the business of the taxpayer.

This concept is further elaborated in the IRS regulations of the two applicable sections. IRS regulations define the placed-in-service standard of section 46 to refer to the earlier of two possible tax years. The investment is placed in service during either (1) the taxable year in which depreciation (per section 167) begins or (2) "the tax year in which the property is placed in a condition or state of readiness and availability for a specifically assigned function ...."[153]

The regulations implementing section 167 also provide for depreciation to begin "when the asset is placed in service."[154] The regulations direct that IRS regulation 1.46-3(d) "shall apply for the purpose of determining the date on which property is placed in service ....[155] The point at which an asset is first placed in service, therefore, can control both the ITC and depreciation treatment it receives in a tax year.

Even these elaborations are inadequate in setting forth the criteria as to when a nuclear powerplant would obtain the tax provided by sections 46 and 167. The IRS has issued, therefore, several revenue rulings (interpretive advisory opinions) that serve as additional guides.

Revenue Ruling 76-428[156] allowed ITC and depreciation treatment for a nuclear unit[157] that was operational on December 23, 1975, even though it was undergoing further testing to eliminate defects. The unit at that point was at 17% of its rated power level. The criteria used in determining that the unit had met the placed-in-service test of the regulations were the following:

1. All necessary permits and licenses had been approved;
2. Critical tests for the various components had been completed;
3. The nuclear generating unit had been placed in the control of the taxpayer by the contractor;
4. The generating unit had been synchronized into the taxpayer's grid for its function in the business of generating nuclear energy for the production of income.

In view of these attributes, Revenue Ruling 76-428 concluded that the unidentified nuclear unit[158] was "in a condition or state of readiness... "[159] and, therefore, placed in service in 1975.

One unusual aspect of the unit under analysis in Revenue Ruling 76-428 was the observation that on December 24, 1975 (the day after its status was measured), "there was a partial shutdown of the unit ... due to an abundance of hydro-generated electricity *rather than to any problem concerning the unit."*[160] (Emphasis added.) This "lack of failure" observation was emphasized more completely in a recent revenue ruling. Revenue Ruling 79-98 basically concluded that a unit is first placed in service on the date it becomes operational, not on the date it is accepted by the taxpayer from a constructor.[161] The criteria for this finding were similar to those used in Revenue Ruling 76-428. They were:

1. All permits had been obtained;
2. The unit had been synchronized with the grid;
3. All tests of components had been completed;
4. "And the unit was *able to operate* at its rated capacity *without failure* even though undergoing tests to eliminate any defects and demonstrate reliability."

An additional source of guidance from the IRS with regard to proper tax treatment of a nuclear unit came in a private "letter ruling" (LTR), which was issued on May 8, 1978.[162] Although letter rulings are generally private and attempts are made to disguise the taxpayer involved, in this instance the taxpayer has protested the letter ruling determination and, hence, its identity has become known. Furthermore, letter rulings may not be used as precedent in interpreting the Internal Revenue Code or the applicable regulations.[163] However, since this ruling is directly on point and is indicative of the thinking of the IRS in this area, it is examined in some detail in this report.

Factually, Northern States Power Company (NSP) had contracted for the construction of its Prairie Island I nuclear generating station.[164] NSP received an operating license for the unit on August 9, 1973; achieved criticality on December 1, 1973; and obtained initial synchronization on December 4, 1973.[165] However, on December 17, 1973, a turbine failure caused the unit to shut down, and the power ascension tests then in progress were not completed.[166] The taxpayer (NSP) declared the unit "operational" as of December 16, 1973, in a letter dated 2 days later (1 day following the trip). At that time, Prairie Island I had run at 50% of its capable output for 30 hours.[165]

In a letter dated July 20, 1977, NSP asked for a ruling on the question of whether Prairie Island I "was 'placed in service' during 1973 within the meaning of [the applicable regulations]."[167] In its reply of May 8, 1978, the IRS National Office of Technical Advice reached a negative conclusion on that question. It reasoned that synchronization of a generating unit with a grid alone is not sufficient for a finding of placed in service.[168,169] In the Prairie Island case, the IRS found "the testing of the nuclear power generating facility for demonstrating its specifically designed function, was abruptly ended by a major component failure."[170] The letter ruling specifically challenged NSP's declaration of the unit as (commercially) "operational," stating, "Corporate correspondence ... considered the plant in service ... with only 30 hours of operation in which power escalation was abruptly halted, an obvious condition belying operational status."[171]

The importance of this letter ruling is in its specific linking of two events to tax treatment. Unlike previously reviewed IRS rulings, LTR 7833007 seems to make completion of the power ascension test program a prerequisite to a finding that the plant was placed in service in the tax year. In addition, the ruling links a declaration of commercial operation with tax treatment for the first time.[171, 72] Before this ruling (as discussed below) there was great ambiguity as to the relationship between these two events. In light of the inability to rely on LTR 7833007 as precedent and subsequent communications from the IRS on this subject, that ambiguity may still persist.[173]

The significance in reviewing this body of tax law is an attempt to understand GPU tax planning in 1978, especially as it affected TMI-2. Presuming GPU personnel were aware of these decisions,[174] what planning was made to ensure proper treatment of TMI-2 as consistent with the identified criteria?

Construction on TMI-2 began in 1969. Between that time and the year in which the unit was placed in service for tax purposes,[175] several changes took place in the tax laws. Most importantly, in 1975 Congress enacted amendments to the ITC provision of the Code that allowed taxpayers to take "progress expenditure" credits on projects under construction.[176] In essence, this provided an alternative[177] to the original procedure of waiting until the year the unit (in the case of a generating station) was placed in service before the entire amount of ITC would become available.[178]

A portion of the construction expenditures associated with the TMI-2 unit were credited against GPU taxes through this progress expenditure method[179] However, a portion of the total cost of the unit remained to be claimed in the year in which the plant was placed in service.[179] In other words, some tax planning was necessary in 1978 to judge whether TMI-2 would be placed in service for tax purposes.

Determining when a plant is placed in service is generally not the same as declaring the unit in commercial operation. Despite some recent confusion on this issue,[180] apparently it is possible that a unit would be properly classified as placed in service under the tax criteria before it would qualify for a declaration of commercial operation-as that term has been used before PaPUC.[181-183] As calendar year 1978 drew to a close,[184] GPU's tax department and comptroller began evaluating whether TMI-2 had been placed in service and would hence be eligible for ITC in 1978.

Information on the engineering status of the unit as per the tax criteria earlier discussed was sought in a number of ways. First, the comptroller had access to regular progress reports filed by Robert Arnold, Vice President of Generation.[186] The Comptroller, Edward Holcombe, and Arnold would also talk by telephone about the progress of the unit vis-a-vis the tax criteria.[187] Both the Comptroller and Arnold also attended monthly meetings of the GPUSC Board of Directors. At the December 1978 meeting of the Board of Directors, in fact, Holcombe specifically asked Arnold whether TMI-2 would meet the then-known tax criteria for being a plant placed in service.[188]

The exact nature of the communication between Arnold and Holcombe is subject to minor differences[189] but apparently Holcombe presented a copy of Revenue Ruling 76-428 to Arnold so as to "...get his interpretation of the physical characteristics of the construction of the plant as to whether they met those (of the revenue regulations]."[190] Arnold then reviewed Revenue Ruling 76-428 in the course of the meeting[191] and responded verbally "that if they are the criteria then TMI-2 now meets those criteria and has for some time."[192]

It is, of course, possible to review the condition of TMI-2 on December 17,1978, when Arnold gave this opinion, as compared with the criteria of Revenue Ruling 76-428. As will be recalled, that ruling set as criteria the following: (1) all necessary permits and licenses have been approved, (2) critical tests for various components have been completed, (3) the nuclear generating unit has been placed in control of the taxpayer by the contractor, and (4) the generating unit has been synchronized into the taxpayer's grid for its function in the business of generating nuclear energy.[193]

Briefly, there is no question that criteria (1) and (3) had been met by GPU before December 17, 1978. Met Ed received its operating license from the NRC on February 8, 1978. The outstanding items to be completed before moving to higher power levels were all resolved by April 7, 1978, when the NRC granted permission to go to mode 1 (power operation).[194] Similarly, there could be no question on December 17, 1978, that GPU had been placed in control of the unit. After the replacement of the constructor of TMI-2 with a maintenance contractor in 1977,[195] GPUSC assumed the role of construction manager.

However, the other two items in Revenue Ruling 76-428 deserve closer examination. Although Arnold apparently had no difficulty in understanding the terminology, there is some confusion between the criterion that *critical tests for components* must have been *completed* and the caveat appearing in the same ruling that tax treatment was proper "even though the generating unit would undergo *further testing* to eliminate any defects."[198] (Emphasis added.)

Early in Revenue Ruling 76-428, component testing is equated with the fact that "All systems had been proven operational during the *preoperational testing program."* Thus, it would appear that those tests that must be completed prior to tax treatment (component tests) are the same as those identified in the TMI-2 FSAR as the "preoperational test phase."[197] That phase, according to the FSAR, "consists of functional tests and verifications that demonstrate the components' ability to perform their design function(s), and ... demonstrate the system's ability to operate as designed under actual or simulated conditions."[197] These preoperational tests are generally completed before initial fuel load, which occurred at TMI-2 on February 11, 1978.[1]

Conversely, those tests to determine defects and demonstrate reliability which the revenue rulings allow to occur after qualifying for the ITC appear to parallel those identified in the TMI-2 FSAR as the "fuel loading and initial operation" testing phase) This phase of tests "ends upon completion of the power escalation test program *and designation of the unit as ready for commercial operation."*[199] (Emphasis added.) GPU declared the power escalation "test program completed" on December 28, 1978.[200]

In summary, the "component testing program," which the revenue rulings require to be complete before the granting of tax benefits, had been completed by GPU shortly after February 11, 1978. Both Arnold and Holcombe, therefore, could reasonably have concluded on December 17, 1978, that GPU had met the (hot-functional) testing requirements of the applicable revenue ruling.[201] The program to test for defects or reliability (the power ascension tests required by the FSAR) appears to have been completed on December 28, 1978.2

Another problem in interpreting Revenue Ruling 76-428, as it pertained to TMI-2, is the requirement of synchronization. This criterion is alternately described as "initial synchronization and power operation at greater than 17% of electrical capacity of the unit.[203] TMI-2's generator was initially synchronized with the GPU grid on April 21, 1978 at 6:29 a.m. The unit was then at 15% of its capacity, generating 105 MW. Although slightly less than the (arbitrary) 17% figure of Revenue Ruling 76-428, TMI-2 generated a net of 47 MW on April 21, 1978, and could be argued to have "been synchronized ... for its function in the business of generating nuclear electric energy for the production of income... ,"203

Thus, an analysis of the four tests of Revenue Ruling 76-428 might have led Arnold to the conclusion that TMI-2 was properly first placed in service on April 21,1978: the latest date in which all criteria had been met. However, this ignores the caveat in Revenue Ruling 76-428, which recognized a shutdown as acceptable because it was due to "an abundance of hydro-generated electricity,[203] *rather than to any problems concerning the unit."* (Emphasis added.) The inference is that a "problem concerning the unit" might cause the IRS to scrutinize carefully the performance record of the plant during startup testing. Indeed, in a ruling that became available after this December 1978 time period, the IRS recognized as crucial the fact that the unit in question was "able to operate at its rated capacity *without failure* while undergoing tests."[204] (Emphasis added.)

From a tax planning point of view, it would be impossible, of course, for GPU officials to be aware of standards set in the future. However, as stated above, Revenue Ruling 76-428 suggests that the performance of the unit is important. In addition, the private letter ruling previously discussed was brought to the attention of GPU financial people late in the month of December 1978. That letter ruling makes it perfectly clear that deficiencies in the unit, which require a cessation of the testing program to effect repairs, can jeopardize a finding that the plant was placed in service in that year.[205,206] This is[205] true, even if synchronization had been achieved.

Holcombe first became aware of LTR 7833007 when an employee in the tax department, P. F. Daley,[207] prepared a memorandum on the subject. Daley's December 28 memorandum attached a copy of the letter ruling and noted that two tests remained in the TMI-2 power ascension program. He then stated:

> [If] these remaining tests should disclose major faults which would prevent the unit from accomplishing its intended purpose, i.e., the generation of electricity for the production of income, the 'in service' date could very well be 1979. A private ruling, LTR 7833007, dated May 8, 1978, supports this position[8]

Daley's concern was not an idle one. As discussed later, TMI-2 had already been through a major component failure that necessitated a 3-month delay.[209]

To complete the test program in 1978, it was necessary to resynchronize the unit with the grid following that failure. This was successfully accomplished on September 18, 1978, and the test program continued.[210] Daley's concern apparently was that a similar deficiency would be uncovered very late in the test program in 1978. If so, the claiming of the investment tax credit in 1978 for TMI-2 could be jeopardized.

Holcombe was on vacation when the Daley memorandum was written and distributed to members of the GPU financial group, including President Herman Dieckamp.[211] Apparently, the concerns of the memorandum were never communicated to the operating people and, in fact, on the day Daley wrote his memorandum, GPU declared its test program complete.[212]

Upon his return, Holcombe met with Daley and convinced him that the situation of the plant in the letter ruling and TMI-2 were vastly different.[213] Holcombe then communicated his conclusions to Chief Financial Officer Vernon Condon. As comptroller of GPU, Holcombe then made the decision that TMI-2 had met the applicable tax criteria.[214] He did not seek advice of outside tax counsel because he felt GPU had been through enough such determinations that an inhouse decision was possible.[215] He did consult, indirectly, with the GPU general counsel.[216] From that point on, the tax treatment of TMI-2, as per the 1978 consolidated tax return[117] had been made.

In its 1978 return, GPU claimed $46.5 million of ITCs. Approximately $15 million of this was due to the placing of TMI-2 in service in 1978.[218] However, because of limitation on the amount of ITC that a taxpayer can claim, GPU was forced to take only an $18.5 million credit in 1978. The remaining $28 million was "carried back" to previous tax years and retroactively had the effect of reducing taxes in those years.[219]

An analysis prepared by Edward Holcombe[218] also indicates that the completion of TMI-2 enabled GPU to obtain a $29 million depreciation deduction on its 1978 income tax.[220] This had the effect of, among other things, reducing the amount of income tax (before credits) by $13 million.[221]

In bottom line figures, placing TMI-2 in commercial operation in December 1978 enabled GPU to obtain a $23 million refund, rather than pay $5.4 million in taxes, for a total "savings" of $28 million.[220,222] Because of the limitation on ITC that can be taken in 1 year, the GPU return showed a 1978 payment of $4.7 million. Without TMI-2, GPU estimates it would have paid $7.4 million in taxes,[220] or a difference of $2.7 million.

Although that $28 million represents an undeniable advantage for GPU, it must be kept in the perspective of a corporation that in 1978 had assets of $4.6 billion and $1.3 billion in revenue.[220,223] Furthermore, any analysis of benefits must be dynamic, not static. Had GPU failed to meet the tax criteria for placing TMI-2 in service in 1978, it presumably could have done so in 1979, and all tax benefits that were obtainable in 1978 would then have become available.

In other words, it could be argued that the true tax advantages of placing TMI-2 in service would have simply been postponed 1 year. Hence, the real benefit of completing TMI-2 was that GPU gained the use of the money for 1 year (1979) that would have otherwise been paid as taxes. The money gained is not just the $2.7 million reduction in taxes actually paid but would also include the tax effects of the $28 million in ITC that GPU carried back to previous years. Presuming those carrybacks reduced past income taxes paid, GPU would receive a refund, which could be put to use within the corporation. In addition, because it used the modified half-year convention,[224] GPU would also have the benefit (again, for at least 1 year) of the tax effect of approximately $29 million worth of depreciation.[225,226]

The value of this "interest free loan"[227] to GPU must be valued against what the cost of that money would have been in the marketplace-presuming GPU had a need for such borrowing in 1979.[228] In extremely rough terms, using a 1979 interest rate of 10%, this analysis would yield a final "cash flow" advantage of $2.9 million to GPU.[229]

Again, this amount must be measured against the total needs of a corporation the size of GPU. Although an advantage, the tax incentives for completing TMI-2 were not large, in a relative sense.

c. Other Financial and Nonfinancial Incentives

Beyond the major incentives related to rate recognition, reduction of Federal income taxes and the potential disallowance of AFUDC by FERC, other financial and some nonfinancial incentives could have contributed to the decision to declare TMI-2 in commercial operation on December 30,1978.

Although not one of these items by itself appears to be an overriding incentive, they all add to the benefits received for bringing TMI-2 on line either by December 31, 1978, or as soon as possible after the longstanding May 31, 1978, forecast completion date. As Dieckamp said in speaking about payments to the Pennsylvania-New Jersey-Maryland

(PJM) Pool, "I am sure all nickels add up to dollars and what have you, but I would not in my mind have identified that as an overriding consideration."[230]

PJM Power Pool

The entire GPU system, including Met Ed, is part of the Pennsylvania-New Jersey-Maryland Interconnection. Often referred to simply as the PJM Pool, it coordinates, or pools, the electric bulk power facilities of all PJM members and operates those facilities as if they were a single system.[231]

In a letter dated January 2, 1979, from GPU to the manager of PJM, GPU reported that "Effective 2300 hours on December 30, 1978, Three Mile Island $t2 was made commercial for 880 and 906 MW Summer and Winter rating, respectively. This increases the total GPU installed capacity from 6845 to 7725 MW Summer rating and from 7375 to 8281 Winter rating." The letter suggests that an incentive existed for bringing TMI-2 into commercial operation to increase the "installed capacity" of the GPU system. This requires some understanding of the PJM system.

PJM involvement in the planning for TMI-2 probably goes back at least to 1967 when the "PJM member companies entered into a service-reliability compact known as the Mid-Atlantic Area Coordination Agreement (MAAC). It calls for planned new additions ... to be submitted to the MAAC Executive Board for review by its Area Coordination Committee."[232] While this long range planning is coordinated by MAAC, the PJM Agreement requires PJM members to make firm commitments of capacity and to cooperate with other PJM companies regarding planned outages, transmission facilities, and other matters.[233] All the GPU operating companies (Met Ed, Penelec, and JCP&L) are treated as one entity in PJM operations. In fact, article 2.1 requires the GPU subsidiaries to have in force, arrangements for the allocation of GPU's PJM obligation.

PJM capacity planning begins with setting the requirements for PJM and then allocating the defined requirement to the pool members. The agreement provides, "The electric generating capacity requirement [of PJM] shall be an amount of capacity sufficient to carry the load, permit maintenance and provide reserve adequate to achieve a high degree of reliability."[234] The PJM management committee forecasts this electric generating capacity requirement (called the forecast requirements, which is expressed in megawatts) for future planning periods and sets the equitable allocation of that requirement for each PJM member (each member's portion is called its forecast obligation).

Schedule 2.01(b) requires that forecast requirements be determined annually, before April 30, for all of the planning periods included in the long range PJM plan and that unless otherwise agreed to, the forecast requirements for the "three full planning periods following such annual determination shall be considered firm and not subject to redetermination thereafter."[235] Each PJM member must submit to PJM its plans for carrying its forecast obligation either through (1) installation of generating capacity; (2) purchases of capacity and energy, either from within or outside the pool; or (3) purchases of capacity from other PJM members who have capacity in excess of their forecast obligation.[236] Further, the PJM Agreement specifies the price for deficiency purchases.[237,238] The rate in effect for the period June 1, 1978 through May 31, 1979, was $22.63/kW/yr,[237,238] calculated on a daily basis, or $62/MW/day.[237,239]

Commitments of individual PJM members become locked as much as 3 years before a unit is forecast to become part of a member's installed capacity. Schedule 2.01(e) requires that the plans submitted by each PJM member for a planning period "shall be considered firm commitments as of a date two years prior to the beginning of such planning period."

Because the PJM planning period is "the twelve months beginning June 1 and extending through May 31 of the following year,"[24] o the firm commitment requirement means that generating capacity scheduled to become installed capacity by May 31, 1978 (as an example), is a firm commitment as of June 1, 1975 (2 years prior to the June 1, 1977, through May 31,1978, planning year).

The PJM planning period ends on May 31 because the pool as a whole is a summer peaking pool, that is, the maximum load on the PJM pool occurs in the summer, defined as June through September. A winter peak is similarly defined as the forecast maximum 1-hour load during the period December through March '[241]

Clearly, the early estimated inservice dates for TMI-2 coincided with PJM planning periods. Perhaps the earliest estimate was made in June 1969, when an inservice date of May 1973 was forecast.[242] The date subsequently was revised in 1-year increments to May 1974, 1975, 1976, and 1977, and in September 1974 it was again revised to May 1978.[243] All of these inservice date changes were made before or just after the beginning of the 3-year period when the otherwise unrevised date would have become a "firm commitment" under schedule 2.01(e) of the PJM agreement. For example, prior to the revision in September 1974, the forecast inservice date was May 1977. GPU would have had to make the May 1977 date a firm commitment by June 1, 1974. Instead, in September 1974, the inservice date was changed to May 1978. Because the May 1978 date was not again changed until March 1978,[2] *as of June 1, 1975,* there was a firm capacity commitment to PJM to bring TMI-2 into installed capacity by May 31, 1978. Of course, the May 31, 1978 estimated inservice date would also mean that TMI-2 would be available to meet the actual summer 1978 peak load.

Because the May 31, 1978, date for TMI-2 had become part of GPU's firm capacity commitment to the pool, GPU incurred financial penalty for missing that installed capacity commitment. Over the 6-month period June 1-December 31,1978, the total of that penalty was $7 383 332.[245]

According to Robert H. Sims, GPU's representative to PJM, the PJM pool as a whole has had excess installed capacity since 1972,[2] but GPU, according to their 1978 forecast, was short of their capacity commitment to the pool.[247,2a] Had TMI-2 been available as projected in June 1978, GPU would have paid no capacity penalty to the PJM pool.[249]

Assessment

Although GPU had this incentive to complete TMI-2 as soon as possible, apparently there was little, if any, pressure from PJM to bring TMI-2 into service specifically by December 31,1978.

To the extent that TMI-2 would be a low cost unit, the PJM pool and GPU would both benefit no matter when the unit was brought into service. PJM had excess capacity and because PJM's peak load is in summer, there would be little pressure from the pool to bring TMI-2 into service in December. Testifying in a Davis Besse hearing, one consulting engineer said that interconnected utilities are not anxious to see an untested generating unit declared commercial. He went on to state:

> To ask interconnected neighboring utilities to accept an untested unit as operational is to ask them to support the reliability of service of the owning utility. The untested unit ... would probably be less reliable than more mature units [and] the neighboring utilities would be providing the reserves to backup the unilt in question. This is not only unfair but I am sure it would not be acceptable to the neighboring utilities.[250]

An individual utility member of PJM encountering a forced outage on a plant that has been in service for at least 1 year, also suffers in terms of having to supply larger total capacity requirements in the future.[251] John Herbein recognized this situation when he testified:

> We commit a certain amount of capacity to the [PJM] system and to the extent that we don't meet that capacity why then we are subsequently penalized. So it's to our benefit to declare the unit commercial at some specific power level that we are reasonably confident we can make on a regular basis. And in turn, that means that the plant has got to operate at an acceptable capacity.[252]

Robert Arnold, Vice President of Generation, felt that once the May 31 date was missed, there was no incentive in terms of the PJM Pool until perhaps the end of the following PJM planning period. Arnold said, "I expect that once we identified that we were likely to miss that date, [May 31, 1978] that it probably was diverted a full year or postponed a full year in terms of a commitment on planning to the pool."[263]

In sum, GPU's attitude toward the PJM commitment, as stated by GPU President Herman Dieckamp, was that[254] "when we declare a plant commercial, it is made available to the system dispatchers to call upon that plant for generation when it is needed. So it is, in effect, officially made available to provide power to the pool, but that is... not a terribly significant thing."

Although the PJM penalty appears large, and may be an incentive to complete a unit as close to its committed date as possible, there apparently were no PJM incentives for declaring TMI-2 commercial by the end of 1978 per se.

Corporate Capital

Another possible incentive considered by the Special Inquiry Group was the influence, if any, of TMI-2's commercial operation on GPU's ability to raise money. Utilities constantly need capital to pay for the construction program, meet sinking fund obligations, and refinance maturing indebtedness. The sources of capital to provide the total funds generally are internal funds generated by the company's operations, the sale of common and preferred stock, the issuance of first-mortgage bonds and debentures, and short term sources such as issuance of commercial paper or bank loans.

In mid-October 1978, GPU forecast 1979 capital requirements of approximately $537 million, of which the largest single item was $135 million for construction costs of the Forked River nuclear plant.[255] The financing of the $537 million was forecast to come primarily from internal funds, with the need to issue approximately $156 million long-term bonds and also sell some preferred and common stock as well as issue some commercial paper.

Ordinarily when a company issues debt or preferred stock, limitations or conditions are put on the issuance of additional debt or preferred stock in the future. This was the case with the GPU companies. As Met Ed's form 10-K submitted to the Securities and Exchange Commission for the year ended December 31, 1978 states, Met Ed's indentures and articles of incorporation "contain provisions limiting the total amount of securities evidencing funded indebtedness which the Company may issue...."[256] These limits deal with coverage ratios, that is, the amount by which earnings exceed interest charges and ratios of short term debt to total debt or capital.

In other words, the limiting factor on the issuance of new bonds or other capital financing is the earnings of the company. However, once TMI-2 was declared in commercial operation, large depreciation expenses began to reduce net earnings. Of course, the commercial operation declaration also signaled the cessation of the noncash AFUDC earnings related to TMI-2. Therefore, the commercial operation declaration by itself was not sufficient to increase earnings; rather, the rates regulated by the State PUCs had to be increased to have that effect. This meant securing an order bringing TMI-2 into the rate base. Since rate case matters have been discussed previously,[257] no further elaboration will be presented here.

As Met Ed's form 10-K explains the situation: "Since under the Company's indenture and articles of incorporation such ability [to issue new securities] is measured for a consecutive twelve month period during the fifteen months immediately preceding such issuance, it is to be anticipated that the coverage ratios may deteriorate and might be a limiting factor in the absence of adequate rate relief."[258]

Under the indentures of some electric utilities it is possible that a new electric plant becomes bondable, that is, the plant is eligible to serve as security for the issuance of first-mortgage bonds, only when the plant is placed in commercial service. If this were true for GPU, then the commercial operation declaration would have allowed significant increases in the debt GPU could issue. However, John Graham testified that, "under our indentures, the declaration of the plant as being in commercial service is not material to the issue of bondability" because the indentures were amended in the early 1970s to allow the bonding of construction work in progress.[259] He further stated: "We had bonded TMI as it met the criteria of the indentures and whether it's in commercial service or not... simply doesn't make a difference for purposes of certifying bondable property additions to the various trustees."[260]

Before the December 30, 1978 commercial operation date, $654 million was certified, an increase of $83.5 million that apparently was independent of the commercial operation declaration.[261]

High-quality bond ratings by bond rating companies allow a company issuing bonds to do so at interest rates lower than those for lower quality bonds. The effect of even small reductions in interest rates can amount to millions of dollars over the life of a large bond issue. Did the TMI-2 commercial operation declaration perhaps serve to improve or maintain GPU companies' bond ratings?

At the end of 1978, the first-mortgage bond ratings of the GPU subsidiaries were as follows: Met Ed, "A;" JCP&L, "Baa;" and Penelec, "A."[262] Moody's explanation is that "A" bonds are considered "upper medium grade obligations," while "Baa" bonds are "medium grade" obligations.[263] The highest Moody's bond rating possible is "Aaa" and the lowest possible is "C."

Certainly delays in nuclear plant operation can harm a company's bond rating. *The New York Times* reported that Moody's, a bond rating service, had lowered Long Island Light Company (LILCo) publicly held first-mortgage bonds.[264] "Moody's said the action reflected the company's [LILCo's] low level of internal cash generation, which resulted from the construction of the company's Shoreham Nuclear Station."[265]

Before the LILCo decision, Moody's stated that an *indefinite* delay in TMI-2 in late 1978 would have caused Moody's to seriously review Met Ed's ratings.[266] However, at that time there was no indication of an indefinite delay in declaring TMI-2 commercial. Standards & Poor's (S&P), another bond rating service, saw it as inconsequential if TMI-2 went into commercial operation December 30,1978, or January, February, or March 1979. S&P ratings are planned to be long term ratings and should override any *temporary* adversity.[267] Another Moody's employee said succinctly that if Met Ed's financial condition and thus their bond ratings were dependent on the commercial operation declaration by the end of the year, then most likely the rating would have been in jeopardy long before.[268]

Evidently the timing of the commercial operation declaration, as long as it was in sight, was not crucial to maintaining or improving the bond ratings of the GPU companies. John Graham, GPU Treasurer, felt that the rate case was the important factor in bond ratings. He said S&P was ready to upgrade Penelec's rating "and a delay in the *rate case* may have delayed our ability to accomplish that."[269] (Emphasis added.)

Assessment

The ability to raise new capital is tied not to a commercial operation declaration but to rate cases. Even underlying aspects such as determinations of bondable plant and the setting of bond ratings did not hinge on a commercial operation of TMI-2. Thus, the *rate* cases are the areas of possible incentive, as enhanced by the ability to raise new capital. As Graham said, commercial operation "takes away some financing capability because the loss of the [AFUDC] earnings has the effect of reducing coverage until you get your rate order and begin to recover the cash earnings at which time there is an improvement in financing capability. H270

Nonfinancial Incentives

Although not quantifiable, some nonfinancial benefits existed for declaring TMI-2 to be in commercial operation by the end of 1978.

An annual report, although addressed primarily to shareholders, serves to communicate company progress to a wide spectrum of interested parties. The GPU Annual Report for the calendar year 1978 refers to TMI-2 this way:

> The end of 1978 saw *a major milestone* in the history of General Public Utilities. With *commercial operation* of the second unit on Three Mile Island, Pa., the Company completed a $1.1 billion, two-unit nuclear station (TMI-1 and TMI-2) started a decade ago.[271] (Emphasis added.)

Met Ed's Annual Report similarly states, "For Metropolitan Edison Company, 1978 will remain a memorable year, chiefly because of the completion and entry into commercial service of the second Three Mile Island ('TMI') nuclear station."272

No one can fault the utility for reporting the progress made. The commemorative remarks, however, reflect the attitude existing in GPU in 1978, as can be seen by this statement by John Graham: "There's no question but that completion of TMI-2 was a major corporate objective simply because it was being built for a longer time, was a major investment, would produce a lot of energy at a low fuel cost, and was an awfully good thing to have behind us."[273]

Graham is not alone in recognizing the attitude at that time. Robert Arnold, in talking about the completion of the TMI-2 test program in late December 1978, said that although he did not instruct people to come in over the Christmas weekend, many may have because of "the attitude that existed at that time."[274]

Because the annual report was not published until late February or March 1979, information about the completion of TMI-2 could well have been included in the report even with a commercial operation date several weeks into 1979. The annual report, therefore, was not *in itself* an incentive for completion of TMI-2 in 1978.

Nonetheless, there is at least one element of financial reporting in the 1978 annual report that did have a December 31, 1978 cutoff date. To show TMI-2 as part of utility plant in service[275] rather than as CWIP required a declaration of commercial operation by December 31. Although not a major incentive, this has some appeal for the bulk of GPU shareholders. Otherwise, the reported financial results would show more than $1 billion as CWIP out of a total of $4.1 billion in net utility plant.

Assessment

These benefits are not quantifiable. Financial analysts are generally concerned only with whether a plant is in rate base, not with how it is presented in the annual report financial statements. The reporting of a significant milestone does, however, hold some goodwill benefit. While the corporate attitude to achieve certain objectives is not unique to completing nuclear units, the implications in the nuclear industry are different.

NRC Requirements-Guidelines on Time for Completing Test Program

Previous sections examined the possible incentives for bringing TMI-2 into commercial operation that may emanate from the financial and some nonfinancial aspects of GPU's condition. There may also be some incentives arising from requirements or informal guidance of the NRC.

There is an NRC regulatory format in which this process takes place. Following issuance of the operating license, a licensee must proceed through six "operational modes," obtaining approval from the NRC at each level, before a unit is approved to generate commercial amounts of power. The six modes are: operational mode 6 (initial fuel loading); operational mode 5 (cold shutdown); operational mode 4 (hot shutdown); operational mode 3 (hot standby); operational mode 2 (startup; criticality); operational mode 1 (power operation).

Each license specifies uncompleted action (at the time of the operating license) which must be completed before authorization will be granted to proceed to the next Operational Mode. On the report of the NRC Office of Inspection and Enforcement (IE) that a licensee has fulfilled the requirements specified in the license, the responsible NRC official will issue the necessary authorization letter to the licensee.

It is evident from depositions, however, that NRC guidance beyond this mode system is vague and not well understood either within the NRC or by GPU personnel. Herman Dieckamp, testifying before PaPUC after the accident, said, "The NRC has pointed out that the timing of the beginning of physical operation of a nuclear generating unit and the circumstances of such operation are governed by the NRC operating license and have nothing to do with whether the unit has been declared to be in 'commercial service.'"[276] This statement accurately characterizes the situation in that no NRC requirement is *explicitly a* precondition to declaring a unit to be in commercial operation. However, through the mode system and by establishing various minimum and maximum time limits on the conduct of preoperational and startup testing, NRC can influence the time schedule for declaring a unit commercial.

Regulatory guides are produced by NRC's Office of Standards Development and:

> [A]re issued to describe and make available to the public methods acceptable to the NRC staff of implementing specific parts of the Commission's regulations, to delineate techniques used by the staff in evaluating specific problems on postulated accidents, or to provide guidance to applicants. Regulatory Guides are not substitutes for regulations, and compliance with them is not required.[277]

Regulatory Guide 1.68 deals with the scope and depth of initial test programs acceptable to the NRC staff for light-water-cooled reactors. An initial test program is defined to consist of preoperational (before fuel load) and initial startup tests (after fuel load).[278] Startup tests include power ascension tests. Specifically, Regulatory Guide 1.68 states:

> The power-ascension test phase of the initial test program should be completed in an orderly and expeditious manner. Failure to complete the power ascension test phase within a reasonable period of time may indicate inadequacies in the applicant's operating and maintenance capabilities or may result from basic design problems.[279]

After stating that the power ascension phase of the initial startup testing should be orderly and expeditious, thus setting an unknown maximum time frame, the guide goes on to define a minimum time frame. "Sufficient time should be scheduled to perform orderly and comprehensive testing. The applicants' schedules for conducting the preoperational and initial startup phases should provide for a minimum of approximately 9 and 3 months, respectively."[280]

Essentially, NRC is saying that power ascension tests, which are the last of the initial startup tests and culminate in 100% power tests such as the 100% reactor and turbine trip tests, should be scheduled to be completed no sooner than 3 months after fuel load.

The Standard Review Plan (SRP) is prepared for the guidance of the staff of NRC's Office of Nuclear Reactor Regulation (NRR) in their review of applications for construction permit and operating licenses. SRP section 14.2, "Initial Plant Test Programs-FSAR," was issued on November 24, 1975. Acceptance criteria 11, "Test Program Schedule," contains language nearly identical to Regulatory Guide 1.68, stating that at least 9 months be allowed for conducting preoperational testing and at least 3 months be allowed for conducting startup testing including fuel loading, low power tests, and power ascension tests.[281]

Inspection and Enforcement Manual

The Inspection and Enforcement Manual contains guidance for IE inspectors in preparing for and conducting various types of inspections. Manual Chapter 2514, "Light Water Reactor Inspection Program-Startup Testing Phase," gives the following definition of startup testing: For the purposes of this program, startup testing is defined as that testing conducted following issuance of the operating license, starting with initial core loading, but excepting incomplete preoperational testing; and continuing until the plant reaches commercial operating status at or near its licensed power rating."[282] IE, it seems, recognizes that utilities will normally declare commercial operation at a point where the unit can operate at or near its full licensed power rating. The same Manual chapter also deals with the situation where a licensee may want to operate at a power level less than full power without expeditiously completing the remaining power ascension tests at that and higher power levels. Basically, these criteria do not allow a licensee to remain at a power level if the licensee has not done all the tests at that level.[283] There is further potential adverse impact in that IE will require the licensee to perform at the lower power level tests planned for the next testing plateau so as to demonstrate that the unit can be operated safely at that lower level over a period of time. IE will also require the licensee "to obtain NRR approval for not repeating all planned tests when the power level is increased."[284]

In other words, IE apparently thinks it important to discourage licensees from lagging in performance of startup testing and recognizes that licensees may have some motivation to declare commercial operation at a time when the unit is operating at less than full rated power.

Another Babcock & Wilcox unit, Crystal River 3, is an example of this commercial operation declaration before completion of startup testing:

- Fuel load-December 4, 1976
- Initial criticality-January 14,1977
- Commercial operation-March 13,1977
- Complete startup tests-April 26,1977

From fuel load to completion of startup tests, 143 days elapsed; only 99 days passed from fuel load to commercial operation.

Final Safety Analysis Reports (FSARs) are submiffed by applicants for operating licenses and are reviewed by NRR. The material in the FSAR is considered a commitment to the NRC, although deviations can occur. IE inspectors can cite a licensee for failing to meet FSAR commitments.

Chapter 14 of the TMI-2 FSAR describes a test program divided into three phases: (1) construction, (2) preoperational, and (3) fuel loading and initial operation. The third phase ends with power escalation tests. According to the FSAR, the third phase "starts with initial fuel loading and ends upon completion of the power escalation program and designation of the unit as ready for commercial operation."[285] The FSAR is even more specific: "SP 800/21, Unit Startup and Power Escalation Test Procedure, will be the controlling document for taking the unit from a zero power, hot condition through the various power test plateaus up to commercial operation at licensed power."[286]

Assessment

In the FSAR, the licensee (with guidance from the NRC) makes a commitment to complete the entire test program before declaring commercial operation. There was no explicit requirement linking completion of the power ascension test program with commercial operation, as Dieckamp has said.[287] However, Regulatory Guide 1.68 and SRP 9- and 3-month guidelines were satisfied as illustrated in a test program schedule included in the FSAR. That schedule shows a period of 11 months before fuel load for preoperational tests and shows completion of power ascension tests and estimated commercial operation 4 months after fuel load.[288] The FSAR also incorporates IE concerns by stating that the power escalation tests "will be a step by step procedure that either incorporates or references applicable steps in normal approved unit operating procedures required to increase power from one test plateau to another and maintain steady state power at each test plateau. The normal operating procedure steps will be blended with the power escalation test program to produce a preplanned, orderly, organized test sequence."[2e9] This suggests that the test program will proceed in an orderly manner through completion and, as previously committed, commercial operation at full rated power.

This does not imply that GPU should not have made the commitments in the FSAR nor that NRC should not have requirements governing the completion of test programs. Rather, the finding of the Special Investigation Group is that NRC apparently has seen a need to regulate not only the depth and scope of startup tests (after fuel load) but also the pace for conducting that portion of the test program.

Furthermore, NRC through the Inspection and Enforcement Manual and through NRR's review of the commitments in the FSAR, has found it useful to make expeditious completion of the test program a precondition to a utility's unilateral commercial operation decision and to also require that this not be attempted in less than 3 months.

3. ACTIONS TAKEN AT TMI-2 INDICATING TIME CONSIDERATIONS THAT WERE LINKED TO FINANCIAL INCENTIVES

Having identified the incentives that existed for the completion of TMI-2 in 1978, we now examine the question of whether GPU took any conscious action to obtain those incentives. Although the evidence is equivocal, we conclude that deliberate action was taken to enable completion of the unit by the end of 1978 to obtain the previously identified incentives. This conclusion, however, should not be read as the equivalent of stating that this "rush" compromised the safety of the unit; that question is addressed in the following section.

As a matter of methodology, there is the difficulty of knowing where to begin looking for a rush to complete the plant by the end of 1978. The lifeline of a nuclear plant can be simply sketched: planning, to construction permit, to construction, to operating license, to testing, to operation. At what point do the incentives for operation dictate a rush in the other phases? It could be argued that a rush in those phases is always dictated by the desire to get the unit in operation as soon as possible. But to look to the specific date of December 31, 1978 and imagine that GPU rushed the planning phase of TMI-2 back in the 1960s is difficult.[290] Similarly, GPU did not begin planning for a December 30, 1978, commercial operation date back in 1969 when it received its construction permit to build TMI-2.[291] In fact, GPU officials did not predict an end of the year, 1978, commercial operation date until November of that year.[292]

Thus, the main focus of attention must be on events occurring in the latter half of 1978-on specific action taken when the "cushion" on the earlier predicated date of May 31, 1978 began to evaporate.[293] At the same time, however, the continuing nature of construction at a nuclear plant must be kept in mind. Therefore, certain events in the construction of TMI-2 were examined to determine if there was any indication of a rush even in the pre-1978 period. The results of that examination are set forth to complete the record.

The Construction Period

The Special Inquiry Group's interest in the construction period at TMI-2 was piqued by allegations that GPU may have been interested in rushing construction of the unit to obtain its operating license.[294,295] As the previous timeline suggested, an operating license is necessary before power ascension testing and, ultimately, commercial operation. In turn, because of NRC requirements and practices, construction must be complete before an operating license is possible.[29g] Thus the argument is that GPU could have rushed construction of TMI-2 to obtain an operating license earlier, complete testing earlier, and go commercial earlier. This scenario is not tied to a December 31, 1978 date. For that reason, the incentives discussed previously are probably not involved in any rush to obtain an operating license.[297]

Some evidence exists that GPU was interested in obtaining an operating license as early as possible. Two indications of that are examined: the pace of preoperational testing and the change of contractors.

"Preoperational" or "hot-functional" tests are those conducted before fuel loading. By heating coolant in the primary system with the reactor coolant pumps (RCPs), steam can be produced so that components of the system can be tested. This hot-functional testing is generally well underway before a utility proceeds to fuel loading.

At TMI-2, IE inspectors found that "the [hot-functional] testing program was being pushed to its absolute limit...."[298,299] The project inspector did not consider this a rush, because all utilities establish "an extremely optimistic schedule" for preoperational tests.[300] However, he added:

> At TMI, I think they were pushing a little harder than I had seen in other plants in the test program at this point in time; they were interested in an operating license.[300]

Physical indications of this "push" occurred when GPU test engineers overextended the unit during tests. The first of these was a test in which the reactor coolant pump seals were improperly subjected to high temperatures and needed replacement. The NRC inspector on site concluded that the pace of the test schedule contributed to the incident.[301] The second incident involved exceeding test specifications by failing to wait for a required reaction.[302] This incident resulted in a report of an item of noncompliance.[302,303] As the inspector said, "[the test superintendent] basically gambled and lost in that case."[304] The inspector added:

> [I]t's an example, it was one of the first things that we pointed out to him that we did not care to see the program run at that pace that you had to take chances, which is basically what he did.[304]

Many times during the hot-functional testing, the IE inspectors noticed that the test engineers would have to wait for completion of construction to catch up before they could proceed with their testing.[305] GPU may have tried to solve this problem by replacing the original constructor of the unit.

Technically, "replacement" may be incorrect.[30s] In June 1977, GPU terminated its contract with United Engineers & Constructors (UE&C) as "construction manager" and hired Catalytic, Inc. (Catalytic), as "maintenance contractor." In the process, GPU assumed the duties of "construction manager." Therefore, Catalytic "replaced" UE&C as the constructor on the site only in rough terms.[307]

GPU's decision to replace UE&C was apparently not due to any dissatisfaction with that company's performance as constructor of TMI-2 to that point.[illegible] Rather, GPU was following the system it had used on TMI-1-and had been used at other units[310]-of replacing the constructor with a maintenance contractor as the unit neared completion.[311] There was sufficient notice given such that UE&C was not surprised by GPU's action.[312]

The rationale for replacing a constructor with a maintenance contractor toward the end of construction at a nuclear unit is apparently twofold. First, it recognizes that on a large project, "construction" is never complete. There is always additional work to be done to keep the unit in top condition.[313] Second, it is an admission that worker productivity decreases as a job nears completion.[314,315] To eliminate this slack period, a maintenance contractor comes on board to remotivate craft laborers.[316]

In rough terms, TMI-1 and TMI-2 were in a similar position when maintenance contractors were hired. If anything, TMI-2 was less complete when Catalytic replaced UE&C.[317] GPU officials were, in fact, surprised that there were so many "open items" remaining when Catalytic first reported on the status of the unit.[318]

The timing of this change is crucial. GPU replaced its constructor at TMI-2 just as hot-functional testing began.[319] Thus, the change was a method of motivating the construction work, which was necessary for completing preoperational testing. Some of that testing, it will be recalled, is done before an operating license will be granted.

However, even the substitution of constructors is not a magic solution for getting work completed. As the planned date for the operating license approached, GPU found that many items remained outstanding at TMI-2.[320] In the end, the IE project inspector went through that list of open items and specifically instructed GPU which ones had to be completed before he would recommend that an operating license be issued.[321] Otherwise, GPU would have had to develop its own list of priorities; a list that might have been incorrect and further set back the date of the issuance of the license. The IE project inspector eventually recommended granting of the license, which the director of NRR did pursuant to an order of the Atomic Safety and Licensing Board on February 8, 1978.

As a matter of completeness, any rush in preoperational testing or construction in the late 1977-early 1978 period must be measured against the entire construction history of the TMI-2 project. In the mid-1970s, because of GPU financial problems, the construction schedule at TMI-2 was intentionally staled.[322] In fact, an audit of this decision by the Touche Ross accounting firm was used by the Office of the Consumer Advocate in Pennsylvania and in New Jersey to challenge the total cost of the unit.[323] UE&C's project manager of construction at TMI-2 confirmed that budget restrictions were imposed on his management of the project during the 1974-1977 time period.[324]

In perspective, therefore, if there was a need to rush construction and testing in 1977 to obtain the operating license and proceed with completion of the unit, it may have been due to a previous slowdown in the project. If this fluctuation was caused by financial pressures on GPU, it is something of which the NRC should be concerned.[325]

Assuming GPU did rush to obtain the operating license for TMI-2, both by pressing the hot-functional testing schedule and by motivating increased construction through a change in constructors, what is the impact on the analysis? As stated at the outset of this section, obtaining the operating license on February 8, 1978 does not appear linked to the incentives that flow from a December 30, 1978, declaration of commercial operation. Rather, a desire to obtain an operating license and proceed with power ascension testing indicates only the general desire to complete a unit as soon as possible. GPU was not alone in desiring that result.[326]

In fact, a Babcock & Wilcox (B&W) employee stated that industrywide utilities rush to get their operating licenses.[327,328] This, according to the employee, results in added complications in completing the unit.[327]

In conclusion, even assuming GPU rushed to obtain its operating license, nothing indicates that such action was tied to a commercial operation date of December 1978. The prelicense phase, therefore, reveals no rush to obtain the incentives identified.

However, the action taken by GPU to obtain its operating license in February 1978[329] foreshadowed the resources the company could mobilize to obtain a desired goal: intense test schedules and contractor pressure. Both of these will become important in our analysis of the postlicense period.

Post-Operating License Period

It was not until GPU realized there was a possibility that TMI-2 would not be commercial in 1978 that a rush to obtain the incentives connected with that date was possible. Not to minimize the possibility that there is a general rush to completion of a nuclear unit, or a rush for some other incentives, the focus of this investigation has been the rush to obtain those financial advantages associated with a December 1978 completion date.

The starting assumption made here is that up until the main steam relief valve failure of April 23, 1978, GPU was not concerned with a December 1978 deadline.[332] It was probably only after the April 23 transient that the potential for missing that date first occurred to GPU. Therefore, the majority of our analysis is devoted to two events occurring in this period. If there was a rush to obtain the incentives, it would have to have occurred in this 8-month period.

Specifically, we examine (1) the power ascension test schedule and (2) the replacement of the main steam relief valves as situations in which conscious action might have been necessary to bring the unit into commercial operation before the end of the year.

The power ascension schedule had been transmitted to PaPUC[335] setting forth the steps necessary before GPU would declare the unit in commerical operation. Thus, by its own action, GPU had placed the test schedule on the "critical path."[337] Late in 1978, there was also some reason to believe that the IRS would not consider TMI-2 placed in service if the power ascension tests were not completed in 1978 _

The main steam relief valve failure of April 23, 1978, similarly created problems on the "critical path." Despite numerous small problems, before that failure there apparently was little doubt that TMI-2 would have been in commercial operation by the end of 1978.[339,340] With the discovery that the valves had malfunctioned, however, GPU had to decide quickly what action to take. Without the main steam valves, power ascension testing (and commercial operation) could not begin.

Power Ascension Test Schedule

By way of background, the power ascension test schedule that a utility eventually performs at a nuclear unit is a product of many different sources. The NRC requires that a startup test program be conducted.[341] The NRC further suggests the type of tests that should be included in the power ascension program.[342] Beyond this, a utility is free to impose additional tests upon itself. Some of these are suggested by the nuclear steam system supplier, based upon previous experience at other units.[343] There may also be tests the utility desires to gather data or improve the reliability of a unit. By our definition, the power ascension test schedule is composed of all of these planned tests, as recorded in the unit's master test index.

A lengthy list of tests is also included in chapter 14 of the NRC-required FSAR. While only safety-related tests must be specified in the FSAR,[344] utilities sometime include other scheduled tests. Recalling that the FSAR is filed before an operating license is issued, this requires some long range planning on the part of the utility.

Some other tests are not included in the FSAR. They may show up on the master test index corporate test diagrams or internal memoranda but never be subject to official scrutiny. For example, of the 170 tests initially scheduled in the entire program at TMI-2 (preoperation and power ascension), only approximately 85 were safety related and required by the NRC.[345] In fact, the FSAR for TMI-2 lists 88 tests. Some additional tests were added by the vendor, others by the utility itself. Yet even tests not listed in the FSAR (not required for safety) must be considered relevant in the investigation of a rush. If GPU thought it worth including a test in its planned sequence in 1976, it presumably would have the same opinion of the test in 1978.

In the October 26, 1978, meeting of the Commercial Operation Review Board (CORB) at Three Mile Island,[7] it was announced that "[seven] tests will not be completed as originally written since an evaluation determined that there are no unresolved problems and none of the testing omitted is related to Federal, State or local requirements." W

According to the TMI-2 test superintendent, "There were seven test procedures at that time [of the CORB meeting] that we had not committed to in the FSAR, that we had not performed and these procedures were developed by us and only required by us."[349] As examples, the test superintendent listed the following:

> We had a pretreatment plant that would make drinking water on Unit Number 2. We also had one in Unit Number I that supplied all the water we needed. Therefore, we never did get that system in service. We had a demineralizer that would make demineralized water to fill the condensate system. [The make-up demineralizer discussed in this list is to be distinguished from the full-flow condensate polishers (i.e., demineralizers) that have been associated with the initiation of the March 28, 1979 accident.] The unit one system was quite large and supplied all our needs. When we loaded fuel, we had testing to do on the fuel handling equipment that we had some parts [missing?] that we did not complete at the time.... When we received the parts they would be completed later on. We had a sampling system that would sample water in a condenser.... There are other methods to locate it but it's harder. That's the type testing that was in there [the seven tests)

The TMI project manager said a review of possible deletions was ongoing. "We looked all the time at things that may be in our program that weren't necessary," he said.[351] "If they aren't necessary and they don't provide you something tangible for the operation and the safety of the unit and you can delay it or defer it or not do it, why not?"[352]

In fact, GPU deleted a total of eight tests from its original master test index.[353] GPU, therefore, performed approximately 160 startup tests. Half of those were not required by the NRC.

Posed against these GPU explanations of the reason for deleting the tests must be considered the following: The power ascension program at TMI-2 was completed on December 28, 1978.[354] Immediately following the completion, power escalation began, which resulted in declaring the unit in commercial operation on December 30, 1978, at 11 p.m.[354] What if GPU had followed its original sequence, performing all seven deleted tests, would it have been possible to meet a December 30, 1978 commercial operation date?

If it would not have been possible to complete the test program before December 31, with the seven tests, then their deletion assisted GPU in obtaining the previously identified financiafincentives, by enabling it to declare the unit commercial in 1978.

The explanation of the deletion as necessary for operation is the weaker of the two explanations. The decision to delete the tests must have been made before October 1978. At that time, GPU officials have insisted that they were not concerned with a December 1978 deadline.[355] Although it could be argued that recent events would have counseled against being too optimistic,[356] no evidence suggests that the tests were ordered deleted specifically because of time considerations.

In addition, GPU performed a vast number of voluntary tests. To have provided an even more comfortable cushion on "commercial operation," it could be expected that other tests would have been deleted. We know of none other than those previously mentioned.

Thus, the explanation for deleting seven tests, as offered by GPU officials, seems plausible: experience with TMI-1-and the unexpected capacity of that unit to carry TMI-2 as well-made some test procedures drafted before TMI-1 went into operation[357] obsolete and redundant.

A second change in the power ascension test schedule is more difficult to understand, however. Both the FSAR[358] and GPU internal memoranda[359,360] list the "unit acceptance test" as one that was scheduled to be performed before declaration of commercial operation.[361] Inclusion of the unit acceptance test in the FSAR is somewhat odd. The test, according to an abstract, is designed to "verify that the energy output from the nuclear steam supply system meets or exceeds the (Nuclear Steam Supply System) NSSS contract warranty output."[362] Such a test would seem to be related more to contract requirements than safety.[363,364] In fact, the unit acceptance test is one of the tests in standard B&W FSAR chapter 14.[365] Thus, it can be presumed B&W suggested to GPU that the test be included, and GPU apparently agreed.

The unit acceptance test of TMI-2 was not run before the declaration of commercial operation. It was run in February 1979.[366] The explanation for this postponement from GPU officials was that it was not necessary to run the test before commercial operation. The GPU vice president of generation said that, although the test was "important from a contractual standpoint," it "was not a total overall measurement of performance of all systems."[366] He added:

> I know I was not interested in formally performing that test prior to the end of the period in which I was permitted under the contract to perform it. It was a formality in our case because the warranted output related to about 87 percent power and clearly we had the energy output equivalent to 87 percent power. So there was no incentive from my standpoint to perform that test before the end of the period that the contract provided for....[366,367]

The GPUSC project manager at TMI, whose job description made him responsible until "satisfactory completion of the initial warranty run,"[368] said there was no need to run the test before commercial operation. Calling the test "an academic exercise," the project manager said that data on steam output had already been taken in two earlier runs on TMI-2.[369] He also said that output of TMI-1 indicated to them that there was a "certainty of getting a similar output ... for Unit 2."[370]

Again, the explanations of GPU officials must be compared against the other possibility; that postponement of the unit acceptance test enabled GPU to declare the unit commercial in 1978, when that would not have been possible otherwise. It has been stated that a unit acceptance test is generally run after commercial operation.[371]

The utility wants to be sure that the unit operates as warranted by the vendor. This is best demonstrated by substantial generation at full power over a period of time.[372]

However, GPU clearly stated its intention to perform the test before commercial operation.[373] Leaving aside the confused legality of altering an FSAR-stated test,[374] and the equally confused status of GPU's "communication" to PaPUC that the test would be performed before commercial operation[375,376] GPU's reasoning for postponing the test is questionable. Why would the performance of one unit (TMI-1) *ipso facto* provide assurance of the other's ability? If there was no logical reason for performing the unit acceptance test before commercial operation, why was it so listed in the FSAR?

Recognizing the large amount of full power operation necessary to do the warranty run, 377 postponement until after commercial operation allowed GPU to meet a December 1978 deadline that apparently would have been otherwise impossible. The postponement, therefore, is indicative of conscious action taken to obtain the previously discussed incentives. However, assuming the unit acceptance test is important only for contractual purposes, there is no reason for its inclusion before commercial operation. Thus, GPU could at most be faulted for imposing more stringent standards on itself than it ultimately could meet. The point here goes not to the propriety of the postponement decision, but to the very fact such a decision was apparently "required."

Replacement of the Main Steam Relief Valves

On April 23, 1978, TMI-2 was operating at 28% power during the conduct of that part of the test program known as the "15-40 percent power escalation phase." The reactor tripped leading to an increase in pressure in both the reactor plant and steam plant. Normally, this pressure increase is controlled by main steam safety relief valves designed to open at preset pressure levels. (These valves should be distinguished from the power operated relief valve (PORV) which stuck open and has been identified as a contributor to the March 28, 1979 accident.)

The steam relief valves did open and vent the

the valves did not close as they were supposed to as the pressure returned to a normal range. As a result of the main steam safety relief valves failing to close appropriately, excessive heat was removed from the main steam system. This caused the steam generators to cool down, thereby causing the reactor coolant system to cool down excessively. The rapid cooldown of the reactor coolant system, and the associated decrease in reactor coolant pressure caused the emergency core cooling system to operate "in a manner similar to that expected during a loss of coolant accident."[378] This "excessive blowdown" was caused by the valves not reclosing and it was thought initially to be merely a problem of "adjusting the reclosure pressure."[379] Apparently, however, reclosure pressure adjustments alone were not able to solve the problem: "It became apparent about May 20th that the allowable adjustments were not correcting the reclosure problem with the main steam safety [relief] valves."[379]

Significance of This Event

Thus GPU, in a shutdown mode for almost 1 month, clearly had foregone the planned May 31, 1978, commercial operation date. If December 31, 1978, was ever a critical deadline, it would seem that even that yet far off date was now challenged. If there was a rush to year-end commercial operation, it had to begin with resolving the main steam relief valve problem.[380]

GPU clearly had its sights set on commercial operation because in a letter to the valve manufacturer in late June, it said:

> Since more than two months have elapsed following the discovery of the problem and the trial of various unsuccessful solutions of the problem, it is our opinion that these valves cannot be corrected to meet our requirements. As you know, these defective valves have delayed and are continuing to delay the commercial operation of TMI-2, causing the owners excessive costs and their customers higher rates.='[382]

The full history of the extent of testing the valves and the various adjustments attempted may come out in court as a result of legal actions now underway 'between the valve manufacturer and GPU. A condensed history is contained in the Holcombe August 18, 1978 letter to FERC. What is important relative to the rush to commercial operation issue is whether the decisionmaking process on what to do about the problem was rushed and whether the actions to carry out that decision were unduly rushed.

, 1978. The first meeting with the valve manufacturer occurred May 23, 1978. Within a few days after the April 23 transient, however, GPU acted to create an alternative to rep or adjustment of the existing relief valves. GPUSC personnel began to canvass valve suppliers to identify replacement valves. The only valves found that were the same size as the defective valves would not be available until the end of November 1979. Smaller valves were immediately available from another utility and were similar to those used in TMI-1. Burns & Roe, the architect-engineer, was directed to start engineering work on design modifications that would be needed if the existing valves were to be replaced with the smaller valves.

The answer to the first question, whether the decisionmaking process was rushed, is yes. A decision was made almost immediately after the April 23 incident to create an alternate course of action. Valves were located, and design changes were ordered. In answering a question about these contingency preparations, Robert Arnold said, "We went further than that. We ordered materials and we ordered valves, recognizing that maybe we would fix the problem ... and have to salvage that material."[385] (That is, sell or scrap the newly ordered material).

Part of this contingency planning was establishing a critical path network that would allow one to determine how long testing could continue on the existing valves before this testing would add extra days to the time needed to perform the replacement work. To quote Arnold again:

> Effectively, we stayed [with the old valves] until we were at the point where we had to make a decision whether or not to make the change out if we were to avoid additional delay in the event we had to go that direction eventually. Up until the time that the continued testing of the ... valves would not extend our schedule, we stayed with them."[388]

As to whether the actions to carry out the replacement decision were rushed, modification work was initiated June 23, 1978[387] and completed on August 24, 1978. Several days after August 24 were needed for testing the new valves, cleaning up the feedwater, and returning to power. The turbine generator was synchronized with the grid on September 18, 1978, and power ascension testing resumed. The fact that only 2 months elapsed from the April 23 incident until GPU was ready to proceed with modifications meant that preparations had to be carried out expeditiously. Donald R. Haverkamp, TMI-2 project inspector, stated: "I never heard any discussions to [the] effect" that there was a rush to get the valves replaced.[389]

He also stated that IE was aware (through the Licensee Event Report) of the situation and in fact was notified by GPU before any work began on replacing the valves.[390] Yet he also expected a rush to replace the valves. "I would certainly expect that there would be a rush to get them replaced-that is, that they would expedite the replacement... because ... they couldn't continue with the startup program until they replaced the valves."[390]

Assessment

GPU wrote to FERC explaining the valve problem, stating: "Completion of the main steam safety valve modification in August will permit a return to power in mid-September, a delay of about one hundred forty (140) days in the project."[387] An analysis Arnold requested of test delays reported in January 1979 stated that "because of problems encountered in the Test Program other than the safety valve failure, the safety valve problem itself was solely responsible for a period of delay on the order of 20 to 39 days."[388]

To not replace the valves with those of a different design meant a delay until the early part of November 1979, when similar-sized valves might have been ready from the manufacturer or whenever the existing valves would be fixed.

The early establishing of an alternate course of action and the use of critical path planning cannot be faulted. IE inspectors did some limited testing or observations of welds on the modification work[391] and this turned up no indication of a rush. Therefore, our finding is that the replacement was not rushed but done in an orderly, expedited fashion commensurate with the circumstances of having a nearly complete unit and hundreds of personnel otherwise kept waiting for resolution of the valve problem.

Other Indicia of Time Concern

In addition to the deletion or postponement of tests and the decisionmaking with respect to the main steam relief valve replacement, we have looked at other events at TMI-2 during the latter part of 1978 that could also be indicative of a desire on the part of GPU management to complete the unit before the end of the year, 1978. Some of these are minor; all are only circumstantial evidence of a rush.

As previously discussed, the decision to declare a unit in commercial operation is the utility's. The vagueness regarding the criteria for that declaration flows, in part, from the different standards used by utilities. Recognizing the regulatory impact[392] and risk involved in this decision,[393] Herman Dieckamp, President of GPU, instructed that the decisionmaking on declaring a unit commercial be formalized[394,395] Shortly after becoming President,[396] Dieckamp instructed an assistant to prepare GPUSC criteria for placing a unit in commercial operation.[397] It was first used in a review of GPU's coal unit, Homer City 3.[398]

By the time TMI-2 was ready to be considered for commercial operation, it was simply a matter of applying the GPUSC criteria against the physical status of the unit. A meeting of the GPU organization (CORB)[399] that was to make the determination of readiness for commercial operation was held at Three Mile Island on October 26, 1978. At that meeting, vice presidents and other employees of GPUSC and the operating companies listened to presentations on the status of TMI-2 vis-a-vis the criteria previously established for commercial operation.[401]

By the end of the day, it was clear that some major matters remained to be completed before the members would be satisfied with the unit's readiness. The seven CORB members then appointed a subcommittee of four to follow up on those items,[402] with the understanding that the subcommittee would sign off when those remaining items had been completed.[403] The full CORB concluded:

> Based upon the consideration of the information furnished and discussion of that information, it is concluded that the status of Three Mile Island Unit 2 with respect to all criteria in the (GPUSC Manual Chapter) Procedure is acceptable. Therefore it is determined that the Unit is technically ready for commercial operation and the Operating Company (Met-Ed) is prepared to support commercial operation at a power level of 880 MWe ....

This statement was made on October 26, 1978, even though a number of items remained outstanding.[405] For example, 250 to 300 "deficiencies" requiring physical construction remained to be cured.[406,407]

Nonetheless, the subcommittee, consisting of Arnold, Herbein, Hirst, and Wilson, was passed the ultimate responsibility for seeing that the conditions subsequent to the full CORB's signoff would be fulfilled. In addition to those four officials, TMI-2 Station Manager Gary P. Miller was to "review" the subcommittee decision, just as he had reviewed the initial CORB's conclusions.[409] It should also be noted that, organizationally, Hirst[410] and Wilson reported to Arnold.

The CORB subcommittee held no meetings,[411] but its members said they kept track of the progress of outstanding items for which they were responsible.[411] On December 29, 1978, 1 day after successful completion of the power ascension program,[412] the CORB subcommittee members signed off on a report, which concluded:

> It is the opinion of the Subcommittee that the Unit (TMI-2) has demonstrated its ability to operate safely and reliably up to and including 959 MW gross and *should be placed into commerical service....*[13] (Emphasis added.)

It is perhaps somewhat inaccurate to state that members of the CORB subcommittee "signed-off" on their report on December 29, 1978. For, in fact, only those members working at corporate headquarters (Parsippany, N.J.) physically signed their names.[414] Arnold signed "per telecon" for both Herbein and Miller.[414]

The explanation for this signing "per telecon" is logical. Arnold said that he telecopied a copy of the subcommittee report to both Herbein and Miller.[415] "Since I was in Parsippany or Mountain Lakes, Herbein was in Reading and Miller was at the site," he said, "it was not felt necessary on my part to send a messenger on a round-trip to get the signatures from them personally."[415] Mr. Herbein has testified that he had "no problem" with the telecon procedure and "agreed it was certainly appropriate."[416]

There is no suggestion that Arnold improperly signed off for either Miller or Herbein. In fact, the very existence of a CORB is not required by the NRC.[417] Furthermore, Arnold had the responsibility for declaring TMI-2 in commercial operation.[418] It, therefore, was consistent with his responsibilities that he would oversee the CORB subcommittee report-even if that required consulting with other members via telecopier and telephone.

However, the very fact that Arnold felt the need to complete this approval process *before the end of the year* is an additional indication that GPU was concerned with the timing of the commercial inservice date of TMI-2. The signing of a signature "per telecon" is, in itself, insignificant. But the attitude and pressure that it reflects is of interest.

Under such circumstances, it could be argued, the pressure of a superior asking for approval from his employees is not conducive to frank dissent. On the other hand, there is no indication in the TMI-2 case that Arnold's method improperly influenced any other member of the CORB subcommittee. As Dieckamp foresaw when he proposed the establishment of commercial operation criteria, the operating company personnel would not accept a unit that was not ready for commercial operation.[419]

In sum, while the signing "per telecon" of the CORB subcommittee report 2 days before the end of 1978 does not *look* like good procedure in retrospect, it probably was an exercise of good business judgment. There probably would have been no difference had Arnold convened a late-night meeting on December 30,1978.

However, the episode remains indicative of the fact that GPU officials were aware of the importance of completing the commercial operation process before the end of the year, 1978.[420] Why else would Arnold take the trouble of contacting officials by telephone on December 29, 1978? If December were not an important deadline, why not simply mail the CORB subcommittee report to the distant members? This statement is made in full recognition of the fact that there was no regulatory significance to the CORB subcommittee approval. There apparently was, however, a desire to carry out the corporate procedure for that decision consistent with the December 31, 1978, date, which was important for other purposes. 421,422

Aggressive Power Ascension Test Schedule

In addition to the CORB procedure, there were several other indications of time concern that we investigated. One of these-the pace of the power ascension test program-was prompted by worker comments that the pace had been demanding.[423] As previously discussed,[424] the power ascension test program was on the critical path to commercial operation.[425] Because of various representations, GPU could have come to the conclusion that the test program would have to be completed in 1978 to obtain rate treatment and tax incentives.[426]

Because of the main steam relief valve problem, GPUSC employees did not begin the power ascension test program until September 19, 1978. They completed the power ascension test sequence, by their definition,[427] on December 28, 1978. In those 2 1/2 months of testing, GPU completed testing that had been originally slated to take exactly that long.[428]

The relationship between GPUSC and Met Ed employees in completing the power ascension tests should be understood. GPUSC test engineers were responsible for running the tests and preparing the plant for commercial operation.[429-431] However, because there was nuclear fuel in the core, only NRC-licensed operators could manipulate the controls necessary to perform the tests.[432] In informal conversations, we heard reports of conflicts between Met Ed employees and GPUSC test engineers over the pace of the test schedule. Herbein admitted that such a "conflict" was possible but dismissed it as "healthy".[433] Such pressure, however, is indicative of the pace of the test sequence itself.

The IE inspector at TMI-2 at the time of the power ascension testing observed:

> I would say that the power ascension testing was conducted in a manner to complete it as soon as they could-that is, people were working overtime or additional hours because it was necessary to do more work each day than you could normally perform in an eight-hour day. I think it was a very aggressive pace.[434]

GPU officials agree, calling the test schedule an "optimistic one."[4] However, both NRC officials and GPU employees have stated that it is the nature of the test program and the job of the test superintendent to establish an "aggressive" schedule.[436,437] In fact, the test superintendent in charge at TMI-2 said that he would have been even more "aggressive" if he had not been forced to wait for construction to catch up with the scheduled test.4

A comparison with other power ascension test test periods does not indicate the TMI-2 program to be unusually short. An analysis prepared by the B&W manager of plant startup services showed a "B&W planned start-up schedule" to run 5 months from fuel load to unit acceptance test.[440] [441] On the basis of experience with eight B&W units, however, B&W found that that period could range anywhere from several months to 20 months.44o

The time from fuel load to unit acceptance test took 12 months at TMI-2.[442] The power ascension test program, as defined by GPU,[443] took 10 months.[442] If there was not the 3-month delay caused by replacement of the main steam valves, a 7-month power ascension schedule at TMI-2 would certainly have been reasonable, when compared with other units. It would, in fact, be longer than the "planned startup schedule."

Another independent analysis of 62 operating plants in the United States demonstrated that a period of approximately 6 months between initial criticality (necessary for power ascension testing) and commercial operation was typical.[444] Assuming those plants also completed their power ascension test program before declaring commercial operation,[445] GPU would again appear to be within average time limits. Initial criticality occurred at TMI-2 on March 28, 1978, and commercial operation was declared 9 months later on December 30,1978 446 Allowing 3 months for main steam valve replacement would give TMI-2 a 6-month period, exactly the average.

In sum, if the unusual downtime caused by the main steam relief valve is taken into account, the power ascension test schedule at TMI-2 was not unusually short. If anything, it was slightly longer than the average.[447] Even assuming the pace to have been aggressive, it was apparently not unusually so, when measured against industry performance records. 448

Discontent Among Workers Regarding Quality of Work

In a related matter, our investigation touched on a report in the *Philadelphia Inquirer* that quoted former Met Ed and GPU sources as suggesting that tests at TMI-2 had been "faked" or skipped entirely. 449 Workers were quoted as saying, ". .. unit two was rushed. Everybody who works there knows that."[449]

The majority of named workers in that article were contacted. However, many of the more serious statements came from unnamed sources. Because the newspaper would not reveal those sources and this Special Inquiry Group had limited time and resources, not all allegations were investigated. The picture that emerges, however, does not support the broad allegations in the article.[450,451] Specifically, there was no one on the record[452] who was aware of tests being "faked" or "skipped." This includes NRC officials[453] as well as GPU and Met Ed employees.[454]

Apparently, the worker discontent expressed in the newspaper article, as with the allegations that the pace of the power ascension test program was demanding, is more in the nature of typical worker gripes, than serious safety allegations. In themselves they may indicate some pressure to push the completion of the unit, but we cannot assess how those pressures were different from pressures on other large projects.[455]

Nexus Between Incentives and Action Taken

We have stated in this report that GPU took specific steps to enable a declaration that TMI-2 was in commercial operation by the end of December 1978. We have further stated this action was *for the purpose* of obtaining the previously identified incentives, which were linked to that date.[56] However, this is an inference. It might be argued that these are separate phenomena; whatever deliberate action was taken to complete TMI-2 in 1978 was taken for reasons *other than* the financial incentives.[457]

However, our investigation suggests that the circumstances connecting these two items is credible enough to draw the nexus. Specifically, GPU operating officials, and through them, other personnel at the site, were explicitly informed of the financial benefits associated with completion of work at the site before the end of the year. Despite explicit instructions not to rush to obtain those incentives, operating people were arguably indoctrinated with the financial goals of GPU. Thus, we have inferred that the actions we have described were the *result* of a desire on the part of management to obtain the previously described incentives.[458]

As stated previously, Robert Arnold attended the December 1978 meeting of the GPUSC Board of Directors.[459] In the course of that meeting, GPUSC Comptroller Edward Holcombe testified that he showed Arnold Revenue Ruling 76-428 because "I wanted Mr. Arnold to be aware of what the revenue regulations said, to get his interpretation of the physical characteristics of the construction of the plant as to whether they met those."[460] In other words, Holcombe was attempting to get Arnold's assessment of the status of the TMI-2 construction and testing vis-a-vis the unit described in the revenue ruling.

But exactly why it was necessary to provide Arnold physically with the revenue ruling has not been explained. Holcombe had access to monthly reports describing the progress of construction at TMI-2.[461] Although Revenue Ruling 76-428 involves some engineering judgment, its interpretation apparently is more a matter for legal and financial experts rather than GPO's top operations (generation) official.

Arnold is not sure he reviewed the revenue ruling.[462] He recalls receiving a memorandum describing GPU's position on obtaining tax benefits for TMI-2 in 1978.[463] The only such memorandum we know of is that prepared by Daley of the GPU tax department. Holcombe insists that Arnold did not receive a copy of the Daley memo.[464]

However, no one disagrees that Arnold was asked a number of questions at the December 17, 1978, GPUSC Board meeting with regard to the status of TMI-2, as measured against explicitly defined tax criteria.[465] There is little doubt that a discussion took place, either before all members of the board or at a sidebar,[466] in which Arnold was intimately acquainted with the tax consequences of completing TMI-2 in 1978. It was his opinion at that December meeting that TMI-2 had, in fact, met the criteria set forth in Revenue Ruling 76-428.[467,468] Whether Arnold picked up on the caveat in Revenue Ruling 76-428 regarding problem-free operation[469] is not known, but he did make reference to the main steam valve problem in assessing the unit's tax acceptability.[470]

Arnold was also heavily involved in the rate proceedings that were pending as TMI-2 neared completion in 1978. He was aware of the calendar 1978 test year in the Penelec proceeding and the potential for technical arguments should TMI-2 go into commercial operation outside that test year.[471] He also prepared Met Ed's version of the Memorandum of Law requested by the administrative law judge in that proceeding dealing with the issue of "commercial operation."[472]

Thus, it could be said that Arnold, the chief operations official of GPU, was well informed of the two major incentives previously identified: rate recognition and TMI-2 tax benefits. As the person directly responsible for allowing TMI-2 to go into commercial operation,[473] he knew the "costs" of a failure to do so by December 31,1978.

However, Arnold did not share this burden alone. Many GPU and Met Ed employees, of both senior and relatively minor stature, knew that there were corporate advantages to declaring TMI-2 commercial before the end of 1978. For example, Arnold discussed "the posture of being commercial vis-a-vis the rate case and not being commercial" in his monthly staff meetings.[474] John Herbein, Met Ed's Vice President for Generation, recalled that he "Discussed [commercial operation]... a number of times between myself and Walt Crietz [former Met Ed President] with Bob Arnold."[475]

Even in lower levels of plant operations, engineers-in-training, control room operators, and other employees[476] knew that there were financial advantages to GPU in declaring TMI-2 commercial in 1978.[477,478] Even contractors, such as Burns & Roe and Catalytic, Inc.,[479] knew "that it was important to GPU ... for accounting reasons, if for no other reason, to try to get the plant on-line commercially before the end of 1978."[480]

With such knowledge disseminated throughout the plant, it is logical to draw a nexus between the action taken to complete the unit (as previously identified) and the known incentives. GPU officials dispute this by pointing out that top management explicitly instructed that there be no rush. GPU President Herman Dieckamp and Chairman of the

Board William Kuhns contacted Robert Arnold late in December, "when completion of the test program (in 1978) was problematic. "[481] Their message, according to Arnold, was "...that I was not under any pressure to declare the test program complete or to take the approach of declaring it commercial at some partial load.[482] Dieckamp remembers telling Arnold " ... that the staff was not to depart from the requirements of the test program ... they were not to depart from doing things in accordance with their own judgment for the simple purpose of achieving the schedule."[483]

Arnold apparently passed these instructions along to certain senior officials. In turn, Arnold instructed that, unlike past holidays, there would be no extra manning over Christmas 1978.[5] Arnold said the action "grew out of a concern on my part as to whether it would be prudent to put that kind of pressure on them [the workers at the site] _

When asked why he felt it was necessary to give the "do not rush" instruction that he did, Dieckamp said it was important that Arnold "understood the relative importance of conducting the program safely in relationship to the schedule. ...I felt it important to make sure he [Arnold] didn't imply some pressure that I didn't want to convey."[487]

The effectiveness of these "do not rush" messages is difficult to measure. In some ways, saying "do not rush" in late December 1978, after previously instructing the same officer in the ramifications of not completing the unit in 1978, is similar to the "do not fix prices" advice given in the late 1950s to the marketing employees in the electric industry investigation.[488,489]

Arnold said some employees did, in fact, work over Christmas. He attributed this to a "sense of pride,"[490] rather than any corporate pressure. Those distinctions may be difficult to make when dealing with ambitious engineers and employees looking at long term careers. Although GPU officials explicitly attempted to balance the pressures that were building toward a rush to completion, they may not have succeeded entirely. Our conclusion is that some action was taken to enable completion of TMI-2 by the end of 1978. The nexus between action and the financial incentive previously discussed is provided by the intentional communication of the importance of those incentives to the operating personnel responsible for completion of TMI-2. [491]

Assessment

In this section we examine the construction period (rush to operating license), deletion of seven self-imposed tests from the power ascension sequence, postponement of the initial warranty run, replacement of the main steam relief valves on a critical path, and other minor indications of time pressures. Although each issue deserves separate treatment and qualification, the cumulative impact-in our minds-is to substantiate the conclusion that these actions were taken to enable completion of TMI-2 by the end of 1978. But before proceeding to an analysis of the safety impact of the action taken at TMI-2 to enable commercial operation in 1978, we should pause to assess the nature of these actions.

Many of the actions which we have spotlighted as indications of deliberate action to complete the unit were self-imposed standards of GPU. Desiring to go beyond NRC requirements, GPU established more sophisticated test sequences, commercial operation criteria, and the like.[492] Because of time constraints,[493] as the end of 1978 approached, GPU chose to relieve itself of the requirements that it had earlier imposed. Thus, when we examine this action as taken to enable completion of TMI-2 by a certain date, we are not suggesting that GPU violated any regulatory requirements. We are simply recognizing these factual changes as indications of a time concern.

Several considerations should be balanced against our conclusions. First, there are the explicit statements of the GPU personnel offering alternate explanations for the actions on which we have focused. Second, no evidence suggests that an explicit order to complete TMI-2 by the end of 1978 to obtain financial advantages existed. Third, the practice in the industry should also be considered. In practice, a rush to complete a unit as soon as possible may be extremely common.[494] This would enable a utility to generate (presumably) surplus power that it could sell to other utilities.[495] Many of the actions taken by GPU, in fact, might be seen as above average when compared with industry practice. Critical path planning, a CORB, and advanced test sequences may be indicative of superior utility management; not dereliction of responsibility.

Finally, the entire environment in which decisions regarding TMI-2 were made must be understood. GPU and other utilities do not operate in a vacuum, but in a highly regulated system. The effect of that system must be factored into any allegations of a "rush to commercial operation."

4. IT CANNOT BE CONCLUDED THAT THE ACTION TAKEN TO ENABLE COMPLETION OF TMI-2 IN 1978 COMPROMISED THE SAFETY OF THE UNIT

As emphasized in the introduction to this report,[496] the ultimate question in this investigation is whether the safety of TMI-2 was compromised by the alleged rush to commercial operation. Having identified that there were incentives to rush,[497] and that deliberate action was taken at TMI-2 to obtain those incentives,[498] we now reach that ultimate question.

In our analysis below we conclude that it is not possible to say that the rush to commercial operation that we have identified affected the safety of TMI-2. At the same time, however, we believe there is a need to address the implications of our investigation.[499]

Association with the Accident

In assessing the impact of the alleged rush to commercial operation, our investigation looked beyond the March 28, 1979, accident. That is, we were interested in learning if the overall safety of TMI-2 had been compromised in some fashion, such that another hypothetical accident might have occurred.

For the sake of clarity, however, it should be noted that nowhere in our investigation did we uncover any connection between the action taken by GPU to obtain the 1978 incentives and the March 28 accident. There was no rush of which we are aware in any procedures, practices, or equipment that has been identified as contributing to the accident at Three Mile Island on March 28,1979.[5m] When we, therefore, discuss the possible "compromising of safety" at TMI-2, we are not suggesting that the specific March 28 accident was caused by the rush we have investigated.[501]

The Presumption of Safety Compliance

NRC is responsible for ensuring that each license authorizes activity "not" inimical to the common defense and security or to the health and safety of the public.[502] Specifically, NRC regulations provide that a license to operate a commercial nuclear power-plant shall be based on a finding that:

> The processes to be performed, the operating procedures, the facility and equipment, the use of the facility, and other technical specifications ... collectively provide reasonable assurance that the applicant will comply with the regulations in this chapter ... and that the health and safety of the public will not be endangered.[503]

and that

> The issuance of a license to the applicant will not, in the opinion of the Commission, be inimical to the common defense and security or to the health and safety of the public.[504]

By these directives, the NRC is required to define what is necessary for the "safety of the public."[505] Therefore, NRC reviews applications submitted by applicants as measured against defined criteria – In its most basic terms, if a license to operate a unit is issued, the NRC believes it to be "safe."

Following issuance of a construction permit or an operating license, however, NRC regulations maintain control over a licensee by providing:

> A license or construction permit may be revoked, suspended or modified ... for failure to construct or operate a facility in accordance with terms of the construction permit or license ... or failure to observe, any of the terms and provisions of the act, regulations, license, permit, or order of the Commission.[507]

With this authority, the NRC Office of Inspection and Enforcement monitors the construction and operation of a nuclear unit. If IE determines that a unit is not being constructed in conformance with NRC regulations (which, as previously noted, define what is safe), it presumably takes enforcement action. This action could be citing the license with a notice of violation,[508] or in serious instances, halting construction or operation[9]

The point of this discussion is that the NRC system of regulation operates so as to define and enforce what is the "safe" construction and operation of a nuclear plant. Given this presumption-that the NRC defines what is safe[510]-it is relatively easy to answer the question of whether the safety of TMI-2 was compromised by the rush to commercial operation. We need only look to the regulatory action taken by the NRC.

The first NRC action was the issuance of a construction permit to Met Ed.[511] As noted, such action required the determination that construction of the proposed facility would not be "inimical to the public health and safety." The second, and more important, regulatory assessment of TMI-2 safety came in the issuance of the operating license. As previously discussed, IE wrote a memo to the NRR stating that all necessary work had been completed at TMI-2 and issuance of an operating license was proper[512,513] Upon the conclusion of the hearings regarding TMI-2,[51a] NRR issued an operating license to Met Ed to operate TMI-2. That license was based on the findings that:

> Construction of the Three Mile Island Nuclear Station, Unit 2 (the facility), has been substantially completed in conformity with Construction Permit No. CPPR-66 and the application, as amended, the provisions of the Act, and the rules and regulations of the Commission.[515]

and:

> There is reasonable assurance: (i) that the activities authorized by this operating license can be con-

> ducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the rules and regulations of the Commission.

Using information transmitted by IE,[516] the NRC (through NRR) believed TMI-2, as *constructed,* to be "safe." No deficiencies or violations of NRC requirements had been noted to challenge that finding.

However, as we have discussed, the period from issuance of the operating license to commercial operation was the crucial period in determining whether there was a rush. During that period, inspectors were periodically on the site and made routine inspection reports.[517] Our review of TMI-2 inspection reports for 1978 indicates no safety-related deficiency that can be connected with the action previously analyzed.[518,519]

In the case of the main steam relief valve replacement, GPU obtained an amendment to the TMI-2 operating license, finding no safety problem in the proposed replacement.[520] Additional postlicensing relief was obtained during this time period as well, all with the required finding that the change would not be inimical to the public health and safety.[521]

For example, Met Ed obtained permission to perform a test required by the operating license earlier than its specified date.[522] Met Ed received "relief" from performing another test because it was considered "impractical"[523,524] Again, however, this was done pursuant to a finding that such an exemption would "not endanger life or property ... and is otherwise in the public interest."[525]

In addition to these regulatory actions in 1978, the operators of TMI-2 had to satisfy conditions built into their operating license. They apparently did so, as letters from NRR granting the utility permission to proceed through the necessary modes of operation cite reports from inspectors reporting Met Ed's conformance with the conditions.[526]

Finally, we have uncovered no Licensee Event Reports (LERs) or other indications of problems with the startup of TMI-2 during 1978 that might be indicative of an unsafe status of the plant.[527]

In sum, there is no record of NRC concerns that TMI-2 was built or began operation in an unsafe condition. With the assumption that the NRC defines what is safe, the inescapable conclusion is that *whatever* the effects of the rush to commercial operation previously discussed, the safety of the unit was not compromised.

Without the Presumption of Safety

It is not surprising that some people do not accept the assumption that the NRC defines what is safe. They would dispute a conclusion, therefore, that without some NRC finding of a violation of its standards, TMI-2 must be deemed to have been built and operated in a safe fashion. This analysis has two dimensions: the quality of the NRC definition of safe and the ability of the NRC to enforce its standards. The latter is addressed first.

Even with the assumption that the NRC can properly define what is safe, critics have pointed out that deficiencies in the NRC regulatory program might allow a licensee to violate that standard and still be allowed to build and operate a nuclear plant. The basis of this assertion is that the NRC regulatory program is an audit system.[528] Licensees are required by their license and the rules and regulations of NRC to assume primary responsibility for the safe construction and operation of the facility. NRC attempts to make sure that this responsibility is carried out through an audit inspection program. However, as presently designed, it would be impossible for the NRC to observe and approve each action a utility takes in constructing and operating a nuclear facility.[529]

Critics point out that this creates the possibility that safety violations go unnoticed and unpunished. Despite an elaborate system designed to encourage self-reporting, a utility has the ability to hide a safety problem.[530] Even though this is done at great risk to the licensee,[531] the possibility cautions against the conclusion that a review of NRC records is sufficient for addressing the question of whether a rush to commercial operation at TMI-2 compromised the safety of the unit.

The more difficult contention is that the NRC does not define what is safe and that NRC standards are inadequate in this respect. For example, the failure of the NRC to devote adequate regulatory attention to small-break loss-of-coolant accidents (LOCAs) has been identified as a safety problem that has been underscored by the TMI accident.[532]

The problem with this argument is that no other standard of safety can be used to measure the status of TMI-2. Some have apparently equated the number of problems encountered during the startup phase at TMI-2 with a conclusion that the unit was, *ipso facto,*[533] unsafe. The NRC was aware, however, of these problems and found no safety ramifications. Indeed, the low dependability of nuclear units in the startup phase is well known. Are all units with a large number of problems during this period unsafe? What of those units such as TMI-1 that have smooth startup programs? Are they safer?

Perhaps the most difficult standard is to equate safety with "not having an accident." By this definition, TMI-2 was "unsafe" because it was the site of the March 28, 1979, accident. This post hoc standard is an impossible one to use for both a licensee and a regulator. Such a standard ignores the complexity of a nuclear unit and places full liability on the licensee for what may be contributing causes.[534]

In sum, although we recognize the problems with the presumption that the NRC properly defines what is safe, we know of no other standard to use. Those safety standards discussed do not seem helpful. Therefore, we are unable to conclude that the rush to commerical operation we have identified played any role in the March 28, 1979, accident or compromised the safety of the unit in general. Its importance, as discussed below, is rather in its implications for the regulatory system as a whole.

5. IMPLICATIONS

Although no evidence suggests that TMI-2 was placed into commercial operation in such a fashion as to jeopardize the safety of that unit, our investigation did identify a number of financial incentives[535] that are available to utilities that meet "artificial" deadlines. Indeed, quite apart from our conclusions with respect to TMI-2, the most significant insight of our inquiry was that the existence of these incentives could, under certain circumstances, tempt a utility to compromise its commitment to safety, which is essential to the construction and operation of a nuclear unit. To put it another way, our inquiry has indicated that there is a "tension" between the necessary commitment to safety required at a nuclear unit and the economic and regulatory pressures imposed on the utility that operates that unit.

It is necessary to expand on these implications for a number of reasons. First, the current NRC regulatory system is of an "audit" nature. Some areas of utility performance are physically reviewed, in the majority of areas NRC inspectors check only the "paper record" that the licensee maintains. If the paper trail appears in conformance with NRC regulations and standards, a utility will pass inspections. In essence, the NRC assumes that a licensee is operating in conformance with its license and all applicable regulations.

Given a "less than scrupulous" licensee, the existence of incentives increases the potential that corners will be cut in the safe construction and operation of the plant, and still go undetected by the NRC regulatory program. Obviously, if this occurred on a widespread basis, the NRC would be unable to retain an audit program and the credibility of the entire system would be open to question.

Of course, penalties are imposed for violating an NRC license or regulation, and some observers would argue that a licensee would never intentionally risk a license for the "minor" incentives discussed previously. With the assumption that this is true, there is a second reason for being concerned with the presence of these pressures on utilities that operate nuclear units. The NRC is basically a technology regulator. Its staff of scientists and engineers are constantly attempting to give definition to the commandment of the Atomic Energy Act that nuclear power not be "inimical to the health and safety of the public."[536] In other words, the NRC attempts to define the minimum standards necessary for safety. But the NRC does not set the minimum, maximum, and only safety standards. As stated previously, the NRC looks to the industry to develop and implement more stringent safety standards for nuclear units. In short, implicit in all regulation of nuclear units is the requirement that the utility be committed to the safest possible operation of the unit,

Our point here is that this commitment, "above and beyond the call of duty," can be inhibited by the incentives previously discussed. If a utility would delete a system (not required by the NRC), safety of a unit may not be enhanced. Thus, it is in this area of self-imposed improvements that financial and regulatory pressures can have their greatest (negative) impact. It would be improper for the NRC to ignore this area, for, as noted, the premise of the current system depends on a wholehearted commitment to safety on the part of each licensee.

In recognizing these complex problems in the current NRC regulation of nuclear powerplants, however, we are not suggesting that States should assume a more active role in regulating the economics of nuclear powerplants. For, as is discussed below, State regulation has, to some extent, contributed to the current problem.

It should be clear that the implications discussed below go beyond GPU and TMI-2. They affect the entire nuclear licensing system and the regulatory environment in which licensees operate. Indeed, TMI-2 is not alone in facing financial or other types of incentives obtained by meeting some artificial deadline. The Vermont Yankee nuclear unit was allegedly declared commercial before the end of a certain year to sell electricity to meet bond payments, as required in its indentures.[537] Prairie Island 2, operated by Northern States Power Company, was declared to be in commercial operation 4 days after criticality, and the utility is currently involved in a tax protest with the IRS because of IRS's refusal to recognize Prairie Island 1 as placed in service in 1973.[538] In an unusually candid statement, the executive vice president of Toledo Edison Company testified before the Ohio PUC that the

Davis Besse nuclear unit was declared commercial in consideration of more than "physical and operational engineering status of the unit."[539] He said:

> There were other financial considerations which have to be considered and the impact on the financial health of the company, starting and taking of [tax] depreciation being one of the significant items. These things are all considered.[540]

Generically, a review of NRC records shows that 25% of all plants currently holding operating licenses were declared to be in commercial operation in December of some year.[541] This percentage seems higher than a mere chance would dictate.

Are these examples significant? Do they indicate that the safety of nuclear units has been compromised in some fashion by attempts to obtain incentives? Those questions are impossible to answer without the same kind of detailed investigation we used to examine the history of TMI-2. Rather, what we propose to discuss in this "implications" section is a "worst possible case" scenario. If there could be a licensee who would compromise the safety of a nuclear unit to obtain incentives, what should be done?

The incentives that exist in this area have been discussed at length in the first section of this report. To understand why those incentives persist and have complicated this gray area requires an understanding of the systemic problems we have uncovered in this area. The final section of our report discusses possible changes that could be made to rectify the situation, changes for both the NRC and other institutions.

Ambiguous Regulatory Responsibilities

In theory, there is a clear division of authority among the regulatory bodies involved in a nuclear powerplant. In broad terms, one would expect the NRC to regulate nuclear safety, the public utility commission (PUG) to regulate retail rates associated with the plant, and FERC to regulate the wholesale rates associated with the plant.

However, we have discovered-not surprisingly-that regulation does not fit into such neat little boxes when a nuclear plant is concerned. In reality, the economic decisions of PUCs and FERC could conflict significantly with a utility's commitment to nuclear safety. It is this spillover effect that creates ambiguity for a utility. In trying to satisfy an economic regulator (or obtain an incentive under the control of that regulator), a nuclear licensee may be consciously allowing that regulator to make a safety determination.

One example of this problem is the authority of economic regulators to disallow portions of the claimed value of a completed plant as improper. This can occur in a number of situations, but the end effect is the same: utility shareholders bear the burden of whatever has been disallowed. Because the management of a utility is responsive to shareholders' concerns (if they wish to remain in office), the goal of management is clear: reduce the *possibility* of such disallowances.

One method by which a portion of the completed plant can be disallowed is FERC's Electric Plant Instruction 9D provision that AFUDC for a test period greater than 120 days must be justified. Although this provision may be more of a threat than a weapon actually used, utilities seem to respond to even the possibility that FERC might follow through on the threat. For example, at TMI-2,[542] GPU was anxious to minimize the period of testing greater than 120 days.

The rationale behind Instruction 9D is not illogical. Some method of limiting the abuse of AFUDC (through a longer-than-necessary test period) seems reasonable, but that evaluation cannot be made in a vacuum. Any analysis as to the propriety of the length of a test program necessarily involves questions of nuclear safety and the readiness of the unit to begin full operation. The NRC has recognized as much in establishing standards for the length of test programs.[543]

Under these circumstances, FERC probably should yield to considerations of nuclear safety and the responsibility of the NRC. FERC's legitimate economic regulation could be served by presuming that a nuclear unit was constructed in the most expeditious manner possible consistent with nuclear safety. If a legitimate concern was raised in a specific case, alleging an unnecessarily long test period, the NRC should be available to offer an opinion as to whether the lengthened test program could be said not to have contributed to safety.[544]

A second method by which utilities are faced with possible disallowance of a portion of plant value is through specific challenges to inclusion of certain costs. For example, at TMI-2, the cost of replacing the main steam relief valves was challenged by the Pennsylvania Office of the Consumer Advocate as "imprudent management." Although not accepted on that basis, PaPUC did disallow a portion of the replacement cost in the rate base associated with TMI-2.[545]

The Office of the Consumer Advocate argument is not unique. PUC staffs have generally been concerned with the possibility of "goldplating;" that is, the inclusion of unnecessary costs in a plant so as to boost its value abnormally high.[546] This may indeed be a legitimate concern, but when dealing with a nuclear unit, the distinctions between "goldplating" and "commitment to safety" become unclear. In seeking to avoid allegations of the former, utilities may back away from the latter.

The ultimate effect of these kinds of pressures is exactly contrary to what should be encouraged. There should be incentives for utilities to go beyond NRC minimum standards of safety and invest in innovative, improved equipment, rather than disincentives for doing so. Utilities, it could be argued, operate at the "margin" set by the NRC because to do otherwise invites attacks of "goldplating." No matter how committed management is to nuclear safety, an investor-owned utility cannot fund such a commitment indefinitely out of shareholder (as opposed to ratepayer) funds.[547]

To cite one example of the effects of this economic oversight on nuclear safety, we point again to Vermont Yankee. In 1976 NRR asked Vermont Yankee to voluntarily shut down its boiling water reactor so that a study could be made of a generic problem. Vermont Yankee agreed-presumably in the interest of general improvement of reactor safety. While the unit was down, more expensive replacement power was purchased to supplant the Yankee power and this higher cost was passed on automatically to consumers through fuel adjustment clauses.

By order of the Governor, the State Public Service Board held a hearing on the propriety of billing customers for this replacement power. Intervenors argued that because Vermont Yankee did not receive an NRC order to shut down, it was improper to have done so voluntarily and pass the costs on to customers. Shareholders, not ratepayers, should bear the cost of the replacement power above what Vermont Yankee costs would have been, they argued. The Vermont Board rejected the argument, but not without considering it on its merits.[548]

Does economic regulation such as the Vermont Yankee example improve reactor safety? It seems doubtful. The added delay in obtaining an order and the potential for legal arguments do not seem to add at all to safety.

As in the FERC example, there may be valid reasons for PUCs to be concerned about goldplating and imprudent management in nuclear units. But also as in the FERC example, the detrimental impact of such analyses on nuclear safety by the PUCs appears to outweigh any economic savings to rate payers. With the assumption that PUCs have approved the construction of a nuclear unit as necessary for a utility's power capacity, its attention should not be devoted to a detailed review of the costs of each component thought necessary by the utility. If valid issues of goldplating are raised in a proceeding involving a nuclear unit, again the NRC should be available to testify on a single question: Could it be said that the identified expense is *unnecessary* to nuclear safety?

Ambiguous Regulatory Standards

If it seems implausible that economic regulators have unwittingly impacted on nuclear safety, perhaps the answer lies in the ambiguity that surrounds this entire area of regulation. One of the striking conclusions that occurs to a person looking at these issues for the first time is that this is indeed a gray area; no regulator appears to have clearly taken the responsibility for deciding when a plant is ready for transition from a massive construction project involving high technology to a business asset that produces revenues.

Perhaps one reason for this ambiguity is the type of standards employed. For example, an examination of the different standards and meanings of "commercial operation" (or equivalent phrases) indicates the confusion in this area. As noted previously, a declaration of commercial operation is basically a management decision.[549,550] It affects the accounting treatment of the plant by the utility[551] and has perhaps some other internal purposes.[552] The criteria for making that determination and its impact on regulators are not as clear.

The issue is one of present concern, having been involved in several regulatory proceedings involving nuclear units.[553] As previously discussed, GPU went to great lengths to set forth its criteria for declaring TMI-2 commercial to the Pennsylvania and New Jersey PUCs. Similar issues have arisen in Ohio, where the Davis Besse unit sought to be included in Toledo Edison's rate base because it had been declared "in commercial operation."[554] In the Davis Besse proceeding, a vice president of the utility said his company has compared criteria of utilities around the country for declaring a nuclear unit in commercial operation and had found no common set of rules.[555]

The NRC must assume some responsibility for the confusion in this area. The term "commercial operation" is mentioned several times in NRC regulations,[556] but in each instance the term is used as a point of reference, not as a point of regulatory action. For example, in incorporating provisions of the

American Society of Mechanical Engineers code in 10 C.F.R., the NRC did include references to "commercial operation,"[557] but because no penalties or action flows from that event in any other regulations, it must be seen as no more than a convenient means of expressing a particular point in time.[558]

The NRC has also promulgated a definition of "commercial operation." In Regulatory Guide 1.16, the term is defined as:

> [T]he date that the unit was declared by the utility owner to be available for the regular production of electricity, usually related to the satisfactory completion of qualification tests as specified in the purchase contract and to the accounting policies and practices of the utility 9

Admittedly, the definition is somewhat circular. It is made even less useful by the fact that Regulatory Guide 1.16 is an advisory guide for completing reporting requirements to the NRC for operating units.[561] It has no regulatory impact other than as guidance that some data be provided.

We could find no provision of NRC regulations that imposed regulatory responsibility on the NRC over the declaration of , commercial operation. Numerous depositions with NRC officials of all levels confirmed this finding.[562] Although the NRC is responsible for granting an operating license, approving progressions to necessary modes of preoperation, and finally granting mode 1 (power operation) authorization when a licensee has completed all conditions identified in its license, it is not specifically involved in the movement to commercial operation. Other than the IE review of the power ascension program, there is no NRC input into the utility decision to move the project into a moneymaking proposition.

FERC is interested in the accounting change that the declaration of commercial operations has on the utility's books: shifting the plant from the CWIP account to the plant in service account. However, nowhere does FERC define the criteria for declaring a unit to be in commercial operation. As has been noted in testimony before the Ohio PUC, the closest FERC definition is the inference in Electric Plant Instruction 9D that 120 days after testing begins, a plant should be declared in commercial operation.[563]

Most questions concerning "commercial operation" arise before PUCs, for they have the responsibility for determining when a unit is going to be recognized as "used and useful" (when the ratepayers will begin paying money toward its operation and construction). In a logical system, it might be imagined that "commercial operation" and the date on which the PUC recognized a unit in rate base would be the same. That is not necessarily the case.

In Pennsylvania, where CWIP is not allowed in rate base, a practice seems to have developed of equating "commercial operation" with "used and useful" status.[566,W6] Confusion is possible because the definition of "used and useful" appears to be as ambiguous as "commercial operation."[567] FERC has stated that there is no set formula for determining whether a unit is "used and useful."[568] Rather, FERC states only that "reasonable time should be allowed for test periods ... and ... for the plant to become sufficiently completed to be reasonably reliable for service for the purpose for which it was intended."[569] The similarities with the GPU-defined criteria of "commercial operation"-that is, the completion of the FSAR test program-is obvious.

However, despite assertions that the two terms are identical, the Pennsylvania Office of the Consumer Advocate has pointed out that "commercial operation" is a technical definition of the utility, but "used and useful" is a legal finding that determines when consumers will begin paying for the unit. The distinction is useful for several reasons. First, "used and useful" is the language of the statute, not "commercial operation."[570] Second, as previously noted, simply declaring a unit "in commercial operation"[571] will not bring automatic rate recognition. The PUC must consider that unit in the forthcoming rate application and rule that it is indeed "used and useful" before any return flows to the company.[572]

In summary, "commercial operation" and "used and useful" may be used in similar fashion by PUCs, but they do not indicate the same point in time. As a general rule, apparently a declaration of commercial operation must precede consideration by the regulators as to whether the unit is "used and useful."[573-575] Ignoring this distinction only compounds the ambiguity in this area for all involved. For example, utilities may seek to declare the unit commercial earlier than it should be in order to meet that precondition to consideration of being "used and useful."[576]

Alternately, utilities may hold off declaring a unit commercial until the exact moment when "used and useful" status is assured, to minimize the loss of AFUDC that accompanies the accounting change.[577]

Turning finally to the IRS, we find-as previously noted-that the IRS does not use the term "commercial operation" (or "used and useful") in determining when a unit is first placed in service for tax purposes. Rather, the IRS has established, on an *ad hoc* basis, a definition of placed in service that is different from any other point recognized by regulators. This approach presents two problems.

First, as a theoretical matter, it would be helpful if all regulators used the same physical event as the point at which recognition of the nuclear unit as a business asset would be made. For example, if final completion of the FSAR power ascension test program indicates that a unit has completed its construction and testing phase,[578,579] perhaps all authorities should recognize that as the moment of business recognition; that is, a unit that is in "commercial operation," "used and useful", and "placed in service" all at the same event. Regulators have different interests in regulating, and therefore, their standards must sometimes vary, but it is difficult to see the importance of the couple of months difference to which the present standards give rise. Balanced against the need for clarity in dealing with this complex process, the IRS should develop a more consistent standard with the other institutions involved.

Second, even if the IRS decided not to develop a consistent standard, it would have to turn its attention to the current definition of placed in service. Through a number of regulations, letter rulings, and, especially, revenue rulings, the IRS has attempted to give definition to the term. In the process, the necessary criteria have become more complex until-in the most recent letter ruling-at least one IRS interpreter believes "placed in service" is roughly equivalent to "commercial operation."[580] For example, if it is necessary for a nuclear unit to "operate at its rated capacity without failure"[581] in the year in which it is placed into service, what is "rated capacity"? What is a "failure"? How long must a unit operate "at its rated capacity without failure" in the "placed into service" year? One month? One day? Ten minutes? The answer of the IRS is, of course, that such matters will be decided on a case-by-case basis.

However, one can imagine that a utility just completing a billion dollar unit and attempting to plan for its tax effect would be concerned with the *ad hoc* approach. The IRS needs a better, more technically understandable, set of criteria for allowing tax treatment of a major nuclear generating unit.[582]

In sum, the regulatory agencies have not coordinated their responsibilities in this area. The numerous variations and understandings of the term "commercial operation" are simply symptomatic of this fact and also indicative of the ambiguity over which responsibilities the agencies should exercise.

Conflicting Responsibilities of Regulatory Authorities

It' follows inexorably from the foregoing identification of ambiguous responsibilities and ambiguous standards that conflicts among the various regulatory bodies would arise in this area. In our investigation, we found numerous examples where an agency, in attempting to regulate what it perceived as its area of responsibility, actually came into conflict with the authority of another agency. In one sense, this is a problem only for the utility. It must find a means of either reconciling different agencies' instructions or simply absorbing the cost of choosing one over the other. However, more broadly, it is a matter of general concern when the aims of one regulator are confused by the actions of another. This is especially true when the issue of nuclear safety is in the middle.

We have already discussed how the practice of PUCs and FERC in examining the value of a completed nuclear plant may cause utility managements to be reluctant to explore new safety innovations.[583] Either through direct challenge to specific items included in the unit or through challenge to the length of time it took to complete the unit,[584] FERC and PUC staffs and consumer advocates may create an inhibiting effect on utilities.

However, this is not to suggest that FERC and PUCs act in concert on all matters. In fact, we have uncovered situations in which a PUC ordered one rate treatment and FERC ordered another for the same event. For example, in evaluating whether Philadelphia Electric Company's (PECO) share of the Salem 1 common plant was "used and useful," PaPUC instructed the company to ignore its earlier declaration of commercial operation and continue to[585] accrue AFUDC on half of the common plant. PECO protested that under the Uniform System of Accounts, FERC would probably not allow accrual of AFUDC beyond a declaration of commercial operation. FERC has not yet ruled on the issue but the staff has indicated that precedent suggests the common plant will have to be considered "plant in service." In effect, there will be two different treatments of the same plant: on the one hand, Pennsylvania retail rates will not recognize the Salem 1 common plant as a portion of rate base, but will continue to accrue AFUDC on a completed plant, and on the other hand, wholesale rates will recognize[586] PECO's common plant share of the unit.

There are numerous examples of FERC and PaPUC using different methods of treating the same event.[587] In theory, there is no problem with such separate approaches,[588] but the effect on a utility must be one of attempting to be "all things to all regulators." As GPU Treasurer John Graham stated:

> I would say that as we try to go about our business, we see areas where there may be a conflict between what one agency wants and what another agency wants and we have to try to work out our affairs in such a way [as] to accommodate all of those interests.[589]

There is even the potential that the rate commissions (PUCs and the FERC) will come into conflict with the IRS. As previously discussed, because the IRS "placed in service" standard is not equivalent to "commercial operation" or "used and useful," a utility possibly will receive tax recognition of its investment in a nuclear unit before rate treatment.[590] Indeed, utilities are under a standing obligation, as imposed by their PUCs, to take tax advantages as soon as possible, to reduce the need for revenues.[591] Presumably, utilities will take advantage of the difference between the two standards and take tax credits and depreciation allowances as soon as possible.

PECO's experience with the Salem 1 unit indicates some problems with that approach. PECO declared Salem 1 commercial on June 30, 1977. However, the IRS considered the unit placed in service on July 1, 1976, and had consequently allowed the company to obtain depreciation for the 1976 tax year. On the argument of the PUC staff and Office of the Consumer Advocate, PaPUC reduced the AFUDC associated with Salem 1 by the amount of the tax advantages received by PECO before the date of commercial operation. PaPUC held that this amount should, in essence, be "flowed-through" to the ratepayers and not accrue to the benefit of the company.[592]

The point is that as confusing as the existence of different standards may be, the regulatory bodies have compounded the problem by refusing to recognize the authority of others to fulfill their statutory functions. If Congress intended all corporations (including utilities) to receive ITC at the earlier placed in service date,[593] it seems inappropriate for PUCs to redefine, on their own initiative, the proper distribution of those benefits.[594]

Although the NRC does not fit directly into either of the conflicts discussed, its interests are involved. The NRC has traditionally disclaimed any interest in the financial affairs of its licensees or the impact of other regulators.[595] It does, however, have responsibility by the requirement of both the Atomic Energy Act[596] and its own regulations[597] that a licensee must be "financially qualified" to construct and operate a nuclear facility.

The rationale for such a requirement seems obvious. If financial matters cause a licensee to cut corners in either the construction or operation[598] of a facility, the NRC should be concerned. As previously discussed, such a temptation would be inconsistent with the commitment to safety required of all licensees.

In reality, however, the "financial qualification" analysis has been less than stringent. Most of the attention at the NRC has been focused on the initial construction permit or operating license adjudications proceedings. If an applicant could demonstrate to the staff that it had the necessary financial resources to build the unit, the NRC would, in essence, deem the licensee financially qualified for the life of the license.

Indeed, the best indication of the relative unimportance of the financial qualification analysis is the fact that the staff has (at NRC invitation) proposed reducing its scope. Under a proposal currently pending before the Commissioners,[599] if a licensee (1) was a regulated utility and (2) held a bond rating of "A" or better, it would be deemed financially qualified.[600] This is not the forum to debate the merits of this proposal, but it seems fair to say that this would reduce even the somewhat superficial scrutiny currently given to the financial position of the utility.

The point is that even under the present system, there is no ongoing analysis of the financial condition of a licensee vis-a-vis its ability to operate a nuclear facility. The section at NRR that evaluates financial qualification for purposes of the construction period or operating license proceedings is not equipped to undertake a detailed ongoing analysis. Furthermore, IE specifically denies an interest in the financial position of the utility while it is involved in inspections. As we were told by numerous IE personnel, that is considered outside its responsibility.[601] There is apparently no system at NRC for gathering and evaluating these data on an ongoing basis.[602]

As is discussed in detail below, we believe this to be a serious deficiency. Combined with a failure to maintain adequate contacts with the economic regulators, it leaves the NRC blind to important financial considerations that may have an impact on the safety of the unit. Postulating a licensee that would be willing to compromise safety-and might do so to satisfy conflicting regulatory demands-there is no clear indication that the NRC would become aware of the action.

6. RECOMMENDATIONS

The combined information obtained in this inquiry, from both TMI-2 and generic cases, indicates a need for change in the regulation of nuclear power-plants when decisions regarding economic recognition of the unit are being made. In the common, but ambiguous, phrase that has been at the center of this report, "commercial operation" must be better regulated.

Our recommendations, it might be suggested, go beyond TMI-2 and propose broad-ranging and sweeping changes in some fundamental aspects of utility regulation. However, as the foregoing made clear, this is an area of complex and overlapping interrelationships. Restricting recommendations to TMI-2 or the NRC alone would not reach systematic problems and the other institutions.

Having said that, we recognize that each agency best knows its strengths and weaknesses. We presume that having been shown the potential problems that exist in this area, agencies will take the necessary and appropriate action. Our recommendations, therefore, are more in the way of example than completely thought-through solutions. We propose them as further restatements of what we perceive as key problems in this area.

Our recommendations break down into two major areas: those that affect the NRC and those that affect non-NRC institutions. Finally, we propose some long range studies that our inquiry has suggested might be of benefit.

NRC Recommendations

1. *The NRC Should Establish an Expanded Financial Analysis Office to Monitor Situations in Which Business Considerations May Impact on Nuclear Safety*

The NRC has been deficient in recognizing the fundamental conclusion of our investigation. That conclusion, again, is that attempts to obtain incentives and deal with regulatory pressure could compromise the commitment to safety required of a nuclear unit licensee.

However, the NRC has implicitly recognized the importance of financial pressures. In a somewhat backhanded fashion, the requirement that a utility be financially qualified indicates an awareness of the impact that the "business" side of a utility can have on nuclear safety. In a decision involving the Seabrook (N.H.) nuclear station, the Commissioners established that a utility need only demonstrate that it has "reasonable assurance of obtaining the necessary funds" to construct and operate a nuclear powerplant in order to be found "financially qualified."[603] Two factors discussed by the Commission in reaching a decision in that case were the bond rating of the utility and the pending rate increase requests. The premise of this analysis appears to be that existence of sufficient funds (or "reasonable assurance" or obtaining those funds) at the start of the licensing process will militate against the development of financial pressures which might affect the safety of the unit.[605]

As this report has demonstrated, however, there are numerous points in the construction and operation of a nuclear plant when the potential to improve a utility's financial position could create pressures which conflict with the commitment to nuclear safety, earlier identified. As a dissenting member of the Atomic Safety Licensing and Appeal Board said in *Seabrook:*

> [T]here is a need to avoid a situation in which financial pressures on the applicant become so persuasive as to influence the manner in which the plant is constructed ... financial constraints can play a heavy influence on day-to-day decisions.... In insidious fashion, each such decision (less testing, lower quality materials, borderlike workmanship) even though not consciously designed as believed to do so, increases the risk from an eventual accident.[6m]

We therefore recommend that the NRC expand the "financial qualification" analysis to include the gathering of data during the operating life of the unit, with special emphasis on the year in which the unit is completed and declared in commercial operation. Rather than reduce the depth of financial qualification review,[607,608] the NRC should encourage its expansion. Rather than focus on construction permit and operating license proceedings, the financial qualification review should be expanded to become a "financial analysis" review, which looks to the impact of business activities on the commitment to nuclear safety.

Furthermore, the NRC should provide the necessary personnel and authority to collect and analyze business data. Rather than work with outdated annual reports and newspaper clippings, the NRC staff should have access to the most intimate financial details of a licensee's operations. This would enable a prospective analysis of the pressures the utility faces in the future and an evaluation of the possible effect that pressure would have on nuclear safety. Should a problem in this regard come to the attention of the NRC staff, it would then be in a position to meet with the licensee to discuss the ramifications. At a minimum, such a meeting would alert a licensee of the NRC's concern.

2. The NRC Should Establish Better Communication and Coordination with the "Economic Regulators"

A second significant failure in this area has been the lack of coordination between the NRC and PUCs. Far from assisting each other in understanding the complexities of putting a nuclear unit into commercial operation, the NRC staff has not attempted to stay informed of relevant PUC decisions. In the apparent belief that action following the issuance of an operating license and mode 1 authorization is not of importance, the NRC staff has ignored the impact of PUC and FERC decisions on those milestones.

As the NRC establishes an expanded financial analysis office, it should specifically instruct the NRC staff to develop better lines of communication with the PUC staffs, including joint annual meetings to review matters of mutual concern. Although such meetings would entail some cost, the additional information would assist the NRC licensing system.

3. The NRC Should Establish a Better System at IE for Balancing the Pressures Created by Financial Incentives

At the same time that a Washington-based office (presumably in NRR) is developed to keep track of relevant financial and regulatory data, field offices of the NRC must become more sensitive to the incentives that may be pushing utilities toward certain dates. Regulatory systems are built on a system of checks and balances; if there are advantages to some action that is detrimental to the public interest, regulations, inspections, and enforcement are posed in counterbalance. If our assertion is true that there are financial incentives for completing a nuclear unit by certain "artificial dates," what is the balancing regulatory action? Our investigation has not indicated any agency that even accepts responsibility for this area. We would propose that IE establish a system for informing inspectors in the field, of identified financial incentives and of important dates for obtaining those incentives for utilities constructing nuclear plants.[610] The field inspectors could then increase their monitoring during those crucial periods to make sure that no corners are cut in meeting the financial deadlines.

At the same time, IE headquarters could require reports on observations during these key financial periods to better assess the generic implications of financial incentives. Based on such an analysis of identified violations during these periods, IE might want to create a specially trained team of inspectors who would descend on a site where financial incentives have been identified. This would send a message to the utility: Proceed at whatever pace you think appropriate to obtain the incentives that exist, but the site will be subjected to additional scrutiny during that period to prevent the cutting of corners.

Parenthetically, the NRC has begun the implementation of a resident inspector program that would place an IE inspector at each nuclear site.[611] We suggest a resident inspector might be in a good position to observe changes in the pace of construction, which may be indicative of a push to meet artificial deadlines.

In addition, resident inspectors could provide an outlet for worker dissatisfaction or safety concerns that arise from increased production demands. Many times, in the course of this investigation, we were told that workers would not go to an NRC official with an allegation of improper work or rush because they feared losing their jobs.[612] The NRC must increase its protection of such employees to promote free communication of safety concerns. Perhaps a resident inspector program is one method.

4. NRC Offices Should Strictly Scrutinize the Power Ascension Test Program and Any Problems Encountered on the "Critical Path" to Commercial Operation To Prevent Any Compromising of Safety

In addition to the recommendation that the NRC become more sensitive to the possible impact of financial concerns on nuclear safety, there is much the NRC can do to tighten the existing regulatory system such that a rush to commercial operation will not impugn minimum NRC safety standards.

Our investigation into allegations surrounding TMI-2 focused on two major developments during the startup test program that were key in enabling completion of the plant by the end of 1978: the pace of the power ascension test program and the main steam relief valve failure. We would suggest that, generically, the NRC should pay close attention to similar developments in all units as indications of possible rushes to meet artificial deadlines.

The power ascension test program, as identified in the FSAR, need not be complete to declare a plant in commercial operation under current regulatory practices.[613] However, corporate,[614] tax[615] and regulatory[616] pressures are moving utilities toward a linking of these two events. Therefore, the NRC should pay careful attention to completion of power ascension testing. This involves more than the current IE observation of one or two major tests.[617] Rather, we recommend that an NRC inspector personally view each power ascension test in mode 1 and certify acceptance of results within the criteria set forth in the FSAR. At the completion of the program, the NRC inspector would issue a final certificate so indicating. Following a careful power escalation, the unit would then be allowed to proceed to full power and, if the utility so desired,[619] be declared in commercial operation.

The NRC inspector should be concerned with several matters during this period: not only the acceptability of the tests, but the pace, the effect on workers,[620] and variations from the FSAR schedule should be of interest to the NRC. If, at any time the IE inspector felt that the testing schedule was proceeding too rapidly or was overtaxing the work force, a full investigation (with possible suspension of the program) would result.

Our investigation into the TMI-2 main steam relief valve problem also demonstrated that major equipment deficiencies which occur on the "critical path" of commercial operation create pressures on the utility to complete repairs as soon as possible. Recognizing the potential for compromise to remain "on schedule," we recommend strict NRC scrutiny of any such deficiencies that arise during the startup test phase. This scrutiny would involve (1) a licensee event report (or its equivalent) on the discovered deficiency, (2) mandatory filings with NRR assessing the safety impact of the deficiency, (3) filings with the financial analysis office assessing the financial impact of any delay, and (4) strong IE presence during the period of repair.

As discussed above, GPO's action with respect to its main steam relief valve problem was in full accord with NRC regulations and good business practices[621] Our concern is that neither NRR nor IE appeared to be concerned about, or interested in, the pressures on the utility to complete repairs on its "critical path."[622] Given our hypothetical "worst case," such an attitude might not be proper.

5. The NRC Should Examine the Status of the FSAR Listing of the Power Ascension Tests To Be Performed

A number of minor items also deserve NRC attention. For example, the FSAR section that deals with startup testing can be so cryptic as to be useless. The NRC should require licensees to list (1) all tests scheduled; (2) all tests required by NRC regulations, with citation to each provision in the regulations;[623] (3) all tests that the NSSS has suggested; (4) all tests proposed by others; and (5) all tests that are optional and subject to deletion. A realistic estimate of the time period necessary to complete the program-both with major deficiencies and wthout-should be included in the FSAR. Only with such a complete before-the-fact list of utility intentions can NRC personnel be in a position to judge whether rushes in the schedule are occurring.

At the same time, the legal ambiguity regarding the status of the FSAR should be addressed[624] If a licensee deletes tests listed in the FSAR, the NRC should-at a minimum-be informed of that decision. Whether that specific test is necessary for safety or not, its deletion may be indicative of a broader problem of which the agency should be aware.

Finally, the difficulty of knowing when to begin scrutinizing a unit for signs of a rush remains. Although we have recommended changes that affect, primarily, the startup phase, previous recommendations of (1) increased NRC sensitivity to financial impacts and (2) increased IE involvement with those issues should begin with issuance of a construction permit. Hence, there would be, under our recommendations, increased oversight during the construction phase, as well as during the startup testing phase (after fuel load).

Recommendations for Other Institutions

Recommending that the NRC do a better job in this area is only the first step in changes that must occur.[625] For, as previously discussed, the NFIC system is designed to impose minimum safety requirements through an imperfect "audit" procedure. Without a utility commitment to nuclear safety-above and beyond NRC requirements-there is serious question as to whether the entire regulatory process can succeed. It has been argued that most utilities are committed to nuclear safety, as a matter of ethics and good business sense.[626] However, our concern is for the "worst case" licensee who would be tempted away from that commitment by the existence of financial and regulatory pressure. For the benefit of the entire system of regulation, that "gap" must be plugged.

This requires recommendations for changes not only in the NRC, which must address itself only to minimum safety standards, but in other institutions as well. In effect, we are recommending a two-pronged approach: (1) increased NRC sensitivity and action to make sure that minimum safety standards are not compromised and (2) the elimination of incentives that might tempt a utility away from its commitment to safety. Our recommendations in this second area reach three institutions: State PUCs, FERC, and the IRS.

6. PUCs Must Recognize the Unique Problems Associated with Challenging Utility Decisionmaking as a Nuclear Unit

State PUCs must come to a better understanding of the complexities of building and operating a nuclear powerplant. Both utility executives and PUC commissioners have fallen under the illusion that nuclear stations are like any other generating unit, except for the fuel source. That "except" is a crucial distinction. Nuclear powerplants are unique and require special attention.[627] If that self-evident truth is recognized, then it is not inconsistent to realize that in regulating the economics of these units, State PUCs have special responsibilities and must, at times, make special arrangements for nuclear units. Although we recognize the added complexity that treating nuclear units differently from other sources of generation may cause PUCs, we see such differentiation as unavoidable.

7. When Nuclear Units Are Involved, a Truly Future Test Year Should Be Employed by PUCs

Our investigation into the TMI-2 case indicated that the importance of the Penelec 1978 test year may have influenced GPU[628] into completing the unit before that deadline. This event was possible because the future test year[629] was not far enough in the future to avoid the "present" catching-up.. Thus, because of delays in the regulatory process, the Penelec rate proceeding was ongoing during the test year. Rather than be either a "historical" or "future" test year, Penelec had, in fact, a "present" test year. That increased the pressure to be in commercial operation before the case ended.[630]

We recommend that when a nuclear unit is being introduced into rate base, a future test year should be set far enough in the future that there is no danger of overrunning the test year. Thus, in the Penelec case, a future test year of June 1979 to June 1980 might have been advisable. The further the test year is placed in the future, the greater the reliance on projections and estimations. However, PUCs have vast discretion to rectify any overpayment by ratepayers due to such imperfections.[631] Furthermore, the difficulties of scheduling PUC proceedings create problems of running into the test year.

One solution to this problem was developed in California, where the PUC has committed itself to rendering a decision in a case *before* the test year begins.[632]

8. CWIP in the Rate Base Should Be Allowed for Nuclear Units by PUCs To Reduce the "Lump Sum" That Is Otherwise Accumulated

A second major problem in the PUCs requires considerably more thought and perhaps legislative action. However, allowing utilities to accrue AFUDC through the construction life of a nuclear unit creates a large incentive for the utility to complete the unit by a certain "artificial" date. The magic phrase "used and useful" releases large sums of money to the utility, including vast amounts of AFUDC.

To reduce this presssure on a single point in time, PUCs consider recognition of nuclear plant CWIP in rate base. That is, during the construction of a nuclear unit, a utility should be allowed to earn a rate of return on the money that has been expended into the unit to that time. The goal is to reduce a utility's incentive to rush to meet a certain date when it nears the end of construction and, instead, to spread out recognition of the unit over the life of the construction project. If, for some reason, the unit was eventually not found to be used and useful," the money collected under CWIP would have to be refunded by the company.

This recommendation is not without problems. There are serious questions among utility regulators as to whether CWIP in rate base is proper. For example, one argument against its inclusion is that today's ratepayers should not have to pay for tomorrow's plants. There are many other difficult questions concerning CWIP in rate base, but they can be debated elsewhere. Our recommendation is meant simply as one example of a means to reduce the pressure of a "one-shot" inclusion of a billion dollar facility in a utility's rate base.

9. PUCs Should Define and Recognize a Distinction Between a Nuclear Plant in "Commercial Operation" and One that Is "Used and Useful"

State PUCs must also find a means of better defining the relationship between "commercial operation" and "used and useful." If the two are identical in usage, PUCs should so recognize. If the phrases indicate a difference between technical and legal meanings, that too should be stated clearly. We have recommended that a standard definition of commercial operation include completion of the FSAR-identified tests. We have also recommended that the NRC certify completion of the power ascension test program. It is consistent, therefore, to recommend that a PUC require a utility to submit such an NRC certificate before declaring a utility to be in commercial operation and seeking that it be declared "used and useful."

In this context, "used and useful" is a final finding that the unit as completed is capable of serving the ratepayer in a reliable fashion. If CWIP in rate base has been allowed in the past for that unit, a finding of "used and useful" eliminates the possibility that CWIP will need to be refunded by the utility. If no CWIP in rate base has been allowed, of course, the entire plant costs would become part of the rate base on the finding that the unit was "used and useful." At a minimum, the standards for that finding should be clear-which at present is not the case. Perhaps the greatest change in State PUCs is one that

We have detailed extensively[634] how the potential for disallowance of AFUDC causes utilities to hesitate to go beyond the bounds of NRC minimum safety standards. It is doubtful that PUCs and Offices of Consumer Advocates understand that this could be the effect of their economic challenges to a utility's claimed value of a nuclear plant.

10. *PUCs and Related Organizations Should Consider the Long Term Effects on Nuclear Plant Decisionmaking of Disallowance Arguments*

We recommend that PUCs, PUC staffs, and Offices of Consumer Advocates become more sensitive to the impact that their disallowance arguments have on a nuclear licensee. Looking to long term effects, they should make challenges to plant costs only when they seriously believe the utility is attempting unfairly to increase the cost to the customer *with no increasing benefit in nuclear safety. To* assist the PUCs themselves in reaching conclusions on allegations of goldplating, we recommend that they fashion a standard of evaluation that asks whether the challenged expense could be said to be *unrelated to safety.* In other words, the burden of disallowance must clearly rest on the challenger.

Futhermore, to assist PUCs in this area, we recommend that the NRC make witnesses available to answer the question of safety costs. Rather than engage in a debate of value-impact or risk assessment,[635] the NRC witnesses should utilize their expertise only to ask the question posed above: Could the challenged expense be said to be unrelated to safety?

11. *PUCs Should Attempt To Improve a Dialogue with the NRC and Other PUCs To Coordinate Nuclear Plant Treatment*

Our final recommendation for PUCs is the converse of our earlier recommendation for the NRC: We recommend improved dialogue between agencies involved in regulation of nuclear plants. In recognition of our earlier assertion that regulation in this area does not fit into "neat little boxes," State PUCs and the NRC should maintain an ongoing discussion of each other's relevant concerns. For example, should the NRC become aware of a "present test year" problem, it might suggest to the PUC staff that a stipulation be developed that would extend the test year beyond the date of the proceeding.[636] Conversely, requires no legislation but only a change in sen- , should the PUC staff have questions regarding the length of safety-imposed delays and the proper method of assessing its impact on ratepayers, the NRC might be in a position to render advice.[637] Further, given the multistate nature of ownership in current nuclear units, PUCs should attempt to better coordinate rate treatment of such units among themselves'so as to provide a measure of consistency. In sum, all parties would gain from a sharing of information and concerns in their different areas of regulation. The "spillover" effects, after all, affect a matter of mutual concern: a nuclear unit.

12. *FERC Should Improve Its Communication and Coordination with the NRC*

FERC should also improve its communication skills. FERC apparently does not coordinate very well with either State PUCs or the NRC. Because of its similar economic role with the PUCs, one would think there would be close contact between the two bodies, but that does not appear to be. This situation leads to different interpretations of the same Uniform System of Accounts and, at times, conflicting rulings.[638]

At the same time, because the NRC and FERC are sister Federal agencies, closer communication might be imagined than exists. Over the years, there has been a perception of differences over the precise distinction in their regulatory functions: the NRC deals with matters of safety, and FERC with matters of economic regulation. It scarcely needs repeating that such a dichotomy ignores the many forces involved in bringing a nuclear unit into operation as a business component of a utility.' We recommend that FERC attempt to establish better lines of communication between both State PUCs and the NRC when it is regulating a utility with a nuclear unit.

13. FERC Should Eliminate the Threat of Disallowance of AFUDC that Is Implied in Electric Plant Instruction 9D

Although we have identified few deficiencies in the FERC system of regulation as it impacts on nuclear units, one we believe needs rethinking is Electric Plant Instruction No. 9D. As pointed out,[639] setting a time limit on a test program directly impacts on nuclear safety and belongs within NRC's authority; not the FERC's. The danger of disallowance associated with Instruction 9D could cause a utility to attempt to minimize a test period that runs greater than 120 days. This action could be detrimental to nuclear safety.

We recommend, therefore, that FERC explicitly eliminate the provision allowing a reduction of AFUDC in a unit because the test period ran longer than 120 days. Instruction 9D may continue to seek information on an extended test program, but should not contain the threat of disallowance. FERC could handle allegations of an improperly lengthy test program through the same device as that suggested for goldplating allegations before the PUCs. That is, an NRC staff person will testify as to whether the delay was unnecessary for safety.

14. The IRS Should Require the Use of the Qualified Progress Expenditures Basis for Recognizing ITC for Nuclear Units

The final external agency we address is the IRS. We recommend that the IRS require the use of qualified progress expenditures for all ITCs associated with a nuclear unit. Recognition of a utility's expenditures over the period of actual construction (subject to recapture if the unit is not ultimately placed in service) reduces the impact of placing the unit in service in a certain tax year.

***15. The IRS Should Bring Its Standard for Recognizing a Nuclear Unit into Closer Conformity** with the Standards Used by Other Regulators*

One advantage in using the qualified progress expenditures basis is that it eliminates at least a portion of the uncertainty created by the currently vague standards of "placed in service"[641] used by the IRS. We recommend that the IRS consider giving greater content to this phrase, as it involves nuclear generating stations, than do current regulations, revenue rulings, and letter rulings. Specifically, the IRS should attempt to relate the criteria for placing in service a nuclear unit with standards used by other regulators (for example, "commercial operation," "used and useful," and "mode 1 authorization").

For example, the author of LTR 7833007 probably recognized the true nature of NRC-mandated power ascension tests when he ruled that completion of such tests are necessary before a nuclear unit may be placed in service.[642] Therefore, a linking of tax treatment and the recommended NRC certificate of completion of power ascension tests seem appropriate.

Long Term Studies

16. A Study Should Be Conducted into the Relative Safety of Privately Owned Vs. Publicly Owned Nuclear Units

Our final recommendations go to two long term studies that are suggested by our investigation into this area. The first goes to the basis of the development of nuclear power: the suggestion that the profit motive of investor-owned utilities conflicts with their commitment to nuclear safety. A number of people have raised this point after the accident at Three Mile Island and the subsequent allegations that we have investigated in this report.[643] Our investigation did not focus on this broad question, but such a study of the relative safety of public versus private nuclear units should be considered.

For example, a statistical study of the number of Licensee Event Reports, violations, and other indications of safety problems could be done for both investor-owned and public units. If both types of units have similar safety records, there would be reason to doubt about the validity of the public versus private distinction. Numerous other studies in this area could also be imagined.

17. A Study Should Be Conducted into the Conflicting, Ambiguous Responsibilities of the Various Regulatory Agencies in This Area

Finally, we recommend a broad study into the conflicting and ambiguous regulatory responsibilities in this area. As identified in this report, the period of completing and obtaining business recognition of a nuclear reactor is full of tensions that can force a utility to choose one regulator over another. Perhaps congressional committees would do well to consider the causes and solutions to this problem. Otherwise, both utilities and regulators will continue attempting to reconcile the competing demands of different authorities, all of which ultimately are bestowed by Congress [4]

Conclusion

The accident at TMI-2 has the potential to effect drastic change in the system of regulation of nuclear powerplants. In investigating allegations made regarding financial incentives to complete TMI-2, we have uncovered a confused system of regulation where economic considerations and pressures threaten the commitment to nuclear safety required of licensees. It is our hope that the findings, implications, and recommendations of this section, when read in connection with the entire report of the Special Inquiry Group, will add to the ultimate improvement of nuclear regulation.

REFERENCES AND NOTES

'Statement of Policy of the NRC (June 13, 1979) at 1.

[2]Technically, the term "commercial operation" (or "commercial service"), as more fully discussed below, is the *declaration* by a utility that a generating unit is capable of reliably producing power to its customers and is available to the associated power pool. Because a declaration of commercial operation may be a prerequisite to certain regulatory treatment (see note 564 infra and text accompanying), the term is used in several different ways.

[3]"1978 Opening Saved Power Company Millions," *The Washington Star,* April 5,1979.

[4]"President Forms Panel to Probe A-Plant Mishap," *The Washington Post,* April 6,1979.

[5]Public Citizens, Inc., "Death and Taxes: An Investigation of the Initial Operation of Three Mile Island No. 2," mimeographed copy released April 5,1979; see also "Tax Policy Collides with a Lax Regulatory Policy ... and the Result is the Three Mile Island Nuclear Accident," *Caveat Emptor,* April/May issue, 1979.

[6]By our definition, "incentives" consist of both positively awarded benefits and the avoidance of detrimental results.

[7]GPU is a utility holding company under the Public Utility Holding Company Act of 1934. It is composed of three operating utilities: Metropolitan Edison (Met Ed), Pennsylvania Electric Co. (Penelec) and Jersey Central Power and Light Co. (JCP&L). GPU also includes a subsidiary service corporation, General Public Utilities Service Corp. (GPUSC), which provides technical services to the operating subsidiaries.

[8]See also "1978 Opening Saved Power Company Millions," *The Washington Star,* April 5, 1979 and Public Citizens, Inc., "Death and Taxes," mimeograph released April 5,1979, which similarly suggested such an incentive.

[9]Indeed, there are few States in which utilities are not regulated by some authority. Although we use the term "PUCs" in this report to refer to such regulators, these authorities are known by various titles in different States. With regard to TMI-2, each of the operating companies owned a portion of the unit as follows: Met Ed, 50%; Penelec, 25%; and JCP&L, 25%.

10A map of GPU service territories is a part of the SIG's records.

[11]By way of their power interchange and their interconnection with the PJM pool.

[12]FERC was formerly the Federal Power Commission (FPC).

13 Penn. *Consol.* Stat., Chap. 13, Sec. 1307(a) (1966).

[14]*Penn. Consol. Stat.,* Chap. 13, Sec. 1308 (1966).

[15]*Penn. Consol. Stat.,* Chap. 13, Sec. 1308(d) (66).

[16]*Penn. Consol. Slat.,* Chap. 13, Sec. 1308(c) (1966).

[17]*penn. Consol. Stat.,* Chap. 13, Sec. 1308.

[18]*Penn. Consol. Slat.,* Chap. 13, Sec. 1308(c) (1966).

[19]*Penn. Consol* Stat., Chap. 13, Sec. 1307 (1966). The complexities and legal arguments concerning the "used and useful" standard are discussed further, infra at note 564 and text accompanying.

[20]18 C.F.R. Part 101.

[21]18 C.F.R., Electric Plant Instruction 3(17).

[22]Dieckamp testimony, Pres. Corn. Hearing (May 30, 1979) at 50.

[23]Failure to obtain prompt regulatory recognition of O&P expenses could cause a utility to attempt to minimize such costs. For example, at TMI-2 there was a cutback in maintenance work around January 1, 1979, 2 days after the plant was declared commercial. Workers reported that Met Ed officials "told us ... we would be working a lot less hours on maintenance because they didn't [yet have] the rate increase "Countdown: How the Nation's Worst Nuclear Accident Happened," *Philadelphia Inquirer,* April 8,1979.

[24]Dieckamp dep. at 105-06 (Pres. Corn.). Mr. Dieckamp describes the process as "synchroniz[ing]" the declaration of commercial operation and rate relief. "Relief" need not always be seen as higher rates for the customer. If a large baseload (e.g., nuclear) unit replaces a less efficient and more costly unit, the rise in rate base charges to the customer may be offset by a lowering in fuel adjustment clauses, such that rates remain essentially the same. However, it is relief to the shareholders, who have capital invested in the project.

25See e.g., Schultz prepared testimony before the Ohio PUG in 76-1174-EL-AIR; "Declaring a generating unit to be by test is to gamble with the Company's Earnings." *Id.* at 11-12.

[26]See e.g., Dieckamp dep. at 107 (Pres. Corn). "One of the motivations for [setting forth the commercial operation criteria] ... [was] the absence of definitive criteria on the books of the FPC [now FERC] that could be used, so we were attempting to provide a set of ground rules that everyone could work to."

[27]*See* also Arnold dep. at 86.

[28]See note 392 *infra* and text accompanying. GPUSC was primarily responsible for construction management and testing of TMI-2. Upon the declaration of commercial operating, GPUSC turned the unit over to the principal operating utility, Met Ed.

[29]Dieckamp prepared testimony in PaPUC I-79040508 at 2.

[30]Letter from W. Kuhns, GPU, to L. J. Carter, PaPUC, dated August 11, 1978, at 1.

[31]1d. at 2.

[32]Letter from H. Dieckamp, GPU, to L. J. Carter, PaPUC, dated July 19, 1978

[33]Letter from W. Kuhns, GPU, to L. J. Carter, PaPUC, dated August 11, 1978, at 3.

34 See "Memorandum of Law: Criteria for Determining When a Nuclear Facility is Used and Useful." Filing of PaOCA dated October 31, 1978 in PaPUC R-78060626 (R.I.D. 626), at 1.

[35]Response of Met Ed to the request of Administrative Law Judge Cohen at N.T.4 (etc.), Met Ed Exhibit no. E21 in PaPUC R-78060626. (Arnold dep., Exhibit 1114).

The FSAR itself must include "[p]lans for preoperational testing and initial operations." 10 C.F.R. 50.34b(6)(iii). However, only tests necessary to check safety systems are required; the licensee may (as did GPU) schedule additional tests.

[37] Met Ed Exhibit no. E21 in PaPUC R-78060626 at 1 (Arnold dep., Exhibit 1114).

[38] Letter from W. Kuhns, GPU, to J. R. Jacobson, New Jersey Board of Public Utilities, et al., dated November 30, 1978, at 1.

[39] Dieckamp prepared testimony in PaPUC I-79040308 at 3. This proceeding took place after the March 28, 1979 accident.

[40] Met Ed Exhibit no. E21 in PaPUC R-78060626 (Arnold dep., Exhibit 1114).

[41] *See e.g.,* Arnold dep. at 83, 86,115, (Herbein dep. at 173-174).

[42] Graham dep. at 17.

[43] See Herbein dep. at 117. For a discussion as to whether the NRC requires this link, *see* note 276 *infra* and text accompanying.

[44] *Mark Widoff et al. v. Metropolitan Edison Company,* PaPUC R.I.D. 434 at 4 (May 31,1978).

[45] *1d.* at 5-6.

[46] *1d.* at 5.

[47] Penelec had sought to decrease its share in TMI-2 from 25% to 10% to increase JCP&L's share. This request was denied by the Pennsylvania PUC in another proceeding (A. 100548) but the 10% figure was used in the pending proceeding (R.I.D. 392) to assess the Company's rate base.

[48] See definition *infra* note 85 and text accompanying.

[49] *Robert C. Humphrey et alt v. Pennsylvania Electric Company,* PaPUC R.I.D. 392 at 8 (June 8, 1978).

[50] 1d. at 9.

[51] 1n *the Matter of the Petitions of Jersey Central Power & Light Company,* New Jersey Board of Public Utility Commissioners, Docket no. 7610-1021, September 1, 1977.

[52] *1d.* at 2.

[53] *14.,* Appendix A at 1 (unnumbered). New Jersey does allow some CWIP recovery in rate base.

[54] Graham dep. at 10-11.

[55] K. C. *Springirth v. Pennsylvania Electric Company,* PaPUC R-78040599 at 1.

[66] WI-2 Monthly Operating Report for March, 1978.

[57] *K. C. Springirth v. Pennsylvania Electric Company,* R-78040599 atl.

[58] *Id.* at Appendix A.

[59] 14 at 14.

[80] Decided May 31, 1978. See note *45 supra* and text accompanying.

[61] *J. F. Romann v. Metropolitan Edison Company,* PaPUC R.I.D. 626 (decided March 31, 1979). Of course, the decision was made before the accident at TMI-2 on March 28, 1979.

[62] TMI-2 Monthly Operating Report for June, 1978 (filed July 11, 1978). The dramatic slip between this predicted date and that in the Penelec petition was due primarily to the problems with the main steam relief valves. *See* text accompanying note 378 *infra.*

[63] PaPUC R.I.D. 626 at 2.

[64] *1d.* at 1, 5.

[65] "Memorandum of Law: Criteria for Determining When a Nuclear Facility is Used and Useful," filing of PaOCA dated October 31, 1978 in R-78060626 (R.I.D. 626) *supra.*

[66] Portions of the TMI-2 total were disputed and, in some cases, deleted. See discussion *infra* regarding main steam relief valves, Touche Ross & Co. report.

[67] PaPUC R.I.D. 626 at 2.

[68] /d. at 59.

[69] *1n the Matter of the Petitions of Jersey Central Power and Light Company* (New Jersey Board of Public Utility Commissioners), Docket nos. 7610-1021 and 776-492 (Phase II).

[70] *1d.* at 3. *See also* Graham dep. at 8.

[71] 1n *the Matter of* the *Petitions of Jersey Central Power and Light Company* (New Jersey Board of Public Utility Commissioners), Docket nos. 7610-1021 and 776-492 (Phase II) at 4.

[72] *1d.,* Appendix A-1 at 6.

[73] *See* text accompanying note 10 *supra.*

[74] FERC order of September 28, 1978, Docket no. ER78-494 (Penelec) at 1.

[75] Federal Power Act, Sec. 205(e), 16 U.S.C. 824d(e).

[78] Of course, the rate went into effect on December 1, 1978. Following the accidents, intervenors in the proceeding noted that TMI-2 had not gone into commercial operation until December 30, and hence "it has been unfair for the company to collect the rate at issue here for the first 29 days of December [1978] Hafer testimony in Docket no. ER78-494 (postaccident).

[77] FERC order of January 12, 1979, Docket no. 79-58 (Met Ed) at 1.

[7] S!d. at 3.

[79] FERC order of February 16, 1979, Docket no. ER 79-112 (JCP&L) at 1.

[80] 14. at 4.

[81] Portions were disallowed by the FERC at the outset on motions for summary disposition. *Id.* at 2.

[82] Approximately $150 million of this is from the State PUCs and another $15 million is the automatic increases allowed by the FPA procedure but subject to refund. There have been modifications in these increase orders as a result of the accident.

[83] The other major factor was probably taking account of rising inflation.

[84] In 1978, GPU earned a rate of return equity of 10.4%, *GPU 1978 Annual Report* at 2. The Penelec and Met Ed PaPUC orders allowed rates of return on equity of 10.03% and 10.15%, respectively, PaPUC R-78040599 at 24 and R.I.D. 626 at 44.

[85] See PaPUC R.I.D. 392 at 2.

[86] *But see* text accompanying note 628 *infra* on the danger of not coordinating future test years and regulatory decisionmaking.

[87] Dieckamp testimony, Pres. Com. (May 30, 1979) at 51

[88] *See* text accompanying notes 55-80.

[B9] New Jersey Board of Public Utility Commissioners, Docket nos. 7610-1021 (Phase I), Appendix A at 1.

[90] This eliminates the "gap" problem previously discussed. *See* text accompanying note *24 supra.*

[91] *See* note 55 *supra* and text accompanying.

[92] TMI-2 Monthly Operating Report for March 1978.

Discussed *infra.*

[94] Dieckamp testimony, Pres. Corn. (May 30, 1979).

[9A] Arold dep. at 90.

[96] Graham dep. at 12. GPU had been rebuffed previously, it should be recalled, in attempting to include TMI-2 in rate base outside the test year (See note 50, *supra* and text acccompanying).

[97] Dieckamp dep. at 66-68.

[98] Graham dep. at 14. Graham added: "I don't think anyone thought of that strategy any more than they thought of the strategy of putting it [TMI-2) in service before December 31 [1978) in order to keep it within the Penelec test year."

[99] Of course, there were other considerations, discussed *infra,* which might discourage this approach (regulatory oversight over amount of AFUDC).

[100] The decision was actually made on January 11, 1979. PaPUC R-78040599.

[101] See note *22 supra* and text accompanying.

[102] The cost of testing a unit is included in the final capital cost. 18 C.F.R. Part 101 Electric Plant Instruction 9D.

[1o3] 18 C.F.R. Part 101.

[104] FERC has the authority to prescribe accounting procedures for the utilities it regulates. State Commissions (including the PaPUC) use the same system of accounts, which in itself was developed by the National Association of Regulatory Utility Commissions (NARUC). Holcombe dep. at 46. However, each Commission may interpret the accounting standards differently.

[105] 18 C.F.R. Part 101, Electric Plant Instruction 9D.

[106] Letter from W. M. Donald, FERC to M. Rogovin, SIG, dated September 11, 1979.

[107] FERC "pay[s] very careful attention to the application of AFC .. . [they are] very protective of the asset values which form the basis for the earning power for the companies." Holcombe dep. at 45.

[108] *1d.* at 40-41.

[109] 1d. at 41-42. The adjustment of the books would result in a decrease in earnings per share.

[11°] TMI-2 Monthly Operating Report for April 1978. See text accompanying note 378 *infra* regarding the main steam relief valves failures.

'"Letter from E. Holcombe, GPU, to L. H. Drennan, FERC, dated August 18,1978.

[112] Holcombe dep. at 38. In the September 29, 1978 telephone conversation, Morris Fitzgerald told Mr. Holcombe to file a log of problems connected with the extended test period.

[n3] Arnold dep. at 119.

[114] Holcombe dep. at 44.

[115] 1d. at 43.

[116] Letter from W. McDonal d, FERC, to M. Rogovin, SIG, dated October 9,1979.

[117] Holcombe dep. at 43-44.

[116] "Review of the Three Mile Island Unit 2 Construction Project," Touche Ross & Co. October, 1978 (Heward dep., Exhibit 1107).

[119] 14., conclusions at 6.

[12o] Touche Ross estimated the cost of the delay to be $18-26 million. PaPUC R.I.D. 626 at 16.

[121] Touche Ross report is cited only as an example of the danger of arguments for disallowance which confronted Met Ed; GPU challenged the report. See statement of James P. Liberman, GPU General Counsel, in Graham dep. at 45-46.

[122] Brief of PaOCA in PaPUC R.I.D. 626 at 58. However, in neither jurisdiction, apparently, was the argument accepted. *See e.g.,* PaPUC R.I.D. 626 at 17. *See also*

[123] Such a disallowance based on delay had, in fact, been argued in the TMI-1 proceeding (PaPUC R.I.D. at 170-171) and rejected. Brief of PaOCA in R.I.D. 626 at 71. See Philadelphia Electric Co., R.I.D. 438 at 20.

[124] Graham dep. at 34.

[125] Dieckamp dep. at 70. See text accompanying note 22 *supra.*

[126] Brief of PaOCA in PaPUC R.I.D. 626 at 88-92. The PUC ultimately reduced the plant inservice account by $7.8 million.

Decision in PaPUC R.I.D. 626 at 14. The Commission did not find the decision to install Lonergan valves to be imprudent management but only that the shareholders should "bear the risk of performance failure."

[128] PaPUC R.I.D. 170-171, (Met Ed) 50 PUC 77,102.

[129] Indeed, it has been the consistent position of GPU officials that TMI-2 was declared in commercial operation as soon as the criteria it had previously established were met. It was the end of December before that event occurred.

[130] Graham dep. at 11.

[131] note *43 supra* and text accompanying.

[132] By "all tests" we are not, of course, suggesting deletion of those required by the NRC or some other regulatory body but those tests GPU voluntarily included.

[133] See discussion *infra,* beginning with text accompanying note 290.

[134] Discussions with Pennsylvania OCA.

[135] See Brief of PaOCA in PaPUC R.I.D. 626 at 7.

[136] Compare Arnold dep. at 117 (doesn't recall discussion of impact of telling PUC it was commercial) with Dieckamp dep. at 68 ("the kind of thing we would recognize as a factor" to "minimize our vulnerability on those technical arguments").

[137] On January 14, the reactor was shut down to repair leaks on pressurizer instrumentation isolation valves. Another trip occurred on January 15, 1979. Memoranda from R. C. Cutler, GPU, to R. C. Arnold, GPU, "Three Mile Island Nuclear Station Unit 2-Startup Test Program History and Delay Analysis," January 23 and March 13, 1979.

[13B] Dieckamp dep. at 68.

[139] See text accompanying note 95 *supra.*

[140] See Public Citizens, Inc., "Death and Taxes," mimeograph released April 5, 1979, at 5.

[141] 26 U.S.C. Sec. 38, 46, and 48; and 167, respectively.

[142] Surrey, S. S. et al., *Federal Income Taxation* Vol. 1 (The Foundation Press, Mineola, N.Y., 1972), pp. 452-453.

[143] 26 U.S.C. Sec.167(a). Depreciation is also a method of returning capital to the investor.

[144] Most utility commissions take the position that "regulated utilities are expected to take advantage of all available tax deductions. A utility should utilize all available cost-saving opportunities ... in order to keep rates at a reasonable level." Philadelphia Electric Co., PaPUC R.I.D. 438 at 83.

[145] The accelerated methods are those other than the straight-line method. 26 U.S.C. Sec. 167(b).

[146] Some commissions also "pass through" the difference between book and tax accounts, as well. See D. S. Gillmore, "Three Issues in Utility Tax Allowance Determinations," *Public Utilities Fortnightly*, p. 13 (September I, 1977).

[147] 26 U.S.C. Sec. 46(f).

[148] 26 U.S.C. Sec. 46(c)(3).

[149] 26 U.S.C. Sec. 46(a)(7).

[150] 26 U.S.C. Sec. 46(a).

[151] 26 U.S.C. Sec. 46(c)(1)(A).

[152] 26 U.S.C. Sec. 167(a).

[153] 26 C.F.R. Sec.1.46-3(d)(1)(ii).

[154] 26 C.F.R. Sec. 1.167(a)-10(b). Cf. 26 U.S.C. Sec. 46.

[155] 26 C.F.R. Sec. 1.167(a)-11(e)(1)(i).

[156] Rev. Rul. 76-428,1976-2 *Cum. Bul. 47.*

[157] The nuclear unit discussed in Rev. Rul. 76-428 was not TMI-2.

[1]WThe factual data appears to indicate that the unit under review was the Trojan Nuclear Plant, owned by Portland General Electric Company and located in Columbia, Oregon.

[159] **See** 26 C.F.R. 1.46-3(d)(I)(ii).

[1 0] Rev. Rul. 76-428,1976-2 *Cum. But 48.*

[161] Rev. Rul. 79-98, Internal Revenue Bulletin, March 19, 1979. The plant had been constructed under a turnkey contract. It should be emphasized that Rev. Rul. 79-98 had not been issued at the time GPU was planning its taxes in 1978.

[162] IRS Letter Ruling 7833007 (Northern States Power Company).

[13] 26 U.S.C. Sec. 6110(j)(3).

[164] IRS Letter Rutind 7833007 at 1.

*51d. at 2.

*6 1d. at 2-3.

[167] Letter from G. S. Pettersen, NSP Controller, to C. D. Switzer, IRS, dated July 20, 1977.

[1]sIRS Letter Ruling 7833007 at 5.

[169] NSP argued in its protest of the ruling that synchronization is the crucial date because engineers would never risk either the grid or the generating plant if they "did not feel certain that the new facility was in fact in a condition of readiness to perform within the grid." Letter from NSP to A. L. Woodman, IRS, dated February 27.

[170] IRS Letter Ruling 7833007 (Northern States Power Company) at 5.

171!. at 4.

[172] The position of NSP in its protest is that the date of operation "is entirely irrelevant to the question of whether the plant is or is not in service for tax purposes. The tax in-service date is defined in the tax law, and the determination thereof is totally independent of [the commercial decision] .... The company has not asked IRS to consider the plant in service on the grounds of this internal responsibility transfer." Letter from NSP to District Director IRS Exam. Div. Review Staff dated May 19,1979 at 13.

-n3 Letter from J. Kurtz, IRS, to M. Rogovin, SIG, dated October 4, 1979 at 2. "mhe term 'commercial operation' is used by regulatory bodies and is not a tax term ... that ... term is more restrictive than that of the Standards used by the Service as expressed in the regulations and Revenue Rulings for property to be placed in service."

[174] Other than Rev. Rul. 79-98.

95 26 U.S.C. Sec.46.

[176] 26 U.S.C. Sec. 46(d).

77 Use of the qualified progress expenditures requires an election by the taxpayer. 26 U.S.C. Sec. 46(d)(6).

[178] 26 C.F.R. Sec. 1.46-(3)(d)(4)(1) allowed ITC "only for the first taxable year in which such property is placed in service by the taxpayer."

[179] HokCOmbe dep. at 23.

=See IRS Letter Ruling 7833007 (Northern States Power Company) at 3.

'("Letter from J. Kurtz, IRS, to M. Rogovin, SIG, dated October 4,1979.

[182] Dieckamp prepared testimony in PaPUC 8-79080606 (PaPUC) at 4.

[153] Letter from NSP to A. L. Woodman, IRS, dated February 27,1978, at 5.

[184] GPU, as are almost all regulated utilities, is a calendar year taxpayer.

[185] Hok ombe dep. at 8.

*6/d. at 19-20.

[187] Arnold dep. at 110.

[188] At this time Holcombe probably was unaware of IRS Letter Ruling 7833007 *(see* note 207 *infra* and text accompanying). it was also not possible for him to have seen Rev. Rul. 79-98, because it was published in 1979.

[189] *Compare* Holcombe dep. at. 8-12 (Arnold gives Rev. Rul. 76-428 but no memo) with Arnold dep. at 109-111. (Arnold, contacted by telephone, may have seen summary of Rev. Rul., was shown company memorandum as to whether TMI-2 met criteria.)

[19] oFblcombe dep. at 8.

"Again there is confusion as to whether Arnold's review was a matter which the Directors were interested in hearing or whether it was a discussion at "sidebar" between Arnold and Holcombe. Holcombe dep. at 10.

[192] 14. at 8-9.

[193] Rev. Rul. 76-428,1976-2 *Cum. Bul. 47.*

[194] Letter from R. S. Boyd, NRC, to J. Herbein, Met Ed dated April 7,1979.

[195] United Engineers and Constructors was replaced by Catalytic, Inc. See note 306 *infra* and text accompanying.

[196] Rev. Rul. 76-428,1976-2 *Cum. Bul. 47.*

[197] Final Safety Analysis Report (FSAR), Three Mile Island-Unit 2, Vol. 9, Sec. 14.1.3.2.

[198] Memoranda from R. C. Cutler, GPU, to R. C. Arnold, GPU, "Three Mile Island Nuclear Station Unit 2-Startup

Test Program History and Delay Analysis," January 23 and March 13, 1979. Some preoperational tests were, however, conducted after fuel load at TMI-2. Toole dep. at 28.

Final Safety Analysis Report (FSAR), "Three Mile Island-Unit 2," Vol. 9, Sec. 14.1.4.

[200]Memoranda from R. C. Cutler, GPU, to R. C. Arnold, GPU, January 23 and March 13, 1979.

[201]December 17 is the date of the GPUS Board Meeting. As is discussed below, doubts as to that conclusion might have been equally reasonable later in the month.

[202]There is some dispute as to exactly what tests GPU should have run as part of the power ascension test program. See text accompanying notes 341-357 *infra.* We have used GPU's own declaration date for simplicity.

[203]Rev. Rul. 76-428,1976-2 *Cum. But* 47, 48.

[204]Rev. Rul. 79-98, See discussion *supra.*

[205]IRS Letter Ruling 7833007, *supra.*

[206]It is interesting to speculate as to whether one of the tests postponed or deleted had decreased the possibility of finding a deficiency. But it would be disingenuous to suggest that the possibility of such a discovery and its impact on tax planning was the reason for the deletion.

[207]Mr. Daley reported to Mr. Holcombe. Holcombe dep. at 13.

[208]Memorandum from P. F. Daley and J. R. Thren, GPU, to V. H. Condon, et al., GPU, "Status of TMI No. 2 for Income Tax Purposes," December 28, 1978,

[209]The reference is to the main steam relief valve failure growing out of an April 23, 1978 transient. See note 378 *infra* and text accompanying.

[210]Memoranda from R. C. Cutler, GPU, to R. C. Arnold, GPU, "Three Mile Island Nuclear Station Unit 2-Startup Test Program History and Data Analysis," January 23 and March 13, 1979.

[211]Holcombe dep. at 15.

[212]Id. at 16-17.

[213]Id. at 17-18.

[214]Id. at 17, 20.

[215]*Id.* at 6.

[216]Id. at 7.

[217]GPU files a consolidated tax return for the corporation and all subsidiaries. GPU 1978 Annual Report at 24.

[218]Analysis prepared by GPU Comptroller E. Holcombe, GPU, (Holcombe dep., Exhibit 1110) at 3.

[219]26 U.S.C. Sec. 46(e).

[220]Analysis prepared by E. Holcombe, GPU, (Holcombe dep., Exhibit 1110) at 3.

[221]Id. The credits are discussed *supra.*

[222]Primarily, this reduction was due to the ITC and depreciation deductions discussed *supra.*

[223]GPU 1978 Annual Report at 16.

[224]26 C.F.R. 1.167(a)11(c)(2)(ii). The modified half-year convention states that if a unit is "placed in service" in the second half of a tax year, it is allowed depreciation for one-half of the year. As in the case of TMI-2, which was placed in service some time in the fall of 1978, this can amount to a significant difference.

[225]Analysis prepared by E. Holcombe, GPU, (Holcombe dep., Exhibit 1110) at 2.

[226]See Dieckamp dep. at 108 (Pres. Com.).

[227]See Public Citizens, Inc., "Death and Taxes," mimeograph released April 5, 1979, at 5.

[228]The only major construction ongoing at the start of 1979 was the Forked River Nuclear Unit. GPU does, however, generate a large portion of its funds (59%-GPU 1978 Annual Report at 10) from internal sources. A reduction in tax advantages (ITC carryback, 1/2-year convention) might have impacted upon the company's continuing ability to finance such a large portion from within. See Public Citizens, Inc., "Death and Taxes," mimeograph released April 5, 1979 at 6-7.

Presuming an interest rate of 10%, the calculation would be 0.10 x $29 million = $2.9 million.

[230]Dieckamp dep. at 71.

[231]"Pennsylvania-New Jersey-Maryland Interconnection, 1976" at 3.

[232]*Id.* at 5.

[233]See Article 4.1 of the Pennsylvania-New Jersey-Maryland Interconnection Agreement for a listing of members' responsibilities to coordinate planning and operation of bulk power facilities.

[234]Pennsylvania-New Jersey-Maryland Interconnection Agreement, Article 6.1.

[235]Id., Schedule 2.01(b).

[236]Id., Schedule 2.01(d).

[237]Pennsylvania-New Jersey-Maryland Interconnection Agreement Supplemental Agreement, Schedule 4.01.

[238]Letter (with attachments) from J. D. Gassert, GPU, to D. J. Evans, SIG, dated December 3, 1979.

[239]The rate effective June I, 1979 was $25.55 per kilowatt as shown in Schedule 4.01 of the PJM Agreement, Rev. no. 2, dated March 15, 1979. If TMI-2 was taken out of GPU's "installed capacity" a charge would be assessed on this rate since GPU would be under their forecast obligation. However, TMI-2 is currently considered as installed capacity but on 100% forced outage.

[240]PJM Agreement, Article 1.1(f).

[241]PJM Agreement, Schedule 2.211(b).

[242]Report of Touche, Ross & Co., October 1978, (Reward dep., Exhibit 1107) conclusions at 2.

[244]JMe 2M at A-I.

19,1 um from R.C. Arnold, GPU, to T.L. Carroll, Jr., July 1979.

[245]Letter from J. D. Gassed, GPUSC., to D. J. Evans, SIG, December 3,1979.

[246]Summary of interview with R. H. Simms, September 6, 1979.

[247]Summary of telephone conversation between D. J. Evans and J. D. Gassert, November 29,1979.

GPU 1978 Forecast, (Graham dep., Exhibit 1115) GPUPlanning Department.

Summary of telephone conversation between D. J. Evans and J. D. Gassert, November 29, 1979; see letter from J. D. Gassert, GPU, to D. J. Evans dated December 3,1979.

[250]Schultz prepared testimony before the Ohio PUC in 76-1174-EL-AIR.

[251]Forced outages for units in service less than 1 calendar year may not affect the capacity requirement of a PJM member. See PJM Agreement Schedule 2.212(e),

(f) and (g). This increases future forecast obligations. See PJM Schedule 2.21 (showing the formula for calculating a member's forecast obligation).

[252] Herbein dep. at 118.

253 Arnold dep. at 118.

[254] Dieckamp dep. at 104 (Pres. Com.).

255 Statistical information attached to letter from GPU Service Corp. to Standard & Poor's Corp., dated October 20, 1978.

[256] Met Ed form 10-K (SEC) for fiscal year ended December 31, 1978 at 3.

[257] *See* discussion *supra*, beginning with text accompanying note 8.

[258] Met Ed form 10-K (SEC) for fiscal year ended December 31, 1978 at 4.

[259] Graham dep. at 37.

[260] 1d. at 37-38.

[281] Letter from J. B. Liberman to L. Vandenberg, SIG, dated October 5, 1979.

[262] 1n *the Matter of Public Service Company of New Hampshire*, Seabrook Station Units 1 and 2, CU-78-1, 7 NRC 1, 14.

[263] *Moody's Bond Surveys*, January 9, May 29, and September 4, 1978.

[264] From AA to A.

[265] "Lower Bond Rating Troubles Lilco," *New York Times*, August 20, 1979.

266 Summary of telephone conversation between L. Vandenberg and B. Burke, Moody's, Inc., July 19, 1979.

[267] Summary of telephone conversation between L., Vandenberg and T. Fendrick, Standard & Poors, July 17, 1979.

268 Summary of telephone conversation between L. Vandenberg and P. Jadrosick, Moody's, Inc., July 17, 1979.

269 Graham dep. at 31.

2701d. at 37.

[271] GPU 1978 Annual Report at 2.

272 See Met Ed Annual Report 1978 at 20.

[273] Graham dep. at 21.

274 Arnold dep. at 113.

[275] See GPU 1978 Annual Report at 20.

[276] Dieckamp prepared testimony in PaPUC I-79040308 at 1.

[277] NRC Regulatory Guide 1.68 at I (footnote).

[278] NRC Regulatory Guide 1.68 at 3.

[279] NRC Regulatory Guide 1.68 at 3.

280 Standard Review Plan at 14.2-5(a) and (b), reprinted as Acceptance Criteria #10 in Revision 1, issued January 1979.

[281] NRC Regulatory Guide 1.68, Sec. C.5, at page 1.68-**4.**

282 Inspection and Enforcement Manual, Chap. 2514 at 2514-11 April 1, 1978.

[283] Kellogg dep. at 48-51.

284 Inspection and Enforcement Manual, Chap. 2514 at 2514-10, April 1, 1978.

[285] Final Safety Analysis Report (FSAR), Sec. 14.1.4.

286b., Sec. 14.1.4(d).

[287] Dieckamp dep. at 58.

[288] Final Safety Analysis Report (FSAR), Three Mile Island-Unit 2, Vol. 9, Fig. 14.1-1, "Test Program Schedule," (October 8, 1975).

[289] ki., Sec. 14.1.4(d).

[29] °GPU began planning for two nuclear units at TMI back in the mid-1960s as environmental factors made coal look less attractive. Summary of telephone conversation between D.J. Evans, SIG. and Conrad Six, PaPuc, July 11, 1979.

[2] 'The commercial operation date of TMI-2 was set as May 30, 1978 in Monthly Operating Reports filed with the NRC up to the May 1978 report (filed June 15, 1978), which set a September 1, 1978 date.

[292] TMI-2 Monthly Operating Report for November 1978 (filed December 15, 1978). *See also* Arnold dep. at 123.

[293] That occurred on April 23, 1978 when the main steam relief valves malfunctioned and, subsequently, GPU determined that these valves would need to be replaced. *See* note 378 *supra* and text accompanying.

[294] Kellogg dep. at 13.

295 See *also* Varga dep. (August 15, 1978) at 12. Nagle dep. at 41.

[296] 42 U.S.C. Sec. 2235. Inspection and Enforcement writes a letter to NRR, commonly called a 94-300 letter (after the applicable IE manual procedure module) stating that all *necessary* construction is complete and issuance of an OL is proper. NRR (and Atomic Safety and Licensing Boards) are required to find that the plant was constructed in conformance with its construction permit (CP). 10 C.F.R. Sec. 50.57(a)(1). Some additional "construction"-generally of a "finishing" nature-is conducted after the operating license (OL) is granted. *See* Inspection and Enforcement Manual, Chap. 2513 at 2513-3 (February 28, 1975.)

[297] Again, GPU apparently was not concerned with a December 31, 1978 date until November 1978. The OL was obtained on February 8, 1978. There may have been other incentives for an OL rush, such as the need for a May 31 commercial operation date for PJM Pool purposes. *See* note 231 *supra* and text accompanying. However, we did not examine that question.

298 Kellogg dep. at 11.

[299] IE Inspection Report 50-320/77-32.

[300] Kellogg dep. at 12.

"Id. at 10.

302 The test involved addition of lithium to the reactor. Under the test procedure, GPU should not have gone to a higher temperature until checking to see where the lithium had been distributed. However, the test engineer did not sample for the lithium until after exceeding the specified temperature. Kellogg dep. at 24.

3031E Inspection Report 50-320177-32.

[304] Kellogg dep. at 24.

[305] Kellogg dep. at 11.

[308] Nagle dep. at 10.

307 Catalytic did, however, assume responsibility for remaining construction. While UE&C test engineers remained at the site under a separate contract, the craft labor answered to Catalytic.

[306] Heward dep. at 14-15.

300 Nagle dep. at 12-13.

310 For example, Baltimore Gas & Electric reportedly used a similar procedure at its Calvert Cliffs station.

311 Kelbgg dep. at 34.

312 Nagle dep. at 12. UE&C was informed of the shift around August 1976. The change occurred in June 1977. See Heward dep. at 15.

313 Heward dep. at 16-17.

Kellogg dep. at 34.

Interviews with Catalytic, Inc. management.

316 Kellogg dep. at 34.

317 Nagle dep. at 14. Nagle estimated that TMI-2 was 90-95% complete. Heward dep. at 14.

318 Arnold dep. at 104.

319 Heward dep. at 15.

Kellogg dep. at 17. Mr. Kellogg said the list was "several thousand" diems contained in three, 3-inch volumes. By comparison, he said, "[i]t was a larger number than I had been previously exposed to at other programs of that type."

321 *Id.* at 18.

322 Report of Touche, Ross, and Co., October 1978, (Heward dep., Exhibit 1107) conclusions at 4.

323 See note 118 *Supra* and text accompanying

324 Nagle dep. at 21.

325 The issue was discussed in a TMI-2 prehearing conference on January 28, 1977. Transcript at 137. See discussion of "financial qualification" and recommended changes. Note 595 *infra* and text accompanying.

326 Babcock & Wilcox was the nuclear steam supply system (NSSS) vendor at TMI-2.

327 Spangler dep. at 36-37.

328 Spangler dep., Exhibit 1151.

329 GPU had predicted initial criticality on March 25, 1978. Monthly Operating Report for February 1978 (filed March 13, 1978). It would take approximately a month to load fuel and reach that point.

330 It could be argued that the advantage of having a large baseload unit producing cheap, nuclear baseload energy is sufficient incentive for all utilities to complete a unit as soon as possible.

331 *See e.g.,* discussion of PJM pool incentives, note 242 *supra* and text accompanying.

332 Internal GPU correspondence indicate that the commercial operation date was changed in March 1978 (before the April 23 transient). But that change was from May 31 to June 30,1978. Following the April 23 transient the date was further postponed in late June to October 31, 1978. Memorandum from R. C. Arnold to T. L. Carroll, March 29,1979 (July 19, 1979). Further postponements in the predicted commercial operation date are shown in GPU TMI-2 Monthly Operating Reports as follows: December 1, 1978 (October report); December 31, 1978 (November report). See *also* Arnold dep. at 123.

333 GPU would contend, in fact, that this thought did not occur until early December 1978. Arnold dep. at 123.

334 April 23, 1978 through December 30, 1978. This point seems to have been implicitly recognized by a number of people. *See e.g.,* former Pennsylvania Consumer Advocate Mark Widoff in ***The Washington*** *Star* "1978 Opening Saved Power Company Millions," of April 5, 1979.

335 And also transmitted to the New Jersey GPU.

336 See **note 26 *supra*** and accompanying text.

337 There is some suggestion that a combination of FERC and NRC requirements assist in making completion of power ascension tests a prerequisite to commercial operation. See text accompanying note 276.

338 IS Letter Ruling 7833007 so suggested. This information was available to top GPU officials in late December 1978. See text accompanying note 276.

339 Toole dep. at 17.

340 Meeting the May 31, 1978 PJM Pool date might have been difficult, as GPU apparently realized in postponing the inservice date in March to June 30, 1978. Memorandum from R.C. Arnold, GPU, to T.L Carroll, GPU, *supra.*

341 10 C.F.R. Sec. 50.34(b)(6)(iii).

342 See Regulatory Guides 1.68,1.70.

343 Babcock & Wilcox proposed tests are contained, for example, in Babcock & Wilcox "Standard Nuclear Steam System," B-SAR-205 at Vol. 3,14-i.

344 10 C.F.R. Sec. 50.34.

346 Summary of telephone conversation between D. Evans and J. Barton, GPU, November 26,1979.

Final Safety Analysis Report, "Three Mile Island Nuclear Station-Unit 2," Vol. 9, Chap. 14.

347 See discussion regarding this meeting, note 400 *infra* and text accompanying.

348 GPUS, Commercial Operation Review Board Report, October 26, 1978 (Reward dep., Exhibit 1109) at 4. Presumably, the reference to "Federal requirements" means the tests were not required by 10 C.F.R. Sec. 50.34.

349 Toole dep. at 29.

350 Id. at 29-30.

351 Heward dep. 20, 22-23. *But compare* Toole dep. at 30 (No review in September-December 1978 time period).

352 Heward dep. at 20.

353 Summary of telephone conversation between D. Evans, SIG, and J. Barton, December 4,1979.

354 Memoranda from R. C. Cutler, GPU, to R. C. Arnold, GPU, January 23 and March 13,1979, *supra.*

355 Arnold dep. at 123.

356 The schedule had already slipped 6 months overall at that point.

357 The test procedures in the FSAR were drafted as late as December 1975. TMI-1 went into commercial operation September 2,1974.

358 Final Safety Analysis Report, "Three Mile Island Nuclear Station-Unit 2," Vol. 9, at 14A-90,14.1-5.

359 See e.g., Jersey Central Power and Light, TP 800/21, "Power Escalation Test Sequence, Three Mile Island Nuclear Station Unit No. 2."

360 See e.g., Memorandum from T. Faulkner, GPU, to R. Toole, GPU, (TMI-H-6765) June 29,1978, at 4.

361 The "unit acceptance test" is apparently also known as the "initial warranty run." Reward dep. at 18-19; *Cf.* Spangler dep. at 16.

[382] Final Safety Analysis Report, "Three Mile Island Nuclear Station-Unit 2," Vol. 9, at 14A-90.

[363] Amold dep. at 120.

Summary of telephone conversation between D. Evans and J. Barton, December 4, 1979. Apparently it is common for NSSS vendors to include such acceptance tests in their supply contracts. *See e.g.,* contract between General Electric and Commonwealth Edison for Carroll County Units at VIII-3, VIII-5. The purpose of such a clause is to set a definitive date beyond which acceptance of the unit will be deemed to have occurred. The unit acceptance test is not required to be included in the FSAR by Regulatory Guide 1.68.

[365] Babcock & Wilcox "Standard Nuclear Steam System," B-SAR-205 at 14.1-8.1-8.

[366] Arnokf dep. at 120.

[367] B&W notified GPU in November 1978 that it considered TMI-2 to be ready for the unit acceptance test. By terms of the contract, GPU had 90 days to run the test, which it did in February, 1979. Summary of telephone conversation between D. Evans and J. Barton, December 4, 1979.

[368] GPUSC job description of TMI Project Manager. (Heward dep., Exhibit 1108) at 2.

[369] Heward dep. at 20.

370. at 18.

[371] Spangler dep. at 17.

[372] The test is for this reason sometimes known as the 100-hour warranty test, for it follows, in theory, 100 hours of full-power operation.

[373] Heward dep. at 19.

[374] There is some debate as to whether a utility must obtain NRC approval for a change in an FSAR. See 10 C.F.R. Sec. 50.59 (c).

[375] See note *41 supra* and text accompanying.

[370] GPU officials did, however, clear their decision to postpone the test with NRC Project Inspector Donald Haverkamp, who presented no objections. Summary of telephone conversation between D. Evans and J. Burton, December 4,1979.

[377] 100 hours of operation.

[378] Letter from E. 'Holcombe, GPU, to L. H. Drennan, Jr., FERC, dated August 18,1978. (Attachment).

379k1. at 2.

sO As William Spangler of B&W wrote in 1978 internal B&W paper: "... because of the dollar investment, reducing downtime during the test period is just as important to the operating utility as it is in follow-up operating years." (Spangler dep., Exhibit 1151) at 3.

June 27, 1978 letter from GPU Service Corp. Contracts Dept.

[382] See Holcombe letter from E. Holcombe, GPU, to L. H. Drennan, Jr., FERC, dated August 18,1978, *supra.*

Arnold stated that "We started fairly shortly after the incident to do the engineering and procurement activities necessary to change the valves." Arnold dep. at 133, 134,

Letter from E. Holcombe, GPU, to L. H. Drennan, Jr., FERC, dated August 18,1978.

Arnold dep. at 135.

[3] w/d. at 134.

[387] Letter from E. Holcombe, GPU, to L H. Drennan, Jr., FERC, dated August 18, 1978.

Memoranda from R. C. Cutler, GPU, to R. C. Arnold, GPU, January 23 and March 13, 1979.

[389] Haverkamp dep. at 94.

1d. at 94-95.

[391] Haverkamp dep. at 96.

[392] As discussed below, some utility commissions equate commercial operation with "used and useful" status. See notes 565 and 566 *infra* and text accompanying.

See note 22, *supra* and text accompanying. Another aspect of this risk has to do with the intracorporate relationships at GPU. Dieckamp said he was interested in assuring the operating companies (Met Ed, Penelec and JCPSL) that the unit the GPUSC startup team was turning over to them was truly ready for commercial operation. Dieckamp dep. at 115 (Pres. Corn.).

[394] Amold dep. at 78.

[395] Dieckamp said the concept of this formulation probably grew out of his past experience in the space program where such formal turnovers were common. Dieckamp dep. at 117-118 (Pres. Corn.).

John Bachofer was the principal GPUSC individual who drafted the procedures.

[397] GPU Service Corporation Manual at 301-305, included in "Determination of Technical and Organizational Readiness for Placing Three Mile Island Unit 2 into Commercial Operation," October 26, 1978 (Herbein dep., GTF Exhibit 13).

[3] ftieckamp dep. at 116 (Pres. Corn.). Actually, a draft of the GPUSC procedure was used.

[398] GPU Service Corporation Manual, Sec. 3.2 (included in Herbein dep., GTF Exhibit 13).

[400] GPUS, Commercial Operation Review Board Report, October 26,1978 (Reward dep., Exhibit 1109) at 1.

[401] This material is contained in "Determination of Technical and Organizational Readiness for Placing Three Mile Island Unit II into Commercial Operation," October 26,1978 (Herbein dep., GTF Exhibit 13.)

[402] GPUS, Commercial Operation Review Board Report, October 26, 1978 (Heward dep., Exhibit 1109), Sec. 1.2 at 1.

°03 Amold dep. at 95.

[404] GPUS, Commercial Operation Review Board Report, October 26, 1978 (Reward dep., Exhibit 1109), Sec. 2.0 at 1.

[406] Among the outstanding items were "Test Completion" and "NSSS vs. Turbine Generator Capability." GPUS, Commercial Operation Review Board Report, October 26, 1978 (Heward dep., Exhibit 1109), Sec. 5.0 at 6.

[406] *1d.* at 4.

[407] There is some confusion as to how members of the CORB could sign off on the conclusion stated above when such an important item as the test program had not been completed. Apparently, the signatures do not certify the plant as being ready for commercial operation at the moment of signing by the CORB members (December 18 to December 26, 1978). That required the report of the subcommittee on the open items. Rather, members were stating that, based on the information they had seen

at that point, "that they had no information at that time which was the basis for not proceeding to place the unit in commercial operation, once its test program had been completed." (Arnold dep. at 100; *See generally Id.* at 97-101).

See Arnold dep. at 100-101.

Mr. Miller participated, as specified in the GPUSC Procedure, because it was felt the station manager should have input into the readiness of the unit for commercial operation. Herbein dep. at 131. Mr. Miller did, in fact, contribute. GPUS, Commercial Operation Review Board Report, October 26, 1978 (Heward dep., Exhibit 1109) at 6.

[410] Arnold dep. at 103

[4]'Herbein dep. at 129.

[412] Memoranda from R. C. Cutler, GPU, to R. C. Arnold, GPU, January 23 and March 13, 1979, *supra.* GPU declared the power ascension test program complete with the successful running of the full-power generator trip test on December 28, 1978.

[413] GPUS, Commercial Operation Review Board Report, October 26, 1978 (Heward dep., Exhibit 1109), Supplement A (CORB Subcommittee Report) at 1.

[414] GPUS, Commercial Operation Review Board Report, October 26, 1978 (Heward dep., Exhibit 1109), Supplement A, (CORB Subcommittee Report) at 2. R. Arnold, W. H. Hirst and R. F. Wilson signed the CORB Subcommittee Report.

[415] Arnold dep. at 129-130.

[41O] Herbein dep. at 132.

[417] Dieckamp dep. at 117 (Pres. Com.).

[418] Arnold dep. at 74-75.

[419] See *Id.* at 102.

[42°] See text accompanying note 456 *infra* regarding Mr. Arnold's knowledge of the financial consequences of going into commercial operation in 1978.

[421] See discussion of incentives, *supra.*

[422] One of the reasons for the establishment of a CORB and the formalization of the commercial operation decisionmaking appears to have been the perceived need on the part of GPU to document the prudence of bringing the plant into commercial operation. See Arnold dep. at 80.

[423] Informal discussion with Met Ed or GPU employees. Because of the nature of these assertions, we have not identified the sources. See Heward dep. at 38.

[424] *See* note *43 supra* and text accompanying.

[425] Representations were made to the Pennsylvania PUC that the FSAR power ascension test program would be completed before TMI-2 was declared in commercial operation. See note *42 supra* and text accompanying.

[426] See IRS Letter Ruling 7833007, *supra.*

[427] See note 358 *supra* and text accompanying.

[428] Final Safety Analysis Report (FSAR), "Three Mile Island-Unit 2," Vol. 9, at Fig. 14.1-1

[4]~Herbein dep. at 133-134.

[4] Toole dep. at 5.

[431] Other test engineers assisted the 10 GPU employees involved in the test program. For example, there were 30 to 35 UE&C test engineers present under a separate contract from the construction agreement. Nagel dep. at 43-44, 49.

[432] 10 C.F.R. Sec. 55.3 et seq.

[433] Herbein dep. at 138.

[434] Haverkamp dep. at 101-102.

[435] Arnold dep. at 121.

[438] Haverkamp dep. at 102.

[437] Kellogg dep. at 11.

[438] Toole dep. at 14.

[439] GPU had a contract with B&W to provide startup services at TMI-2. Spanger dep. at 6.

[440] W. H. Spangler, "Startup Service and Training Activities During 1977", (prepared for internal B&W management meeting) (Spangler dep., Exhibit 1151) at 29 (Fig. 6).

"Apparently TMI-2 had just loaded fuel when this report was written. The other units compared were: Oconee 1 and 2, TMI-1, Arkansas Nuclear One-1, Oconee 3, Rancho Seco, Crystal River and Davis Besse 1.

[442] Memoranda from R. C. Cutler, GPU, to R. C. Arnold, GPU, January 23 and March 13,1977, *supra.*

[443] Without the unit acceptance test.

[444] Schultz prepared testimony before the Ohio PUC in 76-1174-EL-AIR at 11.

[445] While there is wide variety on this criterion, it would seem to be prudent management to complete the test program before exposing the shareholders to any risk, *Id.* at 11-12.

[44O] TMI-2 Monthly Operating Reports for March and December, 1978, respectively.

[447] Obviously we are not dealing with precise numbers here. Because each nuclear unit has its own problems, a comparison of schedules can never be a precise indicator of the "average" time.

[448] See *also* Haverkamp dep. at 93.

[449] "3 Mile Island Workers Talk of 'Rush Job,'" *Philadeiphia Inquirer,* April 16,1979.

[450] '

[451] For example, the article quoted a subordinate of Jack Herbein as hearing Herbein say, "A lot of times you have to take shortcuts to get back on line." Herbein does not recall making such a statement. Herbein dep. at 136-137.

[452] Richard Blakeman did, however, repeat his assertion in the article that tests on the snubbers in Unit 2 had been "passed with a magic pencil," a euphemism for "faking" the tests. Summary of telephone conversation between L. Vandenberg and R. Blakeman, Met Ed, September 18, 1979.

[453] Haverkamp dep. at 90.

[454] See e.g. Herbein dep. at 145.

[455] NRC did investigate allegations made during the construction of Unit 2 that improper welding had taken place. Eventually, the improper welds were discovered and corrected. See Narrow dep. at 18-21.

[45] See discussion of incentives *supra.*

[457] For example, utility management might simply desire to bring to a completion a long term project.

[458] See note 188 *supra* and text accompanying.

459 This was not unusual. As an officer of the Corporation, Arnold usually attended meetings. The meeting took place on December 17, 1978.

460 Holcombe dep. at 8.

461 Id. at 19.

462 Arnold dep. at 109.

463 Id. at 109, 110.

464 Holcombe dep. at 15.

465 See Dieckamp dep. at 52-54.

466 *See* note 189 *supra.*

467 Arnold dep. at 109.

468 Dieckamp dep. at 53.

469 As will be recalled, Rev. Rul. 76-428 permitted recognition of a unit which had shutdown "due to an abundance of hydroelectrically generated power" not "because of any defect in the system." See Rev. Rul. 79-98.

470 Arnold dep. at 109. As previously discussed, the steam valve failure was probably the type of deficiency that would cause the IRS to conclude that the unit had not "operated without failure." *See* Rev. Rul. 79-98.

471 Arnold dep. at 86-90.

472 The company's memorandum, it will be recalled, was a copy of FSAR, chapter 14. See note *37 supra* and text accompanying.

473 Despite the existence of the CORB, Arnold has acknowledged that he had the final responsibility for TMI-2 going into commercial operation. Arnold dep. at 101-102.

474 Id. at 122.

475 Herbein dep. at 119.

476 Learned through informal discussions with past Met Ed-GPU employees. It should be noted, however, that the specificity of knowledge drops off at lower levels. Further, some employees insist they did not know of any financial incentives associated with a 1978 deadline. See e.g., Heward dep. at 4.

477 The architect-engineer.

478 Cobean dep. at 157-159 (Pres. Com.).

479 Interview with Catalytic, Inc., September 13, 1979.

480 Cobean dep. at 157 (Pres. Com.).

481 Arnold dep. at 112.

482 Id. Declaring a unit complete at something less than 100% power was provided for in the commercial operation procedures.

483 Dieckamp dep. at 59.

484 See e.g., Herbein dep. at 135.

485 Arnold dep. at 112.

486 *Id.* at 113.

487 Dieckamp dep. at 60.

488 *See Philadelphia Electric versus Westinghouse Electric Corp.,* 1964-Trade Cases, para. 71,123 (E.D. PA. 1964).

489 See Arnold dep. at 113.

490 Arnold dep. at 113.

491 This intermingling of business and operating concerns is not unique to GPU. Rather, it is common in the utility business that top operations personnel are involved in rate proceedings and consult with management on finance-related questions. Our recognition of this "nexus" does not indicate fault, it is simply a recognition of reality.

492 Arnold dep. at 137.

493 We have postulated that this was the motivating force but, as noted previously, there are alternate explanations. See note 352 *supra* and text accompanying.

494 As Norman Mosley of IE said: "... these motivations to hurry are already there, with, or without [concern with the date of commercial operation]." Mosely dep. at 215.

495 *Id* at 214.

496 See note *6 supra* and text accompanying.

497 See text accompanying note 8, *supra.*

498 See text accompanying note 290, *supra.*

499 *See* text accompanying note 535, *infra.*

500 The "cause" of the TMI-2 March 28, 1979 accident has been addressed by several reports, which should be consulted for a complete analysis. "Investigation into the March 28, 1979 Three Mile Island Accident" by Office of Inspection and Enforcement, Investigative Report 50-320/79-10 (NUREG-0600); "Report of the President's Commission on the Accident at Three Mile Island," October 31, 1979. *See also* other sections of this Special Inquiry Group report.

501 *Compare* Public Citizens, Inc., "Death and Taxes," mimeograph released April 5, 1979 at 3: "...the haunting question remains: Could the March 28, 1979 accident have been prevented by a rational utility tax system and nuclear regulatory structure."

502 42 U.S.C. Sec. 2133(d).

503 10 C.F.R. Sec. 50.40(a).

504 10 C.F.R. Sec. 50.40(c).

505 Obviously to determine what would be "inimical to ... health and safety," the commission must understand what is "safe."

506 See discussion in this SIG report dealing with the regulatory system.

507 10 C.F.R. Sec. 50.100.

508 There is a range of IE action which can be taken in such instances. See Inspection and Enforcement Manual, Chap. 0800.

509 There is such authority under 10 C.F.R. Sec. 50.100.

510 *In the matter of Maine Yankee Atomic Power Company* (Maine Yankee Atomic Power Station), ALAB-161, 6 AEC 1003, 1009 (1973).

511 Construction permit, CPPR-66, issued November 4, 1969.

512 Memorandum from H. Thornburg to S. Boyd, January 27, 1978.

513 See note 296 *supra* and text accompanying.

514 In *the Matter of Metropolitan Edison Company, et* al., (Three Mile Island Nuclear Station, Unit No. 2), LBP-77-70, 6 NRC 1185 (1977).

515 NRC Facility Operating License No. DPR-73 (TMI-2), Feburary 8, 1979.

516 Eisenhut dep. at 32 (Pres. Com.).

5'In total, some 40 IE inspectors were involved in TMI-2 inspections in 1978. (List prepared by Bruce Grier, IE Region 1 Director, August 16,1979.)

5* The testing program was subjected to some scrutiny. See IE Inspection Reports 78-32, 78-39, See also Toole dep. at 32.

5*IE inspectors observed a number of major startup tests. Haverkamp dep. at 88-89.

S2ONRC, Amendment No. 6 to DPR-73 (August 17, 1978). In fact, the NRC Staff's Safety Evaluation Report found the replacement valves to be more effective. Safety Evaluation Report at 7-8.

5 10 C.F.R. Sec. 50.91; See 10 C.F.R. Sec. 50.40(a).

522 NRC, Amendment No. 1, License No. DPR-73. (March 3, 1978). The amendment allowed hydrostatic testing before criticality, "(1) in the interest of minimizing delays... " Safety Evaluation Report at 1. Cf. Varga dep. (August 15, 1979) at 21-23.

523 NRC, "Notice of Granting of Relief from ASME Section XI Inservice Inspection (Testing) Requirements" (April 21,1978).

524 See 10 C.F.R. Sec. 50.55a(g)(6)(i).

525 10 C.F.R. Sec. 50.55a(g)(6)(i).

S26See e.g., letter from R. S. Boyd, to J. G. Herbein, dated March 10, 1978, authorizing proceeding to mode 4 (hot shutdown). *See also* letter from J. Sniezek to D. Vassallo, dated March 24, 1978, stating that the OL conditions necessary before' mode 2 authorization "have been resolved to the satisfaction of E."

527 *Washington Star* ("1978 Opening Saved Power Company Millions") April 5, 1979, stated that "four events at reactor No. 2 that could be labeled as 'reportable' took place between December 13 and December 26, 1978 that were reported in 1979." However, LER nos. 78-72, 78-73, 78-74 were reported in accordance with the 30-day reporting rule since they were not of immediate concern. There is no reason for believing that the NRC would have taken some action against Met Ed before the end of 1978 had it known of these events.

528 Varga dep. (August 15,1979) at 12.

See discussion elsewhere in this SIG report regarding the regulatory system. See also Haas dep. at 91, 98-100 (quality assurance review of applicant's proposed startup test program).

53°Afthough it might decrease this possibility, even a resident inspector program will not eliminate such action.

53tThe penalties for failing to report a reportable event, per the technical specifications, is potential loss of the license or lesser fines. 10 C.F.R. Sec. 50.71; 10 C.F.R. Sec. 50.100.

532 See NRC "Reactor Safety Study-An Assessment of Accident Risks in U.S. Commercial Nuclear Power Plants," WASH-1400 (NUREG-75/014), October 1975.

S33PUblic Citizen Inc., "Death and Taxes," mimeograph released April 5, 1979 at 1-3.

534For example, if a licensee applied state-of-the-art technology and installed approved equipment in a unit which ultimately caused an accident, did the licensee build and operate the unit "unsafely?"

535 "Artificial" deadlines, by our definition, are those established for nontechnical reasons, including such matters as tax years, test years and so forth.

53642 U.S.C. Sec. 103(d).

537 Summary of telephone conversation with SIG Consultant Allen Schultz.

S38See text accompanying note 164, *supra.*

Johnson testimony before the Ohio PUC in 76-1174-El-AIR.

5401d. at XX-30.

541See "Operating Units Status Report," NUREG-0020, Vol. 3, no. 8, August 1979.

542 See note 127 *supra* and text accompanying.

5 The NRC Standards are not, however, regulations. Rather they exist in Regulatory Guide 1.68 "Initial Test Programs for Water-Cooled Nuclear Powerplants," and *Inspection and Enforcement Manual,* Chap. 2415.

5••Notice this is a negative standard, so that "ties go to the utility". Unless the NRC witness could conclusively state that the longer test period had no safety value, FERC should not disallow any AFUDC associated with the longer period.

545 See note 127, *supra* and text accompanying.

STTo perhaps state the obvious: given a determined rate of return on equity, the higher a utility's rate base, the larger the revenues allowed.

547 By contrast, public systems, such as the Tennessee Valley Authority (TVA), can afford to fund innovation. For example, TVA recently announced that it would require control room operators to have college degrees, even though the NRC has no such requirements. TVA can assume this added cost without fear of "goldplating" charges for two reasons. First, TVA is not regulated by local PUCs and, hence, there are no fore for such arguments. And, second, even if these arguments were possible and succeeded, there are no "investors" (other than taxpayers) who would be concerned- with absorbing the added costs through methods other than rates.

54Bln *re: Investigation of Outage of January-February 1976 at Vermont Yankee,* Vermont Public Service Board, Docket no. 4115 (October 13,1976).

See note 22 *supra* and text accompanying.

550 However, it should be recognized that the management decision "follows the engineering" conclusion that the plant is capable of operation. Schultz testimony before the Ohio PUC in 76-1174-EL-AIR at XVII-157.

551 Schultz testimony before the Ohio PUC in 76-1174-EL-AIR at XVII-157.

552 For example, as with TMI-2, it may relieve a construction manager of responsibility and put the utility in full control.

553 See text accompanying note *37 supra.*

554 Actuaily, Toledo Edison sought rate recognition at a point earlier than "commercial operation." The PUC agreed and allowed rate inclusion when the unit had been synchronized with the grid. In arguing against that before the PUC, the Ohio Office of the Consumer Advocate helped develop the record as to the significance of "commercial operation." Ultimately, the Ohio Supreme Court overturned the PUC decision. *Consumers' Counsel vs. Pub. Util. Comm.* (1979) 58 Ohio St. 2d., no. 78-1238, (slip opinion) (June 27, 1979). Although the Ohio Court did not say "commercial operation" was the proper point for finding a unit to be "used and useful," it did rule that synchronization was too early. Slip opinion at 5.

MJohnson testimony before the Ohio PUC in 76-1174-E1-AIR.

[556] 10 C.F.R. Sec. 50.55a(g)(4ci), 10 C.F.R. Sec. 50.55a(g)(4)(iii), 10 C.F.R. Sec. 50.55a(g)(4)(b), 10 C.F.R. Sec. 50.55a(g)(5)(iv),10 C.F.R., Part 50, Appendix J.

[557] 10 C.F.R. Sec. 50.55a(g).

Indeed, in light of the widespread use of the term "commercial operation" in the industry, perhaps the NRC was simply trying to state a time in understandable terms.

NRC Regulatory Guide 1.16, "Instructions for Completing Operating Data Report," item 21, (August, 1975)

Regulatory Guides have no legal force. They are one method (the staff's view) of complying with regulations.

"is information is included in the operating unit reports, previously cited.

[582] Each NRC official stated that the NRC had no responsibility over a "declaration of commercial operation." Mosley dep. at 211; Davis dep. at 185; Kellogg dep. at 54; Narrow dep. at 34; Hanauer dep. at 152; Haverkamp dep. at 98; Eisenhut dep. at 33.

MSchultz prepared testimony before the Ohio PUC in 76-1174-EL-AIR, at 10.

Construction work in progress is a standard utility account under the FERC system. (It is to be contrasted with the plant in service account.), Balance Sheet Chart of Accounts, 107. When CWIP is allowed in rate base, it simply means that rate payers begin paying a rate of return on the plant under construction and do not wait until the PUC finds the plant "used and useful." 18 C.F.R. Part 101. New Jersey allows CWIP in rate base.

Graham dep. at 17-18.

See also "Memorandum of Law: Criteria for Determining When a Nuclear Facility is Used and Useful," Filing of PaOCA dated October 31, 1978 in R-78060626 (R.I.D. 626) at 1, citing transcript of August 30, 1978 proceeding at 4, 8. PaPUC AW equated "commercial service" and "used and useful."

[567] The term "used and useful" is from *Smythe v. Ames,* 169 US 466 (1897). Graham prepared testimony in FERC Docket no. ER 78-494.

[sea] "Memorandum of Law: Criteria for Determining When a Nuclear Facility is Used and Useful," Filing of PaOCA dated October 31, 1978 in R-78060626 (R.I.D. 626).

[5%] *Re Pennsylvania Water & Power Co.,* 82 PUR NS 193, 237 (1949 FPC), AS CITED IN PaOCA Memorandum of Law filed in PaPUC R-78060626.

[570] *Penn. Consol.* Stat., Chap. 13, Sec. 1307(a) (1966).

[571] See note 19 *supra* and text accompanying.

[572] Note that this timing question (when) is quite apart from the possibility of disallowance (how much) which has been previously discussed. See note 126 *supra* and text accompanying.

[573] Herbein dep. at 117.

[574] "Memorandum of Law: Criteria for Determining When a Nuclear Facility is Used and Useful," Filing of PaOCA dated October 31, 1978 in R-78060626 (R.LD. 626) at 3.

[575] *Schuylkill Valley Lines, Inc. v. PaPUC,* 165 Pa. Super. Ct. 393, 68 A.2d 448 (1949) as cited in I-79040308, brief of PaPUC staff, at 11.

[57]eAnother possibility is to disengage the connection between commercial operation and used and useful and allow PUCs to find a plant used and useful before commercial operation. This appears less likely after the Ohio Supreme Court decision regarding Davis Besse, previously discussed.

[577] The problem with this tactic, of course, is the danger of disallowance of AFUDC. See notes 103 and 104 *supra* and text accompanying.

[578] Tis was, in essence, the position of GPU with regard to TMI-2.

[579] See *also* testimony of A. J. Schultz before the Ohio PUC in 76-1174-EL-AIR at XVII-151.

°IRS Letter Ruling 7833007, *supra.*

Rev. Rul. 79-98.

[582] Informally, some technical people at the IRS have agreed to as much. See Dieckamp dep. at 110 (Pres. Com.).

See text accompanying notes 542-548, *supra.*

Offices of consumer advocates, a recent development, are charged with representing the (generally, retail) consumer, with the goal of reducing the final bill.

Meenan Oil Company, et al/ v. Philadelphia Electric Company, PaPUC R.I.D. 438 (December 28,1978).

[5ss] FERC Docket no. ER 78-409 (Philadelphia Electric Company.) The effect of this split in interpretation of the Salem plant is that investors look to see earnings from the common facility (per the FERC approach) but see none (because of the PaPUC ruling).

[587] For example, after the TMI accident, the PaPUC removed TMI-2 from the Pennsylvania rate base, while it remained in the wholesale rate base of the GPU companies, pending final decision on the FERC rate increases filed before the accident.

[8] Except, of course, that different classes of customers pay on different methods of evaluating a plant's worth.

Graham dep. at 44.

See text accompanying notes 578 and 579 *supra.*

The same proposition was, ironically, noted in the PECO Salem 1 decision (PaPUC R.I.D. 438).

[592] R.LD. 438 at 37.

[M] Although Congress did not establish the standards which have defined "place in service," it has made it clear that it does not want the benefits of ITC and accelerated depreciation to "flow-through" to the ratepayer. 26 U.S.C. Sec. 46(f)

[5] This is a matter of debate in public utility regulation.

[595] NRC has continued to do so even after these allegations of "rush to commercial operation" were first made See "1978 Opening Saved Power Company Millions," *The Washington Star,* April 5, 1979.

[596] 42 U.S.C. Sec. 2232(a).

[597] 10 C.F.R. 50.40b.

[598] Operating costs include decommissioning costs.

[599] SECY-79-299, NRC staff paper, "Generic Issue of Financial Qualifications: Licensing of Production and Utilization Facilities, April 27, 1979.

[80°] *Id.* at 12.

See note 562 *supra.*

e02Kelkgg dep. at 55.

eo31n the *Matter of Public Service Company of New Hampshire, et al.* (Seabrook Station Units 1 and 2, CLI-78-1, 7 NRC at 1, 17 (1978).

old., 7 NRC at 20.

This apparently suggests that there is some "threshold" level of financial stability, above which an applicant can be assumed to be "financially qualified." Thus, the "standard" by which to measure this threshold level was a major issue in the Seabrook case. 7 NRC at 17. However, the standard used to measure financial qualification is not as important as the length and depth of the financial review itself.

em*In the Matter of Public Service Company of New Hampshire, et al.,* (Seabrook Station, Units 1 and 2), ALAB-422, 6 NRC 33, 108 (Dissenting Opinion of Mr. Farrar)

A07As proposed in NRC Staff Paper, SECY-79-299, April 27,1979. See note 599 *supra* and text accompanying

s08An article appearing in *Nucleonics Week* suggested that the commission was favorably disposed toward SECY-79-299 but was awaiting the report of this Special Inquiry Group before taking final action. Nucleonics *Week,* Vol. 20, no. 34 (August 23,1979).

Which appears to be the current practice. See note 598 *supra* and text accompanying. Recently, NRR has also focused on the financial qualification of GPU to operate TMI-1, *See e.g.,* letters from F. D. Hafer, GPUSC., to Richard H. Vollmer, NRC. (October 17 and 19, 1979), transmitting financial information.

810Presumably this system would draw on information obtained from the financial analysis office at NRR, previousy discussed.

"See "Revised inspection Program for Nuclear Power Plants," NUREG 0397, NUREG 0425.

m2See e.g., Narrow dep. at 34.

813See note *43 supra* and text accompanying. However, we propose such a requirement below.

The corporate pressures are (1) not to impose a risk on shareholders by declaring commercial too early and (2) not to shift the risk of an incomplete plant to an operating utility. See note *24 supra* and text accompanying.

The most recent IRS Letter Ruling (7833007) suggests completion of the tests is a prerequisite to a finding that the plant is "place in service" in that tax year.

"For example, the PaPUC inquiries into the meaning of commercial operation produced from GPU a voluntary linking of the test program and that declaration.

617Haverkamp dep. at 89-90.

Such a careful power escalation would be required if the last test performed involved a reactor trip. This was the case at TMI-2 when the final test run in 1978 was the full-power generator trip test.

••iThe NRC cannot and would not require commercial operation.

e2° For example, no worker should work excessive overtime.

e2nSee text accompanying note 391, *supra.*

e22 Haver tramp dep. at 94-98.

823A listing of startup tests in the FSAR is required by 10 C.F.R. Sec. 50.34(b)(6)(iii). The Staff has promulgated NRC Regulatory Guide 1.68, "Initial Test Programs for Water-Cooled Nuclear Powerplants," and NRC Regulatory Guide 1.70, "Standard Format and Content of Safety Analysis Reports for Nuclear Powerplants,"to assist licensees in drafting chapter 14 (initial test program) of the FSAR.

8247, question presented is whether a licensee can delete tests listed in the FSAR without NRC approval; and even if such deletion is permissible under 10 C.F.R. 50.59, whether the NRC is informed after the fact.

62sSee text accompanying note 535, *supra.*

626The "good business" is both a matter of rewards and punishment. A "reward" for safety might be improved operating efficiency. The "penalty," of course, is that no utility wants the expense of a nuclear accident. See NRC Staff Paper, SECY-79-299, April 27,1979, at 4.

827 would there not be a Coal Regulatory Commission and a Hydroelectric Safety Commission?

628See note 139 *supra* and text accompanying.

829For a full discussion of "future test years" see note 85 *supra* and text accompanying.

830See note *94 supra* and text accompanying. Failing outside the test year would have created a potential argument as to the propriety of including TMI-2 in rate base.

"For example, if TMI-2 had not gone into commercial operation at all, although projected to do so in the June 1979 to June 1980 test year, the PaPUC could have ordered refunds to ratepayers for the amount collected. *Penn. Consol. Stat.* Chap. 13, Sec. 1312 (1966).

e32 PUC of the State of California, Resolution no. M-4706 at 3 (June 5, 1979).

The construction life of a nuclear unit spans a number of years which may be prolonged by deferrals or unanticipated events.

834See notes 102-129 *supra* and text accompanying.

See Northern States Power v. *State of Minnesota,* 405 U.S. 1035 (1972).

838tt will be recalled that such a stipulation was agreed to in the New Jersey Met Ed proceeding. See note 52 *supra* and text accompanying.

837For example, the NRC might have provided useful information as to the lengths of the shutdowns of five reactors in early 1979 for seismic code concerns, so that PUCs could assess the cost of replacement power.

6MSee note 587 *supra* and text accompanying.

MSee note 543 *supra* and text accompanying.

64OCurrenty, use of this device is elective.

64'26 U.S.C. Sec. 46(c)(1)(A), 167.

642IRS Letter Ruling 7833007.

e43See Library of Congress, Congressional Research Service, "Nuclear Power: The Three Mile Island Accident and Its Investigation," Issue Brief #IB79035 at Crs-6; *Nucleonics Week,* August 16,1979 at 12.

"Even state PUCs have recently been subject to suggestions" on how goal of enemy conform their regulation to Public Utilities Regulatory Policy Act of 1978, Pub. L. No. 95-617, 92 Stat. 3117. The national goal of nuclear safety would seem deserving of similar attention.

APPENDIX 1.1

THE STATUTORY ORIGIN OF THE NRC's ORGANIZATIONAL STRUCTURE

The U.S. Nuclear Regulatory Commission was created by the Energy Reorganization Act of 1974, Public Law 93-438.[1] Its organizational structure was the result of a compromise in conference of distinctly different approaches in the House and Senate bills.

The House bill, H.R. 11510,[2] provided for a Nuclear Energy Commission as a renamed Atomic Energy Commission.[3] It redesignated the Director of Regulation as the "Executive Director for Operations."[4] Otherwise, the renamed Commission would have continued to perform the licensing and related regulatory functions which the AEC, its Chairman, members, officers and components performed prior to the effective date of the Act.[5] The House bill did not change the existing organizational structure. The report gives no indication that the duties of the Executive Director for Operations would differ from the duties of the Director of Regulation.

The Senate bill, S. 2744, as introduced,[6] retained the AEC regulatory organization in which a single Director of Regulation supervised and reported to the Commission on all licensing and other regulatory activities. As reported, S. 2744 provided "for three coequal Directors, each with direct and independent access to the Commission, and each responsible for separate operations relating to nuclear reactor safety, nuclear materials security, and nuclear safety research."[7] As reported, S. 2744 established the Nuclear Safety and Licensing Commission which was "based upon the Regulatory Division of the AEC" but with "a revised internal organization to promote well-balanced and closely supervised regulation of the burgeoning nuclear power industry."[8] The mission of the new Commission was "to ensure the safety and the security of the nuclear industry and the weapons-grade and other radioactive materials used to fuel it."[8] The committee's intention was to "upgrade the role of the Commission in its exercise of exclusively regulatory responsibilities by insuring fullest possible access to all available information within the organization on the safety and security of the nuclear power industry."[9]

The report on S. 2744 offered the following comment about the new regulatory organization which "has been designed by the committee to help [the Nuclear Safety and Licensing Commission] effectively perform its function in all categories":10

> As reported by the committee, NSLC will have a bipartisan, technically qualified Commission, which will directly supervise a balanced three-part regulatory organization. The high-level position of Direcfor of Regulation is eliminated, thereby allowing the heads of the three key programs-safety, safeguards and research-direct access to the Commission and a freer interplay of regulatory proposals and priorities at the Commission level than is now possible in the present system.
>
> Each Director is appointed by and serves at the pleasure of the Commission.
>
> It is the intent of the committee that an Office of Administration which now assists ... the Director of Regulation, would be attached to the Chairman of the Commission.
>
> The committee intends that the Chairman of the NSLC will see to the faithful execution of the Commission's policies and decisions and will coordinate and supervise the tripartite regulatory organization accordingly.
>
> [T]he original bill ... would have simply renamed the AEC the Nuclear Energy Commission, and retained the Regulatory Division intact, without modification. This would have perpetuated the present system in which a Director of Regulation supervises three directorates-for regulations, licensing and inspection-thereby exercising nearly all the regulatory functions of the Commission. This system has its purpose in the present AEC, where the Commissioners exercise developmental responsibilities of a magnitude in terms of dollars, manpower and physical resources that outweigh the regulatory operations and facilities many times over. Therefore, the Director of Regulation is needed to supervise the day-to-day regulatory responsibilities, while the Commission devotes the time needed to develop new industrial technology that is one of the modern wonders of engineering.
>
> With only licensing and related regulatory responsibilities, the new Commissioners will now be in a position to devote full time to the activities which are presently supervised by the Director of Regulation r

There was no Executive Director for Operations in S. 2744 as reported. Instead, the committee upgraded the Director of Regulation from a level V to a level IV on the Executive Schedule and changed his title to "Director of Nuclear Reactor Safety." In this way, according to the report:

> [T]he former top regulatory position is assigned to the Commission's largest and most challenging line responsibility: licensing and otherwise ensuring the safe operation of nuclear power reactors. This includes two of the key areas in nuclear power: the performance of the Emergency Core Cooling System (ECCS) in the current generation of Light Water Reactors (LWR) and the development of the next generation of reactor, the Liquid Metal Fast Breeder (LMFBR)1[2]

The committee stated its intent that the Director of Nuclear Reactor Safety:

> [W]ill continue to supervise the existing directorates of regulations, licensing and enforcement as they pertain to the safety of nuclear powerplants and other facilities in the licensed industry. As such, he will remain the chief officer beneath the Commission responsible for safety. The other two Directors will be the chief officers on behalf of the Commission for safeguards and research respectively. [13]

The committee established "a separate, coequal safeguards Bureau to draw together and coordinate all safeguards personnel who are now combined with ... [other personnel] and scattered among the existing three regulatory directorates." [12]

The revised organization, in the committee s words, was:

> [I]ntended to give balance to the new Commission so that no one regulatory area is stressed to the detriment of another. The Commission is in a position to weigh priorities and make decisions accordingly. In particular, safety and safeguards are given equal recognition within the organization. This is an expression of the Committee's judgment that they are of equal importance in terms of public health and safety and of the future of the nuclear power industry. [14]

The committee noted that the continued existence of the Atomic Safety and Licensing Appeal Panel "will ensure that the Commission will be able to oversee the licensing and rulemaking workload while carrying out its principal administrative and coordinating functions essential to the nation's health, safety, security, and energy supply "15

Presumably, the overall management of the Commission would be the responsibility of the Chairman who "shall see to the faithful execution of the policies and decisions of the Commission, and shall report thereon to the Commission from time to time or as the Commission may direct." [16] However, the committee did not explain what the dimensions of the Chairman's authority were; how, other than with the assistance of an "Office of Administration,"[10] the Chairman would be expected to carry out this authority; or how the Chairman's authority related to that of the three coequal divisions, each under a Director having direct access to the Commission. The report does state that:

> It is contemplated that the Office of Administration, now attached to the Director of Regulation of the AEC, will be attached to the Chairman of the Commission-to assist in coordinating the duties of the three directors, consistent with the policies and directives of the Commission. [17]

H.R. 11510, as reported, was passed by the House on December 19, 1973, without pertinent amendment.[18] The Senate passed S. 2744, as amended, on Augkist 15, 1974, with an amendment by Senator PercY that added the following:

> (2) The Chairman of the Commission shall be the principal executive officer of the Commission and he shall exercise all of the executive and administrative functions of the Commission, including funstons of the Commission with respect to (A) the appointment and supervision of personnel employed under the Commission (other than personnel employed regularly and fulltime in the immediate offices of Commissioners other than the Chairman, and except as otherwise provided in this Act, (B) the distribution of business among personnel appointed and supervised by the Chairman and among administrative units of the Commission, and (C) the use and expenditure of funds.
>
> (3) In carrying out any of his functions under the provisions of this subsection the Chairman shall be governed by general policies of the Commission and by such regulatory decisions, findings, and determinations as the Commission may by law be authorized to make.[20]

The purpose of this amendment, in the words of its sponsor, was "to insure that the NSLC chairman has adequate power to perform his functions."20 The explanation of the amendment included the following remarks by Senator Percy:

> I recognize that the committee report addresses the problem. It states that it is the committee's understanding that the Chairman of the Commission will be responsible for implementing the Commission's policies. And the report states that an Office of Administration is to be attached to the Chairman of the Commission. But the language of the bill should be amended to provide explicitly for the clear assignment of primary administrative responsibility to the NSLC Chairman. Not to do so would be to risk the development of a chaotic organization subject to crippling conflict among three strong, coequal Bureau of Office Directors.
>
> If the Chairman of the Commission were weakened by the absence of strong administrative authority, if the other members of the Commission strongly contested the implied-but not explicit-power of the Chairman, the functioning of the Commission could be tragically impaired. I submit that the assignments of the Commission are of such gravity and such overwhelming significance to the safety of our population that we cannot afford even to risk the possibility that the Commission will be administratively impaired in carrying out its mission.
>
> Mr. President, this amendment has the strong support of the Office of Management and Budget and the Atomic Energy Commission. Because it assigns to the NSLC powers now held by nine other Federal Commissions, there should be no controversy about its acceptability.
>
> Mr. President, my last point is probably the most important because if this activity is to really succeed, it will succeed only because it has outstanding men and women involved in it.
>
> I really cannot imagine the Chairman assuming those responsibilities if he or she did not really have the authority to carry out the responsibilities that have been thrust upon him or her by the intent, purpose, letter, and spirit of the legislation before US.

The explanation also included these remarks by Senator Ribicoff, the bill's manager on the floor:

> The committee, in its report, states that the Chairman is provided this supervisory authority in section 201, which cites him as the one who 'in behalf of the Commission, shall see to the faithful execution of the policies and decisions of the Commission.' This same language is used in the Atomic Energy Act to describe the authority of the Chairman of the AEC, and it was incorporated into this bill to apply to the authority of the Chairman of the NSLC.
>
> At the same time, the committee has designed a new regulatory organization for the NSLC, which will require a more active role by the Commission than is presently the case in the AEC. The bill establishes three basic, coequal divisions-safety, safeguards and research--each under a Director having direct access to the Commission. The posilion of Director of Regulation, which now oversees regulatory operations while the Atomic Energy Commission directs most of its energies to developmental matters, is abolished under the bill. With nuclear developmental and promotional responsibilities transferred to ERDA, the new NSLC will devote full time to regulatory activities which are presently supervised by the AEC's Director of Regulation.
>
> The new regulatory organization is designed to permit a freer interplay of regulatory proposals and priorities at the Commission level than is now possible in the present system. Hopefully, crucial safety and safeguards issues, which are now sometimes buried or modified at lower bureaucratic levels, will be aired and resolved by the Commission itself.
>
> Obviously, the Commission will be playing a more active supervisory role in regulatory affairs than is now the case, and the committee intends that the Chairman will be instrumental in coordinating the activities of the three regulatory divisions accordingly.
>
> The committee report states, for example, that an Office of Administration which now assists the Director of Regulation, would be attached to the Chairman of the Commission.
>
> The Percy amendment goes beyond the general language of the Atomic Energy Act to specify that the Chairman of NSLC 'shall be the principal executive officer of the Commission, and he shall exercise all of the executive and administrative functions of the Commission.' This would include the supervision of, and distribution of business among, the three Directors and other executive-level personnel appointed by the Commission.
>
> This language, which is identical to that contained in nine other regulatory commission statutes,

will insure effective supervision of the NSLC organization by the Chairman on behalf of the Commission. The Percy amendment is consistent with the purpose and the more general language of the bill.22

H.R. 11510 then went to conference to resolve the differences between the House and Senate.23

The conference substitute deleted the provision for placement of executive and administrative functions in the Chairman.[24] The reason for this was the conferees' belief "that the duties and responsibilities of the Chairman and the members, and the administrative arrangements as provided in this Act, are fully adequate to effectuate its purpose."24

The conferees' substitute followed the Senate language with modifications in providing three "coequal administrative or operating units titled, respectively, the Office of Nuclear Reactor Regulation, the Office of Nuclear Material Safety and Safeguards, and the Office of Nuclear Regulatory Research .... "[25] According to the conferees, this arrangement "will provide ample flexibility in the Commission to devise the most effective administrative arrangements within its own organization and at the same time give due and proper emphasis to functions which are vital to the public health and safety and the safe and efficient operation of nuclear powerplants and other licensed facilities."[26]

The conferees substituted a section 209 which "follows the House language in providing for an Executive Director for Operations."[26] As the conference report explained:

> The Act does not specify his [the Executive Direcfor for Operations] functions, leaving that determination to the Commission's discretion and judgment. However, it is expected that the Executive Director for Operations will be the coordinating and directive agent below the Commission for the effective performance of the Commission's day-to-day operational and administrative activities. He will coordinate and direct in behalf of the Commission, the operating and administrative units.
>
> At the same time, the conference substitute provides that the head of each component provided in the conference substitute shall be able to communicate with and report directly to the Commission itself whenever he deems necessary to carry out his responsibilities. In this way, the conferees make it clear that the Executive Director for Operations will not be able to suppress or limit information needed for the Commission's discharge of its own collective responsibilities.[26]

The subject dealt with in section 209 was discussed in the Joint Conference Committee's session of October 3, 1974. The transcript of this session is reproduced in the "Legislative History of the Energy Reorganization Act of 1974", Vol. 2 (compiled by the now defunct Energy Research and Development Administration).[27] The following excerpt appears to explain the conferees' intent in section 209:

> Senator Percy: We might as well eliminate the Executive Director if they report directly everything. The purpose of that Executive Director is to screen out most of those things. Now, you are not going to have a good Executive Director if he sits in there, he's got a title, and he's got no authority whatsoever.
>
> But, you are going to have better Commissioners if they know they've got the power to go directly, and you are going to find the Executive Director more responsive if he knows they can do it directly if they can't do it through him.
>
> Representative Holifield: I think the Senator's logic is irrefutable, and that is my concept of this. I want that kind of concept.
>
> Representative Fuqua: Mr. Chairman, I don't think what Senator Percy has in mind, I don't think that language does that.
>
> Senator Percy: That's why it's important to leave when they deem it necessary; that's the reason for it?s

The Aftermath

On June 17, 1975, Senator Baker offered an amendment to the Nuclear Regulatory Commission's authorization bill for fiscal year 1976, S. 1716, to ensure that the Chairman of the NRC has adequate power to perform his functions.[29] The amendment was adopted and was subsequently enacted in Public Law 94-79.[30] In essence, this amendment restored to section 201 of the Energy Reorganization Act, the "principal executive officer of the Commission," language which had the previous year been deleted in conference-[31,32]

Senator Baker made the following remarks when he offered the amendment

> [T]he purpose of the amendment is to assure that the Chairman of the Nuclear Regulatory Commission has adequate power to perform his functions. The statutory language in section 201 of the Energy Reorganization Act of 1974 pertaining to the chairmanship of the NRC is quite restrictive, at least when it is compared with the statutory language regarding the role of the Chairman of other independent agencies such as the CAB, FPC, ICC, FTC and SEC.
>
> , "
>
> In spite of a statutory mandated organizational structure which calls for leadership of the highest caliber to manage successfully, there is no statutory provision, either for the designation of a chief executive officer, or for the grant of authority to that officer. The obvious leader of the Nuclear Regulatory Commission, or any other independent regulatory agency, is its Chairman. A Chairman must

have the necessary statutory authority to carry out the executive and administrative functions needed to manage and lead the Commission.

This amendment is needed to provide explicitly for the clear assignment to the Chairman of the primary administrative responsibility for the implementation of NRC's policies. Not to do so would be to risk the development and growth of an organizational structure with weakened leadership. This would lead to crippling conflict among responsible officials which clearly would not serve the public interest. If the Chairmanship of the Commission were weakened by the lack of clear and explicit administrative authority, the functioning of the Commission could be significantly impaired.... [33]

In 1978, section 209 of the Energy Reorganization Act of 1974, as amended, was amended by adding the following sentence at the end of subsection (b):

Notwithstanding the preceding sentence, each such director shall keep the Executive Director fully and currently informed concerning the content of all such direct communications with the Commission.[34]

This amendment was included in the report on S. 2584, the NRC's authorization bill for fiscal year 1979, by the Committee on Environment and Public Works, United States Senate. This report stated that, in addition to the Directors of three statutory offices who may report directly to the Commission, the NRC practice also allows the Directors of the other staff offices to report directly to the Commission "if the Director deems it necessary to carry out his responsibilities."~ The committee stated in its report that "it supports this policy, especially in the case of the statutory offices and the other two major line offices [Standards Development, and Inspection and Enforcement].^3s

Continuing on this subject, the committee stated in its report:

There appear to be problems with the ability of the Office of Executive Director for Operations to propery discharge its responsibilities. The committee is concerned that this situation may be caused by the provision in existing law which permits Office Directons to communicate directly with the Commission and leave the Executive Director uninformed of important matters.

The present Executive Director has reported that during the period from formation of NRC in 1975 until approximately April 1977 there was a strong tendency for the Office Directors and the Commissioners to deal directly with one another, even on routine matters. On May 13, 1977, the Commission issued a new manual for the Executive Director for Operations (EDO) which, in effect, provides that the Office Directors shall report to the EDO although they still have the right to communicate directly with the Commission when they consider it necessary in carrying out their responsibilities.[38]

On November 5, 1979, the person who has been Executive Director for Operations since the NRC was created on January 19, 1979, in stating his intendon to resign from that position, observed:

I recognize that there are many pressing demands that the Commission must meet in the coming months, and that some time will be required for the Commission to clearly define the relationships between the Commission, the Executive Director for Operations, and the major program Office Directors-a step which I believe to be absolutely necessary before selecting my successor.

July 19,1977

MEMORANDUM FOR: James L. Kelley
Acting General Counsel

FROM: Stephen S. Ostrach
Attorney, OGC

SUBJECT: POWERS OF THE CHAIRMAN OF THE COMMISSION

SUMMARY:

The powers of the Chairman are virtually identical to those of the Chairman of other major regulatory agencies such as the FTC, FPC, CAB and SEC. The legislative history concerning the relationship between the Chairman and the Commission is not entirely clear but it shows that the Commission is primarily intended to function as a collegial body of which the Chairman is the **head**.

DISCUSSION:

As originally enacted by Congress in 1974, section 201 of the Energy Reorganization Act was carrigid over without change from section 21 of the' Atomic Energy Act of 1954. Section 21 had been quite carefully drawn to restrict the exercise of power by the Chairman of the AEC over the other Commissioners. During the hearings prior to enactment of the Atomic Energy Act in 1954 several of the sitting Commissioners testified before the Joint Committee on Atomic Energy that the then Chairman of the AEC, Admiral Lewis Strauss, was limiting their access to information and to the President and that the functioning of the Commission as a collegial body was being impaired.

In response to these complaints section 21 of the Atomic Energy Act specifically provided (and section 201(a)(1) of the Energy Reorganization Act still provides) that:

> Each member of the Commission, including the Chairman, shall have equal responsibility and authority in all decisions and actions of the Commission, shall have full access to all information relating to the performance of his duties or responsibilities, and shall have one vote.

This explicit commitment to the concept of the Commission as a collegial body acting only through the joint vote of a quorum was a direct legislative response to a perceived problem, has not been altered in the intervening years and is the essential backdrop against which the powers of the Chairman must be viewed.

The Chairman's role as "the official spokesman of the Commission" in its relations with Congress and others and his responsibility to "see to the faithful execution of the policies and decisions of the Commission" were given to his office by section 21 of the Atomic Energy Act and have been carried over intact in the text of section 201(a)(1) of the Energy Reorganization Act. All of the other powers of the Chairman are found in subsections (a)(2)-(a)(5) of section 201. These subsections were added to the ERA by ammendment in 1975. Pub. L. 94-79, Sec. 201. Those subsections provide:

> (2) The Chairman of the Commission shall be the principal executive officer of the Commission, and he shall exercise all of the executive and administrative functions of the Commission, including functions of the Commission with respect to (a) the appointment and supervision of personnel employed under the Commission (other than personnel employed regularly and full time in the immediate offices of Commissioners other than the Chairman, and except as otherwise provided in the Energy Reorganization Act of 1974). (b) the distribution of business among such personnel and among administrative units of the Commission, and (c) the use and expenditure of funds.
>
> (3) In carrying out any of his functions under the provisions of this section the Chairman shall be governed by general policies of the Commission and by such regulatory decisions, findings, and determinations as the Commission may by law be authorized to make.
>
> (4) The appointment by the Chairman of the heads of major administrative units under the Commission shall be subject to the approval of the Commission.
>
> (5) There are hereby reserved to the Commission its functions with respect to revising budget estimates and with respect to determining upon the distribution of appropriated funds according to major programs and purposes.

The subsections were added to the original ERA by a floor amendment to the NRC authorization bill for fiscal 1976. Senator Baker's comments in introducing the amendments offer the only significant legislative history. In part, Senator Baker said:

> [T]he purpose of the amendment is to assure that the Chairman of the Nuclear Regulatory Commission has adequate power to perform his functions. The [pre-existing] statutory language in section 201... is quite restrictive, at least when it is compared with the statutory language regarding the role of the chairman of other independent regulatory agencies such as the CAB, FPC, ICC, FTC and SEC.... mhe statutory position of the Chairman of the Nuclear Regulatory Commission is relatively weak in comparison with the arrangements in most other agencies.
>
> A Chairman must have the necessary statutory authority to carry out the executive and administrative functions needed to manage and lead the Commission.
>
> This amendment is needed to provide explicitly for the clear assignment to the Chairman of the primary administrative responsibility for the implementation of the NRC's policies. Not to do so would be to risk the development and growth of an organizational structure with weakened leadership. This would lead to a crippling conflict among responsible officials which clearly would not serve the public interest.
>
> Put quite simply the Chairman of the Commission must have the responsibility to carry out the responsibility that has been placed on the Nuclear Regulatory Commission under the Atomic Energy Act of 1954, the Energy Reorganization Act of 1974 and the National Environmental Policy Act. I repeat again that this amendment would give the Chairman of the Nuclear Regulatory Commission the authority which is now held by the long-established Federal regulatory agencies.
>
> I believe it [the amendment] brings the NRC into conformity with other practices....

Remarks of Senator Baker, S10829-30, Cong. Rec. Daily Ed. (June 17, 1975).

The language of the Baker amendment is virtually identical to Reorganization Plans Numbers 8, 9, 10, and 13 of 1950, U.S.C. App., which transfer certain functions of the FTC, FPC, SEC and CAB to their Chairmen, with the single exception of the phrase "principal executive officer" which is not found in those plans. It is also quite similar to Reorganization Plan Number 1 of 1969, 5 U.S.C. App., which transferred certain functions of the ICC to its Chairman. As Senator Baker said, the major purpose of his amendment was to make the Commission's formal administrative structure the same as that of other regulatory agencies.

The key provision of the Baker amendment is the one that makes the Chairman the "principal executive officer of the Commission" and directs him to "exercise all of the executive and administrative functions of the Commission." But this provision must be read along with subsection 201(a)(3) which provides that in carrying out his functions under section 201, the Chairman "shall be governed by general policies of the Commission and by such regulatory decisions, findings, and determinations as the Commission may by law be authorized to make." These provisions could be reconciled by creating a somewhat unrealistic dichotomy between "executive and administrative" functions which would be the responsibility of the Chairman and "policy" questions that would be for the entire Commission. Resolution of how to decide matters failing in the gray area between the polar extremes of purely administrative and pure policy issues has to be resolved by the Commission and the Chairman on a case-by-case basis.

Analyzing the specific language of the Baker amendment shows that it does give the Chairman considerable authority. In addition to being the principal executive officer of the Commission, he is given apparently sole authority to exercise *all* of the Commission's executive and administrative functions. Specifically, subject to the exceptions noted below, he can appoint and supervise all personnel under the Commission; he can distribute business among the personnel and offices of the Commission; and he can determine the use and expenditure of appropriated funds.

However, the Baker amendments do contain a number of explicit limitations on the Chairman's executive powers in addition to the implicit limitation created by the Commission's power to create policy pursuant to subsection (a)(3). First, the Chairman does not have the authority to supervise personnel working directly for another Commissioner. Second, the authority to revise budget estimates and to determine the distribution of appropriated funds among major programs and purposes is reserved to the Commission.

More importantly, the Chairman's power to make appointments of the "heads of the major administrative units under the Commission" is subject to the approval of the Commission. The quoted phrase is not defined either in the Baker amendment or in its scanty legislative history and is taken directly from the reorganization plans referred to above. It is generally agreed that the phrase includes more than the four "statutory" Commission offices which were explicitly referred to in the ERA (Executive Directors for Operations, Office of Nuclear Regulatory Research, Office of Nuclear Material Safety and Safeguards, Office of the Nuclear Reactor Regulation). Precisely how much more it includes is a question that has never arisen in view of the past policy of Chairman Anders and Rowden to consult with their fellow Commissioners on all arguably significant appointments as well as on all policy questions. It should also be noted that in the past it has been the practice of Commission officers to inform the Commission prior to making any appointment to a supergrade position and to obtain their approval prior to making any appointment to a position at the Office Director or any higher level.

To summarize, the Chairman clearly has considerable authority over the staff and responsibility for supervising it in the conduct of its duties. The extent to which this authority may or must be shared between the Chairman and the Commission is not clearly defined. Past practice by both Chairmen of the NRC has definitely been in the direction of offering maximum opportunity for the Commission to participate in deciding all significant matters.

REFERENCES AND NOTES

'Energy Reorganization Act of 1974, Pub. L. 93-438, 88 Stat. 1233 (1974).

[2]H.R.11510, 93rd Cong., 2d Sess.

[3]H.R. Rep. No. 93-707, 93rd Cong., 1st Sess.(December 7,1973).

[4]1d. at 38, 45, 58.

[5]/d. at 34.

[6]S. 2744, 93rd Cong., 2d Sess.

[7]S. Rep. No. 93-980, 93rd Gong., 2d Sess. at 9.

[8]1d. at 2.

[9]1d. at 75.

[t]*Old.* at 22.

[11]1d. at 22-23.

[12]*ld.* at 23.

[13]14. at 73.

[14]14. at 25.

[ɞ]*ld.* at 58.

[18]*1d.* at 22,104.

171d. at 55.

[18]119 Cong. Rec. H11755 (daily ed.).

[19]120 Cong. Rec. S15048, S15114 (daily ed.).

[20]*11.* at S15048.

[21]1d. at S15048-S15049.

[22]14. at S15049.

[23]120 Cong. Rec. S15114 (daily ed., August 15, 1974), and H9444 (daily ed., September 23, 1974).

[24]H.R. Rep. No. 93-1445, 93rd Cong., 2d Sess. 32 (October 8,1974).

[25]*14.* at 35-36.

[28]*14.* at 36.

[27]Energy Research and Development Administration, "Legislative History of the Energy Reorganization Act of 1974," Vol. 2, p. 1707 *et seq.,* transcript pp. 63-65, 76, and 79-85.

[28]*14.* at transcript pp. 84-85.

[29]121 Cong. Rec. S10829 (daily ed.).

[30]Pub. L. No. 94-79, 89 Stat. 413 (1975).

[31]See 121 Cong. Rec. S10829 (daily ed.).

[32]See H.R. Rep. No. 93-1445, 93rd Cong., 2d Sess. 32 (October 8, 1974).

[33]121 Cong Rec. S10829-S10830 (daily ed.).

[34]Pub. L. No. 95-601, 92 Stat. 2949 (November 6, 1978).

[35]S. Rep. No. 95-848, 95th Cong., 2d Sess. (May 15, 1978).

[38]14. at 21.

APPENDIX 1.2

AGREED-UPON DIVISION OF RESPONSIBILITY BETWEEN NRR AND IE WHERE THEIR FUNCTIONS INTERFACE

1. DESIGN REVIEW/INSPECTION INTERFACE

NRR is responsible for evaluating facility design and programmatic plans (QA program, security plan, emergency plan, preoperational and startup test programs), as described in the SAR and other documents for conformance with NRC requirements. IE is responsible for inspecting licensee facilities to verify implementation of the design and programmatic plans described in the SAR and other documents. IE will inform NRR of the results of such inspections. To enhance their understanding of the design commitments described in the SAR, NRR personnel may need to visit facilities sites. NRR will inform and/or invite IE to all site visits, thereby facilitating subsequent followup inspection activities by IE. IE will inform NRR on a timely basis of any SAR commitments IE believes are not inspectable or consistent with NRC criteria. NRR will inform IE of special emphasis that should be placed on verifying licensee implementation of SAR commitments.

IE needs current information on licensee commitments; therefore NRR will inform IE promptly of any approvals, agreements or proposed actions with licensees by copies of minutes of meetings or other correspondence regarding design, installation, or procedure which differ from SAR or other commitments.

2. COORDINATION FOR LICENSING ACTION

NRR has responsibility for all NRC licensing actions related to reactor facilities licensed under 10 CFR Part 50. IE has the responsibility for making certain findings with respect to licensee/applicant activities as pre-requisites for some licensing actions and therefore appropriate "hold points" in the licensing procedures are established so that licensing action will not proceed until appropriate findings have been made by IE. IE will keep NRR informed of progress made toward reaching the required findings and will conduct inspections as necessary to minimize any delays in licensing action.

3. COORDINATION FOR ENFORCEMENT ACTION

IE is responsible for effecting enforcement action upon detection of instances where the rules and regulations of the NRC have been violated. Significant enforcement action has a bearing on pending licensing action; therefore, IE will notify NRR of all proposed enforcement actions that involve movetary penalties or more severe sanctions.

4. QUALITY ASSURANCE

NRR has the responsibility for review and acceptance of quality assurance program descriptions presented in SARs or topical reports. IE has the responsibility for reviewing the associated implementing procedures to assure their acceptability with regard to carrying out the program description commitments and meeting NRC requirements.

In order to assure proper coordination on QA matters, IE and NRR agree to: (a) participate jointly in predocket conferences with new utility applicants; (b) coordinate prior to completing action on docketing of SARs, acceptance of QA topicals and preparations of SERs; (c) provide joint testimony to hearing boards when issues involving the adequacy of quality assurance programs are raised; (d) inform each other regarding matters having significant quality assurance implications; and (e) request comment on interfacing programs and activities.

5. TECHNICAL SPECIFICATIONS AND LICENSE CONDITIONS

NRR is responsible for developing and issuing licenses, including radiological-safety and environmental technical specifications (TS), for operating facilities and for review and approval of licensee amendments including TS changes. IE is responsible for enforcing compliance with the TS. All operating licenses are now being issued with standardized radiological-safety technical specifications (STS), which IE has reviewed and found to be inspectable and enforceable. NRR will provide IE the opportunity to review proposed TS which differ significantly from the STS to ascertain whether the specific TS requirements are inspectable and enforceable. IE will inform NRR of any TS items, in STS or non-standardized TS, requiring revision which are identified as not inspectable, enforceable, or that need NRR attention as the result of IE reviews or IE inspections. NRR agrees to inform IE regarding the disposition of all such items identified.

6. 10 CFR 50.59 DETERMINATIONS

IE is responsible for reviewing changes to the facility and to procedures that were made and documented in accordance with 10 CFR 50.59 requiremarts. IE is also responsible for forwarding to NRR, information detected during inspections relating to changes made to the facility or the procedures which may involve an unreviewed safety question as defined by 10 CFR 50.59. NRR will provide timely feedback to IE indicating whether or not the issues identified . by IE constitute an unreviewed safety question and for this reasons, or otherwise, require NRR review.

NRR is responsible for review and approval of licensee-requested license amendments or technical specification changes relating to changes to the facility which require prior review and approval by NRC. The NRR approved changes will serve as the basis for any IE inspection of the change or modification.

IE is responsible for inspecting the approved change/modification to verify that it has been performed and tested in accordance with commitments, the requirements of the amendments and related safety evaluations. IE will verify that appropriate operating procedures have been prepared and that the new or modified system has been completed and is ready for initial operation.

7. 10 CFR 50.54(p) DETERMINATION

IE is responsible for reviewing changes to the facilities' security plan that were made by the licensee and considered not to decrease the effectiveness of the security plan and documented in accordance with 10 CFR 50.54(p) requirements. If IE disagrees with or questions the validity of the licensee's conclusions that effectiveness is not decreased, IE will refer the matter to NRR for resolution. IE is also responsible for forwarding to NRR information detected during inspections relating to changes made to the facilities' physical protection systems, security plans or procedures which may decrease the effectiveness of the security plan. NRR will provide timely feedback to IE indicating whether or not the issues identified by IE constitute a decrease in effectiveness of the security plan.

8. RESPONSE TO LICENSEE EVENT REPORTS

IE is responsible for the initial review of and response to notification of reportable events received from reactor licensees. IE will review each event and make a determination as to the acceptability of the licensee's corrective action or program for correction. IE will assure that information regarding significant events is provided to NRR in a timely manner commensurate with the importance of the event. If the corrective action cannot be accomplished under the existing license requirements, if an unreviewed safety or safeguards question is identified, or if technical issues requiring special expertise not available within IE are involved, responsibility for resolving the matter will be formally transferred to NRR. NRR will inform IE of the resolution of any such matters.

9. RESPONSE TO OTHER MATTERS REPORTABLE TO IE

IE is responsible for the initial review of and response to matters reportable to IE under NRC requirements such as 10 CFR 50.55e and 10 CFR Part 21. IE will review each such report, investigate as appropriate, and make a determination as to the acceptability of the reported corrective action or program for correction. If the corrective action cannot be accomplished under existing NRC requirements, if unreviewed safety questions are raised, or if technical issues requiring special expertise not available within IE are involved, responsibility for resolving the matter will be formally transferred to NRR. NRR will inform IE of the resolution of such matters.

10. HANDLING OF SAFETY AND SAFEGUARDS PROBLEMS

Significant safety and safeguards related problems beyond those reported formally by licensees may be identified by IE or NRR as a result of site visits, inspections, allegations, informal communications with the licensee, or other sources. The resolution of such matters should normally be achieved through the IE enforcement procedures where possible. When resolution cannot be accomplished in this manner, and neither IE nor NRR have clear responsibility for resolving the matter, responsibility will be formally transferred to NRR. IE will provide NRR with all available information and may make recommendations to NRR regarding disposition of the matter.

NRR will inform IE of the resolution of such matters and will provide periodic status information. for items requiring an extended period of time for resolution.

11. NRC RESPONSE TO INCIDENTS

NRR and IE response to incidents will be in accordance with the guidance contained in NRC Manual Chapter 0500.

IE is responsible for managing the initial NRC response to incidents until the Executive Management Team is available. During this interim period, NRR will provide prompt technical assistance to IE when requested. As soon as the Executive Management Team is assembled, it will assume full management of NRC incident response activities. The EDO will be kept fully informed. IE will notify NRR promptly of known significant facts pertaining to incidents. Likewise, NRR will notify IE promptly when NRR is initially made aware of significant facts involving an incident.

12. IE BULLETINS AND CIRCULARS

IE has the responsibility for issuing Bulletins and Circulars. Bulletins are issued when a significant safety or safeguards issue is involved, when prompt involvement of licensees is desired, when specific actions are recommended to the licensee and when a response is requested from the licensee. Circulars are issued to distribute information of generic interest to licensees, but do not require written response from the licensee. IE will consider Bulletins or Circulars which may be proposed by any NRC office, but retains ultimate responsibility for the decision regarding issuance.

IE will give NRR an opportunity to comment on all proposed Bulletins or Circulars prior to their issuance, however, IE has the prerogative to accept or reject any comments. IE will respond to NRR comments not incorporated in substance into a Bulletin or Circular. If NRR specifically requests that a Bulletin or Circular not be issued as proposed, the matter will be resolved at the Division Director level. When a proposed Bulletin requests action which could alter existing license requirements, IE will obtain NRR concurrence before issuance of the Bulletin.

IE has responsiblity to evaluate licensee responses to Bulletins except when that response alters an existing license condition. IE will provide a summary of the responses to NRR and if NRR action is required, all responses, together with the summary and possible recommendations for resolution, will be forwarded to NRR.

13. NRR GENERIC LETTERS

NRR has the responsibility for requesting information needed for review of generic issues. If the issue can be expected to impact on the IE inspection program, NRR will give IE an opportunity to comment prior to issuance of such letters and will inform IE of all letters issued. If IE specifically requests that a Generic Letter not be issued as proposed, the matter will be resolved at the Division Director level. NRR will inform IE of any actions resulting from the review of generic issues.

14. OPERATOR LICENSING

NRR is responsible for evaluating training programs and requalification programs, as described in the SAR and other documents, for conformance with NRC criteria. Further, NRR is responsible for evaluating applications from individuals for operator and senior operator licenses, including those for renewal or amendment of existing licenses. Also, NRR reviews facility examinations administered as part of the licensed operator requalification programs to determine whether the scope and depth are comparable to the NRC-administered examinations. NRR will notify IE of any approved changes in a facility licensee's training program.

IE is responsible for verifying that operators are performing consistent with the provisions of their license. IE is also responsible for verifying that training and requalification programs have been conducted in accordance with commitments made in the SAR, in the license applications, and those requirements established in 10 CFR 55. IE will provide NRR any information obtained during inspections which may impact on the issuance or renewal of an operator's license and will effect enforcement action, as appropriate.

15. MEETINGS WITH LICENSEES

IE will be notified in advance of all NRR meetings pertaining to licensing actions which could impact on the inspection program. NRR will be notified in advance of all IE meetings which could have impact on licensing activities. Such notifications will be made to a single designated point of contact.

For NRR/IE interface matters, the principal points of contact within NRR are the Director, Division of Project Management, or his designee, for all matters related to reactor construction projects, and the Director, Division of Operating Reactors, or his designee, for all matters related to operating reactors. Within IE, the principal points of contact are the Director, Division of Reactor Inspection Programs, or his designee, for all safety and environmental matters related to reactors, and the Assistant Director for Safeguards for all matters related to safeguards.

The matters described above will be reviewed at regular intervals to assure they represent current positions, and NRR/IE Interface Meetings will be held at approximately monthly intervals to discuss matters involving the two Offices.

APPENDIX 1.3

PLANT DESIGNS LICENSED TO OPERATE USING B&W NUCLEAR STEAM SYSTEMS

Unit	Reactor Megawatts Thermal	Plant Megawatts Electric	Construction Permit Docket Date	Construction Permit Date	Operating License Date
Indian Point 1	585	265	4/2/55	5/4/56	3/26/62
Oconee 1	2568	887	12/1/66	11/6/67	2/6/73
Oconee 2	2568	887	12/1/66	11/6/67	10/6/73
Oconee 3	2568	887	12/1/66	11/6/67	7/19/74
TMI-1	2535	819	5/3/67	5/18/68	6/24/74
Crystal River 3	2452	825	8/10/67	9/25/68	12/3/76
Rancho Seco 1	2772	913	11/20/67	10/11/68	8/16/74
Arkansas 1	2568	850	11/29/67	12/6/68	5/21/74
TMI-2	2772	906	4/29/68	11/4/69	2/8/78
Davis Besse 1	2772	906	8/1/69	3/24/71	4/22/77

APPENDIX 1.4

LICENSING ORGANIZATION, 1969 TO 1979

Staff Organization, Postconstruction Permit Review Period, 1969-1974

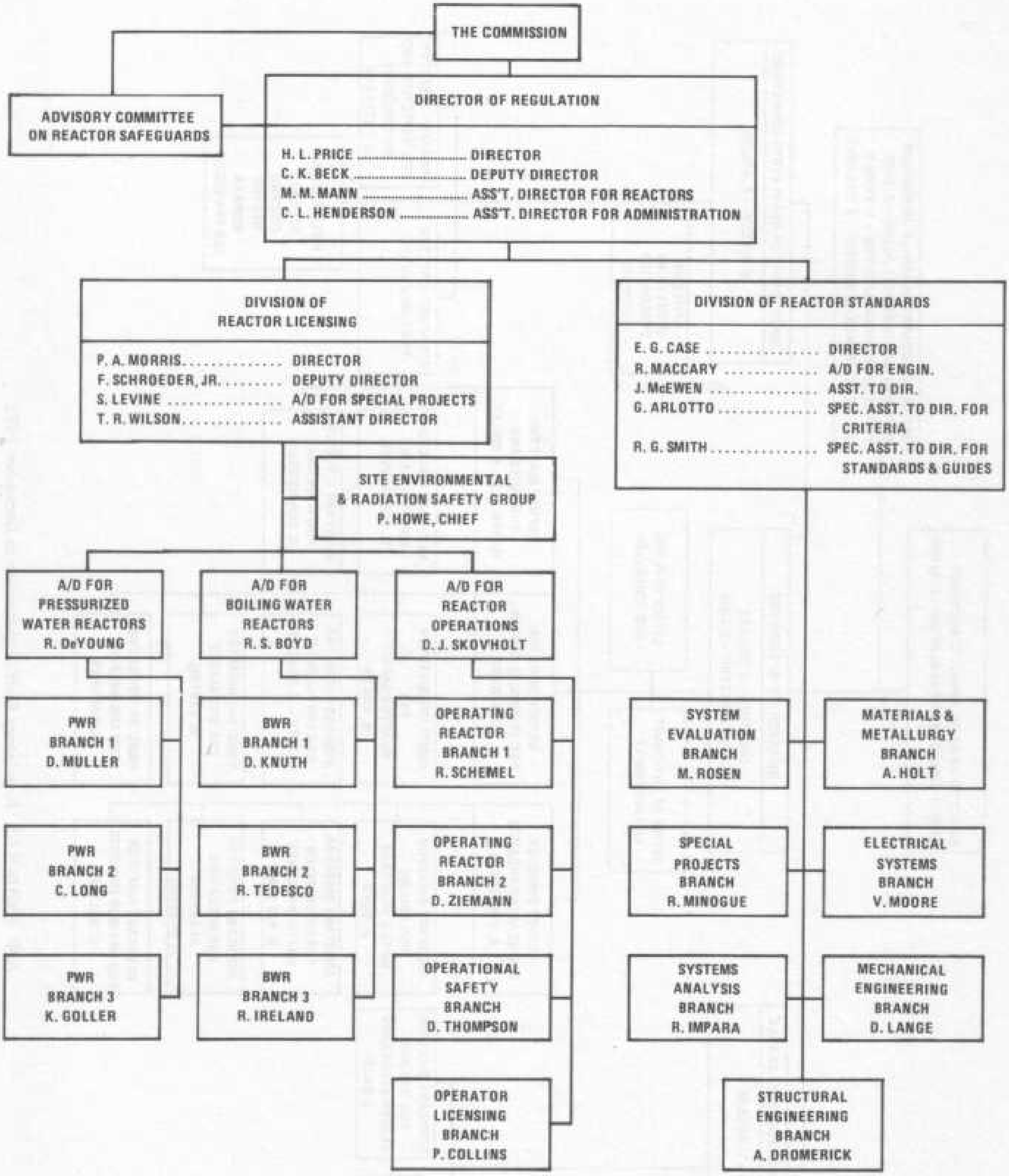
In March 1970, the part of the regulatory staff that was engaged in the review of new reactor plant applications was reorganized. Within the Division of Reactor Licensing directed by Peter Morris, the assistant directorate for reactor technology was abolished and most of the personnel were assigned to the Division of Reactor Standards, where two additional technical specialist branches were created. Also within the Division of Reactor Licensing, the project management function was expanded as the former assistant directorate for reactor projects became two assistant directorates, one for boiling water reactors and one for pressurized water reactors. The reorganized divisions are shown in App. Figure I-1. This organization remained, with minor changes due to expansion, through 1971.

In July 1971, James Schlesinger was appointed Chairman of the AEC and L. Manning Muntzing became the new Director of Regulation, replacing Harold Price. In April 1972 the regulatory *staff* under Muntzing was completely reorganized, as shown in App. Figure 1-2.[1] Seven divisions became three directorates. The former Division of Reactor Standards gave up its direct role in reviewing applications for licenses. The new Directorate of Regulatory Standards would consolidate all AEC activities in the development of standards for powerplants, other facilities, and for the use of radioactive materials.

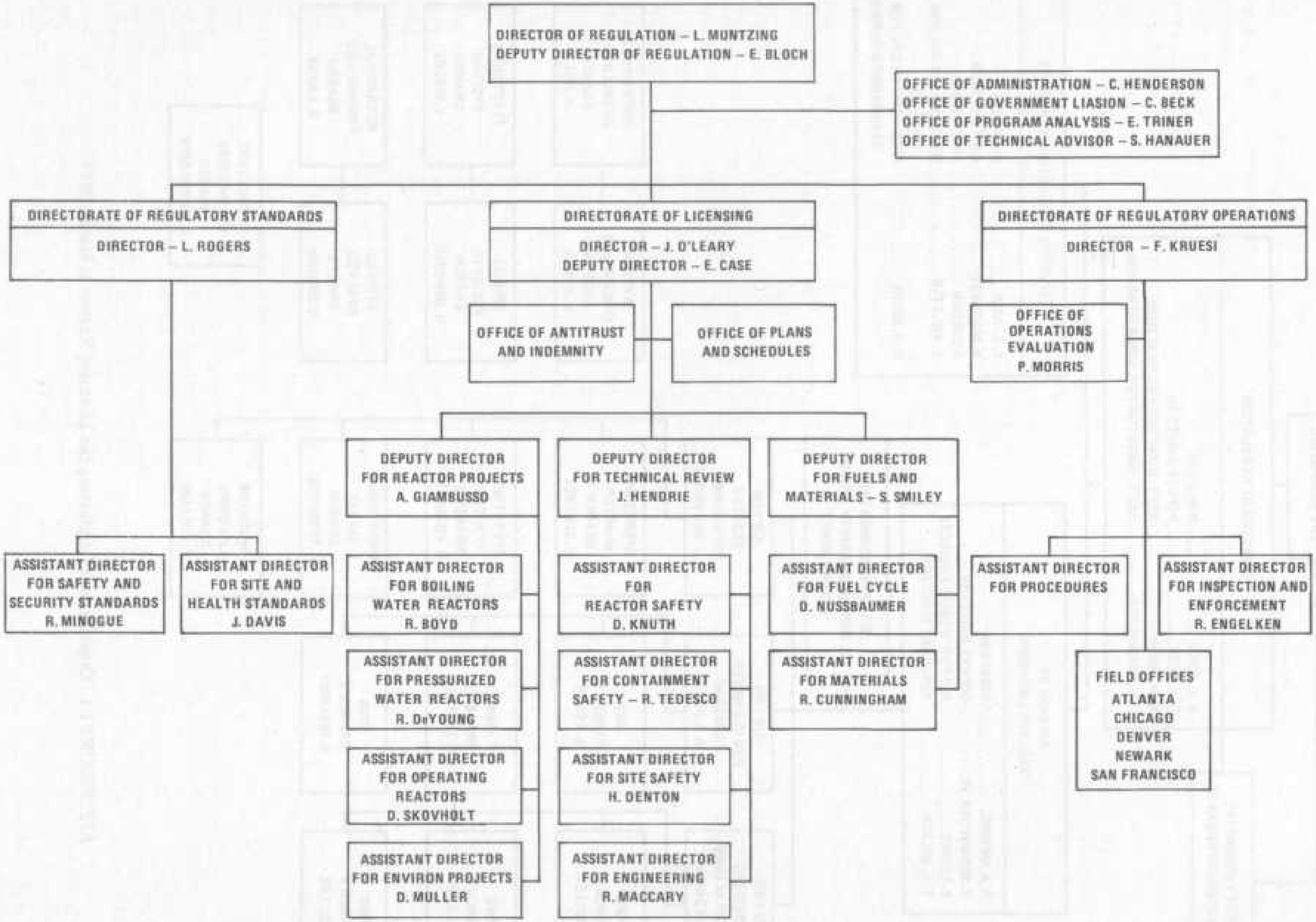
The Directorate of Licensing, the largest of the three directorates, would perform all staff review and processing of applications for and amendments to licenses, and would conduct the program for licensing of reactor operators. This directorate was also responsible for the review of applicant's submittals in compliance with the National Environmental Policy Act of 1969, and would prepare environmental statements for each plant application. The Directorate of Licensing was comprised of three subordinate directorates each headed by a deputy to the director of licensing. Edson Case was the acting Director of Licensing for most of 1972, until John O'Leary was appointed to the post.

The deputy director for reactor projects headed four assistant directorates that were collectively responsible for the project management of applications to construct and operate new plants and for the project management of licensing matters involving operating plants. For applications in process, reactor projects managed both safety reviews and environmental impact reviews.

The deputy director for technical review managed three assistant directorates comprised of technical specialists that performed the specific and detailed reviews of material submitted by applicants for licenses. These groups also reviewed technical material received from operating plants in conjunction with applications for amendments to their licenses. The technical review was generally done in response to specific project directives received from the reactor projects directorate.



APP. FIGURE I-1. Organizations Conducting the Licensing Review in March 1979



APP. FIGURE I-2. Regulatory Staff Organization in December 1972

The deputy director for fuels and materials was assigned the responsibility to manage those matters concerning licenses to utilize radioactive materials for all purposes other than commercial power production.

A third major directorate, that for regulatory operations, was created to consolidate the AEC's licensee inspection and enforcement program previously contained in several divisions. Within this directorate, the Office of Operations Evaluation was established "to collect and evaluate data on licensee operations, and to provide feedback to the licensing and standards efforts."[1]

The Directorate of Licensing organization remained essentially constant throughout 1973 and 1974. Eighteen new CP applications were received in 1973, more than four times the number received in either 1971 or 1972.[2] The Division of Technical Review was 40% larger at the end of 1973 than a year earlier. The project management assistant directorates increased by about 14% in the same time.

Two reactor units similar to the TMI units received operating licenses during 1973. Oconee 1 and 2, constructed and operated by the Duke Power Company, commenced operation on Lake Keowee in South Carolina. The TMI-1 plant received an operating license in April 1974. Oconee 3, also at the Lake Keowee site, began operation in July 1974.

In early 1973, Dixie Lee Ray became Chairman of the AEC. During 1974, the final separation of the regulatory and promotional organizations within AEC were debated by the Congress in developing what would become the Energy Reorganization Act of 1974. Also during this year the TMI-2 operating license application was tendered and finally accepted for review on April 4,1974.

Staff Organization, January 1974 to February 1978

The organization during 1973 and 1974 was essentially constant, and as previously described. On January 18, 1975, the AEC was abolished by the Energy Reorganization Act of 1974, and replaced by the Nuclear Regulatory Commission (NRC) and the Energy Research and Development Administration (ERDA).

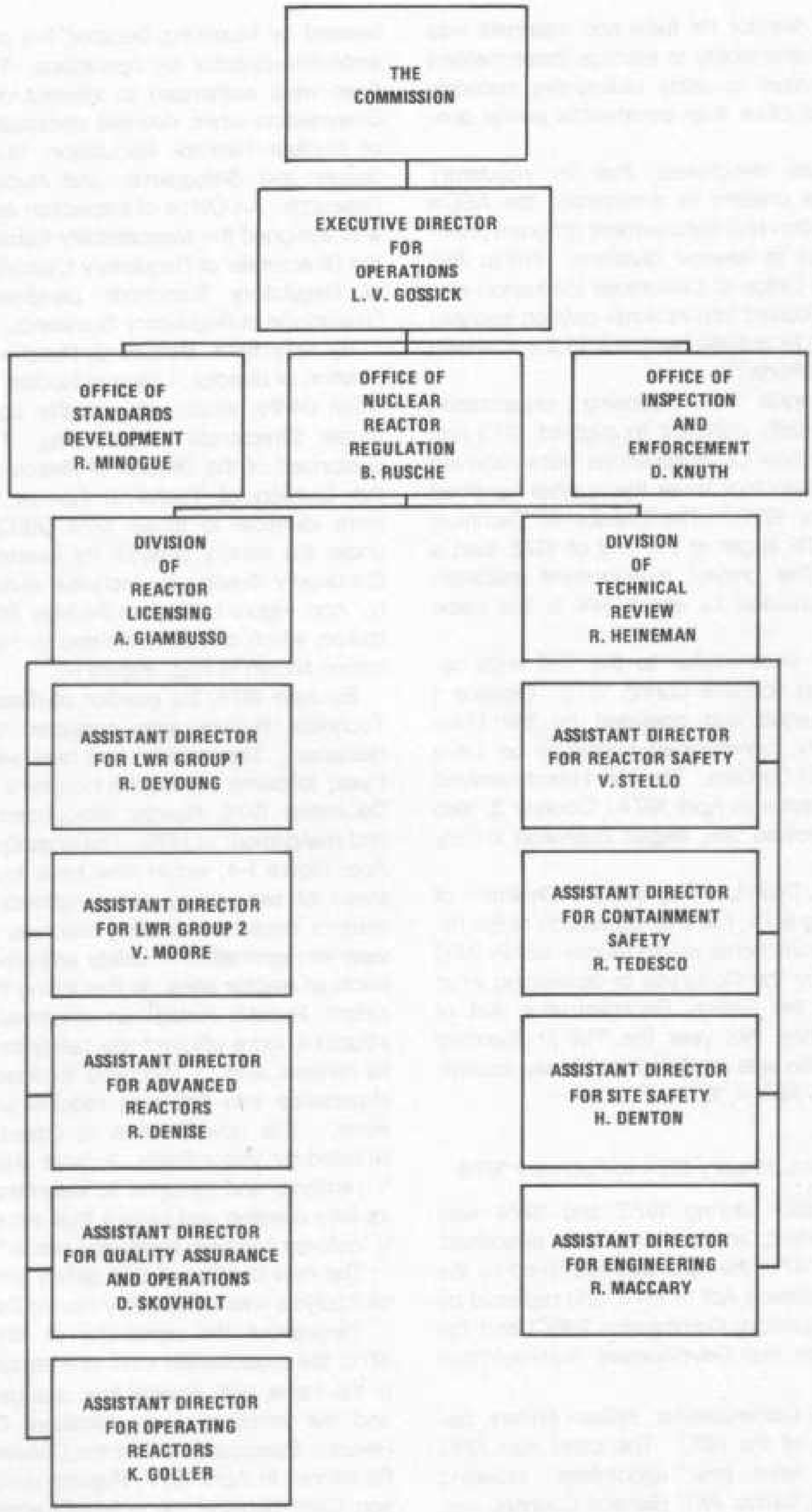
A former AEC Commissioner, William Anders, became Chairman of the NRC. The other four NRC commissioners were new appointees, including Marcus Rowden, former AEC General Counsel, who would later become NRC Chairman. The three directorates, which in 1974 were the line operating organizations in the AEC's regulatory organization headed by Muntzing, became five offices under an executive director for operations. Three of the offices were authorized to interact directly with the Commission when deemed necessary: the Offices of Nuclear Reactor Regulation, Nuclear Materials Safety and Safeguards, and Nuclear Regulatory Research. An Office of Inspection and Enforcement was assigned the responsibility formerly assigned to the Directorate of Regulatory Operations. An Office of Regulatory Standards paralleled the former Directorate of Regulatory Standards.

By May 1975, Benard C. Rusche had taken the position of director, Office of Nuclear Reactor Regulation (NRR), which was roughly equivalent to the former Directorate of Licensing. This office was comprised of the Division of Reactor Licensing and the Division of Technical Review, entities which were identical to those 1974 (AEC) organizations under the deputy director for reactor projects and the deputy director for technical review, respectively. App. Figure 1-3 shows the May 1975 NRR organization, which can be compared to the earlier organization shown in App. Figure 1-2.

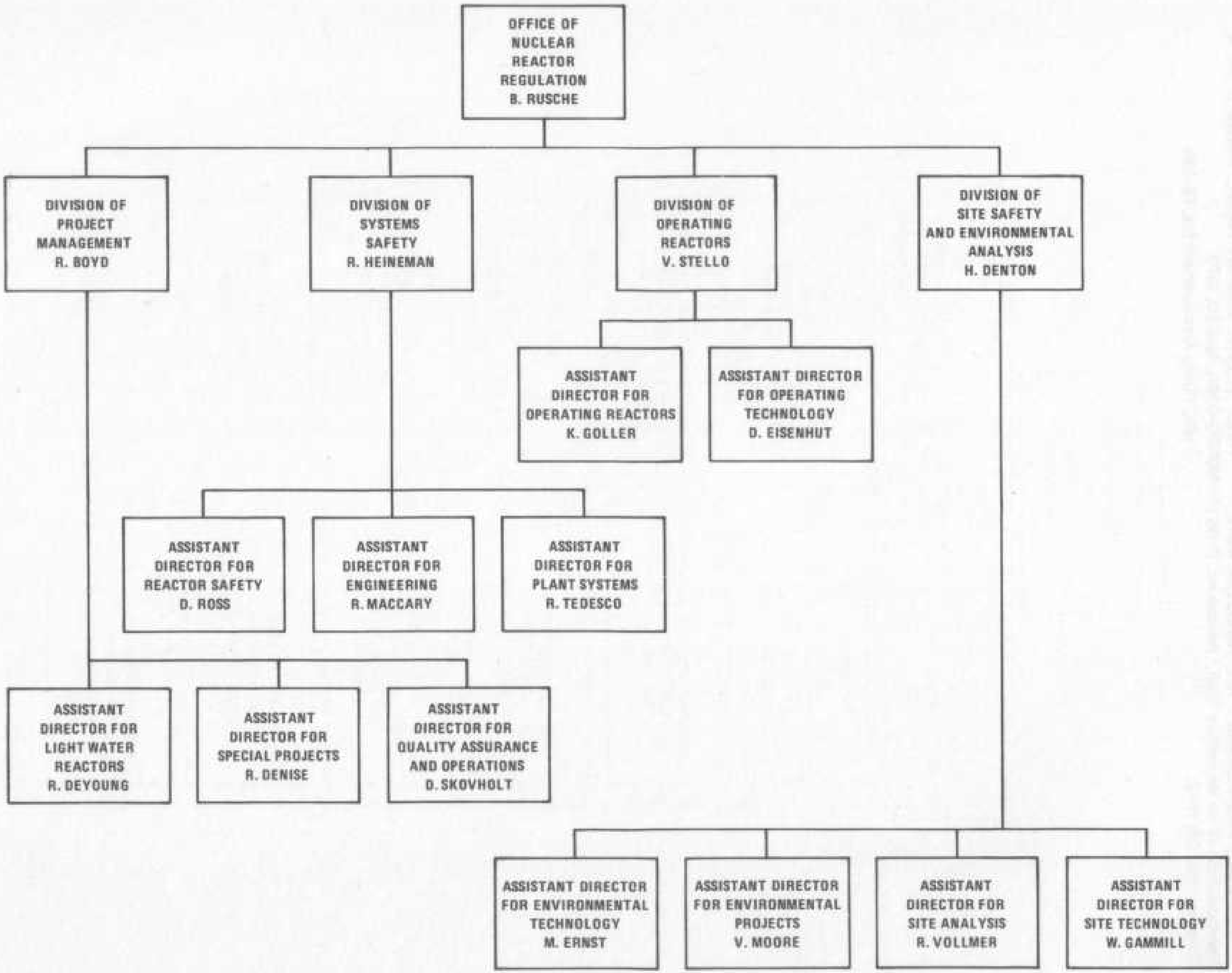
By June 1975, the position of director, Division of Technical Review was accepted by Dr. Robert Heineman_ The position had been vacant for about 1 year following Dr. Joseph Hendrie's resignation. In December 1975, Rusche announced an expansion and realignment of NRR. The organization, shown in App. Figure 1-4, would now have four divisions instead of two, giving new emphasis to regulatory matters involving operating reactors, and to the review and evaluation of safety and environmental aspects of reactor sites. In describing the new organization, Rusche noted' an improved management structure, more efficient site safety and environmental reviews, and "...improved feedback of operating experience into licensing requirements and decisions." The new Division of Operating Reactors, directed by Victor Stello, Jr., was created in part to "... analyze and respond to operating experiences as they develop and assure that current experience is factored into new licensing actions."[3]

The new Division of Site Safety and Environmental Analysis was directed by Harold Denton.

Throughout the remainder of 1976, 1977, and 1978, the organization structure remained essentially the same, with several key changes in personnel and the addition of an Assistant Directorate for Reactor Safeguards within the Division of Operating Reactors. In April 1977, Rusche resigned, and Edson Case became the acting Director of NRR until July 1978 when Denton took that position. Roger Mattson became the new Director, Division of Systems Safety in July 1977.



APP. FIGURE I-3. Regulatory Staff Organization in June 1975



APP. FIGURE I-4. Licensing Organization in December 1975

REFERENCES AND NOTES

[1] AEC Public Announcement, "AEC Announces Major Reorganization of its Regulatory Staff," release no. P-118, Tuesday, April 25, 1972.

[2] NRC, "Program Summary Report," Volume 3, No. 4, NUREG-0380, April 20, 1979.

[3] NRC Public Annoucement No. 75-284.

APPENDIX 1.5

THE STANDARD REVIEW PLAN

(This Appendix is taken in entirety from the Introduction to the Standard Review Plan, Revision 1, issued in November 1978)

"The Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants, LWR Edition," NUREG-75/087, was issued on November 24,1975, and revised in March 1979.

The Standard Review Plan (SRP) is prepared for the guidance of staff reviewers in the Office of Nuclear Reactor Regulation in performing safety reviews of applications to construct or operate nuclear powerplants. The principal purpose of the SRP is to assure the quality and uniformity of staff reviews, and to present a well-defined base from which to evaluate proposed changes in the scope and requirements of reviews. It is also a purpose of the SRP to make information about regulatory matters widely available and to improve communication and understanding of the staff review process by interested members of the public and the nuclear power industry.

The safety review is primarily based on the information provided by an applicant in a Safety Analysis Report (SAR). Section 50.34 of 10 CFR Part 50 of the Commission's regulations requires that each application for a construction permit for a nuclear facility shall include a Preliminary Safety Analysis Report and that each application for a license to operate such a facility shall include a Final Safety Analysis Report. The SAR must be sufficiently detailed to permit the staff to determine whether the plant can be built and operated without undue risk to the health and safety of the public. Prior to submission of an SAR, an applicant should have designed and analyzed the plant in sufficient detail to conclude that it can be built and operated safely. The SAR is the principal document in which the applicant provides the information needed to understand the basis upon which this conclusion has been reached.

Section 50.34 specifies, in general terms, the information to be supplied in an SAR. The specific information required by the staff for an evaluation of an application is identified in Regulatory Guide 1.70, "Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants-LWR Edition." The SRP sections are keyed to the Standard Fomat, and the SRP sections are numbered according to the section numbers in the Standard Format. Review plans have not been prepared for SAR sections that consist of background or design data that are included for information or for use in the review of other SAR sections.

The Standard Review Plan is written so as to cover a variety of site conditions and plant designs. Each section is written to provide the complete procedure and all acceptance criteria for all of the areas of review pertinent to that section. However, for any given application, the staff reviewers may select and emphasize particular aspects of each SRP section as is appropriate for the application. In some cases, the major portion of the review of a plant feature may be done on a generic basis with the designer of that feature rather than in the context of reviews of particular applications from utilities. In other cases, a plant feature may be sufficiently similiar to that of a previous plant so that a de novo review of the feature is not needed. For these and other similar reasons, the staff may not carry out in detail all of the review steps in each SRP section in the review of every application.

The individual SRP sections address, in detail, who performs the review, the matters that are reviewed, the basis for review, how the review is accomplished, and the conclusions that are sought. The safety review is performed by 18 branches. One of the objectives of the SRP is to assign the review responsibilities to the various branches and to define the sometimes complex interfaces between them. Each SRP section identifies the branch that has the primary review responsibility for that section. In some review areas the primary branch may require support and the branches that are assigned these secondary review responsibilities are also identified for each SRP section.

Each SRP is organized into four subsections as follows:

I. Areas of Review

This subsection describes the scope of review i.e., what is being reviewed by the branch having primary review responsibility. This subsection contains a description of the systems, components, analyses, data, or other information that is reviewed as part of the particular SAR section in question. It also contains a discussion of the information needed or the review expected from other branches to permit the primary review branch to complete its review.

II. Acceptance Criteria

This subsection contains a statement of the purpose of the review and the technical basis for determining the acceptability of the design or the programs within the scope of the area of review of the SRP section. The technical bases consist of specific criteria such as NRC Regulatory Guides, General Design Criteria, Codes and Standards, Branch Technical Positions, and other criteria.

The technical bases for some sections of the SRP are provided in Branch Technical Positions or Appendices which are included in the SRP. These documents typically set forth the solutions and approaches determined to be acceptable in the past by the staff in dealing with a specific safety problem or safety-related design area. These solutions and approaches are codified in this form so that staff reviewers can take uniform and well-understood positions as the same safety problems arise in future cases. Some Branch Technical Positions and Appendices may be converted into Regulatory Guides if it appears that this step would aid the review process. Like Regulatory Guides, the Branch Technical Positions and Appendices represent solutions and approaches that are acceptable to the staff, but they are not required as the only possible solutions of approaches. However, it should be recognized that, as in the case of Regulatory Guides, substantial time and effort on the part of the staff has gone into the development of the Branch Technical Positions and Appendices and that a corresponding amount of time and effort will probably be required to review and accept new or different solutions and approaches. Thus, applications proposing other solutions and approaches to safety problems or safety-related design areas than those described in the Branch Technical Positions and Appendices must expect longer review times and more extensive questioning in these areas. The staff is willing to consider proposals for other solutions and approaches on a generic basis, apart from a specific license application, to avoid the impact of the additional review time on individual cases.

III. Review Procedures

This subsection discusses how the review is accomplished. The section is generally a step-by-step procedure that the reviewer goes through to provide reasonable verification that the applicable safety criteria have been met.

IV. Evaluation Findings

This subsection presents the type of conclusion that is sought for the particular review area. For each section, a conclusion of this type is included in the staff's SER in which the staff publishes the results of their review. The SER also contains a description of the review including such subjects as which aspects of the review were selected or emphasized; which matters were modified by the applicant, require additional information, will be resolved in the future, or remain unresolved; where the plant's design or the applicant's programs deviate from the criteria stated in the SRP; and the bases for any deviations from the SRP or exemptions from the regulations.

APPENDIX 1.6

ACRS LETTER OCTOBER 22, 1976

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
Nuclear Regulatory Commission
Washington, D.C.

October 22,1976

Honorable Marcus A. Rowden
Chairman
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

SUBJECT: REPORT ON THREE MILE ISLAND NUCLEAR STATION, UNIT 2

Dear Mr. Rowden:

During its 198th meeting, October 14-16,1976, the Advisory Committee on Reactor Safeguards completed its review of the application of the Metropolitan Edison Company, Jersey Central Power and Light Company, and Pennsylvania Electric Company (Applicants) for a license to operate Three Mile Island Nuclear Station, Unit 2. This project was also considered during a Subcommittee meeting held in Harrisburg, Pennsylvania, on September 23 and 24,1976. Members of the Committee visited the facility on September 23, 1976. During its review, the Committee had the benefit of discussions with representatives and consultants of the Applicants, General Public Utilities Service Corporation, the Babcock and Wilcox Company (B&W), Burns and Rowe, Inc., and the Nuclear Regulatory Commission (NRC) Staff. The Committee reported on the application for a construction permit for Unit 1 on January 17 and April 12,1968, and for an operating license for Unit 1 on August 14, 1973. The Committee reported on the application for a construction permit for Unit 2 on July 17,1969.

The Three Mile Island Nuclear Station, Units 1 and 2, is located on Three Mile Island near the eastern shore of the Susquehanna River, about 12 miles southeast of Harrisburg, Pennsylvania. About 2380 people live within a two-mile radius of the site (the low population zone). The minimum exclusion distance is 2000 feet. The nearest population center is Harrisburg (1970 population 68,000).

Several changes have been made to bring the Babcock and Wilcox Emergency Core Cooling System (ECCS) evaluation model into conformance with the requirements of 10 CFR 50.46, and Appendix K to Part 50. Analyses of a spectrum of break sizes appropriate to Three Mile Island, Unit 2 have been completed using the approved B&W generic evaluation model. The results of the analyses for the reactor coolant pump discharge break, believed to be the "worst" break, show maximum allowable linear heat generation rates as a function of elevation in the reactor core ranging from 15.5 to 18.0 kilowatts per foot. Corresponding calculated post-accident peak clad temperatures range from 2002°F to 214°F. The NRC Staff has identified additional information that it will require to complete its review and the Applicants' submittal is expected by the end of 1976. The Applicants propose to use both in-core and ex-core instrumentation to assure accuracy of measurement of core power distributions. The Committee believes that the proposed monitoring methods may be acceptable, but that an augmented startup program should be employed, and that satisfactory experience at 100% steady state power and during transients at less than full power should be obtained. This experience should be reviewed and evaluated by the NRC Staff prior to operating at up to full power in a load following mode. The Committee wishes to be kept informed.

A question has arisen concerning asymmetric loads on the reactor vessel and its internal structures for certain postulated loss-of-coolant accidents in pressurized water reactors. The Staff has required the Applicants to supply further information in order to complete its assessment of this matter. This issue should be resolved in a manner satisfactory to the NRC Staff.

The question of whether Unit 2 requires design modifications in order to comply with WASH-1270, "Technical Report on Anticipated Transients Without Scram for Water-Cooled Power Reactors", remains an outstanding issue pending the NRC Staff's completion of its review of B&W generic analyses of anticipated transients without scram. The Committee recommends that the NRC Staff, the Applicants and B&W continue to strive for an early resolution of this matter in a manner acceptable to the NRC Staff. The Committee wishes to be kept informed.

Emergency plans have been developed to allow plant shutdown and maintenance of safe shutdown in the event of a maximum probable flood. Such a postulated flood would top the levee surrounding the plant by several feet. Included in the plan is the fastening of water tight steel panels in doorways and other openings of safety related structures. The Committee believes that the details of this plan, particularly relating to re-entry into the station during the post-flood period, need to be more clearly delineated.

The Committee supports the NRC Staff's program for evaluation of fire protection in accordance with Branch Technical Position APCSB 9.5-1, Appendix A, "Guidelines for Fire Protection for Nuclear Power Plants". The Committee recommends that the NRC Staff give high priority to the completion of both owner and Staff evaluations and to recommendations for Three Mile Island Unit 2 and other plants nearing completion of construction in order to maximize the opportunity for improving fire protection while areas are still accessible and changes are more feasible.

The Committee notes that long-term post-accident operation of the plant to maintain safe shutdown conditions may be dependent on instrumentation and electrical equipment within containment which is susceptible to ingress of steam or water if the hermetic seals are either initially defective or should become defective as a result of damage or aging. The Committee believes that appropriate test procedures to confirm continuous long-term seal capability should be developed.

The Committee recommends that further review be made of the battery supplied DC power system to assure that non-essential loads do not interfere with its safety function. The Committee recommends that further review be made to assure no unacceptable effects such as release of hydrogen into the plant can occur from the failure of a hydrogen charging line. The Committee also recommends that studies be made to assure that failure of an instrument line cannot cause plant controllability problems of significance to public safety.

The management organization proposed by the Applicants to delineate the safety related responsibilities of the off-site and on-site personnel of the Three Mile Island Station left open questions as to how these responsibilities are to be discharged during normal working hours and during evening, night, and weekend shifts. This matter should be resolved to the satisfaction of the NRC Staff.

The NRC Staff is still reviewing various issues related to accidents leading to loss of fluid in the steam generator secondary side, such as steam line breaks. The Committee wishes to be kept informed of the resolution of these issues.

The Committee recommends that, prior to commercial power operation of Three Mile Island Unit 2, additional means for evaluating the cause and likely course of various accidents, including those of very low probability should be in hand in order to provide improved bases for timely decisions concerning possible off-site emergency measures. The Committee wishes to be kept informed.

The Committee believes that the Applicants and the NRC Staff should further review the Three Mile Island Nuclear Station for measures that could significantly reduce the possibility and consequences of sabotage, and that such measures should be implemented where practical.

Other generic problems relating to large water reactors are discussed in the Committee's report entitled "Status of Generic Items Relating to Light Water Reactors: Report No. 4", dated April 16,1976. Those problems relevant to the Three Mile Island Station should be dealt with appropriately by the NRC Staff and the Applicants as solutions are found. The relevant items are: II - 1, 2, 3, 4, 5, 6, 7, 9, 11; IIA - 1, 4, 5, 6, 7, 8; IIC - 1, 2, 3, 4, 5, 6, 7.

The Advisory Committee on Reactor Safeguards believes that, if due regard is given to the items mentioned above, and subject to satisfactory completion of construction and pre-operational testing, there is reasonable assurance that Three Mile Island Nuclear Station, Unit 2 can be operated at power levels up to 2772 MWt without undue risk to the health and safety of the people.

Sincerely yours,

Dade W. Moeller
Chairman

References

1. Three Mile Island Nuclear Station, Unit 2 Final Safety Analysis Report (April, 1974) with Amendments 1 through 44.

2. Safety Evaluation Report (NUREG-0107) related to operation of Three Mile Island Nuclear Station, Unit 2, dated September, 1976.

APPENDIX 1.7

EXTRACTS FROM ADJUDICATORY DECISIONS-THREE MILE ISLAND NUCLEAR STATION UNIT2

DOCKET NO. 50-320

IN THE MATTER OF JERSEY CENTRAL POWER & LIGHT COMPANY AND METROPOLITAN EDISON COMPANY (THREE MILE ISLAND NUCLEAR STATION, UNIT 2)

Issued November 12, 1969

(4 AEC Reports 283)

INITIAL DECISION

PRELIMINARY STATEMENT

1. This proceeding involves the application of Jersey Central Power & Light Company and Metropolitan Edison Company (Applicants) for a provisional construction permit to construct a pressurized water reactor designed for initial operation at core power levels up to 2,452 megawatts (thermal). The facility, designated as Three Mile Island Nuclear Station Unit 2, (hereinafter, Unit 2) will be located on

a site at Three Mile Island adjacent to Unit 1, a nuclear electric generating plant which is now under construction by Metropolitan Edison Company. The island site in the Susquehanna River is in Dauphin County about 10 miles southeast of Harrisburg, Pennsylvania. The application has been reviewed by the Regulatory Staff (Staff) of the Atomic Energy Commission (Commission) and the Advisory Committee on Reactor Safeguards (ACRS), both of which concluded that there is reasonable assurance that the described facility can be constructed and operated at the proposed site without undue risk to the health and safety of the public.

2. In accordance with the requirements of the Atomic Energy Act and the Commission's regulations, and pursuant to the notice of Hearing published in the Federal Register on August 27,1969, at 34 Fed. Reg. 13708, a public hearing was held before this Atomic Safety and Licensing Board (Board) on October 6,1969, in Middletown, Pennsylvania, to consider whether a provisional construction permit should be issued to the Applicants. The parties to the proceeding were the Applicants and the Staff. No petitions for leave to intervene were filed. Pursuant to Section 2.715(a) of the Commission's Rules of Practice, Dr. Arthur Socolow, an area resident who attended throughout the hearing, presented a limited appearance statement expressing concern relating to protection of the facility from aircraft using the nearby Olmstead State Airport. Mr. Thomas M. Gerusky, representing the Pennsylvania Department of Health, stated that mutually satisfactory programs relating to radiological health and emergency procedures had been established in cooperation with the Applicants and the U.S. Public Health Service. Subsequent to the hearing proposed findings and conclusions were filed by the Applicants and the Staff.

3. This is not a contested proceeding as defined in Section 2.4(n) of the Commission's Rules of Practice. Accordingly, the Board is instructed by the Rules and in the Notice of Hearing to consider the issues of whether the application and the record of the proceeding contain sufficient information, and the review by the Staff has been adequate to support the findings proposed to be made and the provisional constructional permit proposed to be issued by the Director of Regulation. The findings and the permit proposed by the Director of Regulation were published in and with the Notice of Hearing. The post-hearing pleadings of the parties propose affirmative conclusions upon the issues: they are supported by and in accordance with the reliable, probative, and substantial evidence in the record.

FINDINGS OF FACT

4. Jersey Central Power & Light Company and Metropolitan Edison Company will share the financing and ownership of Unit 2 in the ratios of 25 percent and 75 percent, respectively. Each of the Applicants is an operating utility engaged in the generation, transmission and sale of electric power. The Applicants are two of four wholly-owned subsidiaries of General Public Utilities Corporation (GPU), a Pennsylvania corporation registered under the Public Utility Holding Company Act of 1935. Each of the Applicants is financially sound and plans to finance its share of the costs of construction of the proposed facility as part of its overall construction program. Funds to meet construction requirements will be provided by internal sources and capital contributions from GPU and by the sale of debt securities in such a manner as to maintain a sound and conservative capital structure.

5. Metropolitan Edison Company is responsible for engineering, design, construction, operation and maintenance of Unit 2. Metropolitan Edison Company has 85 years' experience in the design, construction, and operation of electric generating stations, and is now constructing Three Mile Island Nuclear Station Unit 1. The GPU Nuclear Power Activities Group, with nuclear experience in operating power reactors at Saxton and Oyster Creek, will provide technical assistance and guidance to the Three Mile Island Project Director, John G. Miller, who is Vice President and Chief Engineer of Metropolitan Edison Company. The nuclear steam supply system is being designed and fabricated by the Babcock & Wilcox Company. Burns and Roe, Inc., has been engaged as the project architect-engineer except in the areas of cooling tower design and interfaces between Unit 1 and Unit 2 for which Gilbert Associates, Inc., has been engaged. United Engineers and Constructors, Inc., is the construction manager for both Unit 1 and Unit 2. Applicants will rely also on assistance in design, quality assurance, and structures to be provided by Pickard & Lowe Associates, MPR Associates, and Schupack & Associates. The record supports the Staff's conclusion that "the applicants are technically qualified to design and build the Three Mile Island Nuclear Station Unit 2".

6. The Unit 2 reactor will operate initially at core powers up to 2,452 Mwt and is designed for an

expected ultimate capacity of 2,772 Mwt. This higher power has been used as the design basis for the containment and the engineered safety features, and it has been used by the Staff and the Applicants in the accident analyses and in the evaluation of all major structures, systems, and components which bear significantly on the acceptability of the site. The exclusion distance for the Three Mile Island site is 2,000 feet. Based upon the combined population of the Middletown-Steelton communities (22,450) with their nearest boundary at 2.2 miles, the Applicants have proposed a low population zone radius of two miles. The plant design will take into account local hydrological conditions, earthquakes, tornados, and possible aircraft impacts. The Applicants will provide protection against the Probable Maximum Flood (PMF) as calculated by the Corps of Engineers.

7. A comprehensive pre-operational environmental monitoring program has been in progress at this site for some time in connection with the Three Mile Island Unit 1. The Applicants will continue to cooperate with interested government agencies concerning radiological surveys and in accordance with recommendations of the Fish and Wildlife Service. This record includes evidence from the Applicants and Staff which indicates that the Susquehanna River basin as well as the Chesapeake Bay can accommodate the installation of the proposed plant and an additional number of other such plants without causing total or cumulative concentrations of radiological effluents to exceed more than a small fraction of the values set forth in 10 CFR Part 20.

8. The proposed facility incorporates numerous systems, components and features for the protection of plant personnel and the public and is similar in design to plants incorporating pressurized water reactors which have been previously approved for construction by the Commission. An important safety feature is the containment system which will completely enclose the reactor and major components of the primary coolant system. The containment system consists of a reinforced prestressed concrete structure with a vapor tight steel liner. The prestressed tendons will be grouted to provide protection against corrosion. The containment structure is designed to accommodate, without loss of integrity, functional loads resulting from a loss-of-coolant accident occurring simultaneously with the maximum hypothetical earthquake and normal operating loads.

9. The proposed facility has two separable cooling systems which assure adequate core cooling and pressure reduction within the containment structure even if a loss-of-coolant accident should occur. For immediate short-term cooling, an emergency core cooling system will inject cool borated water into each of the primary coolant loops and directly into the reactor vessel, thereby limiting the fuel pin clad temperatures and fission product release into the containment. For cooling containment air to reduce the containment vessel internal pressure in the unlikely event of a major accident, there are two independent spray systems which deliver cool borated water into the containment atmosphere. These systems will provide borated water containing dissolved sodium thiosulphate and sodium hydroxide to remove iodine in the event of an accident.

10. The Applicants and the Staff recognize that in order to develop the final design of the facility further information and data will be needed. Such additional information and data will be developed by research and development projects in the course of the final design work for the plant. In addition, basic work in progress is expected to provide some confirmation that the proposed designs are conservative. The major areas of research and development include the xenon oscillations, core thermal and hydraulic tests, fuel rod clad failure, high burnup fuel tests, internal vent valves, control rod drive test, once-through steam generator, in-core neutron detector test, blowdown forces on reactor internals, chemical spray system, and effects of radiolysis. The objectives of these programs have been defined, and a schedule for the furnishing of information prior to completion of construction of the proposed facility has been established.

11. Applicants have established a comprehensive quality assurance program which is consistent with the intent of, and which has been evaluated by the Staff in accordance with, the AEC's "Quality Assurance Criteria for Nuclear Power Plants" which was recently published as a proposed Appendix B to 10 CFR Part 50. Applicants' quality assurance organization, including the GPU Manager of Quality Assurance, will undertake to assure that the facility will be fabricated and constructed in accordance with applicable codes and specifications. The quality assurance program encompasses overall direction, guidance and surveillance over the quality assurance practices to be observed by the reactor supplier, the architect-engineer, the construction manager, and their subcontractors.

12. The facility will be located 2 1/2 miles from Olmstead State Airport. Although the probability of an aircraft incident at the Three Mile Island Nuclear Station is remote, the vital structures of the station will be designed to withstand a significant range of

aircraft strike loadings, including such secondary effects as missiles, fire, pressure and temperature. Dr. Socolow's statement inquired about the capability of the containment building and other critical components to withstand an impact of a larger than the design basis aircraft (200,000 lbs.). The responsive evidence presented by the parties, in addition to that concerning the low probability of impact, is persuasive that there is little likelihood that any aircraft impact on the facility could cause the release of radioactivity. This view rests upon an evaluation of the conservative design of the containment to withstand impact, and the value of the additional protection provided to the reactor and the primary cooling system by shield walls inside the containment. In addition, under adverse weather conditions involving poor visibility, landings by all large aircraft using Olmstead Airport would be under instrument flight regulations which then would not permit flights over the site.

13. The activities to be conducted under the provisional construction permit will be within the jurisdiction of the United States, and all of the directors and principal officers of the Applicants are United States citizens. The Applicants are not owned, controlled or dominated by an alien, a foreign corporation or a foreign government. The activities to be conducted do not involve any restricted data, but the Applicants have agreed to safeguard any such data which might become involved in accordance with 10 CFR Part 50.33(j). Special nuclear material for use as fuel in the proposed facility will be subject to Commission regulations and will be obtained from sources of supply such that there will be no diversion of such material to unauthorized uses.

CONCLUSIONS

14. Upon consideration of the entire record in this proceeding and the findings of fact and statements set forth above, the Board concludes that the application and the record of the proceeding contain sufficient information, and the review of the application by the Staff has been adequate to support the findings proposed to be made by the Director of Regulation, and the issuance of the provisional construction permit as proposed by the Director of Regulation.

ORDER

Pursuant to the Act and the Commission's regulations, IT IS ORDERED that the Director of Regulation issue a provisional construction permit to the Jersey Central Power and Light Company and the Metropolitan Edison Company substantially in the form set forth in Appendix "A" to the Notice of Hearing in this proceeding.

IT IS FURTHER ORDERED, in accordance with 10 CFR Section 2.760, 2.762 and 2.764 of the Commission's Rules of Practice, that this Initial Decision shall be effective immediately and shall constitute the final action of the Commission 45 days after the date of issuance, subject to the review thereof and further decision of the Commission upon its own motion or upon exceptions filed pursuant to the cited rules.

ATOMIC SAFETY AND LICENSING BOARD,
CLARKE WILLIAMS,
ABEL WOLMAN,
J. D. BOND, CHAIRMAN.

Cite as **6 NRC 1185 (1977)**

LBP-77-70

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

ATOMIC SAFETY AND LICENSING BOARD
Edward Luton, Chairman
Ernest O. Salo
Gustave A. Linenberger

In the Matter of
METROPOLITAN EDISON COMPANY
JERSEY CENTRAL POWER & LIGHT COMPANY
PENNSYLVANIA ELECTRIC COMPANY
(Three Mile Island Nuclear Station, Unit no. 2)

Docket No. 50-320

December 19. 1977

I. INTRODUCTION

1. This is a proceeding on the application of Metropolitan Edison Company, the Jersey Central Power and Light Company, and the Pennsylvania Electric Company ("Applicants") for licenses to construct and operate the Three Mile Island Nuclear Station, Unit No. 2 ("TMI-2"). The plant is located adjacent to a similar unit (Three Mile Island Nuclear Station, Unit No. 1) on Three Mile Island in the Susquehanna River in Londonderry Township, Dauphin County, Pennsylvania.

2. Construction of TMI-2 was authorized on November 4, 1969. By application dated April 4, 1974, Applicants requested authorization, pursuant to Section 104.b of the Atomic Energy Act of 1954, as amended, to possess, use, and operate TMI-2, a pressurized water nuclear reactor, at a steady state power level of 2,772 megawatts thermal. On May 20, 1974, the Commission issued a notice which provided that any person whose interest might be affected by the proceeding could file a request for a public hearing in the form of a petition to intervene in accordance with the Commission's regulations contained at 10 CFR Section 2.714. Petitions to intervene were received from the Citizens for a Safe Environment and the York Committee for a Safe Environment (as "joint petitioners"), and from Mrs. Barbara Pradel of Greencastle, Pennsylvania. Additionally, the Commonwealth of Pennsylvania requested leave to participate as an interested State pursuant to 10 CFR Section 2.715(c). On July 24, 1974, the Atomic Safety and Licensing Board designated to rule on intervention requests granted the joint petitioners' request to intervene, granted the Commonwealth's request to participate, and denied the intervention petition of Mrs. Barbara Pradel. [1]

3. This Atomic Safety and Licensing Board ("Board") has conducted a public evidentiary hearing to consider (1) issuance or denial of a full-term operating license for TMI-2 or its appropriate conditoning to protect environmental values and (2) because TMI-2 is subject to the provisions of Section C of Appendix D of 10 CFR Part 50, whether considering those matters covered by Appendix D, the provisional construction permit for TMI-2 should be continued, modified, terminated, or appropriately conditioned to protect environmental values. With respect to its consideration under Appendix D of the TMI-2 construction permit, the Board has conducted a full NEPA review covering both contested and uncontested environmental matters. With respect to the operating license the Board has, in accordance with Section 2.760a of the Commission's Rules of Practice, confined its findings to the matters in controversy. [2]

4. The Board has considered the entire record of this proceeding and all of the proposed findings of fact and conclusions of law submitted by the parties. All proposed findings and conclusions submitted by the parties which are not incorporated directly or inferentially in this initial decision are rejected as being unsupported in law or in fact, or as being unnecessary to the rendering of this decision.

Contention 5

The containment structure and other buildings designed to withstand certain aircraft impact events are of inadequate strength to withstand the impact of airplanes which can reasonably be expected to frequent Harrisburg International Airport. Both the Boeing 747 and the Lockheed C-5A are reasonably expected to frequent Harrisburg International Airport and greatly exceed the kinetic energy set for the design consideration.

38. The Board views this Contention as, in effect, comprising the following two allegations:

(a) A first allegation that claims that critical (safety Category I) structures are not capable of withstanding the impact of the Boeing 747 and the Lockheed C-5A aircraft.

(b) A second and follow-on allegation that these two types of aircraft will potentially use the Harrisburg International Airport with sufficient frequency to generate more than *a de minimus* concern for the health and safety of the public.

39. The Applicants and the Staff both presented prepared testimony and proposed findings on this Contention (testimony of Applicants' Witness J. M. Vallance, following Tr. 511; testimony of Staff's Witness J. B. J. Read, following Tr. 617; supplemental testimony of Read, following Tr. 1297). The Joint Intervenors relied on cross-examination of the Applicants' and Staff's witnesses and upon argument presented in their proposed findings.

40. The evidence is that the TMI-2 facility is not capable of withstanding the impact of an aircraft weighing in excess of 200,000 pounds. In addition, the Boeing 747 and the Lockheed C-5A, in flight at 200 knots or greater velocity, each has a kinetic energy that exceeds the impact resistance for which the TMI-2 structures (particularly the containment) are designed to withstand (Vallance, cited above). The Board thus finds that Item (a) is a correct statement of fact.

41. The follow-on allegation, Item (b) above, reflects the remaining substantive issue within this Contention. The nature of the direct testimony and the scope of the Joint Intervenors' cross-examination prompts the Board to, in effect, subdivide Item (b) into three subissues:

i) Has the computation of the probability of an aircraft impact been properly carried out?

ii) If so, is the result adequate to justify a negligible concern for the health and safety of the public, absent an analysis of the consequences of such an impact?

iii) Are the current and anticipated frequencies of heavy aircraft operations at the Harrisburg Airport properly taken into account?

The Board considers it appropriate to resolve Item (b) via these subissues.

42. The probability computation (Item (b)(i) above) is addressed first. The Applicants have calculated a probability of about $3x10^{-9}$ events per year, per unit, for aircraft larger than 200 thousand pounds, based upon Harrisburg International Airport data that yielded an estimate for 1976 of approximately 511 operations (takeoffs or landings) of such planes, using those runways that could require a flight pattern imposing a potential threat to TMI-2. This result includes all strikes upon any structure, irrespective of whether there is disabling damage leading to shutdown; it disregards the angle of strike; and, further, it disregards any protective shielding effect from the cooling towers and other noncritical structures. Finally, the Applicants' analytical approach incorporates an angular correlation consideration that results in *a decrease* of strike probability for planes whose approaches lie along lines displaced at *increasing* angles from the extended runway centerline (Vallance, *loc. cit.).*

43. According to the testimony of Vallance, the Staff assumed for the sake of conservatism that the TMI Station lies within (although it is slightly outside of) a 60 degree sector centered on the runway centerline, and that all strike locations are equally probable within that sector. Using otherwise similar geometry and flight frequency assumptions, the Staff, per Valiance's testimony, has obtained a probability of 10"7 events per year, per unit (Vallance, loc.cit.). The Staff's witness stated the Staff's conclusions as follows:

> The staff (sic) has concluded that, with respect to the TMI-2 site, the risk from aircraft is acceptably low if fewer than 2400 operations per year at Harrisburg International Airport are flown by aircraft larger than the design basis aircraft. The basis for this conclusion is that the expectation of aircraft larger than the Boeing 720 striking the plant would then be less 10"7 per year (estimated by the algorithm contained in Standard Review Plan Section 3.5.1.6, NUREG-75/087 (September 1975)). At present, about 600 four-engine jets per year use the airport, which is considerably within our criterion of 2400.

(Testimony of J. B. J. Read, following Tr. 617.)

44. The Board here interprets the above quoted airport usage of "600 four-engine jets per year" to

be consistent with the Applicants' value of 511 operations per year. The two different probability results are judged by the Board to be compatible in the sense that the difference between them is plausible, based upon the cited assumptions regarding conservatism. The Board finds that the probability assessments have been properly carried out.

45. The Joint Intervenors, as the result of cross-examination, have submitted proposed findings that challenge the validity of the computational model used by the Applicants and by the Staff, criticize the lack of "peer review" given to the model, and question its applicability of the results. After a careful weighing of the cross-examination and the results of our own examination of the witnesses, the Board finds that, while certain of the Intervenors' proposed findings are literally true, none of them represents a significant flaw in the adequacy and applicability of the strike probability results. Nor were the competence and judgments of the two witnesses impugned to any significant extent. We find to be acceptable and conservative the result that the probability of an impact of any nature on some portion of the TMI-2 facility by a heavier than 200 thousand-pound aircraft is currently less than 10^{-7} per year, under the various qualifying conditions imposed.

46. Item (b)(ii) is addressed next. Regarding the health and safety of the public, neither the Applicants nor the Staff refuted the concern of the Joint Intervenors that the impact of a plane weighing more than 200 thousand pounds into a safety Category I structure might give rise to radiological consequences greater than the exposure guidelines of 10 CFR Part 100. This concern, in turn, prompted the Intervenors to file a motion to compel the appearance of a witness to discuss the consequences of such an event (nature and disposition of this motion discussed below).

47. Applicants' witness and counsel for the Staff appealed to the guideline probability values set forth in NUREG-75/087 (in particular, Section 3.5.1.6, AIRCRAFT HAZARDS), whereby an analysis of consequences is not required if, as here, the probability assessment yields a value of less than 10^{-7} per year. The Staff's witness, in response to Board questions, indicated that in his professional judgment consequences are not entirely ignored by the 10^{-7} probability guideline. If, for example, the consequences were so severe as to threaten a monumental loss of life or property, a different approach would be taken before deciding whether to permit plant operation (Tr. 673-675).

48. Irrespective of the foregoing, the Joint Intervenors at various times during the course of the hearing requested that the Applicants and the Staff provide witnesses to discuss the consequences of an accident caused by a larger than 200 thousand-pound aircraft colliding with the facility (Tr. 590-600, 615-616, 621, 632-650, 713). By written motion dated April 15, 1977, Joint Intervenors sought to have this Board compel the Applicants to produce witnesses on such consequences. We denied that motion orally at the evidentiary hearing on May 18, 1977 (Tr. 1549). On August 8, 1977, we set out in writing the basis for that denial. We there took the position that under the Commission's scheme of regulation, Applicants need not be concerned with the consequences of extremely improbable accident events (less than 10^{-7} per year) such as we find here. We adhere to that view for the reasons stated in our Order of August 8.

49. We turn now to the frequency of heavy aircraft operations (Item (b)(iii) above). As noted above, the Applicants have established that for 1976 about 511 heavy (200 thousand pounds or greater) aircraft used the Harrisburg International Airport in those flight patterns that could potentially pose a threat to the TMI-2 facility. This corresponds to one to two operations per day for 1976, compared with five to six per day at the time of the Staff's review of Unit 1. At that time, the Staff concluded that about 2,400 operations per year represented no undue risks to the health and safety of the public. The Unit 1 technical specifications require that the Applicants monitor and report to NRC the number and size of craft using the field. Only a substantial increase in the usage rate would warrant the Staff's reconsideration of its position (supplemental testimony of J. B. J. Read, following Tr. 1297). The Board's questions concerning the options that the Staff might then exercise resulted in supplemental Staff testimony to the effect that Department of Transportation information projects a 50% to 100% increase in airport operations during the period 1975 to 1990; conservatism in the crash probability analyses are consistent with the Staff's judgement that a significant increase in the frequency of operations is needed to justify a reevaluation of the risk to the public of larger than design basis aircraft; corrective measures such as restrictions of airspace in the site vicinity or hardening of plant structures could potentially be undertaken; alternatively, plant shutdown may be required if the crash probability becomes unacceptably large.

50. We find that proper account has been taken of the current and anticipated airport traffic. Indeed, we find that there will be an adequate opportunity to anticipate an increase in heavy aircraft traffic well in advance of any increase potentially posing an unac-

ceptable risk. We find that such an increase is unlikely and that should it nevertheless occur, acceptable corrective measures can be taken to make the risks acceptable.

Contention 6

The environmental radioactivity monitoring program of the Applicants is inadequate to accurately measure the dose delivered to the public during normal and accident conditions. Only active, real-time detectors can determine what the actual dose rate is. Furthermore, an array of offsite detectors could greatly aid in possible evacuation plans. No operating license should be granted until the Applicants provide a network of active radiation monitors.

51. The Board views this Contention as comprising two allegations:
(a) The actual radiation dose received by the public during normal and accident conditions can be properly measured only if offsite, real-time detectors are deployed.
(b) The implementation of evacuation plans could be greatly aided by the deployment of such detectors.

52. Based upon a review of Applicants' present capabilities to monitor and assess radioactive releases from TMI-2, as well as upon the advantages and disadvantages of employing active real-time detectors, the Applicants and the NRC Staff are in agreement that the current monitoring capabilities of Applicants are adequate. They also agree that installation of the type of real-time detectors currently commercially available would provide no meaningful improvement over the existing system; indeed, certain disadvantages were noted. For normal releases, the Applicants sample and analyze the release at its source prior to discharge, monitor the release at the time of discharge, and variously take continuous composite samples and grab samples of releases. Through a wide variety of types of samples, of types of detectors, and of locations, including thermoluminescent dosimeters, sampling of surface water, drinking water and rain water, collection of particulates and iodines, and collection and analysis of vegetation, soil, and agricultural products in the TMI site environs, radiation levels and radioactivity around the plant site are measured to assist the Applicants in assessing the impact of releases, and to provide confirmation of the effluent monitoring results done at the points of release.

53. With respect to off-normal conditions that might justify the evacuation of members of the public within the low population zone, testimony was offered to the effect that the environment monitoring program is not intended for use in formulating nor in implementing evacuation plans. With respect to the ability of active, real-time detectors to aid in evacuation plans, such detectors would again be of little or no value. Instrumentation used to determine the severity of an accident, and the need for any offsite emergency action, is located on site and is monitored from the reactor control room. This instrumentation monitors area conditions and process variables such as the reactor coolant temperature and pressure and any abnormal release of radioactivity. In the event that accident conditions arose for which evacuation would be an effective protective measure, necessary measurements and corrective actions to mitigate the consequences, including notification of offsite emergency personnel, would be performed quickly, within 10-15 minutes of the incident. It would, therefore, be unlikely that any offsite active detectors would register any abnormal reading since no release from the containment would as yet have occurred. Only after some period of time (to allow the release and transport of radiation emitters) would the detectors be of any use, and even then they would add nothing to the information that the previously dispatched offsite survey teams would not already have gathered.

54. In summary of this matter, the Board finds that the radiological effluent and environmental monitoring programs as proposed by the Applicants and approved by the Staff are adequate to measure and evaluate normal radioactive effluent releases and to measure radioactivity in the plant environs; and that active, real-time detectors would add nothing to the present capability. We further find that the response or effectiveness of both in-plant instrumentation and offsite personnel in the event of an accident would not be aided or improved by such detectors (testimony of Porter, following Tr. 1011; testimony of Osloond and Stoddart, following Tr. 1060; testimony of Van Niel, following Tr. 1060; testimony of Wayne Britz).

Contention 8

The warning and evacuation plans of the Applicants and the Commonwealth of Pennsylvania are inadequate and unworkable. The plans assume that all local and state officials involved are on 24-hour notice and can be contacted immediately. They further assume that all people notified will promptly react and know how to respond and are trained in what to do. They also assume that the public which has been assured that accidents are "highly unlikely" or "highly improbable," will respond and allow themselves to be evacuated. No operating and evacuation plans are shown to be workable through live tests.

58. The Applicants' prepared testimony described the plans and procedures which govern their actions in accident situations; described the equipment relied upon both for accident detection and evaluation and for assured communications with offsite authorities; and described pertinent portions of their training program, including emergency drills (testimony of J. G. Herbein, G. P. Miller, and R. W. Dubiel, following Tr. 757; testimony of Thomas Potter, following Tr. 1556). The Joint Intervenors presented no prefiled testimony, but conducted extensive cross-examination and submitted proposed findings on this contention. This was the only contention for which the Commonwealth presented prepared testimony and submitted proposed findings, adopting as its own the Applicants' proposed findings numbered 43 through 56.

59. The Witnesses for the Commonwealth of Pennsylvania were from the state and local civil defense organization. Their testimony described the civil defense organizational structure; the action plans that would be followed in the event of an emergency, including a nuclear power incident; and described their experience in evacuation involving nonnuclear events (testimony of K. J. Molloy and C. A. Williamson, following Tr. 801).

60. The Staff's testimony described the results of its review of the Applicants' emergency response plans, including the ability to provide early warning to the public, to arrange for public evacuation, and to interface appropriately with the state (testimony of C. R. Van Niel, following Tr. 1701; testimony of Charles Gallina and Phil Stohr).

61. We see no need to recite here-as do the proposed findings of the Applicants, the Commonwealth, and the Staff-those uncontradicted, descriptive characteristics of the Applicants' state of preparedness, nor that of the cooperating state and local agencies upon whom the success of the emergency plans depend. We find these to be adequate. We do address those assumptions deemed by the Intervenors to be necessary for the success of the emergency plans, and hence challenged by this contention, namely,

(a) that appropriate state and local officials are available to be contacted any time they are needed;

(b) that such personnel, upon being notified, will know the right thing to do and will do it promptly because they have been so trained; and

(c) that any members of the public that should be evacuated will respond appropriately and will permit themselves to be evacuated despite there having been no live drills or tests of the public response.

Underlying all of those is the need for the existence of dependable, prompt, and intelligible modes of communication amongst the emergency plan participants and with the public. The referenced testimony is replete with evidence confirming this. Examination by the Intervenors and the Board cast no doubt upon the adequacy of the communications equipment and the various modes of communication. The Board finds these matters to be satisfactory.

62. We turn now to Item (a) above. In the event of an accident, TMI-2 personnel initially contact the State Council of Civil Defense Duty Officer and the Dauphin County Civil Defense Headquarters. Calls also would be made by Applicants directly to Pennsylvania State Police, Hershey Medical Center, and the Brookhaven Assistance Group, as necessary. The State's Civil Defense (CD) Duty Officer is available twenty-four hours a day, seven days a week; the County Civil Defense Headquarters, which serves as the constant communications center for all emergencies in the county, is always manned. Similarly, Pennsylvania's Bureau of Radiological Health (BRH), which is the Commonwealth's expert radiological advisor and whose personnel are notified immediately by the state civil defense duty officer, maintains a number of contact points where BRH representatives can be reached by the CD duty officer. Upon receipt of the call from the CD duty officer, the BRH representative then contacts TMI on one of its multiple phone lines to confirm the validity of the initial notice to CD and to receive details of the event. In the event that BRH cannot be contacted (considered remote in view of BRH's multiple contact points and successful drills in the past), civil defense could proceed based on Applicants' expert recommendations as to the need for protective action.

63. The Dauphin County CD unit claims to have responded effectively to several disasters over the past several years involving evacuation of the public and the handling of physical injuries. These claims were not disputed. The Board finds that a randomly required initiation of the appropriate emergency response plans will not fail due to any inability to contact state and local officials.

64. Regarding Item (b) as noted above, prior successful disaster responses (albeit to nonradiological events) also support the conclusion that state and local officials are knowledgeable about their jobs. Joint Intervenors and the Board were particularly interested in the effect on the emergency response plans if the state's lead radiological assessment agency, i.e., the Bureau of Radiological Health, should suffer a reduced capability. This

possibility was suggested by a press release from the Department of Environmental Resources, within which BRH operates, indicating that the state budget may reduce funds for radiological monitoring (Board Exhibit 1). NRC Staff witnesses, when presented with information in the press release, generally observed that the NRC requires an adequate emergency plan, and that should that plan become insufficient for some reason, the Applicants would be required to fill the gap (Tr. 1075-1090). In fulfilling the Board's request to specifically address the question of responsibilities (Tr. 1097-1099), the Staff determined that it would, in fact, have several options available to it, including having the Applicants fill the void, looking to other groups within the state, or perhaps filling the void at the Federal level (Tr. 1745-1749). Furthermore, the Staff's witness observed that the Applicants' monitoring capability outside the LPZ would be more than adequate until such time as subsequent or supplemental monitoring teams would be available to the Commonwealth. Indeed, the NRC regional office itself could provide up to 20 additional inspectors, in addition to other teams from Brookhaven Laboratory and radiological teams from western Pennsylvania (Tr. 1806-1809).

65. The testimony stresses the drills and training that various emergency response groups undergo. The Commonwealth's civil defense witnesses saw no compromise of their own effectiveness of response because of their not having technical knowledge and training concerning radiological matters. Staff witnesses testified that the Commonwealth's BRH possessed the requisite radiological know-how needed to assist with protection of the public health and safety. The Board finds that the evidence adequately supports the conclusion that the effectiveness of state and local officials is based upon an adequate knowledge of their job. These officials will not be hampered by not having had technical training in radiological matters.

66. Finally, we address Item (c), regarding the necessity of the public's being subjected to live tests or drills in order to insure that it will respond appropriately. All witnesses agreed that members of the public need not be drilled to assure their proper response to emergency evacuation instructions. Witnesses for the Commonwealth's CD organization explicitly offered the opinion that such drills might be counter-productive, citing a Stanford Research Institute study to support this opinion, and pointed to the actual behavior of the public during disasters in their own recent experience as being satisfactory and supportive of the lack of need for drills. The Staff similarly cited an EPA evacuation study. Examination by the Intervenors elicited the information that conclusions regarding the lack of need for public drills were without the benefit of experience with radiological events requiring evacuation. Nevertheless, the Board's examination revealed that such diversity of nonradiological events had been successfully dealt with to provide confidence that drills are not necessary. Furthermore, the Board additionally determined that the civil defense emergency preparedness literature that has been disseminated to the public is being revised to include radiological awareness and response information. The ability of the County's CD organization to adequately cope with the management of public vehicular traffic during an evacuation was also examined by the Board (Tr. 1731-1735; Tr. 1840-1841; Tr. 2528-2541).

67. The Board thus finds that Item (c) states an assumption supported by a preponderance of the evidence. More broadly, we find that the record supports the conclusion that Contention 8, in its entirety, is without merit and that the Staff has properly assessed the adequacy and workability of the emergency response. We also find the emergency and evacuation plans to be both adequate and workable.

[1]On August 15, 1974, a petition to intervene was filed by Gertrude and Frederick Hellrich, et al. Intervention was granted by the Board but thereafter, on August 20, 1976, these intervenors withdrew from the proceeding.

[2]At the evidentiary hearing in this matter, the Applicants and the Commission's Regulatory Staff made their responses to a number of questions asked by the Licensing Board. The matters raised by the Board concerning the issues in controversy among the parties, or the environmental review, are discussed in this decision.

Cite as 8 NRC 9 (1978)

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

ATOMIC SAFETY AND LICENSING APPEAL BOARD

Alan S. Rosenthal, Chairman
Dr. W. Reed Johnson
Jerome E. Sharfman

Docket No. 50-320

In the Matter of
METROPOLITAN EDISON COMPANY, et al.
(Three Mile Island Nuclear Station, Unit No. 2)

July 19, 1978

DECISION

Unit No. 2 of the Three Mile Island Nuclear Station (TMI-2), located adjacent to a similar unit on an island in the Susquehanna River about 12 miles from Harrisburg, Pennsylvania, received a construction permit in November 1969, prior to enactment of the National Environmental Policy Act (NEPA). Therefore, no environmental review was performed in connection with the application for that permit. Subsequently, after the applicants (Metropolitan Edison Company, et al.) had sought an operating license, a Licensing Board undertook to consider both (1) those environmental and safety questions bearing upon the issuance of such a license; and (2) whether, as a result of a complete environmental review, the previously issued construction permit should be continued, modified, terminated, or appropriately conditioned to protect environmental values[1]

On December 19, 1977, the Licensing Board issued an initial decision in which it concluded that the construction permit should remain in effect and authorized the Director of Nuclear Reactor Regulation to make findings requisite to issuance of a full-term operating license (subject to specified environmental conditions).[2] Exceptions to that decision were filed by Citizens for a Safe Environment and the York Committee for a Safe Environment, joint intervenors below.[3] Those intervenors also moved us to stay the effectiveness of the initial decision. In ALAB-456, 7 NRC 63 (January 27, 1978), we denied the motion.

The intervenors renewed their stay request before the Commission.[4] They stressed, as they had before us,[5] their disagreement with the Licensing Board's rejection of their claim that the environmental review of the nuclear fuel cycle had not correctly dealt with the effects of radon (Rn-222) releases generated by mill tailings produced in the course of the mining and milling of uranium. In ALAB-456, we had held that this claim was "barred as a matter of law for the reason that it constitutes an impermissible attack upon a generic regulation of the Commission"-Table S-3 of 10 CFR 51.20(c).[6] The Commission, however, as was within its (but not our) authority, agreed with the intervenors that the radon release values in Table S-3 were incorrect and accordingly set aside that portion of the table. CLI-78-3, 7 NRC 307 (March 2, 1978). Although it denied the requested stay, the Commission directed us to review the issue "as though no Rn-222 release figure had been determined by regulation iii Table S-3." Id. at 310. With that in mind, and following discussion of the matter with the parties at oral argument, we remanded the radon issue to the Licensing Board for further consideration. ALAB-465, 7 NRC 377 (March 27, 1978). But subsequently, in an order encompassing all the cases before us involving the radon matter, we determined that one particular proceeding pending before a licensing board should be treated as the "lead case," with supplementary material to be received in other cases (including this one) where appropriate. *Philadelphia Electric Company* (Peach Bottom Atomic Power Station, Units 2 and 3), et al., ALAB-

480, 7 NRC 796 (May 30, 1978). As a result, we vacated the remand in ALAB-465. The radon issue remains before us pending the pursuit of the procedures outlined in ALAB-480.[8]

Now ripe for disposition are the remaining issues raised by the intervenors on appeal. Only two are sufficiently substantial to warrant discussion: the adequacy of the applicants' emergency plan and the probability of a crash of a heavy aircraft into the plant. With respect to the former question, the intervenors have moved to reopen the evidentiary record. We have reviewed their claims and have found insufficient cause either to reopen the record on the emergency plan or to disturb the result reached by the Licensing Board on that question. As for aircraft crashes, our review has led to a different result. The record does enable us to find reasonable assurance of safety given present levels of aircraft traffic in the vicinity of the plant. But it contains sufficient inconsistencies and ambiguities relative to aircraft crash probabilities over the life of the plant that we must order a further hearing on that question. There is, however, no need to suspend the operating license pending the outcome of that hearing.[9]

I. EMERGENCY PLANNING

A. The Final Safety Analysis Report (FSAR) for every operating license application must include "[p]lans for coping with emergencies." 10 CFR 50.34(b)(6)(v). While it need not include the "details of these plans and the details of their implementation," the FSAR must at least describe certain defined elements "to an extent sufficient to demonstrate that the plans provide *reasonable* assurance that appropriate measures can and will be taken in the event of an emergency to protect public health and safety and prevent damage to property." 10 CFR Part 50, Appendix E, Part III (emphasis supplied).[10]

The emergency plan for this reactor appears in Section 13.3 of the FSAR, as supplemented by Appendix 13A. Additional descriptive material relating to the plan was presented by a panel of the applicants' witnesses (Herbein, et al., prepared testimony, fol. Tr. 757) and by two witnesses sponsored by the Commonwealth of Pennsylvania (fol. Tr. 801). The staff both reviewed the plan in its Safety Evaluation Report (SER, Section 13.3) and presented testimony on it (Van Niel, prepared testimony, fol. Tr. 1701).

In general, the plan anticipates that "the station will be self-sufficient in handling emergency conditions" but that "outside agencies will be called upon as needed" (FSAR, Section 13.3.1). The applicants are to be responsible for initially detecting the occurrence of an accident or event giving rise to an emergency situation; taking corrective action (where possible); assessing potential offsite and onsite effects, and timely notifying local, State, and Federal authorities (Herbein, *et al.,* pp. 1, 4). Among the authorities that might assist in responding to an emergency are the State and local (Dauphin County) civil defense organizations, the Pennsylvania Bureau of Radiological Health (BRH), the State Police, local fire departments, and the NRC Brookhaven Assistance Group (id., pp. 3-4, 10). The record includes agreements between the applicants and various outside organizations spelling out the responsibilities the organizations would assume.

Stated in an extremely simplified way, the sequence of activities following an accident or incident, or other cause of radioactive release, would be as follows. The occurrence of the event would be detected, and its severity assessed, by means of instruments located onsite and monitored in the control room (and confirmed and augmented by portable equipment)(see Herbein, *et al., p. 5;* also, LBP-77-70, 6 NRC at 1201-02). Thereupon, the applicants would notify first the State Council of Civil Defense duty officer (who is available at all times) and then (as necessary) the State Police, a nearby medical center, and NRC (Herbein, et al., p. 10; Tr. 792). In the event of the most serious type of incident, the occurrence would become known in seconds, and the duty officer would be notified within 5 minutes (Tr. 1606). That officer in turn would notify the county civil defense organization (ibid.), which is also manned without interruption (Molloy, prepared testimony, fol. Tr. 801, p. 3), and the BRH duty officer. BRH would confirm the notification by recontacting the applicants (Tr. 1611, 1745, 1827A).

The information provided by the applicants to the State and local organizations would vary depending upon the nature of the event in question (Tr. 767-68); in all instances, however, it would include such data as might be available to assist in determining whether (and in what area) evacuation was called for. The applicants would also make a recommendation as to evacuation (Tr. 1606-07), but the State would make the final determination, based upon the advice of BRH (Herbein, et *al.,* pp. 3-4; Tr.

1363-64, 1481-82, 1625, 1654-57). The Dauphin County Civil Defense organization, acting through local fire and police departments and local civil defense personnel, would carry out the evacuation.

The Environmental Protection Agency has promulgated guidelines which would call for protective action to avoid doses to individuals in excess of 5 rem whole body of 25 rem to the thyroid." The applicants' evidence indicated that, assuming the occurrence of the maximum hypothetical accident postulated under 10 CFR Part 100, nondispersive atmospheric conditions, and the transport of radioactive material in the direction of the greatest number of people near the site (i.e., north, toward Middletown, Pennsylvania), those dose levels would not be exceeded (1) within 45 minutes of the time of the event at a distance of 1 mile from the site; (2) within 3 hours at a distance of 2 miles from the site (on the fringe of the more densely populated areas of Middletown); (3) within 5 hours in the center of Middletown; and (4) at any time beyond 4.8 miles from the site (Herbein, *et al.,* pp. 8, 9). The Director of the Dauphin County civil defense organization (Kevin J. Molloy) testified that, in these circumstances, no more than 15,000-18,000 persons would have to be evacuated (Molloy, *supra,* p. 7; Tr. 1409,1447-48,1452). He concluded that "we could effect and complete an evacuation of this type within the period allotted us"-i.e., less than 1 hour for persons located closest to the island, less than 3 hours for those on the edge of the more densely populated areas of Middletown, less than 5 hours for those in the center of Middletown, and "a couple more hours" out to 5 miles (Molloy, pp. 10, 6; Tr. 1411). The staff determined that the organization and procedures proposed were adequate and that the applicants' plan satisfied applicable requirements (Van Niel, pp. 4-5). The Licensing Board agreed, finding the emergency and evacuation plans to be "both adequate and workable." 6 NRC at 1206.

B. With this background in mind, we turn to the particular criticisms leveled against the emergency plan by the intervenors. Both before the Licensing Board and on appeal, the intervenors have asserted that the plan is "inadequate and unworkable" for several discrete reasons-vir

> The plans were based upon the unproven and questionable assumptions that all necessary officials will be available at all times, will know how to respond and will react promptly, and that members of the public will respond to a radiological emergency and allow themselves to be evacuated....

Brief on appeal, p. 8. They additionally have advanced two legal claims: that the Board improperly limited the scope of their cross-examination, and that the plan is inconsistent with the Price-Anderson Act. We will treat these matters *seriatim.*

1. Central to the intevenors' challenge to the adequacy of the evacuation plan is their expressed belief that "live tests and drills" are essential. They reason that radiological emergencies are different from other emergencies and that the effectiveness of the plan can be ascertained only through tests involving the potential evacuees.

The evidence, however, is to the contrary. Witnesses for the Commonwealth expressly discounted the need for or desirability of live drills. The Director of Civil Defense for Dauphin County questioned whether such drills would be meaningful and whether most people would participate; indeed, he suggested that they might prove counterproducfive inasmuch as a real emergency was not likely to conform to a test situation and an appropriate response to one might not be an appropriate response to the other (Molloy, p. 13; Tr. 1463). On the basis of a Stanford Research Institute study, substantiated by his personal knowledge of two events in Pennsylvania, the Deputy Director of the State Council on Civil Defense expressed a similar view (Williamson, prepared testimony, fol. Tr. 801, p. 10). He specifically pointed to (1) a planned extensive public evacuation exercise in Erie, Pennsylvania, in which actual public participation had been "minimal" and (2) the successful evacuation within approximately 4 hours of more than 100,000 people from Wilkes-Barre in the wake of Hurricane Agnes *(ibid.).* To the same effect, see also Tr. 1463, 1468-69 (Molloy); Tr. 1642-43 (applicants' witness); Tr. 1829-32, 1938-42 (staff witness); but cf. Tr. 1835 (recognizing "some diversity of opinion" in this area). Accordingly, the Licensing Board's rejection of the intervenors' thesis regarding live drills (6 NRC at 1206) is well-founded in the record.[12]

Closely tied to the intervenors' claim regarding the need for live drills is their assertion below that a predicate to a successful emergency plan is knowledge on the part of those who would be evacuated of the nature and consequences of radiological events.[13] As in the case of live drills, however, the record firmly establishes that such knowledge is not necessary. Indeed, a staff witness who had participated in the review of the emergency plan testified, on the basis of his more than 5 years' experience in emergency planning, that "the general population reacts more readily, fears more readily things which it knows nothing about" (Tr. 1852); and that, when confronted with such an event, a person "generally responds to people who tell him what to do to protect his health.... It is the fear of the unknown that makes [people] act" *(ibid.).*

2. Although discounting the need for live drills involving the public, the witnesses for the Commonwealth, the applicants, and the staff all acknowledged the desirability of drills for personnel assigned responsibilities under the emergency plan.[14] The plan provides for such drills by applicants' personnel and others charged with responsibilities under the plan. **See** FSAR, App. 13A, Section 13A.10; Herbein, et al., pp. 11-12; Molloy, p. 12, and Tr. 1457; Williamson, pp. 9-10; Van Niel, p. 4 and Tr. 1829-30

The intervenors' only challenge to these provisions (aside from the failure to involve the general public, as discussed above) appears to rest on their assumption that the drills are announced in advance and hence are not "random." This assumption is not justified. It is founded wholly on the acknowledgement by an applicants' witness that some drills are scheduled and the participants so advised (Tr. 786-88, 793). But the same witness indicated that such notice is given for only one-third to one-half of the drills (Tr. 793)(see also Tr. 1079).

It bears noting that the provision for drills for Unit 2 parallels the requirement in effect under the emergency plan for Unit 1 (Tr. 1655). A staff witness testified, without contradiction, that he had observed two full-scale drills at Unit 1 and "in my opinion the drills [were] probably some of the best drills that I have seen conducted, wider in scope than I have seen in other areas, and the emergency planning as a whole has proven to me, or has been shown to me as being much more than adequate" (Tr. 1856).

3. The intervenors challenge the adequacy of the training program for persons who will carry out an emergency plan.[15] Specifically, they claim that the plan can be effective only if those persons have expert knowledge of the effects of radioactivity. But they point to no evidentiary foundation for that proposition.[16] Indeed, all the testimony on this subject contradicts the intervenors' conclusion. Mr. Molloy emphasized that he is able to fulfill his evacuation responsibilities effectively without specialized knowledge of radiation. He maintained that his evacuation personnel are adequately trained to carry out their responsibilities and, additionally, have expert assistance available to assist them-primarily from BRH and the applicants (Molloy, p. 5). Further, one of his staff members is a radiological defense officer (Tr. 1356-58,1361) and several hundred persons in Dauphin County have been trained in radiological monitoring and are available to assist in an emergency, in most instances as volunteer firefighters (Tr. 1359-60). Approximately 50 percent of those who might aid in an evacuation have either taken Pennsylvania's radiological monitoring course (as Mr. Molloy did)[17] or had other radiological training (Tr. 1449-50).

Even more important, Mr. Molloy insisted that those responsible for an evacuation would not need "detailed knowledge" of the event compelling that action (Molloy, p. 6). Rather, useful knowledge would be strictly limited and of a different genre:

> What we need to know is generally the nature of the problem, secondly what segment of the public will be or could be affected, and what action on our part is recommended. With this information, our organizational structure and communications capabilities allow us to respond very quickly, calling upon and coordinating whatever groups or agencies the situation dictates.

Ibid.; see also Tr. 1363. To the same effect, see Tr. 1686-87 (applicants' witness). Mr. Molloy expressed confidence that his organization had (or would have available to it) adequate knowledge of this sort (Molloy, pp. 5-6, 10-11; Tr. 1370-73,1722-24).

On this score, the staff testimony went even further. It pointed to an Environmental Protection Agency study (EPA-520/6-74-002, June 1974) analyzing some 500 events-including floods, fires, hurricanes, explosions, and release of toxic substances-that had prompted evacuation. The study had found no statistically significant difference in the effectiveness of evacuation with an emergency plan and without such a plan. A staff witness opined that the study was relevant "because it talks about the movement of people. The reason for the movement, I think, is of secondary importance" (Tr. 1828). He added that the staff nonetheless believes it prudent that there be "proper training and planning on the part of the officials responsible for evacuation" (Tr. 1833). Another staff witness attributed the emergency plan requirement to the Commission's concept of "defense in depth" (Tr. 1834).

Finally, Mr. Molloy pointed to the wide variety of emergency situations in which his organization had successfully carried out evacuations (Molloy, p. 11). He specifically mentioned floods, a plane crash, a passenger bus accident, a train derailment *(ibid.),* and natural gas seepage (Tr. 1361-62). And he unequivocally stated that his actions did not depend on detailed knowledge of these matters (Tr. 1362).

Given this evidentiary record, the Licensing Board's conclusion that the effectiveness of State and local officials will not be hampered by a lack of technical training in radiological matters (6 NRC at 1206) is manifestly correct.

4. The intervenors' remaining factual challenge to the Licensing Board's evacuation determination is somewhat vague and diffuse; we understand it,

however, to question the "availability at all times" of "officials" charged with evacuation responsibilities. Although their brief on appeal does not specifically identify the "officials" intervenors have in mind, it seems probable that the intended reference was either to State (or local) civil defense or to radiological health personnel.

a. No evidence of record casts doubt upon the testimony that the State civil defense duty officer is available continuously and that Dauphin County civil defense headquarters is likewise always staffed (Herbein, *et al., p. 10;* Molloy, p. 3; Van Niel, p. 2). Moreover, in every test of the communications system, whether announced or random, the State or county official sought to be reached was available (Tr. 792-94).

b. Insofar as BRH personnel are concerned, we have seen that those individuals serve as radiological advisers to State and local civil defense personnel and, under the evacuation plan, would advise as to the appropriateness of evacuation in a given situation (see pp. 15, 18, *supra).* BRH also engages in offsite monitoring following an accident (Tr. 1075-76, 1668-69). Further, both Mr. Herbein (the applicants' witness) (Tr. 1607, 1625) and Mr. Molloy (Tr. 1363-64) indicated that the receipt of advice from a knowledgeable source (such as BRH) was perhaps the most significant element in determining whether evacuation should occur (as well as the area involved).

At the hearing below, the intervenors questioned whether budgetary curtailments would make BRH unavailable for or incapable of performing its assigned functions. Their inquiry was founded on a public announcement of the Pennsylvania Department of Environmental Resources (BRH's parent organization), dated May.13, 1977, to the effect that a budget cut for the 1977-78 fiscal year approved by the Pennsylvania Senate would result in a drastic curtailment of that department's services, including, *inter alia,* a reduction in the "radiologic health environmental monitoring program and emergency response capability" (Bd. Exh. 1, Tr. 1081-82).

But the record contains more than enough to support the conclusion that others could fulfill BRH's responsibilities under the emergency plan. The applicants indicated that, if necessary, they would notify NRC and make specific recommendations to achieve a substitution for BRH's capabilities (Tr. 1570-71). And there are clear indications that State and local civil defense officials are willing to rely upon advice provided by the applicants or NRC, either in conjunction with that of BRH or independent of it (Tr. 1363-64, 1368, 1499-1500, 1541, 1720-21, 2467, 2529-32). Beyond that, the staff stated that it would require resort to one or more of a number of available means to fill the "void in the overall emergency preparedness" created by any inability of BRH to provide expected services (Tr. 1780-82; 1748-49).[18] Still further, the staff pointed out that-it will keep track of the Commonwealth's continuing ability to fulfill its assigned responsibilities (Tr. 1078-79, 1087, 1746). Notwithstanding the intervenors' claim to the contrary, the record amply supports the conclusion that others could take over the functions assigned BRH in the emergency plan without the public safety being compromised.

c. In their appellate brief, the intervenors attempted to augment their position on BRH's potential lack of capability by referring to a statement made by the BRH Director at an EPA workshop (November 30-December 1, 1976). The statement analyzed the BRH experience in monitoring radioactive fallout from Chinese nuclear tests conducted in October 1976; and although indicating that BRH generally reacted satisfactorily to demands made upon it in the "fallout crisis," expressed serious doubt that it "would have been able to have responded as well" had there been a nuclear reactor accident.

That statement appeared in a draft EPA report which was not in the record before the Licensing Board. At oral argument, therefore, we advised the intervenors' representative that we could consider it only if he moved to reopen the record to include it. Somewhat belatedly, he did so.[19] In ALAB-474, 7 NRC 746, 748 (May 5, 1978), we decided to hold the motion in abeyance pending our review of the record on emergency planning and then to determine it on the merits (despite its tardiness) because it addressed an important safety question.

We recently have had occasion to reiterate the standards for reopening a record. *Kansas Gas & Electric Company* (Wolf Creek Generating Station, Unit No. 1), ALAB-462, 7 NRC 320, 339 (March 7, 1978). As we there stressed, the proponent of a motion to reopen bears a heavy burden. The motion normally must be timely presented and addressed to a significant issue. Moreover, if an initial decision has already been rendered on the issue, it must appear that reopening the proceeding might alter the result in some material respect. In the case of a motion which is untimely without good cause, the movant has an even greater burden; he must demonstrate not merely that the issue is significant but, as well, that the matter is of such gravity that the public interest demands its further exploration. See *Vermont Yankee Nuclear Power Corp.* (Vermont Yankee Nuclear Power Station), ALAB-138, 6 AEC 520, 523 (1973); id., ALAB-167, 6 AEC 1151-52 (1973). These criteria govern each issue to be reopened; the fortuitous circumstance that a proceeding has been or will be reopened on other issues has no significance. See *Georgia Power Company* (Alvin W. Vogtle Nuclear Plant, Units 1 and 2), ALAB-291,.2 NRC 404, 413-14 (1975).

Plainly, intervenors' motion does not satisfy the above criteria for reopening.[20] Review of the statement and analysis of the issue demonstrate that the BRH Director raised only one matter relevant here: whether the bureau could fulfill its responsibilities for postaccident monitoring under the emergency plan. The statement does appear to question BRH's existing ability to conduct widespread environmental sampling and long-term laboratory analyses of such samples-activities incident to, but not directly involved with, emergency evacuation procedures. As we have seen, however, the question of BRH capability to respond to an emergency has already been fully litigated, in the context of the budgetary constraints which BRH might face. And we have also determined on this record that BRH participation is not essential to a successful emergency evacuation, since the applicants and NRC could fulfill the responsibilities assigned under the plan to BRH. That being so, reopening the record could not change the result previously reached and hence is not warranted.[21]

5. The intervenors claim that the Licensing Board improperly limited their cross-examination with respect to the size of the area to be considered for evacuation in the emergency plan. They insist that they should have been allowed to explore the feasibility of evacuation of areas beyond 5 miles from the reactor.

Intervenors' position is directly contrary to *New England Power Company* (NEP, Units 1 and 2), et al., ALAB-390, 5 NRC 733 (1977). We there determined that existing Commission regulations do not require consideration in a licensing proceeding of "the feasibility of devising an emergency plan for the protection (in the event of an accident) of persons located outside of the low population zone." 5 NRC at 747. The LPZ for this facility extends 2 miles out from the reactor (SER, Section 2.1.3). It is true that, for reasons which need not be discussed here, the applicants and the staff nevertheless looked into the possible need for protective measures within a 5-mile radius of the reactor-and the intervenors were permitted to cross-examine on the evidence presented in this regard. It scarcely follows from this fact, however, that the question of emergency planning at still greater distances from the LPZ boundary had to be explored at the intervenors' instance.

Intevnenors further argue: "The prejudice to the public interest by this restriction of inquiry to evacuation of the areas in the immediate vicinity of TMI-2 is compounded because the record had already shown that a Class 9 accident at TMI-2 could occur by the crashing of a large aircraft into the TMI-2 plant." The likelihood of such a crash is discussed in Part II of this opinion and in Mr. Sharfman's dissent. It suffices for our purposes here to recall that the requirements for evacuation planning are rooted in 10 CFR Part 100,[22] and that Part 100 assumes releases of radiation based upon a hypothetical major accident "that would result in potential hazards not exceeded by those from any accident considered credible."[23] Thus, what accidents might conceivably occur at the particular plant in question is irrelevant to planning for emergency evacuation; that is based solely on the Part 100 hypothetical accident and the assumed releases of radioactivity resulting therefrom.

6. Intervenors' claim that the emergency plan[24] somehow runs afoul of the Price-Anderson Act merits little discussion.[25] It appears to rest on the thesis that the applicants will be the sole source of radiological information in the event of an accident; that, as a result of Section 190 of the Atomic Energy Act, as amended, 42 U.S.C. 2240, such information "cannot be used as evidence against the applicant in court"; and, hence, that the vesting of emergency plan responsibilities in the applicants (particularly those related to monitoring) "denies victims of a nuclear accident the opportunity to introduce in court the only evidence likely to establish a claim under the Price-Anderson Act." This line of reasoning is, however, defective in several respects.

In the first place, intervenors' factual premise that applicants are the sole source of radiological information is plainly incorrect. Postaccident monitoring is the responsibility not only of the applicants but also of State agencies (primarily BRH), the Department of Energy, the NRC, and others (Tr. 1093-94, 1578-81, 1613-14, 1668-70, 1678, 1742-43, 1767, 1805-06). Even if BRH should be unable to fulfill its monitoring responsibilities, other agencies (both Federal and State) would take up the slack. See p. 20-21, *supra*.

More important, the intervenors' legal premise is far wide of the mark. Section 190 of the Atomic Energy Act provides that

> No report by any licensee of any incident arising out of or in connection with a licensed activity made pursuant to any requirement of the Commission shall be admitted as evidence in any suit or action for damages growing out of any matter mentioned in such report.

The "action for damages" which intervenors have in mind is one arising under the provisions of

Price-Anderson (i.e., Section 170 of the Act (see fn. *24, supra.))* Under those provisions, the licensees waive, *inter alia,* "any issue or defense as to conduct of the claimant or fault of persons indemnified" (Section 170n. (I)(c)(i), 42, U.S.C. 2210 (n)(I)(c)(i); 10 CFR 140.2(c)). With limited exceptions not relevant here, a claimant would have to prove only causation and the severity of any injury in order to recover damages. The availability of the licensees' monitoring reports would be of little consequence because the Commission itself is required to make a public report on the incident (presumably to be based in part on information supplied by the licensees)(Section 170i, 42, U.S.C. 2210(i)).

Further, the use limitations in Section 190 are strictly limited to particular reports submitted to the Commission and (as the applicants concede) would restrict neither (1) an individual's rights informally to request or formally to discover information and data possessed by the applicants (as licensees) concerning the offsite consequences of an accident; nor (2) his use of that information and data. In other words, while the use of the report itself may be circumscribed by Section 190, the use of the information and data undergirding the report is not.

II. AIRPLANE CRASHES

As a result of the facility's relative proximity to Harrisburg International Airport (formerly Olmstead Air Force Base), a significant issue throughout this licensing proceeding (as well as that for Unit 1) has been whether the public is adequately protected against the hazards of a crash of an airplane into the facility. The reactor's vital structures, power supplies, and cooling water sources ("safety structures") have been designed to withstand the aircraft impact and fire effects from the crash of a 200,000-pound plane traveling at 200 knots, the "design basis crash."[26] The crash of an airplane heavier than 200,000 pounds into TMI-2 has been calculated by the applicants and staff to have such a low probability that it does not present a hazard to the public, and therefore the plant need not be designed to withstand its effects. Because the probability of an airplane crash is proportional to the level of aircraft traffic, the determination that the crash probability for heavy aircraft is acceptably low reflected both the current level of heavy aircraft traffic at the airport and the projected magnitude of such traffic in the future.

The Licensing Board accepted this analysis (6 NRC at 1197-1200), despite the intervenors' challenges to the crash probability assessments of the applicants and the staff. The intervenors appeal from the Board's determination.

[1]See 10 CFR Part 50, Appendix D, Section C (1974 ed.).

[2]LBP-77-70, 6 NRC 1185. An operating license (DPR-73) was issued on February 8, 1978. See 43 Fed. Reg. 7073 (February 17,1978).

[3]An appeal was also filed by a nonparty; we dismissed it for that reason. ALAB-454, 7 NRC 39 (January 23, 1978).

[4]On February 27, 1978, they also sought a judicial stay of the operating license authorization, but the court of appeals denied their request. *Kepford V. NRC,* No. 78-1160 (D.C. Cir., March 8,1978).

[5]The issue was before us both through the intervenors' exceptions and as part of the stay request.

67 NRC at 65. The Licensing Board had applied the Table S-3 values; the intervenors' position was that those values were erroneous. But that Board also admitted into evidence (and permitted cross-examination on) testimony proffered by the intervenors (and responsive testimony offered by the staff) on the health effects of radon releases and the effect of such releases on the comparative nuclear-coal cost-benefit balances. Without determining whether such testimony constituted an impermissible challenge to Table S-3, and granting *arguendo* the correctness of the intervenors' analysis, the Board determined the radon impact "to be of negligible materiality" and insufficient to alter the comparison between the nuclear and coal alternatives 6 NRC at 1224.

[7]*Duke Power Company* (Perkins Nuclear Station, Units 1, 2, and 3), Docket Nos. STN 50-488, STN 50-489, STN 50-490.

[8]On July 14, 1978, the *Perkins* Licensing Board rendered its partial initial decision on the radon matter. LBP-78-25, 8 NRC 87.

[9]This Board's *sua sponte* review of the remainder of the record has disclosed no other error warranting corrective action.

Insofar as intervenors' request for financial assistance is concerned, the Commission has held that no such assistance is to be granted in a proceeding of this type. *Nuclear Regulatory Commission* (Financial Assistance to Participants in Commission Proceedings), CLI-76-23, 4 NRC 494 (1976). We and the licensing boards are, of course, bound by that ruling. *Detroit Edison Company* (Greenwood Energy Center, Units 2 and 3), ALAB-376, 5 NRC 426, 428 (1977).

[10]The elements of an emergency plan which are identified in the regulations pertain to, *inter alia,* the organizational structure relied upon for coping with emergencies; communications systems to be used to keep various involved organizations informed of matters bearing upon their responsibilities, the means for determining the magnitude of radioactive releases; identification of first aid, decontamination, and treatment facilities; training of and drills for persons charged with emergency planning responsibilities; and criteria for determining the appropriateness of reentry into the facility and resumption of operations. 10 CFR Part 50, Appendix E, Part IV.

[11]Herbein, *et al.,* p. 9.

[12]We note that about a year ago the Commission denied a rulemaking request which sought a general requirement for licensees to conduct an "actual evacuation drill" as a precondition for obtaining a license 42 Fed. Reg. 36326 (July 14, 1977).

[13]The assertion does not appear to have been directly advanced on the intervenors' appeal.

[14]An emergency plan must include, *inter alia,* "[p]rovisions for testing, by periodic drills, of radiation emergency plans to assure that employees of the licensee are familiar with their specific duties, and provisions for participation in the drills by other persons whose assistance may be needed in the event of a radiation emergency." 10 CFR Part 50, Appendix E, Part IV.1. Significantly, the appendix lacks any requirement or suggestion that live drills involving the public be included in an emergency plan.

[15]An emergency plan must include "[p]rovisions for training of employees of the licensee who are assigned specific authority and responsibility in the event of an emergency and of other persons whose assistance may be needed in the event of a radiation emergency." 10 CFR Part 50, Appendix E, Part IV.H.

[16]In support of the proposition, they rely solely upon Mr. Molloy's admissions that his only special knowledge of radiation (or of the consequences of radiation) is derived from a week-long seminar on emergency planning for nuclear facilities (Tr. 1355-56, 813-14, 837; see also Tr. 1567). Plainly, that evidence provides no basis whatsoever for the point intervenors are attempting to make.

[17]See n. 16, *supra.*

[18]These means include the expansion of the applicants' capabilities, replacement of BRH by another State agency, development of an "interagency cadre" to handle the BRH functions, or possible assumption of responsibility by the Federal Government *(ibid.)* Cf. Williamson, p. 5.

[19]At our request, the applicants, by letter dated March 24, 1978, supplied us with a copy of the draft report.

[20]There is some question whether the intervenors' failure to raise the issue suggested to them by the December 1976 statement earlier than January 1978, when they filed the brief which first mentioned it, should preclude them from raising it now. The draft report is undated and it is unclear precisely when it was issued. An affidavit of the BRH Director states that he received it "early in 1977" (Gerusky, affidavit dated April 26, 1978, par. 3). Intervenors claim they were not aware of it until January 1978. But that, even if true, does not settle the matter.

Pennsylvania was participating in this proceeding as an "interested State" (see 10 CFR 2.715(c)). During the hearing below in April 1977, intervenors requested that a BRH witness appear and testify as to that organization's capabilities (Tr. 888). After the Commonwealth interposed an objection to that request, the intervenors withdrew it (Tr. 891). Even if the intervenors were not aware at that time of the December 1, 1976, statement of the BRH Director, had they persisted in their attempt to examine a BRH witness on BRH's capabilities and had their request to do so been granted, any present or projected weaknesses in those capabilities could have been brought to light by thorough questioning.

[21]There appears to be no evidentiary support whatsoever for other assertions made by the intervenors in their motion to reopen, to the effect that the Director of BRH had suggested in an otherwise unidentified public statement that he and members of his staff would not be on 24-hour call to respond to an emergency, and that the Director had stated in another unidentified statement that BRH had suffered a manpower loss "since the date of the EPA document." The Director by affidavit has explicitly denied making any such statements and has confirmed that BRH is in fact on 24-hour call. Gerusky, affidavit dated April 26, 1978, pars. 4, 5.

[22]NEP, *supra.*

[23]Footnote 1 to 10 CFR 100.11(a).

[24]The provisions of the Price-Anderson Act are contained in Section 170 of the Atomic Energy Act, as amended, 42 U.S.C. 2210. Their constitutionality recently was upheld by the Supreme Court. *Duke Power Company v. Carolina Environmental Study Group,* ___ U.S. ___, 46 U.S.L.W. 4845 (June 26, 1978).

[25] The applicants correctly point out that the Price-Anderson question was not explicitly encompassed by the intervenors' contentions. The staff goes on to assert that the question also "was not raised otherwise below" and asks that we dismiss the exception on this issue for that reason. In making this argument, which we reject, the staff has apparently overlooked the intervenors' unsuccessful attempt to include the Price-Anderson matter in their cross-examination on evacuation (Tr. 1782-83, 2505-12) and their filing of a proposed "finding" (par. 65) and "conclusion" (par. 94) on the subject (Intervenors' Proposed Findings of Fact and Conclusions of Law, dated August 15, 1977).

Cite as 8 NRC 295 (1978) **CLI-78-19**

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

COMMISSIONERS:

Victor Gilinsky, Acting Chairman
Richard T. Kennedy
Peter A. Bradford
John F. Ahearne

Docket No. 50-320

In the Matter of
METROPOLITAN EDISON CO., et al.

(Three Mile Island Nuclear Station, Unit No. 2)

September 15, 1978

The Commission denies a petition for review of ALAB-486, 8 NRC 9 (1978), but outlines additional detailed data and analyses which the Appeal Board should request when it conducts the hearing on aircraft crash probabilities directed by ALAB-486.

ORDER

In ALAB-486 (8 NRC 9), decided July 19, 1978, the Atomic Safety and Licensing Appeal Board reviewed the Licensing Board decision which authorized the issuance of an operating license to the Three Mile Island, Unit No. 2, facility. A central issue before the Appeal Board was the adequacy of the record with respect to the probability of the crash into the facility of an airplane heavier than 200,000 pounds. The Appeal Board found that the record did not permit it to determine the future level of heavy aircraft traffic-which is being monitored under a technical specification in the operating license-at which further protective measures (such as reassessing structural design limits, restrictions on air traffic patterns, redesign of exterior structures, and plant shutdown) must be taken, and it directed a reopened hearing to address that matter. Stating that it would conduct that hearing itself, the Appeal Board instructed the parties as to the data it wished them to submit. ALAB-486, *supra,* 8 NRC at 44-46. The Appeal Board made clear that the further hearing would result not only in a determination with respect to crash probabilities at future air traffic levels, but also in a firmer finding with respect to current crash probabilities than can presently be made, owing to differences in the data bases and calculational methods used in developing the present record. Finding that all data and analyses in the record led to acceptable crash probabilities at current air traffic levels, the Appeal Board ruled that there was a reasonable assurance of no undue risk to public health and safety from operation at this time, and it declined to suspend the operating license during the pendency of the reopened hearing.

A petition seeking Commission review of ALAB-486 pursuant to 10 CFR 2.786 was filed on August 8, 1978, by the representative of the Citizens for a Safe Environment and the York Committee for a Safe Environment. Since our review is not on the basis urged by the petition, the petition is hereby denied.

As noted, the Appeal Board has indicated in some detail the information it considers necessary for the reopened hearing. We believe that the Appeal Board should request still more detailed data and analyses. We have outlined in an attachment to this order areas we believe should be pursued. The Commission recognizes that the analysis will have to be done on the basis of available data. Nothing in this order should be construed as implying that calculations made in the absence of the full complement of data so outlined would necessarily be deficient.

It is so ORDERED.

For the Commission

Samuel J. Chilk
Secretary of the Commission

Dated at Washington, D.C.
this 15th day of September 1978.

Data and Analysis To Be Pursued in Further
Proceedings on
Three Mile Island Nuclear Station, Unit No. 2