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AZ CORP COMMISSION
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Transcript Exhibit(s)

Docket #(s): E-01345A-05-0816

E-01345A-05-0826

E-01345A-05-0827

Arizona Corporation Commission
DOCKETED

DEC 29 2006

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Exhibit # : APS96 - APS104, IEA1 - IEA6, Merchant Generator 1, DEAA1 - DEAA5

(Part 8 of 9)

INPO®

Institute of Nuclear Power Operations

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770-644-8000
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RECEIVED
DEC - 5 2006
J.M. Levine

December 1, 2006

Mr. James M. Levine
Executive Vice President, Generation
Arizona Public Service Company
MS 9046
Palo Verde Nuclear Generating Station
400 North 5th Street
Phoenix, AZ 85004

Mr. ~~Levine~~: Jim

I am writing in response to your inquiry whether the Institute of Nuclear Power Operations ("INPO") would agree to the production of an INPO Evaluation Report and overall assessment regarding the Palo Verde Nuclear Generating Station ("PVNG") in a matter pending before the Arizona Corporation Commission ("ACC").

My understanding is that the Evaluation Report and assessment would be subject to an appropriate confidentiality order entered by the ACC that would be intended to limit use of the Report and assessment to this particular proceeding and to prohibit public disclosure.

The mission of INPO is to promote the highest levels of safety and reliability - to promote excellence - in the operation of commercial nuclear power plants. INPO does not engage in public, media, or legislative activities to promote nuclear power. It is strictly a safety organization.

INPO regards its interactions with each of its Members as private. The evaluation reports prepared by INPO remain the property of INPO and are maintained confidential. I have attached a copy of the current INSTITUTIONAL PLAN for INPO.

EXHIBIT
APS 96
Admitted

You will note on page 14 that it provides that: "Evaluation reports and specific information related to the evaluation (such as the overall assessment) are not distributed external to the member utility organization." This has been INPO's consistent policy since the mid-1980s.

This policy of preserving the privacy of the interactions between INPO and each of its Members is necessary to enable INPO to carry out its mission of promoting the public health and safety. Without confidentiality, it would be difficult or impossible for INPO to obtain the candid views and observations of the men and women who work in commercial nuclear power plants. Thus, without confidentiality, the quality of the information on which INPO depends for promoting nuclear safety would inevitably decline.

I note that in the early 1990s, Arizona Public Service Co. ("APS") and INPO filed suit against the ACC in the Superior Court for Maricopa County to prevent the ACC from releasing to the public an INPO Evaluation Report that had been provided to the ACC pursuant to confidentiality order. The Court, after an evidentiary hearing, entered an Order vacating and setting aside the ACC's action "as arbitrary and capricious." In addition, the Court found that, "[t]he evidence supplied by APS and INPO establish *a clear need for protection of the Evaluation Reports* provided by INPO to its client nuclear plants" (emphasis added). I have enclosed a copy of the Court's Order dated April 18, 1991.

The federal courts have also protected INPO reports. *Critical Mass v. NRC*, 975 F. 2d 871 (D.C. Cir. 1992) (INPO reports protected from disclosure under Freedom of Information Act), *cert. denied*, 507 U.S. 984 (1993); *Finestone v. Florida Power & Light Co.*, No. 03-14040-CIV-COHN/SNOW (S.D. Fla. Nov. 4, 2004), Slip Op. at 6 (prohibiting production of INPO Evaluation Reports and holding that, "INPO makes a *compelling argument for why those documents should not be produced,* even under the parties' Protective Order") (emphasis added); *see id.* (June 14, 2004), Slip Op. at 4 (granting INPO leave to intervene and holding, "The effectiveness of INPO's mission . . . is substantially dependent on *maintaining the confidentiality of communications* between INPO and nuclear power operators, *so as to ensure candor in those communications*") (emphasis added).

In light of INPO's consistent policy of protecting the privacy of its interactions with each of its Members, and also giving due consideration to the result of the litigation with the ACC on a similar issue in 1991, INPO does not agree to any disclosure of any of its Evaluation Reports on PVNGS, or any related information (such as the overall assessment).

If I can provide you with any further information with respect to INPO's policies in this regards, please telephone me at 770-644-8556.

Sincerely,

Terry E. Young
Director
Communications

TEY:eb

Enclosures: Institutional Plan
Court Order dated April 18, 1991

cc/wo: Mr. Michael F. Healy

4042.1 / 4/10

SUPERIOR COURT OF ARIZONA
MARICOPA COUNTY

COPY

CLERK OF THE COURT

April 19, 1991 HON. PHILIP W. MARQUARDT D. Robertson
Deputy

No. CV91-07813

ARIZONA PUBLIC SERVICE COMPANY

George H. Lyons/
Steven M. Wheeler/
Jeremy D. Mussman

v.

Andrew D. Hurwitz/
David B. Rosenbaum

ARIZONA CORPORATION COMMISSION, et al.

Christopher C. Kempley

James D. Miller/
Kerrie S. Covell
KING & SPALDING
1730 Pennsylvania Ave., N.W.
Washington, D. C. 20006-4706

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COALITION/ENERGY EDUCATION
315 West Riviera Drive
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Roger A. Schwartz

Paul J. Roshka, Jr./
Raymond S. Heyman

Richard L. Sallquist

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SOUTHWEST GAS CORPORATION
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Norman J. Furuta
DEPARTMENT OF NAVY
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P.O. Box 727 (Attn: Code 90C)
San Bruno, CA 94066-0720

Michael S. Dulberg

C. Webb Crockett

SUPERIOR COURT OF ARIZONA
MARICOPA COUNTY

CLERK OF THE COURT

April 18, 1991 HON. PHILIP W. MARQUARDT D. Robertson
Deputy

NO. CV91-07813

APS v. ACC

Continued

Larry R. Graber
Cypress Metals Company
9011 E. Mineral Circle
Englewood, Colorado 80112

Paul A. Bullis

David C. Kennedy

Thomas Sheets
Director, Regulatory Affairs
Southwest Gas Corporation
P. O. Box 98510
Las Vegas, NV 89193

Rick Lavis
ARIZONA COTTON GROWERS ASS'N
4139 E. Broadway
Phoenix, AZ 85040

William F. Sullivan

This Court accepts jurisdiction over this special action. This Court is called upon to make a twofold decision:

1. Is there a common law privilege or should one be created for a "self-critical analysis" such as the INPO Evaluation Report;

2. Did the Arizona Corporation Commission violate the agreement of confidentiality in reference to the INPO Evaluation Report and thus, act in an arbitrary and capricious manner.

The evidence supplied by APS and INPO establish a clear need for protection of the Evaluation Reports provided by INPO to its client nuclear plants. The Court will not reiterate those reasons but refers to Exhibit "A" attached to INPO's Memordum of Points and Authorities in support of its Complaint. However, this Court can find no legislative mandate or Arizona appellate Court decision of a self-critical privilege such as is sought here. In absence of either appellate Court guidelines or legislative mandate, this Court will not create such a privilege.

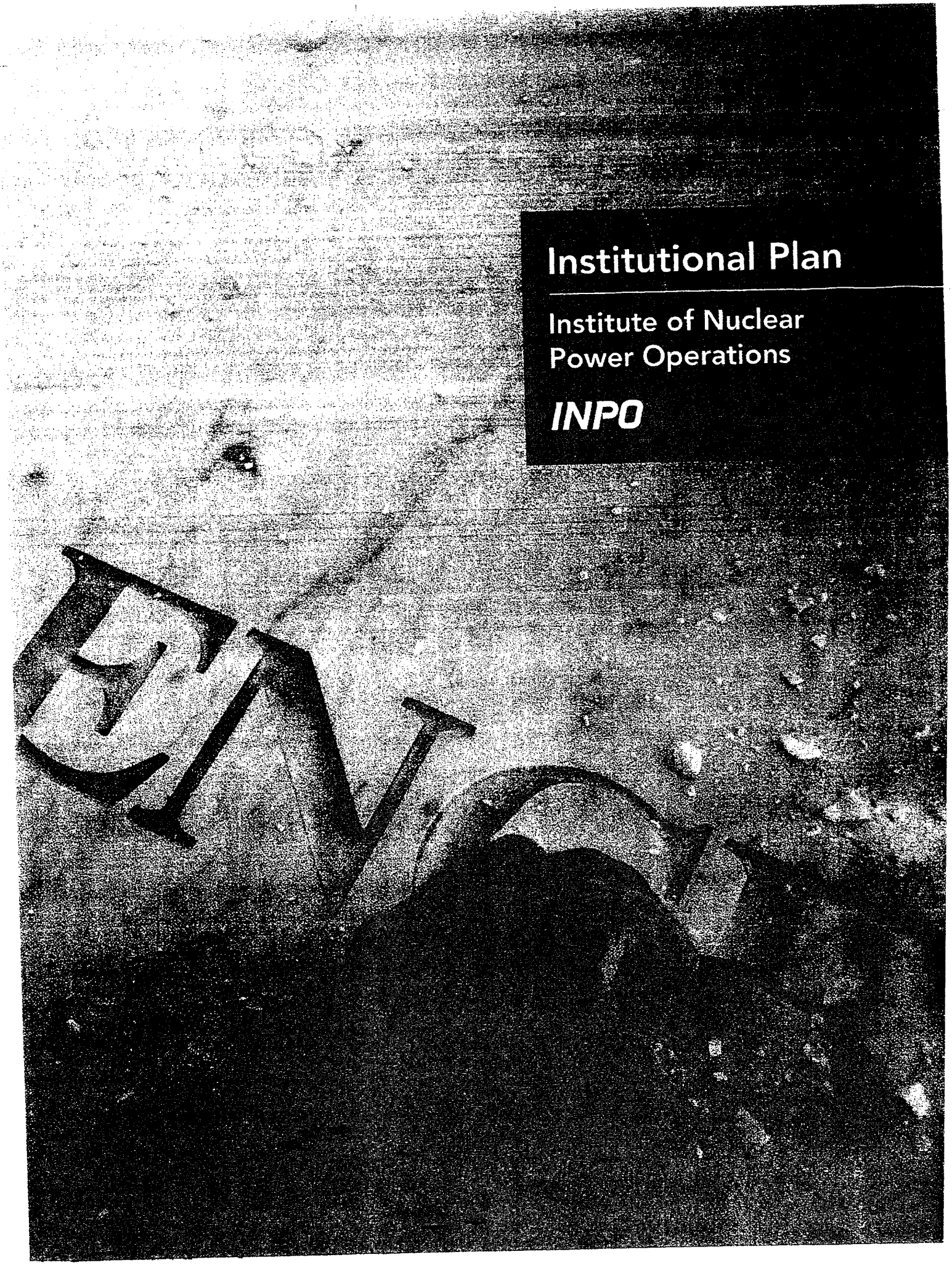
The Court next turns to the second question before it. There has been no waiver of the confidentiality agreements entered into by the parties. That confidentiality agreement provides in part that the information shall not be made part of the public record except upon a motion filed presenting specific grounds upon which it is claimed that the confidential information should be made part of the public record and a specific finding by the Commission that the confidential information needs to be made part of the public record. The decision of the Corporation Commission to reverse the Chief Hearing Officer Burns and release the contents of the INPO Evaluation Report to the public was done in violation of the Confidentiality Agreement which requires specific grounds based upon competent evidence as to the need to disclose these reports to the public. For this reason, the decision of the Commission is vacated and set aside as arbitrary and capricious, and this matter is remanded to the Commission to make those findings consistent with the Confidentiality Agreement that would warrant the release of the document in question to the public.

Each side shall bear their own costs and attorney's fees.

Institutional Plan

Institute of Nuclear Power Operations

INPO



Preface

The U.S. nuclear electric utility industry established the Institute of Nuclear Power Operations (INPO) in 1979 to promote the highest levels of safety and reliability—to promote excellence—in the operation of its nuclear plants.

In forming INPO, the nuclear utility industry took an unusual step. The industry placed itself in the role of overseeing INPO activities, while at the same time endowing INPO with ample authority to bring pressure for change on individual members. That feature makes INPO unique. By committing to meet INPO's performance objectives and criteria and to implement improvements in response to INPO recommendations, the industry clearly established and accepted a form of self-regulation through peer review. The industry's recognition that all nuclear utilities are affected by the action of any one utility motivated its commitment to and support of INPO. Each individual member is responsible for the safe operation of its nuclear electric generating plant(s). The U.S. Nuclear Regulatory Commission (NRC) has statutory responsibility for overseeing the licensees and verifying that each licensee operates its facility in compliance with federal regulations. Compliance with regulations alone, however, does not necessarily result in the best possible performance. INPO's role is to promote excellence in the operation of its members' nuclear power plants. The nuclear industry's commitment to continually strive for excellence has resulted in performance improvements.

The Institute grew from a handful of on-loan personnel in late 1979 to an established workforce of about 350 permanent and on-loan personnel. INPO's early years were marked by growth and evolution of its programs and organization. It now focuses on the effectiveness and enhancement of established programs and activities.

To carry out its role, INPO must have the support of its members and participants, as well as a cooperative but independent relationship with the NRC. A basis for that support and cooperation is an understanding of INPO's role. This Institutional Plan is intended to provide that understanding by defining the Institute's role and its major programs.

This plan considers the existing and projected needs of the industry and the overall environment in which INPO and its members and participants operate.

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I. Purpose

This Institutional Plan describes INPO's programs and provides a foundation for implementing them. This plan accomplishes the following:

- Sets forth the Institute's mission and principles of operation
- Sets forth the obligations for membership
- Defines the Institute's role in the industry and its relationship with its members and participants, other industry organizations, and government agencies
- Describes the Institute's key organizational elements
- Describes the programs the Institute is expected to carry out, including the objectives of each program

II. Background

The Institute of Nuclear Power Operations was established in 1979. An organizational plan and charter were developed with the assistance of several industry groups formed for that purpose. INPO's founders issued this original organizational plan and charter in September 1979. U.S. utilities with operating licenses or construction permits for nuclear plants were involved in its development, and all became members soon after the Institute was formed.

Since that time, all organizations having direct responsibility and legal authority to operate or construct commercial nuclear electric generating plants in the United States have maintained continuous membership in the Institute. Many organizations that jointly own these nuclear power plants are associate members. A number of international utility organizations and major supplier organizations also participate.

The Institute was incorporated as a nonprofit corporation in the State of Delaware on October 12, 1979 and began operation in Atlanta, Georgia on December 3, 1979. Since then, INPO's mission has remained the same: "to promote the highest levels of safety and reliability—to promote excellence—in the operation of nuclear electric generating plants."

The period following the Three Mile Island Nuclear Station accident was one of rapid change for the industry. Over the Institute's first few years, its role evolved to accommodate changing requirements in the industry and to build on the experience gained. Significant changes were made to the original organization, and new programs and activities were added to best achieve the Institute's mission. Nuclear operating organizations and supplier companies from the United States and other countries helped broaden the Institute's role. This period of development was guided by INPO's Board of Directors, with the advice of its Advisory Council; and by INPO management, with the advice and counsel of industry review groups.

After three years of continued growth, the Institute began consolidating its efforts, focusing on improvements in and refinements to established programs. INPO defined its emerging role in its Institutional Plan, first issued in May 1983. INPO and its Board of Directors stay abreast of issues affecting the nuclear utility industry to continually improve established programs and refine INPO's methods and products.

In 1993, with its member utilities facing an increasingly competitive environment, INPO undertook an extensive review of its mission and Institutional Plan and concluded that the INPO mission should not be changed, finding it appropriate for the new climate.

The utility business environment continues to change. The period of state-by-state deregulation, growing competition, and increasing merger and acquisition trends that dominated the late 1990s is continuing to affect the commercial electric power industry. The nuclear regulatory environment is changing as the Nuclear Regulatory Commission implements more risk-informed, performance-based regulatory processes. In light of these changes, INPO conducted comprehensive reviews of its mission and Institutional Plan in 2000 and 2003. As a result, INPO's mission was reaffirmed, and the Institute continues its strong focus on excellence in nuclear power plant operational safety and reliability.

III. Organization

In many ways, the Institute's organization is similar to that of a typical U.S. corporation. A board of directors, elected by INPO members, provides overall direction for the Institute's operations and activities. The president and CEO of the Institute is elected by and reports to its Board of Directors.

An Advisory Council of 12 to 18 professionals from outside INPO's membership meets periodically to review Institute activities and provide advice on broad objectives and methods to the Board of Directors. The Advisory Council is composed of distinguished professionals in areas related to the Institute's activities. Members include prominent educators, scientists, engineers, and business executives, as well as experts in organizational effectiveness, human relations, and utility finance.

The Institute's activities to enhance nuclear plant safety and reliability are reflected primarily in its cornerstone programs of on-site evaluations of each nuclear plant, training and accreditation, events analysis and information exchange, and assistance, as described in Appendix A. Nuclear technical divisions are organized to carry out the cornerstone functions. Other departments, such as support services, industry and external relations, and information services, support the nuclear technical divisions as well as the Institute's overall mission.

The National Academy for Nuclear Training operates under the auspices of INPO and integrates the training efforts of all U.S. nuclear utilities, the activities of the National Nuclear Accrediting Board, and the training-related activities of the Institute. An INPO executive normally serves as the executive director of the Academy.

The Atlanta Center of the World Association of Nuclear Operators (WANO) is co-located with the Institute. WANO was formed by the international nuclear community to promote worldwide improvements in the quality of nuclear plant operations. WANO's mission is to maximize the safety and reliability of the operation of nuclear power plants by exchanging information and encouraging communication, comparison, and emulation among its members. INPO provides operational support and facilities for the Atlanta Center and represents the U.S. nuclear utilities' membership in WANO. An INPO executive serves as the director of the WANO-Atlanta Center.

Non-U.S. nuclear utility organizations participate in the Institute's International Participant Program, managed by WANO-Atlanta Center at INPO's request. This program involves the active exchange of information on nuclear plant operations among utility organizations around the world. Each international participant organization is represented on an advisory committee that provides advice on the operation of this program as well as input on other Institute programs, as appropriate. (See Appendix C for information about INPO's relationship with WANO-Atlanta Center.)

Organizations engaged in providing commercial design, engineering, nuclear fuel cycle, or other services directly related to the construction, operation, or support of nuclear electric generating plants also participate in INPO through the Supplier Participant Program. This program allows supplier organizations to share experience and expertise with the Institute's members and provides a means to provide feedback on operational experience to the suppliers. The Supplier Participant Advisory Committee, made up of representatives from all supplier participants, provides advice on the operation of the program as well as on other Institute programs.

The Institute encourages members and participants to actively participate in its programs. Representatives from member utilities serve on the Executive Review Group, the Academy Council, the Analysis Review Board, and the Industry Communications Council. The Executive Review Group advises INPO management on the programs and products in the nuclear technical areas. The Academy Council provides advice in the areas of training, accreditation, and human performance. The Analysis Review Board advises on INPO's analysis activities, and the Industry Communications Council advises on effective communication of INPO programs and activities. Frequently, ad hoc industry groups are established to provide input on specific initiatives.

The Institute's permanent staff is augmented extensively by industry professionals who serve as loaned employees or international liaison engineers on long-term assignments. The Institute's resources and capabilities are further leveraged by the extensive use of U.S. industry and international utility peers and executive industry advisors. These peers participate in a wide range of short-term activities, especially on teams that visit nuclear plants.

IV. Mission, Principles of Operation, and Core Values

In carrying out its mission to promote the highest levels of safety and reliability—to promote excellence—in the operation of nuclear electric generating plants, the Institute strives to apply the following principles:

1. Encourage excellence in all phases of nuclear power plant operations.[1]

2. Promote improved management and leadership development in the industry through means such as Academy-sponsored courses and educational assistance.

3. Promote the highest levels of professionalism among all personnel involved in nuclear technology, including a strong emphasis on safety culture and conservative decision-making.

4. Assist members in the emulation and implementation of effective industry programs and practices to improve plant performance.

5. Assist members in achieving and maintaining accreditation of performance-based training programs at their facilities. Provide guidance for use by members in training and qualifying personnel to operate, maintain, and support their nuclear plants.

6. Analyze events that occur in the operation of nuclear plants worldwide and other operational data to identify possible precursors of more serious events and adverse trends. Communicate the lessons learned to facilitate understanding and prevent recurrence.

7. Assist members in identifying human performance and equipment problems and their root causes, and provide information and techniques that can assist plants in achieving effective preventive and corrective actions. Enhance the diagnostic abilities of nuclear plant operators.

8. Promote the exchange of information that assists in achieving safe, reliable, and efficient operation of nuclear electric generating plants.

9. Assist members in specific areas where the effective use of resources enhances the safe and reliable operation of nuclear electric generating plants.

10. Involve personnel from members and participants in INPO work to promote information exchange and to ensure INPO programs meet the current needs of members and participants.

11. Use expertise and experience from outside the U.S. nuclear utility industry to provide industry access to the best methods and technologies available, including information exchange through the World Association of Nuclear Operators.

12. Encourage members, through such means as the annual INPO CEO Conference, to hold each other accountable for the performance of their nuclear plants and to hold INPO accountable for its mission.

[1] Operations is used in a broad context in this document and includes the activities that support the operation of the plant (maintenance, training, engineering, and so forth).

13. In all interactions with members, recognize that, ultimately, safety is the responsibility of the member (licensee). Avoid undermining or preempting member management responsibilities and prerogatives.

INPO strives to apply similar principles for excellence and professionalism in its internal programs and activities. In carrying out its mission and principles of operation, INPO employees conduct themselves in a manner that is consistent with the following core values:

Excellence...Make it better.
We are committed to learning, improvement, and personal growth.

Perseverance...There is no finish line.
We are relentless and vigilant about nuclear safety and reliability.

Leadership...Make things happen.
We work with the industry to identify needs and aggressively stimulate industrywide progress.

Relationships...Knock down walls. Build bridges.
We respect each other. We work as a team and build a community that shares, compares, and improves.

Integrity...We are what we say and do.
We are accountable for our words and actions. Honesty and sincerity are fundamental to our credibility.

V. Programs and Activities—Overview

INPO's cornerstone technical programs are described in detail in Appendix A. The following is an overview of the Institute's major activities.

A. CORNERSTONE TECHNICAL PROGRAMS

1. **Evaluation Programs**
   Evaluations of nuclear plants operated by member utilities are conducted regularly. Corporate support of operating plants is also evaluated from time to time. In these evaluations, the INPO teams use standards of excellence based on experience and best practices. Written performance objectives and criteria guide the evaluation process.

2. **Training and Accreditation Programs**
   INPO interacts with all members in preparing for, achieving, and maintaining accreditation of training programs for personnel involved in the operation, maintenance, and technical support of nuclear plants. These interactions include evaluations of accredited training programs, activities to verify that the standards for accreditation are maintained, and assistance at the request of member utilities. Written objectives and criteria guide the accreditation process.

   The National Academy for Nuclear Training operates under the auspices of INPO. The Academy was formed to focus and unify industry efforts to ensure high standards in training and qualification and to promote professionalism of nuclear plant personnel. The Academy integrates the training-related activities of all members, the independent National Nuclear Accrediting Board, and the Institute. Through INPO, the Academy conducts seminars and courses and provides other training and training materials for utility personnel, as well as manages an industrywide educational assistance program.

3. **Analysis and Information Exchange Programs**
   The events analysis program is designed to identify the root causes of industry events that may be precursors of potentially more serious events. INPO personnel analyze off-normal events that occur in the operation of nuclear plants and conduct on-site reviews of selected events. Lessons learned are communicated to members and participants. Nuclear station responses to the resulting recommendations from this program are reviewed as part of the plant evaluation process. In addition, INPO analyzes a variety of operational data to detect trends in industry performance and communicates the results to the industry.

   INPO operates and maintains extensive computer databases to provide members and participants ready access to information on plant and equipment performance and operating experience. These databases are accessible from INPO's secure member Web site.

   Nuclear Network®, a worldwide Internet-based communication system, is used by INPO and its members and participants for the exchange of information on the operation of nuclear plants. The World Association of Nuclear Operators also uses Nuclear Network as a primary means for communicating and exchanging operating

experience among its members and regional centers.

WANO collects and monitors worldwide nuclear plant performance indicator data and shares this information with INPO members and participants. (See Appendix C.) Periodic reports are provided to the industry and are available on INPO's member Web site. Nuclear utilities are encouraged to use these indicators to monitor the performance of their nuclear plants and to emulate best practices that contribute to the highest levels of performance.

4. **Assistance Programs**
Between evaluations, INPO monitors the performance of member utility stations to identify areas where assistance can be used to improve plant performance or respond to declining performance. INPO also provides members with comparisons of their plants' performance with overall industry performance in a variety of areas.

Visits to member or participant utilities by INPO personnel and industry peers are also arranged in response to utility requests. This assistance is targeted for specific technical concerns, as well as for broader management and organizational issues.

Documents describing nuclear safety principles, effective leadership and management practices, and good work processes and practices are provided to assist member utilities. Members are encouraged to use these documents to address specific improvement needs.

Workshops, seminars, working meetings, and other activities are also conducted to assist in the exchange of information among members and to support development of industry leaders and managers.

B. SUPPORTING PROGRAMS

1. **Loaned Employee and Liaison Engineer Programs**
To augment its professional staff with a continuing source of personnel with recent nuclear plant experience, INPO uses the expertise of members and participants through the loaned employee program. This program also gives loaned personnel an opportunity to gain broader industry experience.

International participants and international supplier participants are eligible to assign liaison engineers to the INPO staff. This program provides ongoing liaison with these international organizations and helps support the INPO staff.

2. **INPO Reverse Loaned Employee Program**
INPO employees are loaned to member or participant organizations to meet the specific needs of these organizations. These reverse loan assignments also provide opportunities for INPO personnel to receive current industry experience while further developing their leadership and management skills.

3. **Peer Evaluator Programs**
Industry peers augment INPO field and other activities. Each plant evaluation team includes senior reactor operators and

other peer evaluators from selected plant functional areas. The peers assist INPO teams in reviewing plant performance.

Similarly, INPO accreditation teams are augmented by peers from utility training organizations. Peers are also used extensively on assistance, review, and international technical exchange visits. Most field visits involve one or more host peer evaluators from the plant being visited. Senior executives from member utilities serve as advisors on the Institute's plant and corporate evaluation teams.

4. **INPO Member Web Site**
A secure INPO member Web site provides INPO members and participants electronic access to a wide array of information that supports each of the Institute's cornerstone programs and supporting activities. The site is continually updated with new information and products to meet member needs. Examples of INPO information available on the member Web site are operating experience documents and associated training materials, guidelines and good practices, key strengths and areas for improvement from evaluation and accreditation team visits (with station and utility names removed), and the Nuclear Network and Equipment Performance and Information Exchange (EPIX) databases.

Entities other than INPO members, such as international participants, supplier participants, the Nuclear Regulatory Commission, EPRI, and the Department of Energy, have access to selected portions of the member Web site, in accordance with specific agreements with these groups.

C. INTERNATIONAL PARTICIPANT PROGRAM

A number of nuclear power operating organizations in other countries have become participants in INPO. This self-supporting program is intended to facilitate the exchange of information and experience, thereby promoting safe and reliable nuclear plant operations worldwide. International participants are invited to INPO workshops and receive many INPO products and services that are provided to domestic members. In addition, international technical exchange visits are conducted both in the United States and abroad to further enhance information exchange and emulation of best practices. International participants have access to INPO experience and can adopt INPO methods, as desired, in areas such as plant evaluations, training program accreditation, training courses, and operating experience analysis. At INPO's request, the International Participant Program is managed by the WANO-Atlanta Center. (See Appendix C.)

D. SUPPLIER PARTICIPANT PROGRAM

Organizations providing commercial design, engineering, nuclear fuel cycle, or other products and services directly related to the construction, operation, or support of nuclear electric generating plants are eligible to participate in INPO's Supplier Participant Program. This program is intended to promote the exchange of technical information to enhance INPO's programs as well as to incorporate plant operating experience into supplier participant activities that support the operation of nuclear power plants.

Supplier participants interact with INPO to

share experience and can use INPO practices, as appropriate, in support of their efforts. Supplier participant experience and expertise also are requested by INPO to support the Institute's programs and activities. To facilitate this interaction, supplier participants receive most INPO documents and data provided to domestic members and are invited to most INPO workshops and working meetings.

Occasionally, INPO assists supplier participants in technical areas related to INPO's mission.

E. ACTIVITIES WITH THE U.S. DEPARTMENT OF ENERGY

INPO provides assistance to the Department of Energy (DOE) to support improvement of operational safety at DOE nuclear facilities. A contract with the DOE specifies a baseline scope of assistance that is available. Under this contract, INPO conducts a limited number of assistance visits to DOE nuclear facilities, provides the DOE with copies of selected INPO documents and domestic operating experience reports, and allows DOE personnel to attend industrywide workshops and conferences. DOE personnel are provided access to Nuclear Network and selected information available on INPO's secure member Web site.

Occasionally, operating experience events at DOE facilities are communicated to INPO members and participants via the INPO Significant Event Evaluation and Information Network (SEE-IN) program.

VI. INPO's Relationship with Members, Participants, and Other Organizations

In carrying out its mission, INPO depends on the support of its members and participants and the cooperation of other industry organizations and federal agencies, particularly the Nuclear Regulatory Commission.

To ensure credibility with its members and with the federal government, INPO must maintain its independence with respect to any individual member and to government agencies. At the same time, INPO responds to the collective needs of its members and their requests for assistance. INPO also coordinates its activities with other industry and government organizations.

The principles and assumptions below provide for the coordination, support, and implementation of INPO programs.

A. MEMBERS ARE EXPECTED TO DO THE FOLLOWING:

1. Strive for excellence in the operation of their nuclear plants.

2. Establish a nuclear line organization that has clearly defined lines of responsibility and accountability for nuclear plant operation, maintenance, training, engineering support, and other activities necessary to ensure safe and reliable plant operation. The senior nuclear executive in the nuclear line organization shall be accountable in an unambiguous way to the organizational entity that holds federal authority (is licensed) to operate the nuclear facility.

3. Strive to meet INPO performance objectives and to meet the intent of INPO guidelines.

4. Respond to areas for improvement identified through INPO's evaluation, accreditation, and events analysis programs.

5. Achieve and maintain accreditation of training programs for personnel who operate, maintain, and support their nuclear plants.

6. Fully participate in other generic INPO programs designed to enhance nuclear plant safety and reliability. Examples are providing INPO with detailed and timely operating experience information and participating in the loaned employee, peer evaluator, and WANO performance indicator programs.

7. Share information, practices, and experiences to assist each other in maintaining high levels of operational safety and reliability. (See Appendix D, Principles of Sharing.)

8. Maintain the confidentiality of INPO evaluation reports and related information (such as the overall assessment), including not distributing this information external to the member utility organization.

B. MEMBERS AND PARTICIPANTS ARE EXPECTED TO DO THE FOLLOWING:

1. Use information provided by the Institute to improve nuclear operations and not for other purposes, such as to gain commercial advantage.

2. Avoid involving INPO or INPO documents in litigation.

3. Limit requests for assistance from INPO to areas or activities that are within the scope of the Institutional Plan.

C. INPO IS EXPECTED TO DO THE FOLLOWING:

1. Provide members with written reports describing results from evaluation, accreditation, and review visits. INPO follows up and verifies that effective corrective actions are implemented. INPO reports are maintained confidential. Evaluation reports and specific information related to the evaluation (such as the overall assessment) are not distributed outside of the member utility organization.

2. Ensure that, as appropriate, the Executive Review Group, Academy Council, and Analysis Review Board are provided an opportunity to review and comment on performance objectives, criteria, guidelines, and other INPO or National Academy for Nuclear Training documents.

3. Interact, in matters relating to its technical programs, with the member holding the operating license and having direct line responsibility for plant operation. This policy is necessary to maintain the responsibility for safe and reliable operation of the nuclear plant with the line organization. INPO expects its members to coordinate such matters with any joint owners. The Institute maintains a cooperative relationship with the Nuclear Non-Operating Owners Group.

4. Assist members in maintaining an environment that reinforces line management authority and responsibility in matters related to nuclear safety and reliability and that provides flexibility for self-improvement initiatives. INPO performance objectives and criteria are written without regard to constraints or agreements an individual member may have. Because the performance objectives and criteria and associated evaluation areas for improvement involve reactor safety and public health and safety, each member is expected to resolve any impediments to their implementation that may be imposed by outside organizations. Examples of such impediments are bargaining unit agreements or regulatory interactions.

D. THE FOLLOWING ARE ADDITIONAL PRINCIPLES AND ASSUMPTIONS:

1. A special procedure, approved by the INPO Board of Directors, provides guidance in the event a member is not responsive to INPO programs, is unwilling to take action to resolve a significant safety issue, has persistent shortfalls in performance, or has accreditation for its training programs put on probation or withdrawn by the National Nuclear Accrediting Board. The procedure stipulates that INPO and the member's management work to resolve any issues in contention. Should resolution not be satisfactory, the procedure calls for specific interactions between INPO's chief executive officer and the member's chief executive officer and, ultimately, the member's board of directors. The procedure gives INPO the authority to suspend the organization from membership if it continues to be unresponsive.

2. INPO members that also are members of Nuclear Electric Insurance Limited (NEIL) have authorized and instructed INPO to make available to NEIL copies of INPO evaluation reports and other data at the Institute's office. NEIL reviews these reports and data for items that could affect the insurability of its members.

3. INPO does not become involved in or conduct assistance visits in response to specific regulatory issues between individual members and the NRC. Such activities could result in INPO involvement in legal or enforcement proceedings and could adversely impact its independent status.

4. INPO does not engage in public, media, or legislative activities to promote nuclear power. Such activities would undermine INPO's credibility and objectivity.

To best serve its members and participants, INPO coordinates its activities with various domestic and international nuclear industry support organizations and nuclear steam supplier owners groups. A mutually supportive relationship is cultivated with these organizations, because they often perform related activities in helping to achieve nuclear safety and reliability goals. Coordination of activities among these groups also helps make efficient use of utility resources.

INPO has designated points of contact with these groups to facilitate information exchange and coordination. This includes serving on each other's advisory bodies and working groups and attending each other's workshops and conferences on issues of mutual interest. Each organization also supplements its technical expertise by soliciting input from the others.

INPO, EPRI, NEIL, and the Nuclear Energy Institute have a mutually supportive and cooperative relationship that is set out in a Memorandum of Agreement. These organizations' activities are often interrelated because many industry issues include elements of plant performance, research and development, and regulatory, political, or public interaction. To achieve the benefits of collaboration and unified approaches, it is important that nuclear utilities and industry support organizations coordinate their activities.

The Institute and the NRC have a formal Memorandum of Agreement that reflects the desires of both organizations for a continuing and cooperative relationship in the exchange of experience, information, and data related to the safety of commercial U.S. nuclear power plants. Although nuclear plant safety and protection of the public are fundamental goals of both INPO and the NRC, their roles, while complementary, are different. Coordination of INPO activities with the NRC is described more fully in Appendix B.

INPO coordinates its activities with other federal government agencies, as appropriate. For example, certain aspects of its international program are coordinated with the Department of State and the Department of Energy.

During its ongoing interactions with members and participants, INPO may become aware of policies or actions by a federal or state agency (or its personnel) that potentially detract from nuclear plant safety. INPO recognizes that it has an obligation to make the responsible agency aware of such issues in an appropriate manner and to follow up to see that the issues are addressed.

Appendix A
Description of Major INPO Programs

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Appendix A
1. Evaluation Programs

INPO conducts periodic evaluations to promote the highest levels of excellence in the operation, maintenance, and support of operating nuclear plants. All evaluation visits are based on performance objectives and criteria, developed by INPO with industry input and review. The evaluations are performance-oriented, emphasizing both the results achieved and the behaviors and organizational factors important to future performance.

a. Plant Evaluations

Teams of qualified, experienced personnel conduct evaluations of operating nuclear plants, focusing on plant safety and reliability. The evaluation teams are augmented by senior reactor operators, other peer evaluators from different utilities, host utility peer evaluators, and an executive industry advisor. The scope of the evaluation includes traditional functional categories such as operations, maintenance, and engineering that generally correspond to the nuclear station organization. The following areas are evaluated:

- Operations
- Maintenance
- Engineering
- Radiological Protection
- Chemistry
- Training

In addition, teams evaluate cross-functional performance areas—processes and behaviors that cross organizational boundaries and address organizational integration and interfaces. The following cross-functional areas are evaluated:

- Safety Culture
- Operational Focus
- Configuration Management
- Equipment Reliability/Work Management
- Performance Improvement (Learning Organization)
- Organizational Effectiveness

The performance of operations and training personnel during simulator exercises is included as part of each evaluation. Also included, where practicable, are observations of plant startups, shutdowns, and major planned evolutions. Evaluations of each operating nuclear station are conducted at an average interval of 24 months.

Team managers provide a focal point for evaluation of station management and leadership. Intensive training has been provided in this area, and a second team manager on each team concentrates on evaluating organizational effectiveness topics. In addition, teams are augmented with a senior utility executive as an advisor in this area.

Formal reports of areas for improvement are provided to the utility. The utility's response to the areas for improvement, with commitments to improve performance, are included in the final report. In subsequent evaluations, INPO assesses the effectiveness of actions taken to implement improvements.

In addition to the areas for improvement provided in the evaluation report, subjective team comments are often communicated during the evaluation exit meeting. These comments are intended to help utilities recognize and address potential issues before they adversely

impact actual performance. Copies of the plant evaluation report are distributed according to a policy approved by the Institute's Board of Directors.

WANO peer reviews conducted by the WANO-Atlanta Center are sometimes performed in lieu of INPO plant evaluations. These peer reviews use a methodology similar to that of plant evaluations, but with teams augmented with international peers.

b. *Corporate Reviews*

INPO occasionally conducts reviews designed to promote improvements in members' corporate support and monitoring of nuclear station activities. In most cases, these visits are conducted in conjunction with an operating plant evaluation.

c. Review Visits

INPO conducts review visits in selected areas to supplement the evaluation, accreditation, and events analysis programs. These visits are separate and distinct from assistance visits in that they are typically initiated by INPO and are evaluative in nature. The results of review visits are used as an input to the evaluation process. The visits are also used to monitor utility progress on issues.

Excellence
Perseverance
Leadership
Relationships
Integrity

Appendix A
2. Training and Accreditation Programs

a. **National Academy for Nuclear Training**

The National Academy for Nuclear Training was formed in 1985 to focus and unify industry efforts to continue improvements in training and qualification programs and to promote the professionalism of nuclear plant personnel.

The Academy operates under the auspices of INPO and is composed of the following three components:

- Nuclear utility training activities supported by the utilities' training centers, control room simulators, and training staffs
- Activities of the independent National Nuclear Accrediting Board, composed of eminent scholars and executives
- Training-related activities of the Institute

Plants with accredited training programs are branches of the Academy. A utility becomes a member of the Academy when all its operating plants have achieved accreditation for all applicable training programs.

The National Nuclear Accrediting Board examines the quality of utility training programs and makes all decisions with respect to accreditation. If training programs meet accreditation standards, the Board awards or renews accreditation. If significant problems are identified, the Board may defer initial accreditation, place programs on probation, or withdraw accreditation. The National Nuclear Accrediting Board is formed and supported by INPO, but it is independent in its decision-making authority.

An INPO executive normally serves as the Academy's executive director.

The Academy conducts and supports workshops, meetings, training courses, seminars, and other programs. It also produces documents designed to improve performance of nuclear plant personnel.

b. **Performance-Based Training**

The Academy provides assistance to members in establishing and maintaining performance-based training and qualification programs so personnel have the knowledge and skills to perform their jobs competently. The Academy provides guidance and assistance to utilities on a systematic approach to training that is used to develop performance-based training programs.

c. ***Accreditation Program***

The National Academy for Nuclear Training manages the accreditation of utility training programs. The accreditation process is designed to identify strengths and weaknesses in training programs and to assist in making needed improvements. The process includes self-evaluations by members, with assistance provided by INPO staff; on-site evaluations by teams of INPO and industry personnel; and decisions by the independent National Nuclear Accrediting Board. Members are expected to seek and maintain accreditation of training programs for the following positions or skill areas:

- Shift managers
- Senior reactor operators
- Reactor operators
- Nonlicensed operators
- Continuing training for licensed personnel
- Shift technical advisors

- Instrument and control technicians and supervisors
- Electrical maintenance personnel and supervisors
- Mechanical maintenance personnel and supervisors
- Chemistry technicians
- Radiological protection technicians
- Engineering support personnel

Accreditation is maintained on an ongoing basis and is formally renewed for each of the above training programs every four years.

The accreditation process is independent of, but recognized by, the NRC as a means for satisfying regulatory training requirements.

d. Training and Qualification Guidelines

The Academy develops and distributes training and qualification guidelines for operations, maintenance, and technical personnel. These guidelines are designed to assist the utility in developing quality training programs and in selecting key personnel.

Training and qualification guidelines are revised and updated periodically to incorporate changes to address industry needs and to take into account lessons learned from other INPO programs such as evaluations, accreditations, events analyses, working meetings, and workshops. These training and qualification guidelines provide a sound basis for utility training programs.

e. Courses and Seminars

The Academy conducts courses and seminars to help personnel better manage nuclear technology, more effectively address leadership challenges, and improve their personal performance. Examples of courses conducted are as follows:

- Chief Executive Officer Seminar
- Reactor Technology Course for Utility Executives
- Senior Nuclear Executive Seminar
- Senior Nuclear Plant Management Course
- Human Performance Fundamentals Course
- Event Investigation Training
- High Performance Teamwork Development
- Professional development seminars for shift managers, operations supervisors, maintenance supervisors, engineering supervisors, radiation protection and chemistry supervisors, and training supervisors
- Seminars for new plant managers and for new managers in operations, radiological protection, chemistry, maintenance, engineering, and training

In addition to these courses and seminars, the Academy provides other training to its members on request.

f. Educational Assistance

The National Academy manages an industry educational assistance program to provide undergraduate scholarships and graduate fellowships for students majoring in nuclear or nuclear-related engineering or power generation health physics programs. Scholarship and fellowship recipients are encouraged to pursue careers in the nuclear power industry.

Appendix A
3. Analysis and Information Exchange Programs

a. **Events Analysis Program**

INPO reviews and analyzes operating events from both domestic and non-U.S. nuclear plants. The program is designed to provide in-depth analysis of nuclear operating experience and to apply the lessons learned across the industry. Events are screened and analyzed for significance, and those with generic applicability are disseminated to the industry in one or more of the following forms:

- Significant Operating Experience Reports (SOERs)
- Significant Event Reports (SERs)
- Significant Event Notifications (SENs)

The Institute conducts field reviews of selected events to determine root causes and provides accurate, timely communication of lessons learned to the industry to help prevent recurrence.

Members are expected to support the events analysis program by providing INPO with detailed and timely operating experience information. They are expected to evaluate and take appropriate action on recommendations provided in SOERs. During on-site evaluations, INPO follows up on the effectiveness of each utility's actions in response to SOER recommendations.

INPO provides SENs, SERs, and other reports to members for action, as appropriate. Unlike SOER recommendations, INPO does not follow up on the effectiveness of utility actions in response to these reports. INPO does evaluate the effectiveness of utility programs in extracting and applying lessons learned from industrywide as well as in-house operating experience.

INPO also provides just-in-time and equipment failure experience information in a format designed to assist plant personnel preparing to perform specific tasks.

b. **Equipment Performance Data**

The Institute operates and maintains the Equipment Performance and Information Exchange (EPIX) system. INPO members are expected to report equipment performance information to EPIX in accordance with established guidance. INPO and member utilities use the data to identify and solve plant equipment performance problems, with the goal of enhancing plant safety and reliability.

c. **Nuclear Network® System**

Nuclear Network is an international electronic information exchange for sharing nuclear plant information. It is the major communication link for the Significant Event Evaluation and Information Network (SEE-IN) and the WANO event reporting system. Operating experience information, Signifi-cant Event Reports, and other nuclear technical information are transmitted by the system. Nuclear Network also provides a vehicle for disseminating questions and other correspondence among INPO members and participants. Questions, for example, can be sent simultaneously to one, several, or all users.

The system includes a special dedicated topic for reporting plant emergency situations. This feature allows the affected utility to simultaneously provide timely information to all Network users, including the U.S. industry, INPO's international and supplier participants, and WANO members.

d. Performance Data Collection and Trending

The Institute operates and maintains the Consolidated Data Entry (CDE) System to collect data and information related to nuclear plant performance. Members provide data on quantitative performance indicators on a quarterly basis. This plant data is then consolidated for trending and analysis purposes. Industrywide data, plus trends developed from the data, are provided to member and participant utilities for a number of key operating plant performance indicators. These include the performance indicators used by WANO for worldwide nuclear plant performance comparisons. Members use this data in setting specific performance goals and in monitoring and assessing performance of their nuclear plants. INPO uses performance goals from individual utilities to help establish industrywide performance goals for plants in the United States.

e. Event Report Databases

INPO maintains an event database accessible from its member Web site. This database is designed primarily to support INPO's SEE-IN program activities and related efforts by members and participants. Operating experience information is received by INPO directly from the utilities and is entered into the database. The database is used for initial screening of operating experience information to identify potentially significant events, as well as for trending plant events. INPO, as a member of WANO, also has access to the WANO database of international event reports. These reports are maintained on the WANO Web site. The WANO event reports are also screened and used to support INPO's SEE-IN program activities.

f. Analysis Activities

The Institute analyzes industry operational data from a variety of sources—events, equipment failures, performance indicators, and regulatory reports—to detect trends in industry performance. Results of analyses are communicated to the industry using products such as Topical Reports. In addition, individual plant performance data is analyzed, with results used in support of other INPO activities.

Appendix A
4. Assistance Programs

INPO helps members improve in nuclear operations areas through assistance programs and activities that continually evolve to meet the changing needs of the nuclear industry. INPO provides assistance to member utilities on request and offers proactive assistance to selected stations that can benefit most from INPO and industry assistance. INPO monitors the performance of member utility stations in the interval between plant evaluations. The purpose of this monitoring is to identify, as early as possible, stations exhibiting indications of declining performance so that proactive assistance can be provided to help reverse the performance trend. INPO managers are assigned as senior representatives for all domestic stations, to facilitate INPO assistance efforts. The senior representatives maintain close liaison with station and utility management, to help identify where INPO resources can best be used to address specific issues and help improve overall station performance.

INPO assistance resources are assigned using a prioritized approach, such that plants with greater performance improvement needs receive a higher level of support and tailored assistance.

INPO facilitates information exchange among member utilities by identifying and cataloging information on a wide range of activities that stations are doing especially well. This information on effective programs and practices is shared with members on request and through a number of other forums. This assistance fosters comparison and the exchange and emulation of successful methods among members.

a. **Assistance Visits**

Members may request assistance visits in specific nuclear operations areas in which INPO personnel have experience or expertise.

Such visits are conducted by qualified INPO personnel and industry peers. For example, if a member requests assistance in some specific aspect of maintenance, INPO will include a peer from another plant that handles that aspect of maintenance well. Written reports detailing the results of the visits are provided only to the requesting utility. Where possible, actual methods and plans for improving performance are included as part of the assistance.

Several individual INPO staff members have detailed technical expertise in specific focus areas. These "niche" experts provide a focal point for INPO assistance to members and participants in their respective areas and represent INPO in industry forums related to these areas.

b. **Development of Documents and Products**

Several categories of documents and other products are designed and developed to assist member utilities and participants to achieve excellence in the operation, maintenance, training, and support of nuclear plants. Key categories of INPO documents and products are as follows:

1. Performance objectives and criteria and accreditation objectives and criteria documents provide a basis for INPO evaluation and accreditation programs. Members are expected to strive to meet the objectives set forth in these documents.

2. Principles documents address

professionalism, management and leadership development, human performance, and other cross-functional topics important to achieving sustained operational excellence. These documents are prepared by INPO with substantial involvement of industry executives and managers.

The first of these documents was *Principles for Enhancing Professionalism of Nuclear Personnel*, which addresses several human resource management areas focused on developing nuclear professionals, including personnel selection, training and qualification, and career development. Two supplemental documents—*Management and Leadership Development* and *Excellence in Human Performance*—build on the *Principles for Enhancing Professionalism of Nuclear Personnel*. Utility executives use *Management and Leadership Development* as assistance to identify, develop, assess, and select future senior managers. *Excellence in Human Performance* provides practical suggestions for enhancements in the workplace that promote excellent human performance.

In 1999, INPO distributed *Principles for Effective Self-Assessment and Corrective Action Programs*. This document also builds on the *Principles for Enhancing Professionalism of Nuclear Personnel*, emphasizing the importance of establishing a self-critical station culture and identifying the key elements of effective self-assessment and corrective action programs.

In 2003, INPO distributed *Principles for a Strong Nuclear Safety Culture*. This document is complementary to, and for use in conjunction with, previously published principles documents. It describes the essential attributes of a healthy nuclear safety culture, with the goal of creating a framework for open discussion and continuing evolution of safety culture throughout the industry.

INPO uses these documents, and the principles extracted from them, extensively in its evaluation and assistance activities.

3. Guidelines establish the bases for sound programs in selected areas of plant operation, maintenance, and training, as well as cross-functional areas of direct importance to the operation and support of nuclear stations. Guidelines assist members in meeting the objectives used in evaluations and accreditation. Member utilities are expected to strive to meet the intent of INPO guidelines.

4. Good practices, work process descriptions, Nuclear Exchange documents, and other documents are provided to assist members. Typically, these documents are developed from programs of member utilities and INPO's collective experience and are synthesized into documents by the INPO staff, with industry input and review. In general, the documents define one method of meeting INPO performance objectives in specific areas. It is recognized that other programs or methods may be as good or better. Utilities are encouraged to use these documents selectively in developing or improving programs applicable to their plants. These documents

can be used in whole or in part, as furnished, or modified to meet the specific needs of the plant involved.

5. Various other documents are produced, such as analysis reports and special studies, as needed. Assistance products include lesson materials, computer-based and interactive video materials, videotapes, and examination banks.

c. **International Technical Exchange Visits**

INPO usually conducts technical exchange visits coordinated by the WANO-Atlanta Center to international participants' facilities. These visits have the dual purpose of identifying strengths at non-U.S. plants that can be shared with plants worldwide and noting opportunities for improvement at the host facilities. When requested by international participants, technical exchange visits are focused on specific areas of interest to the participants. Technical exchange visit teams are often augmented with experts from other international participants or U.S. members to further enhance the mutual benefits of the international technical exchange.

d. **Workshops and Meetings**

INPO sponsors workshops and working meetings for specific groups of managers or on specific technical issues to provide forums for information exchange. This exchange provides an opportunity for INPO personnel and various levels of member and participant management to share industry lessons learned and obtain industry feedback on INPO programs and activities. INPO-sponsored workshops and working meetings also allow individuals from members and participants to meet and exchange information with their counterparts.

e. **Emergency Preparedness Program**

The Institute maintains an Emergency Response Center to assist members in mobilizing the resources of the nuclear industry to meet the needs of an emergency and to provide other resources or assistance if needed.

In 2004, following industry requests, INPO initiated a program to conduct review visits in emergency preparedness at member stations.

Appendix B
INPO's Relationship with the NRC

This appendix provides background and sets forth principles necessary for INPO to support the industry within the existing regulatory framework.

The nuclear utility industry in the United States, like other industries that may affect the health and safety of the general public, is regulated by the federal government. This regulatory function is based principally on the Atomic Energy Act of 1954, as amended, and is carried out by the U.S. Nuclear Regulatory Commission. In 1979, following the accident at Three Mile Island Nuclear Station, the President of the United States appointed a commission to investigate the accident. In its report, the commission, which came to be known as the Kemeny Commission, stated, "It is, of course, the responsibility of the Nuclear Regulatory Commission to issue regulations to assure the safety of nuclear power plants. However, we are convinced that regulations alone cannot assure safety."

INPO was not created to supplant the regulatory role of the NRC, but to provide the means whereby the industry itself could, acting collectively, make its nuclear operations safer. It was envisioned that peer reviews and performance objectives and criteria based on excellence would be effective in bringing about improvements. In the broad sense, the ultimate goals of the NRC and INPO are the same, in that both strive to protect the public; therefore, both review similar areas of nuclear power plant operations. How these goals are achieved is necessarily different. It was recognized that in establishing and meeting its goals and objectives, INPO would have to work closely with the NRC, while at the same time not becoming or appearing to become an extension of or an advisor to the NRC or an advocacy agent for the utilities.

The conduct of evaluations is one of INPO's most important functions. It is also the function that is closest to the role of a regulator. The NRC issues regulations and is required to determine that licensees consistently meet these regulatory requirements. INPO issues performance objectives and conducts evaluations to determine how well they are being met. While the two functions may appear similar, they differ significantly. There are two basic differences between NRC regulations and INPO performance objectives. NRC regulations set limits or conditions that are intended to provide reasonable assurance of protection of the public health and safety. Therefore, it is important that they reflect a consistent level of performance. INPO's performance objectives are broad statements of conditions that reflect striving for a higher level of overall plant performance—striving for excellence. These performance objectives, by their very nature, are difficult to achieve consistently. Regulations should be objective, whereas INPO performance objectives usually are subjective.

Another difference relates to the purpose of an evaluation in contrast to a regulatory inspection. The former stresses striving to achieve excellence as reflected in a given performance objective, whereas the latter stresses the licensee's ability to consistently meet regulatory requirements. Both are considered necessary.

It is because of these differences that INPO and its members conclude there should be a clear separation between INPO evaluations and NRC inspections. The NRC takes the INPO cornerstone programs into account when determining the extent and focus of its regulatory activities. However, in making this determination, the NRC focuses on the performance of the industry as a whole and the results achieved by individual

utilities, rather than through monitoring INPO's activities or specific interactions with an individual member.

Entanglement of NRC activities and INPO programs would divert INPO and the NRC from their respective missions. NRC and INPO activities are independent, yet complementary. INPO's effectiveness would be seriously undermined if an NRC regulatory document or activity incorporated, or in effect codified, INPO programs, documents, or performance objectives.

At the same time, INPO communicates frequently with the NRC on topics of mutual interest. Additionally, INPO participates in industry working groups and task forces that interface with the NRC on specific regulatory issues and initiatives relative to the Institute's mission and strategic objectives. These cooperative interactions have led to the elimination of some redundant activities, benefiting INPO members while enabling both the NRC and INPO to maintain or strengthen focus on their respective missions. For example, the Consolidated Data Entry System, operated by INPO, collects NRC monthly operating data. In some areas of interface with the NRC, INPO has expanded its role, enabling the NRC to focus on areas more directly related to its statutory responsibility.

The industry expects INPO to keep the NRC apprised of its generic activities, while INPO's interactions with an individual member are between that member and INPO (except where reportable occurrences are encountered, as discussed below).

INPO recognizes the need for the NRC to assess the overall quality of INPO's products and the success of its programs. The NRC has independent and diverse methods to assess industry progress or results that might be derived, in part, from INPO programs. In addition, INPO expects to obtain recognition for the industry's self-improvement and self-regulation efforts by providing the NRC with information on INPO programs and activities, including the following:

- Copies of selected generic documents
- Access to other pertinent information, such as EPIX, as described in specific agreements
- Attendance at periodic coordination meetings and briefings
- Observation of certain INPO field activities by NRC employees, with agreement from members
- Observation of National Nuclear Accrediting Board sessions

INPO encourages member utilities to make their plant evaluation reports and accreditation reports available to the NRC for review at each utility or site.

On the other hand, the NRC recognizes that evaluation of INPO activities or records is the responsibility of INPO's chief executive officer and Board of Directors. Reviews of INPO technical activities are carried out by the Executive Review Group and other ad hoc groups or organizations, as directed and approved by the CEO of INPO or the INPO Board of Directors. In view of this, while the industry expects and welcomes INPO's exchange of information with the NRC and NRC review of INPO products and results, it would be inappropriate for the NRC staff or a contracted third party to audit or inspect INPO activities. In recognition of their different roles but common goals, the NRC and INPO have entered into a Memorandum of Agreement that includes coordination plans covering specific areas of mutual interest.

INPO performance objectives and recommendations are based on best practices and the industry's commitment to excellence, not on regulatory requirements. In addition, INPO follows up to verify members are responsive to INPO evaluation and accreditation areas for improvement. Consequently, utilities should not have to answer to the NRC concerning INPO areas for improvement, except as noted below.

INPO has implemented a policy and appropriate procedures with regard to the handling of items that are potentially reportable to the NRC. INPO's policy is to inform utility management of such items during the normal course of business so that the utility can evaluate and report the items as appropriate. If INPO becomes aware of a defect or failure to comply that has been properly evaluated and requires a report under 10 CFR 21, the Institute has an obligation to ensure that the item is reported.

Transactions between INPO and its members are private. For example, when a member recognizes it is experiencing difficulty in an area where INPO has expertise, INPO encourages that member to request an assistance visit. NRC participation in or requests for copies of correspondence concerning such visits could be a deterrent to future requests for such visits. Similarly, the exit meetings following INPO evaluations are more productive if information is openly exchanged between the INPO team and the utility. NRC presence in these meetings would be a deterrent to open dialogue.

The NRC does not use the routine proceedings between INPO and its members as a basis for actions against INPO's members. In this regard, INPO evaluation-related reports, SEE-IN reports, assistance reports, correspondence between INPO and its members, and other INPO technical documents are all integral parts of INPO's private, routine interactions with its members. Both INPO and its members believe it would be counterproductive for the NRC or any party to use information derived from routine INPO proceedings with its members in licensing proceedings or to determine the level or degree of actions that might be taken against a licensee. The NRC has consistently used its best efforts to protect the privacy of these materials. The NRC's regulatory process provides ample data from which to make enforcement decisions.

Appendix C
INPO's Relationship with the World Association of Nuclear Operators-Atlanta Center (WANO-AC)

This appendix describes the relationship between INPO and WANO-AC.

WANO was formed in 1989 by the international nuclear community as the result of the Chernobyl Nuclear Power Plant accident. WANO's mission is to maximize the safety and reliability of the operation of nuclear power plants by exchanging information and encouraging communication, comparison, and emulation among its members. It operates through regional centers in Atlanta, Paris, Moscow, and Tokyo and a coordinating center in London. All operating nuclear power plants, and operator organizations formed by them, are ordinary members of WANO and members of one (or more) of the regional centers.

INPO, as an operating organization, is an ordinary member of WANO and represents the U.S. nuclear utilities in WANO activities. INPO is a member of WANO-AC. The WANO-AC Governing Board usually appoints an INPO executive to serve as the Atlanta Center director.

INPO provides WANO-AC resources in terms of seconded staff to support the center's day-to-day operation. To minimize duplication, INPO also provides WANO-AC administrative support services, such as payroll, computer support, and benefit administration. WANO-AC reimburses INPO for this support.

INPO supports the full range of WANO activities and programs and facilitates direct contacts between U.S. and non-U.S. WANO members. Such activities and programs include the following:

- WANO Voluntary Peer Reviews: Such reviews are conducted at the request of INPO members by WANO teams of U.S. and international peers who identify strengths and areas for improvement associated with nuclear safety and reliability. When conducted at a U.S. INPO member plant, a WANO peer review is performed in lieu of an INPO plant evaluation.

- WANO Exchange of Operating Experience Information: Detailed descriptions of events and lessons learned are distributed to member utilities worldwide.

- WANO Performance Indicators: Quantitative nuclear plant performance data is collected, trended, and disseminated to facilitate goal-setting, performance trending, and monitoring and to encourage emulation of the best industry performance.

- WANO Technical Support Missions: On-site visits are conducted to allow direct sharing of plant operating experience and ideas for improvement.

- WANO Professional and Technical Development: Courses, seminars, and workshops are designed for enhancing staff development and sharing operating experience.

At INPO's request, WANO-AC provides management and support services for the conduct of the INPO International Participant Program. For example, WANO-AC organizes and coordinates INPO technical exchange visits and International Participant Advisory Committee meetings.

Appendix D
Principles of Sharing

Throughout the process of electric deregulation in the United States, INPO's goal has remained the same: to promote the highest levels of safety and reliability—to promote excellence—in the operation of nuclear electric generating plants. That U.S. utilities were now in competition in certain areas meant a clear understanding was needed to continue sharing pertinent operational information to strengthen safety and reliability.

As nuclear professionals, we affirm our commitment to share information with each other to enhance the safe and reliable operation of our nuclear power plants. This cooperation is fundamental to our future success.

INDUSTRY RESPONSIBILITIES

We will continue to share the following:

- Practices important to safety and reliability
- Operating experience and operational performance data
- Information related to failure of equipment or processes
- Information to improve human performance
- Operational safety experiences with license renewal and decommissioning activities

We will assist each other in the following areas:

- Benchmarking to emulate best industry practices
- Nuclear oversight, self-assessment, and corrective action activities, as requested

We will provide support for the following:

- INPO cornerstone programs—plant evaluations, training and accreditation, events analysis and information exchange, and assistance

INPO RESPONSIBILITIES

We will continue to do the following:

- Emphasize nuclear safety and the sharing of principles
- Analyze and share operating experience, lessons learned, operational performance indicator data, and safety equipment performance data
- Promote industry use of plant strengths and areas for improvement

We will facilitate industry participation in the following:

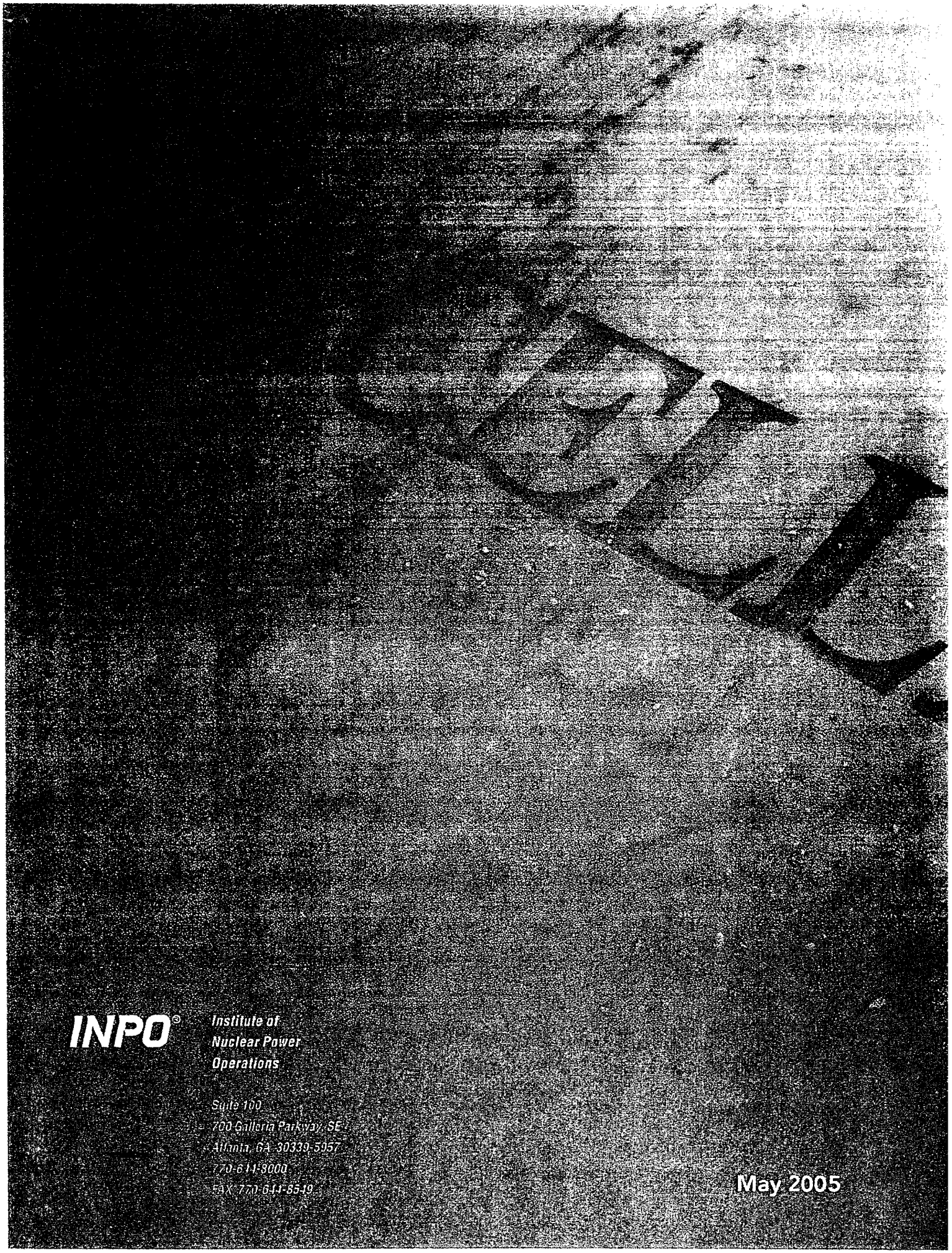
- INPO cornerstone programs—plant evaluations, training and accreditation, analysis and information exchange, and assistance

We will communicate sharing through the following:

- The member Web site, Nuclear Network, and other databases
- Guidelines, Nuclear Exchange documents, and other publications

NUCLEAR INDUSTRY BUSINESS CONDUCT

The industry and INPO recognize that certain information is private in nature. Examples include INPO plant evaluation and accreditation results, personal employee and individual performance information, and appropriate cost and power marketing data.



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May 2005

EXHIBIT
APS-97
Admitted

REJOINDER TESTIMONY OF PETER M. EWEN

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0816
Docket No. E-01345A-05-0826
Docket No. E-01345A-05-0827

November 3, 2006

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REJOINDER TESTIMONY OF PETER M. EWEN
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-05-0816)
(Docket No. E-01345A-05-0826)
(Docket No. E-01345A-05-0827)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Peter M. Ewen. My business address is 400 North Fifth Street, Phoenix, Arizona, 85004. I am Manager of the Revenue and Fuel Analysis and Forecasts Department for Arizona Public Service Company ("APS" or "Company"). In that role, I am responsible for preparing the Company's short-range and long-range forecasts of system peak demand and energy sales, and projecting the optimal dispatch of available resources to minimize the cost of meeting those energy requirements.

Q. DID YOU PREVIOUSLY FILE DIRECT, REBUTTAL AND REJOINDER TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR PALO VERDE REJOINDER TESTIMONY?

A. I am responding to the Surrebuttal Testimony of Staff Witness Dr. Jacobs. Dr. Jacobs disagreed with certain adjustments that I proposed in my Rebuttal Testimony to his recommended disallowance of replacement power costs related to alleged imprudent Palo Verde outages occurring in 2005.

Q. DOES YOUR SILENCE REGARDING ANY OF THE ISSUES DISCUSSED BY OTHER PARTIES INDICATE AN ACCEPTANCE OF THOSE POSITIONS?

A. No, it does not. An absence on my part of a response to a surrebuttal issue should not be taken as acceptance of any party's testimony; instead it is an indication that I maintain my position, as discussed in previous testimony.

II. SUMMARY OF REJOINDER TESTIMONY

Q. PLEASE SUMMARIZE YOUR REJOINDER TESTIMONY.

A. Although Dr. Jacobs accepted two of the Company's adjustments to his recommended disallowance of 2005 Palo Verde replacement power costs, he failed to adequately consider the remaining adjustments.

First, Dr. Jacobs provided no support for his conclusion that prudent maintenance work performed during the October 2005 Unit 2 refueling water tank ("RWT") outage did not allow the Company to avoid a later unplanned outage or downpower. Neither did he appear to disagree in principle with the Company's quantification of the avoided replacement power costs of $5.1 million (after 90/10 sharing). In his Rejoinder Testimony, APS Witness Jim Levine provides the detailed evidence that supports the conclusion that the Company did avoid such a future outage.

Second, with respect to the impact of Palo Verde outages on off-system sales margins, Dr. Jacobs offered a high-level critique of the analysis provided by the Company, but failed to provide any analysis to demonstrate that his original calculation was more accurate than the one provided by the Company. He also mischaracterized the manner in which the analysis was conducted and erroneously concluded that the Company's assessment was performed only during hours in which the Company was not purchasing power.

Finally, Dr. Jacobs continued to take an unbalanced approach to the Company's

unplanned outages. He made disallowances for poorer-than-planned performance at Palo Verde, yet ignored the better-than-planned performance at the Company's fossil units.

III. AVOIDED OUTAGE COSTS DUE TO MAINTENANCE DURING OCTOBER 2005 UNIT 2 RWT OUTAGE

Q. HAS DR. JACOBS DISAGREED WITH YOUR QUANTIFICATION OF THE AVOIDED OUTAGE COSTS RELATED TO THE MAINTENANCE WORK PERFORMED DURING UNIT 2'S RWT OUTAGE IN OCTOBER 2005?

A. Dr. Jacobs offered no specific disagreement with the quantification of the outage costs that were avoided due to the maintenance work undertaken during the Unit 2 RWT outage during October 2005. Apparently he did disagree with the Company's conclusion that additional future outage costs were avoided, calling such a conclusion "speculative." (Surrebuttal Testimony of William R. Jacobs, p. 40) In his Rejoinder Testimony, Mr. Levine provides detailed evidence associated with the extent of leakage in the RCP oil seals, which conclusively demonstrates that such an outage was imminent. The Company's best estimate of the avoided costs resulting from this maintenance work is the $5.6 million I described in my Rebuttal Testimony in this docket.

IV. OFF-SYSTEM MARGIN IMPACTS

Q. DID DR. JACOBS CORRECTLY CHARACTERIZE YOUR METHODOLOGY FOR CALCULATING THE OFF-SYSTEM SALES IMPACTS FROM THE PALO VERDE OUTAGES?

A. No. At page 41 of his Surrebuttal Testimony, Dr. Jacobs stated that the Company:

> [P]rovided for an adjustment to margins for lost off-system opportunity sales in those hours when both (1) Palo Verde was shut down due to an imprudent outage and (2) APS was not buying power in the wholesale market.

He was correct that the analysis of lost margins I provided in my Rebuttal Testimony covered only the hours during which he has recommended a disallowance, but he was not correct in his assertion that I further limited the analysis to only hours in which the Company was not purchasing power. My analysis covered all outage hours at issue in Dr. Jacobs's recommendation.

Q. ARE THERE OTHER CHARACTERIZATIONS OF YOUR ANALYSIS BY DR. JACOBS THAT ARE NOT CORRECT?

A. Yes. Dr. Jacobs observed that there were three days out of fourteen where the actual realized off-system margins during a Palo Verde outage exceeded the expected margins without a Palo Verde outage. As a result, he concluded that the analysis must be wrong and totally disregarded it. Unfortunately, he did not take into account that other factors, such as better than expected coal plant performance, could help alleviate the reduction in margins related to Palo Verde being out of service. Another significant factor that helped improve off-system margins was the use of certain generating units at low incremental heat rates. This occurred in instances when, for example, a 2x1 combined cycle unit would not normally be run on a particular day (and therefore did not contribute to off-system sales on that day), but was turned on to replace the unplanned Palo Verde outage. These units were not always needed during the Fall and Spring because they compete with other similar units on the margin and have significant start-up costs. However, once they are started and ramped up to minimum load, their incremental heat rates are much lower than their average heat rates, which can make them economic enough to make off-system sales. The replacement costs already reflected the start-up and higher heat rate costs related to these units, so the additional sales margins helped defray those costs.

Q. DOES THE PRESENCE OF THESE DAYS MAKE A DIFFERENCE IN YOUR CONCLUSIONS ABOUT THE LOSS OF OFF-SYSTEM SALES MARGINS?

A. No. Even if each of these days were ignored for purposes of establishing the impact of the Palo Verde outages on off-system sales margins, the impact increased by only $200,000 to a total of just over $500,000. This is significantly different from the more than $2 million calculated by Dr. Jacobs.

Q. WHY IS YOUR METHOD A MORE ACCURATE REPRESENTATION OF OFF-SYSTEM SALES COMPARED TO THE METHOD EMPLOYED BY DR. JACOBS?

A. The method I propose is based on an analysis of hourly data that relied on actual system conditions to the largest extent possible. Dr. Jacobs has based his calculation on a set of assumptions that are far too general to rely on when confronted by a difference of almost $2 million. In particular, he has assumed that every megawatt-hour (MWh) of lost Palo Verde generation leads to a reduction in off-system sales. This is simply impossible when the Company typically makes annual aggregate off-system sales on the order of 1,500 gigawatt-hours (GWh) and Palo Verde generation can be as high as 9,000 GWh. Additionally, Dr. Jacobs assumed that every lost off-system sale can be priced at the average across all sales during 2005. This gross simplification failed to take into account the specific time periods and corresponding market conditions during the outages that are in question. Taken together, it is clear that the analysis of hourly data yielded a more realistic and accurate result: that the off-system sales impact can be quantified at $0.3 million.

V. EXEMPLARY PERFORMANCE

Q. DO YOU AGREE WITH DR. JACOBS'S STATEMENT THAT THERE SHOULD BE NO OFFSET DUE TO COAL PLANT PERFORMANCE?

A. No. Dr. Jacobs has taken a one-sided approach to the Palo Verde outage costs and chose to focus only on higher outage costs, despite the fact that significant mitigation of those

costs has already occurred through the superior performance of the Company's coal plants. As I previously indicated in my Rebuttal Testimony, the coal plants outperformed their expected unplanned outages by $10 million.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

TRANSCRIPT OF PROCEEDINGS

BEFORE THE

PUBLIC UTILITY COMMISSION OF TEXAS

AUSTIN, TEXAS

RECEIVED
APR 13 2006
LEGAL DIV.
ARIZ. CORPORATION COMMISSION

APPLICATION OF GULF STATES UTILITIES COMPANY TO RECONCILE FUEL COSTS, ESTABLISH NEW FIXED FUEL FACTORS, AND RECOVER ITS UNDER-RECOVERED FUEL EXPENSE	)	**DOCKET NO. 10894**

EXHIBIT
tabbies
APS-98
Admitted

ORAL DEPOSITION OF WILLIAM R. JACOBS, JR., Ph.D.

ANSWERS AND DEPOSITION OF WILLIAM R. JACOBS, JR., Ph.D., a witness produced at the instance of the Applicant, beginning at approximately 2:45 p.m., on Tuesday, the 13th day of October 1992, at the Offices of GDS Associates, Inc., 7600 Burnet Road, Suite 400, Austin, Texas; and the following proceedings were reported by Aloma J. Kennedy, a Certified Shorthand Reporter of:

Q.1-6 #4

1 components are manufactured without defects?
2 A It should ensure that if defects
3 exist, that they are identified.
4 Q 100 percent of the defects that exist
5 should be identified through a QA program?
6 A That would be the goal.
7 Q Is that the reality?
8 A Well, this one wasn't; so, no.
9 Q Is it the reality at any plant, that
10 100 percent of the defects are discovered through
11 a QA program?
12 A No.
13 Q In a QA report, just curiosity, they
14 can use hindsight -- correct? -- in drawing their
15 conclusions?
16 A Correct.
17 Q And the Independent Safety Evaluation
18 group could also use hindsight in drawing
19 whatever conclusions it draws?
20 A That's correct.
21 Q And in writing up the root cause for a
22 condition report, the author can use hindsight in
23 drawing his conclusions regarding root cause?
24 A That's correct.
25 Q Let's discuss the diesel generator

CONFIDENTIAL

EXHIBIT
APS-99

PAGES 1-11

EXHIBIT
APS-100
Admitted

GEORGIA POWER COMPANY
Docket No. 18300-U
Staff Data Request No STF-GDS-1

STF-GDS-1-42

Question:

Please describe in detail any activities or programs conducted because of the existence of the Nuclear Performance Standard that would not have been conducted if the Nuclear Performance Standard did not exist.

Response:
None.

Contact Person: Dave Pershing

EXHIBIT
tabbies
APS-101
Admitted

56 FR 33945
Published 7/24/91
Effective 7/24/91

Possible Safety Impacts of Economic Performance Incentives: Final Policy Statement

AGENCY: Nuclear Regulatory Commission.

ACTION: Final policy statement.

SUMMARY: This statement presents the final policy of the Nuclear Regulatory Commission (NRC) with respect to the possible safety impacts of economic performance incentive (EPI) programs established by State commissions regulating electric utilities. The policy statement (1) Contains a discussion of the possible effect of the policies and actions of State regulatory bodies, emphasizing that these actions can have either a positive or negative effect on public health and safety; (2) reflects the Commission's concern that certain forms of economic performance incentive (EPI) regulation may adversely affect the operation of nuclear plants and the public health and safety; (3) specifically identifies those methods that are of particular concern (e.g. the use of sharp thresholds, the measurement of performance over very short time intervals, the lack of "null zones," and inappropriate reliance on systematic assessment of licensee performance (SALP) scores or other performance indicators; (4) indicates that the NRC will continue to monitor the application of EPIs and performance criteria to nuclear power plant operations; and (5) urges licensees and State regulatory commissions to inform the NRC of EPI programs that are being considered for application to NRC licensees.

EFFECTIVE DATE: This policy statement becomes effective July 24, 1991.

FOR FURTHER INFORMATION CONTACT: Anthony T. Gody, Sr., Chief, Policy Development and Technical Support Branch, Office of Nuclear Reactor Regulation, U.S. Nuclear Regulatory Commission, Washington, DC, 20555, Telephone: (301) 492-1254.

SUPPLEMENTARY INFORMATION: In exercising their jurisdiction over the economics of the generation of electricity, a number of State regulatory commissions and the Federal Energy Regulatory Commission (FERC) have established economic performance incentive (EPI) programs for electric power plants. Although some programs have existed unchanged for a number of years, others have been substantially modified or are newly established. They can significantly help to improve the economic performance of electric power plants. They can also affect the safety of nuclear power plants. The NRC monitors and evaluates these incentive programs to determine the affect that they may have on the safe operation of nuclear power reactors.

After reviewing the information on EPI programs established by State regulatory commissions that regulate the economic returns of utilities operating nuclear power plants, the Commission decided that it should set forth its views in a Commission Policy Statement on the manner in which such programs could affect safety.

Summary of Comments

On October 28,1990, the NRC published the draft policy statement, "Possible Safety Impacts of Economic Performance Incentives," in the Federal Register (55 FR 43231). The NRC received 37 comments: 14 from State

public utility commissions, 12 from utility licensees or law firms representing utility licensees, and 11 from public interest groups, trade associations, non-affiliated individuals, or governmental bodies other than public utility commissions.

Most of the commenters believed that the NRC should provide advice but not endorse any specific EPI program. They indicated that the NRC should monitor the effectiveness of EPI programs but should not interfere in the proceedings of State public utility commissions. Almost all of the commenters also indicated that the NRC, the utilities, and the State utility commissions should continue to communicate with one another. Many of the utilities or their representatives that commented stated that the NRC should discourage the use of EPIs in the absence of evidence that they promote safety. Further, a number of utility commenters indicated that the SALP scores and other performance indicators should not be used for assessing penalties. In addition, certain commenters stated that regulators should not use the results of root-cause and self-assessment analysis to determine if costs should be disallowed. In separate correspondence, one utility informed the Commission of its concerns that State regulators had used the utility's voluntary corrective actions to justify a disallowance. Certain commenters also believed that the NRC should evaluate the manner in which specific EPI programs either benefit or hinder safety but should not endorse specific types of programs. Finally, some commenters suggested that the Policy Statement should be more specific by stating, for example, the difference between a long-term performance measure and a short-term performance measure.

Most of the State public utility commissions that commented indicated that rational incentive programs do not adversely affect the operation of nuclear power plants and thus do not adversely affect public health and safety. Many of the States that commented indicated that they do not use any of the criteria of concern to the NRC, such as sharp thresholds, short term performance measures, or SALP scores. The State utility commission for New York stated that it does not penalize or reward utilities for operating at or close to the industry's average capacity factors. However, it imposes penalties and rewards on a sliding scale for deviations from the target factors. The State utility commission for North Carolina stated that it establishes targets based on long-term averages of nuclear capacity factors for testing the efficiency of nuclear plant generation. It does not automatically impose penalties for not meeting these targets if a utility can show that its nuclear operations were prudent. The State public utility commissions generally indicated that States cannot legally be precluded nor should be precluded from adopting performance standards that encourage utilities to both economically and safely operate nuclear power plants.

The public advocacy group, Massachusetts Public Interest Research Group (MASSPIRG) provided a substantial amount of comments. It was a major participant in the settlement agreement that resulted in the Massachusetts performance incentive plan for the Boston Edison Company relating to the Pilgrim Nuclear Plant. MASSPIRG generally supported the objectives of the draft Policy Statement and desired to work with NRC in identifying superior alternative indicators for use in EPI plans.

MASSPIRG indicated that the Massachusetts plan was of necessity in confidence because it was a part of a larger settlement with the Boston Edison Company. MASSPIRG stated that it understood the concerns that the NRC had previously expressed relating to the use of SALP scores and performance indicators. However, in developing the plan for the Boston Edison Company, MASSPIRG used expert consultants and searched for indicators that could correlate with long-run economic performance, correspond with recurrent Pilgrim problems, encourage the timely maintenance of equipment, and provide early indications of problems that would lead to long-run economic and safety performance. MASSPIRG also looked for indicators that were easy to evaluate and use in an incentive system and would cover a broad range of plant activities and systems.

The Pacific Gas and Electric Company (PG&E) provided many comments on the manner in which the comprehensive performance-based ratemaking settlement approved in 1988 by the California Public Utilities Commission (CPUC) for the Diablo Canyon Nuclear Power Plant provides long-term incentives to improve the reliability of the Diablo Canyon plant. The settlement, which will be in effect for 28 years, provides a number of incentives to PG&E to improve the reliability and safety of plant operations. PG&E assumes risks associated with equipment failures, prolonged outages, and new regulatory requirements for the entire 28 year period of the settlement. This program provides PG&E with an economic incentive to ensure that the plant operates well over many years. The Diablo Canyon settlement does not rely on short-term performance measurements with sharp thresholds and does not use SALP scores—features that the NRC has identified that may adversely affect the public health and safety.

NRC Response to Comments

Many of the comments related to the role of the NRC in EPI programs. The NRC certainly agrees that economic regulatory agencies should be the groups to develop and approve EPIs. However, the NRC reviews matters that raise safety concerns at licensed facilities. The NRC deals with safety issues regardless of the source of the concern.

The commenters provided a number of suggestions for changing the Policy Statement, particularly to more clearly specify certain issues. The NRC believes this should not be done. A wide variety of acceptable EPI programs could be devised. Because rate regulatory agencies and licensees are more familiar with economic regulatory options than is the NRC, they are more capable of devising plans to meet these regulatory objectives. It is the position of the NRC that the Policy Statement provides sufficient guidance on safety issues for the parties to use in developing or improving EPI programs.

Some licensees commented that the NRC should allow licensees to voluntarily report to it on EPI programs. These licensees also indicated that the NRC should not require licensees to evaluate or analyze information. However, the NRC believes that some EPI programs clearly could be of major safety concern, and that the NRC must obtain sufficient information to properly conduct its regulatory responsibility.

Certain commenters also stated that confidential negotiations may be necessary under certain circumstances to develop EPI programs because other regulatory matters are also involved. While the NRC concedes that such negotiations may be necessary, it is unlikely that the program developed must be withheld from the NRC until after final adoption. The NRC is issuing the Policy Statement to improve communications with agencies having economic regulatory responsibilities of nuclear power plants.

After carefully considering all the comments on the draft Policy Statement, the NRC has decided to issue the final Policy Statement with little change from the draft Policy Statement.

Statement of Policy

Potential Impacts

The NRC recognizes that the existing programs very considerably from State to State and that the plans are not easily classified, especially as to the effect that they may have on the safe operation of plants. However, certain general characteristics of programs can be evaluated and found to have an effect on safety that is either desirable (or at least neutral) or undesirable.

A desirable plan provides incentives to make reasonable improvements in operation and maintenance that result in long-term improvement in the reliability of the reactor, the main generator, and their support sytems. An undesirable plan provides incentives to operate a facility that could have safety problems or to start up before it is fully ready, merely to meet an operational goal.

A desirable EPI program rewards a utility for having sound operations and maintenance programs and for correcting recurrent or predictable failures or other problems that could lead to an operational transient, an unplanned plant outage, or a derating. Such an incentive is desirable because a well run plant and the prompt correction of problems enhance safety. Unanticipated transients and shutdowns challenge operators and safety systems and, although with a low probability, could initiate a more serious event.

Economic performance incentives can encourage a utility's operational organization to improve its performance, which can help to improve both safety and economic performance. However, current safety and economic requirements also provide utilities with incentives to operate safe plants.

The current influence of incentive plans on reactor safety is believed to be small. However, the Commission's concern with incentive plans is that, in the interest of real or perceived short-term economic benefit, the utility might hurry work, take short cuts, or delay a shutdown for maintenance in order to meet a deadline, a cost limitation, or other incentive plan factor.

Therefore, an incentive program could directly or indirectly encourage the utility to maximize measured performance in the short term at the expense of plant safety (public health and safety). By keeping a reactor on line when it should be taken down for preventive or corrective maintenance and by using shortcuts or compressed work schedules to minimize down time, the licensee could decrease the margin of safety.

Adverse Effects on Plant Operation and Public Health and Safety

Some specific features of incentive plans now used by some States could adversely affect public health and safety. These features are (1) Sharp thresholds between rewards and penalties (or between penalties and null zones, or rewards and null zones) and (2) performance measurements that have short time intervals. The NRC believes that these features should not be allowed to prompt licensees to operate a plant when it should be shut down for safety reasons.

A sharp threshold is a situation in which a licensee narrowly misses a target capacity factor and must bear a large part or all of the resulting replacement power costs. By creating a sharp threshold in its incentive program, a State could prompt a licensee to continue to operate a plant to achieve a target capacity factor in order to avoid the large replacement power cost or to earn a substantial reward. This type of incentive could divert attention from safe plant operation. To minimize these effects, States should consider incorporating a reasonably broad null zone of acceptable performance in which no rewards or penalties are imposed.

Performance measurements for short-term intervals would encourage the licensee to focus on a short term target or performance goals such as a higher capacity factor or availability factor. This target could become the primary focus, diverting attention from long-term goals of reliability and operational safety. In contrast, performance measurements for long-term intervals would prompt the utility to follow sound maintenance and operational practices to improve operating performance. For example, an incentive program could include a three or four year period with a rolling average capacity factor evaluation period and could account for other factors such as refueling outages, inclement weather and other periodic events. Short-term measurements tend to make safety and economic goals conflict with each other, while long-term measurements tend to make the two goals complementary.

Other Special Features or Ratemaking Actions That Cause NRC Concern.

The Commission is also concerned about undue reliance on NRC's SALP ratings in EPI programs and about any State public utility commission's undue reliance on a utility's corrective actions following an incident to justify the disallowance of costs related to the incident.

Sharp thresholds and short-term performance measures coupled with substantial reliance on NRC's SALP ratings can adversely affect safety and present several major concerns. First, the NRC's SALP ratings assist the NRC and licensees in identifying trends and areas of performance that should receive a more detailed assessment, in assessing the safety of the performance at individual facilities, and in communicating to the licensee. Therefore, these ratings address selected areas of licensee activity, but do not necessarily cover all significant performance areas. Further, the scores and ratings are not based on absolute quantitative considerations, and therefore produce numerical scores that are of limited significance. The NRC expects licensees to focus on the facts in the SALP report, the issues identified, and the apparent root causes of problems. By determining financial rewards or punishments for the licensee based on SALP, the State may cause the licensee to focus on improving the numerical scores instead of addressing the underlying issues, where the focus should be. If the issues identified in SALP reports are obscured by concerns over the financial consequences incurred as a result of those ratings, the process may not achieve the desired objective and may instead prompt a licensee to take corrective actions that produce rapid results rather than taking those that yield the highest increase in safety in the long term. Undue emphasis on performance indicators in an incentive program could prompt a licensee to improve the scores by taking inappropriate actions rather than by identifying and correcting underlying safety conditions.[1]

The Commission is also concerned about State public utility commission ratemaking actions that might be interpreted as penalizing a utility for improving its own procedures or methods of operation. For example, where a State public utility commission observes that a utility has modified its procedures following an incident, infers from the utility's actions that the original procedures must have been inadequate, and then disallows certain costs on the basis of such assumed inadequacies, the utility will have a strong disincentive voluntarily to enhance or improve its operations and procedures in the future. Such State public utility commission action can discourage utilities from making needed improvements in procedures and operations and, thus, can be detrimental to the long-term safety of operation.

Continued NRC Monitoring Program

The NRC will periodically survey FERC and State regulatory commissions that regulate the utility rates of power reactors to identify any new programs or substantial changes in existing programs and to ascertain how the

[1] For further information on existing economic incentive programs and the possible effect of such programs on nuclear safety, see NUREG/CR-4971, Incentive Regulation of Nuclear Power Plants by State Regulators, 1991. Copies of NUREG/CR-4971 may be purchased from the Superintendent of Documents, U.S. Government Printing Office, P.O. Box 37082, Washington, DC 20013-7082. Copies are also available from the National Technical Information Service, 5285 Port Royal Road, Springfield, VA 22161. A copy is also available for public inspection or copying at the NRC Public Document Room, 2120 L Street, NW, Washington, DC.

programs have been implemented, and to determine if large penalties have been imposed.

We will update the survey annually. We will periodically assess the frequency of the surveys to determine the need to adjust the schedule.

Licensees and Utility Commissions Urged To Inform NRC of Program Initiatives

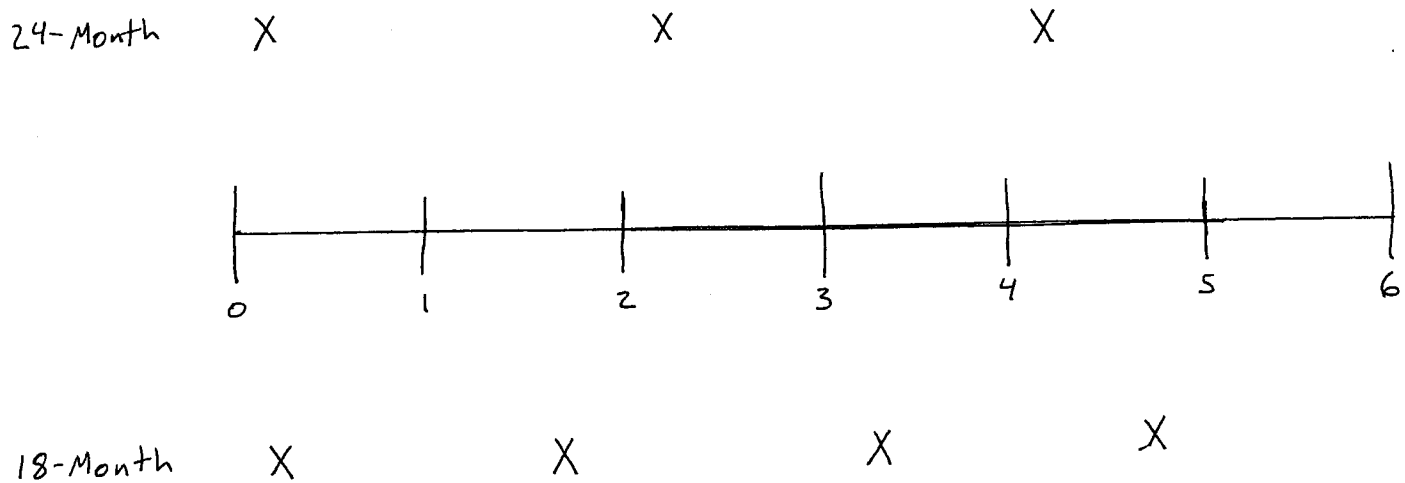
The NRC needs to be informed of EPI programs that are being planned by State regulatory commissions and that can affect safety. Information on these programs enables the Commission to judge not only whether they could adversely affect safety but also whether they could enhance safety. A number of commenters supported certain features of an EPI program. The Commission has reviewed these features and believes State Public Utility Commissions (PUCs) may want to consider these features in establishing programs that prompt licensees to both economically and safely operate nuclear power plants. These features include (1) capacity factor targets based upon industry's average performance to account for problems throughout the industry, (2) equal opportunities for rewards and penalties, (3) the "banking" of superior performance to offset lower performance, and (4) using performance measures of the entire system instead of those for a specific unit. Frequently, the States develop these programs in coordination with regulated utilities. Therefore, the NRC will request by generic letter that licensees report whenever these commissions develop or substantially revise EPIs. The NRC also will ask FERC and the State utility regulatory commissions to discuss with the NRC initiatives to impose or change an EPI program that applies to an NRC licensee. The NRC will take these actions in order to gain information on the principal features of the program so that the NRC can assess the extent to which the program will affect plant safety. Further, by a generic letter, the NRC will request licensees to report the rewards and penalties assessed through these programs as they occur. A free exchange of information between the NRC and the agencies with economic jurisdiction over nuclear utilities will help the NRC and those agencies to work together to achieve the goals of the safe and economic operation of nuclear power plants.

Dated at Rockville, Maryland, this 18th day of July 1991.

For the Nuclear Regulatory Commission.

Samuel J. Chilk,

Secretary of the Commission.



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Attachment 1

EXHIBIT
APS-103
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ARIZONA PUBLIC SERVICE COMPANY
PV Audit Off-System Margin Calculation
Actual -vs- Simulated Margin and Volume

Date	Actual Revenue	Actual Fuel & PP Cost	Actual Margin	Simulation Margin	Difference	Actual Mwh	Simulation MWh	MWh Difference
8/26/2005	200,496	185,081	15,415	18,035	(2,620)	1,671	2,837	(1,166)
8/27/2005	94,260	88,262	5,999	65,793	(59,795)	1,130	3,534	(2,404)
8/28/2005	171,270	171,693	(423)	4,040	(4,464)	1,461	1,642	(181)
8/26-8/28			20,990	87,869	(66,879)	4,263	8,013	(3,750)
10/11/2005	403,062	344,107	58,955	223,126	(164,171)	5,127	7,828	(2,701)
10/12/2005	315,967	265,160	50,807	76,411	(25,604)	4,568	2,909	1,659
10/13/2005	128,959	115,228	13,731	100,929	(87,198)	2,381	4,326	(1,945)
10/14/2005	139,403	153,673	(14,270)	83,226	(97,496)	2,428	3,534	(1,106)
10/15/2005	98,882	50,543	48,339	52,072	(3,733)	1,239	2,569	(1,330)
10/16/2005	108,918	93,231	15,687	40,777	(25,091)	2,138	2,589	(451)
10/17/2005	170,513	119,786	50,728	78,563	(27,835)	2,259	3,733	(1,473)
10/18/2005	225,463	105,440	120,024	70,851	49,173	2,636	3,588	(952)
10/19/2005	587,646	336,633	251,013	139,944	111,069	7,526	5,180	2,346
10/20/2005	453,966	319,458	134,508	118,935	15,573	5,722	4,903	819
10/21/2005	50,450	38,472	11,978	25,965	(13,987)	657	3,111	(2,454)
10/11-10/20			729,521	984,835	(255,314)	36,025	41,160	(5,135)
Total			750,512	1,072,705	(322,193)	40,287	49,173	(8,886)
Remove RCPs 1A and 2A oil seal replaced					53,012			
Total Off-System Margin Impact					(269,180)			

APS08321

1 STATE OF ARIZONA)
) ss.
2 COUNTY OF MARICOPA)
3
4
5
6
7 I, COLETTE E. ROSS, Certified Court Reporter
8 No. 50658 for the State of Arizona, do hereby certify
9 that the foregoing printed pages constitute a full, true
10 and accurate transcript of the proceedings had in the
11 foregoing matter, all done to the best of my skill and
12 ability.
13
14 WITNESS my hand this day
15 of , 2006.
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18
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20 COLETTE E. ROSS
Certified Court Reporter
21 Certificate No. 50658
22
23
24
25

EXHIBIT
tabbies
104 APS
Admin Notice

1 CHMN. HATCH-MILLER: I was going to say Maledon.
2 Thank you very much, all of you. This meeting
3 is adjourned.
4 (The special open meeting adjourned at
5 4:30 p.m.)
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1 frame that the engineer groups are telling us.
2 COM. MAYES: If that's a case scenario, then
3 this is best case scenario, is two to four weeks?
4 MR. LEVINE: Best case scenario is mid-February.
5 COM. MAYES: Right.
6 CHMN. HATCH-MILLER: Disappointing news to say
7 the least, but you have got to face reality. Again,
8 Styrofoam cups work for me, kind of like the
9 hydroelectric -- it is less expensive.
10 MR. LEVINE: Let me just mention here again,
11 nobody wants to bring this plant up to full power more
12 than we do. We have set limits on this plant. And the
13 overriding concern here is going to continue to be
14 safety. So we will move toward those limits. But when
15 we get close to those limits, when we hit those limits,
16 then we will stop the power essentially at that point
17 and stay within the safety bounds that we have
18 established.
19 CHMN. HATCH-MILLER: Thank you very much.
20 Before you leave today, I would like you to try and
21 start working on a date with Staff to continue with our
22 discussion.
23 Thank you very much, all of you, Mr. Davis,
24 Mr. Levine, Mr. Maledon.
25 MR. MALEDON: Maledon.

1 which is being deigned now, which is an application that
2 has been used on other piping systems, not just power
3 plants, but it is a pipe, piping system, and shown to be
4 effective in reducing vibration. That is going through
5 the modification process now and we would expect that
6 that modification is going to be to us by mid-February.
7 And then we are talking a couple days of installation.
8 If it has the desired or the expected effect here of
9 reducing the vibration 50 percent, it certainly will
10 help us get up and power a significant amount. How
11 much, whether we get to 100 percent power or not at this
12 point is unknown.
13 We have another design that is going on parallel
14 that would basically put a shock absorber type of an
15 arrangement in there on the pipe to again dampen the
16 vibration that we are seeing here. That particular mod
17 is about two weeks or so behind the tuned mass absorber.
18 So more than likely we will get the tuned mass absorber,
19 and that's the one we are going with.
20 COM. MAYES: So at the very least, Mr. Levine,
21 we are looking at at least two more weeks of Palo Verde
22 at being at significantly reduced capacity, possibly a
23 month more?
24 MR. LEVINE: That's correct. And that's
25 assuming we get these modifications done in the time

1 MR. LEVINE: So let me just summarize there and
2 I will leave the rest.
3 CHMN. HATCH-MILLER: We won't do the emergency
4 preparedness.
5 MR. LEVINE: Okay. Go ahead, Sue.
6 So the bottom line is we start up. We have this
7 problem. We end up limiting because of our, because of
8 the limits that we have put on the vibration on this
9 line. And we have come up with three different
10 approaches here to try and mitigate that.
11 This mass dampener was basically to hang weights
12 on the pipe to change the resonance frequency of the
13 pipe, and then similar to your Styrofoam cup a little
14 bit, but --
15 CHMN. HATCH-MILLER: You tried it already.
16 MR. LEVINE: Yes.
17 COM. MUNDELL: That's encouraging.
18 COM. MAYES: Inspirational.
19 MR. LEVINE: So we hang weights on the pipe.
20 Again, that proved not to be. And what it has proved to
21 us is the modeling, and we have some of the best models
22 or not the best models out there, very sensitive to a
23 lot of different things in this system, and the modeling
24 is not accurate enough to totally predict everything.
25 We have what is called a tuned mass absorber

1 positive change in Unit 1 if they are exactly the same
2 technology?
3 MR. LEVINE: Commissioner, that's one of the
4 questions we are wrestling with.
5 COM. MUNDELL: Okay.
6 MR. LEVINE: Because they are essentially
7 identical design.
8 COM. MUNDELL: I thought they were. I thought I
9 was missing something.
10 MR. LEVINE: No, they were identical design.
11 CHMN. HATCH-MILLER: I say this only for levity.
12 It is not serious. But I have a vibration in my car.
13 And I tore a Styrofoam cup apart and put it behind
14 there, and it stopped. You might try that.
15 COM. MAYES: Is that your radio?
16 CHMN. HATCH-MILLER: We are going to have to
17 have this discussion fairly quickly now. And I know we
18 all have a lot of questions. I know Staff needs to have
19 an opportunity to ask questions of you, but not today.
20 I know we as Commissioners have additional questions.
21 But I would like you to take maybe one minute and just
22 summarize.
23 MR. LEVINE: Okay. I am actually at the end of
24 Unit 1 here.
25 CHMN. HATCH-MILLER: I know you are.

1 COM. MUNDELL: Correct.
2 MR. LEVINE: And essentially we saw no
3 difference in vibration.
4 COM. MUNDELL: So there wasn't even a positive
5 then.
6 MR. LEVINE: Right.
7 COM. MUNDELL: Because in Unit 1 you thought
8 there would be a positive, but in Unit 2 there was no
9 positive and no negative.
10 MR. LEVINE: Right. It was basically neutral in
11 Unit 2. The reason I said we believe that the expert,
12 well, the newer generators would be helpful is we
13 believed that one of the reasons the vibration was
14 coming up over these four years was the fact that every
15 time you came down for an outage we would have to plug
16 tubes in the old steam generator. Every time you plug
17 tubes, you change the flow, you limit the flow some
18 more. So we believed that if you went back to a higher
19 flow rate that would help you get back to that lower
20 vibration.
21 COM. MUNDELL: And I may be missing something
22 but if it didn't change for the positive in Unit 2, then
23 are there different infrastructure in Unit 1? Why
24 wouldn't, I mean, why wouldn't you have a positive
25 change in Unit 2 if you thought you were going to have a

1 plants that have had this problem on this particular
2 line. So when they did their steam generator
3 replacements, it had no effect.
4 COM. MUNDELL: Their vibration problems have
5 been different? Because there has been periodicals that
6 talked about vibration problems in other facilities
7 around the United States where there has been a new
8 bigger generator put in.
9 MR. LEVINE: Yes. Commissioner, and I am not, I
10 would have to have the specifics on that, but there have
11 been vibration problems. But the ones that I am
12 thinking of are all on different components. They are
13 up in the steam generator or they are on something else.
14 They are not on this particular line, nor did they go in
15 to try and resolve a problem by putting this plate in to
16 fix the vibration.
17 COM. MUNDELL: Just one question to clarify what
18 you said earlier. When you went and after you installed
19 the bigger generator in Unit 2, you said that when you
20 made the decision for Unit 1 you thought that would help
21 the vibration. And I wasn't clear. Did it -- what
22 happened to the vibration in Unit 2 then? Did it --
23 MR. LEVINE: We went back to look whether we saw
24 any difference before and after changing the generators
25 in Unit 2.

1 worse. And that less flow was being caused by a plug in
2 the steam generators, the old steam generators. So we
3 believed that by putting new steam generators in, which
4 would increase the flow, would actually have a positive
5 effect on the vibration, not a negative vibration.
6 COM. MAYES: You believed that? You believed
7 that would have a positive effect?
8 MR. LEVINE: A positive meaning in the right
9 direction, yes.
10 COM. MAYES: Okay.
11 MR. LEVINE: The other data point we had, and
12 again we had already placed some generators in Unit 2,
13 when we looked at the vibration measurements in Unit 2,
14 although they are a different magnitude, the change in
15 vibration was very, very small. So, if anything, we
16 felt, you know, we felt that additional flow should help
17 it. And then we -- data point in Unit 2 would say at
18 worst case it wouldn't make it any worse.
19 COM. MAYES: Did you ask around the industry or
20 did you look to see whether this had been tried by other
21 plants where they had a vibration problem? We heard
22 from the NRC the vibration problems are routine. We
23 know that steam generators get replaced. So did you
24 look around and survey the field?
25 MR. LEVINE: No. We don't know of any other

1 point where you had to turn down, that came after the
2 steam generators were implemented?
3 MR. LEVINE: That's correct.
4 COM. MAYES: Can you fast forward to that
5 point --
6 MR. LEVINE: Next slide.
7 COM. MAYES: -- in order to save time.
8 MR. LEVINE: So we put that design in in the
9 outage. We ended up getting ready for start-up. We had
10 to test this concept for two reasons, one, obviously for
11 what it was there for, to eliminate the vibration. The
12 second part of this, though, is that vortex plate could
13 not restrict flow going to the shutdown cooling pumps.
14 And what we ended up, what ended up happening was, when
15 we did our flow testing, we found that in certain
16 conditions, depending on the water level in the RCS, we
17 were not able to meet our flow requirements going to the
18 shutdown cooling pump, not the reactor cooling pump. So
19 we ended up having to take the plate out because we
20 couldn't meet that criteria.
21 So now we were in a position where we were
22 starting the plant back up. We had shut the plant down.
23 We were running at about 1.75, I think, IPS, so still
24 under our limit. We had indications over the cycles
25 that it appeared that less flow was making the problem

1 coming off here. And they were varying the different,
2 the flow rates and the temperatures and the other things
3 and trying out different things in this opening to see
4 which one had the best effect of eliminating this
5 acoustic problem.
6 So after a number of months of testing -- go
7 ahead to the next one, Sue -- they came to a conclusion
8 that the best mod was to, and this is again, this is the
9 reactor cooling pipe here, 16-inch line coming off --
10 the best fix was to put this plate in there with the
11 openings which would now, when the flow came across it,
12 it would break up those vortex and it would change the
13 acoustic, which would then eliminate the problem coming
14 down the pipe and causing the vibration. So this was
15 tested both as part of the ASU test and obviously had
16 the calculations and everything to support it. And that
17 was what was decided during the last cycle to put in to
18 eliminate this problem.
19 Now, again, all along we are operating well
20 below our criteria that we had set for the limits on
21 this vibration. And we had not been limited in power at
22 that point in time. So we had an issue; we didn't have
23 a problem. The --
24 COM. MAYES: Moving forward, Mr. Levine, to the
25 point where you, the vibrations got aggravated to the

1 gun either, if you will.
2 And that outage we also then put heat trays on
3 that line permanently to try and mitigate and dampen
4 that vibration.
5 Okay. Now we go into cycle 12, which is in the
6 May '04 time frame and October 5th time frame. This is
7 the outage that we are preparing to replace the steam
8 generators. One of the fixes that we had come up with,
9 and then our expert panel had agreed with, was to put in
10 a plate. Well, let me back up.
11 To get there, we did significant test -- we had
12 a third party reviewing. We have EPRI as part of this
13 review panel. I think you are all aware of EPRI, the
14 industry's research arm. They came in. They brought in
15 a couple independent people to support them. We also
16 had our independent experts in. We brought everybody
17 together. We shared ideas. We came up with what
18 possible things would work. And then we did some
19 testing at ASU, some testing.
20 This is just to show you a little bit of the
21 flow loop, but basically it replicates what we would
22 see. We would have the steam generator on this end and
23 we would have the vessel on this end. They were pushing
24 water through here. And this is about a quarter scale
25 model. And then we have the shutdown cooling line

1 problems with it.
2 This outage we also went in, and again back to
3 the earlier discussion, Commissioner Mayes, about the
4 core barrel, we went in and when we took the fuel out of
5 the vessel, it gave us access to this core barrel, which
6 is a big metal container that sits inside the vessel.
7 It holds the fuel.
8 So you have, you have this water circulating
9 around. It comes in the bottom of the vessel. It goes
10 through the fuel. It goes out a hole in this core
11 barrel into the pipe. So one of the things that we
12 wanted to make sure was that the hole in the core barrel
13 was properly aligned with the nozzle of the pipe, the
14 RCS, because if it was skewed any amount, it could have
15 a significant effect on the flow coming out of that
16 vessel.
17 What we were able to see on a limited inspection
18 with cameras, because we were working 40 feet under
19 water, was that there was no obvious misalignment
20 between the core barrel exit hole and the nozzle of the
21 pipe. So that, again, it didn't give us the magic
22 answer of root cause which we are all looking for, you
23 know, the misalignment of this core barrel. We have
24 not -- you know, this position, now, we haven't said it
25 absolutely isn't, but it isn't necessarily the smoking

1 move properly. And that caused the working on the weld
2 and the weld eventually got a small crack in it. And
3 that's why we had that particular leak.
4 Okay. Then we go into the cycle 11. We, at
5 this time now we are working with a number of hydraulic
6 experts in the industry and Westinghouse, who was the
7 designer of the NSSS system, to try and, one, to
8 validate what we believed was causing this acoustic wave
9 across that opening, and, two, to see what their ideas
10 were as far as being able to limit this vibration.
11 One of the things that they had come back with
12 is, if we remember that line coming down from the RCS
13 getting close to the valve to actually heat that area of
14 the pipe up, not so much for the pipe but the water, and
15 which would change the density of the water so that when
16 that acoustic wave came down it wouldn't be seeing -- it
17 would have a different effect on the valve, we actually
18 did a proof of concept there, and we put some heat trays
19 on. And we were able to show that it did make some
20 small difference in the effect.
21 We went into the outage in March of 2004.
22 Again, all these outages we went into an accelerated
23 ISI, In-Service Inspection, program where we tested the
24 welds on the pipe. And we also rebuilt the operator of
25 the valve every outage to make sure there weren't any

1 question, during the cycle run, engineering worked up a
2 modification to go in and try and dampen that vibration,
3 which was to put a stiffener in under the pipe. So
4 during the outage, we put that stiffener in.
5 When we came up out of the outage, we started
6 power or doing power ascension. We got to 70 percent
7 power, and we had the vibration coming up. So the fix
8 that we put in was not being effective. It was being
9 counterproductive, quite frankly. And so we shut the
10 plant down, went back and took that out. And you can
11 see that the vibration level came pretty much back down
12 to where it had been the previous cycle.
13 Now, over that cycle, which is from November of
14 '02 to March of '04, we did start to see this vibration
15 slowly creep up so that at the end of the cycle we were
16 in the 1.6 IPS range.
17 One of the things that was also mentioned
18 earlier about a valve that was not properly anchored,
19 this is the valve that Troy mentioned that we brought
20 the unit down during this cycle because we had a pinhole
21 leak on it, an unisolatable leak, so that means we have
22 to shut the plant down, and what we found is that they
23 had, there had been a hanger mod on this valve a number
24 of years earlier. It was not properly done. The valve
25 was actually restrained too much. It didn't allow it to

1 putting in this last outage, yes. To do some other
2 fixes that we are looking at doing now, which are more
3 to mitigate the vibration rather than make it go away,
4 we can do some of those on line.
5 COM. MAYES: How many outages occurred between
6 the time you noticed the vibrations and today?
7 MR. LEVINE: Let's see. This was 1 R-10, so
8 three.
9 COM. MAYES: During those three outages did you
10 make any attempts to repair the vibrations?
11 MR. LEVINE: Yes. And I am --
12 COM. MAYES: Okay.
13 MR. LEVINE: I am walking through the sequence
14 here, the timeline.
15 COM. MUNDELL: Before we get to that, does the
16 power ascension stopped at 70 percent RTP, does that
17 mean you went up to 70 percent and that was it? What
18 does that mean? Power ascension, I think I know what it
19 means.
20 MR. LEVINE: Yes. The previous slide we went
21 through, we were down. We did a number of things to
22 monitor, add monitoring to the system and do some other
23 things.
24 We came out of -- one of the things we did
25 during that outage was, to answer Commissioner Mayes'

1 '01 -- we don't need to go back -- we had to break or
2 run. We came out of the outage. We ran continuously
3 until the next outage. We had vibration readings that
4 were basically stable that entire time between 1.0 and
5 1.2 IPS.
6 COM. MAYES: Meaning that they are within your
7 safety specifications?
8 MR. LEVINE: Well within any safety limits we
9 had established, yes.
10 COM. MAYES: During that time frame did you make
11 any attempts to fix other vibrations?
12 MR. LEVINE: Well, first of all, we don't have
13 the ability to do anything on the system while we are
14 operating. So anything -- well, not -- we have some
15 ability. We have limited ability to do anything on the
16 system.
17 What we started to do at that point during that
18 cycle was to try and determine what was causing the
19 issue. So we were starting to look at why is the
20 vibration higher than we would expect and what can we do
21 to eliminate it.
22 COM. MAYES: So you would have to fix it during
23 an outage?
24 MR. LEVINE: It depends on the, it depends on
25 the fix. I mean to do the fix that we ended up with

1 we did as we went through it.
2 COM. MUNDELL: Thank you.
3 MR. LEVINE: So we identify this in that
4 February 2001 time frame. It was about 1 IPS, to put it
5 so we can compare numbers as we go along here. Again,
6 as I said, when we got into this, we set a limit of 2.25
7 for safe operation. Okay? So anything under 2.25 was
8 safe to operate the unit.
9 We took a number of actions during that next
10 refueling outage. Unit 1, refueling outage number 10
11 was between September '02 and November. Again, we had
12 the isolation valve. We had a, we actually had a
13 failure of the motor operator on the valve at that point
14 in time. We went and looked at that and the failure was
15 attributed to the fact that you have some tabs in the
16 operator that are very sensitive. It appeared they were
17 not pretorqued properly, and then on top of that the
18 fact that we had the vibration there.
19 We installed the new actuator. We actually
20 looked at the welds on the system and did and inspection
21 on all the welds to make sure there was no indication of
22 any problems with that. We stiffened the actuator to
23 limit the vibration. We did a number of things to
24 alleviate the problem.
25 From when we came back out of the outage in

1 as stated before, you know, all these systems have some
2 amount of vibration. And maybe I should back up here a
3 second.
4 They all have some amount of vibration. If we
5 went in, and we have, and measured that same area in
6 Units 2 and 3, what we would find is vibration, but much
7 less vibration.
8 COM. MUNDELL: But not to the --
9 I am sorry, Commissioner. Did you --
10 COM. GLEASON: No, no, I am through.
11 COM. MUNDELL: Okay. I understand you always
12 have vibration, but not to the point where you can't
13 power it up to 100 percent I mean.
14 MR. LEVINE: That's correct.
15 COM. MUNDELL: That is sort of the issue at
16 least I am concerned about.
17 MR. LEVINE: I understand, Commissioner. But we
18 were never in that condition until we came out of this
19 outage. And we had a fix going into this outage, that I
20 will get to, to eliminate the problem that we actually
21 had to take out for another reason.
22 COM. MUNDELL: I am in charge now, so go ahead.
23 MR. LEVINE: What I want to do is try and walk
24 you through this and I will give you relative levels of
25 vibration. And I can tell you some of the things that

1 MR. LEVINE: They are stating that they believe,
2 again, that this potentially started in that previous
3 outage which would have been in the 1999 time frame.
4 All I am saying is we actually discovered the vibration
5 in February of 2001. That's when we had an engineer in
6 there that actually identified the fact that we had
7 vibration.
8 COM. MAYES: But did you notice something in
9 1999? You just said you noticed a difference.
10 MR. LEVINE: No, after we found it.
11 COM. MAYES: Oh, in 2001?
12 MR. LEVINE: Yes, after we found it in 2001, we
13 went back to look at the records to see if we could find
14 any evidence of finding it. And, again, we found a data
15 point basically that said there was a change.
16 COM. MAYES: Okay.
17 COM. MUNDELL: And again maybe I am mixing
18 apples and oranges. Is the vibration the same or is it
19 getting worse since the new bigger generators, generator
20 was put in? Are you going to get to that?
21 MR. LEVINE: I am.
22 COM. MUNDELL: Okay.
23 COM. GLEASON: Pardon me. But it is not in 2
24 and 3?
25 MR. LEVINE: That's correct. I mean like, well,

1 changing the flow coming out of the reactor vessel. And
2 that potentially then is creating a different flow
3 pattern over that hole, which is creating the issue. We
4 haven't been able to prove that yet.
5 COM. MUNDELL: Just so I am clear, because I am
6 confused, what facts did they rely on in reaching their
7 conclusion that the vibration started in 1999? Why
8 would they say that?
9 MR. LEVINE: They are going by what we are
10 telling them, or what our records are showing right now.
11 But I can't tell you that it absolutely started -- we
12 had limited, we had limited monitoring on this system at
13 that particular time. So we could go back and we could
14 take a data point off of some instrumentation that is
15 actually on the reactor vessel that gives us the
16 vibration readings. We can compare before the outage
17 and after the outage in 1999, and we can see a
18 difference.
19 COM. MUNDELL: Okay.
20 MR. LEVINE: So we knew there was a difference.
21 COM. MUNDELL: But that's how they, they
22 concluded -- I am not -- you know, 2000, 1999, I am just
23 trying to make sure, you know, they reached a different
24 conclusion than you have reached or you agree with their
25 conclusion.

1 CHMN. HATCH-MILLER: Mr. Mundell.
2 COM. MUNDELL: Is this the -- this is the
3 vibration that was been occurring since '99? Am I
4 mixing apples and oranges or is this the one?
5 MR. LEVINE: Actually the vibration, we first
6 identified the vibration in February of 2001. Okay?
7 That is when we were in containment. We had an engineer
8 in containment. Before we come down for an outage we go
9 in and do a walk down in containment to look for any
10 obvious issues. In the process of doing that, an
11 engineer identified a sound. So he kept looking for it.
12 And he identified this sound, this humming coming from
13 this area and identified that this valve was shaking.
14 So that is when we first identified it. Now,
15 the question is when did it really start.
16 COM. MUNDELL: Did I misunderstand the NRC
17 earlier? That's why I said -- they said 1999. Are we
18 talking about a different vibration?
19 MR. LEVINE: No. We are talking about the same
20 thing. The reason they are saying 1999 is, again, if
21 you go back to the beginning of that cycle, you are
22 basically back into 1999, the end of 1999. And we have
23 some theory, and that's all it is right now, that some
24 of the work we did in the reactor vessel at that time
25 and when we put the internals back in, could actually be

1 the frequency enough, if you could alter the system
2 enough and move the frequency, you would what we call
3 decouple the issue, so you wouldn't have it. One of our
4 problems is some of the things we have tried to do to
5 decouple it to remove that frequency haven't been
6 effective. So that's one fix.
7 The other fix, which is what we put in during
8 this last outage, was to not address that frequency but
9 actually to address the water going over that opening
10 and breaking up. What happens is, if this is the hole
11 in the pipe and you have got this water going over it,
12 you get to that hole, the water actually splits. Some
13 of that water goes down into the hole and some of this
14 will then go up. And you create a high pressure zone on
15 the back side of this. And that is what causes what
16 they call a vortexing, which eventually is what leads to
17 this pulsation, this acoustic sound going down here
18 causing the vibration.
19 COM. GLEASON: But if you run it at 100 percent,
20 the frequency stays the same?
21 MR. LEVINE: We don't know that because we
22 haven't been able to get there. It changes slightly but
23 we don't know if it would change enough in order to
24 decouple the situation.
25 COM. GLEASON: Okay, thank you.

1 doesn't respond to the acoustic wave.
2 CHMN. HATCH-MILLER: When you say it vibrates at
3 that point, are we talking about violent shaking and --
4 MR. LEVINE: Very good question.
5 CHMN. HATCH-MILLER: -- whiplashing the pipe?
6 MR. LEVINE: We have a tendency to use terms and
7 stuff and I think everybody understands them exactly.
8 What, as I go through this, what I will talk
9 about are inches per second, IPS. We take a reading
10 with an accelerometer and we measure inches per second.
11 We put a limit on this particular valve of 2.25 inches
12 per second.
13 Now, first thing you think, wow, that is pretty
14 good movement. The actual displacement is ten- to
15 fifteen-thousandths. So the valve, you can hardly see
16 the valve actually moving or the pipe actually move.
17 But IPS is the, is the addition of the number of times
18 that it is doing that in that second. So what it is, it
19 is very small movement but very rapid.
20 COM. GLEASON: Excuse me. Does that frequency
21 change when you change the pressure in your steam
22 generator line?
23 MR. LEVINE: No. The frequency, one of the
24 problems is we have not been able to change the
25 frequency. One of the fixes is to, if you could move

1 the reactor coolant pumps. You have the reactor. You
2 have two pipes that are going one to each steam
3 generator called a hot leg. It is the larger pipe here,
4 it is about 42 inches in diameter. You have a line
5 coming off of that which is about 16 inches in diameter
6 that comes down and it goes through a wall and then it
7 goes over and it eventually comes out. I will show you
8 another drawing in a second.
9 The valve that was mentioned earlier as being
10 the component that was seeing the majority of this
11 vibration is this valve right here, SI-651. Okay.
12 A more simplified diagram of that, again, if
13 this is a reactor coolant pipe between the vessel and
14 the steam generator, this is the configuration.
15 It comes down. What happens, what is happening
16 here is the flow across from the reactor to the steam
17 generator is going across to this open nozzle in the top
18 of this pipe. And it is setting up an acoustic wave
19 that is coming down the pipe. And it is manifesting
20 itself at this valve because this valve is closed. So
21 that valve is basically the dead end of that pipe for
22 all intents and purposes.
23 What we are trying to do is resolve, one, or
24 have been trying to do, is resolve how to change that or
25 how to change the dynamics of the pipe so that it

1 had to have at least 16 feet from this suction line of
2 head above that in order to be in compliance with our
3 design. Well, you can see we actually have 40. But
4 what we couldn't answer was whether or not there was a
5 possibility, because we didn't have the calculations and
6 the analysis for it from the original design, whether or
7 not you could actually get air in here. So, again, we
8 couldn't say that the system was operable. We had to
9 declare it inoperable. That led to the shutdown of the
10 plant.
11 CHMN. HATCH-MILLER: How long was the shutdown
12 for?
13 MR. LEVINE: That was -- do you have the dates?
14 I want to say it was a ten-day outage.
15 CHMN. HATCH-MILLER: Ten days in the middle of
16 the summer?
17 MR. LEVINE: 11th through the 25th, nine days.
18 CHMN. HATCH-MILLER: So nine days in the heat,
19 the time that we have the hottest weather.
20 MR. LEVINE: Right. Okay. That brings us up to
21 Unit 1, the current situation we have where Unit 1 is
22 operating at a reduced power.
23 Again, if you look at the depiction here of the
24 reactor coolant system, you have the steam generators
25 which were replaced in this refueling outage. You have

1 a tech spec action statement that had us doing immediate
2 shutdown.
3 On the refueling water storage tank that was
4 talked about earlier -- Sue, if you would just go to the
5 drawing, this might help clear this up a little bit.
6 But you have the containment here. You have a pipe
7 coming out of the containment. This was the '04 issue
8 of whether or not there was a void in the pipe, which
9 had nothing to do with the '05 issue, okay, but it is
10 the same. Over here we have a tank that is outside the
11 containment that is full of water. And that water is
12 there for emergency, emergency use. So in a postulated
13 accident where you have a break in the reactor coolant
14 system and you are pumping water into it, your initial
15 water is coming from this tank. So this tank gets
16 depleted. When it gets to a certain level, it actually
17 opens valves in containment, because now you have water
18 in the sump and you are going to take the suction off of
19 here and you are going to isolate this tank.
20 The question that was asked by the NRC during
21 the review was, if this water got down to this pipe,
22 could you potentially suck enough air in there to come
23 down the line, eventually get into that header which was
24 going to the pumps that would impact the pumps. The
25 design criteria that we were designed to was that you

1 line there we had a governor fail.
2 We have to have diesel generators available by
3 our tech specs. If we have to do work on those and test
4 them in certain configurations, we have to shut down.
5 So this was an outage that was required, and Troy
6 mentioned this before, in order for us to do the
7 adequate testing after we fixed it. So we actually had
8 the problem fixed but we couldn't test it on line.
9 On the diesel generator problem on the voltage
10 regulator in August, again this ended up being a problem
11 with a diode in a voltage regulator that failed. In
12 this case, we had a 72-hour action statement we had to
13 do this maintenance in. We could not, we did not
14 identify the problem and get it done in that 72 hours so
15 we had to shut the unit down in order to finish the
16 repair. And then it would have been another situation
17 like the previous one, we would have had to shut down
18 anyway to do the retest.
19 The core protection calculator software, this is
20 another one of the vendor issues, where in August we had
21 a vendor notify us that some software we had put in a
22 few months earlier that they had designed and control
23 was not totally doing what it was supposed to do. It
24 put us in a position where our core protection
25 calculators were not operable. And again that put us in

1 COM. GLEASON: Thank you.
2 CHMN. HATCH-MILLER: Mr. Levine, I am listening
3 carefully. I am very interested. But I am also
4 realizing I have about 25 minutes. And I am thinking
5 that some of the details of what you are presenting
6 would be best to be presented to Staff in a special
7 meeting between you and Staff. And I am going to ask
8 you, just for the sake of, in the timeliness of our
9 meeting, and I don't mean to put you in a limited time
10 because you need to, you need to be able to share this
11 information with us, but we do have the realities of
12 time, so if you would hit the highlights. Then I will
13 ask Commissioners Gleason and Mundell and Mayes if they
14 have any specific questions to each of those. And then
15 I would ask you to follow up with Staff on the details
16 of your presentation.
17 MR. LEVINE: Okay.
18 CHMN. HATCH-MILLER: Thank you.
19 MR. LEVINE: I am happy to do that,
20 Mr. Chairman.
21 CHMN. HATCH-MILLER: I know that's not what you
22 expect but...
23 MR. LEVINE: Okay. Going on to the next one, I
24 will just hit these real quick, we have the diesel
25 generator governor failure in March on Unit 1. Bottom

1 problem.
2 COM. GLEASON: Excuse me. Is that -- you are
3 just talking about journal bearing seals?
4 MR. LEVINE: Actually, the journal bearings are
5 right here. And your thrust bearings are right here.
6 And the seals are actually for the whole cavity. So it
7 is not actually on the journal bearing, but it is below.
8 It is for the entire, it is for the entire housing, the
9 cavity there. So you have one above the top journal
10 bearing and one below the lower journal bearing.
11 COM. GLEASON: Yes.
12 MR. LEVINE: The problem we have here is we have
13 very few, if any, problems with the lower seal. And we
14 believe the reason for that is the lower seals are
15 continually submerged in oil, which obviously keeps it
16 cool and keeps it lubricated. The way this design
17 works, the upper seal is not constantly submerged in oil
18 and it actually gets a spray of oil, so therefore it is
19 not getting the same lubrication nor is it getting the
20 same cooling. And what we have found is some of these
21 seals, which are carbon, are overheating.
22 So that's what we believe the major mechanism
23 is. So the seal we are going to replace this with more
24 than likely is a different design so it is basically
25 floating.

1 But more important, it would require us to take that
2 pump off line, which then would automatically trip the
3 plant. So we brought the plant down in order to go in
4 and repair these oil seals in the cases that we are
5 talking about here.
6 This oil seal is not a common piece of equipment
7 in other plants. These pumps are somewhat unique
8 because of their size and their design. They are German
9 designed plant pumps that are used on our units and are
10 used on some of the Korean units. We compared some of
11 our notes with some of the Korean units and we found out
12 that they also were having similar problems with these
13 oil seals leaking and that they in fact had done some
14 mods also and were trying to improve the situation.
15 Since all of this, we have brought in the
16 vendor, the KSB vendor. We have brought in
17 Westinghouse, who was an NSSS supply vendor, and others.
18 And we have set up a full-size test facility to actually
19 take one of these seal assemblies, put different seals
20 in it and actually run those for some period of time to
21 find out which seal performs the best. And those tests
22 are going on as we speak.
23 Our intent is to be able to go into the upcoming
24 Unit 3 refueling outage with a different seal and
25 replace the seals that we have and eliminate the

1 So over time we had done some modifications to these
2 seal assemblies in order to try and stop that leakage
3 that we had.
4 The leakage did not stop. And, in fact, we had
5 in this time frame, now, we were seeing as much leakage
6 out of this top seal, where what happens is it leaks,
7 comes down the outside here. It actually gets drained
8 back into a cavity. And it is, as Troy Pruett put it,
9 we were repumping that lower reservoir back up to the
10 upper reservoir. So we weren't losing all the oil but
11 it isn't the way the seal mechanism is supposed to work.
12 So we were constant -- we were pumping this back up on a
13 frequent basis.
14 Well, we have a small pump that is part of the
15 assembly here that will allow you to do that. But that
16 pump was not designed for a continuous cycle or
17 continuous process. It was designed to be used
18 infrequently and just be able to move that oil back and
19 forth. So as the leakage got worse, it required more
20 and more frequent pumping, and we got to the point
21 where, if we continued to, we would have to basically
22 run the small pump continuously, which in our estimation
23 it would lead to failure of that pump probably in a
24 fairly short time frame. And then that would
25 potentially cause a problem with that seal assembly.

1 That was one event where we changed an oil seal.
2 Unit 3, in the July time frame, we brought the
3 unit down because of an oil seal problem. These and --
4 Sue, maybe go to the next page, please.
5 Remember that schematic I showed you of the
6 reactor coolant system that had four RCPs in it, reactor
7 coolant pumps. The actual pump is this lower section
8 and the pipes going to the reactor vessel down in that
9 area. Then in the middle section here you have what is
10 called the thrust bearing assembly or module and then
11 you have this 12,000 horsepower motor sitting on top
12 here.
13 The seal assembly, this thrust bearing seal
14 assembly is depicted over here in the little bit bigger
15 drawing. But it basically has a cavity in here that is
16 filled with oil for lubrication purposes for the
17 bearings. The lower, there is a lower seal in this
18 arrangement. And then there is an upper seal in this
19 arrangement.
20 What we had had over a number of years is we had
21 had some leakage out of these seal assemblies. And they
22 were not a reliability or an operational factor but they
23 were a housekeeping issue, where, after 18 months or
24 15 months of running, you would go into containment, you
25 could feel oil around that area because of some leakage.

1 manufacturer, but we didn't have enough. We actually
2 were able to get heaters from a sister Korean unit that
3 had some units in their warehouse. And we had to take
4 some of the heaters out that we had taken in the
5 previous outage, refurbish them and put them back in.
6 So we went through all that process in order to replace
7 this new style heater with basically the old style
8 heater.
9 Then, as we were getting ready to come back up
10 again, the vendor notified us that the heat generated in
11 that portion of the pressurizer vessel may have caused
12 us to exceed our limit, design limit, on the temperature
13 for that metal. So then we had to go through an
14 analysis to show that in fact for the amount of time
15 that we had, and having never seen this condition, and
16 the temperatures that we actually knew we had, that we
17 had not exceeded the design limit, but we had to go
18 through the analysis in order to show that before we
19 could start back up. So that was the primary reason why
20 that outage went the length of time that it did.
21 Bottom line is we ended up replacing the heaters
22 with the old style heaters and we have not had any
23 issues with the old style.
24 The reactor coolant pump oil seal, I will skip
25 over to the next slide because this issue is the same.

1 nine out, obviously we now had heaters, we had the
2 opportunity to do that. We pulled the heater, or we cut
3 the heater apart. And what we found was that internal
4 to the -- and this is, this is just a long rod with a
5 sheath on it with a copper strip in it -- what we found
6 out was the manufacturer of these heaters did not
7 manufacture the heater to the specification that we had
8 given and had actually brought the heating zone of the
9 heater down into this area. And it should not have
10 been. It should have been up in this area. So what was
11 happening is there was getting too much, heat was being
12 generated down into this part of the heater because of
13 the design that was not in accordance with the spec we
14 gave them. And we were having failures there because
15 the heater was opening up, shorting out at that time.
16 That put us in a position where now we knew that
17 the 36 heaters, all of them, were susceptible to this
18 type of failure. So instead of having a relatively
19 short outage to do this and bring down, we had to bring
20 the unit back down from the start-up we were in and we
21 had to go in and we had to find heaters and replace
22 those heaters with something else.
23 We had some of those heaters in our warehouse
24 that we could replace them with. And, again, this is
25 not the same manufacturer, this is a previous

1 So we had this trend now of failures and we were
2 heading into the summer window. So we made the decision
3 from a reliability standpoint to take the unit off so
4 that we could replace these heaters that operate in this
5 particular mode and put us in a position to actually go
6 in and replace nine heaters.
7 And at the same time, we had an issue with one
8 of the reactor cooling pump seals, which I will talk
9 about in a minute. And we wanted to make sure we had
10 that resolved prior to the summer window also for
11 reliability purposes.
12 So we brought the unit off and we replaced
13 those, we replaced nine heaters. We started the unit
14 back up, heated it up. One of the things you do with
15 these heaters when you come up, you turn them all on
16 because they help bring the temperature up. And during
17 that start-up, we had failures in the other heaters that
18 were not in this cyclical mode of operation, the ones
19 that are just frequently turned -- or infrequently
20 turned on and off. So that obviously led us to believe
21 that what we believed was the failure mechanism here was
22 not the failure mechanism.
23 Now, prior to this time, we had no opportunity
24 to take a heater and take it apart and actually find out
25 what was wrong. When we came down, when we pulled those

1 in a number of other plants and had performed
2 successfully.
3 Unfortunately, early in the operating cycle,
4 very shortly after start-up, we started having a couple
5 of these heaters fail. And, again, these are electrical
6 heaters so you are turning them on and off. So, you
7 know, first one fails, you wonder if it is a premature
8 failure and it is just an infant mortality type thing.
9 But then we had additional failures.
10 We started looking at where these failures
11 occurred. And they were occurring all in one type of
12 heater which is used to cycle on and off frequently to
13 maintain that temperature and that pressure pressurized.
14 The heaters that are not turned on and off frequently
15 were not having the problem. So at first we felt that
16 it may be the way these heaters were being cycled on and
17 off that was causing the problem. So we looked at that.
18 These heaters are, again, they are heaters that
19 are required by our tech specs and we have to have so
20 many of them in order to run the plant. So we had had
21 nine failures between December 4th and -- or, yes,
22 December '04 and May '05 from our reliability
23 standpoint. And we needed, if we had had two more
24 failures, we would be having to shut down without any
25 notice.

1 And, Sue, if you can go to the next slide.
2 If you can, the pressure -- if you look at the
3 simple diagram of the reactor cooling system, you have a
4 reactor vessel, you have the steam generators, you have
5 the reactor cooler pumps, and you have the pressurizer.
6 The intent of that pressurizer is, when you are
7 running full power, is to maintain the pressure in the
8 system. And it is, basically it is half full of water,
9 half full of steam. You have electric heaters that
10 are -- next slide -- you have electric heaters in the
11 bottom of this that are turned on and off in order to
12 maintain the temperature to maintain the pressure. And
13 the rest of the system is solid water. So this is how
14 you control your pressure in the system.
15 So when we had an issue with the material that
16 was used in the pressurizer that had changed, we changed
17 that. At the same time, to make sure that the heaters
18 were good for a long period of time, we changed out
19 those heating elements. And there are 36 of these
20 heating elements in each of the pressurizers.
21 So the new heaters were bought, they were bought
22 from a different vendor than we had previously used, for
23 a number of reasons. One, the design mods that they had
24 were an enhancement over the heaters that we had, and
25 some other reasons. But they were a heater that we used

1 COM. MUNDELL: Okay, thank you.
2 MR. LEVINE: Okay. I am going to take a little
3 bit of time now and try and go through this. There was
4 a -- some of these were discussed already on these
5 outages.
6 CHMN. HATCH-MILLER: To the point we just made,
7 have there been other low power operations in the past
8 two years?
9 MR. LEVINE: There are -- I cannot remember any
10 low power. I can remember a couple of minor down powers
11 to 75 percent or so for a day or two to fix a piece of
12 equipment, then bring it back up.
13 CHMN. HATCH-MILLER: So to your knowledge this
14 is the first reduction?
15 MR. LEVINE: Of this magnitude and this length,
16 yes.
17 CHMN. HATCH-MILLER: Thank you.
18 MR. LEVINE: Okay. The pressurizer heater
19 outage, and, Commissioner Gleason, this is one of the
20 issues that is a vendor issue, but the pressurizer
21 heaters back in the previous outage for this unit, we
22 actually replaced the pressurizer heaters. We had a
23 problem that, not a problem, but we had a replacement
24 program for a certain type of material called Inconnel
25 600. And these go in the pressurizer.

1 MR. LEVINE: Slide 20, again, during the
2 refueling outages we do most of our major component work
3 on the primary side of the plant and all the equipment
4 that generates the electricity on the secondary side of
5 the plant.
6 The only thing again I point out, on Unit 1's
7 outage, it was a much longer outage because of the steam
8 generator replacement and the turbine replacement. On
9 the short notice outages --
10 COM. MUNDELL: Can I ask a quick question?
11 Is outage defined as --
12 CHMN. HATCH-MILLER: Surely.
13 COM. MUNDELL: Well, let me reverse the
14 question. If you could run at 50 percent, how do you
15 define outage?
16 MR. LEVINE: Commissioner, anything that takes
17 the unit off line is considered an outage. Anything
18 that would just bring the power part way down would be a
19 reduction.
20 COM. MUNDELL: So right now --
21 MR. LEVINE: Outage means it is off line.
22 COM. MUNDELL: So right now with Unit 1 running
23 25 percent, that is not a, quote, unquote, outage?
24 MR. LEVINE: No. It is running a lower power
25 level.

1 Of the outages we talked about for 2005 earlier,
2 you can see the three outages that fell under this
3 category of SNO outage. The pressurizer heater, the RCP
4 oil seal, which we learned earlier were done at the same
5 time, and then two subsequent reactor coolant pumps.
6 And I will get into these in more detail.
7 Forced outages, again, these are the unit has a
8 trip and it is an instantaneous type thing, or as again
9 was talked about earlier, in some cases shutdowns that
10 are required by our license on an immediate basis.
11 Again, if you look at the outages for '05, you can see
12 that these outages on this sheet were, according to that
13 category, forced outages.
14 Going through these in a little more detail, and
15 I don't intend to spend much time on the plant outages
16 which are the refueling outages unless you have some
17 questions, but the --
18 CHMN. HATCH-MILLER: Is this a planned outage?
19 MR. LEVINE: Okay. You have it in your handout.
20 CHMN. HATCH-MILLER: This would be an unplanned
21 outage.
22 COM. MAYES: If it is, it is cheaper than the
23 other.
24 CHMN. HATCH-MILLER: That's for sure.
25 COM. MAYES: It is a lot cheaper.

1 projects that I talked about earlier.
2 Planned outages are expected to be done very
3 efficiently and scrutinized as far as the type of work
4 we put into them. I have listed here just what our
5 typical outages would be. Typically a refueling outage
6 for us would be in that 32- to 36-day window. We have
7 had a couple of steam generator replacement outages.
8 They both fell between that 75- and 80-day window. And
9 we have some outages that will be outside the norm
10 coming up in the next couple years, because one of the
11 activities we have to do as capital replacement is
12 change reactor vessel heads.
13 COM. MUNDELL: Is the steam generator
14 replacement, is that what just occurred at Unit 1 or is
15 that something different?
16 MR. LEVINE: No, Commissioner, that is what just
17 occurred in Unit 1. And it occurred in Unit 2 in 2003,
18 and will occur in Unit 3 in 2007.
19 What we call short notice outages are outages
20 where we have, through our predictive maintenance/
21 preventative maintenance program, potentially identified
22 a piece of equipment that is either failing or degraded
23 and we get into a situation where we need to take the
24 unit out to deal with that. That is the type of outage
25 that would fall in here.

1 MR. LEVINE: Oh, for the capital investment?
2 COM. GLEASON: Yes.
3 MR. LEVINE: We are on budget for those.
4 COM. GLEASON: Okay, thank you.
5 MR. LEVINE: When you look at the outages, again
6 we break those down into basically three different
7 categories. Planned refueling and maintenance outages,
8 again, those are the two I talked about that we will
9 have every year. Short notice outages, some of the
10 examples that we will talk about fall in this category
11 you talked about before, but these basically are outages
12 to prevent an issue. And then a forced outage is the
13 instantaneous outage where it happens, for instance,
14 June '04, back where we had the disturbance on the
15 system and all three plants tripped.
16 Just to break those down a little bit finer,
17 again, the planned outages are the refueling outages.
18 The major activity there is to refuel. When we go into
19 a refueling outage, we change about 40 percent of the
20 fuel out as part of that process. We perform all the
21 major system components required, operating license
22 required testing. And we perform preventative
23 maintenance on the primary system and secondary system
24 for areas where we cannot typically get to when we are
25 operating the unit. And, again, we install the capital

1 the units.
2 The latter part of the discussion with the NRC
3 talked about an aging management program. A number of
4 the things that are on this list fall in that category.
5 They fall in the category of preserving the plant for a
6 longer period of time. They also fall in the category
7 of staying ahead of known problems.
8 For instance, low pressure turbines that were
9 replaced is a problem that the manufacturer has with the
10 design of the turbines that led to cracking of the disks
11 that hold the blades on. We learned of that problem a
12 number of years ago, put together a plan to very
13 systematically go through the turbines and replace them
14 over a reasonable period of time to make sure that we
15 didn't end up with some kind of a forced outage because
16 of potential failure.
17 COM. GLEASON: Mr. Chairman, can I ask a
18 question?
19 CHMN. HATCH-MILLER: Yes, of course you can.
20 COM. GLEASON: The maintenance program is, are
21 you on budget? Over budget? Under budget?
22 MR. LEVINE: It depends on the activity, quite
23 frankly, Commissioner. You know, some years --
24 COM. GLEASON: I mean you have got a billion
25 dollars.

1 daily basis. We have gone through a program for some of
2 our more critical systems called reliability centered
3 maintenance, where we have actually now taken not only
4 the vendor data and what they suggest we should do for
5 maintenance, but we have taken the history now of almost
6 20 years of plant activities and we have pulled them
7 together to adjust the maintenance programs to hopefully
8 make them as most efficient as we possibly can and
9 maximize the time and the resources.
10 About 30 percent of the activities performed are
11 in outages. So there is a tremendous amount of our
12 activities during the outage periods. And when I talk
13 about outages here, I am talking about refueling
14 outages. So in this case, Palo Verde is going to do two
15 refueling outages every year. We are on what is called
16 an 18-month cycle, so basically every outage, every unit
17 gets an outage every 18 months. So every spring and
18 every fall one of the three units will be in its
19 refueling outage. So during those outages we do a
20 tremendous amount of maintenance.
21 During those outages we also do the vast
22 majority of our capital improvements. And just for an
23 example, over the six-year period of 2001 to 2007, we
24 will have spent somewhere in the neighborhood of
25 $1 billion to do capital improvements and retrofits to

1 post-maintenance testing and what we call surveillance
2 testing. And surveillance testing relates back to what
3 Dr. Mallett talked about, and we have tests that tie
4 back to our license, our technical specifications. And
5 those surveillance tests have to be done in order to
6 achieve those requirements. And of course we have
7 corrective maintenance where we actually have a
8 component that fails or is not working properly.
9 Just to give you an idea of the magnitude of
10 that over any given year, last year's numbers,
11 predictive maintenance tasks that we did were over
12 6,200. We did over almost 12,000 preventative
13 maintenance tasks. We performed almost 6,000
14 surveillance or post-maintenance tests. And corrective
15 maintenance was in the neighborhood of about 4,800
16 tests.
17 So if you just take those categories and you
18 look at it, you can see that Palo Verde's efforts are in
19 the preventative/predictive maintenance area. Over
20 80 percent of the work done at the facility is there to
21 try and prevent equipment malfunctions and to improve
22 the equipment reliability.
23 Maintenance activities, we try to make sure we
24 focus on the right thing. Again, we have 61,000
25 components. You can't go out and work on those on a

1 you have talked --
2 CHMN. HATCH-MILLER: Yes, we are free to ask
3 questions about that later if we saw something that we
4 wanted to ask about.
5 MR. LEVINE: Let me talk a little bit in general
6 about maintenance, again to address some of the
7 questions that you asked in your letter, Mr. Chairman.
8 Maintenance activities at Palo Verde at all our
9 plants are intended to prevent issues so that we don't
10 have to do corrective maintenance. Palo Verde
11 department, maintenance department works on 61,000
12 components, so obviously no small amount here.
13 To that end, Palo Verde implements an integrated
14 maintenance process that utilizes qualified maintenance
15 workers that go through a rigorous training program, and
16 in most, if not all, cases have to do that under written
17 procedures.
18 When you talk about maintenance activities, you
19 are talking about four main classifications: Predictive
20 maintenance, which includes things like thermography,
21 vibration readings, oil testing; preventative
22 maintenance program, the more typical change the oil,
23 filters, adjustments to the equipment; testing program
24 in a nuclear power plant is much more rigorous than you
25 would find in a conventional power plant,

1 Again, I will go through these but we will go on to the
2 next slide.
3 Palo Verde, as you have heard many times today,
4 its overriding priority is to operate the facility
5 safely. And that is, will override everything we do and
6 all our decision making.
7 Our mission is to be a leader, if not the
8 leader, in producing safe electric power from the Palo
9 Verde units supplied to the grid. The capacity factor
10 performance in 2005, Palo Verde did not meet our
11 expectations. There were several short notice outages
12 that you have already heard some about today that I will
13 get into more detail. But at no time during those
14 outages or leading up to those outages was the plant
15 operating unsafely or under unsafe conditions that
16 weren't addressed.
17 The APS team has responded to a number of
18 complex technical issues over this time frame. And they
19 have done a very good job, a very prudent job of
20 minimizing the amount of time that these outages
21 occurred. And we are taking a number of actions to
22 return that performance to where we believe it should
23 be.
24 I am not going to go through this. This is some
25 background data you got it. This shows our ownership as

1 pressurizer heaters that you heard about.
2 COM. GLEASON: I am just asking as you go
3 through your presentation.
4 MR. MALEDON: We can certainly identify which
5 ones are vendor issues.
6 COM. GLEASON: Okay, that's all. Okay, thank
7 you.
8 CHMN. HATCH-MILLER: Mr. Levine, nice to see you
9 again.
10 MR. LEVINE: Mr. Chairman, Commissioners, thank
11 you for the opportunity to respond to your inquiries.
12 This presentation has been put together based on
13 the Chairman's letter of October 25th, I believe it was,
14 to address some of the ways we do business from a
15 maintenance standpoint and some other questions. It
16 also covers a number of the questions asked by
17 Commissioner Mayes in her more recent letter that dealt
18 with the Unit 1 outage, or Unit 1 reduced power I should
19 say. We will move through these rather quickly.
20 Obviously, if you have questions, please let me know.
21 CHMN. HATCH-MILLER: Mr. Levine, I believe it is
22 accurate that all of us have been to the facility and
23 actually have had very up-close opportunity to see it
24 and its operation.
25 MR. LEVINE: I guess this isn't going to work.

1 presentation by the NRC some issues relating to problems
2 resulting from vendor issues, as they were called. And
3 I just want to explain to the Commission that I have
4 asked Mr. Levine not to get into those issues, because
5 those are issues that, actually if I could describe them
6 very generically, are in what you might call litigation
7 or prelitigation mode. And so obviously we would not
8 like to have discussed in a public forum what exactly we
9 are doing in that regard. To the extent that the
10 members of the Commission are interested in what is
11 being done with respect to some of those vendor issues
12 and potential claims against the vendors, we would be
13 happy to discuss that in a different manner, but we
14 think it is not appropriate to discuss that in the
15 course of an open meeting.
16 CHMN. HATCH-MILLER: Thank you very much. Well
17 understood.
18 MR. MALEDON: Thank you.
19 CHMN. HATCH-MILLER: Mr. Gleason.
20 COM. GLEASON: Could you identify them?
21 MR. MALEDON: Identify the vendors?
22 COM. GLEASON: No, just let us know this is a
23 vendor issue.
24 MR. MALEDON: There are a number of them,
25 Commissioner Gleason. One has to do with the

1 this is the time for Arizona Public Service Company to
2 make presentation to us from their vantage point about
3 the facility and to respond to any questions that arose
4 as a result of the NRC presentation and/or respond to
5 questions of this Commission.
6 Please proceed.
7 MR. MALEDON: Mr. Chairman, my name is Bill
8 Maledon. I am the outside counsel for APS. And Mr. Jim
9 Levine is here today to respond to the matters that you
10 just mentioned. But let me just make two quick
11 comments, if I could, at the outset.
12 Number one, you will see that Mr. Levine brought
13 with him today some slides which he will use in the
14 course of his presentation, which he believes will be
15 helpful in explaining some of the issues that have been
16 talked about. The second point that I want to make --
17 and by the way, Mr. Chairman, we have copies of the
18 slides for each of the Commissioners to the extent that
19 they cannot be seen on the wall.
20 CHMN. HATCH-MILLER: Please, appreciate you
21 handing those out now.
22 (Brief pause.)
23 MR. MALEDON: Mr. Chairman, members of the
24 Commission, the other quick point I wanted to make at
25 the outset is that you heard in the course of the

1 to the many questions we had.
2 Mr. Pruett, thank you as well for your comments.
3 Look forward to seeing you as the chief.
4 And, Mr. Dricks, I can't thank you for your
5 comments, but obviously you kept them on track. And I
6 saw your confidential suggestions to the administrator.
7 So, but thank you, all three of you, for being
8 here. And it is an honor and pleasure to have had you
9 with us.
10 We are going to take a five-minute break and
11 then allow the licensee to come forward.
12 COM. GLEASON: Let me just quick comment.
13 Thank you very much for coming. I think it was
14 correct to start with you are more interesting than I
15 am, so...
16 CHMN. HATCH-MILLER: Okay. We are in recess.
17 (A recess ensued.)
18 CHMN. HATCH-MILLER: The Arizona Corporation
19 Commission will come back to order on our special open
20 meeting of January 26 regarding the Palo Verde nuclear
21 generating facility.
22 We are here for a follow-up on a presentation by
23 the Nuclear Regulatory Commission, Dr. Bruce Mallett and
24 two of his staff who discussed their responsibilities
25 for and their finding regarding the facility. And now

1 In fact, I mentioned the voiding issue in the
2 piping that occurred back in the 2004 time frame. I
3 think Commissioner Gleason was referring to that. Palo
4 Verde picked up on that because of an event design
5 question that was asked at the Waterford nuclear plant
6 in New Orleans. So that was a good thing.
7 So my answer is, rather than answer the why, are
8 there things we are doing now to look for those things?
9 And then we are.
10 Troy, anything you want to add?
11 MR. PRUETT: No.
12 CHMN. HATCH-MILLER: Well, Mr. Mallett, I
13 understand you oversee 21 nuclear reactors, nuclear
14 generating facilities in the United States. You are one
15 of four --
16 MR. MALLETT: Plus many other nuclear uses.
17 CHMN. HATCH-MILLER: But you are, you are one of
18 four people who administer these different regions in
19 the United States.
20 MR. MALLETT: That's correct.
21 CHMN. HATCH-MILLER: We thank you for that
22 service, thank all of you for that service to all of us,
23 to this country and to the energy that we all love to
24 use for various purposes. And we thank you for your
25 coming here today and for your frank and sincere answers

1 waiting for them to happen. And that's what we have
2 chosen to do, to do that. That inspection is so intense
3 we only do it every couple years at the facilities, but
4 we have found its use out of that and resolved them
5 because of that.
6 The licensees, and they can answer more from
7 Arizona Public Service, also look at design issues. And
8 they have programs in place. I don't know exactly what
9 Palo Verde's is at this time; Troy may know. But they
10 have programs in place. We call it design basis
11 reconstitution. They go back and look at the license
12 basis and design and select and pick are there areas
13 they missed as well.
14 So there are actions people are doing to look at
15 this. And the question is should you ever stop. In our
16 view, no, you should always keep looking.
17 The third thing we do is, when there is an event
18 that occurred at one particular facility, we call it
19 operational experience, we ask the licensees. They do
20 it, we do it, and various other forums look at those
21 events to determine could that design issue happen at
22 our facility. So you can bet that the Palo Verde issue
23 was reviewed by the other combustion engineering design
24 plants around the country to see could we have this
25 issue. In fact, we reviewed it with them.

1 should have been discovered at an earlier date.
2 MR. MALLETT: That's an excellent question. We
3 ask ourselves that question each time we find a design
4 question where we have asked the plant to consider and
5 they end up shutting down or where there is a problem
6 that evolves from it. So it is an excellent question.
7 Let me answer by saying a couple things, one that we
8 have undertaken and one that licensees have done,
9 including Palo Verde.
10 For the NRC, we have recognized that when you
11 look back over the last several years at nuclear plants,
12 not only Palo Verde, these design questions, if you
13 will, that you have all been through problems, we ask
14 ourselves could they have been resolved earlier, just
15 the same question you are asking. And we found that in
16 many cases they might have been. So what are we going
17 to do about that?
18 We embarked a few years ago upon these
19 engineering inspections to where we come out to the
20 plants. We take a particular system or particular event
21 design, these design basis events that we license them
22 to, and we spend at least two, maybe three weeks on-site
23 evaluating those to make sure that all those design
24 questions have been asked. Okay? So the NRC recognizes
25 that we need to be looking for these issues and not just

1 CHMN. HATCH-MILLER: Thank you very much.
2 COM. MAYES: Okay.
3 CHMN. HATCH-MILLER: I would like to try to -- I
4 kind of gave them a promise we would get them out in a
5 reasonable period of time and get to APS, but please
6 proceed, take your time and get the information you
7 need.
8 COM. MAYES: Really one more question. Going
9 back to what Commissioner Gleason was talking about
10 earlier, now, I don't find fault with the decision to
11 shut down Palo Verde in October. We want, we want Palo
12 Verde to be operated in a safe manner. What I do have
13 questions about is why some of these questions weren't
14 asked years ago. And so I guess my question is: Is
15 there a procedure that the NRC or APS should be engaging
16 in to uncover the next design flaw?
17 I mean, you know, it is leading me to question
18 what other design flaws are lurking on the horizon that
19 we, that we ought to know about now and that we might
20 possibly, that APS should be trying to uncover before
21 the height of the summer cooling season.
22 I guess that was the most problematic aspect of
23 having the shutdown in October was, while we wanted safe
24 operations, it seemed as though it was something that
25 could have been discovered at an earlier date and maybe

1 COM. MAYES: Okay. So they had to shut down
2 because of the oil seal leak --
3 CHMN. HATCH-MILLER: Oil leak.
4 COM. MAYES: -- on October 2nd.
5 And on May 22nd, okay, so May 22nd there were --
6 so two of those summer of '05 shutdowns are '05
7 shutdowns and the leaks or the problems were dealt with
8 when they were already shut down for something else?
9 MR. PRUETT: That's correct.
10 COM. MAYES: August 12th and which other date?
11 May 23rd?
12 MR. PRUETT: May 23rd, that's correct.
13 COM. MAYES: Okay.
14 CHMN. HATCH-MILLER: And to that point,
15 Commissioner Mayes, if I am not mistaken, you said that
16 you have not yet determined, made a determination on the
17 5/23, 7/05, 8/05 and 10/2/2005 incidents?
18 MR. PRUETT: Involving the reactor coolant pump
19 oil seals, right, we still have not completed our review
20 of the root cause.
21 CHMN. HATCH-MILLER: And you will make us aware
22 of that? That will be a report?
23 MR. PRUETT: Once they complete their
24 investigation, we will likely review it and document our
25 results in our report.

1 COM. MAYES: Okay. Then on May 23rd, July 5th,
2 August 12th and October 2nd, there were oil pump bearing
3 seal leaks that could have been -- that were
4 operationally erroneous.
5 MR. PRUETT: No. They were reactor cooler pump
6 oil seal leaks, some of which they replaced while they
7 were already shut down for other reasons. In the case
8 of the May 23rd date that you mentioned --
9 COM. MAYES: That was the pressurized heater?
10 MR. PRUETT: They shut down due to the
11 pressurizer heaters and, while they were shut down, they
12 also repaired the reactor coolant oil seals.
13 COM. MAYES: The other dates they had to shut
14 down because of the leaks.
15 MR. PRUETT: The July 5th date was a shutdown
16 due to an issue with the reactor cooler pump oil seal.
17 On August 12th they had shut down because of an issue
18 with the diesel generator that required them to shut
19 down and complete testing. While they were shut down
20 for that testing, they also replaced reactor coolant
21 pump oil seals.
22 COM. MAYES: Okay. And October 2nd?
23 MR. PRUETT: October 2nd was a shutdown to
24 replace the oil seal on one of the reactor coolant
25 pumps.

1 listed some '04 events that you would characterize
2 events as poor operations. And then you listed some '05
3 events. And I just want to go back over that because
4 this is important for us to know what you consider to
5 have been the shutdowns as a result of poor operations.
6 One you said, Unit 1 tripped on, when a -- a
7 high steam generator caused a trip. I don't know if I
8 am saying that correctly, but Unit 1, August 26, 2005,
9 that could have been prevented.
10 MR. PRUETT: It was, that was an operational
11 error that could have been prevented.
12 COM. MAYES: Okay.
13 MR. MALLETT: Let me clarify, though. The word
14 could have been prevented, that phrase, it is hard to
15 predict that. What we are trying to explain is the
16 events occurred and was there some complication caused
17 by operation of the facility. There is a difference
18 there.
19 COM. MAYES: Okay.
20 MR. MALLETT: To me.
21 COM. MAYES: It was the result of an
22 operational --
23 MR. MALLETT: Error.
24 COM. MAYES: -- deficiency or error?
25 MR. MALLETT: That's correct.

1 evaluate and detect for that and correct if it occurs.
2 COM. GLEASON: Then that is going to be a
3 decision, I guess, we --
4 MR. MALLETT: The Nuclear Regulatory Commission
5 has to make a decision first whether we agree and issue
6 a license extension.
7 COM. GLEASON: What I am saying, they have that
8 aging repair and come to us for more money to do that,
9 that is something that we should evaluate rather
10 critically, is that --
11 MR. MALLETT: Well, you will have to evaluate it
12 per whatever criteria you want to use and judge whether
13 that is an appropriate expenditure of the funds, but we
14 don't get into that. We get into can they operate
15 safely for the next 20 years.
16 But I can tell you licensees that have done a
17 very good job in explaining their programs and we have
18 been very successful in having them do that and issue
19 those license renewals in the last several years now.
20 COM. GLEASON: Thank you very much.
21 CHMN. HATCH-MILLER: Commissioner Mayes.
22 COM. MAYES: Thank you, Mr. Chairman.
23 I just want to go back to something you said I
24 found very interesting. The Chairman asked you about
25 poor operations and maintenance at Palo Verde and you

1 Pruett mentioned earlier, are such that they can
2 maintain the plant for another 20 years beyond that. So
3 we give them license extensions for 20 years beyond that
4 if they can show they have adequate programs in place to
5 monitor the systems and equipment and they can withstand
6 another 20 years of operation. And I would say most of
7 the plants, at least within the last five years, have
8 been applying for and have received those license
9 renewals. So it is a pretty good record.
10 I remember in the probably early 1990s some
11 plants that have elected to decommission and not go
12 through that process. It is a decision you have to
13 make, because there are some stringent conditions in
14 order to receive that. But I don't want to preclude
15 that decision. I don't know if Arizona Public Service
16 is even anticipating that. But the plants that have
17 applied for it have received those renewals.
18 CHMN. HATCH-MILLER: They have --
19 MR. MALLETT: Does that answer your question,
20 Mr. Gleason?
21 COM. GLEASON: Yes. Let me just -- so if APS
22 comes to us and says we are going to spend some more
23 money on aging repair --
24 MR. MALLETT: They have to set up aging repair
25 programs and show us that program is in place to

1 MR. PRUETT: I didn't have anything.
2 CHMN. HATCH-MILLER: But you can assure me that
3 Palo Verde nuclear generating facility is being -- is a
4 safe facility?
5 MR. MALLETT: Absolutely.
6 CHMN. HATCH-MILLER: Mr. Gleason.
7 COM. GLEASON: Yes. That aging gets to me.
8 COM. MAYES: No, it doesn't.
9 CHMN. HATCH-MILLER: This is Mr. "Get to the
10 Point" Gleason over here.
11 COM. GLEASON: But the -- thank you. This plant
12 is supposed to have a date that it is to be
13 decommissioned. What has been your experience with
14 other plants? Is that decommissioning date a hard and
15 fast line or can you keep it patched up and repaired?
16 MR. MALLETT: I don't like the phrase patched up
17 and repaired.
18 COM. MUNDELL: We are making that car analogy.
19 MR. MALLETT: Thank you. The plant, our designs
20 to operate and license we believe are safely within a
21 certain time frame. And that time frame is a 40-year
22 time frame. Or is that correct? Yes. And so plants
23 that have come across that date in the last few years
24 have renewed their license and they have sent us
25 sufficient evidence that their aging programs, as Troy

1 safely, we use the general term protecting the public
2 health and safety.
3 What we mean when they are operating the
4 facility, they are within their design, they have
5 maintained the safety margins, and the equipment is
6 reliable to perform its function if it is called upon.
7 CHMN. HATCH-MILLER: Is this a failsafe system,
8 no possibility ever of some kind of threat to safety of
9 the public?
10 MR. MALLETT: I wouldn't call it failsafe but we
11 have taken appropriate controls to make sure there is
12 redundant systems to respond to all the scenarios that
13 we have developed that they need to respond to.
14 That's why I mentioned in October of this last
15 year we came across a new question, and we may not have
16 asked it before or they may not have. It is important
17 to evaluate that and determine if that's correct.
18 The reason I don't say failsafe, as you
19 mentioned earlier in your comments about the Davis-Besse
20 facility, there are some times when we have indicators
21 of issues and that, if we don't take the appropriate
22 action, they can erode away the safety margins. And
23 that's what occurred in David-Besse.
24 CHMN. HATCH-MILLER: But you can assure me -- go
25 ahead.

1 things you do to test and surveil for problems there.
2 We don't see any difference between Palo Verde and the
3 other plants in that arena. And they are taking
4 appropriate steps for that. But it does increase the
5 amount of effort you have to take to surveil these
6 pieces of equipment more than a brand new plant. And
7 you have to sometimes increase your efforts to look for
8 things.
9 Troy, do you want to add anything to that?
10 MR. PRUETT: No. I think it is incumbent on
11 Palo Verde to develop an aging management plant program
12 to determine predictive and preventative maintenance,
13 replace those types of components prior to their being
14 affected.
15 CHMN. HATCH-MILLER: When you say a plant is
16 operating safely in terms of people and environment,
17 what does that mean?
18 MR. MALLETT: When I mentioned early on safety,
19 we define it as they have to have adequate facilities,
20 they have to have people that are qualified in certain
21 areas like the control room operators, and you have to
22 have procedures in place that are appropriate to not
23 only operate the plant within its safety margins by the
24 license and the design but also to make sure the plant
25 is not eroding away those margins. So when we say

1 one of the opportunities they took to replace one of the
2 reactor coolers.
3 MR. MALLETT: And the heater, the reason I
4 mentioned the heater elements, that was a vendor issue
5 that they could not have foreseen. The vendor didn't
6 follow the specifications they put in. And they found
7 that through problems and did an effective repair for
8 that.
9 CHMN. HATCH-MILLER: I am sure this is a very
10 complex operation, you know, and many hands on every
11 component of that reactor.
12 MR. MALLETT: Many qualified hands.
13 CHMN. HATCH-MILLER: Yes, many qualified hands
14 that have to do with it.
15 Let me ask you this: Palo Verde is getting
16 older, as I am. And should we expect more problems of
17 this kind as the plant gets older? Is that what you
18 have seen in other units around the country?
19 MR. MALLETT: We won't comment on you getting
20 older; we will comment on Palo Verde.
21 CHMN. HATCH-MILLER: I can feel it.
22 MR. MALLETT: The Palo Verde unit is not
23 different from other plants in the country. As they do
24 get older, you do identify more equipment problems. You
25 have to increase your maintenance programs, increase the

1 another reason, took the opportunity to work that seal
2 while they were already shut down to prevent a future
3 forced outage. So it was a prudent move on their part
4 to address the problem while they were already off line.
5 CHMN. HATCH-MILLER: To speak humorously, not in
6 any way to speak factually, they didn't go down to the
7 local Ace Hardware, get some cheap seals and put them in
8 themselves?
9 MR. PRUETT: I am sure they are very expensive.
10 You have got to get Mr. Levine to answer that question.
11 CHMN. HATCH-MILLER: Okay, thank you.
12 MR. MALLETT: I would give an example -- Troy,
13 you have to help me with exactly the date on this one --
14 to where they did the right thing.
15 They have heaters in one of their systems called
16 a pressurizer that you use to control pressure in a
17 reactor coolant system, very important function to carry
18 out. They had problems in those heaters in the heating
19 elements. And they identified that. And that was not
20 their fault. And they did come down to repair those. I
21 don't remember the time frame.
22 Do you have the time frame?
23 MR. PRUETT: Yes. One is May 23rd and on
24 June 2nd. The May 23rd date, when they were down to
25 work the pressurized heaters, around the May 23rd was

1 Mr. Gleason, either poor maintenance or poor operations.
2 MR. PRUETT: The issues with the reactor cooler
3 pump oil seal leaks we talked about. We haven't
4 completed our investigation on that.
5 CHMN. HATCH-MILLER: So there is a question
6 mark. What is the date on that one?
7 MR. PRUETT: There were a couple of occurrences
8 where they -- reactor cooler pump oil seal work,
9 May 23rd of '05, one occurrence. July 5th of '05 is a
10 second occurrence. August 12th of '05 is a third
11 occurrence. October 2nd of '05 is a fourth occurrence.
12 Some of these they chose --
13 CHMN. HATCH-MILLER: Those were the seals?
14 MR. MALLETT: Reactor cooler pump.
15 CHMN. HATCH-MILLER: Okay. And that was in
16 Unit --
17 MR. MALLETT: Some were in Unit 3.
18 CHMN. HATCH-MILLER: So it was Unit 1, 2 and 3,
19 correct?
20 MR. PRUETT: These were --
21 MR. MALLETT: I have Unit 2 and Unit 3. Do you
22 have any for Unit 1?
23 MR. PRUETT: Also in Unit 1 as well. So they
24 were spread out across the units. Some of these the
25 licensee, because they were already shut down for

1 I believe.
2 Bear with me. I am running through the list
3 here to see which ones might qualify.
4 CHMN. HATCH-MILLER: Please, take your time.
5 MR. PRUETT: Of course, I went through a number
6 of shutdowns earlier in this presentation in the summer
7 of '05 time frame already.
8 CHMN. HATCH-MILLER: You mentioned. But were
9 any of those due to poor operation or maintenance
10 practices?
11 MR. PRUETT: No. There was the one issue with
12 Unit 1 on the plant restart where the operator failed to
13 maintain control of steam generator water level. The
14 unit tripped on high steam generator water levels. That
15 is something that operators should be able to control.
16 CHMN. HATCH-MILLER: Okay. And what was the
17 date on that one?
18 MR. PRUETT: That was August 26 of '05 and that
19 was Unit 1.
20 COM. GLEASON: Let me -- that isn't strictly
21 maintenance; that's operation?
22 MR. PRUETT: That's an operational issue, that's
23 correct.
24 MR. MALLETT: That's correct.
25 CHMN. HATCH-MILLER: And I asked about both,

1 CHMN. HATCH-MILLER: And to some degree, the
2 buck stops with the licensee.
3 COM. MUNDELL: Right.
4 MR. MALLETT: They are our licensee, okay.
5 CHMN. HATCH-MILLER: Right.
6 MR. MALLETT: Now, sometimes we will inspect
7 vendors. And they have licenses and they have
8 requirements they have to fulfill. And we will cite a
9 vendor as well if we believe they are at fault.
10 CHMN. HATCH-MILLER: Good. I am glad you do.
11 MR. MALLETT: I only mentioned a few events in
12 2004 to try and give you a flavor.
13 CHMN. HATCH-MILLER: Well, right. Are there any
14 others that you would characterize as the cause was poor
15 operations or poor maintenance practices?
16 MR. MALLETT: Troy, do you want to answer?
17 MR. PRUETT: I will give it a try.
18 There are a couple of issues that might fall
19 into that category. In February of '04 the plant, the
20 Unit 1 had to shut down to repair a leak on a high
21 pressure safety injection drain line. The cause of that
22 was a pipe support that was not removed during previous
23 modification of the facility which focused distresses on
24 this particular drain line and resulted in a weld crack.
25 That is something that was within their span of control,

1 COM. MUNDELL: Don't misunderstand my question.
2 I mean I agree that at some point in time, you know,
3 they have a responsibility. I just didn't, I was just
4 trying to understand the timeline.
5 You are saying right on the front end, I mean if
6 it is like a lot of -- again, you are talking, I am a
7 lawyer, not an engineer, so bear with me -- but on a lot
8 of mechanical devices and electrical devices, I mean
9 there are some things that you can't inspect unless you
10 take, you know, the big screen totally apart and look at
11 it. So that's what I am just trying to understand. I
12 am not suggesting there shouldn't be some safety and
13 there is not a responsibility by the licensee. I am
14 just trying to understand the process.
15 MR. MALLETT: And we don't disagree with you.
16 You are exactly right. In fact, when we go look behind
17 an event like this when we do a special inspection, we
18 try and make that evaluation, and many times we say that
19 something is beyond their control. In the case of the
20 steam generator, we don't believe it was something
21 beyond the vendor's control or their control.
22 COM. MUNDELL: I see that. And I appreciate the
23 follow-up.
24 MR. MALLETT: Good question. Do you want
25 Troy -- Sorry. Go ahead.

1 Honestly, that doesn't seem fair to me just
2 sitting here saying the licensee. I mean they have it
3 for awhile and it is running, and then there is a
4 problem. That's one thing. But using the car analogy
5 again, if I just get it and I drive it home and
6 something goes wrong with it, why is the licensee held
7 to some standard? Explain that to me.
8 MR. MALLETT: Yes, the reason being is we expect
9 licensees to put equipment in the plant that don't
10 challenge the plant or safety systems of the plant. So
11 steam generators, when you put them in, one of the
12 safety systems is the integrity of the tubes in that
13 steam generator so that it you won't leak radioactive
14 materials from the primary system to the secondary
15 system. Plus it could impact how you respond to safety.
16 So we expect them to take the proper quality controls
17 through you, the vendor or themselves to make sure, when
18 you put a new generator in it, it doesn't have a leaking
19 tube in it.
20 Now, I do agree with you, to what extent you
21 create that sometimes is not their fault or the vendor's
22 fault. But the NRC's view on this was that someone
23 should have checked and found that. When you look back
24 behind, you found that the cause is -- when you see
25 those causes, someone should have found that problem.

1 COM. GLEASON: Yes. Palo Verde shut down
2 satisfactorily, didn't they?
3 MR. MALLETT: That's correct.
4 COM. GLEASON: Okay. In fact, they did a
5 stellar job of stabilizing all three units that were
6 challenged at the same time.
7 CHMN. HATCH-MILLER: To that point, Mr. Mundell.
8 COM. MUNDELL: Well, I just, I think it will
9 help me understand one of the answers. He used the car
10 analogy and you said --
11 MR. MALLETT: I knew you were going to pay me
12 back.
13 COM. MUNDELL: I was going to talk about if my
14 tire is vibrating and I am in the middle of the desert
15 versus, you know, the oil light goes off, I am probably
16 going to take different responses to that when it is 120
17 out.
18 But having said that, what I was trying to
19 understand is you said that there was some design flaws
20 and you said the licensee had some responsibility as
21 well as the maker of the product. And what I was trying
22 to understand, using the car analogy, if I buy a new
23 car, I expect it to run properly. And so what is the
24 responsibility then of the licensee when they buy
25 something and it doesn't work out?

1 checking, I will go through the 2004. If you took some
2 of the ones I used in my opening remarks, you take the
3 2004 shutdown of Unit 2 for the steam generator tube
4 leak, that was not due to a poor maintenance issue, but
5 it was in our view due to poor quality control of new
6 steam generators that were made at the vendor's
7 facility. And the licensee and vendor both have
8 accountability to make sure that those tubes have their
9 integrity before they are installed. So that was not
10 due to maintenance.
11 The June 2004 event, we talked of loss of
12 off-site power, was not caused by maintenance issues or
13 operation of facility. As you probably know, it was
14 caused by a ground that occurred, I believe you call it,
15 the Westwing, your transmission.
16 COM. GLEASON: It was a bird.
17 MR. MALLETT: Yes. I didn't want to say it. We
18 call it a ground problem.
19 COM. GLEASON: I didn't know we had those words.
20 MR. MALLETT: Now, I don't want to misconstrue.
21 Although it was not caused by maintenance, there were
22 some complications of the licensee's response. So you
23 can attribute it to some maintenance.
24 COM. GLEASON: Excuse me.
25 CHMN. HATCH-MILLER: To that point, Mr. Gleason.

1 develop a more permanent modification maybe during
2 subsequent refueling.
3 COM. GLEASON: Okay. Thank you.
4 CHMN. HATCH-MILLER: Have you determined in any
5 of these outages that the causative factor was poor
6 operation or poor maintenance practices by the licensee?
7 MR. MALLETT: It is probably best not to talk in
8 generalities but to talk about a specific outage. So I
9 think what we could do, if you are willing to for the
10 time, we can have Troy go through some of the individual
11 outages and explain the answer to that question, was it
12 due to their operation or maintenance.
13 I can say in general terms the outages that we
14 have seen are not due to maintenance issues. The ones
15 we have seen are more to design questions and design
16 issues in generalities.
17 But, Troy, if you maybe go through the 2005. Do
18 you have your list available? I think it is best to
19 answer that question by looking at each individual.
20 MR. PRUETT: Did you have a particular?
21 CHMN. HATCH-MILLER: No. I am not just
22 looking -- why don't you point out the ones in 2004,
23 2005 that were due to poor operation or poor maintenance
24 practices.
25 MR. MALLETT: Let me start out while Troy is

1 that, or even longer. The frequency of having to pump
2 that oil up to the upper reservoir became too high and
3 they decided to bring the unit down in order to make
4 repairs.
5 COM. GLEASON: But it was operating, it is just
6 a matter how often they repump that oil, is that the --
7 MR. PRUETT: Right. But you would not want to
8 operate that type of machinery with you continuously
9 cycling the oil from the lower reservoir back up to the
10 upper reservoir.
11 COM. GLEASON: I am tempted to tell you a story
12 about people putting oil in the car.
13 MR. MALLETT: Maybe I shouldn't use those
14 examples. But Troy is right, if they kept operating,
15 you could create some other damage to the coolant pump
16 and seal. So it is not --
17 COM. GLEASON: How did they cure that?
18 MR. PRUETT: They made, and Troy will be able to
19 provide you much more detail with this, but they made,
20 they replaced the seal. I believe they made some
21 modifications to that seal such that it does not leak as
22 much as it was in the past. They also brought in the
23 reactor coolant pump vendor to provide some additional
24 expertise in that area. And they are continuing to
25 evaluate what the exact root cause was so they can

1 at a high level. They would not pump, they have not
2 pumped the entire contents of the entire tank into the
3 containment building. You would only do that under an
4 accident condition.
5 COM. GLEASON: Okay. There was also awhile
6 back, at least we heard there was a bearing that was a
7 malfunctioning bearing and it was leaking oil. Am I --
8 is that --
9 MR. PRUETT: I believe you are referring to the
10 summer of '05, late summer of '05 where they had a
11 pressure safety injection pump that had a bearing oil
12 leak. And they did find some high particulate in an oil
13 sample associated with this --
14 COM. GLEASON: It was a seal that --
15 MR. PRUETT: You are talking about reactor
16 coolant pumps?
17 COM. GLEASON: Yes, the seal. What, what was it
18 leaking?
19 MR. PRUETT: In this case, the reactor coolant
20 pump has an upper reservoir that houses the oil. They
21 had leakage to a lower reservoir which collected the
22 oil. And they were having to pump the oil up in the
23 lower reservoir back up to the upper reservoir on the
24 order of once every couple of hours as opposed to once
25 every, maybe once a week where you might have to do

1 to put the plant in safe condition until they get those
2 answers.
3 Now, it turns out when they got the answers, it
4 was, well, we think it is still operable. And the NRC
5 agreed with them during that situation. But I don't
6 want to put in the criteria that we had to think about
7 the season they are operating in or anything like that.
8 It has to be based on are they taking the appropriate
9 risk, can the system perform its function.
10 COM. GLEASON: Well --
11 MR. MALLETT: And our criteria is they have to
12 have all those questions answered. They are very strict
13 on that.
14 COM. GLEASON: But they had performed that
15 operation, that plant had performed that operation
16 before, right?
17 MR. PRUETT: No.
18 MR. MALLETT: No.
19 MR. PRUETT: That's not performed.
20 MR. MALLETT: This is a design scenario that we
21 have predicted what the system will do.
22 COM. GLEASON: But I mean they pumped water from
23 that tank before.
24 MR. PRUETT: They do pump water from that tank
25 for testing purposes but the level is always maintained

1 by technical specifications, they were required to shut
2 down.
3 COM. GLEASON: Well, two things. Couldn't they
4 have mechanically kept that tank full from another
5 source, or was their tank --
6 MR. PRUETT: Conceivably they could have added
7 water to the tank. But the design of the plant is such
8 that that tank has to function independently without any
9 support water or added makeup water to it. That ensures
10 that we maintain adequate margins of safety for the
11 operation.
12 COM. GLEASON: And what was your, what was the
13 cure for the problem?
14 MR. PRUETT: They, ultimately they did more
15 engineering analysis. It took them several days to
16 complete the analytical work. And there is air that
17 would be entrained into that piping, but it wouldn't be
18 of a sufficient quantity to impact the operation of the
19 pumps.
20 MR. MALLETT: So --
21 COM. GLEASON: False alarm?
22 MR. MALLETT: Well, I don't want to call it
23 false alarm, because when the question was raised, we
24 expect licensees to evaluate it. And if they don't have
25 the answers or we don't have the answers, they have got

1 the containment building for a certain amount of time
2 and eventually the suction from that tank would then
3 swap back over to the containment building and continue
4 to supply water to those pumps. That's redundancy,
5 essentially transferring water from one location to
6 another.
7 The question was raised whether or not when you
8 got to a low level on that tank that you were initially
9 pumping water out of, would you begin to draw air into
10 that pipe. And the initial response we got back was
11 that there was a possibility that you would draw air
12 into that pipe. Now, that was not consistent with their
13 design basis, which said that that pipe would remain
14 full of water. Because of that, they found themselves
15 in a condition outside of their design and implemented
16 the technical specification.
17 It just so happened that because this particular
18 issue had impacted multiple trains, these redundant
19 trains that you mentioned of safety systems, when you
20 impact multiple trains of safety systems, the amount of
21 time you have to resolve it shrunk down. So normally
22 where they would have had maybe 72 hours to resolve it,
23 in this case they only the seven hours to resolve the
24 issue. They were not able to complete the analysis to
25 support operability within that seven-hour window and,

1 scenario occurred. And so we said, well, we won't grant
2 that discretion because we don't have answers to that
3 question.
4 COM. GLEASON: Even though the plant had been
5 operating for years under that situation?
6 MR. MALLETT: That's correct. It is, I would
7 liken it again to your car. If you find out that your
8 brakes don't work when you step on the brakes, even
9 though they have been operating for all these years, yet
10 you have to assess yourself are you still going to drive
11 down the highway with those brakes not being applied or
12 are you going to pull over until you decide you
13 understand why they are not working.
14 COM. GLEASON: I have been in that situation
15 driving down a mountain.
16 MR. MALLETT: Me too. That's the reason I use
17 it.
18 COM. GLEASON: The emergency break.
19 MR. MALLETT: That's correct. There is a back
20 up, very good point. Let me let Troy explain further.
21 MR. PRUETT: I was just -- the specific details
22 of this case involve a tank and the piping to a pump
23 that takes a suction from the tank. Normally when you
24 have one of these design basis accidents, the pumps will
25 take the suction of this tank that would pump water into

1 You know, my question is, it is like you are,
2 the tire that is out of balance. Okay? You know it is
3 out of balance, but you have been driving it for 40,000
4 miles. It is probably going to go another ten. Why,
5 what was the imperative of shutting that plant down at
6 the height of our production season?
7 MR. MALLETT: Let me start and let Troy tell you
8 what occurred. But if you go back to what I said
9 earlier on in my remarks, when there is a question about
10 the design, could the plant safety system fulfill its
11 function in a certain scenario, we require by license
12 that the licensee evaluate whether or not that system is
13 still operable even if that occurred.
14 And in this situation, they did that evaluation
15 promptly and determined that they didn't have the
16 answer, that it could occur or not. So the only option
17 left, well, the only two options left to them are to
18 bring the plant back to a safe shutdown condition until
19 they can answer that question, and that's the option
20 they chose to do, okay, the other option would be to ask
21 NRC for some kind of enforcement discretion to allow
22 them to stay operating. And, in fact, they did ask us
23 for that during this time. And we determined that we
24 didn't have enough answers to satisfy ourselves that
25 they were going to be in a safe condition if this

1 scenarios that we call design basis --
2 COM. GLEASON: Yes.
3 MR. MALLETT: -- for the plant. They have to be
4 able to operate certain safety systems to respond to
5 those scenarios.
6 We felt that for one of those scenarios they
7 didn't have a sufficient answer to the question, this
8 design question, to operate safely in that scenario. It
9 is not that the scenario was occurring at all, but if it
10 did occur, they wouldn't be able to respond the way we
11 thought the plant should respond in the design. Okay?
12 COM. GLEASON: Aren't there usually duplicate
13 back-ups for those procedures?
14 MR. MALLETT: There are back-ups, but for this
15 particular scenario, this was an impact that would not
16 have a backup to it.
17 Correct?
18 MR. PRUETT: It might be beneficial just to talk
19 about what the issue was.
20 MR. MALLETT: Why don't you go ahead, Troy.
21 COM. GLEASON: Go on. My thing is, I won't use
22 that, but it had been operating for 20 years this way
23 and all of a sudden you find this thing and you shut it
24 down at the height of our season which cost us millions
25 of bucks.

1 water in it?
2 MR. MALLETT: Not on October 2005.
3 COM. GLEASON: When was that?
4 MR. MALLETT: There was a line back in 8/2004 --
5 COM. GLEASON: Okay.
6 MR. MALLETT: -- that didn't have water in it,
7 August 2004 time frame.
8 COM. GLEASON: They shut down the plant?
9 MR. MALLETT: They didn't shut down the plant
10 for that. In that case, there was a design issue. In
11 fact, they identified that themselves in 2004 based on
12 experience from another plant in this country that has a
13 similar problem, similar designed plant. The licensee
14 looked at that and said, gee, we might have the same
15 problem, found they did and they corrected that problem
16 and did not have to shut down the plant.
17 COM. GLEASON: Okay.
18 MR. MALLETT: In October 2005 it was a question
19 of could there be air entrainment into this line or not,
20 not that there necessarily was a void, in fact, there
21 wasn't, but could there be entrainment into that line.
22 And they did shut down for that.
23 COM. GLEASON: And the danger of that was it
24 imperiled the shutdown of the plant. Is that --
25 MR. MALLETT: That issue has to do with certain

1 came up in a routine inspection, you know, I think you
2 may have answered it with your follow-up, without saying
3 the type of event that you were investigating, I guess
4 my question was were there any in 2004, 2005 that were
5 initiated by employees?
6 MR. MALLETT: As far as the special inspections,
7 to the best of my recollection, no is the answer to
8 that.
9 MR. PRUETT: But just to add on to that, there
10 were, when we do get concerns from an individual, we
11 will roll those concerns into our baseline inspection
12 program as samples that we take.
13 We take hundreds of samples of inspection
14 activities over the course of a year. If an individual
15 has a concern, let's say, with how they test circuit
16 breakers, then we will go out and monitor maintenance of
17 the circuit breaker or testing of a circuit breaker and,
18 during that activity, we will make sure that we assess
19 the individual's concern to see if it has merit.
20 COM. MUNDELL: Thank you very much. I don't
21 think I have anything at this time.
22 CHMN. HATCH-MILLER: Mr. Gleason.
23 COM. GLEASON: Yes. I want to get back to that
24 October '05. Now, there was a line in the design that
25 was -- didn't have water in it that was supposed to have

1 MR. PRUETT: I think it would be fair, though,
2 to say when an individual does bring us a concern that
3 they have that we will, we ask that individual if he
4 minds whether or not we provide that to the licensee and
5 have the licensee conduct an investigation. If they are
6 okay with that, then we will pass along that problem
7 with that concern back to the licensee. They will do
8 their own investigation and send us a report that we
9 will review and maybe do a little bit more inspection to
10 verify that the investigation was thorough. Otherwise,
11 if the individual is not comfortable with that, then
12 they will pass that issue to us and we will have one of
13 our inspectors do it.
14 MR. MALLETT: And Victor and I were just
15 talking. To the best of my recollection, the events in
16 2004 where we had special inspections were not the
17 result from the concern for any of them. That's a
18 better answer.
19 COM. MUNDELL: And I understand. I mean we
20 receive confidential information here all the time. And
21 I understand your concern.
22 But generically, without saying we did this
23 inspection based on an event or this inspection based on
24 a routine special investigation, excuse me, or this
25 special investigation based on a routine, something that

1 is not risk significant, we don't perform a special
2 inspection. If we do believe it is risk significant, or
3 it has generic implications for other plants, we will
4 perform a special inspection.
5 For example, the loss of off-site power event in
6 June of 2004, that had implications of generic issues
7 for other plants in the country and for grid
8 reliability. So we performed a special inspection to
9 follow up on that issue. The steam generator tube leak
10 in 2004 had some risk significance involved with that,
11 so we followed up on that.
12 So I can go on, but that should answer your
13 question on basis.
14 COM. MUNDELL: No, I appreciate that. I was
15 trying to understand how the special inspections start.
16 Were there any then at Palo Verde based on any
17 employee concerns?
18 MR. MALLETT: I am not going to answer that in
19 an open forum and I will tell why.
20 COM. MUNDELL: Oh, you can't?
21 MR. MALLETT: We try to protect the identity of
22 individuals bringing us concerns. And so if I identify
23 a particular event that we followed up on, you could
24 lead to the identity of that person that might give us.
25 So we don't do that in open forum.

1 of the things they need to fit to block certain piping
2 when they are draining down from that outage. We did a
3 special inspection to look at that as well.
4 So that would have been, what, '4?
5 MR. PRUETT: Right.
6 MR. MALLETT: 2004.
7 COM. MUNDELL: And those inspections, how do
8 you, you sort of talked about it a little bit, how do
9 you decide to do a special inspection as opposed to a
10 routine inspection? Are they based on employee
11 complaints? Are they based on something that your
12 engineers, your regular inspectors see? How did that
13 come to fruition?
14 MR. MALLETT: There are three different ways.
15 You mentioned them. One is during your routine
16 inspection we may come up against an inspection finding
17 and ask that question. We may receive a concern from an
18 individual at the facility that we look into. The third
19 way is an event may occur, and we follow up on that.
20 We have a prescribed process. I know this --
21 people put out numbers and acronyms, but we have
22 management directives. And 8.3 of our management
23 directives describes our process for following up on one
24 of these issues. And we base it on risk significance.
25 If we believe the issue by the formula in there

1 focusing on those things appropriately.
2 COM. MUNDELL: And so to sort of focus on the
3 facility here in Arizona, have you had special
4 inspections? I think you said you have got data for
5 2004 and '5 here today, but you don't go back farther
6 than that.
7 MR. PRUETT: I didn't bring data beyond 2004
8 with me.
9 COM. MUNDELL: So the number, you may have said
10 it and I missed it, the number of special inspections at
11 Palo Verde in 2004?
12 MR. PRUETT: We did do a number of special
13 inspections. Bruce mentioned the steam generator tube
14 leak. We did a special inspection for that item. The
15 initial voiding, some emergency core cooling system
16 piping, we did a special inspection for that issue. The
17 three-unit loop event in the summer of '04, we did what
18 we term an augmented inspection for that because the
19 significance of that was higher than the other two
20 instances where we did special inspections.
21 MR. MALLETT: We did one more where, when they
22 were coming up out of the outage of replacing the steam
23 generators in Unit 2, I am sorry, not coming up out of
24 it but in response to where they shut down to repair the
25 leaking tube, they did have a problem in fitting up some

1 in emergency preparedness, might be in operation of the
2 facility or maintenance area.
3 In addition to that we may perform special
4 inspections to look at particular areas. Like every two
5 years we look at the design of the facility.
6 And in response to Commissioner Mayes, if I
7 pronounced that correctly, we do pick certain
8 facilities, certain systems and components to look at in
9 detail and make sure the design is correct, keep asking
10 the questions were we right when we licensed the
11 facilities or have they changed it, and if that changes,
12 is it appropriate.
13 So those special inspections we may conduct
14 every two years or we may conduct every month depending
15 on what the area is we are focusing on.
16 I want to add one more. It is very important to
17 us. I apologize but I want to make sure you know this.
18 COM. MUNDELL: That's all right.
19 MR. MALLETT: As I said in the beginning, these
20 cross-cutting areas of problem identification and
21 resolution are very important to us. If a plant is
22 performing well, they will have a very healthy system
23 for identifying problems, thoroughly evaluating them and
24 correcting those things. So we look at that once every
25 two years in depth to make sure their program is

1 make sure they operate in a safe condition, and that's
2 our focus.
3 COM. MUNDELL: And then I was intrigued that you
4 said you have three inspectors at the facility.
5 MR. MALLETT: Yes, that's correct. We have for
6 each nuclear plant, as I said, essentially an NRC field
7 office at that facility. And at Palo Verde usually
8 that's one inspector per unit. At Palo Verde, with the
9 three-unit facility, we have three inspectors there.
10 They are there full time to monitor and observe and
11 inspect the licensee's conduct of operations.
12 And in addition to that, we send specialists out
13 from a regional office to look at weeks at a time other
14 special inspections of the facility. That is important
15 to us not only for routinely monitoring what they do but
16 to respond to emergencies quickly if one should come up.
17 COM. MUNDELL: And then those special
18 inspections, how are those triggered?
19 MR. MALLETT: We have, in our reactor oversight
20 process, we have determined there are certain
21 inspections of facilities we want to look at routinely.
22 Those are described in there. We call that a baseline
23 inspection program to make sure that every facility gets
24 a sampling of those areas. That might be in
25 engineering, might be in radius and protection, might be

1 that you drive down the highway and it vibrates, what is
2 the first thing you do?
3 CHMN. HATCH-MILLER: Get it rebalanced.
4 MR. MALLETT: Right, pull in the station or
5 somewhere and have someone to look what the problem is.
6 COM. MUNDELL: Call AAA.
7 MR. MALLETT: They may try to balance it by
8 weights. Okay? We change the frequency of the
9 vibration and reduce it. If that doesn't work, the next
10 thing you do, you look is your tire out of round, look
11 for that.
12 This is similar in the sense that, without
13 knowing the exact cause, you try things to reduce the
14 vibration.
15 I don't know if that makes it easier.
16 COM. MUNDELL: I thought I had the floor.
17 That's the process that you understand the
18 company is currently going through right now?
19 MR. MALLETT: That's correct.
20 COM. MUNDELL: And they will probably be able to
21 go into a little more detail on when they anticipate
22 going through all the different options that they may
23 have to correct the vibration.
24 MR. MALLETT: Right. And it is not like we have
25 a big discussion with them. It is just our focus is to

1 is not an order the NRC has to give for this. It is by
2 the design. But they also are very conservative in
3 their limits they are taking, and we support that.
4 COM. MUNDELL: When I used the word order, it
5 may have not been the correct terminology, order, rule
6 and regulation. You know, I assume then based on what
7 you just told me, they have to comply with the design
8 specifications and that is as a result of some
9 regulation that says you have to do that?
10 MR. MALLETT: Right. There is a regulation that
11 says they have to be within a certain code for piping
12 and systems so you don't affect them. There is also
13 certain recommendations by the vendors of valve
14 actuators and so forth. They have to operate within
15 those design parameters by their license.
16 COM. MUNDELL: So based on your knowledge and
17 experience, there are some solutions to the vibration
18 problem and they are investigating those solutions right
19 now, is that what you are saying?
20 MR. MALLETT: That's correct.
21 COM. MUNDELL: So, okay. And then I was
22 intrigued --
23 MR. MALLETT: Let me explain why it is difficult
24 to give a time frame. This may add to the confusion. I
25 am hoping it doesn't. If you have a tire on your car

1 it. Other things they have tried to do at this point
2 have not allowed them to be below those numbers.
3 COM. MUNDELL: I am sorry. I didn't hear your
4 last.
5 MR. MALLETT: Other things they have done at
6 this point have not allowed them to operate at above
7 25 percent power to get them fixed.
8 COM. MUNDELL: And you may have said this and I
9 may have missed it, sir, is the 25 percent power a
10 result of an order by the NRC or is that a decision that
11 they have made based on their engineers reviewing the
12 problem?
13 MR. MALLETT: The 25 percent power is based upon
14 the design that they have to operate the facility within
15 to make sure that they don't cause an unsafe condition
16 on that piping.
17 For example, if they have a particular valve on
18 that piece of piping and it is above a certain vibration
19 by certain codes they have to operate within, design
20 codes, then they can't operate above that because that
21 valve needs to be activated when called upon. Or if
22 there is a particular weld in that piping, then they
23 can't force a crack in that due to the vibration and
24 cause a leak in this system. So they have to operate
25 within those parameters based on the design. So there

1 MR. MALLETT: That's correct.
2 COM. MAYES: And we can't go back and undo that,
3 can we? That's part of the big problem here, isn't it?
4 MR. MALLETT: It is your decision, I guess, and
5 Arizona Public Service's. So putting in new steam
6 generators is a good thing.
7 COM. MAYES: Right. It increases the power.
8 MR. MALLETT: It increases the life of the unit.
9 It increases the efficiency of the units as long as the
10 tubes aren't leaking after you put them in. It is a
11 good thing. But it does change the flow characteristics
12 and thermodynamics of the plant.
13 Troy, anything?
14 CHMN. HATCH-MILLER: Commissioner Mundell.
15 COM. MUNDELL: Well, the last question is what I
16 wanted to touch on. Then, from your perspective, you
17 have no prognosis on when the Unit 1 could be up and
18 running at full capacity? Is it just sort of continue
19 to try and figure out what is causing the vibration?
20 MR. MALLETT: Well, the prognosis is when they
21 can operate at 100 percent power and not be able to have
22 the limits on amplitude and frequency, that's when they
23 can go back. But there are ways to fix that and they
24 are exploring those, such as putting a dampening system
25 on it and so forth. It depends how quickly they can do

1 attempted to deal with them before now?
2 I guess that's what I am puzzled about and
3 concerned about, is why didn't APS address the
4 vibrations before now, before it became a huge problem,
5 a huge problem.
6 MR. MALLETT: Again let me start out, ask Troy
7 to help me out here.
8 Arizona Public Service has been dealing with
9 these vibrations since they started seeing them in the
10 1999 time frame. But they took actions they thought
11 were appropriate to keep them within what I will call
12 the safety limits of frequency and amplitude of the
13 vibrations. As long as they are within those safety
14 limits, they determined it was appropriate to operate at
15 100 percent power and continue to study to see if they
16 need to take any action. The NRC has accepted that.
17 The issue that has changed now coming out of
18 this last outage here in December, 2005 is those
19 frequencies and the magnitude or amplitude increased.
20 And they increased such that they would be above what we
21 consider those limits to operate safely are. So that's
22 the change. As to why that change is there, that's what
23 they are exploring and we are exploring as well.
24 COM. MAYES: And that changed after the steam
25 generators were replaced?

1 we? I mean you said that it is from the force of water
2 through piping. Is that the root cause or do we not
3 know what the root cause in '99 was?
4 MR. MALLETT: You can probably get a better
5 answer from Arizona Public Service.
6 COM. MAYES: I will ask them.
7 MR. MALLETT: I figured you would. In our view,
8 there are some plausible reasons, that I will call, for
9 why this might be occurring. And so far the licensee,
10 when they look at some of those and try to correct them,
11 it has not corrected the situation.
12 Troy, do you want to answer?
13 MR. PRUETT: I would agree with Bruce, that the
14 licensee still needs to complete all their investigation
15 to determine a root cause or set of root causes and
16 there are plausible explanations for why the vibrations
17 are occurring in that line.
18 MR. MALLETT: And we have some, I will call
19 them, conjecture as to some of the plausible reasons.
20 We have shared that and the licensee has also noted
21 those.
22 COM. MAYES: Did you share any concerns with APS
23 about these vibrations prior to this late problem? I
24 mean since '99, have you shared any concerns about those
25 vibrations with APS? And to your knowledge has APS ever

1 vibration is. So when you don't do that, you take steps
2 to try and minimize the impact. And so they have tried
3 different ways of dampening the pipe, as Troy said.
4 They have tried different things during the outage to
5 look that they thought were going to fix it by heat
6 tracing, all very acceptable methods to try and reduce
7 the vibration to some success. But right now it is
8 still there.
9 So to me, what I am describing is they are
10 fixing the symptoms that are occurring rather than
11 driving back at the root cause. But when you have a
12 vibration like this, we have other plants in the country
13 that have them, it is not easy to identify the root
14 cause.
15 One more comment I want to make. At no point,
16 though, are they operating outside unsafe parameters.
17 That's why they are at the 25 percent level. We sent a
18 team out. They had experts in that evaluated. We
19 determined that at this level of vibration they will not
20 have an impact on any safety system or safety connection
21 in that pipe. That's why they are limited to that
22 level.
23 COM. MAYES: And the root cause, so what you are
24 saying, we don't know what the root cause of the
25 original vibration was, that that began in '99, or do

1 to be removed from the system. But the computer models
2 and the hydraulic monitoring and modeling that was
3 performed indicated that the unit would be able to come
4 back up after the steam generator replacement outage and
5 operate below the administrative limits set for
6 vibration on that line.
7 In particular we are talking about one
8 component. It is a valve. And they shut down the
9 cooling line that is taking the brunt of these
10 vibrations. It has a limiting component. The facility
11 has done a lot of analytical work to demonstrate what
12 the safe operating limit is and are maintaining the
13 operation of the facility below that limit.
14 They did try and install another modification
15 after they started up. Again, once again the computer
16 modeling and the engineering analysis they did indicated
17 that there should be some degree of success in
18 minimizing the vibrations in that line, but that
19 modification proved to be unsuccessful. And currently
20 the licensee is developing other alternatives to install
21 modifications on that line which hopefully will be
22 successful in dampening the vibrations in that system.
23 MR. MALLETT: Let me add to what Troy is saying.
24 This is a case to me of the licensee doesn't know and we
25 don't know at this point what the root cause of the

1 When they started up out of the outage with
2 those, after putting in the new steam generators, the
3 vibration became worse than it was before the outage
4 appeared. So one could draw the conclusion that putting
5 in the steam generators with an increased flow has an
6 impact on that vibration.
7 COM. MAYES: Therefore, one could draw the
8 conclusion that they should have known that was going to
9 happen?
10 MR. MALLETT: As I said, the Commission can make
11 that determination. But in our view, we knew there was
12 a vibration, they knew there was a vibration. I am not
13 sure it is predictable it would have been worse. It
14 could be better.
15 MR. PRUETT: I just want to add a couple
16 comments, Bruce.
17 They did, during the refueling outage prior,
18 during the steam generator replacement outage, install a
19 modification intended to reduce or hopefully eliminate
20 those vibrations. I believe the licensee will term it a
21 vortex plate that goes in that line. There was some
22 reason to believe that vortex plate would have worked.
23 In other words, during the acceptance testing of
24 that modification, it created a separate problem which
25 was not predicted and, therefore, that vortex plate had

1 what has transpired, the facts, and then you can judge
2 yourselves the answer to that question.
3 The vibration issue at Palo Verde in this
4 particular pipeline section of line has had a vibration
5 issue for quite some time. I want to say since, what,
6 1999, time frame.
7 It is not unusual, as you can imagine, for a
8 power plant where you are moving water at significant
9 rates through piping to set up a vibration in that
10 piping. You can equate that to your homes. When you
11 turn on water pressure and turn it off, if you don't
12 have it properly braced, you always have vibration, but
13 if you don't have it properly braced, you can hear that
14 vibration.
15 So plants do have flows in them. They do have
16 vibration. It is not just Palo Verde. But you have
17 appropriately designed the facility to either dampen
18 that vibration to minimize it or to not have it. So
19 they have known they have had a vibration for quite some
20 time.
21 When they put in the new steam generators in the
22 unit, this is Unit 1, it did have an impact on the flow
23 in that system. And whether or not that contributes to
24 the vibration is a question still I think not completely
25 answered. But all they know is the facts.

1 continues to today.
2 I have asked APS to respond to some of these
3 questions in a letter that I sent on January 18th and I
4 have not received a response to my questions yet. But
5 what they have told at least the state's largest
6 newspaper is that the installation of, that this
7 involves a vibration problem and some piping which was
8 aggravated by the installation of larger steam
9 generators during a recent refueling outage.
10 Can you shed some light on that? And I am
11 particularly interested in knowing whether this is a
12 condition that could have been foreseen by APS prior to
13 the installation of those generators, especially if this
14 vibration problem was one that they knew about for six
15 years.
16 MR. MALLETT: Again let me start out, and I will
17 ask Mr. Pruett; although, he didn't help me on the last
18 question. Let the record note that.
19 COM. MAYES: He is going to have to step up.
20 MR. PRUETT: Maintain a low profile.
21 COM. MUNDELL: He will probably hear about it
22 later.
23 MR. PRUETT: That's right.
24 MR. MALLETT: With regard to the vibration issue
25 and whether they could have foreseen it, let me tell you

1 COM. MAYES: Yes. Then just one more question.
2 And I don't know if you can answer this.
3 MR. MALLETT: Let me add one more thing at the
4 risk of being more confusing on that. We have an
5 inspection we were conducting at the time of that and we
6 have a report that is coming out. And the reason I am a
7 little hesitant is that report is due any day. In fact,
8 we will probably issue it tomorrow.
9 COM. MAYES: Okay.
10 MR. MALLETT: And that report will make our
11 conclusions final in that instance that what we looked
12 at.
13 COM. MAYES: About this issue?
14 MR. MALLETT: About this issue.
15 COM. MAYES: Okay. And the Commission can
16 access that report? Can that be provided to us?
17 MR. MALLETT: Sure. In fact, we can make sure
18 Brian McNeil has a copy of it.
19 COM. MAYES: Thank you. You may not be able to
20 answer this question to the degree that it is
21 prospective, but there is an outage currently under way,
22 not a total outage, but as you said, Mr. Mallett, Palo
23 Verde is turned down to 25 percent or so. Palo Verde
24 Unit 1 is at 25 percent or so, starting, that outage or
25 turn down started on December 29th and basically

1 to answer. All I can say in this case is that it was a
2 question we raised and they did the right thing when
3 they couldn't answer the question.
4 COM. MAYES: Is it a question that APS should
5 have asked itself years earlier?
6 MR. MALLETT: It is a question -- I will change
7 the question.
8 COM. MAYES: Okay.
9 MR. MALLETT: Is it something we would expect
10 them to go back and look for? Only if they are
11 inspecting and reviewing that system in depth. Okay?
12 And other licensees have similar systems where we go out
13 and look and ask a question that was not found in the
14 past. And we do evaluate whether they should have found
15 it before us.
16 In this instance, we didn't determine that they
17 should have found it beforehand, I don't believe, Troy,
18 unless you correct me on that, since I have stuck you in
19 this one.
20 But the issue, I think, was it was a new
21 question that was asked. If they were investigating and
22 looking at that system, you would expect them to find
23 out, but I am not sure we would expect them to go in and
24 look at that system at the time we were looking at it.
25 Does that make sense?

1 have of licensees' facilities. Although we design the
2 facilities for certain scenarios, from time to time
3 there is a question that comes up. And sometimes it is
4 a question of did we ask this when we designed the
5 plant. Sometimes it is a new question. So whenever a
6 licensee has the NRC ask any questions of their own
7 staff, they then have to go into something called
8 operability determination. I hope those answer your
9 question. They have to then determine whether that
10 system can perform its function.
11 In the October time frame, when we raised this
12 issue about the design flaw, it was a new question,
13 okay, one that we hadn't come up across before, nor had
14 they to the best of my recollection. And so they did
15 what we expected. They searched that out and said we
16 can't answer the question -- I am oversimplifying -- so
17 that would put us in a condition that we don't believe
18 is within our design. If you can't answer at NRC, and
19 we can't answer it within this certain time frame, we
20 have to shut the plant down by our technical
21 specification until we get it resolved. And that's what
22 they did.
23 There is a question we asked ourselves, that
24 could we have asked that question years earlier, should
25 we have seen it before. Those are questions difficult

1 you.
2 COM. MAYES: Okay.
3 MR. MALLETT: This was a design flaw, you were
4 correct. In the October time frame this was not due to
5 a void in a pipe. This had to do with a question the
6 NRC raised. So the answer to your question who
7 identified it, the NRC identified it during an
8 inspection looking specifically at this system.
9 This emergency core cooling system and using
10 that tank for storage of water and drawing a suction on
11 that for the pumps is very important in certain accident
12 scenarios. So we do various design reviews and
13 inspections to look at those systems.
14 We were focused in on that system because of
15 problems we had with a voiding condition in another
16 portion of the system in the 2004 time frame. So your
17 issue is right, it just wasn't with the October event.
18 In the October what we found was a question we
19 asked about the design of a certain valve in that
20 system, whether or not it would cause air entrainment
21 into the line which could impact the pumps and cause
22 them to not operate appropriately to perform the
23 function. So in the October time frame, what we did was
24 we raised the question.
25 That is not atypical of other inspections we

1 I want to bore down a little bit on the
2 October 20th shutdown which you discussed, Mr. Mallett,
3 I think briefly in your opening comments. That was the
4 shutdown to resolve a refueling water tanks suction
5 issue. And this was, I think, the instance where the
6 design flaw was discovered in a pipe that was not filled
7 with water and it should have been filled with water. I
8 don't know if that, if that layman's description is
9 right, but that was the way that I understood it to be.
10 Palo Verde had been operating for quite some
11 time before that design flaw was found, I guess 15 or
12 more years. And one of the things I was perplexed about
13 was why, why in the world it took so long for someone to
14 discover a flaw that required the NRC to shut Palo Verde
15 down. It seems to me that someone somewhere would have
16 found that flaw.
17 So, again, that's just a layperson's take on it,
18 or a Commissioner's take on it. But can you tell me,
19 one, A, who found the flaw and why wasn't it discovered
20 before that time, if it was so serious that it required
21 the shutdown of the plant?
22 MR. MALLETT: Let me again start out in general
23 and then Mr. Pruett can add more details if I don't pick
24 up on them.
25 First let me clarify, and this is not to pick on

1 investigation, and we are still awaiting for the root
2 cause analysis, the company's investigation of that
3 issue.
4 MR. MALLETT: Let me add something, and I want
5 to be careful.
6 CHMN. HATCH-MILLER: Mr. Mallett.
7 MR. MALLETT: First of all, if you look at a
8 trend at the Palo Verde site in general, the year 2004
9 and early 2005, they were much increased over the past
10 from the outages they have had. And then I think some
11 of the comments I read from this Commission acknowledged
12 that or recognized that.
13 I want to be careful when we talk about the
14 reason. Troy went into specific outages. And I
15 don't -- although we look at unforced outages and track
16 them, we are always careful to not just use a number,
17 because we don't want licensees to have the impression
18 that we are bean counting to where, if they get a plant
19 that they believe is in an unsafe condition, they won't
20 shut it down because, oh, here is another count.
21 So even though we believe the unforced outage
22 rate was higher than we want, we want the licensee to
23 take that plant down if they believe it is an unsafe
24 condition. I just want to make that clear.
25 COM. MAYES: Absolutely. And I appreciate that.

1 subsequently reported that error to the facility. The
2 facility implemented their technical specification, as
3 we would expect. And they had to bring the unit off
4 line in order to provide the software updates that were
5 required to maintain that particular system in a safe
6 operating configuration. That shutdown was essentially
7 beyond the control of the licensee to predict.
8 And for Unit 3, on May 23rd they did have a
9 shutdown to repair the reactor coolant pump oil seal
10 systems and pressurizer heaters. The big problem was
11 the pressurizer heaters. They again had to shut down
12 June 2nd for the pressurizer heaters as well. A
13 subsequent failure analysis of those heaters determined
14 that the manufacturer of the heaters made an error
15 during the construction of the heaters such that they
16 grounded and would not function properly. That was not
17 something that the licensee would have been able to
18 predict prior to installation of the heaters. It was
19 only discovered upon a subsequent failure analysis where
20 they actually did a destructive examination of one of
21 the heaters to determine what the failure mechanism was.
22 And lastly, on July 5th, they did have to
23 perform a shutdown for repair of a reactor coolant pump
24 oil seal leak. The cause of the reactor coolant pump
25 oil seal leak at the facility is still under

1 some of those outages.
2 COM. MAYES: Okay.
3 MR. PRUETT: Especially I want to focus on the
4 summer of 2005. We went and looked at that data from
5 the May 2005 through, just check my notes here, through
6 August of 2005. There were a number of down powers in
7 that time frame. Of course, for Unit 1 they did have a
8 technical specification required shutdown. They had a
9 voltage regulator fail on one of the emergency
10 generators. Those occur with some amount of frequency
11 within the industry.
12 They appropriately replaced the governor for the
13 diesel generator. The retest for that per the technical
14 specification requires that you need to come off line to
15 provide that testing in a safe manner. That was not
16 what I would call a -- that is within the norms of what
17 we would expect to see in a power plant.
18 They did on August 26 have a reactor trip during
19 the subsequent restarting of that facility due to
20 operational issues with controlling steam derivative
21 feed water level.
22 For Unit 2 on August 22nd they did have to
23 perform a technical specification required shutdown.
24 But in this case, the issue was due to computer software
25 supplied from a vendor that was in error. The vendor

1 Verde was .33. The per unit average for Region IV
2 was .48. So Palo Verde operated below the average in
3 terms of number of plant trips in 2005.
4 COM. MAYES: Okay.
5 MR. PRUETT: With respect to the plant
6 shutdowns, be they forced or technical specification
7 required, Palo Verde had 10 during 2005. The Region IV
8 total was 22. If you look at the averages for Palo
9 Verde on a per unit basis, it was 3.3, and for Region
10 IV, 1.05. So Palo Verde was slightly -- or three times
11 above the Region IV plants in terms of forced outages.
12 COM. MAYES: Can you say the region average
13 again. 1 --
14 MR. PRUETT: 1.05.
15 COM. MAYES: 1.05. Palo Verde's average was
16 3.3. And those averages are the average number of per
17 unit of unforced, unscheduled outages?
18 MR. PRUETT: That's correct.
19 COM. MAYES: So Palo Verde's unscheduled outage
20 average for 2005 was three times the western average?
21 MR. PRUETT: That's correct.
22 COM. MAYES: Okay. So that somewhat reinforces
23 my earlier statement, that of concern about the number
24 of unscheduled outages at Palo Verde.
25 MR. PRUETT: Possibly. But I want to clarify

1 control over, Palo Verde?
2 MR. PRUETT: Palo Verde did not -- four of those
3 were outside of, I believe, what the Palo Verde facility
4 could have reasonably been expected to control.
5 COM. MAYES: Okay. And then we could go back
6 and get a compare -- we can get the data over the
7 lifetime of the units at Palo Verde in terms of the
8 number of --
9 MR. PRUETT: That data could be collected. It
10 would be probably a fairly time-consuming research
11 project but we could collect that data.
12 COM. MAYES: I meant the unscheduled outages.
13 MR. PRUETT: In terms of plant shutdowns, that
14 being a forced shutdown because of some equipment
15 deficiency where they had to shut down not required by
16 their technical specifications, or it could have been a
17 technical specification required shutdown. If you group
18 those two together, the Palo Verde total for 2004 was 3.
19 The Region IV total was 4. So if you look at the
20 average of course at Palo Verde, that's 1. And the
21 total for Region IV was .18 for the year 2004.
22 COM. MAYES: Okay.
23 MR. PRUETT: Moving on to 2005, in terms of
24 reactor trips, Palo Verde had one reactor trip. The
25 Region IV total was 10. So the per unit average of Palo

1 plant trips. The Region IV total including Palo Verde
2 was 22. If you break that down, that's an average per
3 unit at Palo Verde of 2 and average per unit Region IV
4 wide of just over 1.0.
5 COM. MAYES: So it is twice the average for the
6 region?
7 MR. PRUETT: It was in '04. But several of
8 those trips were due to circumstances which Palo Verde
9 didn't really control, at least the nuclear facility,
10 such as the three unit loss of off-site power event that
11 occurred in the summer of 2004. They also had an
12 electrical lightening storm which tripped one of the
13 units as well.
14 COM. MAYES: Troy, could you pull the
15 microphone. I am sorry, I am having trouble hearing
16 you.
17 Can you repeat that. So the average trip per
18 unit, tripping per unit for the west --
19 MR. PRUETT: Was 1.04.
20 COM. MAYES: 1.04. And the average trip per
21 unit?
22 MR. PRUETT: At Palo Verde was 2.
23 COM. MAYES: 2. So Palo Verde was twice the
24 western average. But you are saying there were a few
25 instances in there which you believe APS didn't have any

1 let me ask Troy Pruett to do that.
2 COM. MAYES: Thank you.
3 MR. PRUETT: I did not bring data that goes back
4 to the initial operations of Palo Verde, but we did go
5 back and look at the data for 2004 and 2005 and compared
6 it to the other operating units within the region west
7 of the Mississippi.
8 COM. MAYES: Okay. And what did you find?
9 So just to repeat, I don't know if everyone
10 heard, you compared, you went back and looked at Palo
11 Verde, 2004, 2005, and compared that to the rest of the
12 region?
13 MR. PRUETT: To our region, right.
14 COM. MAYES: To your region. And that actually
15 goes to my next question which is I want to ask you how
16 Palo Verde stacks up with the rest of the country. But,
17 okay, the rest of the region sounds good.
18 MR. PRUETT: So we have 21 operating units in
19 Region IV.
20 COM. MAYES: In the western part of the United
21 States?
22 MR. PRUETT: That's right. And Palo Verde
23 operates three of those units.
24 COM. MAYES: Okay.
25 MR. PRUETT: For 2004 Palo Verde had six reactor

1 outages last year if you count the latest one, 10 of
2 which were unscheduled. And APS can correct me if I am
3 wrong but I think that's in the ballpark.
4 MR. MALLETT: That tracks with the information
5 we have.
6 COM. MAYES: Is that right? Okay. So we have
7 had 13 outages in 2005, which I have to believe is
8 almost unprecedented.
9 So I guess I want to ask you: Do you have a
10 record of the number of outages at Palo Verde going back
11 over its life? Can you give me a sense of your feeling
12 of the performance in 2005 relative to the lifetime of
13 Palo Verde? Then I have a follow-up question to that.
14 MR. MALLETT: Yes. Let me give you an
15 overarching comment. Then we will let Troy Pruett
16 answer that more specifically.
17 The NRC does track and look at unforced outages.
18 That is an indicator to us of whether or not things are
19 being adequately maintained or properly operated at the
20 facility. In fact, if you go to our website, that is
21 one of the indicators. You can get that information per
22 unit and you can get that trend, comparing it to other
23 units around the country. So we do track that.
24 And to try and give you a little flavor, to
25 answer your question more specifically where they stand,

1 that I would rather not comment because it discloses
2 some of those activities.
3 CHMN. HATCH-MILLER: I am glad to hear that they
4 are discussing it because I think for us to move forward
5 with another nuclear facility in this state we are going
6 to have to be able to control the operational costs, and
7 part of those operational costs, clearly a major part,
8 are becoming the security.
9 MR. MALLETT: I don't want to leave this
10 Commission with the impression that those discussions
11 are leading to a decision in that area.
12 CHMN. HATCH-MILLER: Okay.
13 MR. MALLETT: It is just a question that has
14 been brought up that has been discussed from time to
15 time.
16 CHMN. HATCH-MILLER: Thank you very much.
17 Questions? Commissioner Mayes obviously has her
18 hand up.
19 COM. MAYES: Thank you.
20 Thank you, Mr. Mallett, for that presentation.
21 As I said earlier, I am very concerned about the
22 performance of Palo Verde in the last year. And I have
23 to edit myself a little bit. I think I said there were
24 13 unscheduled outages. According to a schedule that I
25 have that has been provided by APS, there were 13

1 Capitol Hill or elsewhere in Washington about
2 federalizing these security forces and taking that on as
3 a federal cost?
4 And it really truly is, I want to say, a federal
5 cost. This is a cost to fight off terrorism. This
6 isn't about keeping a teenager from throwing a beer
7 bottle in there or somebody coming in to try and take
8 pictures for their family. This is about a severe
9 threat of terrorism, almost a military like operation
10 that I see going on out there now. And I am glad to see
11 it. But I personally, if it is not happening in
12 Washington, I would like to, I would like to put that
13 idea forward, that perhaps those expenses ought to be
14 borne by the federal government and the personnel that
15 engage in that activity should be federal employees,
16 federal officers.
17 MR. MALLETT: The best way to answer that is
18 there are discussions of that issue. There have been
19 discussions of that very question for quite some time
20 now.
21 But the Nuclear Regulatory Commission believes
22 that we are taking the actions appropriate by licensees.
23 We have taken some other actions, however, to under
24 certain scenarios where you can call those other
25 facilities if you have to have them. And I think beyond

1 requirement. We have been doing that since 2001.
2 The third area, though, you didn't mention was
3 emergency preparedness. And licensees have to be
4 prepared for emergencies. We test, along with the state
5 and with FEMA, Federal Emergency Management Agency which
6 is now part of the Department of Homeland Security, we
7 test that emergency response each year to make sure that
8 they have the people and qualifications and procedures
9 to respond to all types of emergencies.
10 CHMN. HATCH-MILLER: Let me kind of work on --
11 that was a great answer. I really appreciate it. Is
12 there any, since it is something that you have direct
13 involvement in and you probably are aware of this, is
14 there any -- well, let me back up.
15 Obviously the cost of the additional emergency
16 preparedness, the additional security is a major cost in
17 the operating of these plants, not just the Palo Verde
18 but across the United States. I know that, in terms of
19 the airport facilities in the United States, there came
20 a point in time where the federal government decided
21 having a private security force maintained and operated
22 by the airlines was not the way to go so they decided to
23 federalize the personnel involved with safety and the
24 security of the facility.
25 Is there any discussion that you know of on

1 may tip the balance in terms of cost.
2 Do you have any relationship to that aspect or
3 is that the Department of Homeland Security or can you
4 help me with this?
5 MR. MALLETT: Well, let me explain as best I
6 can. There are several agencies that govern the
7 response in this country to security events, terrorism
8 being one. The NRC does regulate that for nuclear power
9 plants and we have taken several actions which have
10 increased security at the facilities. Because we are in
11 a public open environment, I am not going to describe
12 what that security is for obvious reasons.
13 CHMN. HATCH-MILLER: Please don't.
14 MR. MALLETT: But we have increased in many
15 areas. And where we believe we assess that further
16 increase is needed to be done, we will put those in
17 place. Because in the beginning I made the comment
18 about safety and operating a plant safely, but I also
19 said they have to do two other things. They have to
20 operate it securely. And since 2001, September 11th, I
21 think this country has all been aware that our
22 infrastructure, including nuclear facilities, has to be
23 protected against security events. So when we find an
24 event that is of a scenario such that we don't believe
25 that it is the best performance, we will add a

1 through this period of time, 2004, 2005, that you
2 discussed, Palo Verde has been operating in a safe
3 manner, protecting the public safety and the
4 environment's safety.
5 MR. MALLETT: That is correct.
6 CHMN. HATCH-MILLER: Okay. I have one other
7 question I got to get in before I forget it. And it has
8 to do with safety but it is in a different light, and
9 you may not be able to answer this question for me.
10 As I said in my opening remarks, I believe that
11 additional nuclear power has to be brought into Arizona,
12 either the state or at least the power from that
13 facility, brought to the state in order to have a
14 balanced fuel portfolio for the generation in this
15 state. And I think if we are going, if we are going to
16 operate a safe and reliable and inexpensive nuclear
17 grid, nuclear power makes a lot of sense. It is there
18 for us 24 by 7.
19 One of the detriments I have heard to building a
20 nuclear facility is not just the cost of that facility
21 and the time to build it but that there is a, there has
22 been required since 9/11 a tremendous increase in the
23 number of security personnel associated with nuclear
24 facilities to the extent that the cost of providing that
25 security force has gotten so great that that in itself

1 We can go through other examples but that's the most
2 recent.
3 CHMN. HATCH-MILLER: I am taking it it is a
4 pretty clear decision of when to operate and when not to
5 operate. But those even follow the licensee's plans and
6 your rules and regulations.
7 MR. MALLETT: Yes. We have anticipated what we
8 would believe the issues that might come up. And for
9 those we have designed license requirements, we call
10 them technical specifications, that say if you identify
11 a certain operating parameter you are in or piece of
12 equipment that is out, it gives you, if it is a piece of
13 safety equipment, time frames with which you have to
14 correct that. If you don't, we consider that too risky
15 or perhaps heading towards an unsafe condition. Those
16 are prescribed for them. And they, within those time
17 frames, don't have a choice if they want to operate
18 within their license.
19 CHMN. HATCH-MILLER: But the bottom line is, I
20 think you said, even though this is yellow, and yellow
21 kind of makes me nervous and I think of problems -- when
22 I see yellow at a stop light I start to slow down, I
23 hope; maybe that's what it is for, slow down, be
24 cautious, maybe that's what that yellow means -- but you
25 said, and I think you said it fairly clearly, all

1 that would be to talk about a specific event.
2 CHMN. HATCH-MILLER: Okay.
3 MR. MALLETT: Let me give you a general
4 overview, and then my expert here, Mr. Pruett, can add
5 anything he would like. If we go back to the
6 October 2005 time frame, when Unit 1 at the site was
7 down for the refueling outage and Units 2 and 3 were
8 operating in the 100 percent power I believe, we raised
9 during an inspection at the facility a question about
10 the design. And it happened to be about the design of
11 this emergency core cooling system, the key system if
12 the plant had to respond to certain scenarios.
13 When we raised that question, the licensee, as
14 typical of other licensees, has to find out if that is
15 operating outside the design of the plant, and if it is,
16 they have to put the plant in a safe condition unless
17 they can resolve the issue within a certain time frame.
18 In the case of October 2005, we raised the issue. The
19 licensee could not come up with, within that time frame
20 they have to shut down the plant, an explanation of
21 that. They made the right decision and said we can't
22 answer this question that was raised about the design,
23 we must put the plant in a safe condition. So that's
24 required by their technical specifications or by their
25 license to do that if they can't answer that question.

1 think you mentioned protect safety of the population and
2 protect safety of the environment.
3 MR. MALLETT: Yes. There are several aspects to
4 safety. And you are correct, we expect them to operate
5 the plant safely. And all those columns in our action
6 matrix I used to describe, because it is an easy way I
7 believe to discuss this, are not having a plant operate
8 unsafely. If you remember, I said they are not
9 operating unsafely. They are adequately protecting the
10 environment; they are adequately protecting the people.
11 But these problems I identified they are having are
12 challenging the plant and its operation. And they are
13 early indicators, if you don't turn them around, of
14 reducing that margin between where you are operating and
15 being unsafe. And whenever we see that, we want someone
16 to correct that.
17 CHMN. HATCH-MILLER: Okay. You mentioned a
18 number of occasions where one or more of the units was
19 shut down. Was that a, I am not sure how to exactly ask
20 this, was that a voluntary shutdown on the part of the
21 operators of Palo Verde or was that a required shutdown,
22 not necessarily required of you by direct action or
23 order of you, but by the rules and regulations under
24 which they operate?
25 MR. MALLETT: I think the best way to answer

1 put them into that column. Once they correct the
2 actions they need to take for that specific issue and
3 complete it, they will go back to the first column, or
4 green column, of performance where we don't have
5 increased oversight of them.
6 In addition to that action matrix, however,
7 these other problems I listed, we issued them based on
8 their performance, these two cross-cutting issues and
9 problem identification and resolution and human
10 performance. Those have to be corrected by them. They
11 have to address those issues. But they will still be in
12 the green column with those issues.
13 The reason we identified them is those are
14 indicators that we believe lead you to getting into one
15 of the columns to the right of that matrix, or the
16 yellow or red column. So we identify those issues early
17 and hope to turn someone around so they don't, their
18 performance doesn't get worse.
19 Does that make sense?
20 CHMN. HATCH-MILLER: Yes, it does. And I would
21 assume, in terms of the ratings and all your actions,
22 that the paramount issue is safety. And you don't want
23 the plant operating even if that plant is inexpensive
24 power or even necessary power, that you want that plant
25 first and foremost to be safe to all concerns. And I

1 be assured on this Commission and the public that we
2 will do everything to make sure that we inspect those
3 corrective actions to make sure they are complete and
4 that they address the performance issue.
5 This concludes my formal remarks. And at this
6 time we would be glad to answer any questions that the
7 Commission has involving our oversight and our
8 assessment of the Arizona Public Service's running of
9 the Palo Verde nuclear plant.
10 CHMN. HATCH-MILLER: Well, thank you very much,
11 Mr. Mallett. I guess the first question I have is: If
12 Palo Verde and the operators of Palo Verde correct the
13 list of issues that you said, including not a clear and
14 thorough review, more focus on symptoms rather than the
15 cause, recognition and complete awareness of design
16 changes and the like, if those are corrected, they are
17 right now in a condition yellow, do they go to a white
18 or a green? Is that what happens, or how does that
19 work?
20 MR. MALLETT: Good question. Let me clarify.
21 They are in what we call the third column or yellow
22 column of our action matrix because they had a finding
23 with this voiding issue in their emergency core cooling
24 pipe system late 2004 that was risk significant. And we
25 felt that that needed to be corrected. So that's what

1 action program they set up, it is hard to follow a trend
2 or to see what the fix might be;
3 We also felt they had incomplete and untimely
4 engineering evaluations, and communications with
5 operations caused delays in determining whether
6 something was operable.
7 If you remember, I said when you identify a
8 condition when a piece of equipment or maybe the design
9 is not in conformance with what the license says, they
10 have to evaluate whether that is still operable. And we
11 felt there were still delays in that and untimely
12 engineering evaluations to support that.
13 In response to these events of problems I have
14 just gone through in 2004 and 2005, the licensee has
15 initiated their own evaluation and they put in place
16 steps to correct these identified areas and some they
17 have identified for this degraded performance. They
18 refer to this collection of actions they are taking in
19 response to this as their performance improvement
20 program. These issues I have laid out we believe in the
21 NRC to be significant. And they are taking action to
22 correct them. At this time we see them that they have
23 identified the issues, they put steps in place to
24 correct them. But the key will be effective
25 implementation of those corrective actions. And you can

1 whether the design changes needed to be brought to the
2 NRC had some problems and we issued a Security Level III
3 violation, a civil penalty, for that violation in the
4 amount of $50,000 in April of this year.
5 In March 2005, the NRC also notified the
6 licensee of a decision that their performance met the
7 criteria for the issuance of two substantive
8 cross-cutting issues in the areas of problem
9 identification and resolution and in the areas of human
10 performance. Some contributing causes to this declined
11 performance of why we issued these were the following:
12 It was not clear that they were doing thorough
13 reviews of issues of problems in the facility;
14 It appeared to us that they were fixing symptoms
15 of a problem and moving on without completely addressing
16 the causes of those symptoms or of the problems itself;
17 We also felt a contributing cause was not
18 recognizing or perhaps incomplete evaluation of design
19 changes and what their potential impact might be on the
20 safety of the facility;
21 We also observed that not all individuals or
22 organizations at their facility were using their
23 corrective action program to identify the set of
24 actions. It is not necessarily that they weren't
25 correcting issues, but if they don't use the corrective

1 that was identified on all three units in August of
2 2004.
3 They did have a follow-up of a potential design
4 issue I just mentioned in October 2005 in the emergency
5 cooling system for all three units. The reason they
6 didn't shut down all three units at that time was one
7 was already down for a refueling outage.
8 And then lately, in December 2005, the latest is
9 they have reduced power. As you know, they are
10 operating at about 26 percent power now due to a
11 vibration in one of their pipe systems at the plant that
12 is crucial, could be crucial in a certain scenario for
13 emergency response.
14 One issue I mentioned, this voiding issue on
15 August 2004, as a result of that, in the emergency
16 cooling system, the NRC issued, did a special inspection
17 and we issued two enforcement actions because of the
18 significance of that in April of this year. First
19 action was two violations. One had a significance at
20 the yellow level. And in our process, that was a
21 violation from failure to control the design. And that
22 is the reason Palo Verde has all three units today in
23 the third column of our action matrix. It is due to
24 that issue and the significance of it. As a part that,
25 we felt that their process for reviewing and determining

1 or we identify, where they can operate the facility
2 outside a questionable design that we have allowed for,
3 or with a particular piece of equipment inoperable, if
4 they can't answer the question that it will be safe to
5 operate that way, they must take that plant to a safe
6 condition, which is a shutdown. And they did that in
7 October 2005 when a question was raised.
8 Now to their assessment. When Palo Verde began
9 our assessment cycles, if you remember I said we review
10 their performance every six months, it is a 12-month
11 cycle and we go by annual cycles, so in 2004 they were
12 in that first column I talked about in our action
13 matrix, the licensee response column. They were in this
14 because there were no inspection findings or performance
15 indicators that we felt had a significance greater than
16 green in color. In 2004, 2005, they did experience
17 several events at Palo Verde nuclear plant, some of
18 which the Commissioners have mentioned already, which we
19 determined warranted some special inspections because of
20 their significance. I will highlight just a few of
21 them.
22 I mentioned one already, the steam generator
23 tube leak in February 2004. I mentioned the response to
24 the off-site power loss in June of 2004. And they did
25 have a voiding issue in the emergency cooling system

1 and timely and thorough in response to events and
2 emergent issues. I will give you a few examples.
3 In February 2004, in response to an early
4 indication of a leaking tube in one of their steam
5 generators, I believe this was in Unit 2, they did shut
6 down the unit at that time before that leak could become
7 a significant issue. We agreed with that, and that was
8 the right action to take to put the plant in a safe
9 condition.
10 In June of 2004, probably one of the most widely
11 commented on events, all three units at the Palo Verde
12 nuclear site came down due to a grid disturbance and
13 they lost off-site power and tripped off line. While
14 there were some problems associated with the response to
15 that event, it was a great performance on the operators
16 at that plant to stabilize all three units in a rare
17 occurrence that all three come down almost
18 simultaneously.
19 Most recently, and I know you are interested in
20 this event, in October 2005 the licensee did shut down
21 Units 2 and 3 in response to a potential design
22 deficiency that the NRC raised until that deficiency was
23 addressed. This shutdown is what was expected, in fact,
24 it is required by their technical specifications. If
25 they have a condition that either they have identified

1 information specific to the Palo Verde nuclear plant and
2 their performance over the past one to two years.
3 CHMN. HATCH-MILLER: Thank you.
4 MR. MALLETT: We weren't sure exactly what the
5 Commission was interested in so we focused on the 2004,
6 2005 time frame.
7 First and foremost, the licensee, Arizona Public
8 Service, has operated the Palo Verde nuclear plant in a
9 safe and secure condition. They have ensured the
10 protection of the public health and safety. And they
11 have ensured the protection of the environment. They
12 have also responded to emergent plant conditions and
13 emergency events with safety as a primary focus.
14 There have been problems, though, some
15 identified by the licensee and some identified by the
16 NRC, that have challenged the plant safety systems. If
17 you remember in the first comments I made, those systems
18 consist of people, facilities and procedures. This
19 means that their performance is degraded in certain
20 areas and that they and the NRC are taking actions to
21 ensure improvement in these areas. This does not mean,
22 however, that their operation is unsafe.
23 I should also note that there are some areas
24 where their performance is not degraded and their
25 actions have been in compliance with our requirements

1 imagine, we don't want any plants in that column, and at
2 least no operating plants at least.
3 If we determine the licensee's performance in
4 identifying and correcting problems at the site and in
5 human performance or in maintaining a safety conscious
6 work environment have declined and meet certain
7 threshold criteria, we also identify in a letter to the
8 licensee this. And we term the identification of these
9 issues cross-cutting issues, because each of these three
10 areas, identification and correction of problems, human
11 performance, and maintaining a safety conscious work
12 environment, are crucial to safe operation of the
13 facility.
14 The NRC has several actions we can take and have
15 taken to ensure licensees operate nuclear plants in
16 keeping with protecting the public health and safety
17 and in keeping with maintaining the greatest margin of
18 safety problems. For example, we could issue findings.
19 We can issue notices of violations, which we require
20 responsive corrective action from the licensee. We can
21 also issue civil penalties and orders. And we can
22 require a plant to shut down if we believe it is in an
23 unsafe condition.
24 With this information, this background about our
25 oversight process, Mr. Pruett and I will now provide you

1 assessment letters are also available at our public
2 website.
3 To consistently apply our actions in response to
4 inspection findings and these assessments we have
5 created guidelines in a table we call an action matrix.
6 The action matrix concept provides for a gradual
7 increase in NRC's response as safety significance of our
8 findings and assessment and performance increases. As
9 you can imagine, as that safety significance increases,
10 our inspection effort, our involvement, dialogue with
11 the plant and our regulations and requirements
12 increases.
13 The action matrix currently in this country has
14 five columns of licensee performance; in conjunction
15 with that, five columns of NRC response to those
16 performances.
17 Of the 103 nuclear units in this country, and
18 Palo Verde has three of those units at their site, 80 of
19 those units are in the first, or green, column. 17 of
20 those units are in the second, or the white column.
21 Three are in the third or the yellow column and those
22 three units are the Palo Verde nuclear plant. And three
23 are in the fourth column, or the red column. The fifth
24 column I didn't describe. We don't have any plants in
25 that column. That is the unsafe condition. As you can

1 equivalent to various significance.
2 For example, green issues have very low safety
3 significance. There may be a finding that we will have
4 given to the licensee with very low safety significance
5 and require little NRC follow-up.
6 White, yellow and red issues have increasing
7 safety significance and they will trigger additional NRC
8 review. As is probably obvious, red is one of the most
9 significant findings and we would not expect licensees
10 to have red findings.
11 As I said before, this entire inspection process
12 is described at our website as the reactor oversight
13 process.
14 This process also includes an assessment of each
15 licensee's performance every six months. The purpose is
16 to note whether the licensee and NRC need to take any
17 further actions in addition to those already identified
18 and taken at the time we perform our inspection or at
19 the time we follow up on a certain event at the site.
20 The results of this assessment or evaluation are then
21 provided in writing to the licensee during an annual
22 meeting we hold with the licensee. In fact, we are
23 about ready to perform one of those assessments and hold
24 a public meeting out near the Palo Verde nuclear site
25 sometime March, April time frame of this year. These

1 multiple other inspections by inspectors out of our
2 Region IV Arlington, Texas office who spend weeks at a
3 time at the plant with various specialties conducting
4 these inspections. When we complete an inspection at a
5 facility we provide the licensee with our findings both
6 verbally, something we call an exit meeting, and
7 something we call an inspection report. And when we
8 determine something as important as safety, we ask them
9 to address it at that time. These inspection reports
10 are documented and they are available on our public
11 website, NRC.com.
12 In addition to these inspections, each licensee
13 monitors performance in something we call performance
14 indicators for various things like safety equipment
15 availability, whether they have so many shutdowns or not
16 at the facility, and they provide that information to us
17 on a quarterly basis. We examine that information to
18 make sure that it is accurate. And if there is any
19 trends, we will follow those up to make sure that they
20 are addressed. Those performance indicators are also
21 available at our website to the public.
22 As you can imagine, these performance indicators
23 and inspection findings can have varying safety
24 significance. To facilitate communication of this, we
25 embarked about five years ago on assigning a color

1 inspect the plant's operation to ensure compliance with
2 their operating license itself. The bases for that, as
3 I mentioned before, were the procedures, the facilities
4 and their technical specifications and people are
5 qualified. We also issue the license only after we
6 assure that they will comply with our regulations and
7 that they have the greatest margin to any safety
8 problems after they are licensed.
9 Our inspection program in addition to licensing
10 ensures that Palo Verde maintains acceptable design
11 safety margins when they make changes to those original
12 designs. We also make sure that they identify and
13 adequately address problems that may come up during the
14 operation of the plant, and it could impact that safety
15 margin. We also make sure that they maintain the
16 qualifications of those individuals in the control room
17 that operate the plant.
18 Our inspection program is part of something we
19 call reactive oversight process. It includes three
20 inspectors who are stationed here at the Palo Verde
21 plant. They operate and inspect full time. They work
22 out of an NRC field office at the plant. In fact, we
23 have NRC field offices at every nuclear plant in the
24 United States.
25 In addition to these inspections, we conduct

1 MR. MALLETT: -- not a champion. Our chairman,
2 Commissioner Diaz, has changed our mission statement to
3 indicate, although we are a regulator, we have to be an
4 enabler of nuclear power so we don't throw up a
5 hindrance unnecessarily. We don't promote, but we
6 shouldn't throw abandon. So there is a change in our
7 mission statement.
8 Our agency's mission is to ensure nuclear plants
9 like the Palo Verde nuclear plant are operated safely
10 and securely in a manner that protects the public health
11 and safety. We also ensure that they are adequately
12 prepared for emergencies and operate such that they
13 protect the environment.
14 We carry out this mission by two functions,
15 basically licensing facilities to operate, and the
16 second function is inspecting them during the operation.
17 We also evaluate and test the adequacy of qualifications
18 of licensed operators in the control room in the
19 facility to actually operate the controls.
20 We only license nuclear plants to operate after
21 exhausting reviews of the proposed design and after we
22 determine that their procedures, people and their
23 facilities are adequate to protect the public health and
24 safety.
25 After issuance of the license to operate, we

1 plant. So we thought it was important to bring him
2 along to answer some of your questions.
3 I have to my right, who has already been
4 introduced by Commissioner Mayes, Victor Dricks. Victor
5 Dricks is in our public affairs office in the Region IV
6 Office of the Nuclear Regulatory Commission.
7 Our office is one of our four regional offices
8 in the country. As Commissioner Mayes says, we cover
9 the licensing and inspection of the nuclear facilities
10 for everything west of the Mississippi in the United
11 States, so we have a rather large territory that we
12 cover by our office. We are located in Arlington,
13 Texas, and our regulation includes oversight of nuclear
14 facilities like the Palo Verde nuclear plant.
15 At your request we are here to provide you
16 information specific to the operation of that nuclear
17 plant. Before we respond to your questions, I would
18 like to provide you a brief overview of the role in the
19 regulatory commission, how we assess the performance of
20 commercial nuclear plants like Palo Verde and what our
21 mission is. And I think this will address some of the
22 opening statements which you made.
23 I would make a comment, which is dangerous, but
24 the comment we are a regulator and, your words --
25 CHMN. HATCH-MILLER: Not a champion.

1 job to champion the nuclear power, it was yours to
2 regulate nuclear power.
3 And with that said and knowing that's the case,
4 as a Commissioner, as someone who was chairman of the
5 Energy Committee in the House of Representatives and now
6 a member of the Corporation Commission, I do believe
7 that nuclear power is not only essential to the current
8 health of our ability to provide electricity in Arizona
9 but the future health. And so I am looking forward to
10 this discussion as perhaps a step in the long-term, in
11 the -- I am looking forward to this meeting because I
12 believe that in the long term Arizona is going to have
13 to consider additional nuclear assets as part of its mix
14 of providers of electricity to this state.
15 So with that said, Mr. Mallett, the meeting is
16 yours.
17 MR. MALLETT: Thank you.
18 Can hear me all right?
19 Good afternoon. My name is Bruce Mallett. I am
20 the regional administrator in our Region IV Office in
21 the Nuclear Regulatory Commission.
22 I have with me, to my left is Troy Pruett.
23 Mr. Pruett is our branch chief of what we call our
24 projects branch in the region. This branch has
25 oversight for the inspection of the Palo Verde nuclear

1 Palo Verde this year. By my count one unit of Palo
2 Verde has been down at least 13 times, has been forced
3 into unscheduled outages 13 times this year. And every
4 time Palo Verde goes down for one of those unscheduled
5 outages, it costs Arizonans a lot of money, literally
6 hundreds of thousands of dollars a day. So we know that
7 it costs Arizonans money. We know that there are safety
8 concerns whenever, you know, Palo Verde, sometimes when
9 Palo Verde has to be shut down. And we want and need
10 the nation's largest nuclear power plant to be operating
11 safely and efficiently.
12 So I am looking forward to being able to ask the
13 NRC a number of questions, especially questions
14 regarding how the NRC goes about ordering a shutdown, if
15 it has to order a shutdown of the power plant, when it
16 doesn't do that, and how it works with APS in resolving
17 some of these issues.
18 CHMN. HATCH-MILLER: Well said by all the
19 members. And I had the luxury a month or two ago to
20 attend the same meeting with one of your commissioners.
21 And we happened to have lunch together and we had other
22 opportunity to talk.
23 But when he did make his presentation I was
24 shocked when he said that the Nuclear Regulatory
25 Commission did not support nuclear power, it wasn't your

1 This meeting, as was earlier described, is part
2 of our oversight authority. We will be able to learn, I
3 hope, in detail some of the reasons why the Palo Verde
4 facility continues to have problems and has had to be
5 shut down. And so I will look forward to the
6 presentation and the discussion that we are going to
7 have here today.
8 Thank you, Mr. Chairman.
9 CHMN. HATCH-MILLER: Commissioner Gleason.
10 COM. GLEASON: Thank you, Chairman. I am sure
11 everybody is more interested to listen to the people
12 from NRC than they are from me. Let's go.
13 CHMN. HATCH-MILLER: Great.
14 Commissioner Mayes.
15 COM. MAYES: I will try to be brief, too.
16 Welcome to the folks from the NRC, especially Victor
17 Dricks who is sitting on the end. Victor and I actually
18 worked together for two years at the Phoenix Gazette
19 when I was just a cub reporter and he was a grizzled
20 veteran. And so I welcome him in particular. He was a
21 great reporter and now he is the face and voice of the
22 NRC for all of the United States west of the
23 Mississippi.
24 I agree this is an important hearing. Palo
25 Verde, we are all very concerned with the performance of

1 hand, there are nuclear assets around the country that
2 have performed very well. And if you look at the fact
3 that those costs have already been paid, they are now
4 providing energy, with the rising natural gas rates,
5 very economically and effective for ratepayers.
6 And so we want to do everything we can to ensure
7 that the nuclear assets over which we have jurisdiction
8 perform well to benefit the economy in the state, the
9 people of the state and the ratepayers and hold costs
10 down. There are many technical, operational,
11 engineering and then there are the economic issues. But
12 it is an issue that we need to talk very frankly about
13 to provide for the future of our energy in this country.
14 And I very much look forward to that discussion, Mr.
15 Chairman. Thank you.
16 CHMN. HATCH-MILLER: Thank you.
17 Commissioner Mundell.
18 COM. MUNDELL: Thank you, Mr. Chairman.
19 Just briefly, I would echo my colleague's
20 comments and also say that this is truly a historic
21 meeting. I don't recall it ever having occurred before.
22 I know it hasn't occurred, a meeting with the NRC, in
23 the six years that I have been on the Commission. So I
24 want to thank you and welcome you for coming here today
25 to educate and enlighten us.

1 gas, is convening a summit in Iran on the nonexistence
2 of the Holocaust. Russia is terminating or curtailing
3 natural gas supplies to western Europe. Hamas won an
4 election yesterday to represent the Palestinian
5 authority. And all of these are very troubling global
6 issues with regard to energy at a time when we are
7 already in a state of crisis. So a number of eyes are
8 turning to nuclear energy.
9 I was a student in Pennsylvania College 20 miles
10 upwind from Three Mile Island in 1979. So I have a very
11 distinct memory of the Three Mile Island issue. And
12 since then we haven't had any movement on nuclear. And
13 I know that the Congress and those in the industry are
14 turning to that issue.
15 So I am, although I will have to depart shortly,
16 I am very interested in the role of the NRC in terms of
17 future deployment. And then from a regulatory ratepayer
18 oversight, we have facilities that have been in place
19 for some time. They have various degrees of operational
20 success, or lack thereof.
21 The facility in Long Island, the Shoreman
22 facility, caused the bankruptcy of Long Island Lighting
23 Company, LILCO. Other, there have been other issues;
24 the Davis-Besse plant in Ohio, major economic problems
25 arising from the record of that plant. But on the other

1 It has become such a major issue with energy
2 that it is now, where it was formerly sleepy, backwater,
3 the energy regulation at the state and federal level has
4 become top drawer and it is one of the top two or three
5 issues on the mind of the public anywhere you go. And
6 one of the major conundrums we have as a society to come
7 to deal with is where are we going to get the energy to
8 meet our needs. And there are pros and cons of all the
9 various sources.
10 Coal has been disfavored for air quality reasons
11 for 30 years now. And maybe there are new technologies
12 to deal with carbon emissions and mercury and CO and
13 carbon sequestration but these are very unproven
14 technologies, they are very expensive technologies. And
15 we are not actually sure carbon sequestration for sure,
16 we are not sure if it is going to work. And we know
17 that we have, we see a trend towards renewable energy to
18 some degree. We know it has got a cost. We know that
19 there are benefits. Natural gas was considered the
20 source of the future but we have had an unprecedented
21 run-up in natural gas that has caused anxiety all across
22 the country.
23 Add on to that events that are beyond our
24 control, where just in the last two days one of the
25 largest providers globally of fuel, both oil and natural

1 the Arizona Public Service. This is a, this is a
2 dialogue between us and the Nuclear Regulatory
3 Commission.
4 There will be approximately a one-hour
5 presentation, part questions and answers working with
6 the Nuclear Regulatory Commission. And then we will
7 follow that with a discussion and dialogue, with a
8 follow-up by Arizona Public Service Company. And it is
9 my expectation that you will be heading back to the
10 airport, or whatever your next stop is, as that begins.
11 And then of course there will be a conclusion to this
12 matter.
13 With that said, and again welcome, I want to
14 have Commissioner Spitzer begin with some opening
15 remarks.
16 COM. SPITZER: Thank you, Mr. Chairman. I
17 appreciate that. And we are appreciative of our friends
18 from the federal government having this. I know it is
19 rare, if not unprecedented, and I know it is something
20 very much appreciated. And I have some family
21 commitments, and the schedule this week has kind of been
22 chaotic so I will be departing shortly, but I am pleased
23 that we have a transcript that will be made available
24 for, frankly the public as well, and the Commission to
25 perform its oversight.

1 CHMN. HATCH-MILLER: The Commission is called to
2 order.
3 Welcome and good afternoon. This is a special
4 open meeting of the Arizona Corporation Commission held
5 on Thursday, January 26, 2006 at 1:00 p.m. We are in
6 the open meeting hearing room and we have an agenda
7 today that includes a fairly rare opportunity for us, an
8 opportunity to meet with our colleagues and somewhat
9 corollary agency at the federal level. And I am
10 particularly thankful that Mr. Bruce Mallett, the
11 Regional Administrator; Mr. Victor Dricks, the Public
12 Affairs Officer; and Troy Pruett, the Chief, Projects
13 Brand D Division of Reactor Projects. I guess he is
14 chief. So the chief is here.
15 We are very thankful to have you here and we
16 welcome you heartily.
17 Clearly we have always had a careful eye over
18 our nuclear facility to the west of our valley, Palo
19 Verde. That has been an ongoing relationship for years.
20 It continues to be something that we watch over
21 carefully. We appreciate that you are here to help us
22 educate and broaden our knowledge of that facility.
23 We have established an agenda, members. And the
24 agenda is set up so that this is not going to be a
25 dialogue between the Nuclear Regulatory Commission and

1 BE IT REMEMBERED that a presentation by the
2 Nuclear Regulatory Commission came on to be heard before
3 the Arizona Corporation Commission, in Hearing Room 1 of
4 said Commission, 1200 West Washington Street, Phoenix,
5 Arizona, commencing at 1:06 p.m. on the 26th of January,
6 2006.
7
8 BEFORE: JEFF HATCH-MILLER, Chairman
9 MARC SPITZER, Commissioner
WILLIAM A. MUNDELL, Commissioner
10 MIKE GLEASON, Commissioner
KRISTIN K. MAYES, Commissioner
11
12
13 APPEARANCES:
14
For the Nuclear Regulatory Commission:
15
Mr. Bruce S. Mallet, Regional Administrator
16 Mr. Troy W. Pruett, Chief, Projects Brand D Division
of Reactor Projects
17 Mr. Victor Dricks, Public Affairs Officer
18
19 For Arizona Public Service Company:
20 Mr. Jim Levine, Vice President, APS Generation
Mr. William Maledon, Attorney at Law
21
22
23
COLETTE E. ROSS
24 Certified Court Reporter
Certificate No. 50658
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1 AGENDA

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1 BEFORE THE ARIZONA CORPORATION COMMISSION

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NUCLEAR REGULATORY COMMISSION)
4 PRESENTATION) SPECIAL OPEN
) MEETING

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At: Phoenix, Arizona

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Date: January 26, 2006

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Filed:

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14 REPORTER'S TRANSCRIPT OF PROCEEDINGS

15 VOLUME I
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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
JEFF HATCH-MILLER, Chairman
WILLIAM A. MUNDELL
MIKE GLEASON
KRISTIN K. MAYES
BARRY WONG

IN THE MATTER OF THE INQUIRY INTO THE FREQUENCY OF UNPLANNED OUTAGES DURING 2005 AT PALO VERDE NUCLEAR GENERATING STATION, THE CAUSES OF THE OUTAGES, THE PROCUREMENT OF REPLACEMENT POWER AND THE IMPACT OF THE OUTAGES ON ARIZONA PUBLIC SERVICE COMPANY'S CUSTOMERS.	DOCKET NO. E-01345A-05-0826

REPORT OF

GDS ASSOCIATES, INC.

ON BEHALF OF

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

ATTACHMENTS 1 - 18

PUBLIC VERSION
REDACTED

August 17, 2006

ATTACHMENT 1

Palo Verde Nuclear Generating Station

Performance Improvement Plan ("PIP")

October 15, 2005

PALO VERDE NUCLEAR GENERATING STATION

PERFORMANCE IMPROVEMENT PLAN

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PART 2: TACTICAL ACTIONS TO IMPROVE PERFORMANCE

PALO VERDE NUCLEAR GENERATING STATION
PERFORMANCE IMPROVEMENT PLAN

This Performance Improvement Plan ("PIP") sets out clear direction for how performance improvement will be achieved at the Palo Verde Nuclear Generating Station ("Palo Verde"). The PIP will be a supplement to the 2006 Business Plan and is composed of two parts. Part 1 presents an assessment of performance at Palo Verde and provides a *strategic* overview of corresponding Palo Verde performance improvement activities. Part 2 provides *tactical* actions to achieve improved performance. Specifically, Part 1 identifies five Focus Areas for improvement and Part 2 provides associated Action Plans and Action Steps that will ensure improved performance. Part 2 of the PIP is a "living document" and will be revised and expanded as needed. A new organization will be put in place at Palo Verde to implement the PIP and focus on continuous improvement. This new organization is called the Performance Improvement Team ("PIT").

PART 1: STRATEGIC DISCUSSION

1.0 BACKGROUND

This section presents an assessment of recent performance at Palo Verde and concludes that Palo Verde continues to be operated in a prudent manner that protects the public health and safety. When assessing performance at a nuclear power plant different measures can be used. One measure is economic performance which is measured by production costs. Another measure is how well the plant is doing in implementing the various programs and processes that support the day-to-day operation of the plant. As discussed in more detail below, while the economic performance at Palo Verde continues to be at or near the top industry quartile there is a need for improvement in implementing programs and processes.

In late 2002 or early 2003 performance indicators at Palo Verde began a downward trend relative to the sustained high performance levels in previous years. A cause of this trend appears to have been the realignment of key site leadership that in turn caused the team to be more focused on day-to-day tactical matters, and less focused on strategic planning, standards and accountability. Additionally, in 2004, two significant events occurred at Palo Verde. They are the three unit trip in June 2004 that resulted from a grid disturbance and, the discovery, in July 2004, of the absence of water in portions of Emergency Core Coolant System piping ("RAS Sump Event"). These events also revealed issues with regard to various Palo Verde programs and processes that are in need of improvement.

Site leadership did not fully accept that the Palo Verde performance indicators reflected actual performance until mid 2005. Management's mindset resulted in part from ten previous years of Palo Verde operation at top quartile levels of performance. For

example, the Institute of Nuclear Power Operations ("INPO") awarded Palo Verde a 10 Year Excellence Award in 2004 after INPO had given Palo Verde top ratings for five consecutive INPO review cycles. Similarly, U.S. Nuclear Regulatory Commission ("NRC") performance indicators remained all green during this time, and successful inspections caused Palo Verde management and the workforce to be less receptive to declining performance indicators and resulting performance-based criticism. Moreover, Palo Verde is an industry leader in the efficient and economic production of power, as its production costs consistently rank in or near the top quartile relative to industry averages.

1.1 Indications of Performance

Data confirms that Palo Verde performed well from 1993 through most of 2002. This high level of performance was evident from such diverse performance indicators ("PIs") as Reactor Trips, Radiation Exposure, Preventable Recordable Injuries, Capacity Factor, Forced Outage Rate, Net Generation, Average Annual Refueling Time, Production Cost, and Staffing. In late 2002, certain PIs began a downward trend.

1.1.1 Monthly Trend Reports

The Palo Verde Monthly Trend Reports ("MTR") from 2003-2005 reflect a downward trend in performance indicators at Palo Verde. Each PI is given a color rating as follows:

Green – Significant Strength
White – Satisfactory
Yellow – Improvement Needed
Red – Significant Weakness

PI ratings over time are shown in the following table of Palo Verde Performance Indicators.

MTR Date	Green	White	Yellow	Red
December 2002	26	8	3	5
August 2003	14	13	6	10
December 2003	16	8	6	13
August 2004	14	8	2	18
December 2004	14	9	3	16
August 2005	13	15	1	13

This table demonstrates that PIs reflect a downward trend in performance beginning in the first half of 2003, that the trend continued through the last half of 2003, and bottomed in the latter half of 2004. Although the current 2005 MTR PIs show an improving trend as compared to the end of 2004, they confirm that Palo Verde's performance is not at the sustained high level of performance as in previous years.

1.1.2 Assessments

Throughout 2004 and 2005, several assessments were conducted at Palo Verde, many of which concluded that performance at Palo Verde had declined. Some of these assessments are listed below:

- Palo Verde Nuclear Generating Station Nuclear Safety Culture Assessment, ("Synergy"), April 2005
- INPO Mid-Cycle Self-Assessment Report, November 2004
- Utilities Service Alliance ("USA") Safety Culture Assessment, July 2004
- Supervisory Effectiveness Self-Assessment, March 2005
- Root Cause Expert Panel, Observations on Significant Investigation Process & RCEP Self-Assessment, March 2005
- 2005 WANO/INPO Peer Review Report, July 2005
- CRDR 2789716, Failure to Perform A 50.59 When Changing Plant Procedures To Leave The RAS Piping Dry
- CRDR 2780286 NRC Crosscutting issue: PI&R
- CRDR 2729600, Plant Response to RAS Events
- Independent Review of Palo Verde Performance, February 2005
- CRDR 2780273, NRC Crosscutting Issue: Human Performance
- NRC Annual Assessment Report (for 2004), March 2005
- NRC Mid-Cycle Performance Review and Inspection Plan, August 2005
- CRDR 2817300 re, "Operations Assessment of Corrective Actions Contained in CRDR 2729600, 'Station Response to Identification of Voided Emergency Core Cooling System Recirculation Piping', November 2005"
- Various Consultant Assessments

When the above assessments are viewed individually, they identify specific programs in need of attention. However, when these assessments are viewed collectively, they indicate common contributors that require a broader approach to assure improved performance. This conclusion is supported by the results of a streaming analysis and the resultant five Focus Areas discussed in Section 3.0 below.

1.2 The 2005 Business Plan

Based, in part, on the PIs, assessments and plant events occurring in 2004, the Palo Verde Senior Management Team developed and published a significant revision to the Palo Verde Business Plan in January 2005. The 2005 Business Plan represented a departure from traditional business plans of the past. The 2005 Business Plan listed four major focus areas for improving performance – Nuclear Safety, Behaviors, Generation Reliability and Cost. These focus areas are centered on the Palo Verde Mission of "*We will be the industry leader in the safe and efficient production of electricity through the values of: Trust, Clarity, Teamwork, Simplicity, Execution and Positive Attitude.*"

The 2005 Business Plan prioritized these four major focus areas into nine key strategic priorities:

(1) Regulatory Interface Improvements,

(2) Equipment Reliability Improvements,

(3) Leader Development,

(4) Improve Human Performance through Behaviors, Standards, and Expectations,

(5) Efficient Outages,

(6) Program Simplification,

(7) Industrial Safety,

(8) Staffing, and

(9) Communications.

The 2005 Business Plan also listed Level 1 Projects for each key strategic priority, and different groups of senior managers were assigned responsibility for developing the actions necessary to implement each of the nine key strategic priorities. Tactical Priorities were also listed in the 2005 Business Plan.

Subsequent to initial publication of the 2005 Business Plan, the Nuclear Assurance Department ("NAD") cited numerous examples of failure to follow procedures. The NRC also noted a number of examples of failure to follow procedures. Due to the frequency of findings regarding the failure to adhere to procedures, it became apparent that management had not been consistently holding itself and the workforce accountable for inadequate performance. As a result, Senior Management modified the 2005 Business Plan in April 2005 to replace *"Execution"* with *"Accountability"* as one of the mission statement values. Around this time, Senior Management also implemented mandatory departmental procedure stand down meetings emphasizing the need to get "back to basics" with regard to procedure use and adherence.

Although actions under the 2005 Business Plan appear to have reversed the downward trend in performance indicators relative to 2004, the actions have not resulted in Palo Verde's performance returning to the level of performance as in previous years. The 2005 Business Plan did not assure coordinated implementation of improvement initiatives, and targets associated with the 2005 Business Plan were not strictly adhered to. In addition, neither the key strategic priorities nor the tactical priority activities contained measures to confirm resolution of targeted issues. Also, no single person or organization was assigned to coordinate all activities. This resulted in a silo approach toward implementation of the 2005 Business Plan.

The PIP addresses the weaknesses related to the implementation of the 2005 Business Plan by communicating a clear roadmap of how performance improvement actions are determined, implemented, and how progress will be monitored. Through creation of the PIP, performance improvement activities have been separated from routine business

objectives so that the workforce can focus on daily plant issues, but also have a clear understanding of PIP objectives and their role in contributing to performance improvement at Palo Verde. Also, the PIP has designated Senior Management sponsors, the General Manager Regulatory Affairs and Plant Improvement and the Director PIT, who are responsible and accountable for ensuring that PIP objectives are met. The Director PIT also is responsible for ensuring that the workforce understands PIP objectives and their role in its implementation.

2.0 PERFORMANCE IMPROVEMENT ORGANIZATION

In order to achieve sustained, improved performance, and to do so with a renewed sense of urgency, the Executive Vice President Generation established a new organization at Palo Verde to supervise the implementation and completion of PIP activities and assist Senior Management in improving performance As discussed earlier, this organization is called the Performance Improvement Team. Additionally, in order to better align the station to support performance improvement, the Executive Vice President Generation reorganized the Palo Verde organization as illustrated in Appendix A to the PIP. The new organizational structure allows line managers to focus on day-to-day plant operation, while the PIT is responsible for overseeing performance improvement initiatives.

3.0 DEVELOPMENT OF FIVE FOCUS AREAS

As discussed in Section 1.0 above, there is a large volume of information on performance at Palo Verde. To better understand the interrelationship between this data and the causes underlying the performance reflected in this data, a team, using streaming analysis techniques, performed a review of this information.[1]

The streaming analysis process used by the team consisted of a vertical and horizontal evaluation component. The vertical evaluation involved: (1) reviewing, tabulating, and binning corrective action documents; Condition Report Disposition Requests ("CRDRs") and Condition Report Action Items ("CRAIs") into bin categories to determine which areas received the most focus during internal and external assessments ("what" statements) and (2) developing the apparent causes ("why" statements) from the bins.

The horizontal component of the streaming analysis looked for similarities between the bins with the most entries. The objective of this part of the review was to identify global corrective actions that would have the greatest performance improvement impact in multiple areas.

---

1 The team performing the streaming analysis included representatives from Nuclear Regulatory Affairs, Nuclear Assurance, Nuclear Fuel Management, the Senior Vice President Nuclear, the Executive Vice President Generation, the Plant Manager, other key internal personnel and an outside consultant with expertise in performance improvement strategy.

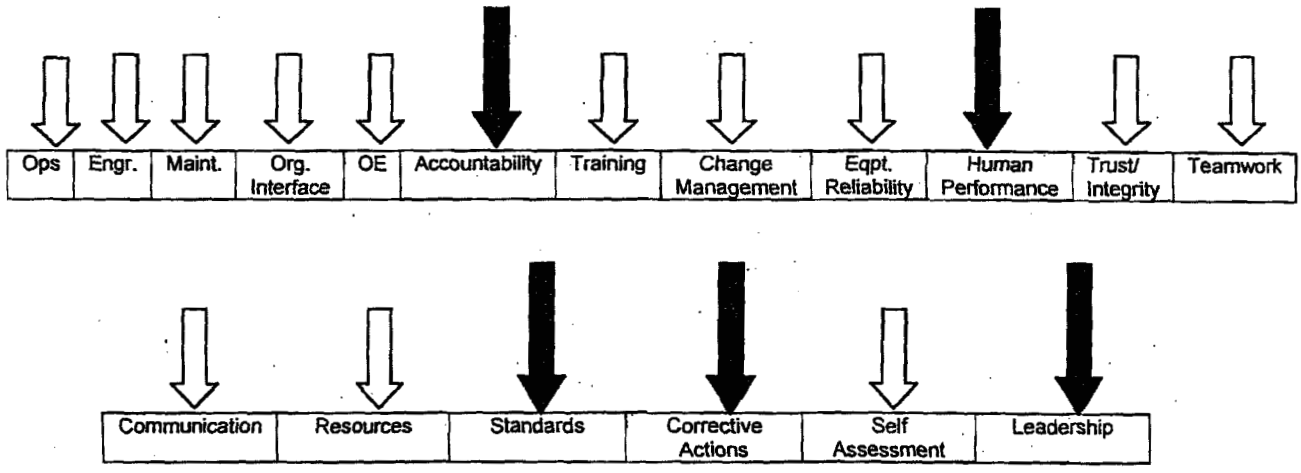
The team then developed corrective actions that corresponded with the horizontal evaluation-related "why" statements. Another team, that worked on the development of Part 2 of the PIP, then compared the corrective actions identified by the team that conducted the streaming analysis against already existing corrective actions in various CRDRs and CRAIs. This effort is reflected in Part 2 of the PIP, which is linked to the Corrective Action Program through CRDRs and CRAIs.

ILLUSTRATION OF STREAMING ANALYSIS PROCESS

Step 1: *Bin findings from review of source documents (grouping of "what" statements).*

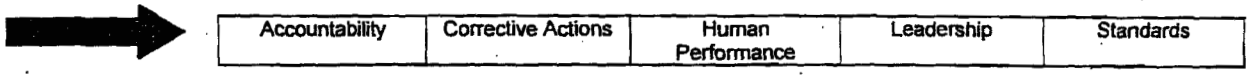
The streaming analysis team evaluated the previously referenced documents (See Part 1, Section 1.1.2 of the PIP) for the first step in the binning process.

Step 2: *Determine Most Populated Bins (⬇). These bins become the Focus Areas.*



Step 3: *Determine "why" for each entry into most populated bin.*

Step 4: *Perform Horizontal analysis of similar "why" statements among the bins.*



Step 5: *Determine necessary corrective actions for horizontal "why" statements. The common Step 4 "why" findings become Action Plans.*

Step 6: *Compare necessary corrective actions to actions already being taken (gap analysis).*

Step 7: *Initiate new corrective actions as necessary. These become Action Steps.*

The binning process highlighted five areas as having the most causal relationship to improved performance. The five Focus Areas are:

- Standards
- Accountability
- Leadership
- Human Performance
- Corrective Actions

The focus of the PIP is on these five Focus Areas which Palo Verde management believes are necessary for prompt and effective performance improvement. In Part 2 of the PIP, each of the five Focus Areas have corresponding Action Plans and Action Steps which in turn are linked to the Corrective Action Program through CRDRs or CRAIs.[2] For each Action Plan, Part 2 also identifies corresponding acceptance criteria.

The following provides a problem statement associated with each of the five Focus Areas.

3.1 Standards

The leadership team has not consistently held the organization to high standards. More directly stated, too many exceptions are made to well-known standards to more easily accommodate a current situation.

3.2 Accountability

Palo Verde leaders have not consistently held themselves and the workforce accountable for the implementation of and compliance with program and process requirements. Accountability must begin with the leadership team. A leader must hold himself or herself accountable to standards and expectations. Leaders must also hold the workforce accountable. Finally, individual employees must hold themselves and their co-workers accountable for individual performance improvement.

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[2] Two of the Focus Areas, Corrective Actions (i.e., PI&R) and Human Performance were also identified by the NRC as substantive cross cutting issues in the NRC's Annual Assessment Letter dated March 2, 2005. Corrective actions were developed for these Focus Areas as part of the reviews associated with Significant CRDR 2780286 NRC Crosscutting Issue: PI&R and Significant CRDR 2780273 NRC Crosscutting Issue: Human Performance, and they are included in Part 2 of the PIP.

3.3 Leadership

Palo Verde leaders have not consistently demonstrated fundamental leadership skills. These skills include clearly communicating standards of performance; leading by example with regard to those standards; maintaining focus on the Palo Verde mission, goals and objectives; engaging the workforce, and holding themselves and the workforce accountable for meeting expectations.

3.4 Human Performance

Human performance has been identified as a substantive crosscutting issue by the NRC. Significant CRDR 2780273 "NRC Crosscutting Issue: Human Performance" was written to address human performance deficiencies. The problem statement for this CRDR is: *"Palo Verde experienced an increase in human performance (HP) errors between 2001 and 2004.... Some of the human errors have resulted in human performance events. Palo Verde has not effectively communicated and addressed the underlying causes associated with this trend."*

3.5 Corrective Action Program/Problem Identification & Resolution ("PI&R")

PI&R has been identified as a substantive crosscutting issue by the NRC. Palo Verde has not, in all cases, adequately evaluated problems, developed corrective actions and assessed effectiveness such that issues are permanently resolved. Palo Verde has opened Significant CRDR 2780286 to address PI&R-related performance deficiencies. That CRDR adopts the NRC's problem statement from the NRC's March 2005 annual assessment letter *"The adverse trend in problem identification and resolution issues indicates that you have not effectively addressed the underlying causes associated with this substantive crosscutting area."*

Additionally, as new issues arise, they will be entered into the Palo Verde Corrective Action Program. The PIT will also continuously evaluate trends from the Corrective Action Program, as well as feedback from internal and external organizations or assessments to determine if the scope and emphasis of the PIP needs to be adjusted. In addition, the PIT will monitor MTR trends to ensure the PIP is having the desired result and whether additional actions are necessary.

4.0 REVISED Palo Verde MISSION STATEMENT

The 2005 Business Plan mission statement is:

> *"We will be the industry leader in the safe and efficient production of electricity through the values of: Trust, Clarity, Teamwork, Accountability, Simplicity, and Positive Attitude,"*

The current level of performance requires a change to the mission statement to better focus on the need for improved performance. The following new mission statement will be incorporated into the 2006 Business Plan:

> *Palo Verde Nuclear Generating Station employees will work as a team, with relentless dedication and focus, to promote high standards of performance, permanently correct problems, and maintain alignment to return Palo Verde to its position as the industry leader in the safe and efficient production of electricity. Our focus is not only on getting the job done, but getting the job done RIGHT the first time.*

5.0 ALIGNMENT OF PALO VERDE MISSION STATEMENT WITH THE PIP

The initial focus of the PIP is to ensure that the near and long-term goals of the leadership team are aligned with the mission statement. The first step in assuring alignment is the development and implementation of Leadership Standards and Expectations, a copy of which is attached to this PIP as Appendix B. These Leadership Standards and Expectations, along with the "Palo Verde Expectations and Standards" booklet set out the foundation for how business will be conducted at Palo Verde. The Leadership Standards and Expectations establish common behavior that will be expected of all leaders, dependent on their level within the organization. A major part of leader accountability will be whether leaders conduct themselves in accordance with these Standards and Expectations, and the Standards and Expectations will form the basis for how leader performance is measured.

In addition, all Palo Verde employees will be briefed on the PIP so that each individual has the opportunity to better understand what actions are being taken by management to improve performance, why they are being taken, and to better understand each individual's role in contributing to performance improvement.

6.0 PIP/BUSINESS PLAN RELATIONSHIP

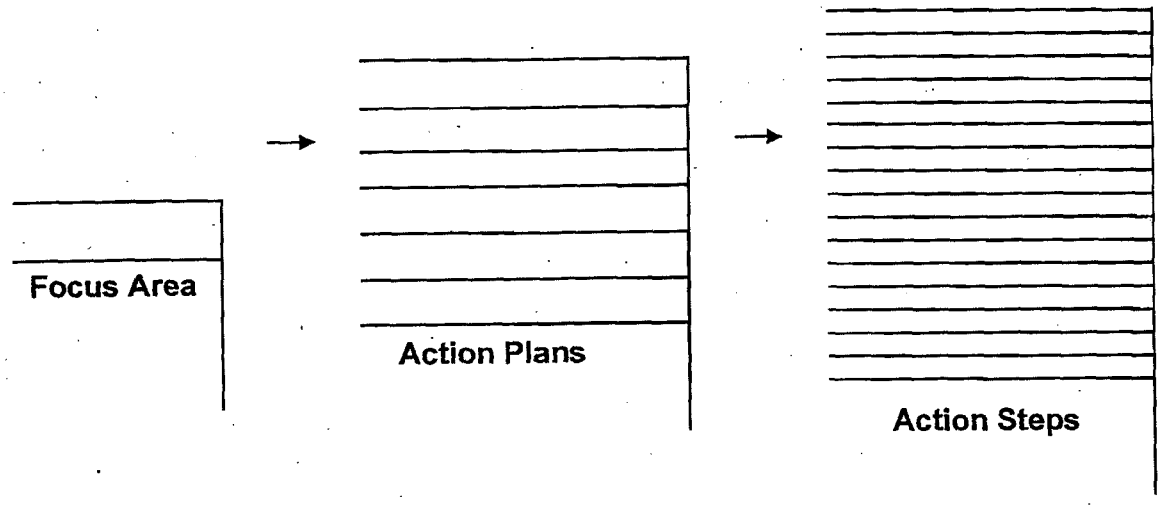
The PIP will be a supplement to the 2006 Business Plan. The 2006 Business Plan will be issued by December 1, 2005. The 2006 Business Plan will address more routine plant activities such as power production goals, capacity factor, and O&M and capital costs. The PIP focuses on actions necessary for improved performance. While some of these activities necessarily overlap (resources and budget), generally the 2006 Business Plan will be managed by the Senior Management Team. The PIP will be managed by the PIT. All Palo Verde personnel will be responsible for implementing aspects of both the 2006 Business Plan and the PIP. Performance improvement activities have been separated from routine business objectives so that the workforce can focus on daily plant issues, but also have a clear understanding of the objectives of the PIP and their role in contributing to performance improvement at Palo Verde.

As previously noted, PIP Focus Areas and Action Plans are being implemented to promptly improve performance. As performance improves, Part 2 of the PIP will be used

as a central document to capture and ensure coordination between new initiatives and ongoing Action Plans. The PIT will be a long-term organization, and the Director PIT will be responsible for working with the Palo Verde Business Plan "owners" to ensure coordination and efficiency of related efforts and to ensure continuous improvement at Palo Verde.

7.0 PIP IMPLEMENTATION

The following figure depicts how the five Focus Areas will be addressed through Action Plans, which in turn will contain more specific Action Steps. Each Action Plan will have corresponding acceptance criteria.



7.1 PIP Implementation Responsibilities

Every Palo Verde employee is responsible for improving performance at Palo Verde and the successful implementation of the PIP. Every member of the Senior Management Team is responsible for ensuring that adequate planning and resources are provided to implement the PIP successfully and in a timely manner. Other more specific responsibilities and accountabilities are described below.

7.1.1 Senior Vice President Nuclear

Responsible and accountable for the *strategic*-based implementation of PIP (Part 1) and is accountable for ensuring that PIP completion will result in the desired improvements in performance. Typically, performance improvement progress will be monitored, in part, through the use of appropriate performance indicators.

7.1.2 General Manager Regulatory Affairs and Plant Improvement

Responsible and accountable for ensuring that the Performance Improvement Team has the necessary resources and support so that PIP objectives can be met.

Responsible for chairing meetings of the Leadership Review Team ("LRT"). The purpose of the LRT is discussed in Section 7.9 below. Consults with the Senior Vice President Nuclear on strategy and setting priorities within the PIP. Responsible for monitoring PIP progress.

7.1.3 Director Performance Improvement Team

Responsible and accountable for day-to-day *tactical*-based implementation of PIP (Part 2), including PIP schedule adherence, and quality of closeout documents so that PIP objectives can be met. The Director PIT approves revisions/closure of Action Plans and recommends closure of Focus Areas to the LRT. The Director PIT, working with the Senior Management Team has the responsibility for reviewing the adequacy of the current PIs. The Director PIT also has the responsibility for the development, and recommendation for approval to the LRT, of a core group of PIP PIs for Palo Verde that are directly related to the PIP and provide key performance-based information regarding PIP implementation and performance improvement.

7.1.4 Focus Area Owner

Focus Area Owners report to the Director PIT and are responsible and accountable for ensuring on-time and effective implementation and completion of all Action Plans in an assigned Focus Area. As a result, a Focus Area Owner must stay apprised of the progress made by Action Plan Owners in the implementation of individual Action Steps.

7.1.5 Action Plan Owner

Individual who is responsible and accountable for ensuring the on-time completion of all Action Steps associated with an Action Plan. The Action Plan Owner must ensure that the Action Steps achieve the defined Action Plan objective and recommends closure of the Action Plan as discussed below in Section 7.7.

7.2 PIP Scheduling and Tracking

Action Steps are entered into and monitored by the Palo Verde Corrective Action Program and are included in the CRDR tracking system. A PIP implementation schedule will be developed for the implementation of overall PIP activities. CRDRs that are related to the PIP will be mile-stoned within the PIP implementation schedule. The PIP implementation schedule will be monitored by the Director PIT, Focus Area Owners and Action Plan Owners. The PIP implementation schedule will also be reviewed with the Palo Verde Senior Management Team as a part of PIP Progress Review Meetings.

7.3 Focus Areas

Focus Areas are those areas at Palo Verde in need of prompt and effective improvement. Improvement in a Focus Area is addressed through Action Plans, which in turn contain specific Action Steps.

7.4 Action Plans

Action Plans, which have defined acceptance criteria, document the primary Action Steps to address Focus Area problem statements. Action Steps, which are linked to the Corrective Action Program through CRDRs and CRAIs, are assigned to individuals and have firm start and finish dates.

7.5 Action Plan Revisions

The need may arise to modify an Action Plan to address emergent issues or to improve effectiveness. Action Plan revisions (*e.g.*, deletion of Action Steps, addition of Action Steps, and change in end dates) require approval by the Action Plan Owner, the Focus Area Owner, and the Director PIT prior to implementation. Regulatory Affairs Department reviews revisions that may impact NRC commitments.

7.6 Action Step Closure Process

The closure of each Action Step in an Action Plan will be accomplished in accordance with the Palo Verde Corrective Action Program.

7.7 Action Plan Closure Process

Following completion of the Action Steps associated with an Action Plan, the Action Plan Owner prepares a final closure report that provides justification for closure of the Action Plan. The Focus Area Owner reviews the closure report. If the Focus Area Owner agrees with the justification for closure of the Action Plan, then the Action Plan Owner and the Focus Area Owner sign the closure report and forward it to the Director PIT for review and approval. If the Focus Area Owner or the Director PIT do not agree with the recommendation for closure of an Action Plan, the reasons will be documented and appropriate actions to address identified concerns will be documented and taken. After the above reviews occur and necessary approvals received, NAD will conduct a final review of the closure of an Action Plan and associated Action Steps in accordance with the Corrective Action Program.

7.8 Focus Area Closure Process

Focus Areas, which are composed of multiple Action Plans, may be closed only when all associated Action Plans have been completed and approved in accordance with Section 7.7. LRT approval is also needed for the closure of a Focus Area.

7.9 Leadership Review Team

A newly formed Leadership Review Team evaluates performance improvement progress on a periodic basis to ensure adequacy of PIP implementation. The LRT is comprised of members of Palo Verde Senior Management who are the direct reports to

the Senior Vice President Nuclear.[3] Other senior managers or external consultants may be invited to participate in LRT activities; however, the responsibility of this team to oversee achievement of PIP objectives cannot be delegated. The LRT provides feedback to the PIT and assesses implementation of the Palo Verde mission statement consistent with leadership standards and expectations, as needed. The LRT approves PIP related PIs. The LRT approves Focus Area closures when requested by the Director PIT and Focus Area Owner and ultimately is the organization that recommends closeout of the PIP to the Executive Vice President Generation.

8.0 PERFORMANCE MONITORING & EFFECTIVENESS REVIEWS

Senior Management currently monitors overall performance at Palo Verde to ensure success and to prevent recurrence of performance deficiencies. Senior Management monitors performance through a variety of means including: status update meetings, performance indicators, self-assessments and NAD effectiveness reviews. NAD will perform effectiveness reviews associated with PIP activities in accordance with the Corrective Action Program. Options for monitoring overall performance at Palo Verde are discussed in more detail in Appendix C to the PIP.

9.0 PIP CLOSURE

After the LRT reviews Action Plan closure packages associated with the closure of a Focus Area, performance indicator assessments, NAD audit and assessment report results, and considers input from Senior Management meetings, the LRT may recommend PIP closure to the Executive Vice President Generation. Only the Executive Vice President Generation, however, may approve closure of the PIP.

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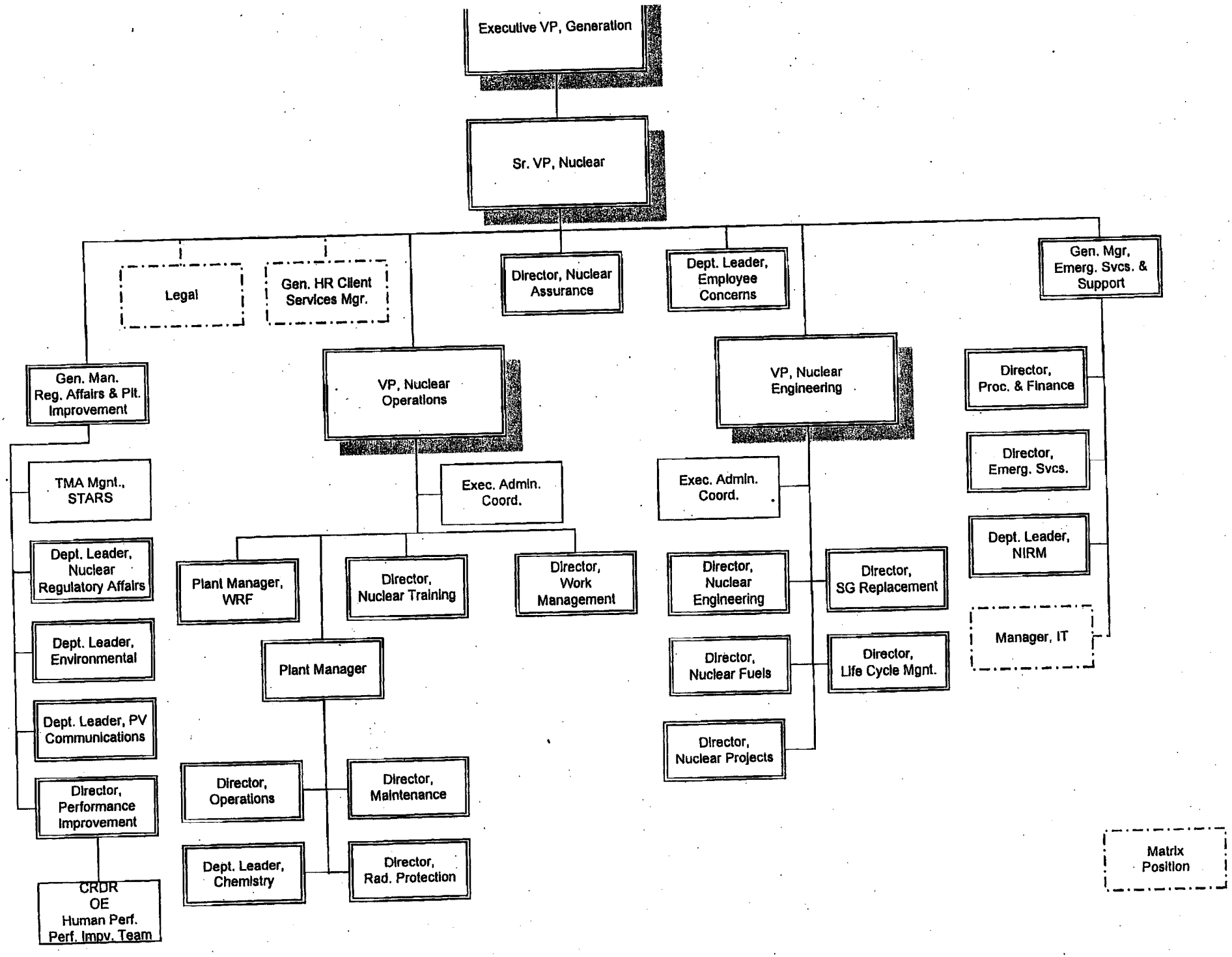
[3] The LRT will be comprised of the Vice President Operations, Vice President Engineering, General Manager Regulatory Affairs and Plant Improvement, General Manager Emergency Services and Support, Director Nuclear Assurance and the Department Leader Employee Concerns.

APPENDIX A

PALO VERDE NUCLEAR GENERATING STATION ORGANIZATIONAL CHART


Executive VP, Generation
Sr. VP, Nuclear
Legal
Gen. HR Client Services Mgr.
Director, Nuclear Assurance
Dept. Leader, Employee Concerns
Gen. Mgr, Emerg. Svcs. & Support
Gen. Man. Reg. Affairs & Plt. Improvement
VP, Nuclear Operations
VP, Nuclear Engineering
Director, Proc. & Finance
Director, Emerg. Svcs.
Dept. Leader, NIRM
Manager, IT
TMA Mgnt., STARS
Dept. Leader, Nuclear Regulatory Affairs
Dept. Leader, Environmental
Dept. Leader, PV Communications
Director, Performance Improvement
CRDR
OE
Human Perf.
Perf. Impv. Team
Exec. Admin. Coord.
Plant Manager, WRF
Director, Nuclear Training
Director, Work Management
Plant Manager
Director, Operations
Director, Maintenance
Dept. Leader, Chemistry
Director, Rad. Protection
Exec. Admin. Coord.
Director, Nuclear Engineering
Director, SG Replacement
Director, Nuclear Fuels
Director, Life Cycle Mgnt.
Director, Nuclear Projects
Matrix Position

APPENDIX B

LEADERSHIP STANDARDS AND EXPECTATIONS

Palo Verde Executive/Director
STANDARDS AND EXPECTATIONS

Palo Verde is engaged in an effort to return the site is to sustained high levels of performance. A key requirement for success is alignment of the leadership team and the absolute commitment of each leader to understand, accept, and demonstrate the standards and expectations listed below. Please review this document with your leader and sign this it, committing that your actions and behaviors will be conducted in accordance with these leader standards and expectations.

RESULTS ORIENTATION

Operational Excellence – *Proactively identifies and addresses conditions that might erode the reliability and availability of the plants, systems, or equipment, or that may erode the quality of products and services; hold self and others to high standards of quality.*

- Emphasize human performance with constant regard for Nuclear, Radiological, and Industrial Safety
- Achieve standards & expectations
- Own actions to resolve identified issues/problems per commitment
- Establish quality as the underlying requirement for all work

Drive for Results - *Proactively asserts influence over events to achieve goals, often taking action beyond what is required.*

- Create PVNGS mission and resource-loaded business plan with metrics as the cornerstone for site results
- Tenaciously pursue execution and closure
- Drive for simplicity and effectiveness
- Remove organizational barriers to site efforts
- Maintain Accountability-Confront non-performers/recognize key contributors

Improvement Seeking/Decision-Making/Problem-Solving - *Generates simple and creative solutions after identifying relevant facts and evaluating viable alternatives and their possible consequences.*

- Champion continuous improvement (across the site/all levels)
- Sponsor development in new technical/functional knowledge – promote benchmarking/use of external resources
- Question identified trends and assumptions using analysis, experience, wisdom, and judgment
- Do not allow Analysis Paralysis
- Fully utilize and support the Corrective Action Program
- Balance short-term priorities with long-term opportunities
- Address both site & enterprise needs in decision-making
- Simplify

Delegation - *Assigns appropriate decision-making and responsibility to appropriate individuals were team member.*

- Broadly share both responsibility and authority
- Assure common understanding when delegating
- Draw on talents/expertise of team members
- Establish timelines and milestones
- LET GO! … but monitor & give feedback

Planning/ Organizing/Time Management – *Develops of and manages a course of action for each of multiple projects and priorities while maintaining organization and effectiveness to completion.*

- Establish organization goals with metrics
- Assure that schedules are adhered to
- Identify and address conflicting issues and priorities
- Require contingency plans
- Assure that resources are used effectively toward site goals
- Optimize meetings

RESULTS ORIENTATION (CONTINUED)

Financial Management/Resource Effectiveness - *Analyzes cost information, and develops alternatives, then pursues courses of action that save on costs (or other resources) while maintaining high levels of performance and reliability.*

- Understand how site performance impacts financial side of the company and vice versa
- Set and maintain appropriate budget levels based on the business plan
- Integrate site work/project budgets so that overall site remains on or under budget
- Prioritize and allocate funds

LEADERSHIP BEHAVIORS

Courage & Integrity – *Takes personal responsibility for one's actions.*

- Voice opinions, questions, agreement, or disagreement immediately – be in the game
- Challenge what isn't right and the "status quo"
- Be accountable - Own your part and the overall site plan
- Seek out those with differing opinions - commit to what's right for the site (Common Purpose)
- Assure full compliance with company/site procedures and policies (ethics, etc)

PV Values, Standards, and Goals – *Words, actions, and decisions are consistent with and promote PV Values, Standards, and Goals.*

- Stay abreast of industry and regulator trends and adjust strategies & objectives accordingly
- Develop the vision; get input; create objectives, expectations, and metrics; then share with your people and implement
  - Accept nothing less than full compliance with expectations
  - Reinforce with employees at every opportunity
  - Monitor metrics and adjust strategies to achieve goals
- Make the tough decisions that support PV Values
- Demonstrate & reinforce PV Values daily

Communications and Interpersonal Skills – *Critically listens and effectively communicates; Values and respects the need of others for inclusion, for being heard, and for having access to information.*

- Ask questions rather than direct to assess level of understanding, develop decision skills, or show respect for employee input/capability
- Involve those who are stakeholders
- Follow-thru with communications, respecting the needs & resources of others
- Validate that the info you receive is correct
- Do it face-to-face or by phone, avoid e-mail whenever possible
- Watch for shifts to silence or violence in yourself or others – address it!
- Recognize the significance of changes – assure that appropriate change management approach is used
- Stop and listen to employees voicing ideas or concerns.
  - Promptly try to resolve the issue and discuss with employee
  - If you cannot resolve it, help bring it to the right person/level
- Demonstrate on-going interest in employee welfare

Teamwork/Relationship Management – *Works effectively with others throughout the organization to accomplish PV goals and to identify and resolve issues.*

- Be a strong and reliable team member – demand the same of others
- Insist that each employee deliver as expected
- Challenge resistance and do not tolerate disrespect
- Listen to show you value others
- Share credit publicly, blame privately
- Assure that the leadership team is unified – from peers to DL, SL, and TL

LEADERSHIP BEHAVIORS (CONTINUED).

Performance Management - *Sets and delivers on challenging goals and expectations in alignment with organizational priorities, tracks results, promptly provides both positive and constructive feedback, and initiates necessary development.*

- Demonstrate Accountability through your actions – As Promised, When Promised – No Surprises
- Create a shared understanding of how the job will be done
- Get agreement to accountabilities
- Address poor performance early and firmly
- Assure person responsible learns from missed accountabilities
- Insist on behaviors that promote team success
- Maintain high standards and perception of fairness – define & calibrate high standards for high ratings
- Assure all leaders meet the requirements of this document

Developing/Inspiring Others - *Uses appropriate styles to coach, inspire, and guiding employees to achieve goals. Identifies employee strengths/weaknesses and provides feedback and support to improve and sustain performance*

- Implement and manage Succession Plan for Director & DL levels
- Accelerate development of high-performing employees
  - Delegate projects/responsibilities to employees for grooming
  - Identify specific development expected when placing employees on special assignments
- Identify employee-specific motivators to increase ownership
- Mentor for increased performance and flexibility
- Cross train to broaden their experience and develop potential
- Evaluate ways to increase creativity for tasks and process improvement
- Engage uniquely skilled employees in knowledge transfer accountabilities to assure continuity of required capability
- Recognize noteworthy individual and team contribution: use rewards as appropriate
- Establish development as a necessary part of dept. operations

Stay In Your Role/Play Your Part – *Maintains the proper strategic focus, employee engagement, and tactical (technical/problem-solving) involvement for assigned role; Respects the ability of others to fulfill their role.*

- KEEP YOUR HEAD UP; Maintain a high-level perspective by:
  - Identify/Evaluate leading indicators and initiative timelines
  - Sr. Team planning and initiatives
  - Assuring planned objectives and site commitments are met
- Display a positive attitude
- Get out and engage employees by listening, coaching and being accessible & visible to employees
- Move decisions to lower levels to develop employee skills, demonstrate confidence, maintain your own independent thought and coach decision process as needed
- Continuously challenge for improvement and alignment with site values & goals
- Follow-up on assignments
- Maintain an achievable schedule

As a member of the Palo Verde Leadership Team,
I am committed to meet the standards and expectations listed in this document.

_____	_____	_____
Leader	Date	One-over Signature

Palo Verde Department Leader
STANDARDS AND EXPECTATIONS

Palo Verde is engaged in an effort to return the site is to sustained high levels of performance. A key requirement for success is alignment of the leadership team and the absolute commitment of each leader to understand, accept, and demonstrate the standards and expectations listed below. Please review this document with your leader and sign it, committing that your actions and behaviors will be conducted in accordance with these leader standards and expectations.

RESULTS ORIENTATION

Operational Excellence – *Proactively identifies and addresses conditions that might erode the reliability and availability of the plants, systems, or equipment, or that may erode the quality of products and services; hold self and others to high standards of quality.*

- Reinforce focus on human performance with constant regard for Nuclear, Radiological, and Industrial Safety
- Monitor operation for compliance to standards & expectations
- Work with leaders/others to resolve identified issues/problems per commitment
- Establish quality as the underlying requirement for all work

Drive for Results - *Proactively asserts influence over events to achieve goals, often taking action beyond what is required.*

- Develop resource-loaded departmental plan with metrics to assure efforts are aligned with site objectives
- Tenaciously pursue execution and closure
- Drive for simplicity and effectiveness
- Removes organizational barriers to department efforts
- Maintain Accountability-Confront non-performers/recognize key contributors

Improvement Seeking/Decision-Making/Problem-Solving - *Generates simple and creative solutions after identifying relevant facts and evaluating viable alternatives and their possible consequences.*

- Demonstrate continuous improvement (your dept.)
- Prioritize & Budget for development of employees in new technical/functional knowledge
- Decisions involve others using analysis, experience, wisdom, and judgment
- Conduct risk analysis for various courses of action
- Avoid Analysis Paralysis – use formal decision tools as able
- Fully utilize and support the Corrective Action Program
- Balance short-term priorities with long-term opportunities
- Consider site view in decision-making
- Simplify to minimize resource demands

Delegation - *Assigns appropriate decision-making and responsibility to appropriate individuals.*

- Obtain input and place ownership for execution at the appropriate level
- Assure common understanding when delegating
- Establish timelines and milestones
- Trust people to perform, but monitor & give feedback

Planning/ Organizing/Time Management – *Develops and manages a course of action for each of multiple projects and priorities while maintaining organization and effectiveness to completion.*

- Align departmental objectives with organization goals – assure leaders understand connection to site goals
- Assure execution of scheduled department commitments
- Identify and address conflicting issues and priorities
- Anticipate roadblocks and oversee contingency plans
- Direct that resources are used effectively toward site goals

RESULTS ORIENTATION (CONTINUED)

Financial Management/Resource Effectiveness - *Analyzes cost information and develops alternatives, then pursues courses of action that save on costs (or other resources) while maintaining high levels of performance and reliability.*

- Know how operations impacts financial side of the site
- Develop appropriate department budgets based on the business plan
- Seek cost saving ideas from others
- Deliver overall department work/projects on or under budget
- Define departmental overtime expectations
- Evaluate and justify funding for proposed emergent work

LEADERSHIP BEHAVIORS

Courage & Integrity – *Takes personal responsibility for own actions.*

- Voice questions, agreement, or disagreement promptly
- Challenge what isn't right and the "status quo"
- Be accountable - Own your part and the overall dept. plan
- Seek out those with differing opinions - commit to Common Purpose
- Assure fully compliance with company/site procedures and policies (ethics, etc)

PV Values, Standards, and Goals – *Words, decisions, and actions are consistent with and promote PV Values, Standards, and Goals.*

- Understand the vision, framework and general expectations, then share with your people and assure their commitment
  - Accept nothing less than full compliance with expectations
  - Reinforce with employees at every opportunity
  - Manage work to achieve metrics goals
- Make the tough decisions that support our Values
- Demonstrate & Reinforce PV Values daily

Communications and Interpersonal Skills – *Critically listens and effectively communicates; Values and respects the need of others for inclusion, for being heard, and for having access to information.*

- Ask questions rather than direct to assess level of understanding, develop decision skills, or show respect for employee input/capability
- Involve those who are stakeholders
- Follow-thru with communications, respecting the needs & resources of others
- Validate that the info you receive is correct
- Do it face-to-face or by phone, avoid e-mail whenever possible
- Watch for shifts to silence or violence in yourself or others – address it!
- Recognize the significance of changes – assure that appropriate change management approach is used
- Stop and listen to employees voicing ideas or concerns.
  - Promptly try to resolve the issue and discuss with employee
  - If you cannot resolve it, help bring it to the right person/level
- Demonstrate on-going interest in employee welfare

Teamwork/Relationship Management – *Works effectively with others throughout the organization to accomplish PV goals and to identify and resolve issues.*

- Be a strong and reliable team member – demand the same of others
- Insist that each employee deliver as expected
- Challenge resistance and do not tolerate disrespect
- Listen to show you value others
- Share credit publicly, blame privately
- Assure that the leadership team is unified – SLs and TLs are all on the same page

LEADERSHIP BEHAVIORS (CONTINUED)

Performance Management - *Sets and delivers on challenging goals and expectations in alignment with organizational priorities, tracks results, promptly provides both positive and constructive feedback, and initiates necessary development.*

- Demonstrate Accountability through your actions – As Promised, When Promised– No Surprises
- Create a shared understanding of how the job will be done
- Get agreement to accountabilities
- Address poor performance early and firmly
- Assure person responsible learns from missed accountabilities
- Insist on behaviors that promote team success
- Maintain high standards and perception of fairness – define & calibrate high standards for high ratings
- Assure all leaders meet the requirements of this document

Developing/Inspiring Others - *Uses appropriate styles to coach, inspire, and guide employees to achieve goals. Identifies employee strengths/weaknesses and provides feedback and support to improve and sustain performance.*

- Accelerate development of high-performing employees
  - Delegate projects/responsibilities to employees for grooming
  - Identify specific development expected when placing employees on special assignments
- Identify employee-specific motivators to increase ownership
- Mentor for increased performance and flexibility
- Cross train to broaden their experience and develop their potential
- Evaluate ways to increase creativity for tasks and process improvement
- Engage uniquely skilled employees in knowledge transfer accountabilities to assure continuity of required capability
- Recognize noteworthy individual and team contribution; use rewards as appropriate
- Provide the planning and time necessary for development

Stay In Your Role/Play Your Part – *Maintains the proper strategic focus, employee engagement, and tactical (technical/problem-solving) involvement for assigned role; Respects the ability of others to fulfill their role.*

- Display a positive attitude
- Maintain focus on department goals but with a site-wide perspective. Emphasize:
  - Managing leading indicators and initiative timelines
  - Engaging leaders and employees – listening and coaching
  - Effective work planning and execution of initiatives
  - Assure department commitments are met
- Engage in decision-making with leaders in your group, as well as appropriate peers, specialists from other groups.
- Delegate responsibility for your effectiveness and for employee development/confidence
- Continuously challenge for improvement and alignment with site values & goals
- Follow-up on assignments
- Maintain an achievable schedule

As a member of the Palo Verde Leadership Team,
I am committed to meet the standards and expectations listed in this document.

_____	_____	_____
Leader	Date	One-over Signature

Palo Verde Section/Team Leader
STANDARDS AND EXPECTATIONS

Palo Verde is engaged in an effort to return the site is to sustained high levels of performance. A key requirement for success is alignment of the leadership team and the absolute commitment of each leader to understand, accept, and demonstrate the standards and expectations listed below. Please review this document with your leader and sign it, committing that your actions and behaviors will be conducted in accordance with these leader standards and expectations.

RESULTS ORIENTATION

Operational Excellence – *Proactively identifies and addresses conditions that might erode the reliability and availability of the plants, systems, or equipment, or that may erode the quality of products and services; hold self and others to high standards of quality.*

- Maintain optimal human performance with constant regard for Nuclear, Radiological, and Industrial Safety
- Verify employee compliance to standards & expectations
- Work with employees to resolve identified issues/problems per commitment
- Assure that workers take the time to do it right the first time

Drive for Results - *Proactively asserts influence over events to achieve goals, often taking action beyond what is required.*

- Consistently achieve objectives of department plan in support of site objectives
- Tenaciously pursue execution and closure
- Assures process simplicity and effectiveness
- Removes barriers to employee efforts
- Maintain Accountability-Confront non-performers/recognize key contributors

Improvement Seeking/Decision-Making/Problem-Solving - *Generates simple and creative solutions after identifying relevant facts and evaluating viable alternatives and their possible consequences.*

- Continually strive to improve performance/process
- Assign development to employees in new technical/functional knowledge
- Use combination of analysis, experience, wisdom, and judgment to arrive at a solution or decision
- Identify/provide all relevant data for higher level decisions
- Be prepared to act promptly when decisions are finalized
- Fully utilize and support the Corrective Action Program
- Consider department/work plan and achievement of site objectives in decision-making
- Generate simpler alternative solutions

Delegation - *Assigns appropriate decision-making and responsibility to appropriate individuals were team member.*

- Plan/assign work, monitor progress to hold staff accountable
- Assure common understanding when assigning work
- Solidify employee accountability for projects/tasks with timelines and milestones
- Trust people to perform, but monitor & give feedback

Planning/ Organizing/Time Management – *Develops of and manages a course of action for each of multiple projects and priorities while maintaining organization and effectiveness to completion.*

- Align daily activities with department objectives with overall objective of achieving higher site goals
- Assure completion of work as scheduled in work plan
- Identify and address conflicting issues and priorities
- Anticipate roadblocks and develop contingency plans
- Use resources effectively and efficiently toward site goals

RESULTS ORIENTATION (CONTINUED)

Financial Management/Resource Effectiveness - *Analyzes cost information, and develops alternatives, then pursues courses of action that save on costs (or other resources) while maintaining high levels of performance and reliability.*

- Know how operations impacts financial side of the site
- Allocate resources effectively
- Manage to budget levels in dept. budget
- Seek cost saving ideas from others
- Deliver work/projects on or under budget
- Ensure overtime limitations are met
- Identify and elevate emergent work for funding

LEADERSHIP BEHAVIORS

Courage & Integrity – *Takes personal responsibility for one's actions.*

- Voice questions, agreement, or disagreement promptly
- Challenge what isn't right and the "status quo"
- Be accountable - Own your part and the overall dept. plan
- Recognize those with differing opinions - commit to Common Purpose
- Fully comply with company/site procedures and policies (ethics, etc)

PV Values, Standards, and Goals – *Words, actions, and decisions are consistent with and promote PV Values, Standards, and Goals.*

- Understand how the vision, framework and general expectations impact your group - share with your people and seek their commitment
  - Reinforce with employees at every opportunity
  - Accept nothing less than full compliance with expectations
  - Direct work in support of metrics goals
- Make the tough decisions in keeping with PV Values to achieve PV Goals
- Demonstrate & Reinforce PV Values daily

Communications and Interpersonal Skills – *Critically listens and effectively communicates; Values and respects the need of others for inclusion, for being heard, and for having access to information.*

- Ask questions rather than direct to assess level of understanding, develop decision skills, or show respect for employee input/capability
- Involve those who are stakeholders
- Follow-thru with communications, respecting the needs & resources of others
- Validate that the info you receive is correct
- Do it face-to-face or by phone, avoid e-mail whenever possible
- Watch for shifts to silence or violence in yourself or others – address it!
- Recognize the significance of changes – use appropriate change management approach
- Stop and listen to employees voicing ideas or concerns.
  - Promptly try to resolve the issue and discuss with employee
  - If you cannot resolve it, help bring it to the right person/level
- Demonstrate on-going interest in employee welfare

Teamwork/Relationship Management – *Works effectively with others throughout the organization to accomplish PV goals and to identify and resolve issues.*

- Be a strong and reliable team member – demand the same of others
- Insist that each employee deliver as expected
- Challenge resistance and do not tolerate disrespect
- Listen to show you value others
- Share credit publicly, blame privately
- Assure that you are unified with the direction of the leadership team.

LEADERSHIP BEHAVIORS (CONTINUED)

Performance Management - *Sets and delivers on challenging goals and expectations in alignment with organizational priorities, tracks results, promptly provides both positive and constructive feedback, and initiates necessary development.*

- Demonstrate Accountability through your actions – As Promised, When Promised– No Surprises
- Create a shared understanding of how the job will be done
- Get agreement to accountabilities
- Address poor performance early and firmly
- Assure person responsible learns from missed accountabilities
- Insist on behaviors that promote team success
- Maintain high standards and perception of fairness – define & calibrate high standards for high ratings
- Assure all leaders meet the requirements of this document

Developing/Inspiring Others - *Uses appropriate styles to coach, inspire, and guiding employees to achieve goals. Identifies employee strengths/weaknesses and provides feedback and support to improve and sustain performance*

- Accelerate development of high performing employees
  - Delegate projects/responsibilities to employees for grooming
  - Identify specific development expected when placing employees on special assignments
- Identify employee-specific motivators to increase ownership
- Mentor for increased performance and flexibility
- Cross train to broaden their experience and develop their potential
- Evaluate ways to increase employee creativity for tasks and process improvement
- Engage uniquely skilled employees in knowledge transfer accountabilities to assure continuity of required capability
- Recognize noteworthy individual and team contribution; use rewards as appropriate
- Effectively utilize the time allocated for development

Stay In Your Role/Play Your Part – *Maintains the proper strategic focus, employee engagement, and tactical (technical/problem-solving) involvement for assigned role; Respects the ability of others to fulfill their role.*

- Display a positive attitude
- Maintain focus on work-group goals but with recognition of overall site-wide objectives. Emphasize:
  - Effective execution of planned work and other initiatives
  - Oversee employee activities, provide feedback & raise standards
  - Assure group commitments are met
- Engage employees in decision-making to develop employee skills, demonstrate confidence, increase ownership, and broaden your perspective.
- Delegate responsibility for your effectiveness and for employee development/confidence
- Continuously challenge for improvement and alignment with site values & goals
- Follow-up on assignments

As a member of the Palo Verde Leadership Team,
I am committed to meet the standards and expectations listed in this document.

_____	_____	_____
Leader	Date	One-over Signature

APPENDIX C

Palo Verde PERFORMANCE MONITORING OPTIONS

The following options will be used to monitor overall performance at Palo Verde.

Status Update Meetings:

The following key meetings will be held at Palo Verde:

- 9:00 AM Plant Status Meeting--This meeting, which is chaired by the Senior Vice President Nuclear, will be held every Tuesday, Wednesday, Thursday, and Friday at 9 a.m. Attendees will include the direct reports to the Senior Vice President Nuclear, the Vice President Nuclear Operations, the Vice President Nuclear Engineering and certain other designated members of the Senior Management Team. If a regular attendee is unable to attend the meeting, then an alternate should be designated to attend. The purpose of the meeting is to discuss plant status, provide a forum for presentations to the Senior Management Team, and allow for the discussion of other station-related events and issues.

- PIP Progress Review Meeting--This meeting, which is chaired by the Senior Vice President Nuclear, will be held every Thursday at 10 a.m. However, depending on the success of performance improvement at Palo Verde, the frequency of this meeting may be adjusted. Attendees will include the direct reports to the Senior Vice President Nuclear, the Vice President Nuclear Operations, the Vice President Nuclear Engineering and certain other designated members of the Senior Management Team. If a regular attendee is unable to attend the meeting, then an alternate should be designated to attend. PIT Action Plan Owners and Focus Area Owners may participate in the PIP Progress Review Meetings as requested, as well as other Palo Verde personnel. The purpose of this meeting is to update the Senior Management Team on the status of the PIP, or other activities related to performance improvement at Palo Verde. The current status of Level 1s as well as the results of Nuclear Assurance oversight activities associated with the PIP will also be reviewed during these meetings.

- Monthly Trend Report (MTR) Meeting--This meeting, which is chaired by the Senior Vice President Nuclear, will be held the 2nd Friday of every month at 10 a.m. Attendees will include the direct reports to the Senior Vice President Nuclear, the Vice President Nuclear Operations, the Vice President Nuclear Engineering and certain other designated members of the Senior Management Team. If a regular attendee is unable to attend the meeting, then an alternate should be designated to attend. The purpose of this meeting is to discuss the Palo Verde MTR.

- O&M Budget Meeting--This meeting, which is chaired by the Senior Vice President Nuclear, will be held the 3rd Friday of every month at 10 a.m. Attendees will include the direct reports to the Senior Vice President Nuclear, the Vice President Nuclear Operations, the Vice President Nuclear Engineering and certain other designated members of the Senior Management Team. If a regular attendee is unable to attend the meeting, then an alternate should be designated to attend. The purpose of this meeting is to discuss the current status of the Palo Verde O&M Budget.

- Capital Budget Meeting--This meeting, which is chaired by the Senior Vice President Nuclear, will be held the 4th Friday every other month at 10 a.m. Attendees will include the direct reports to the Senior Vice President Nuclear, the Vice President Nuclear

Operations, the Vice President Nuclear Engineering and certain other designated members of the Senior Management Team. If a regular attendee is unable to attend the meeting, then an alternate should be designated to attend. The purpose of this meeting is to discuss the current status of the Palo Verde Capital budget.

Performance Indicators

Palo Verde has identified Performance Indicators (PIs) that monitor "critical attributes" of plant and personnel performance. An Action Plan under the PIP is to benchmark these PIs against top quartile performers and modify them as appropriate. These PIs will be captured in the MTR and the current status of the PIs will be discussed during the monthly MTR Meeting.

Self-Assessments

Self-assessments, particularly effectiveness reviews will play an important role in measuring performance improvement at Palo Verde. Self-assessments related to performance improvement will be conducted not only by the PIT, but by other departments at Palo Verde as well. If needed, external resources may be used to assist in conducting self-assessments.

Each Focus Area Owner will schedule self-assessments to monitor Focus Area and Action Plan effectiveness. The plan embodies a variety of self-assessment methods to identify performance gaps when compared to internal and external standards. The PIT may credit self-assessments planned by various departments, if the focus of the department assessment is consistent with the PIP. Conversely, plant departments may credit PIT generated self-assessments as satisfaction for departmental self-assessment requirements if the PIP assessment focuses on appropriate departmental issues.

The PIT oversees the scheduling and implementation of PIP-related self-assessments to ensure they focus on key site issues and that completed self-assessment activities are of a high quality.

Monitoring By the Nuclear Assurance Department

NAD independently monitors PIP progress through audits and assessments. If NAD concludes that the PIP is not being implemented adequately or is not resulting in the desired performance improvement, it is responsible and accountable for notifying the Senior Management Team and identifying deficiency areas requiring corrective action.

ATTACHMENT 2

4Q/2005 ROP Action Matrix Summary

The assessment program collects information from inspections and performance indicators (PIs) in order to enable the agency to arrive at objective conclusions about the licensee's safety performance. Based on this assessment information, the NRC determines the appropriate level of agency response, including supplemental inspection and pertinent regulatory actions ranging from management meetings up to and including orders for plant shutdown. The Action Matrix Summary listed below reflects overall plant performance and is updated regularly to reflect inputs from the most recent performance indicators and inspection findings. Physical Protection information is not publicly available and the associated performance indicators and inspection findings are not integrated into the Action Matrix Summary.

Notes have been added to plants that are not in the licensee response column of the Action Matrix.

Licensee Response Column	Regulatory Response Column	Degraded Cornerstone Column	Multiple/Repetitive Degraded Cornerstone Column	Unacceptable Performance Column
Arkansas Nuclear 1	Brunswick 2[1]	Kewaunee[2]	Perry 1[3]	
Arkansas Nuclear 2	Columbia Generating Station[4]	Palo Verde 1[5]	Point Beach 1[6]	
Beaver Valley 1	Crystal River 3[7]	Palo Verde 2[8]	Point Beach 2[9]	
Beaver Valley 2	Davis-Besse[10]	Palo Verde 3[11]		
Braidwood 1	Fort Calhoun[12]			
Braidwood 2	Hatch 1[13]			
Browns Ferry 2	Hatch 2[14]			
Browns Ferry 3	Indian Point 2[15]			
Brunswick 1	Oyster Creek[16]			
Byron 1	Three Mile Island 1[17]			
Byron 2	Turkey Point 3[18]			
Callaway	Turkey Point 4[19]			
Calvert Cliffs 1				
Calvert Cliffs 2				
Catawba 1				
Catawba 2				
Clinton				
Comanche Peak 1				
Comanche Peak 2				
Cooper				
D.C. Cook 1				
D.C. Cook 2				
Diablo Canyon 1				
Diablo Canyon 2				
Dresden 2				
Dresden 3				

Duane Arnold
Farley 1
Farley 2
Fermi 2
FitzPatrick
Ginna
Grand Gulf 1
Harris 1
Hope Creek 1[20]
Indian Point 3
La Salle 1[21]
La Salle 2[22]
Limerick 1
Limerick 2
McGuire 1
McGuire 2
Millstone 2
Millstone 3
Monticello
Nine Mile Point 1
Nine Mile Point 2
North Anna 1
North Anna 2
Oconee 1
Oconee 2
Oconee 3
Palisades
Peach Bottom 2
Peach Bottom 3
Pilgrim 1
Prairie Island 1
Prairie Island 2
Quad Cities 1
Quad Cities 2
River Bend 1
Robinson 2
Saint Lucie 1
Saint Lucie 2
Salem 1[23]
Salem 2[24]
San Onofre 2
San Onofre 3
Seabrook 1
Sequoyah 1
Sequoyah 2
South Texas 1
South Texas 2
Summer

Surry 1
Surry 2
Susquehanna 1
Susquehanna 2
Vermont Yankee
Vogtle 1
Vogtle 2
Waterford 3
Watts Bar 1
Wolf Creek 1

▲ Note 1: Brunswick unit 2 is in the regulatory response column due to one white performance indicator in the Initiating Events Cornerstone (Unplanned Power Changes per 7000 Critical Hours) originating in 4Q/2005.

▲ Note 2: Kewaunee is in the degraded cornerstone column due to one white inspection finding in the mitigating systems cornerstone originating in 3Q/2005 and one yellow finding in the mitigating systems cornerstone originating in 4Q/2005.

▲ Note 3: Perry is in the multiple/repetitive degraded cornerstone column due to the mitigating systems cornerstone being degraded with multiple white findings for greater than 4 consecutive quarters. In particular, the ESW pump failure finding from 3Q/2003 is being held open in accordance with MC 0305 for greater than 4 quarters because corrective actions were ineffective and the pump failed again in May 2004. This finding, in conjunction with the 4Q/2003 finding involving inadequate venting of the RHR/LPCI keep fill system, which is also being held open in accordance with MC 0305 for greater than 4 quarters pending the implementation of effective corrective actions to address performance deficiencies, resulted in greater than 4 consecutive quarters in the degraded cornerstone column and placed the plant in the multiple/repetitive degraded cornerstone column. In addition, a white finding in the emergency preparedness cornerstone originating in 4Q/2004 was held open in accordance with IMC 0305 for greater than 4 quarters pending the implementation of effective corrective actions to address performance deficiencies which were verified to be complete on December 9, 2005. Therefore, this finding will be closed and no longer be considered in the Action Matrix with the 1Q/2006 update.

▲ Note 4: Columbia Generating Station is in the regulatory response column due to one white performance indicator (Safety System Unavailablity, High Pressure Injection System) in the mitigating systems cornerstone originating in 1Q/2005.

▲ Note 5: Palo Verde unit 1 is in the degraded cornerstone column due to one yellow finding in the mitigating systems cornerstone originating in 4Q/2004. The significance determination for this final yellow finding and corresponding notice of violation were issued on April 8, 2005. The supplemental inspection was completed in December 2005. The team determined that the yellow finding would remain open, because not all of the licensee's root and contributing causes were fully developed, many of the corrective actions were narrowly focused or ineffective, and effectiveness reviews were not adequate. The NRC will perform a follow-up inspection after receiving written notification from the licensee that they have completed additional corrective actions and are ready to support the inspection.

▲ Note 6: Point Beach unit 1 is in the multiple/repetitive degraded cornerstone column due to a red finding and a yellow finding in the mitigating systems cornerstone originating in 1Q/2002 and 1Q/2003, respectively. Both findings are being held open in accordance with IMC 0305 for greater than 4 quarters pending the implementation of effective corrective actions to address performance deficiencies. In addition, a white finding in the emergency preparedness cornerstone originating in 4Q/2005 is not being considered in the Action Matrix due to a deviation approved by the NRC Executive Director for Operations.

▲ Note 7: Crystal River unit 3 is in the regulatory response column due to one white inspection finding in the Mitigating System Cornerstone (Fire Protection) originating in 3Q/2005.

▲ Note 8: Palo Verde unit 2 is in the degraded cornerstone column due to one yellow finding in the mitigating systems cornerstone originating in 4Q/2004. The significance determination for this final yellow finding and corresponding notice of violation were issued on April 8, 2005. The supplemental inspection was completed in December 2005. The team determined that the yellow finding would remain open, because not all of the licensee's root and contributing

causes were fully developed, many of the corrective actions were narrowly focused or ineffective, and effectiveness reviews were not adequate. The NRC will perform a follow-up inspection after receiving written notification from the licensee that they have completed additional corrective actions and are ready to support the inspection.

▲ Note 9: Point Beach unit 2 is in the multiple/repetitive degraded cornerstone column due to two red findings in the mitigating systems cornerstone originating in 1Q/2002 and 1Q/2003, respectively. Both findings are being held open in accordance with IMC 0305 for greater than 4 quarters pending the implementation of effective corrective actions to address performance deficiencies. In addition, a white finding in the emergency preparedness cornerstone originating in 4Q/2005 is not being considered in the Action Matrix due to a deviation approved by the NRC Executive Director for Operations.

▲ Note 10: Davis-Besse is in the regulatory response column due to one white finding in the emergency preparedness cornerstone originating in 4Q2004. This finding was held open in accordance with IMC 0305 for greater than 4 quarters pending the implementation of effective corrective actions to address performance deficiencies which were verified to be complete on October 21, 2005. Therefore, this finding will be closed and no longer be considered in the Action Matrix with the 1Q/2006 update.

▲ Note 11: Palo Verde unit 3 is in the degraded cornerstone column due to one yellow finding in the mitigating systems cornerstone originating in 4Q/2004. The significance determination for this final yellow finding and corresponding notice of violation were issued on April 8, 2005. The supplemental inspection was completed in December 2005. The team determined that the yellow finding would remain open, because not all of the licensee's root and contributing causes were fully developed, many of the corrective actions were narrowly focused or ineffective, and effectiveness reviews were not adequate. The NRC will perform a follow-up inspection after receiving written notification from the licensee that they have completed additional corrective actions and are ready to support the inspection.

▲ Note 12: Fort Calhoun is in the regulatory response column due to one white finding in the mitigating systems conerstone originating in 1Q/2005.

▲ Note 13: Hatch unit 1 is in the regulatory response column due to one white inspection finding in the Emergency Preparedness Cornerstone (TSC removed from service greater than 7seven days) originating in 2Q/2005.

▲ Note 14: Hatch unit 2 is in the regulatory response column due to one white inspection finding in the Emergency Preparedness Cornerstone (TSC removed from service greater than 7seven days) originating in 2Q/2005.

▲ Note 15: Indian Point 2 is in the regulatory response column due to one white inspection finding in the mitigating systems cornerstone originating in 2Q/2005. The white finding related to nitrogen gas that was discovered in the safety injection (SI) system. The 95001 inspection for this finding was completed in December 2005, and provided a positive assessment of the licensee's corrective actions. Therefore, this finding will be closed and no longer be considered in the Action Matrix with the 1Q/2006 update. On October 31, 2005, the EDO approved a Deviation from the ROP Action Matrix to provide a greater level of oversight for the Indian Point 2 plant. The Deviation includes oversight activities to monitor licensee action to: 1) Characterize and remediate tritium found onsite, and 2) improve the reliability of the emergency siren system.

▲ Note 16: Oyster Creek is in the regulatory response column due to one white inspection finding in the emergency preparedness (EP) cornerstone originating in 3Q/2005. The white finding involved an inadequate response to an event involving grassing of the intake structure.

▲ Note 17: Three Mile Island is in the regulatory response column due to a white inspection finding in the emergency preparedness cornerstone originating in 2Q/2005. The white inspection finding involved training of the Emergency Response Organization.

▲ Note 18: Turkey Point unit 3 is in the regulatory response column due to one white performance indicator in the Mitigating System Cornerstone (Heat Removal System, (AFW), Unavailability) originating in 4Q/2005.

▲ Note 19: Turkey Point unit 4 is in the regulatory response column due to one white performance indicator in the Mitigating System Cornerstone (Heat Removal System, (AFW), Unavailability) originating in 4Q/2005.

▲ Note 20:

On July 29, 2005, the Executive Director for Operations approved a renewal of a deviation from the ROP Action Matrix to provide a greater level of oversight for the Salem and Hope

Creek Generating Stations. The deviation includes oversight activities to monitor licensee improvement efforts in SCWE and related performance attributes.

▲ Note 21: One white inspection finding in the initiating events cornerstone originating in 2Q/2005 was determined to be an old design issue in accordance with IMC 0305, and is not considered as an input to the assessment program.

▲ Note 22: One white inspection finding in the initiating events cornerstone originating in 2Q/2005 was determined to be an old design issue in accordance with IMC 0305, and is not considered as an input to the assessment program.

▲ Note 23: On July 29, 2005, the Executive Director for Operations approved a renewal of a deviation from the ROP Action Matrix to provide a greater level of oversight for the Salem and Hope Creek Generating Stations. The deviation includes oversight activities to monitor licensee improvement efforts in SCWE and related performance attributes.

▲ Note 24: On July 29, 2005, the Executive Director for Operations approved a renewal of a deviation from the ROP Action Matrix to provide a greater level of oversight for the Salem and Hope Creek Generating Stations. The deviation includes oversight activities to monitor licensee improvement efforts in SCWE and related performance attributes.

Last modification: Feb 15, 2006

ATTACHMENT 3

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
611 RYAN PLAZA DRIVE, SUITE 400
ARLINGTON, TEXAS 76011-4005

January 27, 2006

EA-04-221
EA-05-051

James M. Levine, Executive Vice
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Arizona Public Service Company
P.O. Box 52034
Phoenix, AZ 85072-2034

SUBJECT: PALO VERDE NUCLEAR GENERATING STATION - NRC SUPPLEMENTAL INSPECTION REPORT 05000528/2005012; 05000529/2005012; AND 05000530/2005012

Dear Mr. Levine:

On December 12, 2005, the U.S. Nuclear Regulatory Commission (NRC) completed a supplemental inspection using Inspection Procedure 95002, "Inspection For One Degraded Cornerstone Or Any Three White Inputs In A Strategic Performance Area," at your Palo Verde Nuclear Generating Station. The enclosed report documents the results of the inspection, which were discussed on December 16, 2005, with you and other members of your staff.

This supplemental inspection was conducted to review your corrective actions for both of the violations issued to you on April 8, 2005. The first was a violation regarding 10 CFR 50, Appendix B, Criterion III, "Design Control," for the failure to adequately control the designed configuration of the containment sump safety injection suction piping of all three units. Specifically, a significant portion of this piping was not consistently maintained full of water since initial operation of all three units. In conjunction with this finding, the NRC also issued a Severity Level III violation of 10 CFR 50.59, with a monetary civil penalty, for a previous change to the facility that was performed without required prior NRC approval. Specifically, a station administrative procedure was changed to maintain the condition of the piping drained instead of filled. Your performance, which led to these violations, was determined to be reflective of that of a degraded cornerstone (i.e., degraded Mitigating Systems Cornerstone) in our Action Matrix. The specific purposes of this inspection, as described in the Objectives Section of Inspection Procedure 95002, were to (1) provide assurance that the root causes and contributing causes for the violations, which resulted in the degraded cornerstone, were understood; (2) independently assess the extent of condition and extent of cause for the violations; and (3) provide assurance that your planned corrective actions were sufficient to address the root causes and contributing causes for the violations and to prevent their recurrence. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

As further detailed in the enclosed report, the NRC concluded that you performed an adequate evaluation and implemented corrective and followup actions necessary to reasonably prevent repetition of the 10 CFR 50.59 Severity Level III violation. Therefore, we have closed this finding. However, the NRC also concluded that, while you performed an adequate root cause evaluation of the Design Control violation, certain corrective actions were incomplete at the time of this inspection. Specifically, the team determined that for each of the root and contributing causes, not all corrective actions were sufficiently developed to ensure that the identified performance deficiencies were adequately addressed. In addition, some of the corrective actions were narrowly focused, or the implementation of those actions was not fully effective. Also, the team concluded that criteria and reviews were not established, for auditing or followup, to ensure that corrective actions were effective in improving performance in the affected areas. Consequently, the team did not have assurance that your planned corrective actions were sufficient to address the causes for the performance deficiencies associated with the violation. We request that you inform us in writing once you have completed steps to assure that your corrective actions are of sufficient scope and breadth to address the subject performance deficiencies. The NRC will then perform additional inspections as necessary to assess the effectiveness of your actions. Pending completion of this followup inspection activity, the subject Design Control violation in the Mitigating Systems Cornerstone will remain open.

This inspection report describes four NRC identified and two licensee identified findings of very low safety significance (Green), involving violations of NRC requirements. Additionally, two summary findings are provided to describe our assessment of your evaluation and implementation of corrective actions associated with the 10 CFR 50.59 and Design Control violations, in accordance with NRC Manual Chapter 0612, Appendix C, "Guidance for Supplemental Inspections." Because of the very low safety significance of these violations, and because they were entered into your corrective action program, the NRC is treating these findings as noncited violations consistent with Section VI.A of the NRC Enforcement Policy. If you contest these noncited violations, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington DC 20555-0001; with copies to the Regional Administrator, U.S. Nuclear Regulatory Commission Region IV, 611 Ryan Plaza Drive, Suite 400, Arlington, Texas 76011-4005; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington DC 20555-0001; and the NRC Resident Inspector at Palo Verde Nuclear Generating Station, Units 1, 2, and 3, facility.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response (if any) will be made available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

//RA//

Bruce S. Mallett
Regional Administrator

Dockets: 50-528; 50-529; 50-530
Licenses: NPF-41; NPF-51; NPF-74

Enclosure:
NRC Inspection Report 05000528/2005012;
05000529/2005012; and 05000530/2005012
w/Attachment: Supplemental Information

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SUNNI Review Completed: __Y_____ ADAMS: ■ Yes☐ No Initials: __JAC____
■ Publicly Available ☐ Non-Publicly Available ☐ Sensitive ■ Non-Sensitive

R:_REACTORS_PV\2005\PV2005-12RP-JAC.wpd

C:DRS/EB1	SRI:DRP/E	SRI:DRS/EB1	RI:DRP/D	RI/RII/DRS
JAClark/lmb	MCHay	DLProulx	MASitek	SNSheldon
/RA/	/RA/ E	/RA/ E	/RA/ E	/RA/ E
1/11/05	1/11/06	1/13/06	1/11/06	1/11/06

C:D/DRP	DD:NRR/DIRS	C:DRS/EB1	D/DRP	RA	
TWPruett	SARichards	JAClark	ATHowell	BSMallett	
/RA/	/RA/ E	/RA/	/RA/ By AV	/RA/	
1/26/06	1/13/06	1/27/06	1/27/06	1/27/06	

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U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Dockets:	50-528; 50-529; 50-530
Licenses:	NPF-41; NPF-51; NPF-74
Report:	05000528/2005012; 05000529/2005012; 05000530/2005012
Licensee:	Arizona Public Service Company
Facility:	Palo Verde Nuclear Generating Station, Units 1; 2; and 3
Location:	5951 S. Wintersburg Road Tonopah, Arizona
Dates:	September 12 through December 12, 2005
Inspectors:	J. Clark, Branch Chief M. Hay, Senior Resident Inspector, Projects Branch E D. Proulx, Senior Reactor Inspector, Engineering Branch 1 S. Sheldon, Reactor Inspector, Division of Reactor Safety, Region III M. Sitek, Resident Inspector, Projects Branch D
Accompanying Personnel:	C. Baron, Contractor, Beckman and Associates S. Unekewicz, Sr. Reactor Engineer J. Groom, Reactor Inspector, Nuclear Safety Professional Development Program
Approved By:	Bruce S. Mallett Regional Administrator

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SUMMARY OF FINDINGS

IR 05000528/2005012; 05000529/2005012; 05000530/2005012; 09/12/05 - 12/12/05; Palo Verde Nuclear Generating Station, Units 1, 2, and 3; Supplemental Inspection Report; Inspection Procedure 95002.

This report documents a supplemental inspection by a branch chief, two resident inspectors, two reactor inspectors, accompanied by a consulting engineer and a team assistant. The inspection identified four noncited violations and two findings. The significance of most findings is indicated by their color (Green, White, Yellow, or Red) using Inspection Manual Chapter 0609, "Significance Determination Process." Findings for which the significance determination process does not apply may be Green or be assigned a severity level after NRC management's review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

A. NRC-Identified Findings:

Cornerstone: Mitigating Systems

•• N/A. The U.S. Nuclear Regulatory Commission (NRC) performed this supplemental inspection, in part, to assess the licensee's evaluation and corrective actions associated with an inappropriate change to an emergency core cooling system procedure without prior NRC approval. This procedure change rendered portions of the system inoperable because of voiding. This performance issue was previously characterized as a Severity Level III violation of 10 CFR 50.59 and was originally identified in NRC Inspection Report 05000528; 529; 530/2004014. During this supplemental inspection, performed in accordance with Inspection Procedure 95002, the inspectors determined that the licensee's evaluation identified the primary root causes of the performance issue to be: (1) The site procedure revision process (01AC-0AP02) was inadequate, in that, the procedure allowed 'pre-screening' of changes that could potentially bypass performing a 10 CFR 50.59 screening for changes to the facility as described in the licensing basis; and (2) The corrective action program implementation was ineffective. The licensee also identified overlap and interface problems between the corrective action program, the engineering evaluation request program, and the instruction change request program. These issues, in conjunction with inadequate training to recognize a corrective action condition, contributed to the failure of station personnel to initiate a corrective action program input document in 1992 for the potential pipe voiding concern. The inspectors concluded that the licensee's evaluation and implemented corrective actions were appropriate to reasonably prevent repetition of the 10 CFR 50.59 violation.

Given the licensee's acceptable performance in addressing the inappropriate procedure change and 10 CFR 50.59 program deficiencies, the Severity Level III violation is closed. (Section 4OA5.6)

- N/A. The NRC performed this supplemental inspection, in part, to assess the licensee's evaluation and corrective actions associated with potential air entrainment into the emergency core cooling system. The licensee failed to incorporate original design requirements into the plant to maintain piping between the containment sump isolation valves filled with water. This performance issue was previously characterized as a 10 CFR 50, Appendix B, Criterion III, violation having substantial safety significance (Yellow), and was originally identified in NRC Inspection Report 05000528; 529; 530/2004014. The inspectors determined that the licensee's evaluation identified a direct cause, nine root causes, and nine contributing causes of the performance issue. The evaluation was also used to develop an extensive list of corrective actions. The inspectors found the licensee's methods of evaluation to be appropriate.

  The NRC concluded that, while the licensee performed an adequate root cause evaluation of the Design Control violation, certain corrective actions were incomplete at the time of this inspection. Specifically, the team determined that for each of the root and contributing causes, not all corrective actions were sufficiently developed to ensure that the identified performance deficiencies were adequately addressed. In addition, some of the corrective actions were narrowly focused, or the implementation of those actions was not fully effective. Also, the team concluded that criteria and reviews were not established, for auditing or followup, to ensure that corrective actions were effective in improving performance in the affected areas. Consequently, the team did not have assurance that the planned corrective actions were sufficient to address the causes for the performance deficiencies associated with the violation. Therefore, the (Yellow) violation (VIO 2004/014-01) will remain open for further NRC review. (Section 4OA5.6)

- Green. The inspectors identified a noncited violation of 10 CFR 50, Appendix B, Criterion III, "Design Control," related to potential air entrainment into the emergency core cooling system suction header from the refueling water tank. Specifically, the inspectors determined that the water level in the refueling water tank could fall below the level of the tank discharge pipe and associated vortex breaker during the transfer from the refueling water tank to the containment sump during design basis accidents. As a result, air could be drawn into the emergency core cooling system piping under accident conditions. This issue was applicable to both trains of all three units. Contrary to proper design control, engineering personnel failed to effectively implement design requirements to prevent potential air entrainment into the emergency core cooling system.

  The inspectors considered this finding to be more than minor, in accordance with NRC Manual Chapter 0612, "Power Reactor Inspection Reports," since it potentially affected the Mitigating Systems cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences, and it affected the attributes of design and configuration control. Using the Manual Chapter 0609, "Significance Determination Process," Phase 1 worksheet, the inspectors determined that the issue was of very low safety significance (Green) because there was no actual loss of safety function. Because the violation was determined to be of very low

safety significance and has been entered into the corrective action program as condition report/disposition request (CRDR 2835132), this violation is being treated as a noncited violation, consistent with Section VI.A of the NRC Enforcement Policy. The inspectors also determined this issue had cross-cutting aspects of human performance. Specifically, the licensee's attention to detail was lacking and there was poor inter- and intra-group coordination. (Section 4OA5.1)

- Green. The inspectors identified two examples of a noncited violation of 10 CFR 50, Appendix B, Criterion III, "Design Control," for failure to translate the design basis volume of 300,000 gallons of usable volume in the condensate storage tank (CST) and reactor water makeup tank (RWMT) into the station's instructions, procedures, or drawings. Without this information, operators were unaware that Technical Specification minimum levels, specified in feet, may not provide sufficient usable volumes of water for auxiliary feedwater pump operation. Contrary to proper design control, the licensee failed to effectively implement design requirements to ensure operability of the auxiliary feedwater system.

  These two examples of a violation affect the Mitigating Systems cornerstone and are more than minor because they were similar to Example 3.I of Manual Chapter 0612, and design calculations were required to be re-performed to assure accident requirements were met. In both instances, the originally calculated available inventory was less than the actual required design basis inventory of 299,700 gallons. Subsequent calculations by engineering personnel, including significant reduction in margins, demonstrated that minimum required volumes in the CST and RWMT were maintained. Using the Manual Chapter 0609, "Significance Determination Process," Phase 1 worksheet, the inspectors determined that the issue was of very low safety significance (Green) because there was no actual loss of safety function. Because the violation was determined to be of very low safety significance and has been entered into the corrective action program as condition report/disposition requests (CRDRs 2839337, 2840186, and 2841773), this violation is being treated as a noncited violation, consistent with Section VI.A of the NRC Enforcement Policy. The inspectors also determined this issue had cross-cutting aspects of human performance. Specifically, the licensee's attention to detail was lacking and there was poor inter- and intra-group coordination. (Section 4OA5.2)

- Green. The inspectors identified a noncited violation of 10 CFR 50, Appendix B, Criterion III, "Design Control," for failure to translate design basis information into the calibration of refueling water tank level instruments. Without this information, operators were unaware that a Technical Specification listed minimum level in this tank may not provide sufficient usable volume of water for emergency core cooling system operation. Specifically, engineers failed to density compensate these instruments for allowable ranges of both temperature and boric acid concentration of the tank. Contrary to proper design control, the licensee failed

to effectively implement design requirements to ensure operability of the refueling water tank.

This issue was determined to affect the Mitigating Systems cornerstone and was more than minor based upon review of Example 3.j of Manual Chapter 0612, Appendix E. The errors were considered more than a minor calculation error because the deficiencies required re-performance of the calculations, significantly reduced the overall margin, and could be applicable to other such instrumentation calculations. However, engineering personnel demonstrated that while there was a loss of margin, there was no actual loss of function because of the inaccuracies in the RWT level instrument calibrations. Using the Manual Chapter 0609, "Significance Determination Process," Phase 1 worksheet, the inspectors determined that the issue was of very low safety significance (Green) because there was no actual loss of safety function. Because the violation was determined to be of very low safety significance and has been entered into the corrective action program as condition report/disposition request (CRDR 2840920), this violation is being treated as a noncited violation, consistent with Section VI.A of the NRC Enforcement Policy. (Section 4OA5.3)

•• Green. The inspectors identified three examples of a (Green) noncited violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings." Specifically, these examples involved the licensee's failure to follow a procedure and to provide appropriate quantitative or qualitative acceptance criteria for determining that important activities have been satisfactorily accomplished, consistent with the facility's administrative procedure for the operability determination process. In the first case an engineer evaluated a concern in a condition report/disposition request without notifying the control room so an operability assessment could be performed. In the other cases, there was inadequate guidance given to operators to address when an operability assessment would be required.

The inspectors considered this finding to be more than minor, in accordance with Manual Chapter 0612, since it potentially affected the Mitigating Systems cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences, and it affected the attributes of procedure quality and human performance. However, subsequent evaluations completed by the licensee verified that actual safety functions were not lost in any of these examples. The inspectors performed a Phase 1 significance determination, using NRC Manual Chapter 0609, and determined this issue screens out as having very low safety significance (Green) because a safety function was not lost. Because the violation was determined to be of very low safety significance and has been entered into the corrective action program as condition report/disposition request (CRDR 2838626), this violation is being treated as a noncited violation, consistent with Section VI.A of the NRC Enforcement Policy. The inspectors also determined this issue had cross-cutting aspects of human performance. Specifically, the licensee's attention to detail was lacking and there was poor inter- and intra-group coordination. (Section 4OA5.4)

B. Licensee-Identified Violations:

Violations of very low safety significance, which were identified by the licensee have been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into licensee's corrective action program. These violations and corrective actions are listed in Section 4OA7 of this report.

REPORT DETAILS

1. REACTOR SAFETY

4OA5 Other Activities

Inspection Scope

In August 2004, the U.S. Nuclear Regulatory Commission (NRC) identified a violation of 10 CFR 50, Appendix B, Criterion III, "Design Control," that involved a failure to adequately control the designed configuration of the containment sump safety injection suction piping at all three Palo Verde Nuclear Generating Station (PVNGS) units. Specifically, a significant portion of this piping was not consistently maintained full of water since initial operation of all three units. The finding was originally documented in NRC Inspection Report 05000528; 529; 530/2004014 (ADAMS ML050050287). This violation was subsequently determined to be of substantial safety significance (Yellow) through the application of NRC Manual Chapter 0609, "Significance Determination Process." In conjunction with this finding, the NRC also identified a Severity Level III violation of 10 CFR 50.59 for a previous change to the facility that was performed without prior NRC approval. Specifically, a station administrative procedure was changed to maintain the condition of the piping drained instead of filled.

Each year, the NRC conducts integrated assessments of nuclear power plant performance. These assessments are based upon the risk significance of the inspection findings by the NRC's resident and region-based inspectors and the insights gained from the licensee-provided performance indicators. As discussed in a followup letter to our most recent annual end-of-cycle assessment, and the current mid-cycle assessment letter, plant performance for PVNGS was categorized within the Degraded Cornerstone Column of the NRC's Manual Chapter 0305, "Operating Reactor Assessment Program," Action Matrix. This was based on the open (Yellow) finding in the Mitigating Systems Cornerstone. The NRC's performance of this supplemental inspection was based upon the licensee's performance, and is consistent with the Action Matrix.

This supplemental inspection was conducted to obtain information for the NRC to determine if the licensee provided reasonable assurance that the problems associated with the degraded Mitigating Systems cornerstone were thoroughly understood, the cause and effects were properly evaluated, and sufficient corrective actions have been taken to prevent recurrence. The inspectors reviewed the licensee's actions for completeness, thoroughness, and effectiveness. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel. The inspectors also performed focused inspection activities to independently assess the validity of the licensee's conclusions. Specific items reviewed are documented in the attachment, or in the following discussions of NRC assessments and findings.

The inspectors primarily used the guidance of Inspection Procedure 95002, "Inspection for One Degraded Cornerstone or Any Three White Inputs In A Strategic Performance

Area," to conduct the inspection. This supplemental inspection was conducted to review the licensee's corrective actions for both of the violations issued on April 8, 2005. The specific purposes of this inspection, as described in the Objectives Section of Inspection Procedure 95002, were to (1) provide assurance that the root causes and contributing causes for the violations, which resulted in the degraded cornerstone, were understood; (2) independently assess the extent of condition and extent of cause for the violations; and (3) provide assurance that the licensee's planned corrective actions were sufficient to address the root causes and contributing causes for the violations and to prevent their recurrence. This inspection procedure also called for a customized plan to assess the validity of the licensee's conclusions. This plan was derived from Inspection Procedures 71111.02, "Evaluations of Changes, Tests, or Experiments," 71111.17, "Permanent Plant Modifications," 71111.21, "Safety System Design and Performance Capability," and 71152, "Identification and Resolution of Problems." Specifically, the inspectors reviewed:

- The translation of original design basis requirements into plant procedures, calculations, setpoints, and modifications. Primary emphasis was on mitigating systems
- The licensee's processes to maintain and control the design basis of the facility
- Revisions to operating, maintenance, and testing procedures to ensure design and 10 CFR 50.59 aspects were addressed
- Interfaces with operations personnel on evaluations and corrective action program implementation
- The use of operating experience
- How the licensee's overall evaluations of the escalated findings, and their proposed corrective actions, addressed all of the previous criteria

.1 Independent NRC Inspection: Refueling Water Tank Voiding

Introduction. The inspectors identified a (Green) noncited violation of 10 CFR 50, Appendix B, Criterion III, "Design Control," related to potential air entrainment into the emergency core cooling system (ECCS) suction header from the refueling water tank (RWT). Specifically, the inspectors determined that the water level in the RWT could fall below the level of the tank discharge pipe and associated vortex breaker during the transfer from the RWT to the containment sump after an accident. As a result, air could enter the ECCS piping system under accident conditions. This issue was applicable to both trains of all three units.

Description. During preparation for the this inspection, the inspectors reviewed the transportability analysis included in Condition Report/Disposition Request (CRDR) 2726509, "ECCS Sump Suction Piping Discovered in an Unanalyzed Condition," Revision 1. This report included extent of condition and extent of cause evaluations for the ECCS sump issue (event date July 29, 2004). The inspectors noted this report included the RWT in its scope, but did not address the RWT as a potential

source of air entrainment into the ECCS. The inspectors also noted that the PVNGS design did not include automatic closure of the RWT isolation valves with a recirculation actuation signal (RAS). The inspectors noted that the licensee did not fully understand the plant design basis and the dynamics of the system at the time of a RAS. Based on these observations, the inspectors questioned licensee personnel further on the potential of air entrainment from the RWT into the ECCS.

The inspectors found the applicable design calculation was Calculation 13-MC-CH-201, "Refueling Water Tank (RWT), Hold-Up Tank (HT) and Reactor Make-Up Water Tank (RWMT) Sizing," Revision 6 (issued July 13, 1999). This calculation included an analysis to demonstrate that "the final RWT level following a RAS was adequate, relative to the minimum water level in containment, to ensure that the suction piping would not void and gas-bind the ECCS pumps." The pumps of concern are in the containment spray system (CSS) and safety injection system (SIS). The associated analysis was based on a minimum containment pressure of 23 psia (approximately 8.5 psig). Revision 0 of this calculation (issued April 20, 1979) was also based on a minimum containment pressure of 23 psia. The inspectors questioned whether the 23 psia value was conservative. Engineering personnel stated that more recent "best-estimate" analyses had indicated that the actual minimum containment pressure was 17.5 to 18.5 psia (approximately 3 to 4 psig).

In response to the inspectors' questions, engineering personnel initiated CRDR 2835132 on October 6, 2005. This CRDR raised a concern that the original Combustion Engineering (CE) design interface requirements, included in Updated Final Safety Analysis Report (UFSAR), Section 6.3.1.3.M.2, may not "preclude the possibility of drawing air from the RWT to the safeguards pump suction during recirculation" as stated in the UFSAR. This interface requirement stated, in part, "The piping for each safeguards train is designed such that the piping junction of the suction pipe, that runs to the refueling water tank and the containment recirculation sump, is located at least 16 feet below the top of the recirculation containment sump, which is 4 feet below the minimum water level in the containment during recirculation. This provides adequate static hydraulic head margin for the minimum containment pressure of -3.5 psig, as described in Subsection 6.2.1, to preclude the possibility of drawing air from the RWT to the safeguards pump suction during recirculation." The inspectors were concerned that, while this was a design interface requirement, it was intended to be a bounding design consideration for the ECCS, especially during dynamic flow conditions.

Operability Determination (OD) 301, Revision 1, was initiated on October 6, 2005, to address this issue. The operability evaluation concluded the ECCS was operable. It stated, in part, "Engineering believes that further evaluation will demonstrate that with appropriate assumptions for containment pressure and water inventory in the RWT/containment, the minimum water level will remain above the vortex breaker in the RWT which eliminates the potential for air entrainment. Based on this information, reasonable assurance exists that the ECCS is capable of performing its specified design function and therefore remains operable." Operability Determination 301 was approved on October 8, 2005.

The licensee also sought additional engineering assistance from outside organizations, including Westinghouse. On October 11, 2005, engineering personnel were informed

that containment pressure analyses, performed by Westinghouse, were based on an assumed RWT temperature of 120•F. This is the maximum assumed RWT temperature allowed by Technical Specifications, and would be a conservative assumption for containment response calculations evaluating high pressures. However, Westinghouse informed engineering personnel that the maximum RWT temperature was nonconservative for determining the minimum containment pressure under accident conditions. Based on preliminary calculations, the correlation between RWT temperature and minimum containment pressure was: 90•F/ 2.0 psig, 105•F/3.8 psig, and 120•F/4.3 psig. The minimum containment pressure required to prevent uncovering the RWT vortex breaker was 4.3 psig. As stated previously, recent licensee containment modeling determined containment pressure could be approximately 3 to 4 psig, indicating negative margin. As a result, during a licensee management review team meeting, held on October 11, 2005, it was determined that the ECCS of both trains of all three units were outside design bases and were declared inoperable at 1333 hours. Units 2 and 3 entered limiting condition of operation (LCO) 3.0.3, "Unanalyzed Condition," and performed orderly shutdowns to Mode 5. Unit 1 was shutdown at this time for scheduled refueling outage activities. Operability Determination OD 301 was subsequently canceled.

On October 17, 2005, the licensee determined that the ECCSs were operable and restart of Units 2 and 3 was approved. The determination that the ECCSs were operable was based on the conclusions of Report FAI/05-107, "The Potential for Air Intrusion and RWT Check Valve Response Following RAS," Fauske & Associates, Inc., Revision 0. This report was transmitted to Palo Verde Nuclear Generating Station (PVNGS) in Westinghouse Letter CVER-05-75, dated October 17, 2005. As documented in the operator logs, the report concluded, in part, "The design of the PVNGS SIS and CSS suction piping meets the subject interface requirement and supports operability of the SIS and CSS. Report FAI/05-107 confirms that the PVNGS plants RWT and containment sump arrangements meet the explicit intent of the CE Interface Requirement 4.3.1.1, such that, there is no possibility of air being drawn into the ECCS pumps during continuous recirculation operation. Also using a conservative and limiting approach, Report FAI/05-107 demonstrates that the design, as implemented, meets the objective of the interface requirement during transition to recirculation at the initiation of RAS. Specifically, water level in the RWT suction piping does not drop below the elevation at the top of its junction with the containment sump piping." The operator logs also stated, "Based on the above, a degraded or non-conforming condition did not exist and the emergency core cooling systems at PVNGS have been operable."

On October 17, 2005, the licensee initiated CRDR 2838368 to address the non-conservative assumption in Calculation 13-MC-CH-201 that the containment pressure at the time of RAS would be no less than 8.5 psig.

After detailed review of the licensee's operability determination and design calculations, the inspectors questioned the conclusion that "a degraded or nonconforming condition did not exist." The inspectors determined that ECCS design basis analyses including Calculations 13-MC-CH-201, Revision 6; 13-MC-SI-018, "Containment Spray System Interface Requirements Calculation," Revision 6; and 13-MC-SI-017, "Safety Injection System Interface Requirements Calculation," Revision 5 were based on the suction

header piping remaining full of water under post accident conditions. Contrary to this, Report FAI/05-107, Revision 0, predicted that the RWT level would fall below the RWT vortex breaker and that some air would enter the piping system. Although this report concluded that the air would not reach the pump suctions, air entrainment in the piping system was not consistent with the design basis. In addition, the inspectors observed that UFSAR, Section 6.5.2.8, "CESSAR Interface Evaluations," addressed potential air entrainment from the RWT. Subsection (RA) 7.16.1 stated, in part, "In addition, vortexing tendencies within the tank are precluded by a suction cage within the tank, similar in design to the cage installed in the containment emergency sump. The minimum required RWT level and volume are the useful level and volume above the volume that is unusable due to vortex considerations."

In response to these questions, PVNGS personnel concluded that this condition did not conform to the design basis and that additional actions were required to correct the condition. Most of these corrective actions were still in progress at the close of this inspection, under CRDR 2835132. However, the licensee did provide Revision 1 of Report FAI/05-107 to the inspectors, which demonstrated that although air could enter the ECCS suction header, that the resultant void fraction would be below the maximum allowable for safe operation of the pumps. The licensee also described proposed actions of increased training and controls for operators, and a proposed modification to the containment sump isolation valves to operate them automatically from a RAS. The inspectors concluded these actions, if implemented, would contribute to mitigating the degraded condition.

In addition to the noncited violation, the inspectors noted several other performance deficiencies during their document review and interaction with station personnel. Based upon the below listed deficiencies, the inspectors also determined this issue had cross-cutting aspects of human performance. Specifically, the licensee's attention to detail was lacking and there was poor inter- and intra-group coordination. These deficiencies are discussed below:

- The inspectors determined that the licensee extent of cause and extent of condition reviews were narrowly focused. The licensee defined very extensive design criteria and features that could be pertinent to the original (Yellow) violation. However, if some design document or interface document addressed the design criteria, the licensee performed no further review. There was not a thorough effort by the licensee to validate the design criteria. This was clearly demonstrated in the RWT voiding issue. Examples included the licensee's misunderstanding of the maximum RWT temperature, and their reliance on a Combustion Engineering interface requirement, for piping elevations, to meet all dynamic thermal-hydraulic design criteria for ECCS piping.

- The licensee also noted, in other ongoing programs at the facility, that design basis information was not handled with appropriate attention to detail. Examples included the licensee's evaluation statements that their UFSAR validation process, under 10 CFR 50.54(f), was shallow; quality assurance reviews indicated that engineers did not verify reference values or conditions for design calculations; and various design organizations did not interface well with each other for multi-disciplinary issues.

- The inspectors determined that the licensee's evaluation of technical issues was iterative, which demonstrated a lack of thoroughness in reviews. The inspectors noted that engineering personnel would address one particular aspect or consideration when a design problem was presented. However, when questioned by the inspectors or engineering management, more discrepancies would be identified by the engineering personnel. The inspectors determined that design engineering personnel were making broad assumptions of criteria in their reviews, and in several cases, were using unverified or unstated assumptions from other groups. An example was the stroke times of the containment sump isolation valves used by design engineers in their RWT required volume calculations. There was no stated basis for the times used, and design engineers could not explain to the inspectors where the values came from. Additionally, other engineering personnel were not challenging these assumptions in peer or supervisory reviews. These organizational and human performance issues caused the inspectors to question the appropriateness of the extent of cause review for the (Yellow) Design Control violation.

- The inspectors noted a lack of communication between organizations, and a lack of attention to detail when coordinating critical design evaluations between organizations. During discussions of this RWT voiding issue, engineering personnel inappropriately described system operation to operators while discussing the operability of ECCS (see Section 4OA5.1). One shift test engineer informed an inspector that on October, 8, 2005, he was told by the operator he was relieving, that "I believe we may be in 3.0.3," based on the emergent RWT voiding issue. The individual apparently did not address this to his crew supervision because he had not had time to reconcile his own questions. Subsequently, the operations crew and the lead shift test engineer reviewed the RWT information, without consulting engineering, and concluded the previous operator's questions were not of concern. The inspectors were concerned this demonstrated problem resolution by isolated groups, and did not look across organizational boundaries.

- The inspectors determined that the licensee had a very limited use of operating experience for the RWT issue. The licensee previously identified that ineffective use of operating experience was a contributor to the (Yellow) ECCS violation. The licensee also had several self-identified findings of ineffective operating experience use in the last year, following reviews of their substantive crosscutting problem identification and resolution issue and their engineering program review. However, during the review of the RWT issue, the licensee did not consider all relevant operating experience. The inspectors brought to the licensee's attention a similar finding in 2003 at the Brunswick Nuclear Power Station, and a specific American Society of Mechanical Engineers' study for uncovering the RWT vortex breaker at the Donald C. Cook facility in 2001. This study not only included detailed flow modeling of the same system, it partly refuted the original operability determination the licensee performed under OD 301 by stating air would enter the suction piping.

- The inspectors determined that the schedule for effectiveness reviews did not ensure a timely review of the adequacy of corrective actions. Two root causes, and one of the contributing causes, were addressed by a condition report action item (CRAI) 2825679, which at the time of the inspection was already closed. This corrective action included all-hands communications from senior management to communicate the need for effective questioning attitudes and technical rigor. This corrective action was closed on September 9, 2005, after such meetings were conducted to "emphasize that it is essential that all employees have a strong and effective questioning attitude and technical rigor, and to challenge assumptions and/or any situations which do not seem safe, or per design, or per procedure, or per expectation, or in general do not seem appropriate." The licensee stated this was placed in the effectiveness review process, but that specific review of effectiveness of these actions was not planned until 2006. The inspectors determined that the effectiveness review was untimely in that unacceptable performance continued without additional corrective actions being implemented.

Analysis. The inspectors determined that the potential of air entrainment into the ECCS suction header from the RWT was a licensee performance deficiency. This condition did not conform to the plant design basis and had not been analyzed. The finding affected the Mitigating Systems cornerstone because of the potential for the safety injection and containment spray systems to be degraded because of air reaching the pump suctions under accident conditions. The inspectors considered this finding to be more than minor, in accordance with NRC Manual Chapter (MC) 0612, "Power Reactor Inspection Reports," since it potentially affected the Mitigating Systems cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences, and it affected the attributes of design and configuration control. The PVNGS engineering staff had to perform additional analyses, and an operability evaluation because of this condition.

The inspectors determined that the specific accident conditions that could have challenged the ECCS have not existed. The licensee also determined that although potentially degraded, the safety injection and containment spray systems remained operable based on engineering analysis. Using the MC 0609, "Significance Determination Process," Phase 1 worksheet, the inspectors determined that the issue was of very low safety significance (Green) because there was no actual loss of safety function.

Enforcement. Criterion III, "Design Control," of 10 CFR 50, Appendix B, states that the applicable regulatory requirements and the design basis shall be correctly translated into specifications, procedures, and instructions. Criterion III also states that measures shall be established for the identification and control of design interfaces and for coordination among participating design organizations. Specifically, the licensee failed to effectively translate into station specifications, procedures, and instructions the design requirement to prevent air entrainment into the ECCS system. Because the finding is of very low safety significance and has been entered into the corrective action program as CRDR 2835132, this violation is being treated as a noncited violation, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000528; 05000529; 05000530/2005012-01, Improper Design Control for ECCS Sump and RWT Swapover.

.2 Independent NRC Inspection: Auxiliary Feedwater Useable Volume

Introduction. The inspectors identified a noncited violation, with two examples, of 10 CFR 50, Appendix B, Criterion III, "Design Control," for the failure to translate the design basis usable volume of 300,000 gallons in the condensate storage tank (CST) and RWMT into plant instructions, procedures or drawings. Specifically, Calculation 13-MC-CT-205, demonstrated that 330,000 gallons of usable volume existed in the CST when taking into account vortexing and air entrainment of the auxiliary feedwater pumps, only if operations personnel took action to close the auxiliary feedwater pump minimum flow recirculation valves. However, the inspectors determined that this operator action was not incorporated in normal, abnormal, or emergency operating procedures. Without shutting the valve on low CST level, the licensee's calculations revealed that only 292,900 gallons of usable volume existed, which is less than the 300,000 gallons credited in the UFSAR and the Technical Specification Bases. Technical Specification Bases 3.7.6 also credits 300,000 gallons of usable inventory for auxiliary feedwater usage with the RWMT at 26 feet. With instrument uncertainties and vortexing concerns, Calculation 13-JC-CH-0214 verified that only 273,000 gallons of usable inventory were available with the RWMT at 26 feet.

Description. As part of the licensee's extent of cause/condition review for the (Yellow) violation, the licensee generated a matrix that detailed if statements in the UFSAR were reflected in calculations, design basis manual, Technical Specifications, and implementing procedures. As with the previously described RWT potential voiding issue (Section 4OA5.1), the inspectors questioned whether the licensee thoroughly reviewed design considerations, or simply accepted that a design aspect was already mentioned in a reference document. Section 9.2.6 of the UFSAR stated that the CST had a usable volume of 300,000 gallons plus 30,000 gallons to support 8 hours at hot standby followed by a cooldown to 350•F at 75•F per hour. This volume requirement was based on the NRC Branch Technical Position RSB 5-1, "Alternate Safe Shutdown Analysis," which required a usable CST volume adequate to support 4 hours at hot standby followed by a cooldown to conditions that allow shutdown cooling to be initiated. Technical Specification 3.7.6 required that the CST be at 29.5 feet. The bases for Technical Specification 3.7.6 stated that the 29.5 feet level in the CST is based on having 300,000 gallons of usable volume to support an 8 hour hold in Mode 3 (Hot Standby) followed by a cooldown to shutdown cooling entry conditions (350•) at 75•F per hour. The inspectors also determined that previous to PVNGS's conversion to Improved Technical Specifications in 1996, the Technical Specification value was the volume of the tank instead of the level. Therefore, it would be incumbent on the licensee to continue to demonstrate the relationship between the tank volumes and required minimum levels for Technical Specifications.

The inspectors determined that the licensee only performed an initial review of the CST volume requirements, with no additional validation. Because of concerns with the licensee's calculations associated with the RWT, on October 17, 2005, the inspectors questioned engineering personnel to determine if the CST volume calculations had been similarly verified.

Following the inspectors' questioning, engineering personnel reviewed Calculation 13-MT-CT-205, Revision 3, which established the amount of available CST

inventory. The inspectors determined that, in 1994, this calculation revealed that the usable volume of the CST was based on ensuring that adequate net positive suction head was available to the auxiliary feedwater pumps, taking into account pump vortexing, and air entrainment. The calculated level initially corresponded to 25 feet in the CST. However, engineering personnel noted that this level did not sufficiently address air entrainment when the minimum flow recirculation valve was open and did not account for instrument uncertainty. With 25 feet of CST inventory, Calculation 13-MT-CT-205 determined that 270,000 gallons of usable inventory existed in the CST. This was less than the credited 300,000 gallons.

On April 4, 1992 engineering personnel generated Engineering Evaluation Request (EER) 89-AF-048 to disposition the recommendations from the calculations. Engineering personnel recommended that the Technical Specification minimum level be revised to 29.5 feet. The EER stated that with the auxiliary feedwater minimum flow recirculation valve open, the usable CST volume at 29.5 feet corresponded to a volume of 292,900 gallons (less than the 300,000 gallons of usable inventory credited in UFSAR, Section 9.2.6, and Technical Specification 3.7.6). To resolve this concern, engineering personnel initiated Instruction Change Request (ICR) 38795 to the Operations Department to request that the minimum flow recirculation valves for the auxiliary feedwater pumps be closed when CST level approached 6.5 feet. This was to prevent air entrainment of the auxiliary feedwater pumps. If the minimum flow recirculation valve is closed then the air entrainment concerns no longer existed, ensuring the 300,000 gallons plus 30,000 gallons of reserve inventory for a total usable volume of 330,000 gallons in the CST. Operations responded to ICR 38795 by stating that closing the auxiliary feedwater pump minimum flow recirculation valves was not advisable because it could lead to pump damage, so that the recommended action when CST level approached 6.5 feet was to switch to the alternate water source (RWMT). The corrective action, including the usable volume question, was then closed by operations personnel without further resolution of the discrepancies.

In May 2001, Calculation 13-MC-CT-205 was updated to incorporate the calculation results and conclusions of EER 89-AF-048. Again, the inspectors found that no further verification was performed to ensure that the design basis was met or that previously described operator actions were incorporated into procedures.

In December of 2001, Calculation 13-MT-CT-205 was revised to determine if the amount of usable volume was adequate to support power uprate of Unit 2 from 3876 to 3990 million watts-thermal (MwT). With the revised reactor thermal power, engineering personnel calculated that 299,700 gallons of usable inventory were necessary to support 8 hours in Mode 3 followed by a cooldown at 75•• per hour to 350•• Since Calculation 13-MC-CT-205 stated that the CST had a usable volume of 330,000 gallons (assuming operator actions to shut the minimum flow recirculation valves), engineering personnel believed that no further procedure or design basis actions were necessary with respect to CST inventory to support the Unit 2 power uprate. The inspectors considered this another missed opportunity to address the CST usable volume discrepancy. The inspectors noted that without crediting the operator action to shut the minimum flow recirculation valves, the usable inventory in the CST (292,900 gallons) was less than that necessary to meet the design basis (299,700 gallons) to support the Unit 2 power uprate. In September 2003, the NRC issued Amendment 149 to the Unit 2 operating

license, approving an uprate to 3990 MwT. Similarly, the licensee submitted power uprate license amendment requests for Units 1 and 3 in July 2004, also with no change to the required CST level or inventory. The failure to incorporate operator action into procedures to ensure adequate CST volume, or other actions such as requiring swapover to the RWMT, was the first example of a violation of 10 CFR 50, Appendix B, Criterion III. The licensee initiated CRDR 283927 to enter this item into the corrective action system.

The licensee determined that resolving the CST inventory discrepancies, by incorporating the operator action to shut the minimum flow recirculation valves upon low CST level, was not a prudent action because it could result in damage to the operating auxiliary feedwater pumps. Therefore, engineering personnel revised the applicable calculations for the amount of water necessary to support the cooldowns, through the removal of available margin, and intended to revise the Technical Specification Bases to support these calculations. In addition, the licensee revised the calculations to more accurately determine the unusable volume because of air entrainment. When these new calculations were completed, engineering personnel determined that 300,000 gallons are currently available, and that less that 292,900 gallons of water is necessary for all accident scenarios and to meet the UFSAR requirement to support 8 hours in Mode 3 followed by a cooldown to shutdown cooling entry conditions. These calculation revisions demonstrated there was no actual loss of safety function.

On October 23, 2005, following discovery of the discrepancies with the usable volume of the CST, the inspectors questioned the usable volume of the RWMT. The RWMT is the Technical Specification referenced alternate source of water to the CST. Technical Specification 3.7.6 allows the RWMT to be used as an alternative source of water for the auxiliary feedwater pumps, for up to seven days of the CST being inoperable, but does not address being used in conjunction with the CST (i.e., available volume from both tanks). Additionally, Technical Specifications stated that the CST and the RWMT must each have minimum volumes of 300,000 gallons to be declared operable. The licensee reviewed Calculation 13-JC-CH-0214 that verified the usable volume of the RWMT when used as a backup auxiliary feedwater source of water. The licensee noted that the calculations for the usable volume in the RWMT, when taking into account vortexing, air entrainment, and instrument uncertainties, revealed that 26 feet in the RWMT corresponded to only 273,000 gallons. The licensee initiated CRDR 284173 to enter this item into the corrective action system. The licensee performed revised calculations (including instrument uncertainty and vortexing concerns) and determined that the minimum level for the RWMT to serve as a backup source for the CST was 28 feet, which demonstrated the Technical Specification Bases was nonconservative. However, the inspectors noted that the RWMT was administratively controlled by a non-surveillance procedure to greater than 33 feet. The licensee plans to revise surveillance procedures and the Technical Specification Bases to require the RWMT to be greater than 28 feet to be declared operable for supplying the auxiliary feedwater system. The licensee performed a review and found no examples in which the RWMT was credited for the CST and the level was less than 28 feet. The failure to adequately translate the design basis into procedures, by requiring 28 feet in the RWMT, is a second example of violation of 10 CFR 50, Appendix B, Criterion III.

Based upon a review conducted after the inspectors' questioning, the licensee identified another minor design control issue with respect to the usable inventory for the CST. Review of calculations for the feedwater line break revealed that the vendor calculations assumed a cooldown from Mode 3 to only 400•F, while the design basis, UFSAR and Technical Specification assumed a cooldown to 350•F. The inspectors considered this to be a minor violation of 10 CFR 50, Appendix B, Criterion III, for inadequate design control. With this assumption, Westinghouse calculated that 253,000 gallons of water were necessary to support the 8 hour hold and subsequent cooldown. The licensee contacted the vendor to perform the proper calculation with the UFSAR and design basis cooldown to 350•F. The revised calculations resulted in a increased required inventory to approximately 270,000 gallons. However, this was less than the available 300,000 gallons. Therefore, the issue was similar to Example 3.I of MC 0612, in which only a minor reduction in margin was noted and the amount of water was sufficient to meet the design basis. Thus, the failure to implement adequate design controls for the feedwater line break analysis is considered an additional minor example of the violation, and is not subject to enforcement action.

In addition to the noncited violation, the inspectors noted several other licensee performance deficiencies during their document review and interaction with station personnel on this issue. The inspectors also determined this noncited violation had cross-cutting aspects of human performance. Specifically, attention to detail was lacking and there was poor inter- and intra-group coordination. These deficiencies are discussed below:

- The licensee established key systems and design parameters for review under the evaluation of the (Yellow) ECCS finding, consistent with Inspection Procedure 95002 criteria. Both the safety injection system and the auxiliary feed system were selected for these key reviews. Similar to the RWT voiding issue (Section 4OA5.1), the inspectors found several deficiencies in an area that was specifically reviewed by the licensee.

- The inspectors determined that the licensee's evaluation of technical issues was iterative. The inspectors noted that engineering personnel would address only a particular aspect or consideration of a design problem. Specifically, during the review of CST and RWMT calculations, inspectors identified multiple problems, during several successive meetings, over the period of a week. This was done because the licensee relied on unstated or inaccurate assumptions in the evaluation, and accepted unverified design criteria from other groups. When additional discrepancies were raised by the inspectors, the licensee required additional rounds of evaluation. The similar organizational and human performance issues in this area, to the original finding, demonstrated lack of effectiveness in the extent of cause review for the (Yellow) ECCS voiding issue.

- The inspectors determined that the effectiveness reviews did not ensure timely review of the adequacy of corrective actions. Two root causes and one of the contributing causes of the (Yellow) ECCS voiding issue were addressed by a condition report action item (CRAI 2825679), which at the time of the inspection was already closed. Similar to that described with the RWT voiding violation (Section 4OA5.1), this corrective action appeared to be ineffective in that

engineering evaluations for the CST and RWMT issues lacked thorough and critical reviews.

- The inspectors found multiple examples of design control findings, and failures to communicate and coordinate design issues between organizations. The inspectors concluded that the licensee had not effectively addressed cross-cutting aspects of problem identification and resolution.

Analysis. These two examples of a violation affect the Mitigating Systems cornerstone and are more than minor because they were similar to Example 3.I of MC 0612, and design calculations were required to be re-performed to assure accident requirements were met. In both instances, the originally calculated available inventory was less than the actual design basis inventory of 299,700 gallons required for Unit 2 (and Units 1 and 3 after power uprate) to support the assumed 8 hours at hot standby followed by a cooldown to 350•F at 75•F per hour. Subsequent calculations by engineering personnel, including significant reduction in margins, demonstrated that minimum required volumes in the CST and RWMT were maintained. Using the MC 0609, "Significance Determination Process," Phase 1 worksheet, the inspectors determined that the issue was of very low safety significance (Green) because there was no actual loss of safety function.

Enforcement. Title 10, CFR 50, Appendix B, Criterion III, states, in part, that the applicable regulatory requirements and the design basis shall be correctly translated into specifications, procedures, and instructions. Contrary to this requirement, two examples were identified where applicable regulatory requirements, and the design basis, were not adequately translated into specifications, procedures, and instructions. Specifically, in Example 1, Technical Specification 3.7.6 and its bases, required 300,000 gallons of usable inventory in the CST, but Calculation 13-MT-CT-205 required an operator action (closing the auxiliary feedwater minimum flow recirculation valve) that was not translated into procedures to ensure that the design basis CST inventory was available. In Example 2, Technical Specification 3.7.6 credited the RWMT as the alternate source of water if the CST was inoperable. The bases for Technical Specification 3.7.6 stated that 300,000 gallons of usable inventory were available at 26 feet, but Calculation 13-JC-CH-0214 (as revised) stated that a level of 28 feet in the RWMT was required for 300,000 gallons to be available. Although an original design calculation error was made in 1992, the licensee missed several recent opportunities in 2004 and 2005 to resolve these discrepancies. Because the two noncited violation examples were of very low safety significance and have been entered into the corrective action program as CRDRs 2839337, 2840186, and 2841773, this violation is being treated as a noncited violation, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000529/2005012-02, Improper Design Control for CST and RWMT Usable Volume to Auxiliary Feedwater.

.3 Independent NRC Inspection: Refueling Water Tank Instrument Calibration

Introduction. The inspectors identified a (Green) noncited violation of 10 CFR 50, Appendix B, Criterion III, "Design Control," related to improper design calculations used to calibrate RWT level instruments. Specifically, the inspectors determined that the RWT level instruments were not properly compensated for either the effects of the

tank's Technical Specification allowable range of temperature, or the tank's allowable Technical Specification range of boric acid concentration. Therefore, the indications to the operators, and the automatic RAS could be in error. This affected both trains of indication on all three units.

Description. The inspectors selected a review of instrumentation for the RWT under the independent inspection portion of Inspection Procedure 95002. Errors in design basis assumed volumes could lead to earlier than anticipated voiding of the RWT discharge piping and, therefore, an earlier onset to potential air entrainment into ECCS piping. The inspectors found that Section 5.3 of design Calculation 13-JC-CH-0209, Revision 6, which was specified to address these uncertainties, was inappropriately deleted in a previous calculation revision. Design engineers subsequently provided calculations to the inspectors that showed how the effects were compensated for in the RWT instrument calibration. However, the inspectors noted that compensation was unidirectional, in that, temperature compensation was performed for only the highest design temperature of the RWT, and that solution density was only compensated for the highest concentration of boron in the RWT. The inspectors verified that the RWT has UFSAR design ranges of 40 to 120•F for temperature, and 4000 to 4400 ppm for boron concentration. The inspectors also verified that the RWT has both maximum and minimum design volumes for various UFSAR accident assumptions, thus, requiring the instruments to account for bi-directional uncertainties. The inspectors found this to be another example of engineering personnel either not understanding, or missing, important design interface requirements needed to properly address design calculations. Engineering personnel were subsequently able to demonstrate that the calculations could be adjusted for this uncertainty without the RWT instruments being declared inoperable. The licensee initiated CRDR 2840920 to address the corrective actions of this issue, including the review of similar systems where bi-directional uncertainties may not have been addressed.

Analysis. The inspectors determined that the engineering personnel's failure to include proper design basis information in the calibration of RWT level instrumentation was a performance deficiency. This issue was determined to affect the Mitigating Systems cornerstone and was more than minor based upon review of Example 3.j of MC 0612, Appendix E. The errors were considered more than a minor calculation error because the deficiencies required re-performance of the calculations, significantly reduced the overall margin, and could be applicable to other such instrumentation calculations. However, engineering personnel demonstrated that while there was a loss of margin, there was no actual loss of function because of the inaccuracies in the RWT level instrument calibrations. Using the MC 0609, "Significance Determination Process," Phase 1 worksheet, the inspectors determined that the issue was of very low safety significance (Green) because there was no actual loss of safety function.

Enforcement. Title 10, CFR 50, Appendix B, Criterion III, "Design Control," states that the applicable regulatory requirements and the design basis shall be correctly translated into specifications, procedures, and instructions. Contrary to this requirement, the licensee failed to translate the design basis into specifications, procedures, and instructions. Specifically, the licensee did not include the UFSAR and Technical Specification minimum and maximum ranges of temperature and boric acid concentration into level instrument calibration design calculations and procedures.

Because the finding is of very low safety significance and has been entered into the corrective action program as CRDR 2814209, this violation is being treated as a noncited violation, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000528; 05000529; 05000530/2005012-03, Improper Design Control for RWT Level Instrument Calibration.

.4 Independent NRC Inspection: Operability Determinations

Introduction. The inspectors identified three examples of a (Green) noncited violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings." Specifically, the licensee failed to follow a procedure and to provide appropriate quantitative or qualitative acceptance criteria for determining that important activities have been satisfactorily accomplished, consistent with the facility's administrative procedure for the operability determination process. These deficiencies resulted in several failures to perform timely or required operability determination evaluations by operations personnel following identification of degraded or nonconforming conditions.

Description. The inspectors evaluated the licensee's operability determination process in order to assess the effectiveness of corrective actions developed for engineering and operations interface problems. These problems were identified by the licensee as contributing factors of both the (Yellow) Design Control and 10 CFR 50.59 violations. The inspectors noted there were a number of deficiencies identified with the operability evaluation process during the special inspection of the original issue in August 2004. NRC inspectors also observed similar problems in 2005. As described in NRC Special Inspection Report 05000528; 05000529; 5000530/2004014, a number of deficiencies were identified involving the failure to implement the operability determination process in accordance with procedural guidance. These identified deficiencies involved: (1) engineering personnel failing to immediately inform the shift manager of the affected units after identifying that a voided condition could adversely affect the operability of the high pressure safety injection and CSS pumps; (2) the licensee operated the facility without a reasonable assurance of operability; (3) operations personnel did not implement a continuous operability determination process; (4) operations personnel did not declare the SIS and CSS inoperable even though mounting evidence suggested the final analysis would conclude equipment would not perform its intended safety function; and (5) operations personnel did not perform an initial operability determination for the as-found conditions of the SIS and CSS.

The inspectors reviewed several CRDRs that documented degraded or non-conforming conditions in order to conduct this assessment. This was done, in accordance with Inspection Procedure 95002, to ensure previous corrective actions for the (Yellow) ECCS finding were properly addressed. In a limited sample size, the inspectors identified several examples where implementation of the operability determination process was inadequate. The inspectors determined that these deficiencies were a result of the failure to follow the procedural guidance and ambiguous/inadequate procedural guidance. The inspectors determined that these deficiencies resulted in the failure to perform operability determinations for the following examples of identified degraded or nonconforming conditions:

- The inspectors reviewed CRDR 2822162, dated August 12, 2005. The CRDR addressed the omission of a design basis requirement from the design basis manual and associated plant procedures. Updated Final Safety Analysis Report, Section 6.3.1.3, stated, in part, that no single failure shall allow the compressed nitrogen system delivery pressure (to the safety injection tanks) to exceed 700 psig. The CRDR identifed that the nitrogen supply relief valve setpoint was 725 psig, which exceeded the 700 psig limitation. The licensee concluded that the condition would not over-pressurize the safety injection tanks because they were provided with adequate relief valves, with setpoints of 700 psig.

  The inspectors questioned if the 725 psig nitrogen supply relief valve was adequately sized to provide relief of the nitrogen air system to prevent over-pressurizing safety-related parts of the system. Following review of this question, engineering personnel determined that the relief valve capacity was not adequate and could result in over-pressurization of nitrogen system containment isolation valve, J-GAA-UV0001, and associated piping. The licensee added this newly identified deficiency into the corrective action process as a revision to CRDR 2822162, even though it involved a different degraded condition. Subsequently, the inspectors questioned if this condition had been reviewed for operability by operations personnel. Engineering personnel stated that the technical justification for operability was included in the revised action item, but that the issue had not been reviewed by operations.

  As a result of these discussions, on October 28, 2005, operations personnel were informed of this nonconforming condition by engineering personnel and an operability determination was performed for the potential over-pressurization condition. The inspectors reviewed the technical basis for operability and also concluded that integrity of the containment isolation valve and piping would be maintained for this nonconforming condition.

  The inspectors noted that Administrative Procedure 90DP-0IP10, "Condition Reporting," Revision 21, stated that if a condition is a nonconforming condition or degraded condition that may affect the ability of a system, structure, or component to perform its safety function the originator shall immediately notify the shift manager of the affected unit(s). Additionally, Administrative Procedure 40DP-90P26, "Operability Determination," Revision 14, stated that all site personnel are to promptly notify the shift manager upon discovery of any degraded/nonconforming condition potentially impacting a system, structure, or component. The inspectors determined that engineering personnel failed to follow procedural guidance to promptly notify the shift manager of the potential over-pressurization condition in order to evaluate the operability of affected structures, systems, or components (SSC).

- The inspectors identified that the licensee failed to perform an operability determination prior to plant restart on October 18, 2005, for a nonconforming condition involving potential air entrainment into the ECCS suction piping from the RWT following a RAS, as described in Section 4OA5.1 of this report. On October 11, 2005, Units 2 and 3 were shut down based on this condition having the potential to adversely affect the operability of the SIS and CSS. While the

units were in a shutdown condition, the licensee performed an analysis that determined the affected systems would not be adversely affected by entrained air, however, the inspectors noted that this analysis concluded that air would be entrained into the systems suction piping constituting a nonconformance with the facility licensing basis. The facility licensing basis assumed that the piping systems would be maintained filled with water and that this condition would remain throughout a loss of coolant accident (LOCA) as demonstrated by the systems available net positive suction head analysis.

The inspectors determined the licensee inappropriately concluded that the analysis supported the facility licensing basis resulting in the failure to consider it a nonconforming condition. Additionally, licensed operators informed the inspectors that the facility procedural guidance did not require an operability determination for this issue because the analysis that was performed demonstrated there was no adverse impact affecting the ability of the systems to perform their specified safety function. Specifically, Administrative Procedure 40DP-9OP26, "Operability Determination," Revision 14, Section 3.1.2, states, that "entry into the operability determination process is not required for degraded/nonconforming conditions that do not impact a specified safety function." The inspectors determined that an operability determination was required for this nonconforming condition since it placed the facility in an unanalyzed condition departing from that described in the UFSAR and departing from the design basis net positive suction head calculations that assumed the piping systems would be maintained full of water.

Additionally, the inspectors noted that Administrative Procedure 40DP-9OP26, "Definitions and Abbreviations," Revision 14, Section 4.0, stated that the definition of operability determination is the process of determining whether or not an identified degraded or nonconforming condition has an impact on the operability of Technical Specification related SSC's and all necessary support systems required to perform the SCC's specified safety function. This definition supported the inspectors' conclusion that an operability determination was warranted to evaluate the identified nonconforming condition. Therefore, the inspectors determined that the ambiguity in the licensee's operability determination process contributed to their failure to perform an operability determination.

- The inspectors reviewed CRDR 2822116, which was initiated on August 12, 2005 (19 days). This CRDR was initiated by engineering personnel following a system walkdown of the Unit 2 safety injection system. The CRDR documented two concerns. The first concern questioned the condition of the oil in containment spray pump Motor 2MSIAP03. The CRDR documented that there had been a history of contaminated oil or the use of incorrect oil being added to those pumps and motors. The second concern documented a "severe" packing leak on high pressure safety injection Valve 1JSIBUV0626.

The inspectors noted that both of the concerns documented in the CRDR potentially impacted the ability of an SSC to perform its specified safety function. As a result, the potentially degraded conditions should have been processed

through the licensee's operability determination process. The inspectors noted that the CRDR was not sent to the control room for review until August 31, 2005. As previously discussed, Administrative Procedure 90DP-0IP10, Revision 21, stated that if a condition is a nonconforming condition or degraded condition that may affect the ability of an SSC to perform its safety function the originator shall immediately notify the shift manager of the affected unit(s). Additionally, the inspectors noted that the control room only addressed the operability of the potentially degraded containment spray pump motor oil and not the degraded high pressure safety injection valve. An engineering evaluation of both conditions was performed and documented in the CRDR on September 2, 2005, where it was determined that operability of the components was not adversely impacted.

The inspectors reviewed Procedure 40DP-9OP26, Revision 14, which addresses when the operability determination process should be implemented. The inspectors determined that the procedural guidance for when an OD is necessary was inadequate. Section 1.2 of the procedure stated that the OD process is entered when the ability of an SSC to perform its specified safety function is questioned. However, Section 3.1.2 stated entry into the OD process is not required when degraded or nonconforming conditions do not impact a specified safety function. Finally, Section 3.2 required entry into the OD process when the control room review of a CRDR cannot readily evaluate the impact on an SSC's ability to perform its specified safety function. The inspectors interviewed various personnel from operations and engineering in order to assess how those groups implemented the OD procedure. The interviews revealed that there was an inconsistent understanding of the phrase "impact a specified safety function." Some personnel indicated that they believed that the phrase meant a complete loss of a safety function as opposed to the degradation of a function. The examples previously cited in this section all question the ability of an SSC to perform its specified safety function or, at a minimum, this ability was not able to be readily evaluated. Either of the conditions required entry into the OD process as described in Sections 1.2 and 3.2 of Procedure 40DP-9OP26. The interpretation by some personnel that the specified safety function was not impacted by these conditions prevented entry into the OD process as described in Section 3.1.2 of Procedure 40DP-9OP26. The inspectors also concluded that the procedure lacked guidance or reference to Regulatory Information Summary 05-020, "Revision to Guidance Formerly Contained in NRC Generic Letter 91-18," (Part 9900 Guidance).

Analysis. The inspectors determined that the licensee's failure to follow and properly implement the station equipment operability procedure was a performance deficiency. The inspectors considered this finding to be more than minor, in accordance with MC 0612, since it potentially affected the Mitigating Systems cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences, and it affected the attributes of procedure quality and human performance. However, subsequent evaluations completed by the licensee verified that actual safety functions were not lost in any of these examples. The inspectors performed a Phase 1 significance determination, using MC 0609, and

determined this issue screens out as having very low safety significance (Green) because a safety function was not lost.

Enforcement. Title 10, CFR 50, Appendix B, Criterion V, states that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, and that appropriate quantitative or qualitative acceptance criteria for determining that important activities have been satisfactorily accomplished. Specifically, the inspectors determined that Administrative Procedure 40DP-90P26, "Operability Determination," Revision 14, was not followed and did not specify appropriate acceptance criteria. Because the finding is of very low safety significance and has been entered into the corrective action program as CRDR 2838626, this violation is being treated as a noncited violation, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000528; 05000529; 05000530/2005012-04, Failure to Properly Implement Station Procedure for Equipment Operability (Technical Specification 5.4.1.a).

.5 Corrective Action Effectiveness

.a Scope of Review

Consistent with Section 02.03 of NRC Inspection Procedure 95002, the team performed inspections to determine that appropriate corrective action(s) were specified for each root/contributing cause or that there was an evaluation that no actions was necessary; determine that the corrective actions have been prioritized with consideration of the risk significance and regulatory compliance; determine that a schedule has been established for implementing and completing the corrective actions; and determine that quantitative or qualitative measures of success have been developed for determining the effectiveness of the corrective actions to prevent recurrence.

.b Corrective Actions for Severity Level III 10 CFR 50.59 Violation

The inspectors reviewed the licensee's corrective actions associated with the Severity Level III violation for an improper 10 CFR 50.59 evaluation of a change to the plant, resulting in the previously mentioned voided condition. The inspectors determined that the licensee performed a comprehensive evaluation of the 10 CFR 50.59 issue, including overall deficiencies identified with the program. The evaluation identified the primary root causes of the performance issue to be (1) The procedure revision process (01AC-0AP02) was inadequate, in that, the procedure allowed 'pre-screening' of changes that could potentially bypass performing a 10 CFR 50.59 screening for changes to the facility as described in the licensing basis; and (2) CRDR program implementation was broadly ineffective. The licensee also identified overlap and interface problems between the CRDR, EER, and ICR programs in conjunction with inadequate training to recognize a CRDR condition contributed to the failure of personnel to initiate a CRDR in 1992 for the RAS piping concern.

The licensee's root-cause evaluation, and extent of cause/condition reviews, noted a number of previous procedural and human performance vulnerabilities with the 10 CFR 50.59 processes. These vulnerabilities accounted for most of the licensee's failures in this area. The inspectors noted that recently completed corrective actions, focused on the 10 CFR 50.59 process, implemented revised station procedures, and

provided mandatory training on handling of changes, test, and experiments. These changes brought the licensee's process in very close alignment with the regulatory requirements of 10 CFR 50.59 and with industry standards such as Nuclear Energy Institute 96-07, "Guidelines for 10 CFR 50.59 Implementation." The inspectors attended licensee training sessions and critically reviewed station procedures for evidence of remaining vulnerabilities. The inspectors did not find any concerns with the licensee's current program. Therefore, the inspectors concluded that corrective actions were effectively developed and implemented for the Severity Level III violation of 10 CFR 50.59 requirements.

The inspectors had a minor concern with the licensee's extent of condition and extent of cause reviews for the previous 10 CFR 50.59 screening and evaluation process. This review was conducted on a limited sampling, based on statistical criteria, to review a representative group of such changes. A body of 116 previous changes were reviewed. The licensee's success criteria was established as there being no missed evaluations requiring prior NRC approval. While the licensee did meet this criteria in their sampling, they also identified 11 cases where they missed performing screenings. While the inspectors agreed with this concept from a risk and statistical approach, they concluded that the process still left the licensee vulnerable to having missed older screenings. However, the underlying requirement of 10 CFR 50.59 is to perform evaluations for issues that may require prior NRC approval. Neither the licensee nor the inspectors had examples of a missed screen leading to a missed evaluation. The inspectors noted that the licensee may want to consider further historical reviews for missed screenings and evaluations during ongoing efforts in design engineering reviews, UFSAR validation, and system safety function inspections.

.c Corrective Actions for Yellow Design Control Violation

The inspectors noted there was some confusion regarding the "problem statement" used in this evaluation. The official problem statement was, "The ECCS suction piping was supposed to be filled with water, but was inappropriately voided." The inspectors were concerned this statement was too narrowly focused to adequately investigate all of the potential performance deficiencies of this issue. However, the inspectors found that a more appropriate statement, "are there any physical or procedural conditions in the plant that differ from the conditions assumed in the plant design basis" was actually being used by many of the licensee's groups investigating the issue. While this would appear to be only an administrative issue, it did not align with the "iterative" process described in the licensee's root-cause methods (i.e., to loop back through the process with subsequently identified problems). In conjunction with this, some problems from this evaluation were worked in parallel to other programmatic issues and corrective actions that were ongoing at PVNGS (e.g.: human performance, engineering performance, corrective actions, etc.). Specific examples included finding problems with the UFSAR while doing system reviews for the ECCS violation, and interface issues between operations and engineering personnel in regard to equipment operability determinations. While the inspectors concluded that appropriate corrective actions were

identified for the ECCS violation, they could not determine whether the violation evaluation, or another site review process, was responsible for implementing the appropriate actions. Therefore, both the licensee and the inspectors had difficulties in assessing the overall resolution of issues, from the problem evaluation process, through implementation of corrective actions.

The inspectors noted the licensee identified the failure to effectively use operating experience as one of the contributing causes of this issue. The inspectors found additional examples of the failure to use available operating experience, as demonstrated under the RWT voiding issue (Section 4OA5.1). The inspectors also found additional examples of human performance issues identified in the evaluation that were contributors to the findings of this inspection. Of particular concern were additional examples of a lack of inter- and intra-group communications regarding engineering design issues as they pertained to equipment design and operability. Specifically, even after management communications with operations and engineering personnel regarding attention to detail, equipment operability, and critical thinking regarding equipment issues, the inspectors observed additional cases where this was not adopted by station personnel (reference CRAIs 2825677, 2825678, and 2825679). These additional cases were evident in all four of the NRC identified noncited violations of this inspection. The additional examples of poor communication of technical issues during this inspection led the inspectors to conclude that these attributes are ongoing deficiencies at PVNGS. At the time of the inspection, the inspectors could not conclude whether this was because of inappropriate corrective actions, or whether additional time was needed for the corrective actions to take effect. In either case, the inspectors concluded that the licensee did not adequately demonstrate the effectiveness of these corrective actions.

Some corrective actions were developed with no direct evidence of plans to periodically review for continuing problems, or to determine if additional or different corrective actions needed to be implemented. Based upon the inspectors' review, and interviews with station personnel, it was determined that the licensee was dealing with such deficiencies by channeling them back into the corrective action program. The NRC has identified there are substantive cross-cutting issues with PVNGS's corrective action program that are currently being addressed by the licensee. Also, the licensee described, in both this and the 10 CFR 50.59 issue evaluation, that there were a number of contributing issues stemming from the corrective action program. The inspectors noted that the licensee had not established additional direction or methods (i.e., contingencies) to deal with ineffective corrective actions from this significant condition investigation.

One specific example of this was evident in CRAI 2785352. The action was, "verify objective evidence (e.g., inspection, surveillance, or completion of fill and vent procedure) that demonstrate the suction lines are filled in each unit and are being maintained in a filled condition while operability requirements dictate." This action was in response to the ECCS voiding violation to ensure the piping between the inboard and outboard containment isolation valves remained filled with water. The measure of success was that no excessive or abnormal air was vented from the system. However, the inspectors noted that since the original Priority 2 corrective actions to fill the pipe (CRDR 2726509, Direct Cause 1) were closed in December of 2004, at least three

CRDRs had been entered into the corrective action program for excessive venting problems in this piping. However, there did not appear to be any specific mechanism to feed results of the corrective action program back into the evaluation of the Yellow finding, or into the assessment of effectiveness of the corrective actions for the Yellow finding. The inspectors were concerned that this could lead to corrective actions being taken independent of the original finding, or potentially being lowered in priority and closed to another process because there was no tie to the significant condition. In response to questions from the inspectors, the licensee stated that effectiveness reviews for this attribute (CRAI 2785352) were not due until February 2006. Therefore, the inspectors could not determine that appropriate success criteria have been developed for determining the effectiveness of these corrective actions to prevent recurrence. Also, in some cases it did not appear that the licensee considered effectiveness reviews to be a part of the corrective action process. The inspectors noted these reviews were not assigned, or maintained at, a priority commensurate with the issue. Therefore, the inspectors could not determine that corrective actions had been prioritized with consideration of the risk significance and regulatory compliance.

The licensee identified approximately 90 corrective actions associated with the Yellow finding. While scope and content of these actions would appear to be appropriate from a technical or logical point of view, further efforts are required to determine if they are effective (especially towards preventing repetition of the root causes). Specific examples include actions developed to improve attention to detail of personnel, actions to implement management expectations for engineering design, calculation reviews, and actions to develop appropriate thresholds for trend reviews. Also, while the corrective actions themselves were considered high priority, the licensee considered effectiveness reviews to be very low priority (Priority 4), consistent with that given to action enhancements. Such priority classification did not require completion ties to the original corrective actions and could allow closure without the formal reviews required for corrective actions to prevent recurrence. Again, coupled to the importance of the issue, and the fact that the licensee and the NRC have identified ongoing areas of concern with the corrective action program, the inspectors were concerned with the adequacy of followup to some important corrective actions. Some of the corrective actions were recently implemented, and effectiveness reviews were not yet formulated. An example of this is the development of human performance error codes for binning CRDRs with specific categories of engineering human performance errors or deficiencies. The inspectors found that personnel had a rough concept of doing this in the future, but they did not have any plan or resources established to do so. Overall, the inspectors could not determine, with some confidence, that these actions will prove to be effective in preventing repetition of the original issue.

The inspectors concluded that some of the attributes the licensee already established for acceptance of corrective actions for this issue, either by effectiveness reviews or by corrective action tracking and trending, did not appear to be appropriate. Examples of such attributes included "no licensee event reports written for failure of a system safety function" because of missed design interfaces (CRAI 2785362), or "no negative trends for significant or noteworthy events" (CRAI 2825633). The inspectors considered the acceptance criteria too high in that other issues of concern, such as system degradation or unanalyzed conditions, should also initiate a review of corrective actions. Another example was the use of terms that lacked content in the acceptance criteria. Repeated

use of the term "rigor" was applied to various corrective actions and even program changes (CRAI 2825632). It was described that an action or program lacked "rigor," that additional "rigor" would be added, and that effectiveness reviews would ensure "rigor" had been increased. The inspectors did appreciate the fact that many of the corrective actions were new, and that some actions are overlapping with other activities at PVNGS. The inspectors also understood that, for some of these issues, the licensee will need additional development or maturity of the actions to come to effectiveness conclusions. However, at the time of the inspection, the inspectors could not determine that measures of success have been developed for determining the effectiveness of all of the corrective actions to prevent recurrence.

.6 Assessment of Licensee Evaluations and Conclusions

a. The NRC performed this supplemental inspection, in part, to assess the licensee's evaluation and corrective actions associated with an inappropriate change to an emergency core cooling system procedure without prior NRC approval. This procedure change rendered portions of the system inoperable because of voiding. This performance issue was previously characterized as a Severity Level III violation of 10 CFR 50.59 and was originally identified in NRC Inspection Report 05000528; 529; 530/2004014. During this supplemental inspection, performed in accordance with Inspection Procedure 95002, the inspectors determined that the licensee's evaluation identified the primary root causes of the performance issue to be: (1) The site procedure revision process (01AC-0AP02) was inadequate, in that, the procedure allowed 'pre-screening' of changes that could potentially bypass performing a 10 CFR 50.59 screening for changes to the facility as described in the licensing basis; and (2) The corrective action program implementation was ineffective. The licensee also identified overlap and interface problems between the corrective action program, the engineering evaluation request program, and the instruction change request program. These issues, in conjunction with inadequate training to recognize a corrective action condition, contributed to the failure of station personnel to initiate a corrective action program input document in 1992 for the potential pipe voiding concern. The inspectors concluded that the licensee's evaluation and implemented corrective actions were appropriate to reasonably prevent repetition of the 10 CFR 50.59 violation.

Given the licensee's acceptable performance in addressing the inappropriate procedure change and 10 CFR 50.59 program deficiencies, the Severity Level III violation (VIO 2004/014-01) is closed.

b. The NRC performed this supplemental inspection, in part, to assess the licensee's evaluation and corrective actions associated with potential air entrainment into the emergency core cooling system. The licensee failed to incorporate original design requirements into the plant to maintain the containment sump suction piping filled with water. This performance issue was previously characterized as a 10 CFR 50, Appendix B, Criterion III, violation having substantial safety significance (Yellow), and was originally identified in NRC Inspection Report 05000528; 529; 530/2004014. The inspectors determined that the licensee's evaluation identified a direct cause, nine root causes, and nine contributing causes of the performance issue. The evaluation was also used to develop an extensive list of corrective actions. The inspectors found the

licensee's methods of evaluation to be appropriate. Additionally, the inspectors found that the corrective actions generally matched the causal factors.

The team determined that for each of the root and contributing causes, not all corrective actions were sufficiently developed to ensure that the identified performance deficiencies were adequately addressed. In addition, some of the corrective actions were narrowly focused, or the implementation of those actions was not fully effective. Also, the team concluded that criteria and reviews were not established, for auditing or followup, to ensure that corrective actions were effective in improving performance in the affected areas. Consequently, the team did not have assurance that planned corrective actions were sufficient to address the causes for the performance deficiencies associated with the violation. Therefore, the Yellow violation (VIO 2004-014-01) will remain open pending further NRC review.

4OA6 Meetings, Including Exit

Exit Meeting Summary

On December 16, 2005, the NRC inspectors leader presented the results of the supplemental inspection, conducted under Inspection Procedure 95002, to Mr. J. Levine, Executive Vice President of Generation, and other members of his staff. The licensee acknowledged the findings presented. The inspectors noted that while proprietary information was reviewed, none would be included in this report.

4OA7 Licensee Identified Violations

The following violations of very low significance (Green) were identified by the licensee and are violations of NRC requirements which meet the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as noncited violations.

.1 The licensee identified several violations of 10 CFR 50.59, "Changes, Tests and Experiments," or the accompanying Station Procedure 93DP-0LC07, "10 CFR 50.59 and 72.48 Screening and Evaluations," during their investigation of the Severity Level III violation. These were associated with failures to follow the station procedure, or the guidance of 10 CFR 50.59 when reviewing potential changes, tests, or experiments at PVNGS. The inspectors reviewed the following items and verified the issues were not greater than very low safety significance (Green), were not repetitive, and were entered into licensee's corrective action program. Missed or improperly performed screenings and evaluations were also verified to not require prior NRC approval.

.a The licensee identified that a change to Procedure 73ST-9SI06, "Containment Spray Pumps and Check Valves - Inservice Test", changed the minimum Containment Spray pump miniflow flowrate from 150 gpm to 132 gpm. This change was made to support the flowrate change specified in Calculation 13-JC-SI-0231. Two 10CFR 50.59 Screenings (S-04-0310 and S-05-0225) were performed to support the changes to these two documents. Both screenings concluded that there was no adverse impact from the change; subsequently, no 50.59 evaluation was conducted. A subsequent review of these two screenings by the licensee found no reference to UFSAR section 6.5.2.7, paragraph

(A)7.13.13. This paragraph stated "Each CS pump bypass flow line shall be capable of passing 150 gpm with its CS pump operating at design operating conditions." The licensee has subsequently changed the CS pump miniflow back to the original 150 GPM. This finding was documented in CRDR 2829177.

.b The licensee identified multiple 10 CFR 50.59 Screenings that were not performed. Subsequent screenings by the licensee revealed no revisions that should have received a 10 CFR 50.59 evaluation. These include:

- A revision to Procedure 36ST-9SI04, "Safety Injection/Shutdown Cooling System Instrumentation Surveillance Test Train A," was made in 2004 with inconsistent instructions for testing the shutdown cooling valve interlocks. The change received no 10 CFR 50.59 screening and the issue was documented in CRDR 2800782.

- A revision to 41ST-1DG02, "Diesel Generator B Test," was made in 1993 that reduced a pressure acceptance value in the non-conservative direction without a source document reference. The change received no 10 CFR 50.59 screening and the issue was documented in CRDR 2799463

- A revision to Procedure 73ST-9SI10, "HPSI Pumps Miniflow Inservice Test," was made in 2001 that inadvertently removed steps from the procedure. The procedure in error was never physically implemented before the error was discovered. The error was corrected upon discovery. The change received no 10 CFR 50.59 screening and the issue was documented in CRDR 2792530.

- A revision to Procedure 43ST-3AF02, "Auxiliary Feedwater Pump AFA-P01 Operability Test," was made in 1994. The procedure revision specified new operational guidance for the pressurizer. The change received no 10 CFR 50.59 screening and the issue was documented in CRDR 2809070.

- A revision to Procedure 36ST-9AF02, "Post Accident Monitoring Auxiliary Feedwater Flow Instrument Calibration," was made in 2001 based on calculation revisions made in 1997, 1998, and 2000. Instruments were calibrated with revised acceptance criteria and a 10 CFR 50.59 screening was not performed for either the surveillance test revision or the 1998 and 2000 calculation revisions (the 1997 calculation revision did have a 10 CFR 50.59 screening performed). The change received no 10 CFR 50.59 screening and the issue was documented in CRDR 2788278.

- A revision to Procedure 41OP-1EW01, "Essential Cooling Water System Train A," was made in 2000 that deleted a component from a table requiring verification of adequate cooling flow. The change received no 10 CFR 50.59 screening and the issue was documented in CRDR 2807325.

- A revision to Procedure 40OP-9SI02, "Shutdown Cooling Initiation," was made in 2004 that deleted a requirement for containment pressure to be less than 0.5 psig when checking the RAS sump level. The change received no 10 CFR 50.59 screening and the issue was documented in CRDR 2810735.

- A revision to Procedure 40OP-9DG02, "Emergency Diesel Generator B," was made in 1999 that allowed the diesel to be shutdown without resetting safety signals. The change received no 10 CFR 50.59 screening and the issue was documented in CRDR 2810830.

- A revision to Procedure 74OP-9SP01, "Manual Chemical Additions to the ESPS," was made in 1999 that added extra steel skid basins were added to the plant. The change received no 10 CFR 50.59 screening and the issue was documented in CRDR 2810961.

- A revision to Procedure 41OP-1SI03, "Safety Injection Tank Operations," was made in 1987 that changed the operation of the HPSI system during Safety Injection Tank fill. The change received no 10 CFR 50.59 screening and the issue was documented in CRDR 2812165.

- A revision to 41OP-1SI01, "Shutdown Cooling Initiation," was made in 1995 that changed the LPSI pump operating temperature band from a high temperature limit of 300• •F to a limit of 350• •F. In addition, the shutdown cooling initiation time following a tornado damage event was changed from 10.5 hours to 13 hours. The change received no 10 CFR 50.59 screening and the issue was documented in CRDR 2812185.

.c Criterion XI, "Test Control," of 10 CFR 50, Appendix B, requires that a test program be established to assure that all testing required to demonstrate that structures, systems and components will perform satisfactorily in service. Contrary to this, the licensee identified cases where test programs were not established. The inspectors reviewed the following items and verified the issues were not greater than very low safety significance (Green), were not repetitive, and were entered into the licensee's corrective action program.

- The licensee identified that required performance tests on the instrument air system have not been performed. The Instrument Air Design Basis Manual, Table 3.1, "System Performance Parameters and Limits," provides specifications and acceptance criteria for the purpose of defining the air quality in terms of clean, dry, and oil free, and table 8.1, "Design Requirements," lists ISA S7.3, "Quality Standard for Instrument Air," as the standard for establishing performance limits for the delivery of clean, dry oil free air. Procedure 73MT-9IA01, "Instrument Air System Quality Testing," implements the testing requirements specified in the design standard for establishing the instrument air system capability for delivering clean, dry and oil free air. The licensee identified that the last

three consecutive semi-annual repetitive task work orders have been either waived or cancelled and the last successful performance of this test procedure was in the fall of 2003. This finding was documented in CRDR 2813390.

- UFSAR Table 9.5-8, "Diesel Generator Fuel Oil Storage and Transfer System Design Specifications," stated the diesel fuel oil day tank has a capacity of 1,170 gallons. Additionally Section 9.5.4.2.3, "Diesel Generator Fuel Oil Day Tanks," stated each diesel generator fuel oil day tank has a capacity of 1170 gallons. Contrary to this requirement, engineering design reference document Drawing M018-218, Rev. 12 indicated each tank only had a capacity of 1100 gallons. The discrepancy is a result of an incorrect volumetric calculation that uses the outer tank dimensions. The licensee plans to submit a license amendment and update the UFSAR to address the discrepancy. This finding was documented in CRDR 2825638.

ATTACHMENT: SUPPLEMENTAL INFORMATION

ATTACHMENT

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

S. Bauer, Department Leader, Regulatory Affairs
P. Borchert, Director, Work Management
D. Carnes, Director, Nuclear Assurance
P. Carpenter, Unit Department Leader, Operations
C. Churchman, Director, Engineering
S. Coppock, Department Leader, System Engineering
J. Copsey, Department Leader, Employee Concerns
E. Dutton, Section Leader, Performance Improvement
C. Eubanks, Vice President, Operations
D. Fan, Department Leader, Design Mechanical Engineering
J. Gaffney, Director, Radiation Protection
T. Gray, Radiological Services Department Leader, Radiation Protection
J. Hesser, Director, Emergency Services
P. Kirker, Unit Department Leader, Operations
D. Leech, Department Leader, Nuclear Assurance
J. Levine, Executive Vice President, Generation
D. Marks, Section Leader, Regulatory Affairs - Compliance
D. Mauldin, Vice President, Engineering and Support
M. McGhee, Unit Department Leader, Operations
M. Muhs, Department Leader, Maintenance
M. Radsprinner, Section Leader, Systems Engineering
T. Radtke, Director, Operations
F. Riedel, Director, Nuclear Training
G. Schiavonne, Manager, Human Resources
J. Scott, Section Leader, Nuclear Assurance
C. Seaman, Director, Regulatory Affairs
M. Shea, Director, Maintenance
D. Smith, Plant Manager, Production
M. Sontag, Department Leader, Nuclear Assurance
E. Sonn, Lead Investigator, Nuclear Assurance
D. Straka, Senior Consultant, Regulatory Affairs
R. Stroud, Senior Consultant, Regulatory Affairs
J. Taylor, Department Leader, Operations Support
T. Weber, Section Leader, Regulatory Affairs
D. Wheeler, Section Leader, Nuclear Assurance

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

05000528; 05000529; 05000530/2005012-01	NCV	Improper Design Control for Emergency Core Cooling System Sump and Refueling Water Tank Swapover (Section 4OA5.1)
05000529/2005012-02	NCV	Improper Design Control for Condensate Storage Tank and Reactor Water Makeup Tank Usable Volume to Auxiliary Feedwater (Section 4OA5.2)
05000528; 05000529; 05000530/2005012-03	NCV	Improper Design Control for Refueling Water Tank Level Instrument Calibration (Section 4OA5.3)
05000528; 05000529; 05000530/2005012-04	NCV	Failure to Properly Implement Station Procedure for Equipment Operability (Technical Specification 5.4.1.a) (Section 4OA5.4)
05000528; 05000529; 05000530/2005012-05	FIN	Summary Finding. 95002 Inspectors Assessment of IR2004-14 Severity Level III Violation for 50.59 Issue (Section 4OA5.6.a)
05000528; 05000529; 05000530/2005012-06	FIN	Summary Finding. 95002 Inspectors Assessment of IR2004-14 (Yellow) 10CFR50, App B, Criterion III Violation (Section 4OA5.6.b)

Closed

05000528; 05000529; 05000530/2004014-04	VIO	Failure to Obtain Prior NRC Approval for a Change to the Facility Involving Maintaining a Significant Segment of Containment Sump Safety Injection Recirculation Piping Void of Water

Discussed

05000528; 05000529; 05000530/2004014-01	VIO	Failure to Maintain Design Control of Containment Sump Recirculation Piping

LIST OF DOCUMENTS REVIEWED

In addition to the documents called out in the inspection report, the following documents were selected and reviewed by the inspectors to accomplish the objectives and scope of the inspection and to support any findings:

CRDRs

2480956	2735332	2788278	2812536	2820942	2825651
2545839	2735671	2789716	2812581	2820943	2825655
2564840	2736059	2792412	2813174	2822116	2825656
2591324	2736344	2792530	2813390	2822162	2825666
2596717	2736931	2793982	2813941	2822173	2825945
2597959	2739903	2796054	2815762	2822179	2826158
2598002	2739903	2799463	2816891	2822183	2826516
2600100	2739906	2799503	2817300	2822185	2827637
2622935	2739907	2800782	2817663	2822188	2828923
2629963	2749131	2806832	2817867	2822189	2829113
2632229	2761657	2807325	2818727	2822199	2829157
2651672	2773847	2807967	2818957	2822493	2832412
2651750	2773947	2808867	2819031	2822997	2833766
2667754	2776864	2808871	2819057	2823022	2833962
2687507	2779536	2809070	2819277	2823174	2833976
2707325	2779536	2810138	2819291	2823205	2834900
2711241	2779903	2810228	2819345	2823598	2835132
2720228	2780273	2810735	2819366	2823676	2838079
2726509	2780286	2810830	2819394	2824540	2838308
2726522	2781196	2810929	2819903	2825078	2838314
2729600	2781602	2810961	2819904	2825103	2838368
2733983	2781795	2811543	2820580	2825209	2839337
2734065	2781949	2811670	2820583	2825354	2840186
2734089	2782645	2811940	2820731	2825638	2840920
2735052	2783898	2812165	2820745	2825644	2841773
2735329	2785296	2812185	2820920	2825647	2841872

CRAIs

2480956	2692688	2780273	2812581	2822183	2837332
2563861	2715910	2780286	2817300	2822493	2833754
2600100	2715911	2781602	2817867	2825655	2833755
2622935	2726522	2789716	2819291	2825666	2833766
2629963	2729600	2792412	2819394	2832381	2833962
2632229	2774508	2799463	2820920	2832809	2837332
2667754	2779903	2810228	2822173	2837051	

Calculations:

NUMBER	TITLE	REVISION
13-MC-SI-017	Safety Injection System Interface Requirements Calculation	5
13-MC-SI-018	Containment Spray System Interface Requirements Calculation	6
13-JC-DG-204	Diesel Generator Starting Air Receiver Pressure Loops J-DGN-P-0221,0222, 0223, & 0224 Uncertainty Calculation	0
13-MC-DF-306	As Built Calc for Sizing of Diesel Fuel Oil Storage and Day Tanks	6
13-MC-SI-230	Containment Spray System Maximum Flow Rate Evaluation	3
13-MC-SI-018	Containment Spray System Interface Requirements	6
13-JC-CH-0206	Refueling Water Tank Level Instruments (CHA-L-200 and CHBL-201) Setpoint and Uncertainty Calculation	7
13-JC-CH-0209	Refueling Water Tank Level Instrument (CHx-L-203x,x=A,B,C,D) Setpoint and Uncertainty Calculation	6
13-MC-CH-201	Refueling Water Tank (RWT), Hold-Up Tank (HT) and Reactor Makeup Water Tank (RMWT) Sizing	6
13-MC-CH-201	Refueling Water Tank (RWT), Hold-Up Tank (HT) and Reactor Makeup Water Tank (RMWT) Sizing	0
13-MC-CT-205	Condensate Storage Tank	4
13-MC-CT-307	CST Minimum Level Setpoint	4
FAI/05-106	Technical Assessment of the Check Valve Response for the Refueling Water Tank (RWT) Suction Line	0
FAI-05/06	Summary Report of MAAP4 LOCA Analysis in Support of Past Operability Assessment of Degraded HPSI Performance During Containment Recirculation at Palo Verde	0
FAI/05-107	The Potential for Air Intrusion and RWT Check Valve Response Following RAS	0

Calculations:

NUMBER	TITLE	REVISION
FAI/05-107	The Potential For Air Intrusion Following RAS	1
MISC-REC-249	ECCS Piping Interface Requirement per "Outstanding CESSAR Review Matter" Number 38, dated January 19, 1976	

Procedures:

NUMBER	TITLE	REVISION
01AC-0AP02	Review and Approval of Nuclear Administrative and Technical Procedures	1
01AC-0AP02	Review and Approval of Nuclear Administrative and Technical Procedures	2
01DP-0AP01	Procedure Process	19
01TD-0AP01	Technical Dictionary	11
12DP-0MC29	Warehouse Discrepancy	13
12DP-0MC29	Warehouse Discrepancy	14
12DP-0MC29	Warehouse Discrepancy	15
30DP-9WP02	Work Document Development and Control	34
30DP-9WP02	Work Document Development and Control	35
30DP-9WP02	Work Document Development and Control	36
40AL-9DG02	Diesel Generator B Alarm Panel Responses	16
40DP-9AP08	Loss of Coolant Accident Technical Guideline	14
40DP-9AP14	Functional Recovery Technical Guideline	16
40DP-9OP06	Operations Department Repetitive Task Program	80

Procedures:

NUMBER	TITLE	REVISION
40DP-9OP25	Special Variance	9
40DP-9OP26	Operability Determinations	14
40EP-9EO03	Loss of Coolant Accident	20
40EP-9EO09	Functional Recovery	25
40EP-9EO10	Standard Appendices	35
40OP-9SI01	Shutdown Cooling Initiation	35
40OP-9ZZ10	Mode 3 to Mode 5 Operations	43
40OP-9ZZ11	Mode Change Checklist	64
40OP-9ZZ23	Outage GOP	36
41ST-1ST09	ECCS System Leak Test	1
60DP-0QQ02	Trend Analysis and Coding	12
64DP-0QQ08	Vendor Corrective Action Report	7
64DP-0QQ08	Vendor Corrective Action Report	8
70DP-0EE01	Equipment Root Cause of Failure Analysis	12
70DP-0EE01	Equipment Root Cause of Failure Analysis	13
70DP-0EE01	Equipment Root Cause of Failure Analysis	14
70DP-0MR01	Maintenance Rule	11
73DP-0AP01	Writer's Handbook for Surveillance Test Procedures	
73DP-9XI01	Containment Spray Pumps and Check Valves - Inservice Test	16
73DP-9XI01	Containment Spray Pumps and Check Valves - Inservice Test	17

Procedures:

NUMBER	TITLE	REVISION
73DP-9XI01	Containment Spray Pumps and Check Valves - Inservice Test	18
81DP-0CC04	Calculations	0
81DP-0CC04	Calculations	1
81DP-0CC05	Design and Technical Document Control	27
81DP-0CC11	Specifications	3
81DP-0CC26	Impact Process	9
81DP-0CC28	Classification of Structures, Systems and Components	
81DP-0DC13	Deficiency Work Order	14
81DP-0DC13	Deficiency Work Order	15
81DP-0DC16	Engineering Document Change	15
81DP-0DC17	Temporary Modification Control	14
81DP-0EE10	Plant Modifications	11
90DP-0IP09	Differing Professional Opinion	8
90DP-0IP10	Condition Reporting	15
90DP-0IP10	Condition Reporting	16
90DP-0IP10	Condition Reporting	17
90DP-0IP10	Condition Reporting	18
90DP-0IP10	Condition Reporting	19
90DP-0IP10	Condition Reporting	20
90DP-0IP10	Condition Reporting	21

Procedures:

NUMBER	TITLE	REVISION
91DP-0EN02	Environmental Regulatory/Permit Review Form	4
93DP-0LC03	Licensing Document Maintenance	13
93DP-0LC07	10 CFR 50.59 and 72.48 Screening and Evaluations	0
93DP-0LC07	10 CFR 50.59 and 72.48 Screening and Evaluations	1
93DP-0LC07	10 CFR 50.59 and 72.48 Screening and Evaluations	2
93DP-0LC07	10 CFR 50.59 and 72.48 Screening and Evaluations	3
93DP-0LC07	10 CFR 50.59 and 72.48 Screening and Evaluations	4
93DP-0LC07	10 CFR 50.59 and 72.48 Screening and Evaluations	5
93DP-0LC07	10 CFR 50.59 and 72.48 Screening and Evaluations	6
93DP-0LC07	10 CFR 50.59 and 72.48 Screening and Evaluations	7
93DP-0LC07	10 CFR 50.59 and 72.48 Screening and Evaluations	8
93DP-0LC07	10 CFR 50.59 and 72.48 Screening and Evaluations	9

10 CFR 50.59 Screenings

S-04-0207 Rev 1	S-05-0211 Rev 0	S-05-0238 Rev 0	S-05-0291 Rev 0
S-04-0310 Rev 0	S-05-0215 Rev 0	S-05-0242 Rev 0	S-05-0292 Rev 0
S-05-0175 Rev 0	S-05-0217 Rev 0	S-05-0251 Rev 0	S-05-0304 Rev 0
S-05-0198 Rev 0	S-05-0218 Rev 0	S-05-0264 Rev 0	S-05-0305 Rev 0
S-05-0199 Rev 0	S-05-0220 Rev 0	S-05-0265 Rev 0	S-05-0306 Rev 0
S-05-0201 Rev 0	S-05-0222 Rev 0	S-05-0280 Rev 0	S-05-0307 Rev 0
S-05-0204 Rev 0	S-05-0224 Rev 0	S-05-0281 Rev 0	S-05-0308 Rev 0
S-05-0208 Rev 0	S-05-0225 Rev 0	S-05-0289 Rev 0	S-05-0309 Rev 0
S-05-0209 Rev 0	S-05-0230 Rev 0	S-05-0290 Rev 0	S-05-0329 Rev 0
S-05-0210 Rev 0	S-05-0234 Rev 0		

10 CFR 50.59 Evaluations

E-04-0001 Rev 0	E-04-0016 Rev 1	E-05-0007 Rev 0	E-05-0014 Rev 0
E-04-0003 Rev 0	E-04-0017 Rev 3	E-05-0008 Rev 0	E-05-0016 Rev 1
E-04-0004 Rev 0	E-04-0019 Rev 0	E-05-0009 Rev 0	E-05-0017 Rev 0
E-04-0009 Rev 1	E-04-0021 Rev 1	E-05-0010 Rev 0	E-05-0020 Rev 0
E-04-0010 Rev 2	E-05-0001 Rev 0	E-05-0011 Rev 0	E-05-0021 Rev 0
E-04-0011 Rev 2	E-05-0002 Rev 1	E-05-0012 Rev 0	E-05-0022 Rev 0
E-04-0012 Rev 0	E-05-0003 Rev 0	E-05-0013 Rev 0	E-05-0024 Rev
E-04-0015 Rev 0	E-05-0005 Rev 0		

Work Orders

2785677	2797835	2810262	2820785
2785680	2799903	2811953	2821677
2785683	2799906	2812589	2821687
2785686	2802503	2818161	2822503
2785688	2808406	2818162	2822503
2785691	2808866	2818599	2838626

Licensee Event Reports

2000-003-00	2004-009-00

Miscellaneous

NUMBER	TITLE	REVISION /DATE
01-M-CHP-002	P& I Diagram Chemical and Volume Control System	44
01-P-SIF-201	Safety Injection System ESF Pump Suction Lines - Train A	6
03-M-SIP-001	P& I Diagram Safety Injection & Shutdown Cooling System	25
102-03859-JML/AKK/GAM	Palo Verde Nuclear Generating Station (PVNGS) Units 1, 2, and 3 Docket Nos. STN 50-528, 50-529, and 50-530 Response to NRC Request for Information Pursuant to 10 CFR 50.54(f) Regarding Adequacy and Availability of Design Bases Information	2/11/97
102-05336-GRO/TNW/GAM	Palo Verde Nuclear Generating Station (PVNGS) Units 1, 2, and 3 Docket Nos. STN 50-528, 50-529, and 50-530 Response to Request No. 2 in NRC Generic Letter 2004-02, "Potential Impact of Debris Blockage on Emergency Recirculation during Design Basis Accidents at Pressurized-Water Reactors."	9/1/05

Miscellaneous

NUMBER	TITLE	REVISION /DATE
10407-13-MM-601	Model Testing of ECCS Containment Sump	
161-01159-EEVB/BJA	Units 1, 2, and 3 Response to NRC bulletin No. 88-04 File: 88-A-056-026, 88-055-026	7/8/88
161-01270-DBK/BJA	Units 1, 2, and 3 Additional Response to NRC bulletin No. 88-04 File: 88-A-056-026, 88-055-026	8/28/88
161-02345-WFC/RAB	Units 1, 2, and 3 Supplemental Response to NRC bulletin No. 88-04 File: 88-A-056-026, 88-055-026	9/21/89
161-04032-WFC/MEP/JMQ	Follow up to the Letter from W. F. Conway, APS, to NRC, 161-02345, dated September 21, 1988 - Reference C and Response to Action #3 of NRC Bulletin 88-04	7/1/91
255-01092-JJH	APS letter to Fauske and Associates, "PVNGS Transmittal of Qualified Data References for Report FAI/05-107"	
88-DG-042	Engineering Evaluation Request	3/11/88
Audit 2004-005	Corrective Actions	4/29/04
Audit 2005-005	Design Control	4/29/05
Audit 2004-010	Dry Cask Storage/ISFSI	9/22/04
Audit 2004-012	Maintenance	11/5/04
Audit 2005-004	Procurement and Material Control	4/14/05
Audit 2004-006	Refueling/Operations	6/25/05
Audit 2004-011	Technical Specifications/Admin Controls	10/8/04
CRDR Report 2726509	ECCS Sump Suction Piping Discovered in an Unanalyzed Condition	1
CVER-05-75	Westinghouse Letter, Evaluation of RWT Suction Behavior during SIS and CSS Transition at RAS and Related Design Interface Criteria	10/17/05
ER-05-0192	Nuclear Assurance Evaluation Report	
LDCR 2003-F039	Fire Protection Change Review	0

Miscellaneous

NUMBER	TITLE	REVISION /DATE
MP2-014-05	Operability Determination MP2-014-05	0
OD 301	Operability Determination #301	10/6/2005
OD 279	Operability Determination #279	7/31/2004
PG 120	PVNGS Self-Assessment and Benchmarking	5
PV-E0039 Ver. 6	Environmental Screening Worksheet	
PV-E0073 Ver. 7	Calculation Form	
PV-E0097 Ver. 4	Independent Verification Checklist	
PV-E0104 Ver. 4	Palo Verde Nuclear Generating Station Weld Data Sheet – 1 for Butt and Groove Welds	
PV-E0105 Ver. 3	Palo Verde Nuclear Generating Station Weld Data Sheet – 2 for Fillet and Socket Welds	
PV-E0117 Ver .8	Engineering Document Change Form	
PV-E0129 Ver. 5	Design Basis Manual Revision	
PV-E0303 Ver. 1	Specification/Revision Title Sheet Form	
PV-E0412 Ver 1	SWMS Associations Screen Changes for Calculation	
PV-E0436 Ver. 2	T-Mod Justification Review Worksheet	
SYS80-PE-IR20	NSSS Interface Requirements for Chemical and Volume Control System	6
	Chemical and Volume Control System Design Basis Manual	11
	Daily Earthmoving Log for Routine Operations & Maintenance Form	0
	Daily Earthmoving Log for Projects Form	0
	Diesel Generator, Class 1E Standby Generation, Fuel Oil Storage and Transfer System Design Basis Manual	15
	Operations Logs, Units-1, 2, and 3	10/28/05
	Operations Logs, Units-2 and 3	10/11/05
	Operations Logs, Units-2 and 3	10/7/05

Miscellaneous

NUMBER	TITLE	REVISION /DATE
	Operations Logs, Units-2 and 3	10/17/05
	Operations Logs, Units-2 and 3	10/16/05
	Operations Logs, Units-2 and 3	10/12/05
	Operations Logs, Units-2 and 3	10/8/05
	Operations Logs, Units-1, 2, and 3	10/6/05
	Safety Injection System Design Basis Manual	21
	Significant CRDR 2789716 Charter	0
	Significant CRDR 2789716 Charter	1
	UFSAR Verification Matrix, SI System	2

LIST OF ACRONYMS

ASME	American Society of Mechanical Engineers
CAP	corrective action program
CEA	control element assembly
CFR	Code of Federal Regulations
CRAI	condition report action item
CRDR	condition report/disposition request
CS	containment spray
CSS	containment spray system
CST	condensate storage tank
ECCS	emergency core cooling system
EER	engineering evaluation request
EPRI	Electric Power Research Institute
ESFAS	engineered safety features actuation system
gpm	gallons per minute
ICR	instruction change request
I&C	instrumentation and controls
LOCA	loss of coolant accident
LPSI	low pressure safety injection
MC	Manual Chapter
NCV	noncited violation
NDE	nondestructive examination
NRC	Nuclear Regulatory Commission
OD	operability determination
PID	Performance Improvement Department
ppm	parts per million
psia	pounds per square inch absolute
psig	pounds per square inch gauge
PVNGS	Palo Verde Nuclear Generating Station
RAS	recirculation actuation signal
RCS	reactor coolant system
RWMT	reactor water makeup tank
RWT	refueling water tank
SFP	spent fuel pool
SFHM	spent fuel handling machine
SIS	safety injection system
SSC	structure, system, and component
UFSAR	Updated Final Safety Analysis Report
VIO	violation

ATTACHMENT 4

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
611 RYAN PLAZA DRIVE, SUITE 400
ARLINGTON, TEXAS 76011-4005

March 2, 2005

Gregg R. Overbeck, Senior Vice
President, Nuclear
Arizona Public Service Company
P.O. Box 52034
Phoenix, AZ 85072-2034

SUBJECT: ANNUAL ASSESSMENT LETTER - PALO VERDE NUCLEAR GENERATING STATION (REPORT 05000528/2005001; 05000529/2005001; 05000530/2005001)

Dear Mr. Overbeck:

On February 3, 2005, the NRC completed its end-of-cycle plant performance assessment of the Palo Verde Nuclear Generating Station. The end-of-cycle review for Palo Verde involved the participation of reactor technical divisions in evaluating performance indicators for the most recent quarter and inspection results for the period from January 1 through December 31, 2004. The purpose of this letter is to inform you of our assessment of your safety performance during this period and our plans for future inspections at your facility so that you will have an opportunity to prepare for these inspections and to inform us of any planned inspections that may conflict with your plant activities.

This performance review and enclosed inspection plan do not include physical protection information. A separate end-of-cycle performance review letter designated and marked as "Exempt from Public Disclosure in Accordance with 10 CFR 2.390" will include the physical protection review and resultant inspection plan.

Overall, Palo Verde operated in a manner that preserved public health and safety and fully met all cornerstone objectives. Plant performance for the most recent quarter, as well as for the first three quarters of the assessment cycle, was within the Licensee Response Column of the NRC's Action Matrix, based on all inspection findings being classified as having very low safety significance (Green) and all performance indicators indicating performance at a level requiring no additional NRC oversight (Green). However, two apparent violations, including the final significance determination of an associated potentially greater than Green finding, involving the voiding of the emergency core cooling system containment sump suction piping is still under review as part of the significance determination and traditional enforcement processes. These apparent violations were discussed at a conference on February 17, 2005.

During the assessment process, the staff identified a substantive crosscutting issue in the area of human performance. The adverse trend in human performance issues indicates that you have not effectively addressed the underlying causes associated with this substantive crosscutting area. The substantive crosscutting issue involved 16 Green findings. These

findings shared several common performance characteristics; however, they were dominated by personnel errors (e.g., instances of failing to follow procedure) and resource issues (e.g., inadequate procedures and work instructions). These problems were identified across several cornerstones and involved multiple groups within your organization. Specifically, nine Green findings involving personnel errors were primarily associated with a failure to follow procedures. Three of these findings involved personnel failing to implement emergency procedures during the loss of offsite power event in June 2004, while other findings pertained to personnel errors involving the movement of irradiated fuel. In addition, four findings were identified regarding the adequacy of procedures and work instructions. In one example, the work instructions for pressurizer spray valve maintenance were not adequate and the valve failed open shortly after maintenance on the valve and valve positioner.

Additionally, a substantive crosscutting issue in problem identification and resolution has been identified based on a number of corrective action findings. The adverse trend in problem identification and resolution issues indicates that you have not effectively addressed the underlying causes associated with this substantive crosscutting area. The substantial crosscutting issue involved 18 Green findings. These findings were indicative of implementation problems within the specific areas of identifying problems and entering them in the corrective action program, evaluating conditions in the corrective action program, and implementing effective corrective actions. These problems were identified across several cornerstones and involved multiple groups within your organization. Specifically, four findings were identified with a common performance characteristic associated with the failure to adequately identify problems in your corrective action program. In two of these cases, NRC inspectors had to prompt Palo Verde staff members to enter problems into your program. In addition, seven findings shared a common performance characteristic associated with a failure to adequately evaluate conditions. Four of these examples involved the failure to promptly evaluate the operability of degraded or nonconforming equipment. This included the failure to promptly evaluate voided suction piping in the emergency core cooling systems. Also of concern were seven Green findings with a common performance characteristic associated with inadequate corrective actions. Several of these findings resulted in plant events or the failure of safety equipment to operate correctly during an event. For example, the failure to take adequate corrective actions for a failure of an emergency diesel generator excitation circuit contributed to the failure of the Unit 2, Train A emergency diesel generator to respond as designed to the loss of offsite power event in June 2004.

Through implementation of the baseline inspection program, we will assess your actions to address both of these crosscutting issues. The closure of these issues will be based on whether your corrective actions reduce the number of findings.

As noted in our previous annual assessment letter, a meeting was conducted at the NRC Region IV Office on January 14, 2004, to discuss aspects of safety conscious work environment at Palo Verde. This issue was discussed again in our midcycle assessment letter, dated August 30, 2004. During the January 14 meeting, you discussed plans to conduct additional employee training related to safety conscious work environment and conduct a site survey in 2005 to gauge the work environment and employee willingness to raise safety issues. We understand that the training has been completed and the site survey is scheduled to be completed by March 2005. We will continue to focus our baseline inspection activities on your actions to address your assessments in this area.

The enclosed inspection plan details the inspections, less those related to physical protection, scheduled through September 30, 2006. In addition to the baseline inspections, NRC will also be conducting inspections related to Inspection Procedure 50001, "Steam Generator Replacement Inspection," Temporary Instructions 2515/150, "Reactor Pressure Vessel Head and Vessel Head Penetration Nozzles," and 2515/160, "Pressurizer Penetration Nozzles and Steam Space Piping Connections in U.S. Pressurized Water Reactors (NRC Bulletin 2004-01)." The inspection plan is provided to minimize the resource impact on your staff and to allow for scheduling conflicts and personnel availability to be resolved in advance of inspector arrival onsite. Routine resident inspections are not listed due to their ongoing and continuous nature. The inspections in the last 9 months of the inspection plan are tentative and may be revised at the midcycle review meeting.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be made available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

If circumstances arise which cause us to change this inspection plan, we will contact you to discuss the change as soon as possible. Please contact me at 817-860-8173 with any questions you may have regarding this letter or the inspection plan.

Sincerely,

/RA/

Troy W. Pruett, Chief
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Enclosure:
Palo Verde Nuclear Generating Station
Inspection/Activity Plan

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Inspection / Activity Plan

03/04/2005 - 09/30/2006

Unit Number	Inspection Activity	Title	No. of Staff on Site	Planned Dates Start	Planned Dates End	Inspection Type
	OB-EP EX	**- EMERGENCY PREPAREDNESS EXERCISE**	5			
1, 2, 3	IP 7111401	Exercise Evaluation		02/28/2005	03/04/2005	Baseline Inspections
1, 2, 3	IP 7111404	Emergency Action Level and Emergency Plan Changes		02/28/2005	03/04/2005	Baseline Inspections
1, 2, 3	IP 71151	Performance Indicator Verification		02/28/2005	03/04/2005	Baseline Inspections
	EB17B	**- PERMANENT PLANT MODS**	2			
1, 2, 3	IP 7111117B	Permanent Plant Modifications		03/07/2005	03/11/2005	Baseline Inspections
	PEB-12B	**- MAINTENANCE EFFECTIVENESS**	2			
1, 2, 3	IP 7111112B	Maintenance Effectiveness		03/07/2005	03/11/2005	Baseline Inspections
	SG REPL	**- U1 STEAM GEN REPLACEMENT**	4			
1	IP 50001	Steam Generator Replacement Inspection		02/28/2005	12/31/2005	Other Routine
	EB	**- 10CFR50.59**	1			
1, 2, 3	IP 7111102	Evaluation of Changes, Tests, or Experiments		03/07/2005	03/11/2005	Baseline Inspections
	EB08P	**- ISI U2 - VESSEL VOL (TI 150/152) AS REQ**	2			
2	IP 2515/150	Reactor Pressure Vessel Head and Vessel Head Penetration Nozzles (NRC Bulletin 2002-02		04/04/2005	04/15/2005	Safety Issues
2	IP 2515/160	Pzr Pene Nozzles & Stm Space Piping Connections in U.S. PWRs [NRC Bulletin 2004-01]		04/04/2005	04/15/2005	Safety Issues
2	IP 7111108P	Inservice Inspection Activities - PWR		04/04/2005	04/15/2005	Baseline Inspections
2	IP 7111108P	Inservice Inspection Activities - PWR		04/11/2005	04/22/2005	Baseline Inspections
	OB-INIT	**- INITIAL EXAM**	3			
1	X02282	PALO VERDE UNIT1 (05/05) INITIAL EXAM		07/11/2005	07/15/2005	Not Applicable
2	X02283	PALO VERDE UNIT 2 (11/05) - INITIAL EXAM		07/11/2005	07/15/2005	Not Applicable
3	X02284	PALO VERDE UNIT 3 (11/05) - INITIAL EXAM		07/11/2005	07/15/2005	Not Applicable
1	X02282	PALO VERDE UNIT1 (05/05) INITIAL EXAM		08/01/2005	08/05/2005	Not Applicable
2	X02283	PALO VERDE UNIT 2 (11/05) - INITIAL EXAM		08/01/2005	08/05/2005	Not Applicable
3	X02284	PALO VERDE UNIT 3 (11/05) - INITIAL EXAM		08/01/2005	08/05/2005	Not Applicable
	EB08P	**- ISI U1 - VESS VOL (TI 150/152) AS REQ**	2			
1	IP 2515/160	Pzr Pene Nozzles & Stm Space Piping Connections in U.S. PWRs [NRC Bulletin 2004-01]		10/10/2005	10/14/2005	Safety Issues
1	IP 7111108P	Inservice Inspection Activities - PWR		10/10/2005	10/14/2005	Baseline Inspections
1	IP 7111108P	Inservice Inspection Activities - PWR		10/24/2005	10/28/2005	Baseline Inspections
	ACRSA	**- ACCESS CONTROL TO RAD SIGNIFICANT AREAS**	1			
1, 2, 3	IP 7112101	Access Control to Radiologically Significant Areas		10/17/2005	10/21/2005	Baseline Inspections
	EB21	**- ENG-SSD&PC**	6			
1, 2, 3	IP 7111121	Safety System Design and Performance Capability		01/09/2006	02/24/2006	Baseline Inspections
	OB-EP2	**- EMERG PREPAREDNESS PROGRAM INSPECTION**	1			
1, 2, 3	IP 7111402	Alert and Notification System Testing		01/23/2006	01/27/2006	Baseline Inspections
1, 2, 3	IP 7111403	Emergency Response Organization Augmentation Testing		01/23/2006	01/27/2006	Baseline Inspections

This report does not include INPO and OUTAGE activities.
This report shows only on-site and announced inspection procedures.

Inspection / Activity Plan

03/04/2005 - 09/30/2006

Unit Number	Inspection Activity	Title	No. of Staff on Site	Planned Dates Start	Planned Dates End	Inspection Type
	OB-EP2	**- EMERG PREPAREDNESS PROGRAM INSPECTION**	1			
1,2,3	IP 7111404	Emergency Action Level and Emergency Plan Changes		01/23/2006	01/27/2006	Baseline Inspections
1,2,3	IP 7111405	Correction of Emergency Preparedness Weaknesses and Deficiencies		01/23/2006	01/27/2006	Baseline Inspections
1,2,3	IP 71151	Performance Indicator Verification		01/23/2006	01/27/2006	Baseline Inspections
	ALARA1	**- ALARA PLANNING AND CONTROLS**	1			
1,2,3	IP 7112102	ALARA Planning and Controls		02/13/2006	02/17/2006	Baseline Inspections
	PEB-05T	**- TRIENNIAL FIRE PROTECTION**	4			
1,2,3	IP 7111105T	Fire Protection		04/10/2006	04/14/2006	Baseline Inspections
1,2,3	IP 7111105T	Fire Protection		04/24/2006	04/28/2006	Baseline Inspections
	EB08	**- U3-ISI**	1			
2	IP 7111108P	Inservice Inspection Activities - PWR		04/03/2006	05/05/2006	Baseline Inspections
	ACRSA	**- ACCESS CONTROL TO RAD SIGNIFICANT AREAS**	1			
1,2,3	IP 7112101	Access Control to Radiologically Significant Areas		04/10/2006	04/14/2006	Baseline Inspections
	PEB	**- PV PIR INSPECTION**	3			
1,2,3	IP 71152B	Identification and Resolution of Problems		05/08/2006	05/12/2006	Baseline Inspections
1,2,3	IP 71152B	Identification and Resolution of Problems		05/22/2006	05/26/2006	Baseline Inspections
	PEB	**- HX PERFORMANCE**	1			
1,2,3	IP 7111107B	Heat Sink Performance		06/05/2006	06/09/2006	Baseline Inspections
	OB-RQ	**- PV REQUALIFICATION INSP**	3			
1,2,3	IP 7111111B	Licensed Operator Requalification Program		08/07/2006	08/11/2006	Baseline Inspections

This report does not include INPO and OUTAGE activities.
This report shows only on-site and announced inspection procedures.

ATTACHMENT 5

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
611 RYAN PLAZA DRIVE, SUITE 400
ARLINGTON, TEXAS 76011-4005

March 2, 2006

James M. Levine, Executive
Vice President, Generation
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Arizona Public Service Company
P.O. Box 52034
Phoenix, AZ 85072-2034

SUBJECT: ANNUAL ASSESSMENT LETTER - PALO VERDE NUCLEAR GENERATING STATION (NRC INSPECTION REPORT 05000528/2006001; 05000529/2006001; 05000530/2006001)

Dear Mr. Levine:

On February 8, 2006, the NRC staff completed its performance review of the Palo Verde Nuclear Generating Station. Our technical staff reviewed performance indicators for the most recent quarter and inspection results for the period from January 1 through December 31, 2005. The purpose of this letter is to inform you of our assessment of your safety performance during this period and our plans for future inspections at your facility.

This performance review and enclosed inspection plan do not include physical protection information. A separate letter designated and marked as "Official Use Only - Security Related Information" will include the physical protection review and resultant inspection plan.

Overall, Palo Verde Nuclear Generating Station, Units 1, 2, and 3, operated in a manner that preserved public health and safety and met all cornerstone objectives with moderate degradation in safety performance. Plant performance for the most recent quarter for all three units was within the Degraded Cornerstone column of the NRC's Action Matrix based on one Yellow finding in the Mitigating Systems Cornerstone involving a significant section of containment sump safety injection piping that was void of water at all three Palo Verde Nuclear Generating Station units.

Our May 3, 2005, Assessment Follow-Up Letter identified that Palo Verde Nuclear Generating Station's performance was within the Degraded Cornerstone column of the NRC's Action Matrix. On June 14, 2005, the Arizona Public Service Company requested postponement of the planned NRC supplemental inspection in order to allow sufficient time to complete the root cause evaluations and develop corrective actions. Accordingly, the NRC staff delayed the inspection until the fourth quarter of 2005. In December 2005, the NRC completed the implementation of Supplemental Inspection Procedure 95002, "Supplemental Inspection for One Degraded Cornerstone or Any Three White Inputs in a Strategic Performance Area." This supplemental inspection reviewed your root cause, extent of cause and condition, as well as, the corrective actions for: (1) the Yellow finding involving the failure to adequately control the design configuration of the containment sump safety injection suction piping of all three units; and

(2) the Severity Level III violation for the failure to perform a 10 CFR 50.59 safety evaluation and receive prior NRC approval of a change to an emergency core cooling system (ECCS) leak test procedure. The results of the supplemental inspection were documented in NRC Inspection Report 05000528/2005012; 05000529/2005012; 05000530/2005012.

The NRC concluded that, while you performed an adequate root cause evaluation of the design control violation for the Yellow finding, certain corrective actions were incomplete at the time of the inspection. Specifically, for each of the root and contributing causes, not all corrective actions were sufficiently developed to ensure that the identified performance deficiencies were adequately addressed. Some of the corrective actions were narrowly focused, or the implementation of those actions was not fully effective at the time of the inspection. Additionally, monitoring criteria and reviews were not fully established to ensure that corrective actions were effective in improving performance. Consequently, we did not have assurance that your planned corrective actions were sufficient to address the causes for the performance deficiencies associated with the violation. We request that you inform us in writing once you have completed steps to assure that your corrective actions are of sufficient scope and breadth to address the subject performance deficiencies. The NRC will then perform additional inspections as necessary to assess the effectiveness of your actions. Pending completion of this follow-up inspection activity, including an NRC assessment that your corrective actions are sufficient to address the performance deficiencies, the Yellow finding in the Mitigating Systems Cornerstone will remain open.

For the violation involving the NRC's identification of a failure to perform a 10 CFR 50.59 safety evaluation and receive prior NRC approval for a change of an ECCS leak test procedure, the NRC concluded that you performed an adequate evaluation and implemented corrective and followup actions necessary to reasonably prevent repetition of the 10 CFR 50.59 Severity Level III violation. Therefore, this violation was closed.

In our Annual Assessment letter, dated March 2, 2005, and our midcycle assessment letter, dated August 30, 2005, we advised you of substantive crosscutting issues in the areas of human performance and problem identification and resolution. During this assessment period, we continued to identify findings with the same causes and common themes in both crosscutting areas. There were 16 Green findings with crosscutting aspects in the area of human performance. Our assessment indicates that your actions to date have not completely corrected the root causes associated with procedural compliance, procedural adequacy, and the interactions between engineering and operations personnel when assessing degraded and nonconforming conditions. Additionally, there were 12 Green and Severity Level IV findings with crosscutting aspects in the area of problem identification and resolution. Our assessment indicates that your actions to date have not completely corrected the root causes associated with the identification of non-conforming conditions, the evaluation of conditions adverse to quality, particularly by engineering and operations personnel, and the implementation of effective corrective actions for deficient conditions.

During the assessment period, the NRC performed periodic reviews of your corrective actions associated with both crosscutting areas. Following the issuance of the August 30, 2005, midcycle assessment letter, you completed re-analyses of the human performance and problem identification and resolution concerns. You also approved the Performance Improvement Plan in November 2005 and began briefing station personnel on improvement initiatives in

January 2006. Nevertheless, as of the end of the period, the implementation of the improvement initiatives had not completely addressed the original causes of the issues identified in our previous letters and discussed during public meetings conducted in April, May, and August 2005.

A meeting has been scheduled for March 30, 2006, in Arlington, Texas, to discuss the Performance Improvement Plan and corrective actions taken or planned to improve performance relative to these substantive crosscutting issues. You are requested to address these two issues during the Annual Assessment Meeting on April 5, 2006, in Tonopah, Arizona. Additionally, you are requested to provide a written response within 30 days of the date of this letter to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington DC 20555-0001; with copies to the Regional Administrator, U.S. Nuclear Regulatory Commission Region IV, 611 Ryan Plaza Drive, Suite 400, Arlington, Texas 76011-4005; and the NRC Resident Inspector at the Palo Verde Nuclear Generating Station, Units 1, 2, and 3, facility. Specifically, your written response should identify the probable causes, corrective actions you have taken or plan to take, and the estimated corrective action completion dates for performance deficiencies associated with: (1) the failure of personnel to follow procedures, (2) the use of inadequate procedures, (3) ineffective interactions between engineering and operations personnel when assessing degraded and nonconforming conditions, (4) inadequate identification of nonconforming conditions, (5) inadequate evaluation of conditions adverse to quality by engineering and operations personnel, and (6) inadequate and ineffective corrective actions.

Our midcycle assessment letter, dated August 30, 2005, also discussed the August 18, 2005, public meeting, in which your staff informed us of the results of the site-wide employee survey. The survey results included some conflicting results (e.g., positive statistical results of survey questions relative to negative write-in comments), and your staff discussed the need for further actions. The NRC focused on safety conscious work environment issues, including actions taken in response to the survey, as part of our routine baseline inspection activities and during the January 2006 problem identification and resolution inspection. No instances were identified in which plant personnel would not raise safety concerns. However, several personnel indicated that they did not believe management would resolve minor concerns when identified. Your 2005 Business Plan and Performance Improvement Plan include actions to address safety conscious work environment issues at the Palo Verde Nuclear Generating Station. We will continue to focus on your initiatives in this area as part of our baseline inspection program to monitor your corrective actions for these issues.

The August 30, 2005, midcycle assessment letter also discussed a Severity Level III violation issued on June 27, 2005. The violation involved the NRC's identification of a change to the Palo Verde Nuclear Generating Station Emergency Plan without prior Commission approval, which decreased the plan's effectiveness. The NRC staff conducted an inspection of your root cause analyses and corrective actions as part of the January 2006 problem identification and resolution inspection. The results of this inspection will be documented in NRC Inspection Report 05000528/2006008; 05000529/2006008; 05000530/2006008.

The enclosed inspection plan details the inspections, except those related to physical protection, scheduled through September 30, 2007. In addition to the baseline inspections, NRC will be implementing Inspection Procedure 50001, "Steam Generator Replacement

Inspection," relative to the planned replacement of the Unit 3 steam generators. We will conduct a follow-up Supplemental Inspection Procedure 95002 after receiving notification from you that the corrective actions for the Yellow finding are of sufficient scope and breadth (including the establishment of appropriate effectiveness measures) to address the subject performance deficiencies. We also plan to perform an additional problem identification and resolution inspection in early 2007 to further evaluate the effectiveness of your corrective actions in resolving the substantive crosscutting issues. The inspection plan is provided to allow for the resolution of any scheduling conflicts and personnel availability issues well in advance of inspector arrival onsite. Routine resident inspections are not listed due to their ongoing and continuous nature. The inspections in the last 9 months of the inspection plan are tentative and may be revised at the midcycle review.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be made available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

If circumstances arise which cause us to change this inspection plan, we will contact you to discuss the change as soon as possible. Please contact Mr. Troy W. Pruett at (817) 860-8173 with any questions you may have regarding this letter or the inspection plan.

Sincerely,

/RA/

Bruce S. Mallett
Regional Administrator

Dockets: 50-528
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Licenses: NPF-41
NPF-51
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Palo Verde
Inspection / Activity Plan
03/01/2006 - 09/30/2007

Unit Number	Inspection Activity	Title	No. of Staff on Site	Planned Dates Start	Planned Dates End	Inspection Type
	EB1-08P - U3-ISI		2			
3	IP 7111108P	Inservice Inspection Activities - PWR		04/10/2006	04/14/2006	Baseline Inspections
3	IP 7111108P	Inservice Inspection Activities - PWR		04/24/2006	04/28/2006	Baseline Inspections
	RP-ORS - OCCUPATIONAL RADIATION SAFETY		1			
1,2,3	IP 7112101	Access Control to Radiologically Significant Areas		04/10/2006	04/14/2006	Baseline Inspections
1,2,3	IP 7112102	ALARA Planning and Controls		04/10/2006	04/14/2006	Baseline Inspections
1,2,3	IP 71151	Performance Indicator Verification		04/10/2006	04/14/2006	Baseline Inspections
	EB2-07B - HX PERFORMANCE		1			
1,2,3	IP 7111107B	Heat Sink Performance		06/05/2006	06/09/2006	Baseline Inspections
	EB1-21 - CDB		8			
1,2,3	IP 7111121	Component Design Bases Inspection		07/31/2006	08/04/2006	Baseline Inspections
1,2,3	IP 7111121	Component Design Bases Inspection		08/14/2006	08/25/2006	Baseline Inspections
	OB-RQ - PV REQUALIFICATION INSP		2			
1,2,3	IP 7111111B	Licensed Operator Requalification Program		09/18/2006	09/22/2006	Baseline Inspections
	EB1-08P - ISI U2		1			
2	IP 7111108P	Inservice Inspection Activities - PWR		10/16/2006	10/20/2006	Baseline Inspections
2	IP 7111108P	Inservice Inspection Activities - PWR		10/30/2006	11/03/2006	Baseline Inspections
	SG REP - U3 SG REPLACEMENT ACTIVITIES		1			
3	IP 50001	Steam Generator Replacement Inspection		01/01/2007	12/31/2007	Other Routine
	RP-ORS - OCCUPATIONAL RADIATION SAFETY		1			
1,2,3	IP 7112101	Access Control to Radiologically Significant Areas		01/08/2007	01/12/2007	Baseline Inspections
1,2,3	IP 7112102	ALARA Planning and Controls		01/08/2007	01/12/2007	Baseline Inspections
1,2,3	IP 71151	Performance Indicator Verification		01/08/2007	01/12/2007	Baseline Inspections
	EB2-12B - MAINTENANCE RULE INSPECTION		2			
1,2	IP 7111112B	Maintenance Effectiveness		01/22/2007	01/26/2007	Baseline Inspections
	PIR - PIR INSPECTION		1			
1,2,3	IP 71152B	Identification and Resolution of Problems		01/22/2007	01/26/2007	Baseline Inspections
1,2,3	IP 71152B	Identification and Resolution of Problems		02/05/2007	02/09/2007	Baseline Inspections
	RP TEAM - RADIATION SAFETY TEAM		5			
1,2,3	IP 7112103	Radiation Monitoring Instrumentation and Protective Equipment		01/29/2007	02/02/2007	Baseline Inspections
1,2,3	IP 7112201	Radioactive Gaseous and Liquid Effluent Treatment and Monitoring Systems		01/29/2007	02/02/2007	Baseline Inspections
1,2,3	IP 7112202	Radioactive Material Processing and Transportation		01/29/2007	02/02/2007	Baseline Inspections
1,2,3	IP 7112203	Radiological Environmental Monitoring Program (REMP) And Radioactive Material Control Pr		01/29/2007	02/02/2007	Baseline Inspections
	EP1 - PV EP EXERCISE		3			
1,2,3	IP 7111401	Exercise Evaluation		03/05/2007	03/09/2007	Baseline Inspections

This report does not include INPO and OUTAGE activities.
This report shows only on-site and announced inspection procedures.

Palo Verde
Inspection / Activity Plan
03/01/2006 - 09/30/2007

Unit Number	Inspection Activity	Title	No. of Staff on Site	Planned Dates Start	Planned Dates End	Inspection Type
	EP1 - PV EP EXERCISE		3			
1, 2, 3	IP 7111404	Emergency Action Level and Emergency Plan Changes		03/05/2007	03/09/2007	Baseline Inspections
1, 2, 3	IP 71151	Performance Indicator Verification		03/05/2007	03/09/2007	Baseline Inspections
	EB1-08P - ISI U1		1			
1	IP 7111108P	Inservice Inspection Activities - PWR		04/02/2007	04/13/2007	Baseline Inspections
	RP-ORS - OCCUPATIONAL RADIATION SAFETY		1			
1, 2, 3	IP 7112101	Access Control to Radiologically Significant Areas		04/09/2007	04/09/2007	Baseline Inspections
1, 2, 3	IP 7112102	ALARA Planning and Controls		04/09/2007	04/09/2007	Baseline Inspections
1, 2, 3	IP 71151	Performance Indicator Verification		04/09/2007	04/09/2007	Baseline Inspections
	EXAM - INITIAL EXAM		3			
1	X02351	PV UNIT 1 - INITIAL EXAM (08/07)		07/09/2007	07/13/2007	Not Applicable
2	X02352	PV UNIT 2 - INITIAL EXAM (08/07)		07/09/2007	07/13/2007	Not Applicable
3	X02353	PV UNIT 3 - INITIAL EXAM (08/07)		07/09/2007	07/13/2007	Not Applicable
1	X02351	PV UNIT 1 - INITIAL EXAM (08/07)		07/30/2007	08/03/2007	Not Applicable
2	X02352	PV UNIT 2 - INITIAL EXAM (08/07)		07/30/2007	08/03/2007	Not Applicable
3	X02353	PV UNIT 3 - INITIAL EXAM (08/07)		07/30/2007	08/03/2007	Not Applicable
	EB2-05T - TRIENNIAL FIRE PROTECTION		4			
1, 2, 3	IP 7111105T	Fire Protection [Triennial]		07/23/2007	07/27/2007	Baseline Inspections
1, 2, 3	IP 7111105T	Fire Protection [Triennial]		08/13/2007	08/17/2007	Baseline Inspections

This report does not include INPO and OUTAGE activities.
This report shows only on-site and announced inspection procedures.

ATTACHMENT 6

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ATTACHMENT 7

CONFIDENTIAL

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ATTACHMENT 8

CONFIDENTIAL

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ATTACHMENT 9

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ATTACHMENT 15

Review of Palo Verde 2005 Outages

Disallowance of Replacement Power Costs For Imprudent Forced Outages For the Period of April through December 2005 (1)

Line No. (a)	Month/Unit (b)	APS' Total Replacement Power Cost Claim For All Forced Outages (2) ($ x 1,000) (c)	Portion Of APS' Claimed Replacement Power Costs For Imprudent Forced Outages (3) ($ x 1,000) (d)	Recommended Disallowance of Replacement Power Costs For Imprudent Forced Outages (4) ($ x 1,000) (e)
	May	[redacted]	[redacted]	[redacted]
1	Unit 1			
2	Unit 2			
3	Unit 3			
	June			
4	Unit 1			
5	Unit 2			
6	Unit 3			
	July			
7	Unit 1			
8	Unit 2			
9	Unit 3			
	August			
10	Unit 1			
11	Unit 2			
12	Unit 3			
	October			
13	Unit 1			
14	Unit 2			
15	Unit 3			
	December			
16	Unit 1			
17	Unit 2			
18	Unit 3			
19	TOTAL	56,922	16,604	14,944

Notes: (1) Source: Docket No. E-01345A-05-0526, APSC confidential responses APS07309 & APS07310 to ACC Staff RFI 1.7. Excluded months are those months in which no forced outages occurred.

(2) Amounts are prior to the 90/10 sharing allocation and net of avoided nuclear fuel costs.

(3) Amount in column (d) is the portion in column (c) related to imprudence.

(4) Amounts in column (e) are equal to 90% of amounts in column (d).

Review of Palo Verde 2005 Outages

Replacement Power Costs For Imprudent Forced Outages For the Period Prior to PSA Implementation (1)

Line No. (a)	Month/Unit (b)	APS' Total Replacement Power Cost Claim For All Forced Outages (2) ($ x 1,000) (c)	Portion Of APS' Claimed Replacement Power Costs For Imprudent Forced Outages (3) ($ x 1,000) (d)
	February	[redacted]	[redacted]
1	Unit 1		
2	Unit 2		
3	Unit 3		
	March		
4	Unit 1		
5	Unit 2		
6	Unit 3		
7	TOTAL	5,380	1,325

Notes: (1) Source: Docket No. E-01345A-05-0526, APSC confidential responses APS07309 & APS07310 to ACC Staff RFI 1.7. Excluded months are those months in which no forced outages occurred.
(2) Amounts are net of avoided nuclear fuel costs.
(3) Amount in column (d) is the portion in column (c) related to imprudence.

Review of Palo Verde 2005 Outages

Replacement Power Costs For Forced Outages Not Caused by Imprudence (1)

Line No. (a)	Month/Unit (b)	APS' Total Replacement Power Cost Claim For All Forced Outages (2) ($ x 1,000) (c)	Portion Of APS' Replacement Power Costs For Forced Outages Due To Faulty Equipment (3) (d)	Portion Of APS' Replacement Power Costs For All Other Forced Outages Not Caused by Imprudence (3) (e)
	February	[redacted]	[redacted]	[redacted]
1	Unit 1			
2	Unit 2			
3	Unit 3			
	March			
4	Unit 1			
5	Unit 2			
6	Unit 3			
	May			
7	Unit 1			
8	Unit 2			
9	Unit 3			
	June			
10	Unit 1			
11	Unit 2			
12	Unit 3			
	July			
13	Unit 1			
14	Unit 2			
15	Unit 3			
	August			
16	Unit 1			
17	Unit 2			
18	Unit 3			
	October			
19	Unit 1			
20	Unit 2			
21	Unit 3			
	December			
22	Unit 1			
23	Unit 2			
24	Unit 3			
25	TOTAL	62,302	20,597	23,776

Notes: (1) Source: Docket No. E-01345A-05-0526, APSC confidential responses APS07309 & APS07310 to ACC Staff RFI 1.7. Excluded months are those months in which no forced outages occurred.

(2) Amounts are net of avoided nuclear fuel costs.

(3) Amount in column (d) is the portion in column (c) related to faulty equipment forced outages.

(4) Amount in column (e) is the portion in column (c) not related to forced outages due to imprudence or faulty equipment

ATTACHMENT 16

Review Of Palo Verde 2005 Outages

Estimated Impact On Off-System Sales Margins Due to Imprudent Forced Outages

Line No. (a)	Month/Unit (b)	Palo Verde Generation Loss Due To Imprudent Forced Outages (1) (c)	Estimated Reduced Margins From Off-System Sales Due To Imprudent Outages (2) (d)	Recommended Disallowance Due To Reduced Margins From Off-System Sales (4) (e)
1	February - Unit 1	[redacted]	[redacted]	
2	March - Unit 1			
3	Subtotal - Pre-PSA (3)	23,882 MWH	$298,286	
4	May - Unit 3	[redacted]	[redacted]	[redacted]
5	June - Unit 3			
6	August - Unit 1			
7	August - Unit 2			
8	October - Unit 2			
9	October - Unit 3			
10	Subtotal - Post-PSA (3)	187,098 MWH	$2,336,854	$2,103,169
11	Total For 2005	210,980 MWH	$2,635,140	$2,103,169

Notes: (1) Source: Docket No. E-01345A-05-0526, APSC confidential response APS07310 to ACC Staff RFI 1.7. Amounts for August - Unit 1 and October - Unit 3 are the portion of the total MWH related to imprudence.
(2) Lost outage generation times average margin per MWh on off-system sales for April through December, or $12.49 per MWh.
(3) PSA became effective on April 1, 2005.
(4) Amounts in column (e) are equal to 90% of amounts in column (d).

ATTACHMENT 17

Review Of Palo Verde 2005 Outages

Adjustment to APS Interest On Fuel Under-Recovery Balances
Due To Imprudent Outages

Line No.	Month	Imprudent Palo Verde Outage Replacement Power Cost Disallowance	Adjustment For Lost Opportunity Sales Due To Palo Verde Outages	Total Disallowed Power Cost And Lost Opportunity Sales	Interest Adjustment
(a)	(b)	(c)	(d)	(e)	(f)
1	April 2005	$0	$0	$0	$0
2	May	$0	$0	$0	$0
3	June	$0	$0	$0	$0
4	July	$0	$0	$0	$0
5	August	$1,134,000	$186,949	$1,320,949	$0
6	September	$0	$0	$0	$3,071
7	October	$13,810,000	$1,916,220	$15,726,220	$3,078
8	November	$0	$0	$0	$39,649
9	December	$0	$0	$0	$39,741
10	Subtotal -	$14,944,000	$2,103,169	$17,047,169	$85,539
11	January 2006				$39,834
12	February				$39,926
13	March				$40,019
14	April				$40,112
15	May				$40,205
16	June				$40,299
17	Subtotal (2) -				$240,395
18	Total	$14,944,000	$2,103,169	$17,047,169	$325,934

Notes: (1) Source: APSC response APS08093 to ACC Staff RFI 7.1, Attachment 15 and Attachment 16. This document is APS' Power Supply Adjustor Report.

(2) Since APS will continue to earn interest on the fuel cost under-recovery in 2006 the interest reduction adjustment must continue after 2005.

ATTACHMENT 18

Review Of Palo Verde 2005 Outages

Summary Of Cost Disallowances For Imprudent Outages
For the Period of April through December 2005

Line No.	Month	Replacement Power Cost Disallowance	Margin Adjustment For Lost Opportunity Sales	Interest Adjustment	Total Recommended Disallowance
(a)	(b)	(c)	(d)	(e)	(f)
1	April 2005	[redacted]	[redacted]	0	0
2	May	[redacted]	[redacted]	0	0
3	June	[redacted]	[redacted]	0	0
4	July	[redacted]	[redacted]	0	0
5	August	[redacted]	[redacted]	0	1,320,949
6	September	[redacted]	[redacted]	3,071	3,071
7	October	[redacted]	[redacted]	3,078	15,729,298
8	November	[redacted]	[redacted]	39,649	39,649
9	December	[redacted]	[redacted]	39,741	39,741
10	2005 Subtotal	$14,944,000	$2,103,169	$85,539	$17,132,708
11	January 2006			39,834	39,834
12	February			39,926	39,926
13	March			40,019	40,019
14	April			40,112	40,112
15	May			40,205	40,205
16	June			40,299	40,299
17	2006 Subtotal			$240,395	$240,395
18	Disallowance for Imprudent Outages	$14,944,000	$2,103,169	$325,934	$17,373,103

Notes: (1) Source: Column (c) = Attachment 15, Column (d) = Attachment 16, Column (e) = Attachment 17.

Review Of Palo Verde 2005 Outages

Summary Of Cost Impacts For Imprudent Outages For the Period Prior to PSA Implementation

Line No. (a)	Month (b)	Replacement Power Cost Disallowance (c)	Margin Adjustment For Lost Opportunity Sales (d)	Total Cost Impact (e)
1	January 2005	[redacted]	[redacted]	$0
2	February			0
3	March			1,623,286
4	Cost Impact for Imprudent Outages			$1,623,286

Notes: (1) Source: Column (c) = Attachment 15, Column (d) = Attachment 16.

EXHIBIT
IEA-1
admitted

International Energy Outlook 2005

Report #: DOE/EIA-0484(2005)
Released Date: July 2005
Next Release Date: July 2006

Table A5. World Natural Gas Consumption by Region, Reference Case, 1990-2025 (also available in xls)
(Trillion Cubic Feet)

Region/Country	History			Projections				Average Annual Percent Change, 2002-2025
	1990	2001	2002	2010	2015	2020	2025	
Mature Market Economies								
North America	22.5	26.6	27.4	31.3	34.8	37.6	38.6	1.5
United States a/	19.2	22.2	23.0	25.6	28.3	30.4	30.9	1.3
Canada	2.4	2.9	3.0	3.9	4.3	4.6	4.7	2.0
Mexico	0.9	1.4	1.5	1.8	2.2	2.6	3.0	3.0
Western Europe	10.1	14.9	15.0	17.3	19.0	20.4	22.4	1.8
Mature Market Asia	2.6	3.8	3.8	4.2	4.8	5.1	5.4	1.6
Japan	1.9	2.7	2.7	3.0	3.4	3.6	3.8	1.5
Australia/New Zealand	0.8	1.1	1.1	1.2	1.4	1.4	1.6	1.7
Total Mature Market	35.2	45.2	46.2	52.8	58.7	63.1	66.4	1.6
Transitional Economies								
Former Soviet Union	25.0	20.8	21.3	25.6	29.0	31.0	33.3	2.0
Russia	17.3	14.4	14.6	16.2	17.9	19.5	20.7	1.5
Other FSU	7.7	6.4	6.8	9.4	11.1	11.6	12.6	2.7
Eastern Europe	3.1	2.7	2.6	4.0	4.6	5.2	5.8	3.5
Total Transitional	28.1	23.5	23.9	29.6	33.6	36.2	39.1	2.2
Emerging Economies								
Emerging Asia	3.0	7.2	7.8	10.6	13.3	16.3	20.7	4.3
China	0.5	1.1	1.2	2.6	3.4	4.2	6.5	7.8
India	0.4	0.9	0.9	1.4	1.8	2.3	2.8	5.1
South Korea	0.1	0.7	0.8	1.2	1.4	1.6	1.9	3.7
Other Asia	2.0	4.6	4.9	5.4	6.8	8.2	9.5	2.9
Middle East	3.7	7.6	8.3	10.6	12.6	14.5	16.6	3.1
Africa	1.4	2.3	2.4	3.1	4.1	4.9	6.0	4.0
Central and South America	2.0	3.5	3.6	4.6	5.6	6.5	7.5	3.3
Brazil	0.1	0.4	0.5	0.9	1.3	1.7	2.1	6.8
Other Central/South America	1.9	3.1	3.1	3.8	4.3	4.8	5.4	2.4
Total Emerging	10.1	20.6	22.0	29.0	35.6	42.2	50.7	3.7
Total World	73.4	89.3	92.2	111.4	127.9	141.6	156.2	2.3

35%

70%

300%

not here yes called

a/ Includes the 50 States and the District of Columbia.
Note: Totals may not equal sum of components due to independent rounding.
Sources: History: Energy Information Administration (EIA), International Energy Annual 2002, DOE/EIA-0219(2002) (Washington, DC, March 2004), web site www.eia.doe.gov/iea/. Projections: EIA, Annual Energy Outlook 2005, DOE/EIA-0383(2005) (Washington, DC, February 2005), October futures case, AEO2005 National Energy Modeling System, run CF2005.D111104A, web site www.eia.doe.gov/oiaf/aeo/; and System for the Analysis of Global Energy Markets (2005).

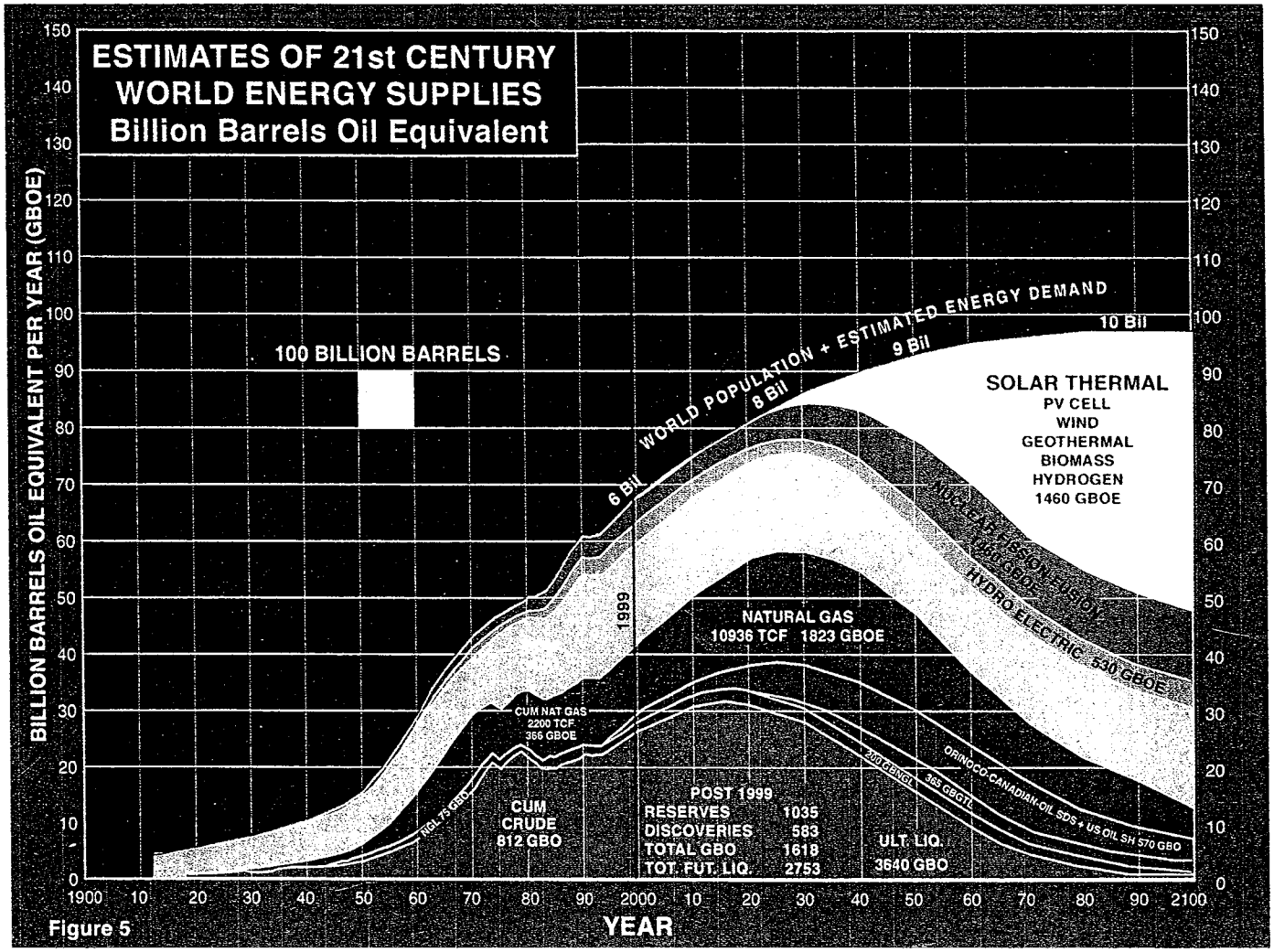


Figure 5

And yet, until the summer of 2002, we at CU's Center of the American West were as oblivious as any other set of citizens to the need for a serious reckoning with the history of energy in the American West. Preoccupied with farming, ranching, logging, and hardrock mining, Western historians had produced a comparatively small shelf of books on the history of the production and consumption of fossil fuel in the region. More important, we were ourselves standard-issue American consumers, relying on abundant energy in a thousand ways, turning ignition switches and light switches on and off and on again, performing tasks in seconds that would have taken people of earlier eras hours and days to complete, and never thinking for a moment about the extraordinary chain of decisions and actions that gave us this extraordinary power.

And then our own "remedial education" began.

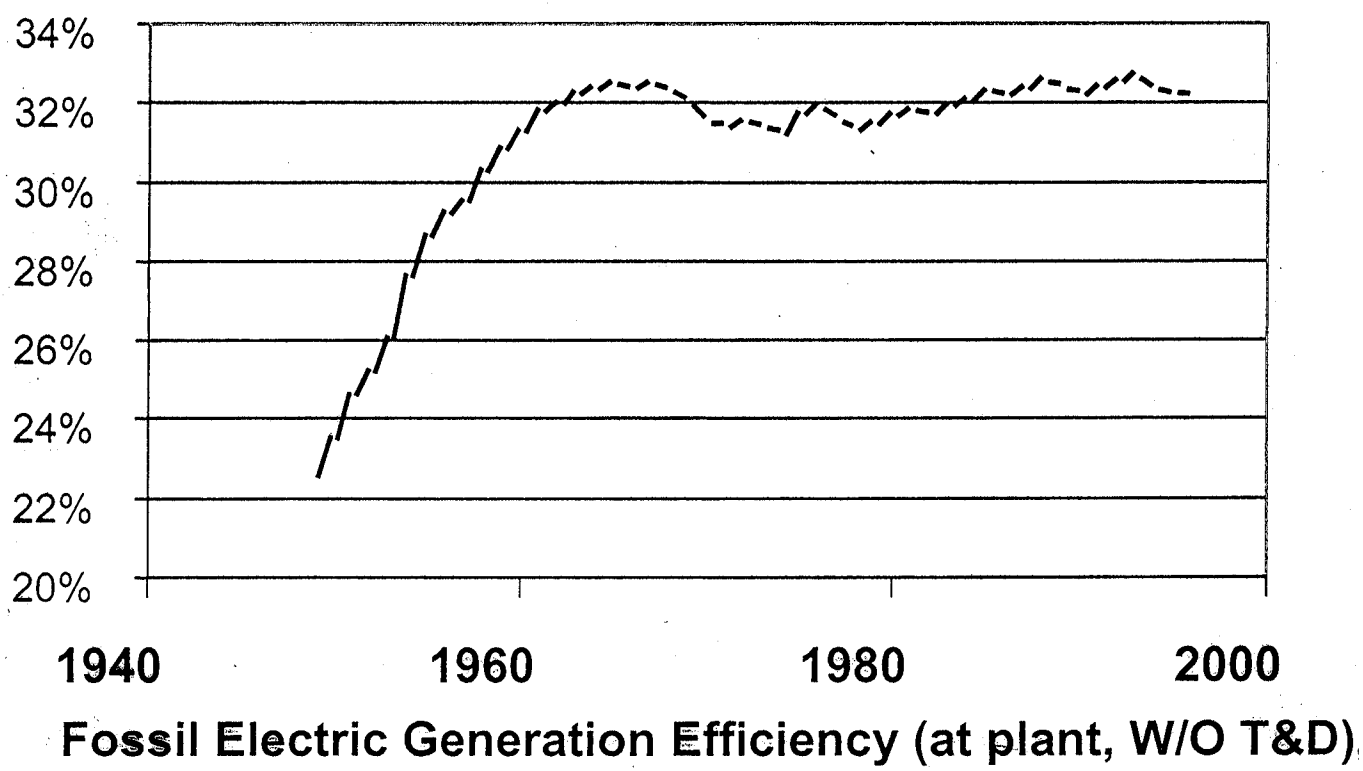
Thanks to funding from the William and Flora Hewlett Foundation, in June of 2002, our Center of the American West convened a group of specialists from many disciplines to talk about regional energy issues. A two-and-a-half day workshop did not transform us into experts, but it did permanently cure us of the "out of sight/out of mind" habit of thought. Now, when we started our cars or used our computers or toasted our bread, we thought about what we were doing and marveled at the ease with which we did it. We also began making better informed choices as consumers of energy. Now, when we filled up our tanks or replaced our light bulbs, we made decisions that made us feel that we were doing at least a small part to secure a brighter energy future for posterity.

Over the next months, we did a lot of reading and met with a variety of groups involved in energy issues. We then did our best to put what we had learned between two covers. Our report, *"What Every Westerner Should Know about Energy,"* published in July of 2003, differs from many current writings about this subject (forgive us this moment of vanity!) by its humor, fairness and dedication to the cause of moving beyond condemnation and lamentation and toward meaningful action.

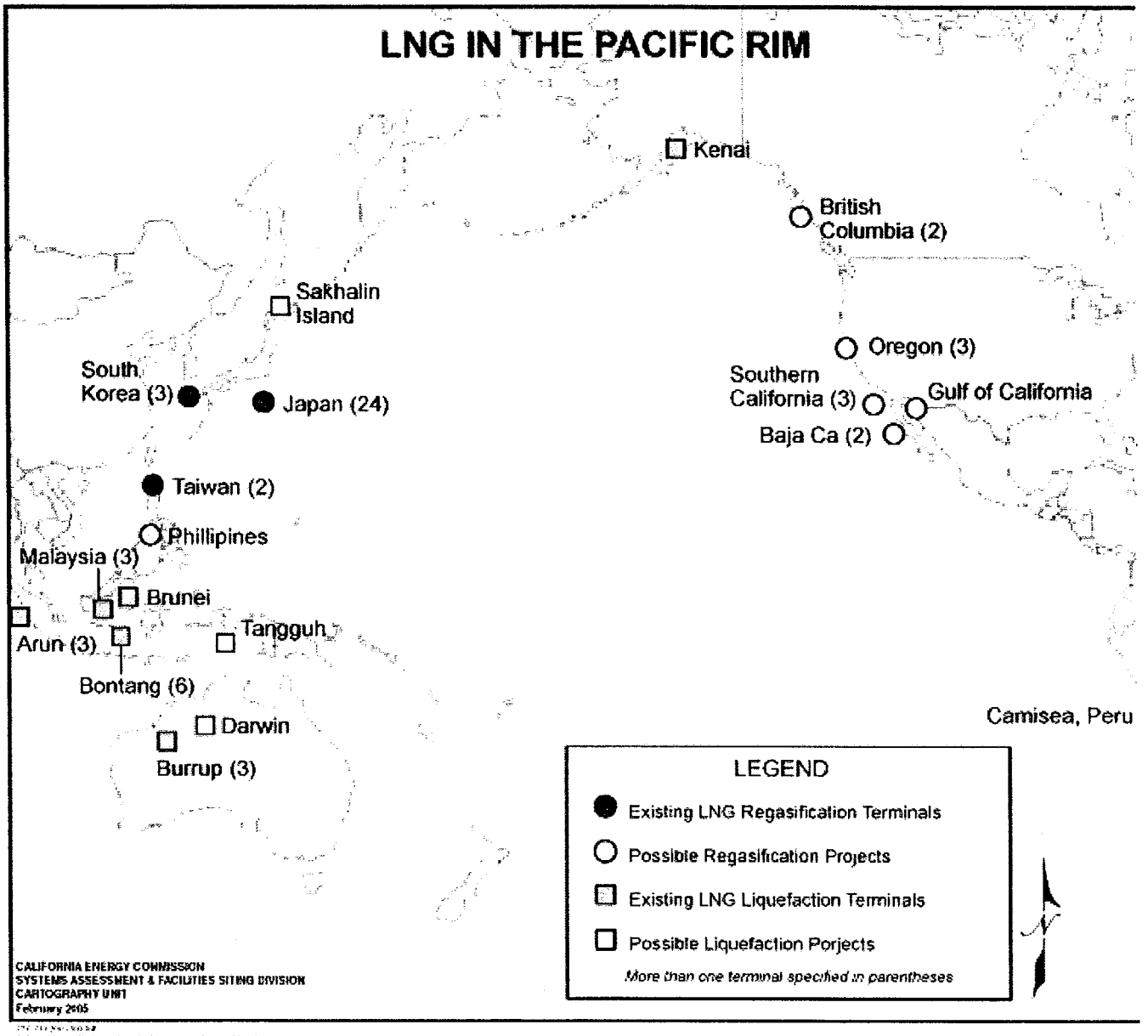
Our goal was to put a focus on anticipating and preparing for what we had taken to calling the "Yellow Zone." At our workshop in 2002, Dr. John D. Edwards, a veteran of 37 years with Shell Oil and now a teacher in CU's Geological Sciences Department, had

The Need For CHP

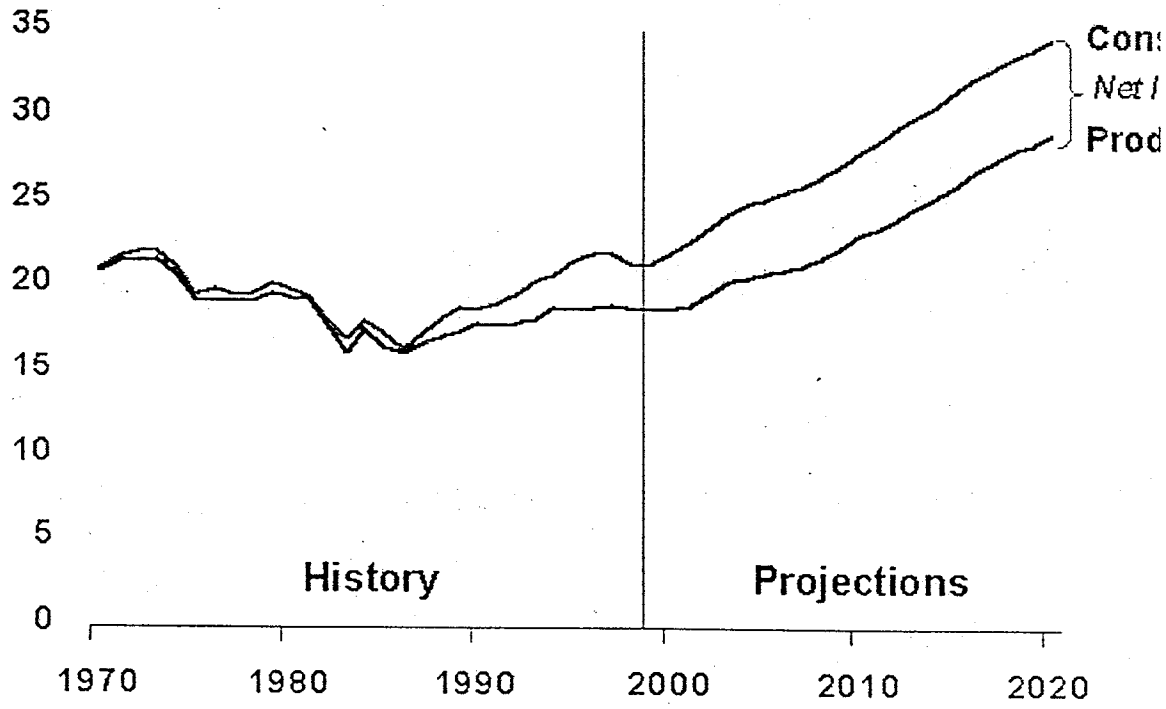
Stagnant Efficiency of U.S. Electric System



Source: EIA, Annual Energy Review 1996


LNG IN THE PACIFIC RIM
Kenai
British Columbia (2)
Sakhalin Island
Oregon (3)
South Korea (3)
Japan (24)
Southern California (3)
Gulf of California
Baja Ca (2)
Taiwan (2)
Phillipines
Malaysia (3)
Brunei
Arun (3)
Tangguh
Bontang (6)
Darwin
Burrup (3)
Camisea, Peru
LEGEND
Existing LNG Regasification Terminals
Possible Regasification Projects
Existing LNG Liquefaction Terminals
Possible Liquefaction Porjects
More than one terminal specified in parentheses
CALIFORNIA ENERGY COMMISSION
SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION
CARTOGRAPHY UNIT
February 2005

U.S. Natural Gas Consumption, Productio
Imports, 1970 - 2020 (trillion cubic fe



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TECHNOLOGY Description	Data Source Reference #	Baseline Year[1] for Data Source	Pollutent Levels Current Regulation #/MBTU or % Capture	EPC Capital Costs Baseline Year $/KW	EPC Capital Costs 2005 Order $/KW	Cost of Electricity Per reference Cents/KW-Hr
Standard PC Boiler - FGCU	Cost Learning Curve:	Low =	0%	High =	0%	
Cost - No CO_2 Capture			0.10 SO_2			
Bituminous - min	#6 #15	2002	0.07 NOx	1114	**1182**	4.22
max	#13 #26	2002	Hg	1290	**1369**	4.92
Sub-Bituminous - min	#8	2003	0.012 PM	1330	**1384**	4.60
max	#8 #26	2003	200 CO2	1446	**1504**	4.30
Lignite - min	#8	2003	90-99% CO_2	1340	**1394**	4.40
max	#26	2003	26 Solid Waste	1585	**1649**	4.76
Cost - CO_2 Capture						
Bituminous - min	#6 #13	2002		2086	**2214**	7.65
max	#15	2002		2373	**2518**	9.70
Sub-Bituminous - min						
max	#25	2000		1981	**2187**	
Lignite - min						
max						
Super-Critical PC - FGCU	Cost Learning Curve: #20 Envir.	Low =	0%	High =	5%	
Cost - No CO_2 Capture			0.10 SO_2			
Bituminous - min	#6 #13	2000	0.07 NOx	953	**1052**	3.74
max	#6 #26 #19	2002	Hg	1410	**1496**	5.15
Sub-Bituminous - min			0.012 PM			
max	#19	2002	173 CO_2	1502	**1594**	4.8
Lignite - min			90-99% CO_2			
max	#19	2002	24 Solid Waste	1644	**1745**	
Cost - CO_2 Capture			0.015 Gal H2O/Day/W			
Bituminous - min	#13 #19	2000		1701	**1878**	6.08
max	#6	2000		2414	**2665**	8.56

EXHIBIT
IEA-2
admitted

Sub-Bituminous - min						
max	#25	2000		1981	**2187**	
Lignite - min						
max	#6 #19	2004		2824	2880	9.28
Ultra-Super-Critical PC - FGCU	Cost Learning Curve:	Low =	5%	High =	10%	
Cost - No CO_2 Capture			0.10 SO_2			
Bituminous - min	#8 #25 #13	2004	0.07 NOx	1059	**1102**	4.28
max	#8 #6 #13	2003	Hg	1262	**1313**	5.1
Sub-Bituminous - min			0.012 PM			
max			170 CO_2			
Lignite - min			90-99% CO_2			
max			22 Solid Waste			
Cost - CO_2 Capture						
Bituminous - min	#24	2004		1521	**1679**	5.83
max	#8 #6 #13	2003		2244	**2335**	8.24
Sub-Bituminous - min	#25	2000		1943	**2145**	8.24
max	#8	2003		2585	**2689**	6.4
Lignite - min						
max	#8	2000		2826	**3120**	7.4
Circulating Fluid Bed Boiler - FGCU	Cost Learning Curve:	Low =	0%	High =	0%	
	#20 Envir.					
Cost - No CO_2 Capture			0.04 SO_2			
Bituminous - min	#13 #2	2004	0.07 NOx	1000	**1020**	4.53
max	#1 #3	2003	Hg	1384	**1440**	
Sub-Bituminous - min			0.01 PM			
max			200 CO_2			
Lignite - min			90-99% CO_2			
max			26 Solid Waste			
Cost - CO_2 Capture						
Bituminous - min						
max	#1 #3	2003		2481	**2581**	
Sub-Bituminous - min						

max						
Lignite - min						
max						
IGCC	Cost Learning Curve:	Low =	10%	High =	15%	
Second Generation						
Cost - No CO_2 Capture			0.017 SO_2			
Bituminous - min	#8 #6 #13 #19	2000	0.0246 NOx	1066	**1177**	4.05
max	#8 #6 #26 #27	2003	0.74×10^{-6} Hg	1620	**1685**	5.6
Sub-Bituminous - min	#8 #19	2004	0.004PM	1480	**1510**	3.73
max	#8 #26	2003	167 CO_2	1757	**1828**	5.5
Lignite - min	#19	2004	90-99% CO_2	1713	**1747**	4.46
max	#13 #26	2002	4.5 Solid Waste	1895	**2011**	5.63
Cost - CO_2 Capture			0.009 Gal H2O/Day/W			
Bituminous - min	#8 #6 #13 #27	2000		1402	**1548**	5.43
max	#8 #6 #19	2003		2190	**2278**	8.3
Sub-Bituminous - min	#24 #19	2004		1791	**1827**	6.1
max	#6	2003		2205	**2294**	7.76
Lignite - min	#24	2000		2292	**2531**	8.2
max	#6 #19	2004		2847	**2904**	10.4
IGCC	Cost Learning Curve:	Low =	20%	High =	25%	
Third Generation						
Cost - No CO_2 Capture			0.005 SO_2			
Bituminous - min	#15	2002	0.05 Nox	1160	**1281**	3.91
max	#15	2002	Hg	1350	**1433**	4.46
Sub-Bituminous - min	#9	2001	0.0003PM	1050	**1137**	3.72
max	#9	2001	150 CO_2	1385	**1499**	4.3
Lignite - min			90-99% CO_2			
max			4.1 Solid Waste			
Cost - CO_2 Capture			0.009 Gal H2O/Day/W			
Bituminous - min	#15	2002		1642	**1743**	
max	#24	2000		2220	**2451**	4.47
Sub-Bituminous - min	#25	2000		1642	**1813**	5.02
max						

Lignite - min						
max						
IGCC	Cost Learning Curve:	Low =	15%	High =	20%	
Poly-Generation[3]						
Cost - No CO_2 Capture			0.03 SO_2			
Bituminous - min			0.054 NOx			
max	#20	2004	Hg	666	**679**	5.07
Sub-Bituminous - min			0.004 PM			
max	#14	2005		730	**730**	5.18
Lignite - min			90-99% CO_2			
max			? Solid Waste			
Cost - CO_2 Capture			0.032 Gal H2O/Day/W			
Bituminous - min						
max						
Sub-Bituminous - min						
max	#14	2005		745	**745**	5.26
Lignite - min						
max						
IGCC	Cost Learning Curve:	Low =	20%	High =	25%	
REPOWERING						
Cost - No CO_2 Capture			0.025 SO_2			
Bituminous - min			0.07 NOx			
max	#7	2000	Hg	1208	**1334**	4.35
Sub-Bituminous - min	See Footnote 5	2000	0.001 PM	1208	**1334**	5.26
(K-Fuel Treated)[5] max	See Footnote 5	2000	160 CO_2	1208	**1334**	5.64
Lignite - min			90-99% CO_2			
max			4.5 Solid Waste			
Cost - CO_2 Capture			0.009 Gal H2O/Day/W			
Bituminous - min						0.507622974
max						
Sub-Bituminous - min						
max						
Lignite - min						

max

ESCALATION Baseline Year	Capital Inflation Annual Factor	CAPITAL COST Escalator to 2005	O&M Inflation Annual Factor	Fuel Inflation Annual Factor	O&M COST Escalator to 2008	FUEL COST Escalator to 2008
2000	1.02	1.10				
2001	1.02	1.08				
2002	1.02	1.06				
2003	1.02	1.04	1.02	1.02	1.10	1.10
2004	1.02	1.02	1.02	1.02	1.08	1.08
2005	1.02	1.00	1.02	1.02	1.06	1.06
2006			1.02	1.02	1.04	1.04
2007			1.02	1.02	1.02	1.02
2008			1.02	1.02	1.00	1.00

1. Assumes equipment orders placed and priced in Baseline Year or Purchase Year

2 Assumes Plant Startup three years after Baseline Year or Purchase Year

3.The "Equivalent KW" rating was based on using the total energy output and converting it to KW; I.e.
Effedtive KW = (Fuel Production in Gal/Hr x HHV of the fuel in BTU/Gal / 3414 BTU/KW-Hr) + Electrical KW out

4. For Reference purposes, the HHV of Bituminous is 13,000 BTU/#, Sub-Bituminous is 10,000 BTU/#, and Lignite is 7,000 BTU/# on a dry basis. These are typical numbers and are subject to +/- 10% variation.

5. K-Fuel treated PRB allows it to be used in equipment designed for Bituminous coal at no penalty. The HHV goes from 8000 to 11000 B and the Mercury content is reduced by 70%. Processing costs will raise the price by 30-40$/ton. Howard Weil Energy Conf., April, 2005 It is presented only as an example of a process that is moving toward commercial status; others are under consideration.

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October 24, 2006 Increased electrical transmission facilities may help Wyoming

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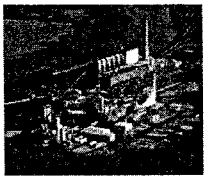
Western Governors laud efforts to expand IGCC technology development in the West (8/16/06)

Western Governors Encourage Wind Energy Producers to Help the Region Achieve Cleaner and More Diverse Energy Portfolio (7/18/06)



" Western North America is blessed with an abundance of natural energy resources that have been critical to accommodating substantial population growth and fueling a dynamic economy.... Given the vast reserves of coal across many of the western states, the region is well-suited to the development of new clean energy technologies to enhance the innovative use of domestic energy supplies both in the region and across the United States in ways that minimize emissions while boosting domestic energy security."
--WGA Policy Resolution 04-14

- Advanced Coal Task Force Report
  Full Report | Text-only Report
- Advanced Coal Task Force Members
- Advanced Coal Working Group Reports
  Carbon Management | Policy | Technology
- Technology Working Group Data
  2015 Spreadsheet | 2025 Spreadsheet | Cost Estimates

Advanced Coal

October 23, 2006 - Energy Announces Million in Grants fo Sequestration Res

October 3, 2006 - M announces coal to IGCC plants

August 15, 2006 - X Increases Commitr

August 14, 2006 - T Programs Promote Power Generation Technologies

June 1, 2006 - Clea Technology Planne (AZ) Power Station

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TECHNOLOGY Description	Data Source Reference #	Baseline Year[1] for Data Source	Pollutent Levels Current Regulation #/MBTU or % Capture	EPC Capital Costs Baseline Year $/KW	EPC Capital Costs 2005 Order $/KW	Cost of Electricity Per reference Cents/KW-Hr
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max	#13 #26	2002	Hg	1290	**1369**	4.92
Sub-Bituminous - min	#8	2003	0.012 PM	1330	**1384**	4.60
max	#8 #26	2003	200 CO2	1446	**1504**	4.30
Lignite - min	#8	2003	90-99% CO_2	1340	**1394**	4.40
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Cost - CO_2 Capture						
Bituminous - min	#6 #13	2002		2086	**2214**	7.65
max	#15	2002		2373	**2518**	9.70
Sub-Bituminous - min						
max	#25	2000		1981	**2187**	
Lignite - min						
max						
Super-Critical PC - FGCU	Cost Learning Curve: #20 Envir.	Low =	0%	High =	5%	
Cost - No CO_2 Capture			0.10 SO_2			
Bituminous - min	#6 #13	2000	0.07 NOx	953	**1052**	3.74
max	#6 #26 #19	2002	Hg	1410	**1496**	5.15
Sub-Bituminous - min			0.012 PM			
max	#19	2002	173 CO_2	1502	**1594**	4.8
Lignite - min			90-99% CO_2			
max	#19	2002	24 Solid Waste	1644	**1745**	
Cost - CO_2 Capture			0.015 Gal H2O/Day/W			
Bituminous - min	#13 #19	2000		1701	**1878**	6.08
max	#6	2000		2414	**2665**	8.56

Sub-Bituminous - min						
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Bituminous - min	#8 #25 #13	2004	0.07 NOx	1059	**1102**	4.28
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max			170 CO_2			
Lignite - min			90-99% CO_2			
max			22 Solid Waste			
Cost - CO_2 Capture						
Bituminous - min	#24	2004		1521	**1679**	5.83
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Cost - No CO_2 Capture			0.04 SO_2			
Bituminous - min	#13 #2	2004	0.07 NOx	1000	**1020**	4.53
max	#1 #3	2003	Hg	1384	**1440**	
Sub-Bituminous - min			0.01 PM			
max			200 CO_2			
Lignite - min			90-99% CO_2			
max			26 Solid Waste			
Cost - CO_2 Capture						
Bituminous - min						
max	#1 #3	2003		2481	**2581**	
Sub-Bituminous - min						

max						
Lignite - min						
max						
IGCC	Cost Learning Curve:	Low =	10%	High =	15%	
Second Generation						
Cost - No CO_2 Capture			0.017 SO_2			
Bituminous - min	#8 #6 #13 #19	2000	0.0246 NOx	1066	**1177**	4.05
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Lignite - min	#19	2004	90-99% CO_2	1713	**1747**	4.46
max	#13 #26	2002	4.5 Solid Waste	1895	**2011**	5.63
Cost - CO_2 Capture			0.009 Gal H2O/Day/W			
Bituminous - min	#8 #6 #13 #27	2000		1402	**1548**	5.43
max	#8 #6 #19	2003		2190	**2278**	8.3
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max	#9	2001	150 CO_2	1385	**1499**	4.3
Lignite - min			90-99% CO_2			
max			4.1 Solid Waste			
Cost - CO_2 Capture			0.009 Gal H2O/Day/W			
Bituminous - min	#15	2002		1642	**1743**	
max	#24	2000		2220	**2451**	4.47
Sub-Bituminous - min	#25	2000		1642	**1813**	5.02
max						

Lignite - min						
max						
IGCC	Cost Learning Curve:	Low =	15%	High =	20%	
Poly-Generation[3]						
Cost - No CO_2 Capture			0.03 SO_2			
Bituminous - min			0.054 NOx			
max	#20	2004	Hg	666	**679**	5.07
Sub-Bituminous - min			0.004 PM			
max	#14	2005		730	**730**	5.18
Lignite - min			90-99% CO_2			
max			? Solid Waste			
Cost - CO_2 Capture			0.032 Gal H2O/Day/W			
Bituminous - min						
max						
Sub-Bituminous - min						
max	#14	2005		745	**745**	5.26
Lignite - min						
max						
IGCC	Cost Learning Curve:	Low =	20%	High =	25%	
REPOWERING						
Cost - No CO_2 Capture			0.025 SO_2			
Bituminous - min			0.07 NOx			
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Sub-Bituminous - min	See Footnote 5	2000	0.001 PM	1208	**1334**	5.26
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Lignite - min			90-99% CO_2			
max			4.5 Solid Waste			
Cost - CO_2 Capture			0.009 Gal H2O/Day/W			
Bituminous - min						0.507622974
max						
Sub-Bituminous - min						
max						
Lignite - min						

max

ESCALATION Baseline Year	Capital Inflation Annual Factor	CAPITAL COST Escalator to 2005	O&M Inflation Annual Factor	Fuel Inflation Annual Factor	O&M COST Escalator to 2008	FUEL COST Escalator to 2008
2000	1.02	1.10				
2001	1.02	1.08				
2002	1.02	1.06				
2003	1.02	1.04	1.02	1.02	1.10	1.10
2004	1.02	1.02	1.02	1.02	1.08	1.08
2005	1.02	1.00	1.02	1.02	1.06	1.06
2006			1.02	1.02	1.04	1.04
2007			1.02	1.02	1.02	1.02
2008			1.02	1.02	1.00	1.00

1. Assumes equipment orders placed and priced in Baseline Year or Purchase Year

2 Assumes Plant Startup three years after Baseline Year or Purchase Year

3.The "Equivalent KW" rating was based on using the total energy output and converting it to KW; I.e.
Effedtive KW = (Fuel Production in Gal/Hr x HHV of the fuel in BTU/Gal / 3414 BTU/KW-Hr) + Electrical KW out

4. For Reference purposes, the HHV of Bituminous is 13,000 BTU/#, Sub-Bituminous is 10,000 BTU/#, and Lignite is 7,000 BTU/# on a dry basis. These are typical numbers and are subject to +/- 10% variation.

5. K-Fuel treated PRB allows it to be used in equipment designed for Bituminous coal at no penalty. The HHV goes from 8000 to 11000 B and the Mercury content is reduced by 70%. Processing costs will raise the price by 30-40$/ton. Howard Weil Energy Conf., April, 2005 It is presented only as an example of a process that is moving toward commercial status; others are under consideration.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

JEFF HATCH-MILLER, Chairman
WILLIAM A. MUNDELL
MIKE GLEASON
KRISTIN K. MAYES
BARRY WONG

EXHIBIT
IEA-4
admitted

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND TO AMEND DECISION NO. 67744	DOCKET NO. E-01345A-05-0816

Direct Testimony of

Amanda Ormond

on behalf of Interwest Energy Alliance

Docket No. E-01345A-05-0816

August 18, 2006

Direct Testimony of Amanda Ormond
Docket No. E-01345A-05-0816

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Direct Testimony of Amanda Ormond
on behalf of Interwest Energy Alliance
Docket No. E-01345A-050816

INTRODUCTION

Q. PLEASE STATE YOUR NAME AND YOUR BUSINESS ADDRESS?

A. My name is Amanda Ormond. My business address is 7650 S. McClintock Drive, Suite 103-282, Tempe, Arizona 85284.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am a consultant to Interwest Energy Alliance and serve as their Southwest Representative.

Q. PLEASE DESCRIBE INTERWEST ENERGY ALLIANCE.

A. Interwest Energy Alliance (Interwest) is a 501(c)(4) trade organization representing the interests of non-governmental organizations and renewable energy developers and product manufactures; primarily wind. Interwest works through education and advocacy to create state-level policies supporting renewable energy development. The organization concentrates its work in the states of Arizona, Colorado, Nevada, New Mexico, Utah and Wyoming.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE RELATED TO YOUR TESTIMONY.

I have worked in the energy and environmental field for 20 years in Arizona. In the mid '80s I was a quality control specialist for an environmental consulting firm and focused on groundwater contamination evaluation and remediation projects. From 1987 to 2001 I was employed by the State Energy Office, a division of the Arizona Department of Commerce. I was appointed director in 1994 where I served for seven years. In 2001 I started the Ormond Group, LLC, a consulting firm specializing in energy and environmental policy development, strategy and education. I hold a BS degree in Environmental Earth Science. I have participated extensively in regional and local stakeholder processes and policy forums as an expert in renewable and energy efficiency and spent 10 years writing and lobbying for energy legislation. I have represented the wind industry for four years.

WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony discusses three topics:

- Addition of an independent expert in future Request for Proposal (RFP) processes for renewable energy resources to ensure fair assignment of costs and review of bids.

- Implementing a solicitation schedule for near-term purchase of renewable energy.
- Developing a performance-based incentive structure for clean energy resource acquisition.

A. WILL YOU BE ADDRESSING ISSUES RELATED TO WIND ENERGY OR ALL RENEWABLE ENERGY RESOURCES?

Q. My testimony relates largely to wind energy development. However, Interwest believes that diversity of resources is important and recognizes that renewable energy resources have different characteristics and bring various benefits to the market. Interwest has found that it is best for consumers if all renewable energy technologies are allowed to compete and to allow utilities to choose the resource that best fits their needs.

INDEPENDENT EVALUATOR

Q. WHY INCLUDE AN INDEPENDENT EVALUATOR WITH RENEWBLE ENERGY EXPERIENCE FOR RFP PROCESSES THAT WILL PROCURE RENEWABLE ENERGY?

A. Interwest believes that when APS evaluated renewable energy in its 2005 RFP process, it attributed a higher than necessary integration cost to wind energy projects, which has resulted in projects not being considered for purchase. To ensure a more fair assignment of such costs, Interwest proposes that APS include in any renewable energy bid evaluation process an independent evaluator that has direct experience with wind and other renewable energy resources. This person may be chosen by the Commission and report to the Commission.

Q. CAN YOU PLEASE SITE AN EXAMPLE OF INAPPROPRIATE COSTS?

A. Please refer to a copy of Mr. Jack Davis' letter of July 19, 2006 to Commissioner Kris Mayes filed in this docket. In that letter Mr. Davis states that the company added a spinning reserve charge of $10 - $20 per MWh for wind projects evaluated in the 2005 renewables RFP. He further states that the company did not assess any ancillary service charge or imbalance penalties to the wind projects in question.

Ancillary services charges are the costs incurred by a utility to integrate the output from a wind project into their system. In the electric industry ancillary services includes the cost of regulation, load following and unit commitment. These categories correspond to second to minute resource needs, minute to hour and day ahead, respectively. The spinning reserve charge to which Mr. Davis refers is typically included in regulation costs. Regulation costs are a subset of ancillary services costs.

Utilities, other than APS, have conducted a number of recent studies in order to determine the projected cost of ancillary services (including spinning reserves)

resulting from wind on their system. The National Renewable Energy Laboratory study *Grid Impacts of Wind Power Variability - Recent Assessments from a Variety of Utilities in the United States* compiled these results[1]. The following chart, from a recent presentation given at the Southwest Renewable Energy Conference, reflects these results:

Comparison of Cost-Based U.S. Operational Impact Studies

Date	Study	Wind Capacity Penetration (%)	Regulation Cost ($/MWh)	Load Following Cost ($/MWh)	Unit Commitment Cost ($/MWh)	Gas Supply Cost ($/MWh)	Total Operating Cost Impact ($/MWh)
May '03	Xcel-UWIG	3.5	0	0.41	1.44	na	1.85
Sep '04	Xcel-MNDOC	15	0.23	na	4.37	na	4.60
July '04	CA RPS Phase III	4	0.46	na	na	na	na
June '03	We Energies	4	1.12	0.09	0.69	na	1.90
June '03	We Energies	29	1.02	0.15	1.75	na	2.92
2005	PacifiCorp	20	0	1.6	3.0	na	4.60
April '06	Xcel-PSCo	10	0.20	na	2.26	1.26	3.72
April '06	Xcel-PSCo	15(1)	0.20	na	3.32	1.45	4.97

(1) Xcel is also working on a study of 20% wind penetration but preliminary results presented were withdrawn by the utility due to a wind forecast calculation error.

National Renewable Energy Laboratory, Brian Parsons & Michael Milligan, *Grid Impacts of Wind Power Variability: Recent Assessments from a Variety of Utilities in the United States*, August 3, 2006

The highest cost for wind integration from these studies is projected to be $4.97 per MWh. This cost includes all integration costs not just the regulation or the spinning reserve components. The projected cost of $4.97 is based on a wind penetration rate of 15 percent on Xcel's Colorado system which is roughly similar to the APS system. The wind projects that were bid into the APS RFP, that were not purchased, were less than 100 MW which would be less than 2% of APS' generation.[2] Yet, APS assigned a cost of $10-20 per MWh. At system penetration rates of less than 5%, Xcel projected a cost of $1.85/MWh, and Wisconsin Energy found an integration impact of $1.90/MWh at a 15% penetration rate. APS has assigned a cost that is at least double the cost found at any penetration rate by any US utility, and more than 10 times the cost actually incurred by utilities with similar penetration rates.

[1] National Renewable Energy Laboratory, Brian Parsons & Michael Milligan, *Grid Impacts of Wind Power Variability: Recent Assessments from a Variety of Utilities in the United States*, August 3, 2006

[2] Based on a rough calculation of a 5000 MW service territory and a 100 MW wind project.

Q. HOW WERE THE APS SPINNING RESERVE CHARGES CALCULATED?

A. In a response to a data request by Western Resource Advocates (WRA5-2) Patrick Dinkel of APS explained that they "applied a one standard deviation to the generation data. The resulting calculation was approximately 25% of the nameplate rating of the wind project." This figure (25%) was then loaded into the PROMOD IV model which produced a cost of $10-20 per MWh.

Q. IS THIS CALCULATION METHODOLOGY REASONABLE?

A. No, this methodology is invalid because energy from a wind plant cannot be treated in isolation from the remaining systems. The methodology employs an unrealistic assumption of needing 25% of nameplate as spinning reserves. By choosing a figure of 25% for a wind project with a capacity factor of 25-30%, the utility assumed that they needed to back up (through spinning reserves) each and every MWh of wind energy on their system. Stated another way, a 100 MW wind project that produces on average 25-30% of its nameplate capacity has a 25 -30% capacity factor. APS estimates that their 5,000 MW system needs 25MWs of back up for a project that would produce an average of 25-30 MWH over the course of a year – essentially a one-for-one back up. This method also assumes the wind component of reserve is also needed even when the wind is not blowing.

The need to have a one-for-one backup for a variable resource such as wind was commonly asserted in the early days of wind development. However, it has been conclusively demonstrated to be incorrect. The actual experience with wind in California and elsewhere in the U.S. has proven that "one-for-one backup" overstates the real impact on spinning reserves by over an order of magnitude. APS operates a relatively large (5,000+ MW) dynamic system which routinely experiences significant variation in both generation and loads. The system is designed to smoothly and cheaply react to these individual load and resource variations. Because the short-term fluctuations in output of a wind project of 100 MW, or less than 2% of the system's capacity, are essentially random and not correlated with the fluctuations of other loads and resources, their impact is not additive. A fundamental reason why modern electric grids are as large as they are is to take advantage of this "portfolio effect."

To address spinning reserves and other integration issues, the Utility Wind Integration Group, composed of over 70 US utility companies, in association with the American Public Power Association, the Edison Electric Institute, and the National Rural Electric Cooperative Association produced a report this year called *Utility Wind Integration State of the Art.* This report summarizes the most current information on the impacts of wind. The study states "On the cost side, at wind penetrations of *up to 20% of peak system demand*, system operating costs arising from wind" variability and uncertainly amounted to about 10% or less of the wholesale value of the wind

energy.[3] (emphasis added) Assuming $70 per MWh operating costs, then the proper integration cost would be less than $7/MWh, which is far less than the $10-20 dollars used by APS. The 10% maximum number is not mentioned here to be definitive, but to illustrate the magnitude of the difference between costs quantified as a result of studies conducted by utilities with actual experience with wind generation in their systems and the assumed costs applied by APS. We believe the data justifies the need for an experienced independent evaluator for future project bids.

Q. WHAT WOULD THE INDEPENDENT EVALUATOR REVIEW?

A. When conducting the review of renewable energy bids, the evaluator should look at the two primary categories; first, what additional cost(s) is the utility adding to the price of a bid (e.g., spinning reserve charges), and what value is the company using for a reference price for conventional resources. Assuming APS will evaluate renewable energy bids in part based on fossil fuel generation costs, it is critical to ensure that the reference price for conventional generation resources is accurate.

In Decision No. 6774 APS was required to purchase 100 MWs of renewable energy but only if the price of renewable energy was no more than 125% of the market price of conventional resources. The price chosen as the 125% was critical to the outcome of the bid process. The Independent Evaluator should provide input on calculating the market (or reference) price.

Q. ARE THERE OTHER REASONS AN INDEPENDENT EVALUATOR IS NECESSARY?

A. Renewable energy resources are significantly different from the conventional fossil fuel generation that APS has relied upon in the past. In addition, renewable energy technology is rapidly changing and evolving to meet the needs of the utility industry. An expert in renewable energy systems would provide the Commission and APS with up-to-date expertise that can be used to evaluate bids and the bid evaluation process to ensure that the process is fair as possible.

Q. DO YOU HAVE ANY OTHER COMMENTS?

A. Yes. Wind energy is the fastest growing segment of renewable energy industry. Worldwide more than 50,000 MW have been installed.[4] Wind resources have been successfully incorporated in neighboring utility systems in N.M., Colorado and California giving utilities in these states valuable experience. As a result of the 2005 RFP process, APS purchased a wind project from New Mexico, and in 2004 purchased 15 MW from a project in the Kingman area. However, these projects have

[3] Utility Wind Integration Group, American Public Power Association, Edison Electric Institute, National Rural Electric Cooperative Association, *Utility Wind Integration State of the Art,* May 2006, page 1. http://www.uwig.org/UWIGWindIntegration052006.pdf

[4] Utility Wind Integration Group, May 2006. *Utility Wind Integration State of the Art,* page 1.

not yet come on line; thus APS has no direct experience with interconnecting, scheduling and monitoring wind systems. One of the benefits of the Environmental Portfolio Standard (EPS) is the expertise APS has gained in solar energy. Interwest believes that APS should embark on a similar learning curve with wind energy. An independent evaluator will provide critical expertise to the utility that it does not possess at the present time.

REGULARLY SCHEDULED SOLICITATIONS FOR RENEWABLE ENERGY

Q. WHAT IS THE RATIONAL FOR REQUIRING RPFs FOR KNOWN AMOUNTS OF RENEWABLE ENERGY AT REGULAR INTERVALS?

A. Unlike many other states, Arizona has no Integrated Resource Planning Process (IRP) for regulated utilities. For renewable energy providers an IRP provides two important sources of information: 1) it details the long term plans for a utility so generation providers can determine the future potential market, and 2) it provides publicly available cost comparisons of technology.

Currently a renewable energy provider interested in the Arizona market can review information related to the Environmental Portfolio Standard and the potential Renewable Energy Standard and Tariff (REST) to assess the amount of energy necessary for compliance, but there is no information available on when and how supplies might be procured, and which type of resources are being considered or preferred.

Q. WHAT SCHEDULE IS INTERWEST PROPOSING?

A. We are proposing that APS solicit for 150 MW of renewable energy generation in years 2007, 2009 and 2011. This would translate to approximately 25% of the needed new generation between 2007 and 2012. APS would use a competitive request for proposal process such as the 2005 renewables RFP process to receive bids for evaluation.

Q. WHY IS USING AN RFP PROCESS IMPORTANT?

A. An RFP process is important because it is a competitive process. Competitive processes tend to drive down prices as technologies compete. A broad-based solicitation for all renewable energy resources will provide the utility with a variety of resources to match their resource needs. Solicitations are also good for determining the breadth of projects available in the region. The wind industry, like many other industries, is highly competitive and keeps project development information confidential until a solicitation asks for bids.

Q. WHY SHOULD APS ACCELLERATE PURCHASE OF RENEWABLE ENERGY RESOURCES BEYOND THE CURRENT EPS OR THE PROPOSED RENEWABLE ENERGY STANDARD AND TARIFF?

A. There are three primary reasons APS should accelerate acquisition and procure 450 MW of renewable energy in the next six years. First, renewable energy resources are stably priced; next, renewable energy resources are not subject to the cost of environmental air regulations and are not vulnerable to changes in or addition of new environmental regulation; and renewable energy is less costly to consumers in the long run.

Q. HOW DOES STABLY PRICED GENERATION BENEFIT RATEPAYERS?

A. APS ratepayers would benefit from the increased purchase of electricity generated from renewable energy resources because renewable energy is not subject to fluctuation in fuel prices. In all cases, except biomass, no fuel needs to be purchased, so there is no cost for fuel.

Recently Arizona and the U.S. have seen dramatic increases in fossil fuel prices. As a result of dramatic increases in the price of natural gas the Commission approved a Power Supply Adjustment (PSA) for fuel and purchase power costs. One purpose of the PSA is to allow the utility a flexible mechanism to recover fuel price increases and the cost of purchased power, and to be able to pass fluctuating costs on to consumers expediently.

In Mr. Don Robinson's direct testimony he states "between 1991....and 2006, APS' energy needs from gas-fired generating facilities and purchased power will increase from 9% to approximately 29%. As a result, gas and purchased power will constitute nearly 70% of the Company's total fuel and purchased power expenses by 2006."[5] This high reliance on natural gas-fired generation and volatility of natural gas markets subjects Arizona consumers to market price fluctuation.

It is interesting to note that Mr. Robinson in his testimony also states "In the recent Request for Proposal ("RFP") that was held pursuant to Decision No. 67744 to seek at least 1000 MW of new long-term generation supply beginning in 2007, *no bidder was willing to accept the risk of gas price volatility*[6] (emphasis added). It is unnecessary and not prudent to increase ratepayer's exposure to that risk.

Unlike natural-gas-fired generation, the cost of energy from a renewable energy project is known from the first day of operation, and those costs do not change. If a wind project is purchased at 60$/MWh in 2007, the price for power will be 60$/MWh in 2017 and 2027. Few, if any, commodities in our society can provide such price

[5] Direct Testimony of Don Robinson, Page 13, lines 6-11.
[6] Direct Testimony of Don Robinson, Page 13, lines 19-22.

certainly. This price stability is a driver for the growing global interest in and development of wind and other renewable energy resources.

Q. CAN YOU EXPAND ON HOW THE COST OF ENVIRONMENTAL REGULATION AFFECTS RATEPAYER?

A. Yes. Another significant benefit of renewable energy to consumers relates to air emissions. Because wind energy generation produces no air emission and other renewable energy resources emit few, if any, emissions that are regulated by state and federal agencies, ratepayers are not saddled with the current or future cost of emissions control and reduction.

In Mr. Ed Fox's testimony[7] he discusses the types of air emissions that are regulated from coal-fired generation. These include sulfur dioxide, nitrogen oxides, particulate matter and mercury. Each of these pollutants requires unique emissions control equipment, and controlling the release of each of these emissions has a cost. APS is requesting an Environmental Improvement Charge (EIC) which, as proposed, would levy a charge of $0.000152 per KWh[8] on most classes of customers. The expected cost for emission control for a single power plant, Cholla, is expected to cost consumers $135 million in the next few years. [9] The EIC, if approved, is expected to be used for clean up of other emissions associated with coal-fired generation. The goal of cleaning up emissions from existing coal-fired power plants is imperative for human health, but use of coal will continue to represent a significant on-going environmental burden for ratepayers.

Q. IS APS EXPECTING TO ADD MORE COAL-FIRED GENERATION IN THE FUTURE?

A. Yes. In its project proposal to build the Transwest Express Transmission line APS is evaluating bring up to 3,000 MW of generation from Wyoming to Arizona. The project is proposing to tap coal and wind resources from Wyoming. The amount of wind energy and the type of coal technology to be built have not been specified, so it is difficult to assess the potential emissions that will need to be captured. However, new plants are subject to the same if not more stringent air emissions requirements which incurs a cost for Arizona ratepayers.

Q. ARE THERE OTHER POLLUTANTS THAT MAY BE REGULATED IN THE FUTURE?

A. Yes, the biggest wild card in the future is how the state and the nation will deal with carbon dioxide, a greenhouse gas. The timeline and type of regulation including potential carbon taxes on carbon dioxide is uncertain, but most in the power industry

[7] Direct Testimony of Ed Fox, Pages 10-12.
[8] Direct Testimony of Greg Delizio, Page 2, line 8.
[9] Direct Testimony of Ed Fox, Page 12, lines 15 & 16.

believe that carbon will be a regulated commodity in the future. APS states that there is an "increased probability"[10] that carbon dioxide will be regulated. Since coal-fired power plants can last from 30 to 50 years it is likely that any existing or new plant may be subject to carbon dioxide regulation taxation and the cost of compliance associated with regulation.

Q. WHY DO YOU BELIEVE RENEWABLE ENERGY RESOURCES WILL COST CONSUMERS LESS THEN COAL OR OTHER SOURCES OF FOSSIL FUEL?

A. If one looks at the total life cycle cost (capital cost, operation and maintenance and fuel) of renewable energy versus conventional energy, renewable energy will be cheaper over the life of the project. Renewable energy projects are capital intensive with all costs but operation and maintenance being up-front costs. Initial costs for renewable energy projects may be more expensive compared to bids for conventional fuels. However, if the full project cost, including capital, O & M and fuel costs of a generation sources is included, the price of fossil fuel generation can change substantially.

It is common in the energy sector to look only at initial purchase price of the commodity and not take into account other factors that influence the ultimate price of the commodity, such as fuel costs. In this rate case APS is requesting an EIC for emissions control that was not included in the initial cost of coal projects when they were first constructed. Additionally, APS now needs the PSA because fiscal impacts of natural gas price fluctuations were not anticipated when plants were built or power purchased. Emissions control, which falls under operation and maintenance, and the EIC, which falls under fuel costs, are part of the life cycle cost of coal and natural gas generation whether or not they are reflected in APS' request. With renewable energy these costs are not variable.

As an example, if the $135 million needed for emissions control was added to the price of energy from the Cholla power plant, instead of charged as an emissions control cost to ratepayers, the price of energy from that power plant would be significantly higher.

For completed projects the cost of energy from renewable energy projects are not subject to market forces such as changes in supply and demand for fuel which affect price. The cost of energy from renewable energy project is not subject to changes due to modifications of current regulations or adoption of new local, state or national air regulations. As demand increases, price will increase unless there is sufficient supply. Global demand for all fossil fuels has increased, including for natural gas. Meeting Arizona's electricity needs will likely be more costly as supplies become more constricted.

[10] Direct Testimony of Ed Fox, Page 9, line 21.

Q. SHOULD THE PURCHASE OF 450 MW OF RENEWABLE ENERGY IN THE NEXT SIX YEARS BE IN LEIU OF THE PROPOSED REST?

A. No, the REST sets out a long term schedule for the procurement of renewable energy resources and results in utilities producing at least 15% of their electric sales from renewable energy generation by 2025. This standard is important because it sets a floor or minimum for renewable energy procurement and provides policy direction to electricity utilities to begin purchasing renewable energy. The REST, as proposed, also instructs utilities to develop distributed resources that are not covered by this testimony. While purchasing 450MW of renewable energy in the next six years is complimentary to the REST, the primary purpose is to avoid additional costs to ratepayers as a result of fuel fluctuation and environmental compliance that will result from the purchase of more fossil fuels.

COLLABORATIVE PROCESS TO DEVELOP PERFORMANCE BASED INCENTIVES

Q.WHAT ARE PERFORMANCE BASED INCENTIVES?

A. Performance based incentives provide a financial or non-monetary reward for achieving a certain outcome. Financial incentive can be a stimulus to achieve a renewable energy or energy efficiency goal or specific level of energy conserved or generation from a renewable energy resource.

Q. WHY SHOULD THE COMMISSION CONSIDER DEVELOPING A PERFORMANCE BASED INCENTIVE SYSTEM FOR CLEAN ENERGY RESOURCES?

A. The current system provides no incentives for APS to purchase clean energy resources or comply with the Environmental Portfolio Standards. Electric utilities have operated the same way, and at about the same level of efficiency, for decades. The job of an Investor Owned Utility (IOUs) is to make money for their shareholders by providing reliable electric service. Historically, IOUs have made large capital investments in power plants and/or transmission lines, and in return, the regulatory agency grants them a rate of return on their investment. While this system has worked well in the past for large capitol investments, the system does not provide financial incentives for the purchase of renewable energy or the conservation of energy through energy efficiency.

As the regulatory environment is currently structured APS is required by Commission Decision No. 67744 and the Environmental Portfolio Standard rules Decisions No. 63486 & Decision No. 63364 to purchase renewable energy. The company does not make a profit on the sale of this electricity. While the amount of renewable energy purchased by APS to date is small, there is an expectation that the amount of renewable energy the company will purchase will grow. APS is a for-profit

company, but they are not allowed to make a profit on the sale of renewable energy. Thus, there is no internal financial incentive for the company to meet or exceed set goals or standards.[11]

If the Commission sees a value in the utility diversifying its generation resources, conserving natural resources and adding clean energy resources then the Commission may want to consider establishing financial incentives.

Q. CAN YOU GIVE A SPECIFIC EXAMPLE?

A. Yes. An incentive could be developed to reward APS for adding renewable energy generation to its portfolio. If APS purchased the total of 450 MW proposed in this testimony, the utility could be allowed to recover from ratepayers a small per KWh assessment. The incentive could be designed to stimulate certain action such as early procurement of renewable energy resources or purchase of Arizona renewable energy resources. The incentive would not be given for compliance with an established program, but provides an incentive for early adoption and/or surpassing the standard.

Q. WHY WOULD THE COMMISSION WANT TO PROVIDE SUCH AN INCENTIVE?

A. The Commission has the difficult job of balancing the immediate financial needs of APS with the longer-term best interest of the public. Because of supply and price concerns, water availability issues, and environmental considerations, utilities around the country are seeking, or being directed to procure, more renewable energy resources. There resources are not well known to Arizona's electric utilities and the institutional inertia is to resist any substantive change. This is especially true if the new activity (purchasing renewable energy resources) provides no profit. Providing an incentive will create a "carrot" for the utility to exceed the standard. Without a financial incentive it is not in the best interest of the utility shareholder to change from their traditional pattern of building or purchasing fossil fuel resources.

Q. HOW DO YOU PROPOSE TO DEVELOP THE APPROPRIATE LEVEL OF INCENTIVE?

A. Interwest proposes using a stakeholder group and collaborative process to develop possible incentives. The process would be lead by APS and would present recommendations to Commission staff and Commissioners. The process should take no more than 9 months. The stakeholder group should include representatives from APS, renewable energy technologies, consumer and clean energy advocacy groups,

[11] While a profit is not allowed for sale of renewable energy APS could be subject to penalties for not meeting the provisions of Decision No. 6774. There are no penalty provisions in the Environmental Portfolio Standard rules. The proposed Renewable Energy Standard and Tariff has penalty provisions as currently drafted.

the Residential Utility Consumer Office, small, medium and large customer classes and commission staff.

The group should be tasked with

- reviewing incentives provided in other states to utilities for energy efficiency, demand side management and conservation programs and development of renewable energy resources,
- reviewing policies that decouple utility rates from energy sales,
- analyzing and documenting the impact of any proposed incentive on ratepayers,
- evaluating the impact of an incentive on meeting or exceeding renewable energy or conservation and efficiency requirements, and
- making specific recommendations on the type and amount of incentives to be considered by the commission.

Recommendations should be submitted to the Commission by October 1, 2007 for consideration.

Q. WOULDN'T IT BE BETTER TO WAIT A FEW YEARS TO SEE HOW COMPLIANCE WITH RENEWABLE ENERGY AND ENERGY EFFICIENCY PROGRAMS ARE PROGRESSING BEFORE CREATING AN INCENTIVE?

A. No, the electric utility industry is at a critical juncture. Over the past 15 years electric utilities have transitioned from coal-fired generation to cleaner, more efficient natural gas-fired turbines. However, with recent volatility and increases in the price of natural gas and supply concerns utilities are not planning on building more natural gas generation. Instead, APS and many western utilities are planning to return to coal as their primary generation source to meet load growth. Currently, there are about 14,000 MW of coal project in various stages of construction in the Interior West.[12] APS is planning on purchasing up to 3,000 MW of Coal via just the Transwest Express Line.[13]

While coal is abundant it is the most polluting fossil fuel. The negative consequences from coal use include land and water impact from extraction, mercury emissions and the associated effect on human health, bioaccumulation in animals and humans and pollution of water sources, air emission such as NOx, SOx and particulates and large consumptive use of scarce water resources.

There are a substantive number of recent government and privately funded reports that document the benefits and availability of renewable energy resources and cost

[12] Environmental Defense, Western Resource Advocates & Center for Energy Efficiency and Renewable Energy Technologies, *Clearing California's Coal Shadow from the American West,* Executive Summary, Page vii., 2005

[13] Peter Krzykos, Arizona Public Service Company, *Transmission Feasibility Study Interim Report,* PowerPoint presentation, Slide 1. (not dated)

effective energy efficiency measures.[14] These reports substantiate the vast amount of potential to conserve energy and avoid building new generation and transmission and the tremendous abundance of renewable energy resources that can be tapped throughout the Interior West to meet Arizona's load growth.

Developing renewable energy resources should be pursued as aggressively as possible. Building a new fleet of pulverized coal plants is a step backwards to a 50-year-old technology that has been largely rejected due to coal's negative attributes. Moving expediently to renewable energy and energy efficiency is a step into the future and to technologies which will not saddle ratepayers with the costs of fuel price increases, air emissions regulations, water use restrictions and carbon regulation. Developing an incentive to help spur action by APS is in the best interest of the state and APS' ratepayers.

SUMMARY OF RECOMMENDATIONS

Q. WILL YOU SUMMARIZE YOUR RECOMMENDATIONS?

A. Yes. Interwest is recommending that an independent evaluator be included in any future APS RFPs for renewable energy to ensure a fair assignment of ancillary service and integration costs, fair determination of a market reference price and a fair evaluation process. The evaluator is necessary because APS, in their 2005 RFP, added costs to wind projects that were double the amount charged by experienced utilities. An independent evaluator will provide expertise to the utility and Commission on renewable energy generation sources.

We are recommending that APS be required to bid for 150MW of renewable energy in 2007, 2009 and 2011 to reduce long-term cost impacts on ratepayers. The regularly scheduled bids will provide notice to the industry for project development and use of an all renewable source RFP will create a competitive process to drive down prices. Greater procurement of renewable energy resources will protect consumers from short and long term fuel price increases and current and expected future emissions regulations.

[14]--Western Governors' Association, *Clean Energy, a Strong Economy and a Healthy Environment,* June 2006, www.westgov.org/wga/meetings/am2006/CDEAC06.pdf
--Western Resource Advocates, *A Balanced Energy Plan for the Interior West,* 2004, www.westernresourceadvocates.org/energy/bep.php
--California Energy Commission's *Renewable Resources Development Report,* November 2003 http://energy.ca.gov/reports/2003-11-24_500-03-080F.PDF
--Western Regional Air Partnership Air Pollution Prevention Forum, *Economic Assessment of Implementing the 10/20 Goals [10% renewable energy by 2005 and 20% by 2015] and Energy Efficiency Recommendations*, October, 2002, http://www.wrapair.org/forums/ap2/docs.html
--Western Regional Air Partnership, *Recommendations of the AP2 Forum to Increase the Generation of Electricity from Renewable Sources,* June 2000 http://www.wrapair.org/forums/ap2/docs.html

Interwest is also recommending that a collaborative stakeholder process be used to evaluate and develop performance based incentives and review decoupling of rates from electricity sales that will encourage APS to procure clean energy resources because it is financially beneficial for their shareholders. This stimulus is intended to change the current dynamic of resisting procurement or purchase of renewable energy because the utility does not earn a rate of return on the sale of electricity generated from renewable energy resources.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

JEFF HATCH-MILLER, Chairman
WILLIAM A. MUNDELL
MIKE GLEASON
KRISTIN K. MAYES
BARRY WONG

EXHIBIT
IEA-5
admitted

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND TO AMEND DECISION NO. 67744.	DOCKET NO. E-01345A-05-0816

Surrebuttal Testimony of Amanda Ormond

on behalf of Interwest Energy Alliance

September 27, 2006

Surrebuttal Testimony of Amanda Ormond
Docket No. E-01345A-05-0816

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Surrebuttal Testimony of Amanda Ormond
on behalf of Interwest Energy Alliance
Docket No. E-01345A-050816

INTRODUCTION

Q. PLEASE STATE YOUR NAME AND YOUR BUSINESS ADDRESS?

A. My name is Amanda Ormond. My business address is 7650 S. McClintock Drive, Suite 103-282, Tempe, Arizona 85284.

Q. DID YOU PROVIDE DIRECT TESTIMONY IN THIS DOCKET?

A. Yes, I provided direct testimony representing Interwest Energy Alliance dated August 18, 2006.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. My testimony supports the proposed Wind Integration Cost Study detailed in Mr. Pat Dinkel's rebuttal testimony and make suggestions for study parameters and organizations to serve as advisors. My testimony clarifies why an Independent Evaluator is necessary for RFP procurement processes and why an auditor, as outline in the proposed REST, will not suffice. Further, I clarify why consistent and orderly acquisition of renewable energy resources is beneficial to the APS customer base and hedges against uncertainties of fossil fuel availability and quality.

WIND INTEGRATION STUDY

Q. DOES INTERWEST SUPPORT THE WIND INTEGRATION COST STUDY PROPOSED BY APS?

Yes. Interwest supports APS' efforts to conduct a wind integration study and believes that it will provide valuable information to assist the utility in understanding the costs and technical issues of integrating a substantive amount of wind into their system.

Q. DO YOU HAVE SPECIFIC SUGGESTIONS FOR THE WIND STUDY?

A. I agree with Mr. Dinkel when he stated that the study should quantify the system impacts and associated costs of integrating wind projects in the APS system. Interwest suggests the following to ensure a complete and valuable study:

- APS should study different wind penetration rates to quantify the impacts and costs of future scenarios. Penetration rates of 5, 10, 15, 20 or 25 percent are reasonable rates to consider for study. APS should choose a near term penetration rate such as 5 or 10 percent, a medium term such as 15, and longer term rate, 20 or 25 percent.
- The study should evaluate reliability and operating (including regulation, load following and unit commitment) impacts of wind penetration and costs associated with each.
- As Mr. Dinkel points out, obtaining sufficient detailed wind data for a study can be challenging. As part of the study a meteorological wind forecasting firm should be engaged to create a data set for use in the study from meso-scale simulations.
- To the extent possible, APS should follow the guidance found in the Utility Wind Interest Group's *Utility Wind Integration State of the Art* report provided in with my direct testimony.

Once the study is complete APS should apply the study findings to future purchases of wind-generated electricity and train staff on the potential system impacts in anticipation of having wind energy on the APS system.

Q. CAN YOU DISCUSS THE IMPORTANCE OF A TECHNICAL ADVISORY COMMITTEE?

A Technical Advisory Committee (or Technical Review Committee) will provide expertise to guide development of the study. Non-utility personnel with wind performance, modeling, and system expertise brought together with APS' system experts will create a strong technical committee. The committee should be convened at the beginning of the study to provide input on study assumptions, processes, and methods and meet periodically throughout the study to provide guidance.

Based on the integration studies completed to date, Interwest recommends the following organizations for members of the technical advisory committee:

- National Renewable Energy Laboratory
- Northern Arizona University
- Wind Integration and Wind Modeling Consultants
- Local Transmission and Energy Experts

INDEPENDENT EVALUATOR

Q. DO YOU THINK PERFORMING A WIND INTEGRATION STUDY NEGATES THE NEED FOR AN INDEPENDENT EVALUATOR (IE)?

No. A wind integration study will provide valuable system-specific information on cost impacts for integrating wind-generated electricity. However, the study will not provide information for other renewable energy technologies. Unlike fossil-fuel generation some renewable energy technologies are rapidly changing, creating the need for an expert on the state-of-the-art of technology. The IE will serve as a renewable energy resource expert to the utility and ensure fair evaluation of a technology's potential and good fit within the system. Due to lack of experience with many commercial scale renewable energy technologies assignment of unreasonable costs is possible with technologies other than wind. An IE would provide expertise in all technologies, not just wind.

A second need, sited in my direct testimony for an IE, is to help review any set reference price for conventional resources from which renewable energy prices will be judged. If the reference price is set using unreasonably low natural gas prices or depreciated capital assets instead of new fossil fuel energy acquisitions/plant costs, then renewable energy projects will appear more expensive.

Q. APS STATES THAT AN IE IS NOT NECESSARY BECAUSE THE REST REQUIRES AN INDEPENDENT AUDIT OF PROCEDURES. DO YOU AGREE?

The REST proposed rules, if adopted, would require that the procedures used by an affected utility to procure renewable energy resources be certified by an independent auditor as fair and unbiased and appropriately applied. This audit will provide assurance to the Commission of a fair process. However, the audit requirement is in the section on Compliance Reports (Docket RE00000C-05-0030, R14-2-1812). Compliance reports must be submitted to ensure fulfillment of program for the previous calendar year. The purpose of an IE proposed here is to be proactive and assist the utility in designing a fair RFP process, assignment of integration costs, reference price and review of bids. Providing an audit, after the fact, does not serve the same purpose.

In addition, the audit process is only required of procurement of resources to meet the REST. Renewable energy resources purchased which exceed or are separate from the REST would not be subject to the auditing provision.

Q. COULD YOU ADDRESS APS' CONCERNS FOR THE COST OF THE INDEPENDENT EVALUATOR?

While the absolute cost of hiring an IE (estimated at $65,000-125,000) is not insignificant, it is an insignificant percentage of the cost of energy that will be procured under an RFP process. I believe it to be penny wise and pound foolish to be unwilling to spend funds on an outside expert who can help the utility cost effectively and efficiently procure stable-priced renewable energy resources. If the cost of $100,000 for an IE is spread over the cost of energy from an RFP procuring 150 MW of renewable energy at $60 per MWh from projects with an average capacity factor of, say 80%, the IE would be just 0.005% of the cost of the energy purchased. This cost would also only be incurred in years where an RFP was put out for bid.

Small changes in the cost or charges assigned to each MW of renewable energy, as a result of input by an IE, would result in significant overall change in the price of a resource. Using the same figures, if the utility adds just 50 cents to each MWh, the cost of the project just mentioned would escalate by a over a half million dollars, much more than the cost of an IE.

Interwest understands that some of the functions of an IE and a REST program compliance auditor may be similar and suggests that in years where an RFP is released the IE report could suffice to meet the auditing provision of the REST. In years where there is no RFP then costs would be incurred for the auditor just for REST compliance.

ACQUISITION OF RENEWABLE ENERGY THROUGH A SCHEDULED RFP PROCESS

Q. DO YOU AGREE THAT APS SHOULD NOT HAVE A MANDATED SCHEDULE FOR RFPs FOR RENEWABLE ENERGY?

A. Interwest understands that APS is not interested in scheduled RFPs for purchasing renewable energy and wishes to preserve its ability to purchase resources when deems necessary. The RFP schedule was proposed by Interwest as a method for APS to begin an orderly, modest and regular procurement of renewable energy resources and also signal to the industry

APS' interest in renewable energy. While the REST, if passed, will create a requirement for APS to derive a significant percentage of its generation from renewable energy, the requirement is long term. In the short term (between 2007 and 2011) APS will only need to procure tens of MWs of renewable energy.

In its last rate case APS agreed to purchase 10% of its growth capacity each year from renewable energy resources. This is approximately 30 MW per year. Interwest has proposed that APS purchase 25% of the utility's future capacity from renewable energy. This is a modest increase of just 15% from current conditions. Such procurement will: help to diversify APS' electricity generation mix, develop domestic resources, and allow orderly development of renewable generation projects and system planning to integrate new generation into system operations. Interwest believes that regularly scheduled RFPs are an effective and viable method for renewable energy procurement at the best price.

Q. DO YOU BELIEVE, AS APS DOES, THAT THE PROPER FORM FOR ADDRESSING RENEWABLE ENERGY IS THE R.E.S.T. RULEMAKING?

The rulemaking process is only one of the appropriate places to deal with renewable energy. The REST is important to provide long-term policy direction for regulated utilities. But, the REST is still a draft rule, and not a final regulation requiring action.

Current market conditions, such as high and fluctuating natural gas prices, warrant that stable priced renewable energy resources be considered in this rate case as well. Renewable energy resources, purchased in greater amounts, will mitigate some of the current and expected negative fiscal impacts on ratepayers. Not requiring the purchase of renewable energy will further increase ratepayer risks to volatile gas prices. This risk and exposure will increase in the short term as the utility will likely meet load growth for the next few years with more natural gas-fired generation.

Q. DO YOU HAVE ANY FINAL COMMENTS?

Yes. APS will continue to experience some of the highest electricity growth rates in the nation. It appears that the utility is expecting to rely primarily upon natural gas and coal to meet new load growth, yet both fuels face issues that may significantly change their costs and availability. Natural gas demand is growing worldwide. As the U.S. outstrips North American supplies, the nation is expected to begin importing liquefied natural gas (LNG) from

foreign countries to meet expected shortage. The price and quality of imported gas is uncertain. Recently, concerns have arisen about the quality of the incoming gas and safety related to burning imported natural gas that burns hotter due to a difference in chemical makeup from domestic gas.

For coal, pressure is mounting to begin controlling carbon emissions. Carbon regulation could add significantly to the cost of new coal generation. Some utilities add a carbon cost to fossil fuels. For example, in evaluating the costs of new resources in its most recent RFP, Public Service Company of Colorado is assessing all CO2-emitting resources an imputed cost of $9/ton of CO2 for bid evaluation purposes. The imposition of the imputed CO2 cost will begin in 2010 (escalating at 2.5% per year). Coal will also be subject to transportation constraints due to lack of available railroad track capacity and cars to meet growth, and will be controversial in the West due to it large consumptive water use.

Interwest believes it is in the best interest of the ratepayer for the Commission to carefully consider the risks and costs that consumers may have to pay to maintain our reliance on fossil fuel. Renewable energy resources do not suffer from many of the pricing and environmental uncertainties that might affect the costs and availability of fossil fuels moving forward. A systematic and modest procurement of renewable energy will ease the transition into a more diverse and cost-stable energy future for Arizona's ratepayers.

SR/OIAF/99-03

EXHIBIT
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admitted

Federal Financial Interventions and Subsidies in Energy Markets 1999: Primary Energy

September 1999

Energy Information Administration
Office of Integrated Analysis and Forecasting
U.S. Department of Energy
Washington, DC 20585

EXHIBIT

This report was prepared by the Energy Information Administration, the independent statistical and analytical agency within the Department of Energy. The information contained herein should be attributed to the Energy Information Administration and should not be construed as advocating or reflecting any policy position of the Department of Energy or of any other organization. Service Reports are prepared by the Energy Information Administration upon special request and are based on assumptions specified by the requestor.

Preface

The analysis in this report was undertaken at the request of the Office of Policy, U.S. Department of Energy. In its request, the Office of Policy asked the Energy Information Administration (EIA) to update the 1992 EIA report on Federal energy subsidies, including any additions or deletions of Federal subsidies based on Administration and Congressional action since the 1992 report was written, and to provide an estimate of the size of each current subsidy. Subsidies to be included are those through which a government or public body provides a financial benefit. The subsidy must be specific; for example, depreciation schedules that can be used in non-energy sectors as well as energy sectors are not included in the definition of a subsidy for this study. This report is to focus on subsidies covering primary energy only; a subsequent report will be requested, covering end-use energy and electricity. The assumptions for the study were noted in a letter provided by the Office of Policy on May 20, 1999. A second letter from the Office of Policy clarified the assumptions further, focusing the analysis of subsidies on goods rather than services. Both letters are provided in Appendix E.

The legislation that established EIA in 1977 vested the organization with an element of statutory independence. It is EIA's responsibility to provide timely, high-quality information and to perform objective, credible analyses in support of the deliberations of policymakers. EIA prepared this Service Report upon special request, using the assumptions specified by the requestor.

This report was prepared by the staff of EIA's Office of Integrated Analysis and Forecasting. General questions about the report may be directed to Mary J. Hutzler (202/586-2222, mhutzler@eia.doe.gov), Director of the Office of Integrated Analysis and Forecasting, or to Arthur Rypinski (202/586-8425, arthur.rypinski@eia.doe.gov). Specific questions about the report may be directed to the following analysts:

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The Scope of Energy Subsidies and Tax Expenditures
Appendix B, Oil and Gas
Appendix C, Federal Energy Research and Development Appropriations
Appendix D, Bibliography

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Trust Funds and Energy Excise Taxes
Appendix B, Coal

Tom Leckey (202/586-9413 tleckey@eia.doe.gov):
Appendix A, Studies of Federal Government Energy Interventions

Larry Prete (202/586-2847 lprete@eia.doe.gov):
Appendix B, Electricity, Nuclear, Alternative Energy.

Executive Summary

Purpose

In May 1999, the Office of Policy, U.S. Department of Energy (DOE), asked the Energy Information Administration (EIA) to prepare an update of EIA's 1992 Service Report on Federal energy subsidies,[1] using a more specific definition of "subsidies" provided by the Office of Policy. In its letter of request, the Office of Policy asked the EIA to examine Federal programs that provided a "specific financial benefit" covering "primary energy only."[2]

Federal energy subsidies take three principal forms:

- **Direct Payments to Producers or Consumers.** These are Federal programs that directly affect the energy industry and for which the Federal Government provides a direct financial benefit. Currently, three energy programs provide direct payments to producers or consumers. Two of them focus on energy end use, and are excluded from this study. The third program is the Renewable Energy Production Incentive.

- **Tax Expenditures.** Tax expenditures are provisions in the tax code that reduce the tax liability of firms or individuals who take specified actions that affect energy production, consumption, or conservation in ways deemed to be in the public interest.

- **Research and Development.** R&D expenditures do not directly affect current energy production and prices, but if successful they could affect future production and prices. An example of the impact of Federal energy R&D is the important role that Federal R&D spending has had in the development of the U.S. commercial nuclear power industry.

In addition to the principal types of programs described above, there are Federal programs that may act as subsidies but for which the existence or impact of the subsidy is uncertain. These programs are represented by the excess liabilities of trust funds, such as the Black Lung Disability Fund. Although trust funds are discussed in this report, no specific estimate of their subsidy element is presented because of the difficulty of estimating the potential future liability to the Federal Government.

The size, scope, and market effects of energy subsidies depend primarily on the definitions and methods used to measure their impacts.[3] In economics, the term "subsidy" is used to define a specific program in which the Government makes direct payments to producers or consumers to defray a portion of the cost of producing or consuming some product. The application of this definition to real-world programs, however, can be much more complex.

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[1]Energy Information Administration, *Federal Energy Subsidies: Direct and Indirect Interventions in Energy Markets*, SR/EMEU/92-02 (Washington, DC, November 1992).

[2]The Office of Policy has indicated that it intends to request a second study that will cover energy end use and electricity.

[3]Appendix A reviews various energy subsidy reports.

This report measures subsidies based on the cost of the programs to the Federal budget. This approach has the advantage of being relatively easy to measure using available information. However, Federal budget estimates generally overstate both the economic costs and the market impacts of specific programs. Programs that offer small subsidies for products for which there are huge existing markets tend to function mostly as transfer programs; that is, their market impacts are negligible, and for the most part they simply redistribute funds from one part of the economy to another, with the Government acting as the intermediary. More often, Federal energy subsidies offer relatively large payments to producers using specific energy technologies that otherwise would be uneconomical. In these cases, the effects on the larger markets are small, but the impacts on the use of particular technologies may be significant. Finally, while subsidy programs are legislated because they are presumed to produce some social benefit that exceeds the expected cost of the program, no attempt is made in this report to measure the social benefits that may accrue from the programs reviewed.

Federal Government intervention in energy industries has generally declined over the past two decades. Price controls for domestic oil and natural gas production were largely eliminated by the mid-1980s. The Tax Reform Act of 1986 reduced or eliminated many tax expenditures, several of which figured prominently in earlier studies. The Energy Policy Act of 1992 (EPACT), while introducing incentives for renewable energy and alternative transportation fuels, set the stage for the eventual privatization of DOE's uranium enrichment activities. The implications of the EPACT provisions were not incorporated in EIA's 1992 subsidy report, because their date of enactment followed that analysis.

Summary of Results

Federal subsidies for primary energy are estimated to be $4.0 billion in fiscal year 1999, down about $1 billion (1999 dollars) from fiscal year 1992 (Table ES1 and Figure ES1). Direct expenditures from the Renewable Energy Production Incentive are estimated to be $4 million in fiscal year 1999, as compared with direct expenditures of $82 million (1999 dollars) for synthetic fuel in the 1992 report. Tax expenditures related to primary energy total $1.7 billion (1999 dollars), with another $0.7 billion for the ethanol exemption from Federal excise taxes. EIA's 1992 report showed greater tax expenditures ($2.2 billion in 1999 dollars) but lower Federal excise taxes ($0.5 billion). In 1999, the two largest items are the alternative fuels production tax credit, largely used to develop coalbed methane and tight sands ($1.0 billion), and the percentage depletion allowance for the oil, gas, and coal industries. Tax deferrals on enhanced oil recovery are the third largest expenditure.

Federal R&D appropriations related to energy markets (excluding basic research) are estimated at a total of about $1.6 billion in fiscal year 1999–down from $2.0 billion in 1992 (in 1999 dollars). Federal spending on coal and nuclear power research has declined substantially since 1992. The decrease in nuclear energy R&D expenditures has resulted largely from declines in spending directed at treatment and storage of nuclear waste and the decommissioning of obsolete nuclear power plants. The fiscal year 1999 budget includes about $0.6 billion for "nuclear" R&D, most of which is related to nuclear waste disposal and cleanup of nuclear research facilities. Less than $0.1 billion is budgeted for research on new nuclear plants. Coal R&D expenditures have also declined, as a result of cuts in spending on clean coal technologies.

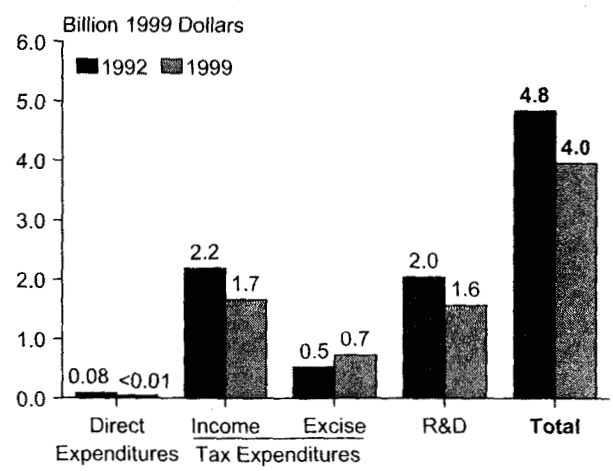
Table ES1. Summary of Primary Energy Subsidy Elements in Federal Programs by Fuel and Program Type on a Budget Outlay Basis, Fiscal Year 1999
(Million 1999 Dollars)

Fuel	Type of Subsidy				Total
	Direct Expenditures	Tax Expenditures		Research and Development	
		Income	Excise		
Oil	0	263	0	49	**312**
Gas	0	1,048	0	115	**1,163**
Coal	0	85	0	404	**489**
Oil, Gas, and Coal Combined[a]	0	205	0	0	**205**
Nuclear	0	0	0	640	**640**
Renewables	4	15	[b]725	327	**1,071**
Electricity	0	40	0	[c]33	**73**
Total	**4**	**1,656**	**725**	**1,567**	**3,953**

[a]The category Oil, Gas, and Coal Combined includes expenditures that were not allocated to any one of the three individual fuels.
[b]Alcohol fuels excise tax.
[c]Electricity research and development is advanced turbine technology. Other generation technology research and development is distributed by fuel.
Sources: Most information drawn from Office of Management and Budget, *Budget of the United States Government, Fiscal Year 2000* (Washington, DC, February 1999).

The total value of Federal subsidies to oil, natural gas, coal, and nuclear power is estimated to be $2.8 billion in 1999 (Table ES1), compared with wholesale spending of $127 billion (1999 dollars)[4] in 1998 for purchases of those fuels and total retail expenditures of $363 billion (1999 dollars) in 1995.[5] Although the value of energy subsidies is low relative to total energy expenditures, some forms of energy receive subsidies that are substantial relative to the value of the fuels. Of the primary fossil fuels, natural gas benefits the most from Federal subsidies in 1999–a total of $1.2 billion, almost all of which comes from a tax credit on the production of alternative fuels, primarily gas from coalbed methane and tight sands. Although no production data are available for natural gas from tight sands, coalbed methane accounted for 6 percent of all natural gas production in 1997. The $1.0 billion alternative fuel credit in 1999 can be compared with natural gas sales valued at $39 billion (1999 dollars) at the wholesale level in 1998 and $79 billion (1999 dollars) at the retail level in 1995. A subsidy amount of $4 billion or $5 billion is, in

Figure ES1. Summary of Primary Energy Subsidy Elements in Federal Programs by Program Type on a Budget Outlay Basis, 1992 and 1999



Source: Tables 1 and 2 in this report.

[4]Wholesale expenditures do not include nuclear fuel.
[5]The 1995 data on retail expenditures for energy are the latest available.

general, too small to have a significant effect on the overall level of energy prices and consumption in the United States; however, the subsidy programs described in this report are, in most cases, targeted at narrow segments of the energy industry (e.g., ethanol production for blending into gasoline and natural gas production from coalbed methane and tight sands).

Appendix A reviews different subsidy reports in the literature. A number of those reports have produced larger estimates of subsidies than this report due to the inclusion of regulation, defense, transportation, and/or tax expenditures that are not specific to energy.

EXHIBIT
Merchant Generator - 1
Admitted

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ADMITTED TO PRACTICE IN:
ARIZONA, COLORADO, MONTANA,
NEVADA, TEXAS, WYOMING,
DISTRICT OF COLOMBIA

November 22, 2006

Chairman Jeff Hatch-Miller
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

Re: Arizona Public Service Company General Rate Case
Docket Nos. E-01345A-05-0816, E-01345A-05-0826,
and E-01345A-05-0827

Dear Chairman Hatch-Miller:

This letter is written upon behalf of Mesquite Power, L.L.C., Southwestern Power Group II, L.L.C., Bowie Power Station, L.L.C. and the Arizona Competitive Power Alliance (collectively "Merchant Generators") in response to your October 24, 2006 letter to APS and the Parties in Docket Nos. E-01345A-05-0816, E-01345A-05-0826, and E-01345A-05-0827 (the "Consolidated Proceedings").

Your letter contains the following statements:

"Additional information related to whether APS has the financial resources to maintain a reliable and adequate electric system for its customers would be helpful in my review of this matter. As part of the APS rate case, I would like the company to explain its resource planning (including financing of it) through 2020 for the development of new generation and transmission projects. (APS' August 1, 2006 letter refers to the subject generally.) This information should include preliminary RFPs for long-term power resources, potential self-build generation projects requiring Commission approval and major interstate transmission projects that would increase import capabilities. [Emphasis added]

I am also concerned that since APS agreed to a self-build moratorium in the Rate Case Settlement (Decision No. 67744), the company may face challenges in procuring additional power supplies through 2015. In the interim, competitive procurement of generation resources may prove problematic as natural gas prices remain volatile and subject to possible supply and delivery constraints. I would

> like APS and the Parties to provide information on this topic as well, in order to develop the evidentiary record in this area." [Emphasis added]

The Merchant Generators are concerned by the foregoing statements for several reasons. First, it is not clear at this juncture what you may have in mind when you express a desire to "develop the evidentiary record" on the subject of the "self-build moratorium" which was approved by the Commission in Decision No. 67744, as issued on April 7, 2005 in Docket No. E-01345A-04-0437. As you may recall, the Merchant Generators were active Intervenors in that proceeding, and they were signatory parties to the August 18, 2004 Settlement Agreement which was the subject of Decision No. 67744. The "self-build moratorium" was the central consideration in their willingness to support the Settlement Agreement and its rate-basing of the Pinnacle West Energy Corporation generation units. In fact, collectively the Merchant Generators incurred approximately $1,000,000 in attorneys' and consultants' fees in order to achieve that key settlement objective. Accordingly, anything pertaining to the integrity of the "self-build moratorium" is of critical importance to us.

Second, in the context of the issues presented in the Consolidated Proceedings, the relevance of "information" pertaining to APS' future "potential self-build generation projects" must be questioned. The financing costs associated with such projects are unknown and speculative at this juncture. Thus, "information" (in the form of speculations) relating to the same would not constitute evidence which could materially assist the Commission in determining APS' cost of capital and rate of return for purposes of the Consolidated Proceedings. Moreover, the concept of "potential self-build generation projects" presupposes that the competitive wholesale market has failed to satisfy APS' projected power resource needs. There is no basis for such a supposition, and the Consolidated Proceedings are not an appropriate procedural vehicle for an inquiry of that nature.

Third, to the extent that the Commission did attribute a hypothetical financing cost to one or more of such future "potential self-build generation project(s)," it might risk creating an appearance that it had favorably prejudged the merit(s) of request(s) for exception(s) to the "self-build moratorium" it was yet to receive and fully consider. Presumably, that is both a reality and an appearance that the Commission does not wish to create.

Fourth, it is conceivable that, your indicated desire to introduce the subject of the "self-build moratorium" into the "evidentiary record" in the Consolidated Proceedings might also occasion some due process problems, given that there may be parties who might have sought to intervene in Docket No. E-01345A-05-0816, had they had notice that information pertaining to the "self-build moratorium" might be considered. Needless to say, they did not have such notice.

Fifth, there is currently pending in Docket No. E-01345A-06-0464 a request by APS for an exception to the "self-build moratorium". That proceeding represents the "case of first impression" as to how the "self-build moratorium" provisions of the Settlement Agreement are to be interpreted and applied to a specific set of facts. The Merchant Generators are deeply involved as parties in that proceeding, which is on an expedited procedural schedule concurrent with the Consolidated Proceedings. Consequently, the Merchant Generators will be unable to

participate as fully in the Consolidated Proceedings as would otherwise be the case to the extent that information relating to the "self-build moratorium" is offered by APS "to develop the evidentiary record."

Accordingly, for the reasons discussed above, the Merchant Generators respectfully request that the Commission not receive into the evidentiary record in the Consolidated Proceedings, and not consider in connection with any opinion(s) and order(s) issued therein, any information pertaining to "potential self-build generation projects". Thank you for your consideration of our serious concerns.

Respectfully submitted,

Lawrence V. Robertson, Jr.
Attorney for Mesquite Power, L.L.C.,
Southwestern Power Group II, L.L.C.
and Bowie Power Station, L.L.C.

and

Jay I. Moyes
Attorney for the Arizona Competitive
Power Alliance

By: Lawrence V. Robertson, Jr.
Lawrence V. Robertson, Jr.

Cc: Commissioner William A. Mundell (Email and Hard Copy)
Commissioner Mike Gleason (Email and Hard Copy)
Commissioner Kristin Mayes (Email and Hard Copy)
Commissioner Barry Wong (Email and Hard Copy)
Chief Administrative Law Judge Lyn Farmer (Email and Hard Copy)
Parties to the Docket (Email)

EXHIBIT
DEAA-1
Admitted

PENGAD 800-631-6989

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

JEFF HATCH-MILLER, Chairman
WILLIAM A. MUNDELL
MIKE GLEASON
KRISTIN K. MAYES
BARRY WONG

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND TO AMEND DECISION NO. 67744	DOCKET NO. E-01345A-05-0816

Direct Testimony of

William J. Murphy

on behalf of DEAA

Docket No. E-01345A-05-0816

September 1, 2006

Direct Testimony of William J. Murphy
Docket No. E-01345A-05-0816

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DIRECT TESTIMONY OF WILLIAM J. MURPHY ON BEHALF OF THE DISTRIBUTED ENERGY ASSOCIATION OF ARIZONA.
(DOCKET No. E-01345A-05-0816)

I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS

A. My name is William J Murphy P.E., and my business address is 5401 N. 25 Street, Phoenix, AZ 85016.

Q. BY WHO ARE YOU EMPLOYED AND WHO DO YOU REPRESENT IN YOUR TESTIMONY?

A. I'm with Murphy Consulting and am working on behalf of the Arizona Cogeneration Assn, (AzCA), d/b/a Distributed Energy Association of Arizona (DEAA).

Q. WOULD YOU PROVIDE SOME INFORMATION ON THE DEAA AND DESCRIBE THEIR INTEREST IN THIS PROCEEDING?

A. The DEAA is a nonprofit coalition of interested parties organized for the purpose of exchanging information on distributed generation and advocating for policies that permit safe, reliable and economically viable use of distributed generation. DEAA members represent utilities customers, gas and electric utilities, environmental consultants, developers and energy industry consultants. DEAA has interest in this proceeding due to the impact the proposed rates would have on customers in terms of their energy budgets as well as their ability to effectively implement and derive economic and operational benefits from a wide range of distributed generation (DG) alternatives in Arizona.

Q.WOULD YOU DISCUSS YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I attended Grammar, and High School in Arizona. I received a BS in Engineering from the University of Arizona; I also attended Phoenix College, Regis University, and ASU.

I worked for a number of small and large businesses in California and Arizona before joining APS as an Industrial Sales Engineer. During the 16 years I served on the various committees including the Totalizing Committee, the Load Forecast Committee, and the Cogeneration Committee, leaving as Manager of Power Contracts for retail and wholesale customers.

Then I operated an Energy consulting firm by the name of Murphy Engineering (ME) for 12 years. ME provided energy and utility rate consultation services for many businesses, governmental, and educational organizations including: Arizona DOA, Arizona DOT, Arizona Corporation Commission, University of Arizona, Arizona Western College, Arizona Interfaith Coalition on Energy, Anderson Clayton, Inc. Arizona Energy Office, Arizona Residential Utility Consumer Office (RUCO), Arizona School Boards Association, America West Industries, Cyprus Mines, and others.

Then I next served as the "Energy Manager" for the City of Phoenix from 1992 until 2003 during this time I managed the Phoenix' 3,000 individually metered electric accounts.

The City pays over $42 million/year for electrical energy.

Q. WERE YOUR TESTIMONY AND ACCOMPANING EXHIBITS PREPARED BY YOU OR UNDER YOUR DIRECTION?

A. Yes any and all were.

Q. WOULD YOU SUMMARIZE YOUR TESTIMONY AND RECOMENDATIONS?

A. My testimony will focus on how the APS rates have changed over the last 10 years. Specific emphasis will be on Distributed Generation (DG) rates, including Standby, Maintenance, and Supplemental. A Rate Case (Docket E-0134A-95- 0491) in 1996 which investigated the rates paid by General Service (GS) (non- residential) customers who generate their own electricity. An Informal Data Request from DEAA to APS in 1996 revealed that E-32R was lower cost For DG customers than E-51, E-52, or E-55.

Changes since this rate case produced rate changes that significantly discourage Distributed Generation, Conservation, and Demand Side Management (DSM).

Over the last 10 years the rates have gone in the opposite direction of costs:

- ✓ The Companies costs have significantly changed with the capital (Demand) costs down 12% and fuel (Energy) costs increasing 85%.
- ✓ The costs of demand are up over 50% and energy charges down by 5%
- ✓ The increased negative impact the current and proposed rates would have on customers who desire to lower energy costs using DG.
- ✓ DG is discouraged by:
    1. The increased costs related to Standby Charges
    2. The increased costs related of Supplemental Energy.
    3. The decreased costs related to DG displaced energy.
- ✓ Increased costs (cents/kWh) related to customers using less energy with conservation/DSM.
- ✓ The continued inability of these rates to communicate pricing signals to the customer

Unfortunately for most GS customers these rates provide incentives to increase energy use or decrease the customer's peak demand (not the system peak). Neither of these alternatives will automatically benefit all customers.

WHAT RATES DO YOU RECOMMEND BE ADOPTED FOR CUSTOMERS WHO CHOSE TO GENERATE THEIR OWN ELECTRICITY?

We recommend the introduction of a rate similar to Salt River Project's E-32 TOU for DG customers with demands between 20 and 1000 kW and SRP TOU E- 61 for larger customers. These rates would cover Standby, Supplemental, and Maintenance energy.

WHY DO YOU PREFER THE SRP RATES TO THE APS RATES FOR THE SAME TYPE OF CUSTOMERS IN THE SAME CLIMATE?

The SRP rates are TOU with the major emphasis on energy (kWh) and have significant differences in on-peak prices, both diurnal and seasonal. This is a much easier to understand and respond to these price signals approach than demand charges (kW) that are not time sensitive.

DOES APS HAVE RESIDENTIAL RATES THAT DISCOURAGE DISTRIBUTED GENERATION?

Yes, there are 2 methods that APS residential rates discourage DG, (primarily renewable). They are:
METHOD #1.Rates: ET-1, ET-2 EC-1, EC- 1R, ECT-1, ECT-1R, AND ECT-2.
The disincentive is that all of these time based rates have on-peak times that are much longer than necessary to meet the primary 4:00 to 6:00 summer on-peak hours.
METHOD #2. Rates: EC-1, ECT-1, ECT-IR, AND ECT-2
These capacity (C) rates discriminate by charging high prices for standby and supplemental energy.

DO YOU HAVE A RECCOMENDATION FOR RESIDENTIAL CUSTOMERS WHO UTILIZE DG?
Due to the fact that the largest residential customers are on Demand/energy rates (EC-1, ECT-2, ECT-1R) these rates discourage renewable (solar) DG. Unfortunately these customers must change to a more expensive rate before they install Solar DG.

COULD YOU PROVIDE A BRIEF HISTORY OF THE PRICING OF ELECTRICITY?

Yes Thomas Alva Edison originally priced his services in "light-hours" as lighting was the primary use for electricity in the early years. In 1898 he changed to billing in "Webbers' (kilowatt-hours) as there were increasing uses of non-lighting electricity (street cars).

Much later the industry began rendering monthly bills with various components including:

- Customer (billing and metering)
- Energy (kVAh, kWh)(FUEL/OPERATIONS)
- Demand (kVA,kWh).(CAPITOL COSTS)

The demand charges are generally intended to recover capital costs, while the energy charges are considered to cover fuel and operating costs.

Q. DO THE CUSTOMERS UNDERSTAND THE FACTORS USED IN MEASURE THEIR ENERGY USE WHEN THEY RECEIVE A MONTHLY BILL?

A. For over 8% of residential customers and 96% of non-residential customers the pricing of electricity is based on two units of electric measure; DEMAND – which is measured in kilowatts (kW), and ENERGY – which is measured in kilowatt-hours (kWh). Most customers do not understand the differences between these two engineering units. I find that most customers believe these two units of measure are basically the same thing, in other words kW= kWh. This common misconception renders these measurements of little use in customers' desire to lower monthly costs.

Q. WHY DON'T CUSTOMERS UNDERSTAND THE FACT THAT THEY ARE BEING BILLED ON BOTH KW and KWH?

A. I believe that this is a very difficult concept and that not only do most customers not understand, but many within the industry, do not understand that kW is not the same as kWh. I have taught utility classes that focused how rates impacted the monthly billing. At the end of the class all my students were delighted to state they now understood this concept. Unfortunately in subsequent conversation they would often discuss energy and interchange kW and kWh.

Q. WHY IS THIS RELATIONSHIP (kWh/kWh) SO HARD TO UNDERSTAND?

A. It may be the similar nomenclature that makes this a difficult concept. As an example of the difficulty of understanding we now look at the most commonly used analogy (miles & MPH). Unfortunately this analogy falls apart because the units that include time are reversed. The total in the car analogy (miles) contains no time, while the rate of use in the car analogy (MPH) does contain time. This is the exact opposite of the electric comparison. Said another way -kW is to MPH- as – kWh is to miles – confusing huh? In addition, the kilowatt is an engineering unit that we do not confront in our life apart from the utility bill.

Q. ARE THERE OTHERS BESIDES CUSTOMERS WHO DO NOT UNDSERSTAND THE DIFFERENCE BETWEEN KW and KWH?

A. Yes, there are many closely associated with the electric utility industry including many utility employees, plus some suppliers of DSM services, including suppliers who provide metering services.

Q. IS IT IMPORTANT FOR CUSTOMERS TO UNDERSTAND THE DIFFERENCE BETWEEN KW AND KWH?

A. Yes, Where customers plan to alter their energy use by conservation, DSM, investments in energy management devices and distributed generation including renewable generators. It is extremely important for the customer to understand the dollar impact these efforts will have on the monthly bill.

Most importantly to small commercial customers who may chose to employ DG (solar, and combined heat and power (CHP)) whether to increase security and reliability, lower their costs and improve the environment, or any combination of the above, the continuing demand (kW) increases in rate E-32R will significantly inhibit these choices by doubling the cost of standby power & energy over what this Commission previously approved.

I addition, it is my testimony that prices for utility purchase of electricity bought from DG are 1/5 to 1/2 of the price that the Company must pay for incremental energy at wholesale. This despite the fact that purchases from DG can be within the "load pocket", thereby unloading the transmission/distribution system.

Q. WHY HAVE YOU CHOSEN TO DIRECT YOUR TESTIMONY TOWARD GENERAL SERVICE (GS) RATES AND SPECIFICALLY E-32R, E-52 & E-55?

A. 96% of all potential GS DG customers will be on Rate E-32R and E-52. Of this large percentage, most are small and medium sized customers (under 1000kW). Small Customers include commercial and industrial operations, such as coffee shops, offices, hair salons, small school buildings, machine shops, and government facilities. Medium customers include high schools, government facilities, resorts, hospitals, manufacturers, and others.

Emerging technologies like DG, and to an extent DSM, can benefit this large population of APS ratepayers only if the rate design will encourage understanding and change. General Service customers pay more than their share of cost to serve them and the proposed rates will only add to that in equity by removing technology alternatives that could benefit them the most.

Q. WHAT STANDARDS ARE THERE FOR PRINCIPLES TO GOVERN RATE DESIGN?

A. I believe Dr. James C. Bonbright's 1961 book best sets out principles for measuring effectiveness of rates. This book lists 8 the principles as follows:

1. Simplicity and understandability
2. Freedom from controversies
3. Effectiveness
4. Revenue stability
5. Rate stability
6. Fairness
7. No "undue discrimination"
8. Discourages "wasteful use"

Q. GIVEN THE BONBRIGHT PRINCIPLES OF RATE DESIGN YOU'VE LISTED, WHAT IS YOUR VIEW OF E-32R, E-52, & E-55, AND ITS ADHERENCE TO

THESE PRINCIPLES? AND GIVEN THAT MOST OF DR. BONBRIGHT'S WORK WAS DONE BEFORE ENVIRONMENTAL AND CONSERVATION ISSUES CAME TO PROMINENCE, WHAT WOULD YOU CHANGE IN THE LIST OF PRINCIPLES?

A. In regard to E-32R's adherence with the Bonbright principles, many conflicts exist. E-32 is neither simple nor understandable. Although "understandability" is first on Bonbright's list (as it should), most GS customers don't begin to understand the complex E-32R, E-52, and E-55 rates for many reasons. I will attempt to include them as appendixes to my testimony although they go on for many more pages than this testimony. Please remember that most customers that I have discussed this with (the few who know the difference between kW and kWh) can't grasp the meaning.

These same rates, I contend, are not free from controversy either. A rate that is free from controversy would be a rate any customer can apply to his/her own billing determinants to quickly and accurately verify their utility bill. The imbedded demand charge, capacity reservation charges, penalty charges, switching from one rate to another for Standby, Supplemental, and Maintenance is confusing and prevents customers from understanding and selecting the proper rate. In addition, as my previous testimony regarding fairness reveals, this approach cannot be considered fair or non-discriminatory.

In regard to conservation I would suggest that Dr. Bonbright's admonishment to "discourage wasteful use" would today be more prominent. While the Bonbright principles indeed list conservation as a criterion for rate design, I suggest that its 'last place' ranking in the order of principles should not be interpreted to mean that it is of least importance. The current E-32R, E-52, & E-55 rates, with the significant shift toward higher demand costs, will discourage the use of distributed generating resources and certain DSM measures and will actually inhibit conservation.

WHAT IS YOUR OPINION OF WHAT ARE THE UTILITIES RANKING FOR THE THREE MOST IMPORTANT ASPECTS OF RATE DESIGN/

1 I think the utility list would be the following:
2 1. Revenue Stability
3 2. Revenue Stability
4 3. Revenue Stability
5
6 Q. BESIDES THE PRINCIPLES DEFINED BY DR. BONBRIGHT, HAVE ANY
7 POLICY MAKING BODIES ATTEMPTED TO CHANGE THE WAY UTILITIES
8 PRICE ENERGY TO CUSTOMERS?
9 A Yes, more recently the United States Department of Energy (DOE) supported the
10 Public Utility Regulatory Policies act of 1978 (PURPA). This National law for the first
11 time created what I consider a "bill of rights" for electricity customers.
12 PURPA, and its related rules, provided guidance that discouraged declining block rates
13 (such as E-32R) and instead attempted to encourage Time of Day (TOD) rates. DOE also
14 provided witness in a 1980's APS rate case to advocate for TOD rates and in opposition
15 to declining block rates.
16
17 One more interesting feature of DOE's approach was an incentive to provide a readout
18 device within the home or business that would read out how much the next unit of energy
19 would cost the consumer.
20 Currently the DOE is advocating the use for larger GS customers of "real time pricing"
21 (RTP) with the billing kWh varying hourly. A Time of Use rate with realistic time
22 periods utilizing kWh units.
23
24 Q WHAT FURTHER COMMENTS DO YOU WANT TO PROVIDE ON HOW THE
25 PRESENT, AND OR PROPOSED; E-32R, E-52, and E-55 RATES AFFECT GS
26 CUSTOMERS?
27 A. The biggest unknown and most vexing problem, for any customer on these rates is,
28 "When exactly was the 15-minute period during the previous billing month when the
29 peak demand was set?" Knowing this helps the customer begin to know how to lower
30 peak demand and reduce costs. But, alas in the case of these rates, even the utility does
31 not know when it occurred as current utility meters cannot record the time peak demand

occurred. This can be solved. To make matters worse, the proposed rates continue the focus on the customers peak demand kW (not the system peak) portion of the bill, no matter when it occurs!

Additionally as the demand is not generally understood by consumers, a significant portion of the charges arise from demand charges imbedded (hidden?) in the energy cost component of the rate. This billing mechanism by its complexity and imbedded nature reduces the customer's ability to determine the impact demand has on their final bill and leaves them hard pressed to accurately modify their usage in an effort to lower their costs. Add to that the utility bill can arrive almost six weeks after the customer may have attempted to change his peak, or consumption, and he has a hard time relating the outcome of his actions to this limited feedback – late as it is.

Finally, billing periods can vary from 33 to 27 days. This is due to the fact that the billing process is dependant on a meter reader physically reading the customer meter every month, often times on a different day of the month. The implementation leaves customers lacking timely, understandable, and actionable information. This also complicates the rate calculation

HOW DOES THIS BILLING INFORMATION COMPARE WITH A CELL PHONE BILL?

It would be the same as receiving an E-32R type cell phone bill that only told you:

- ✓ The total minutes you used (not when or to whom)
- ✓ The length of your longest call (not when it occurred) and
- ✓ The total bill (much money you owe).

Q. DO THE X-LARGE CUSTOMERS HAVE RATES MORE COMPLEX THAN THE CURRENT E-32R RATES?

A. No, extra large GS customers (demand greater than 3,000 kW) have relatively simple three part rates – Customer charges, Demand charges, and Energy charges. These customers generally have a person dedicated to understanding of rates, or they can afford to employ consultants to advise them on energy rate issues. Unfortunately these rates

also punish low load factors and thereby discourage DG and conservation (DSM). This apparent simplicity turns negative once the customer decides to utilize DG. E -55 is so complex as to stifle understanding and utilization.

Q. WHAT DIFFERENCE DOES IT MAKE IF ONLY RATE EXPERTS (WONKS) CAN UNDERSTAND THESE CHANGES?

A. Most customers do want to know what they use, when they used it, and most importantly how to reduce their bill. Not only is peak reduction beneficial to the individual customer, if the reduction is also coincident with the utility peak, all customers will benefit by decreasing the need for more peak capacity and peak energy.

If a customer's actions can contribute to a reduction in coincident peak demand it will ultimately lower the need to invest in new capacity whose costs would be borne by all ratepayers. If these peak reductions is not coincident with the utilities peak there is no across-the-board benefit, but certainly less revenue to the utility, and there is still benefit to the customer. Also, with the proper information, the customer could figure out that rather than cut the peak they could add energy usage away from their peak because it is cheaper to them, though not beneficial to all customers.

Without a clear understanding of the rates, an understanding that most small and medium commercial customers do not possess, customers can not economically reduce energy use by conservation and use of small scale renewable distributed energy resources. If only a few customers, with hired or on-staff rate experts, can understand the rates, then most of the GS population is left with little ability to make a difference. If such a large percentage of the utilities load is incapable of reducing their peak demand and energy consumption then ultimately all ratepayers are adversely affected.

Q. DOES THE EXISTING E-32R, E-52, & E-55 PROVIDES PRICE SIGNALS FOR DECREASING THE SUMMER PEAK DEMAND AND ENERGY USAGE?

A. No, unfortunately the customer that understands the demand/energy details of the rate it provides the price signal that summer cost is not too different from winter costs. It

provides incentives to increase the load factor (whether beneficial to the system or not). The reason for these reactions is that the difference between summer and winter pricing is less than 10% (if the usage is the same). But if there is more air conditioning usage in the summer (duh) it will easily overcome this and result in lower costs in the summer. This provides an inappropriate signal that summer energy use is approximately the same (or lower) cost than winter use.

Q. HAS PRICING FOLLOWED ACTUAL COSTS AS THE GENERATION COSTS CHANGED OVER THE LAST 10 YEARS?

A. Before I answer this let me give a little background on traditional Utility pricing philosophy. Pricing has been split between capital and operating costs.

First, capital investment (generating, transmission, and distribution plant) has traditionally been recovered in demand charges, in units such as $7/ kW/Month. Second, operating costs (fuel, labor, maintenance, losses, etc.) are in turn traditionally recovered in energy charges, in units such as 5¢ per kWh.

This philosophy has resulted over the last 40 years in large central generation investments whose goal was to lower fuel costs but raised capitol charges. Coal and nuclear plants are examples of this investment shift toward low fuel (kWh) costs. The results are rates with low (base load) fuel costs – for example 1 to 2¢/kWh. With corresponding capital costs that are about equal to – say 5¢/kWh (about $14/kW/mo)

In the last five years however, more generating capacity has come on line than previously existed in Arizona. Not only has this new capacity exceeded the capacity of all the previous plants, but the new plants are fundamentally different from their predecessors. The new plants are Combined Cycle (Jet engines with waste boilers) that, in comparison To earlier central station plants, are relatively low capital cost, but have much higher fuel costs. – E.g. 5¢/kwh. (Gas at $6/ million BTU, heat rate of 7,000 BTU/kWh + losses. For a total of 5¢ energy and 2¢/kWh demand equivalent).

This change to Combined Cycle plants has occurred across the world, with a huge impact on natural gas prices – now roughly 3 times the cost from when these plants were announced.

Q. HOW DOES THE CHANGE IN UTILITY ECONOMICS RELATE TO THE CURRENT STANDBY AND SUPPLIMENTAL DG RATES?

A. The shift towards generation plant of lower relative capital cost should equate to a shift away from demand as the vehicle for recovering the investment. The subject rates moving in the exact opposite direction from this concept and comes at a time when APS' and all other new generating plants (with very limited exceptions) have installed facilities whose cost recovery should be based primarily on operating costs, not capital costs. Worded another way, these rates do not properly reflect the cost recovery realities of the new generation fleet.

Q. WILL THE PROPOSED DEMAND-BASED CHARGES IN E-32R IMPACT THE USE OF DG BY CUSTOMERS?

A. Unfortunately yes, even though DG technologies coupled with the grid can significantly increase reliability. But it should be noted that approximately 90% of utility customer outages are caused by utility distribution failures. Generation and Transmission make up the other 10%.

Even though many DG technologies can rival the capacity factors (not to mention the thermal efficiency) of central station utility plants, there must come a time when all generating plants come 'off-line', if for no other reason than to perform scheduled maintenance. In addition, even the highest capacity factor plant design can and will suffer unplanned outages – just like any regulated utility plant.

This Standby problem is exacerbated by the classic utility view and obviously erroneous that all DG plants will fail simultaneously and at the time of the system peak.

A customer's decision to invest in DG, and the economic performance of that asset once installed, is highly dependent on reasonable prices for electricity from the utility when the DG plant is out of service. Under the existing and proposed DG rates, the cost of

"standby" electricity (kW or demand related charges) will increase dramatically due to the significant % of demand charges in these DG rates. This will have the effect of decreasing the economic attractiveness of solar and any other DG application. These technologies require just and reasonable standby electricity pricing in order to hit a rate of return threshold necessary for implementation. As an example, an E-32R customer with 60% load factor will see an almost 150% increase in demand charges from $7.5/kW in 1996 to $11/kW in the current rates. These changes are so dramatic that they could remove DG as a viable alternative to utility generation.

Q. IS THERE SOME UPSIDE IN THE CURRENT RATES FOR THOSE THAT ARE INTERESTED IN ACHIEVING ECONOMIC SAVINGS BY UTILIZING CONSERVATION?

A. Unfortunately, here too, revenue stability wins out over conservation. The small customer mentioned above will change from a savings of 4.8¢/kWh to a savings of only 4.6¢/kWh with the proposed E-32R. – A slight reduction of approximately in the economic benefits of conservation. Customers respond to clear price signals. The proposed & current rates will not send price signals that encourage conservation.

Q. DO YOU BELIEVE THAT UTILITY CONSERVATION & DEMAND SIDE MANAGEMENT (DSM) PROGRAMS ARE NECESSARY?

A. Absolutely, but DSM is not a permanent replacement for understandable price signals to customers. And as long as we have a current rate or a proposed rate design that relies on the declining block structure and demand charges that are generally misunderstood, DSM will not take hold and produce the intended results

Q. DO YOU THINK THAT RATES DESIGNED FOR CLARITY, SIMPLICITY, AND UNDERSTANDABILITY CAN ULTIMATELY DISPLACE OR LIMIT THE NEED FOR DSM PROGRAMS.

A. No, by implementing rates that deliver clear and correct price signals, we can achieve more uniform loads that will result in benefits for all customers. Clear pricing signals that reflect actual market costs, when applied through understandable rates, will further

1 encourage customers to alter their usage in a variety of ways that will benefit all
2 customers.
3
4 IS THE RELATIVELY NEW GENERAL SERVICE RATE E-32TOU A BETTER
5 RATE THAN E-32, FOR DG CUSTOMERS?
6
7 This appears to be a Hobson's choice!
8 It is not better from price signal, encouraging conservation, encouraging DG or DSM.
9 Worse the Company is in the process of eliminating some good rates that were created as
10 the result of efforts of the Interfaith Coalition 0n Energy (ICE) to get fair rates for Houses
11 of Worship that operate mostly on Saturday and Sunday. These rates are being
12 eliminated! They will soon be eliminated or Frozen. (E- 20, 21, 22, 23, & 24)
13
14 Q. DO YOU BELIEVE RATE DESIGN IS AN ART OR A SCIENCE?
15 A. Neither, but I believe that rates can and should be designed to also benefit the
16 customer.
17
18 Q. ARE THERE ACTIONS THAT THIS COMMISSION CAN TAKE TO ANSWER
19 THE RATE DESIGN ISSUES THAT YOU HAVE RAISED IN THIS TESTIMONY?
20 A Yes, and I will attempt to provide a list of actions that this Commission can take to
21 solve these "Revenue Stability" vs. "Clear Price Signals". These actions include the
22 following:
23 1. Provide a rate designs that are at least neutral for DG.
24 2. Provide a rate that provides significant seasonal TOD energy (kWh) price
25 signals.
26 3. This new proposed rate should be designed with clarity, simplicity, A
27 and with the appropriate TOD (energy) pricing signals.
28
29 Q. THERE HAVE BEEN WORKSHOPS IN THE PAST 6 YEARS TO AGREE ON
30 NEW, FAIR INTERCONNECTIONS FOR SMALL COGENERATION AND
31 RENEWAL RESOURCES- WERE YOU PLEASED WITH THESE WORKSHOPS?

A. No, as this turned into an endurance effort in which the Arizona utilities clearly outlasting other stakeholders. The current ratemaking process of continuing workshops and rate proceeding where utilities "rate base" their staff and consultant time (legal and engineering) – and customers who want to be part of the process use their own funds as well as risk higher rates as a result of being involved in the process due to paying the utility's costs of the process. I would suggest a hearing on this subject to decide interconnection rules. We can create a record and settle on the fairest cost-based standard.

Q. DOES THIS COMPLETE YOUR COMMENTS?

A. Yes.

ATTACHMENTS / WEBSITES

Attachment #1 – W JM -1

Website for APS Application (1/31/06)

http://images.edocket.azcc.gov/docketpdf/0000040073.pdf

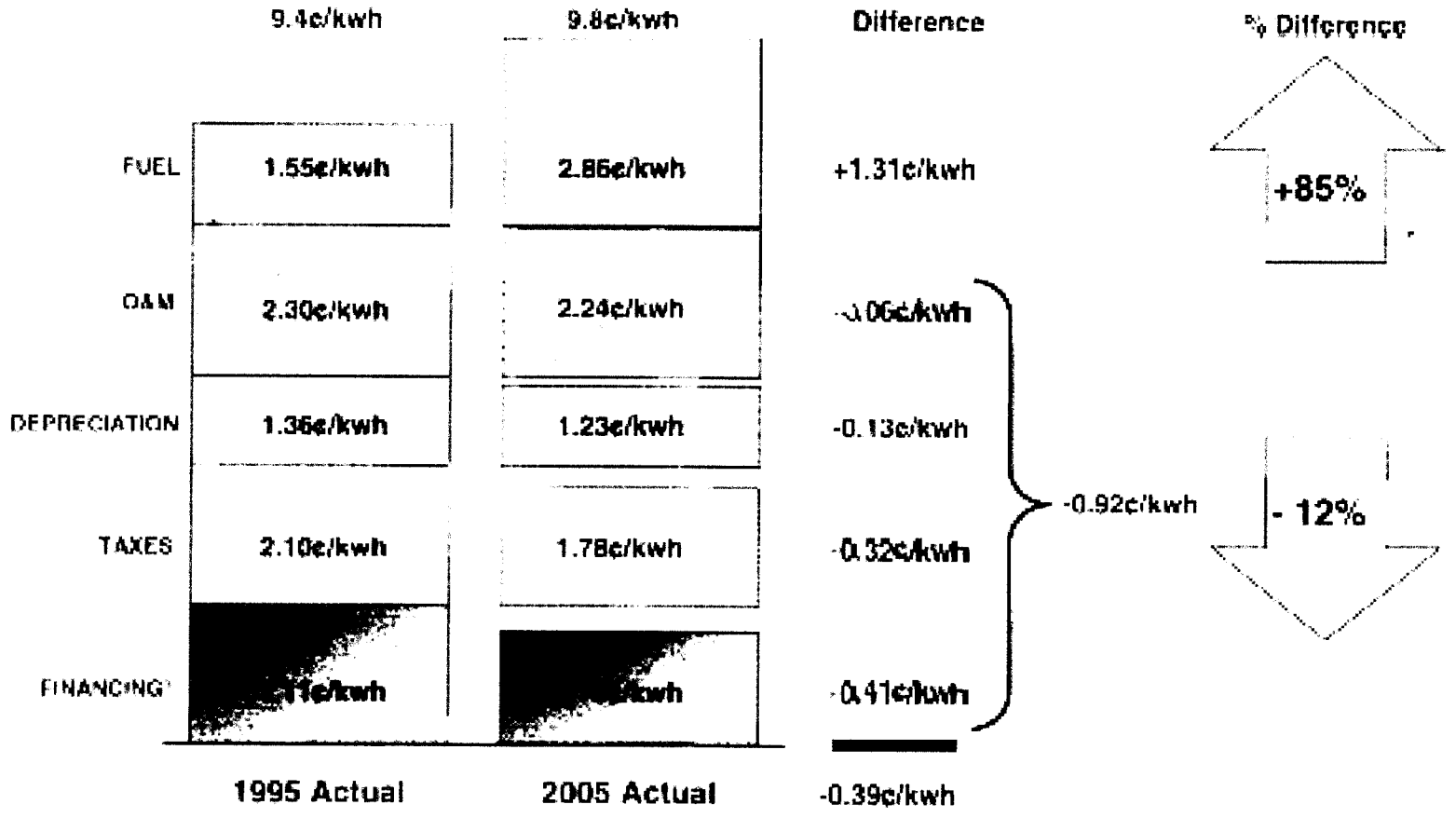
Website -2 - Website for SRP rates - www.srpnet.com /SELECTED SECTIONS - payment, billings, & prices/Complete Price Plan Details/Standard Electric Price Plans

Website 3 – Websites for APS rates

http://www.aps.com/aps_services/residential/rateplans/ResRatePlans_11.html

http://www.aps.com/aps_services/business/rateplans/busrateplans_9.html

Arizona Public Service Company
Cost per kwh Comparison



[1]Includes both debt and shareholder financing costs

SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT AND POWER DISTRICT

E-32

STANDARD PRICE PLAN FOR TIME-OF-USE GENERAL SERVICE

Effective: November 1, 2004
Supersedes: June 1, 2004

AVAILABILITY:

The E-32 Price Plan is subject to equipment availability.

APPLICABILITY:

To electric service supplied at one point of delivery and measured through one meter, for commercial, business, professional, small industrial, wind machines, and recreational facilities. This schedule is an alternative to the E-36 Price Plan. (See conditions.)

CHARACTER OF SERVICE:

Sixty hertz alternating current, three-phase or single-phase, at one standard voltage of approximately 120/240; 277/480; 2,400/4,160; or 7,200/12,000 volts, at the option of SRP.

CONDITIONS:

A. On-peak hours from May 1 through October 31 consist of those hours from 2 p.m. to 7 p.m., Monday through Friday, Mountain Standard Time. Shoulder-peak hours consists of those hours from 11 a.m. to 2 p.m. and 7 p.m. to 11 p.m., Monday through Friday, Mountain Standard Time. All other hours are off-peak. On-peak hours from November 1 through April 30 consist of those hours from 5 a.m. to 9 a.m., Monday through Friday, Mountain Standard Time. Shoulder-peak hours consist of those hours from 5 p.m. to 9 p.m., Monday through Friday, Mountain Standard Time. All other hours are off-peak.

B. Metering is at one point and such that kilowatts and kilowatt-hours or kilovolt-amperes and kilovolt-ampere-hours can be related to time-of-day.

C. A customer may cancel service under this schedule and elect service under another General Service Price Plan. Cancellation becomes effective at the end of the billing cycle in which notice is received. The customer may not subsequently elect service under this price plan for at least one year after the effective date of cancellation.

D. A customer requiring additional interconnection, metering, or other equipment beyond what is necessary for SRP to provide basic service applicable under this price plan will be required to pay SRP for the costs of such additional equipment.

PRICE PER METER:

Monthly Service Charge	
Billing, Collections	$ 9.25
Meter	$17.14
Meter Reading	$4.57
Competitive Customer Service	$4.55
Total	$35.51

	Summer May 1 - October 31		
Per kW Charges (all kW)	On-Peak	Shoulder-Peak	Off-Peak
Distribution Delivery	$2.20	$0.06	--
Transmission Delivery	$2.46	$0.31	--
Competitive Customer Service	$0.04	$0.00	--
Ancillary Services 1 and 2	$0.09	$0.08	--
Total	$4.79	$0.45	--

	Winter November 1 - April 30		
Per kW Charges (all kW)	On-Peak	Shoulder-Peak	Off-Peak
Distribution Delivery	$1.66	$0.04	--
Transmission Delivery	$2.00	$0.22	--
Competitive Customer Service	$0.04	$0.00	--
Ancillary Services 1 and 2	$0.07	$0.05	--
Total	$3.77	$0.31	--

	Summer May 1 - October 31	Winter November 1 – April 30
On-Peak kWh Charge		
Distribution Delivery	$0.0375	$0.0370
Transmission Delivery	$0.0000	$0.0000
Ancillary Services 1 and 2	$0.0000	$0.0000
Ancillary Services 3-6	$0.0008	$0.0008
System Benefits	$0.0016	$0.0016
Fuel and Purchased Power †	$0.0217	$0.0255
Energy	$0.0381	$0.0349
Total	$0.0997	$0.0998

	Summer May 1 - October 31	Winter November 1 – April 30
Shoulder-Peak kWh Charge		
Distribution Delivery	$0.0267	$0.0266
Transmission Delivery	$0.0000	$0.0000
Ancillary Services 1 and 2	$0.0000	$0.0000
Ancillary Services 3-6	$0.0008	$0.0008
System Benefits	$0.0016	$0.0016
Fuel and Purchased Power †	$0.0217	$0.0255
Energy	$0.0235	$0.0229
Total	$0.0743	$0.0774
Off-Peak kWh Charge		
Distribution Delivery	$0.0000	$0.0000
Transmission Delivery	$0.0000	$0.0000
Ancillary Services 1 and 2	$0.0000	$0.0000
Ancillary Services 3-6	$0.0008	$0.0008
System Benefits	$0.0016	$0.0016
Fuel and Purchased Power †	$0.0217	$0.0255
Energy	$0.0125	$0.0119
Total	$0.0366	$0.0398

† The price for Fuel and Purchased Power may be changed periodically consistent with Adjustment A.

ANCILLARY SERVICES:

Ancillary services provided include:

1) Scheduling, System Control and Dispatch Service
2) Reactive Supply and Voltage Control from Generation Sources Service
3) Regulation and Frequency Response Service
4) Energy Imbalance Service
5) Operating Reserve – Spinning Reserve Service
6) Operating Reserve – Supplemental Reserve Service

Direct access customers would need to secure ancillary services 3-6 from an alternate energy supplier or under the terms and conditions outlined in SRP's Open Access Transmission Tariff.

MINIMUM BILL:

The greater of:

A. The Monthly Service Charge or
B. The minimum monthly dollar amount specified in a written Agreement for Electric Service, if any.

DETERMINATION OF DEMAND IN KILOWATTS:

The billing demand is the maximum thirty-minute integrated kilowatt demand occurring during the on-peak and shoulder-peak periods of the billing cycle, as measured by meter.

ADJUSTMENTS:

A. SRP may increase or decrease the price for Fuel and Purchased Power based on changes in the average cost of fuel and purchased power. The price for Fuel and Purchased Power is calculated for each summer and winter season based on the projected cost of fuel and purchased power, adjusted for the actual over- or under-collection of fuel and purchased power revenues relative to fuel and purchased power expenses from prior periods.

B. SRP may increase the Transmission Cost Adjustment Factor to recover transmission related costs or charges incurred by SRP resulting from standardized wholesale market designs, regional transmission organizations, or related activities.

C. SRP increases or decreases billings under this schedule in proportion to any taxes, fees, or charges (excluding federal or state income taxes) levied or imposed by any governmental authority and payable by SRP for any services, power, or energy provided under this schedule.

D. If the power factor falls below 85 percent lagging at any metering point during any billing period, SRP may:

1. Adjust kilowatt-hours and/or kilowatts during this period, for billing purposes, to equal 85 percent of kilovolt-ampere-hours and 85 percent of kilovolt-amperes. Kilowatt-hours and/or kilowatts will be adjusted proportionately for the on-peak, shoulder-peak, and off-peak periods.

2. Require the customer to correct the power factor to an acceptable level.

3. Require the customer to be continuously metered with a separate meter that registers kilovolt-amperes, kilovars, or actual power factor.

   At SRP's discretion, customer may be required to pay all costs associated with additional metering.

E. If, at any time, the current in any phase exceeds the average of the currents in the three phases by more than 5 percent, at SRP's option, SRP may increase the bill for the period during which the imbalance occurs by a percentage equal to that of the imbalance.

F. Customers participating in the 10-day SurePay Automatic Payment program will receive a 1 percent discount on SRP services supplied under this price plan. The discount will be applied before adding sales tax. The discount does not apply to any penalties, fees, credits, or premiums. The discount will not apply to energy or services supplied by an alternative energy supplier.

G. Customers within the SRP distribution service territory who receive all electric services from SRP under E-32, E-36, E-47, E-48, E-61, E-63, or E-65 who meet minimum usage requirements will receive an aggregation discount on their monthly bill(s).

Aggregation Discount = $0.0003/kWh

Single accounts meeting minimum usage levels can qualify for aggregation discounts.

Aggregate usage must meet a minimum usage requirement of 300,000 kWh per month for three consecutive months. Only those accounts receiving energy and delivery services from SRP will count towards the minimum usage requirements.

The discount will be applied only to all kWh sold under the applicable price plan. The discount will be applied before the application of any credits, penalties, fees, or premiums.

H. For customers metered for billing purposes at primary voltage, SRP will deduct 1 percent of the demand and energy charges from each billing. Primary voltage is defined as the same voltage found at the low side of a substation transformer, typically 12.47 kV or 4,160 volts. The deduction does not apply to monthly service charges, facilities charges (where applicable), taxes, penalties, fees, or other adjustments.

RULES AND REGULATIONS:

A. Service under this schedule is in accordance with the terms of SRP's Rules and Regulations, including any amendments.

B. For direct access customers, service under this schedule is in accordance with the terms of SRP's Direct Access Program, as set forth in the Rules and Regulations, including any amendments.

SPECIAL RIDERS:

A. Customers may choose to participate in SRP's Renewable Pricing Rider.

B. Customers with cogeneration or small power production who purchase power and energy from SRP may qualify to sell power and energy back to SRP under the Buyback Service Rider.

C. Customers with a minimum annual load of 100 kW and who have the flexibility to curtail load may qualify for service under the Use Fee Interruptible Rider.

D. Customers with individual accounts or aggregated loads of 1 MW or more, who have energy alternatives and who are willing to sign a term contract, may qualify for service under the Full Electric Service Requirements Rider.

E. Customers interested in receiving a verifiable market price for energy and who are willing to have their energy price per kWh change on a monthly basis, to reflect the electric energy market, may choose to participate in the Monthly Energy Index Rider.

F. Customers may choose to participate in SRP's Renewable Pricing Rider for Large Customers.

EXHIBIT
DEAA-2
Admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

JEFF HATCH-MILLER, Chairman
WILLIAM A. MUNDELL
MIKE GLEASON
KRISTIN K. MAYES
BARRY WONG

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND TO AMEND DECISION NO. 67744	DOCKET NO. E-01345A-05-0816

Rebuttal Testimony of

William J. Murphy

on behalf of Distributed Energy Association of Arizona

Docket No. E-01345A-05-0816

September 27, 2006

Rebuttal Testimony of William J. Murphy
Docket No. E-01345A-05-0816

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Rebuttal Testimony of William Murphy
on behalf of DEAA
Docket No. E-01345A-050816

INTRODUCTION

Q. PLEASE STATE YOUR NAME AND YOUR BUSINESS ADDRESS?

A. My name is William Murphy. My business address is 2422 E. Palo Verde Dr. Phoenix, Arizona 85016.

Q. DID YOU PREVIOUSLY PROVIDE DIRECT TESTIMONY IN THIS DOCKET E-01345A -05-0816?

A. Yes.

Q WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony discusses three topics:
1) A review of parts of the Testimony of RUCO , Staff, and others on rate design.
2) A brief discussion of cents/kWh vs. usage.
3) Recommendations.

Q. DO YOU HAVE AN OPINION OF RUCO'S APPROACH TO RATE DESIGN?

A Yes, I was pleased with the ideas that were presented in the testimony of Marylee Diaz Cortez. The 2 reasons given were as follows:

1) "Since the need for a rate increase is primarily attributable to increased generation and fuel costs....." Page 2 line 22-23.
2) ".....it allows customers to mitigate the cost of the increase through conservation" page 3 lines 4-5.

Q. DO YOU HAVE AN OPINION ON HOW RUCO APPLIED THE APPROACH TO ACTUAL RATES?

A. Unfortunately, on the General Service rate E-32, the approach appears to result in increases in demand charges (kW) and also demand related energy (kWh) costs that are contained in the expanding block, the block that states "$0.07938 per kWh for the first 200 kWh per kW, plus $0.04175 per kWh for all additional kWh"

The only part of demand charges that are fuel related are the difficult to understand "expanding block" discussed in the preceding paragraph.

Q. DO YOU HAVE AN OPINION ON THE STAFF WITNESS ERINN ANDREASEN ON THE RATE DESIGN ISSUES?

A Yes, I was also pleased with Ms. Andreasen's recommendations as follows:

EAAr-6 and EAAr-7, these recommendations request a delay in the elimination of rates E-21, E-22, E-23, & E-24.
These rates were originally intended to assist Houses of Worship and other customers use energy primarily off-peak. Additionally, these Rates offer a choice to the approximately 96% of all General Service customers that are on rate E-32. Equally important these rate choices appeal to rate-payers that are small, medium, and large sized customers. These rate choices partially solve the concerns raised in EAA Recommendation -10, below.

EAAr-10, this recommendation calls for Rate E-32 to be separated into small, medium, and large categories. This is a long overdue action that could solve many problems, including fairness, understandability, cost following, and others.

EAAr-10a, this recommendation is my suggestion to pair the split up of rate E-32 with a redesign of E-32TOU into size sensitive rates similar to E-21, E-22, E-23, & E-24.

Q. ARE THERE ANY RECOMENDATIONS BY MS. ANDREASEN AND MS. DIAZ CORTEZ THAT YOU WILL NOT PRESENT AN OPINION?

A. Yes.

Q. ARE THERE ANY RECCOMENDATIONS BY MS. ANDREASEN WITH WHICH YOU DO NOT AGREE?

A. Yes, there are 2 recommendations that cause concern;

EAAr-13 the entire subject of landlords selling energy to tenants needs to be discussed more fully. Some very large customers have in the past considered these sales as a service and opportunity for the benefit of both the landlord and tenant. These customers are GS customers with large (>1000 kW loads)

EAAr-21 This recommendation covers a Demand-Management study by APS. This runs head-on into the Utilities desire to maintain its Revenue Stability.

This study is a fair idea, but I personally can't handle the thought of another workshop.

Q. PLEASE DESCRIBE HOW A CUSTOMER FUNDED DG UNIT WOULD BE ALLOWED TO OPERATE WITH THE SAME ECONOMIC RULES THAT APPLY TO RATE-PAYER FUNDED UTILITY POWER PLANTS?

A. The answer to this question breaks down into Demand and Energy components:

1) DEMAND: There will no economic penalty for outages (unavailability) unless negligence by the operator can be proven. Otherwise there are no demand or standby charges/penalties during normal operation.

2) ENERGY: On the energy side the rate-payers will contribute 90% of the cost of replacement energy. The DG owner will have to pay only 10% of these energy costs.

Q. PLEASE DESCRIBE HOW A UTILITY POWER PLANT WOULD BE ALLOWED TO OPERATE WITH THE SAME ECONOMIC RULES THAT APPLY TO CUSTOMER FUNDED DG POWER PLANTS?

A. The answer to the question breaks down into Demand and Energy components:

1) DEMAND Charges will be such that any plant capital recovery allowed for that particular month will be zero if the Capacity Factor falls below 99.96% (a very high C.F.)
This zero cost recovery will not be forgiven no matter what is the reason for the failure.

2) ENERGY the Utility Stockholders shall be expected to pay for 100% of all energy use that results from any plant outage. No matter what the cause, Rate-payers will not contribute anything to the cost of the replacement energy. See Exhibit WJM -3 for an outline of the DG rate choices.

Q. YOU MENTIONED EARLIER THAT THERE WERE EXAMPLES OF TECHNICAL TERMS THAT DESCRIBE VELOCITY – ARE THERE OTHER TERMS TO MEASURE RATE OF SPEED?

A. Yes I mentioned earlier in my direct testimony that utility customers were familiar with the term for speed "miles per hour". But there are other terms such as "Furlongs per Fortnight" to measure speed. The equivalent term for 60 MPH would be 162,510 furlongs per fortnight. I don't think there would be much understanding of FPF. It is not as difficult to understand as kilowatt, but it is in the chase.

Q. WOULD YOU SUMMARIZE YOUR RECOMENDATIONS AND HOW THEY MESH WITH OTHER WITNESS'S THAT DISCUSSED RATE DESIGN.

A The most important consideration is that the rates begin to reflect the new higher fuel (Energy) prices, and lower capitol costs (Demand). This is the basis for our Direct Testimony recommendation that general service DG customers utilize a rate similar to the SRP E-32TOU. (See attached Exhibit WJM-5)

We recommend also that rates begin to truly reflect the differences in system costs between summer and winter, Day and Night, the peak seasonal hours. (See Attached Exhibit WJM-4)

We recommend that the commission review the trend that greater energy usage results in lower cents/kWh. (see Exhibit WJM -2) These current rates appear to reflect the capital/fuel cost relationship that existed in the early 1990's.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

ATTACHMENTS

WJM-2 Rate Class 6.6

WJM -3 PARTIAL REQUIREMENTS

WJM -4 RES, GS, TOU RATES

WJM -5 BusE321105.pdf

APS RATE DISTRIBUTION TY ENDING SEPT 30, 2005,ADJUSTED WJM-2

	cents/kWh	ROR Index	Avg Customers	% of total	Avg kWh	Total kWh	% kWh	%Total kWh	Revenues	Total $
RESIDENTIAL										
E-10	9.1	49.0%	78,292	9%	9,546	747,414,000	6%	3%	$68,113,000	
E-12	9.9	109.0%	411,939	46%	9,149	3,768,884,000	30%	14%	$372,438,000	
EC-1	7.8	15.0%	20,840	2%	21,843	455,200,000	4%	2%	$35,431,000	
ET-1	8.5	28.0%	329,062	37%	18,289	6,018,067,000	49%	23%	$510,800,000	
ECT-1R	7.5	-2.0%	46,327	5%	29,639	1,373,087,000	11%	5%	$102,769,000	
TOTAL	8.8	52.0%	886,460	100%	13,946	12,362,652,000	100%	47%	1,089,551,000	51%
GENERAL SERVICE										
E-20	9.1	292%	349	0%	113,367	39,565,000	0%	0%	$3,587,000	
E-21	8.2		25	0%	65,240	1,631,000	0%	0%	$133,000	
E-22	9.3		17	0%	215,176	3,658,000	0%	0%	$339,000	
E-23	7.8		144	0%	296,382	42,679,000	0%	0%	$3,324,000	
E-24	5.9		45	0%	3,666,311	164,984,000	1%	1%	$9,784,000	
E-30	16.7		3,890	4%	1,457	5,669,000	0%	0%	$945,000	
		123%								
E-32 very small(0-20kW)										
E-32 small (21-100kW)		168%	89,976	87%	0	0	0%	0%		
E-32 medium(101-400kW)		211%	4,042	4%	0	0	0%	0%		
E-32 medium (401-999kW)		211%								
E-32 large(1000 + kW)		-7%	162	0%	0	0	0%	0%		
E-32,E-32R,E-53,E-6?	7.8	137%	103,231	96%	105,385	10,879,043,000	79%	41%	$843,836,000	
E-32 TOU	7.8		3	0%	616,333	1,849,000	0%	0%	$144,000	
E-34	5.6	3%	38	0%	31,135,395	1,183,145,000	9%	4%	$66,719,000	
E-35	4.9	-3%	19	0%	72,716,789	1,381,619,000	10%	5%	$67,661,000	
E-40			1	0%	0	0	0%	0%	$1,000	
E-51	6.2		2	0%	5,359,000 ?	10,718,000	0%	0%	$666,000	
G S TOTAL	7.3	135%	107,764	100%	127,265	13,714,560,000	100%	52%	997,139,000	47%
IRRIGATION/PUMPING										
E-38,E-38-8T,E-38TOW	7.1		44	3%	199,523	8,779,000	3%	0%	$620,000	
E-221,E-221-8T,E-221TOW	7.1		1,422	97%	199,620	283,860,000	97%	1%	$20,244,000	
Total	7.1	320%	1,466	100%	399,143	292,639,000	100%	1%	20,864,000	1%
OUTDOOR LIGHTING										
E-58	22.7		564	57%	48,461	27,332,000	23%	0%	$6,208,000	
E-59	8.5		184	18%	401,918	73,953,000	64%	0%	$6,281,000	
E-67 cop	3.6		210	21%	20,876	4,384,000	4%	0%	$159,000	
Contract	6.5		39	4%	275,641	10,750,000	9%	0%	$697,000	
Total	11.5	71%	997	100%	116,769	116,419,000	100%	0%	13,345,000	1%
DUSK to DAWN	23.8	199%				27,037,000		0%	$6,423,000	0%
Weather Adj										
Cust Adj										
TOTAL RETAIL	8.0	89%	996,687		26,601 0	26,513,307,000		100%	$2,127,322,000	100%
RESALE	5.0	155%			?	4,254,644,000	?	10%	$212,732,200	
TOTAL TOTAL	7.6	100%				30,767,951,000		100%	$2,340,054,200	

1. this base data from APS Schedule H-2,
2. ROR index from APS09951 (SJB-3)& KCH-1

rate class 6.6

PARTIAL REQUIREMENTS RATES

WJM-3

RATE	E-51		E-52		E-55			E-32R		
	5/27/1994	4/1/2005	3/1/1996P	4/1/2005	3/1/1996P	4/1/2005		7/1/1996	4/1/2005	
	SUMMER		SUMMER		SUMMER			SUMMER		
CUST	$32.00	$33.58	$123.85	$123.83	$1,733.90	$1,733.90		$12.50	$34.49	
STANDBY										
kW summer"FOR"	$4.50	$4.16	$7.29	$6.59	$6.98	$6.77		$7.00	$11.00	
kWh- on-p	$0.04980	$0.04602	$0.02130	$0.02961	$0.02080	$0.03040	first	$0.11275	$0.07938	200kwh/kw
kWh- off-p	$0.02320	$0.02142	$0.01540	$0.01574	$0.01470	$0.01616	last	$0.04866	$0.04175	remainder
	WINTER		WINTER		WINTER					
kW	$4.50	$4.16	$7.29	$6.59	$6.98	$6.77				
kWh- on-p	$0.03540	$0.03271	0.01870	0.02537	$0.01930	$0.02605	first	$0.10157	$0.06945	200kwh/kw
kWh- off-p	$0.02320	$0.02142	0.01250	0.01006	$0.01390	$0.01033	last	$0.04351	$0.03182	remainder
LIMIT on standby energy - over 250kWh/kW is on supplemental rate										
PENALTY $/kW			$13.84	$12.50	$15.11	$21.28		$7.00	$11.00	
MAINTENANCE										
kWh- on-p	0.03540	0.02142	0.01870	0.02537	$0.01930	$0.02605		see above	see above	see above
kWh- off-p	0.02320		0.01350	0.01006	$0.01390	$0.01033		see above	see above	see above
SUPPLIMENTAL	E-32 or E-34		E-32 or E-34		E-34 0r E-35			E-32 or E-34		
					cust	$2,430.00	34.4736			
ON-PEAK	11:00A - 9:00P		9:00A to 9:00P		kW	$11.42	12.343			
					kWh	0.03365	0.03183			
pages	4	4	5	8	5	10		1+2	1+6	

partial req 9/21/06

TIME OF USE (TOU) RATES

EC-1, ECT-1R, ECT-2, E-20, E-21,E-22, E-23, E-24, E-32TOU EFFECTIVE 5/1/2005

WJM-4

RESIDENTIAL RATES

	EC-1	ECT-1R	PROPOSED ECT-2	ET-1	PROPOSED ECT-2
BASIC SERVICE CHARGE	$7.70	$15.00	$16.67	$15.00	$16.67
SUMMER $/KW/MO (ON-PEAK)	$10.00	$11.81	$11.81	$0.00	$0.00
WINTER $/KW/MO (ON-PEAK)	$7.10	$8.11	$8.11	$0.00	$0.00
SUMMER CENTS/kWh ON PEAK	0.03943	0.04785	0.05690	$0.13310	$0.18200
SUMMER CENTS/KKh OFF-PEAK		0.02672	0.02792	$0.04299	$0.04519
WINTER CENTS/kWh ON-PEAK	0.02978	0.03641	0.03730	$0.10918	$0.08703
WINTER CENTS/kWh OFF-PEAK		0.02570	0.02733	$0.04169	$0.05783
HOURS		9:00A-9:00P	NOON -9:00P	9:00A-9:00P	NOON -9:00P

GENERAL SERVICE RATES

		E-20 CHURCHES	E-21 > 100Kw	E-22 SMALL GS	E-23 MED GS	E-24 LARGE GS	E-32TOU 0 TO 3,000Kw	
BASIC SERVICE CHARGE		$28.62	$28.14	$28.14	$60.47	$1,042.41	$34.49	
SUMMER $/KW/MO		$2.045	$2.010	$2.300	$6.410	$9.390	$15.112	FIRST 100 KW PLUS
	excess	$1.023	$1.005	$1.115	$3.205	$4.695	$10.887	REMAINDER KW
							$7.972	RESIDUAL?????
							$3.747	RESIDUAL?????
WINTER $/kWh/MO		$1.845	$1.810	$2.020	$5.820	$8.510	$15.112	FIRST 100 KW PLUS
	excess	$0.923	$0.905	$1.010	$2.910	$4.255	$10.887	REMAINDER KW
							$7.972	RESIDUAL?????
							$3.747	RESIDUAL?????
SUMMER CENTS/kWh ON PEAK		$0.12305	$0.12097	$0.12125	$0.08163	$0.05283	$0.04815	
SUMMER CENTS/KKh OFF-PEAK		$0.05943	$0.56430	$0.07475	$0.05843	$0.03797	$0.03815	
WINTER CENTS/kWh ON-PEAK		$0.10820	$0.10638	$0.10285	$0.07328	$0.04723	$0.03822	
WINTER CENTS/kWh OFF-PEAK		$0.05327	$0.05237	$0.06430	$0.05237	$0.03393	$0.02822	
ON-PEAK HOURS WEEKDAYS		11:00A-9:00P	11:00A-9:00P	11:00A-9:00P	11:00A-9:00P	11:00A-9:00P	11:00A-9:00P	

RES, GS,TOU RATES 9/21/06

SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT AND POWER DISTRICT

E-32

STANDARD PRICE PLAN FOR TIME-OF-USE GENERAL SERVICE

Effective: November 1, 2005
Supersedes: May 1, 2005

AVAILABILITY:

The E-32 Price Plan is subject to equipment availability.

APPLICABILITY:

To electric service supplied at one point of delivery and measured through one meter, for commercial, business, professional, small industrial, wind machines, and recreational facilities. This schedule is an alternative to the E-36 Price Plan. (See conditions.)

CHARACTER OF SERVICE:

Sixty hertz alternating current, three-phase or single-phase, at one standard voltage of approximately 120/240; 277/480; 2,400/4,160; or 7,200/12,000 volts, at the option of SRP.

CONDITIONS:

A. On-peak hours from May 1 through October 31 consist of those hours from 2 p.m. to 7 p.m., Monday through Friday, Mountain Standard Time. Shoulder-peak hours consists of those hours from 11 a.m. to 2 p.m. and 7 p.m. to 11 p.m., Monday through Friday, Mountain Standard Time. All other hours are off-peak. On-peak hours from November 1 through April 30 consist of those hours from 5 a.m. to 9 a.m., Monday through Friday, Mountain Standard Time. Shoulder-peak hours consist of those hours from 5 p.m. to 9 p.m., Monday through Friday, Mountain Standard Time. All other hours are off-peak.

B. Metering is at one point and such that kilowatts and kilowatt-hours or kilovolt-amperes and kilovolt-ampere-hours can be related to time-of-day.

C. A customer may cancel service under this schedule and elect service under another General Service Price Plan. Cancellation becomes effective at the end of the billing cycle in which notice is received. The customer may not subsequently elect service under this price plan for at least one year after the effective date of cancellation.

D. A customer requiring additional interconnection, metering, or other equipment beyond what is necessary for SRP to provide basic service applicable under this price plan will be required to pay SRP for the costs of such additional equipment.

PRICE PER METER:

Monthly Service Charge	
Billing and Collections	$11.21
Meter	$19.04
Meter Reading	$7.06
Competitive Customer Service	$0.20
Total	$37.51

	Summer May 1 - October 31		
Per kW Charges (all kW)	On-Peak	Shoulder-Peak	Off-Peak
Distribution Delivery	$1.75	$0.03	--
Transmission Delivery	$2.89	$0.33	--
Competitive Customer Service	$0.14	$0.00	--
Ancillary Services 1-2	$0.10	$0.09	--
Total	$4.88	$0.45	--

	Winter November 1 - April 30		
Per kW Charges (all kW)	On-Peak	Shoulder-Peak	Off-Peak
Distribution Delivery	$1.23	$0.02	--
Transmission Delivery	$2.36	$0.24	--
Competitive Customer Service	$0.16	$0.00	--
Ancillary Services 1-2	$0.07	$0.05	--
Total	$3.82	$0.31	--

	Summer May 1 - October 31	Winter November 1 – April 30
On-Peak kWh Charge		
Distribution Delivery	$0.0391	$0.0382
Transmission Delivery	$0.0000	$0.0000
Ancillary Services 1-2	$0.0000	$0.0000
Ancillary Services 3-6	$0.0006	$0.0006
System Benefits	$0.0019	$0.0019
Competitive Customer Service	$0.0003	$0.0002
Energy	$0.0386	$0.0336
Fuel and Purchased Power †	$0.0257	$0.0223
Total	$0.1062	$0.0968

	Summer May 1 - October 31	Winter November 1 – April 30
Shoulder-Peak kWh Charge		
Distribution Delivery	$0.0275	$0.0278
Transmission Delivery	$0.0000	$0.0000
Ancillary Services 1-2	$0.0000	$0.0000
Ancillary Services 3-6	$0.0006	$0.0006
System Benefits	$0.0019	$0.0019
Competitive Customer Service	$0.0000	$0.0000
Energy	$0.0246	$0.0231
Fuel and Purchased Power †	$0.0257	$0.0223
Total	$0.0803	$0.0757
Off-Peak kWh Charge		
Distribution Delivery	$0.0000	$0.0000
Transmission Delivery	$0.0000	$0.0000
Ancillary Services 1-2	$0.0000	$0.0000
Ancillary Services 3-6	$0.0006	$0.0006
System Benefits	$0.0019	$0.0019
Competitive Customer Service	$0.0000	$0.0000
Energy	$0.0128	$0.0124
Fuel and Purchased Power †	$0.0257	$0.0223
Total	$0.0410	$0.0372

† The price for Fuel and Purchased Power may be changed periodically consistent with Adjustment A.

ANCILLARY SERVICES:

Ancillary services provided include:

1) Scheduling, System Control and Dispatch Service
2) Reactive Supply and Voltage Control from Generation Sources Service
3) Regulation and Frequency Response Service
4) Energy Imbalance Service
5) Operating Reserve – Spinning Reserve Service
6) Operating Reserve – Supplemental Reserve Service

Direct access customers would need to secure ancillary services 3-6 from an alternate energy supplier or under the terms and conditions outlined in SRP's Open Access Transmission Tariff.

MINIMUM BILL:

The greater of:

A. The monthly service charge or

B. The minimum monthly dollar amount specified in a written Agreement for Electric Service, if any.

DETERMINATION OF DEMAND IN KILOWATTS:

The billing demand is the maximum thirty-minute integrated kilowatt demand occurring during the on-peak and shoulder-peak periods of the billing cycle, as measured by meter.

ADJUSTMENTS:

A. SRP may increase or decrease the price for Fuel and Purchased Power based on changes in the average cost of fuel and purchased power. The price for Fuel and Purchased Power is calculated for each summer and winter season based on the projected cost of fuel and purchased power, adjusted for the actual over- or under-collection of fuel and purchased power revenues relative to fuel and purchased power expenses from prior periods.

B. SRP may increase the Transmission Cost Adjustment Factor to recover transmission related costs or charges incurred by SRP resulting from standardized wholesale market designs, regional transmission organizations, or related activities.

C. SRP increases or decreases billings under this schedule in proportion to any taxes, fees, or charges (excluding federal or state income taxes) levied or imposed by any governmental authority and payable by SRP for any services, power, or energy provided under this schedule.

D. If the power factor falls below 85 percent lagging at any metering point during any billing period, SRP may:

1. Adjust kilowatt-hours and/or kilowatts during this period, for billing purposes, to equal 85 percent of kilovolt-ampere-hours and 85 percent of kilovolt-amperes. Kilowatt-hours and/or kilowatts will be adjusted proportionately for the on-peak, shoulder-peak, and off-peak periods.

2. Require the customer to correct the power factor to an acceptable level.

3. Require the customer to be continuously metered with a separate meter that registers kilovolt-amperes, kilovars, or actual power factor.

   At SRP's discretion, customer may be required to pay all costs associated with additional metering.

E. If, at any time, the current in any phase exceeds the average of the currents in the three phases by more than 5 percent, at SRP's option, SRP may increase the bill for the period during which the imbalance occurs by a percentage equal to that of the imbalance.

F. Customers participating in the 10-day SurePay Automatic Payment Program will receive a 1 percent discount on SRP services supplied under this price plan. The discount will be applied before adding sales tax. The discount does not apply to any penalties, fees, credits, or premiums. The discount will not apply to energy or services supplied by an alternative energy supplier.

G. Customers within the SRP distribution service territory who receive all electric services from SRP under the E-32, E-36, E-47, E-48, E-61, E-63, or E-65 price plans who meet minimum usage requirements will receive an aggregation discount on their monthly bill(s).

Aggregation Discount = $0.0003/kWh

Single accounts meeting minimum usage levels can qualify for aggregation discounts.

Aggregate usage must meet a minimum usage requirement of 300,000 kWh per month for three consecutive months. Only those accounts receiving energy and delivery services from SRP will count towards the minimum usage requirements.

The discount will be applied only to kWh sold under the applicable price plan. The discount will be applied before the application of any credits, penalties, fees, or premiums.

H. For customers metered for billing purposes at primary voltage, SRP will deduct 1 percent of the demand and energy charges from each billing. Primary voltage is defined as the same voltage found at the low side of a substation transformer, typically 12.47 kV or 4,160 volts. The deduction does not apply to monthly service charges, facilities charges (where applicable), taxes, penalties, fees, or other adjustments.

RULES AND REGULATIONS:

A. Service under this schedule is in accordance with the terms of SRP's Rules and Regulations, including any amendments.

B. At SRP's request, Customer shall sign SRP's then-current form of Agreement for Electric Service as a condition of service under this price plan.

C. For direct access customers, service under this schedule is in accordance with the terms of SRP's Direct Access Program, as set forth in the Rules and Regulations, including any amendments.

SPECIAL RIDERS:

A. Customers may choose to participate in SRP's Renewable Pricing Rider.

B. Customers with cogeneration or small power production who purchase power and energy from SRP may qualify to sell power and energy back to SRP under the Buyback Service Rider.

C. Customers with a minimum annual load of 100 kW and who have the flexibility to curtail load may qualify for service under the Use Fee Interruptible Rider.

D. Customers with individual accounts or aggregated loads of 1 MW or more, who have energy alternatives and who are willing to sign a term contract, may qualify for service under the Full Electric Service Requirements Rider.

E. Customers interested in receiving a verifiable market price for energy and who are willing to have their energy price per kWh change on a monthly basis, to reflect the electric energy market, may choose to participate in the Monthly Energy Index Rider.

F. Customers may choose to participate in SRP's Renewable Pricing Rider for Large Customers.

WILLIAM J. MURPHY DIRECT AND REBUTTALTESTIMONY - ERRATTA
DOCKET # E-01345A-05-0816

EXHIBIT
DEAA-3
Admitted
PENGAD 800-631-6989

DIRECT TESTIMONY

Page 5, line 15 change "4" to "3"

Page 15, line 6, change "150%" to "50%"

Page 13, line 24, insert "Arizona owned" between the words "more" and "generating"

EXHIBIT
DEAA-4
Admitted

EXECUTIVE SUMMARY OF DIRECT AND REBUTTAL
WILLIAM J. MURPHY

ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-05-0816

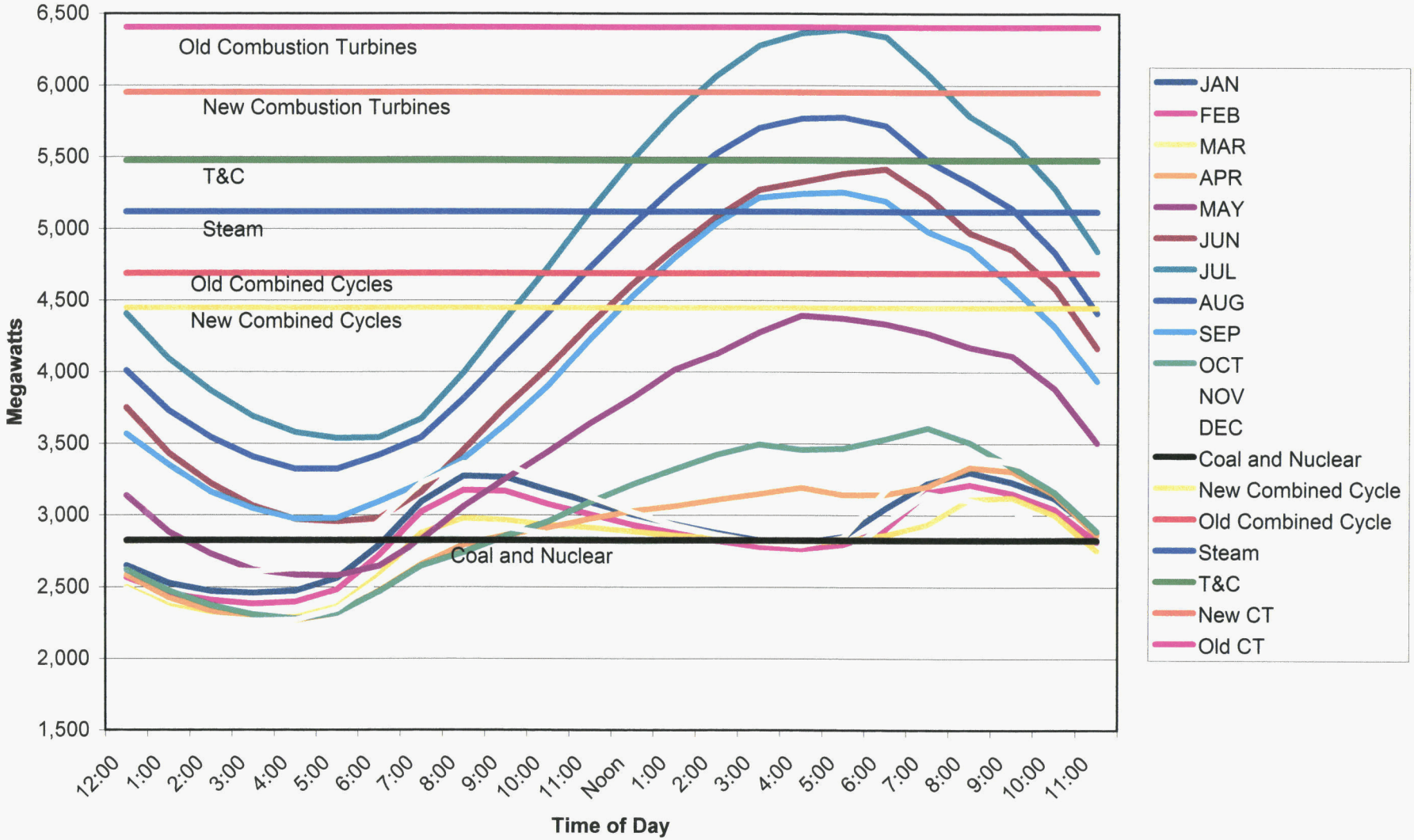
My Direct and Rebuttal Testimony on behalf of the Distributed Energy Association of Arizona addresses the choices or rates offered to customers who create their own electricity. This includes both Residential, and General Service customers who chose to utilize renewable and other methods to generate electricity.

The Company proposes for both Residential and General Service Partial Requirements rates that focus on non-coincident demand. This is a problem (customer owned transformer) that is already solved by the proposed interconnection standards.

What are needed are rates that focus on coincident Demand and Energy cost recovery. We believe the SRP E-32 TOU is just such a rate.

EXHIBIT
DEAA-5
Admitted
PENGAD 800-631-6989

2005 Test Year Monthly Average Load Curve with Dispatch Order



DEAA 5