U. S. NUCLEAR REGULATORY COMMISSION

REGION V

Report Nos: 50-275/87-24, 50-323/87-24

Docket Nos: 50-275 and 50-323

License Nos. DPR-80 and DPR-82

Licensee: Pacific Gas and Electric Company
70 Beale Street, Suite 1451
San Francisco, California 94106

Facility Name: Diablo Canyon Units 1 and 2

Inspection at: San Luis Obispo, California (Diablo Canyon Site)

Inspection Conducted: October 14-21, 1987

Inspectors:

H. S. North, Senior Radiation Specialist, Team Leader, Region V — 12/11/87 Date Signed

H. Zibulsky, Radiation Specialist/Chemist, Region I — 12/11/87 Date Signed

W. J. Ross, Reactor Inspector/Chemistry, Region II — 12/11/87 Date Signed

P. C. Wu, Ph.D., Corrosion Specialist, Chemical Engineering Branch, NRR — 12/11/87 Date Signed

W. TenBrook, Radiation Specialist (E.P.), Region V — 12/11/87 Date Signed

C. A. Hooker, Radiation Specialist, Region V — 12/14/87 Date Signed

Approved by: G. P. Yuhas, Chief, Facilities Radiological Protection Section, Region V — 12/15/87 Date Signed

Summary:

Inspection during the period of October 14-21, 1987 (Report Nos. 50-275/87-24 and 50-323/87-24)

Areas Inspected: Special unannounced team inspection of plant chemistry related areas including organization and management, quality assurance,

training and qualifications, water chemistry control and analysis, facilities, systems affecting plant chemistry, erosion/corrosion control and surveillance, confirmatory measurement/radioactive species and post accident sampling. Inspection procedures 30703, 79501, 79502, 84525, and 83727 were addressed.

Results: In the nine areas addressed, no violations or deviations were identified.

DETAILS

1. Persons Contacted

*J. D. Townsend, Acting Plant Manager
*J. M. Giscoln, Assistant Plant Manager
*D. S. Aaron, Director of Auditing
M. Angus, Manager, Outage Planning
*J. Bellows, Quality Assurance (QA) Auditor
*S. Fahey-Benson, Nuclear Generation Engineer
K. Bieze, Senior Instructor, Chemistry and Radiation Protection (C&RP)
*J. V. Boots, C&RP Manager
K. W. Cortese, C&RP Foreman
*R. D. Cramins, Senior Quality Control Inspector
J. A. Davis, Supervisor, QA, General Office
R. Foster, Senior Power Production Engineer
O. Franks, Ultrasonic Inspector
*J. E. Gardner, Senior C&RP Engineer
M. M. Gibson, C&RP Engineer
D. Gonzales, Ultrasonic Inspector
F. Guerra, Chemistry Foreman
R. C. C. Gururaja, Start Up Supervisor
R. J. Harris, Supervisor, QA, On-Site Auditing Group
*J. R. Hinds, Regulatory Compliance Engineer
*R. L. Johnson, Chemistry General Foreman
M. Leppke, Onsite Project Engineer
R. M. McVicker, Lead Specialist, Quality Control (QC)
J. Niemeyer, C&RP Engineer
*D. H. Oatley, Supervising Nuclear Generation Engineer
*W. A. O'Hara, Senior Nuclear Generation Engineer
R. Potter, C&RP Foreman
J. Raab, Shift Foreman
R. K. Stephens, C&RP Foreman
R. Sovard, Lead Start Up Engineer
*D. A. Taggart, Director Quality Support
B. Tripp, C&RP Engineer
D. Unger, Radiochemical Engineer
R. Waltos, Mechanical Engineer
*E. S. Wessel, C&RP Engineer

*Denotes persons attending Exit Interview on October 21, 1987.

In addition to the individuals identified above, the inspectors met and held discussions with other members of the licensee's staff.

NRC Personnel Attending Exit Interview

M. M. Mendonca, Chief, Reactor Projects Section I, Region V
P. P. Narbut, Senior Resident Inspector, Diablo Canyon Power Plant (DCPP)
C. A. Hooker, Radiation Specialist, Region V
H. S. North, Senior Radiation Specialist, Region V

W. J. Ross, Reactor Inspector/Chemistry, Region II
W. K. TenBrook, Radiation Specialist (E.P.), Region V
H. Zibulsky, Radiation Specialist/Chemistry, Region I

2. Organization and Management

The inspector reviewed the current Chemistry Department organization, staff position assignments and position descriptions to determine the licensee's compliance with Technical Specifications (TS) 6.2.2 and 6.3, Final Safety Analysis Report (FSAR) Section 13.1.3.1 commitments and the licensee's procedures. The adequacy of PG&E management's commitment, policy implementation, assignment of authority and responsibility, and staffing and management awareness of control of the quality of primary and secondary chemistry was evaluated.

The on-site Chemistry and Radiation Protection (C&RP) Department consisted of about 113 permanent PG&E employees with authorization for 117. The four sections under the C&RP Manager were Radiation Protection/Radwaste, Chemistry and Radiation, Systems and Operations Support Projects. The C&RP Manager reports to the Assistant Plant Manager/Plant Support who reports to the DCPP Plant Manager. Within the C&RP Department, the inspection addressed those C&RP sections which were primarily responsible for chemistry control and related programs. The Chemistry and Radiation section, consisted of a Senior C&RP Engineer (Chemistry Supervisor), six degreed (chemistry related) C&RP Engineers assigned and responsible for specific functional areas, a General Chemistry Foreman and six line foremen assigned to specific chemistry functional areas. The licensee's technician staff consists of C&RP technicians whose duty assignments alternate between chemistry and radiation protection. At any one time, about 30 C&RP technicians were assigned to the chemistry section from the total C&RP technician staff. About 20% of the total C&RP technician staff (68) have educational degrees related to chemistry. The licensee was attempting to divide the technician staff into separate specialties. This proposed change was delayed due to negotiations with the union representing the technicians.

Typically, based on rotational assignments, approximately 40% of the chemistry laboratory staff were degreed technicians. The Operations Support Projects Section included a Senior C&RP Engineer, two C&RP Engineers with one assigned to Water Management and one assigned to Chemistry Process Instrumentation, and a Foreman for Hazardous Waste Management.

With respect to shift staffing, swing shift manning consisted of eight senior C&RP technicians and two line foremen during the week, and six senior C&RP technicians and one line foreman on weekends. The graveyard shift was normally manned with six senior C&RP technicians during the week and with three senior C&RP technicians on the weekends. Day shift coverage normally consisted of six senior C&RP technicians and one line foreman on the weekend. Weekday staffing was complimented by the remaining C&RP technician and foreman staff noted above.

Based on observations, the inspector determined that the licensee staffing appeared to be adequate to effectively implement the chemistry control program. However, the Operations Support Projects Section appeared to be slightly understaffed to be fully effective due to a recent long-term absence of one individual (Senior C&RP Engineer) and an unfilled position in the area of Water Management. These observations were presented to the licensee at the exit meeting on October 21, 1987.

The Corporate Nuclear Operations Support Department provides technical support and oversight of the chemistry control programs from the Radiation Projects Support Group Services Section via the Chemistry Support staff, who normally spend about 20% of their time at DCPP.

The inspector reviewed the following documents and procedures:

Documents

- NPG Policy Statement No. 1.10, Chemistry, dated April 8, 1985.
- PG&E's response, dated June 17, 1985, to NRC Generic Letter 85-02, Staff Recommended Actions Stemming from NRC Integrated Program for Resolution of Unresolved Safety Issues Regarding Steam Generator Tube Integrity, April 17, 1985.
- DCPP August and September 1987, Monthly Reports.
- August 1987, Monthly Status Report, from the Corporate Radiation Projects Support Services Section.
- August 1987, Monthly Chemistry Summary for DCPP, from the Corporate Radiation Projects Support Section.
- September 1987, DCPP Objectives Status Report.

Procedures

- NPAP C-200 - Requirements for Radiation Protection Programs
- NPAC C-201 - General Requirements for Chemical and Radiochemical Control Programs
- AP C-201S1 - Analytical Data Processing Responsibilities
- AP C-252 - Chemistry Data Reporting to Other Departments
- OP O-3 - Notification of the Chem/Rad Protection Department
- AP A-101S1 - Relieving the Watch
- NPAP A-104S1 - Shift Chemistry and Radiation Protection Technician Manning Requirements

Based on review of the above procedures and documents, discussions with cognizant on-site and corporate staffs, the inspector made the following observations:

- Management's commitment to maintain control of plant chemistry was adequately documented.
- Responsibilities and authority were adequately delineated.
- Staffing and shift manning appeared to be adequate as noted above.
- The monthly reports, identified above, appeared to be effective tools in maintaining the on-site and corporate management, including the Vice President, Nuclear, aware of the current status and objectives of the Chemistry and Radiochemistry Control Programs.
- The Monthly Chemistry Summary Report (secondary chemistry only), generated by the Corporate Chemistry Support Group, was not as formal as other reports of this nature, with an apparently more limited management distribution. This observation was presented to the licensee at the exit interview on October 21, 1987.
- DCPP appeared to be provided with adequate technical support and oversight from the corporate office.

No violations or deviations were identified.

3. Quality Assurance (QA)

The Chemistry Department's internal QA and Quality Control (QC) programs are addressed in other sections of this report. This section addresses the review of QA audits performed by PG&E's QA Department and the on-site QC Department.

A. QA Audit Report No. 87093T was reviewed. The audit was conducted June 4-July 1, 1987, to verify the adequacy of departmental procedures and the effective implementation of the requirements of QA Policies, DCPP TS, and departmental procedures for chemistry and radiochemistry controls.

The audit, among other items, included: interviews with members of C&RP Department, QC Department, C&RP Training Department, and other PG&E Department's staffs; and reviews of numerous procedures and documents related to the Chemistry and Radiochemistry Control Programs.

The audit identified several deficiencies that resulted in the issuance of five Audit Finding Reports (AFRs) that required corrective action. Although the AFRs were administrative in nature, one AFR (No. 87-126) presented an issue that caused further review into the matter. The Audit Report stated, in part, that, "AFR 87-126 was issued because a clear definition of what constituted the quality-related aspects of the Chemistry Program was not available. Thus, the auditors were not able to make a deterministic evaluation

of the adequacy of DCPP chemistry procedures or the effectiveness of the implementation of chemistry activities. The significance of AFR 87-126 impacts the Quality Assurance effectiveness evaluation for the entire audit." The response to the AFR stated that the root cause was that, "The QA manual does not adequately address the chemistry program. The QA Department, Engineering, and DCPP never properly identified the Secondary Chemistry Program in the QA manual." Based on corrective actions taken and a review of a newly drafted QA Procedure, QAP-2, Chemistry and Radiochemistry Programs, that defined the graded QA Program requirements for the Chemistry and Radiochemistry Programs, the inspector determined that the licensee was effectively resolving this matter.

No Nonconformance Reports were issued. The audit determined that the C&RP Department had effectively implemented the TS requirements that were audited.

In addition to the review of the audit, the inspector interviewed the individual, assigned as lead auditor, and reviewed his qualifications. The inspector determined that the individual met the qualifications outlined in ANSI N45.2.23.

B. QC Surveillance Report No. 87-0219 was reviewed. The surveillance was conducted June 11-18, 1987, to verify that out-of-specification chemistry results were being reported in accordance with the requirements of procedure AP C-20151. The surveillance involved the review of Chemistry data sheets, Shift Foremen and Control Operator's logs and other associated documents for the first quarter of 1987. As a result of the surveillance, three Action Requests (ARs) were initiated for corrective actions. The ARs were administrative in nature involving documentation. The surveillance determined that the procedural requirements concerning the reporting of out-of-specification chemistry were being met. Based on discussions with the QC Lead Specialist and Chemistry Supervisors of the proposed corrective actions, the inspector had no further questions regarding this surveillance.

No violations or deviations were identified.

4. Technician Training and Qualification

The inspector toured the on-site training facility and reviewed the training and requalification program for C&RP Technicians against ANSI N18.1-1971, "Selection and Training of Nuclear Power Plant Personnel" and station procedure number AP B-250, Administrative Procedure C&RP Technician Training. The training facilities were well equipped and have analytical instrumentation which duplicates that in the plant laboratory. The apprentice chemistry technician academic curriculum included:

Administrative Fundamentals
Fundamentals for Evaluations of Radiological Conditions
Corrosion Control
Sample Collection
Chemistry Analyses I and II

Surveys
Special Equipment
Radiochemistry
Basic Chemistry
Laboratory Training
Abnormal Condition Training
Confined Space Entry Training
Shift Technician Training
Accident Condition Training

The program for inexperienced personnel provided 28 weeks of classroom training over a two year period. The training provided experienced personnel was approximately 18-20 weeks.

As a technician demonstrates proficiency in a particular skill, a qualified individual signs off on a Qualification Record. It takes approximately one year of on-the-job training before a technician can begin performing independent radiation protection and chemistry tasks. Due to the dual nature of technician tasks, chemistry related training cannot be clearly separated from the joint C&RP training program on the basis of time required for this training.

The licensee expects the C&RP Training Program to be accredited by INPO in January 1988.

The requalification program requires a written examination and analyses of a set of standards every two years. Every six months, a set of standards are analyzed by the technician. In addition, a continuing training program requires 15-20 hours of technician participation each quarter.

The inspector found that licensee management was supporting a comprehensive training and retraining program.

No violations or deviations were identified.

5. <u>Water Chemistry Control and Analysis</u>

A. <u>Measurement Control Evaluation</u>

The adequacy and effectiveness of the licensee's nonradiological chemistry QC program was reviewed against the requirements of TS 6.8, USNRC Regulatory Guide 1.33 Revision 2, ANSI N18.7-1976, and standard industrial practices. The licensee's performance relative to these requirements and standards was determined by a review of records, discussions with licensee personnel, and observations by the inspector.

The licensee had recently approved site procedure CAP Q-1, Revision 0, <u>Preparation and Use of Quality Control Charts</u>. Implementation of the measurement control program was incomplete. The licensee was still generating data for control charts. The charts were constructed correctly having an acceptance criteria of ±2 sigma and an unacceptable parameter of ±3 sigma. The licensee had not considered the importance of systematic biases and measures to resolve them. Following discussions with the inspector, the licensee's representative stated that this topic will be addressed in Revision 1 of the procedure.

The licensee was using two independent standard stock solutions for calibration and measurement control. The maintenance of two standard stock solutions is required to provide an analytical cross check on the continuing quality of the stock solutions.

When the licensee's measurement control program is complete and in place in the laboratory, it should provide an adequate program to identify trends, biases and acceptance parameters of measurement systems.

B. Analytical Procedures Evaluation

During the inspection, standard chemical solutions were submitted by the inspector to the licensee for analysis. The standard solutions were prepared by Brookhaven National Laboratory (BNL) for the NRC, and were analyzed by the licensee using normal methods and equipment. The concentrations of the standards were adjusted to cover the calibration ranges of the analytical systems used. The analysis of standards was used to verify the licensee's capability to monitor chemical parameters in various plant systems with respect to TS, vendor and fuel warranty requirements. In addition, the analysis of standards was used to evaluate the licensee's analytical procedures with respect to accuracy and precision.

The results of the standard measurements comparison indicated that seven out of thirty-nine comparisons were in statistical disagreement under the criteria used for comparing results (see Attachment 1). The results of the comparisons are listed in the following Tables 1 and 2. It should be noted that in a significant number of cases, the reported values are the result of reruns of standard analyses. The reruns were performed after the identification and correction of a number of problems. The type of problems encountered are briefly summarized in the discussion of individual analyses.

The seven disagreements were due to sampling error or statistical evaluation. The sampling error was a result of poor sample homogeneity (mixing) or laboratory technique. The statistical difference was the result of very small uncertainties generated by the licensee's measurements which resulted in narrow 2 sigma acceptance parameters. The small uncertainties in the measurements is a reflection of good precision. The term "disagreement" should not be construed to indicate that the licensee's results represent an unacceptable degree of accuracy for the measurements from a regulatory perspective.

Many of the sampling errors experienced in the analyses of the NRC standards may be the result of technicians not dedicated to chemistry alone, but, rotated to perform radiation protection tasks. Without constant practice the proficiency of the analyst tends to suffer. When the licensee's measurement control program has been fully implemented, with dedicated chemistry personnel, the licensee's measurement program should be significantly improved.

Comments Concerning Table 1

Chloride

The chloride results were reruns. After recalibrating the ion chromatograph, the results improved. The disagreements were due to sampling error and statistical evaluation. The licensee's differences from the NRC standards were in a conservative direction.

Fluoride

The fluoride results were reruns. The reference solution was replaced in the specific ion electrode. The disagreement was due to the large concentration of fluoride. For that standard sample, the analyst had used the wrong dilution. This disagreement was in a conservative direction.

Iron, Copper, Nickel

The iron disagreements were due to sampling error and statistical evaluation. The disagreements were in a conservative direction. The copper and nickel results were reruns. The licensee's calibration standards had degenerated. When new calibration standards were used, the results improved.

Sodium

The original sodium results were analyzed using the atomic absorption (AA) spectrophotometer procedure. The result of analysis of the NRC standards showed an incomplete burn of the sodium ion. When the licensee analyzed the same standards using the graphite furnace, the results improved. The licensee planned to have maintenance performed on the AA.

Hydrazine, Silica

The hydrazine disagreement was due to a statistical evaluation and the silica disagreement was due to a sampling error.

Ammonia

The ammonia results were reruns. After a new calibration curve was generated and used in the analysis, the results improved.

Comments Concerning Table 2 - Post Accident Sampling System (PASS)

Chloride, Boron

The chloride results, using the PASS in-line ion chromatograph, were reruns. The first analysis indicated a systematic bias of 12%. When the NRC standards were rerun, the systematic bias decreased to 7%. In both analyses, the results were conservative. The boron results, using the spectrophotometric-carminic acid procedure, were reruns. The original analyses were in agreement statistically but

the analyses had poor precision. The poor results for both the chloride and boron were due to sampling error.

TABLE 1

Capability Test Results

Diablo Canyon Units 1 and 2

Chemical Parameter	Analytical Procedure	NRC Value	LIC. Value	Ratio (Lic./NRC)	Comparison
Results in parts per billion (ppb).					
Chloride	Ion Chromatograph	12.1±1.6	10.2±0.1	0.84±0.11	Agreement
		18.7±0.6	21.9±0.6	1.17±0.05	Disagreement
		20.1±0.6	21.6±0.2	1.07±0.05	Agreement
Sulfate	Ion Chromatograph	20.0±0.9	21.0±0	1.05±0.05	Agreement
		41.0±2.4	43.0±0	1.05±0.06	Agreement
		40.4±1.5	42.0±0	1.04±0.04	Agreement
Fluoride	Specific Ion Electrode	23.1±0.5	25.0±2.6	1.08±0.11	Agreement
		43.5±1.9	48.3±1.2	1.11±0.06	Agreement
		167.0±5.6	190.0±8.7	1.14±0.06	Disagreement
Iron	AA	978±70	1062±28	1.09±0.08	Agreement
		1910±68	2129±14	1.11±0.04	Disagreement
		2940±84	3137±0	1.07±0.03	Disagreement
Copper	AA	936±48	938±10	1.0	Agreement
		1932±98	1938±0	1.0	Agreement
		2900±120	2893±20	1.0	Agreement
Nickel	AA	1018±52	976±13	0.96±0.05	Agreement
		2040±60	1980±12	0.97±0.03	Agreement
		3060±80	2962±15	0.97±0.03	Agreement
Chromium	AA	1020±60	999±12	0.98±0.06	Agreement
		1882±60	2011±75	1.07±0.05	Agreement
		2860±160	3046±137	1.07±0.08	Agreement
Sodium	AA Graphite Furnace	45.8±5	47.0±1.7	1.03±0.12	Agreement
		92.3±8	86.7±4.6	0.94±0.10	Agreement
Ammonia	Spectrophotometric	119.9±3	133.3±10.4	1.11±0.09	Agreement
		356.3±10.6	331.7±2.9	0.93±0.03	Disagreement
Hydrazine	Spectrophotometric	100±2	98.3±0.6	0.98±0.02	Agreement
		38.6±3.2	38.0±0	0.98±0.08	Agreement
		52.4±1.3	49.0±0	0.94±0.02	Disagreement

Silica	Spectrophotometric	54.3±5.6	50±0	0.92±0.09	Agreement
		109±7.0	136.7±2.9	1.25±0.08	Disagreement
		160±5.0	155±0	0.97±0.03	Agreement

Results in parts per million (ppm).

Boron	Auto. Titration	1000±10	1014±1	1.01±0.01	Agreement
		3024±46	3028±4	1.0	Agreement
		4947±61	5023±6	1.015±0.01	Agreement

TABLE 2

Capability Test Results for PASS

Diablo Canyon Units 1 and 2

Chemical Parameter	Analytical Procedure	NRC Value	LIC. Value	Ratio (Lic./NRC)	Comparison
		Results in parts per million (ppm).			
Chloride	On-Line Ion Chromatograph	1.03±0.07	1.1±0	1.07±0.07	Agreement
		6.97±0.30	7.37±0.06	1.06±0.05	Agreement
Boron	Carminic Acid	1.01±0.02	1.0±0.1	0.99±0.10	Agreement
		3.05±0.03	3.2±0.15	1.05±0.05	Agreement
		5.04±0.13	4.83±0.06	0.96±0.03	Agreement

C. Facilities

The licensee's laboratory was well equipped with state-of-the-art instrumentation for both primary and secondary analyses. A new laboratory, to be dedicated to secondary chemistry, was nearly complete and will alleviate laboratory crowding and improve sampling efficiency. The sampling sinks for secondary chemistry are more convenient to the new laboratory.

The new secondary chemistry laboratory was equipped with the following items related to prevention of injuries:

- Eye wash fountains
- Safety showers
- Spill control pads
- Fume hoods with air flows of 150 lfpm (as of October 9, 1987)
- Fire extinguishers
- Emergency shut off valves for acetylene, argon, air, and water
- Noise control doors
- Low profile carboys for reagent storage
- Signs controlling eating and smoking

The C&RP Department had a Hazardous Waste Management Group that acts as a focus for control of all plant consumable materials and implementation of OSHA safety requirements. A draft of a new revision to Administrative Procedure AP D-51, Control of Consumable Materials, Revision 3, July 17, 1987, was reviewed. Revision of Administrative Procedure APC-251, Storage and Handling of Hazardous Material, Revision 6, had been completed but not yet approved. This procedure will provide guidance in the use of gas cylinders, among other topics.

No violations or deviations were identified.

6. Systems Affecting Plant Chemistry

Corrosion Control

As the result of the concern related to possible degradation of the primary coolant pressure boundary through leaks in, or catastrophic failure of, steam generator tubes, the NRC recommended in Generic Letter 85-02, several actions to prevent or mitigate tube failure. These recommendations included the following:

"SECONDARY WATER CHEMISTRY PROGRAM

"Staff Recommended Action

"Licensees and applicants should have a secondary water chemistry program (SWCP) to minimize steam generator tube degradation.

"The specific plant program should incorporate the secondary water chemistry guidelines in SGOG Special Report EPRI-NP-2704, "PWR Secondary Water Chemistry Guidelines," October 1982, and should address measures taken to minimize steam generator corrosion, including materials selection, chemistry limits, and control methods. In addition, the specific plant procedures should include progressively more stringent corrective actions for out-of-specification water chemistry conditions. These corrective actions should include power reductions and shutdowns, as appropriate, when excessively corrosive conditions exist. Specific functional individuals should be identified as having the responsibility/authority to interpret plant water chemistry information and initiate appropriate plant actions to adjust chemistry, as necessary.

"The referenced SGOG guidelines above were prepared by the Steam Generator Owners Group Water Chemistry Guidelines Committee and represent and (sic) consensus opinion of a significant portion of the industry for state-of-the-art secondary water chemistry control."

In its response to Generic Letter 85-02, the licensee referenced both a corporate policy statement, related to plant chemistry, and specific plant operating procedures that addressed the measures recommended by the NRC Staff. The inspector reviewed these documents (Policy Statement No. 1.10 and Operating Procedures OP F-5 and OP F-5:II) and concluded that the licensee had endorsed the recommendations for a secondary water chemistry program. In addition, the licensee's response described modifications that had been made during the extended licensing period to improve the design of the plant from that described in the original FSAR. These modifications had been based on industry experience acquired principally after the establishment of the Steam Generator Owners Group (SGOG) in 1977 and were considered to be consistent with the intent of the NRC's Branch Technical Position MTEB 5-3 relative to design and selection of materials.

Through discussions with cognizant licensee personnel, review of pertinent documents, audit of chemistry control data, and a walkdown of old and new chemistry sampling facilities and laboratories, the inspector addressed and evaluated the following topics:

- Comparison of the as-built plant with the description in the updated FSAR.
- The effectiveness of plant components in preventing corrosion of steam generator tubes.
- The effectiveness of chemistry control in preventing chemical and stress-related corrosion throughout the secondary coolant (power conversion) cycle.
- The adequacy of selected elements of the licensee's water chemistry program for implementing SGOG guidelines.

A. Effectiveness of Plant Design and Material Selection

At the time of this inspection both Diablo Canyon units were operating at full power in their second fuel cycles. Much of the information acquired related to problems encountered with systems during the first fuel cycles, maintenance and modifications performed during the first refueling outages, and trends observed during the second cycles (December 29, 1986, to date for Unit 1 and July 14, 1987, to date for Unit 2). In general, the program had been effective in preventing degradation of the primary coolant pressure boundary from both the reactor coolant and secondary coolant sides. However, the possibility of corrosive environments had been increased as the result of transport of soluble corrosive species and solid metal oxides to the steam generators. The presence of metal oxide sludge was of concern because of the potentially corrosive environments that were formed as well as the concomitant loss of metal from carbon steel pipe and copper alloy feedwater heater tubes. The copper alloy feedwater components were removed during the first refueling outage for both units.

(1) Reactor Coolant System

The inspector found that this system was accurately described in Section 5.2 of the FSAR. The materials of construction (low carbon content stainless steel pipe and inconel-clad steam generator tube sheet and inconel steam generator tubes) had provided a corrosion-free barrier against the loss of reactor coolant. Chemistry control had been maintained well within the limits prescribed in TS 3/4 4.7. The control of primary chemistry had been revised during the last year to be more consistent with the recommendations for coordinated lithium-boron control recently recommended by the Electric Power Research Institute (EPRI). These changes were designed to reduce ex-core radiation levels caused by migration of activation products (cobalt-58, cobalt-60, nickel-58) produced through solution of trace amounts of cobalt and nickel from steel and inconel surfaces.

(2) Main Condenser

Based on industry experience the principal pathway for ingress of corrosive species into the secondary water system has been through leaks in the main condenser tubes. Such leaks through the Diablo Canyon condensers were considered to be especially detrimental to the secondary coolant system because the condenser cooling water is sea water with a chloride content of approximately 35% (19,000 ppm). In an effort to make the condenser leak proof, the licensee had taken the following precautions:

- The original 90-10 copper-nickel condenser tubes had been replaced with tubes fabricated from 22 gauge titanium. The intent was to minimize corrosion/erosion and possible loss of tube integrity and to eliminate copper from the

condensate-steam generator cycle. Studies performed during the past decade have shown that copper and chloride in the presence of iron oxide sludge contribute to the phenomenon of denting and possible failure of inconel steam generator tubes.

- The tubes of the condenser had been drained and laid up in a dry condition during the extended pre-licensing period to minimize corrosion.

- Several sections of the condenser cooling water piping had been replaced before plant startup because of partial degradation attributed to corrosion.

- A cathodic protection system had been installed to reduce galvanic corrosion and pitting of carbon steel water boxes and admiralty brass tube sheets.

Discussions with plant personnel and a review of chemistry control data established that no chemically induced degradation of the condenser tubes had occurred since plant startup. However, numerous tube leaks had occurred during the first fuel cycles as the result of flow-induced vibration, tube fatigue, fretting, steam cutting, and missile damage. During the first refueling outages, the licensee sought to correct the identified design deficiencies through several actions including stiffening the support of the tubes through the addition of metal stakes through the tube bundles, changing the location of steam exhaust vents, cleaning debris from the shell side of the condenser, and installing or modifying steam deflector plates and baffles. Since startup for the second fuel cycle, Unit 2 had not experienced further tube leaks while four leaks had occurred in the Unit 1 tubes in July-August 1987. The licensee attributed these leaks to improper staking of one section of the tube bundle.

The licensee had established a task force to review the factors associated with tube damage and was planning to perform eddy current testing of tubes during refueling outages to monitor additional cracking. These actions were consistent with the preventative maintenance program summarized in the licensee's response to Item 3.b of Generic Letter 85-02, Condenser Inservice Inspection Program. The licensee does not intend to incorporate a condenser inservice inspection (ASME Section XI) program in safety-related procedures because the condenser was not considered a safety-related component.

The inspector was informed that power penalties had also been incurred due to fouling and blockage of cooling water flow caused by mussels, barnacles, and kelp. Similar fouling of heat exchangers in the Service Cooling Water Systems had been observed. The licensee was attempting to prevent such fouling through chlorination of the condenser cooling water, but frequently had to resort to heat treatment or shut down a

circulating water pump and mechanically remove the organisms from the tube sheet and water boxes.

Although the condensers had not provided the desired level of protection against ingress of sea water, a review of chemical control data acquired during 1987 showed that the quality of the hotwell water had remained high; i.e., cation conductivity < 0.1 µS. These data indicated that the condenser leak detection system was very effective in allowing the licensee to identify and isolate tube leaks and, thus, minimize contamination of the condensate.

It was noted that throughout both fuel cycles the licensee had difficulty identifying and eliminating pathways of air inleakage into the condensate. Consequently, the concentration of dissolved oxygen had frequently exceeded the 10 ppb limit specified in Operating Procedure OP E5:II. A continuing effort was being made to identify the source of air leaks by means of a helium leak detector.

(3) Makeup Water System

The second potential pathway for ingress of corrosive species into the secondary coolant, and all other plant cooling systems, was the water used to fill these systems and to provide makeup. The as-built portion of the plant that purifies sea water was not consistent with Section 9.2.3 of the FSAR in that a 400 gpm reverse osmosis (RO) plant was being used in place of the flash evaporator described in the FSAR. The RO product had a conductivity of 300 µS and contains < 175 ppb total dissolved solids and was used for makeup to the raw water ponds which are also fed from a nearby freshwater creek. The raw water was being further purified in a second RO plant which was described in the FSAR. The RO plants were producing water at a maximum of 600 gpm with considerably better quality than specifications; i.e., specific conductivity was < 0.07 µS, dissolved oxygen < 20 ppb, silica < 10 ppb, total organic carbon < 100 ppb. As described in Section 9.2 of the FSAR, the water was stored in the Pure Water and Condensate Storage Tanks for each unit. Air was excluded by air impermeable covers within the storage tanks. One of these covers had already been replaced because of loss of integrity.

(4) Condensate Cleanup System

Condensate cleanup systems were installed during the pre-licensing period to minimize contamination as the result of condenser tube leaks. The inspector verified that the as-built system was consistent with Section 10.4.6 of the FSAR.

Full-flow polishing of the condensate was achieved with seven mixed resin - deep bed demineralizers. The effluent was normally very pure with cation conductively of 0.065 µS and the concentrations of sodium, chloride, and sulfate each < 1 ppb.

Discussions with the chemistry staff and examination of 1987 chemistry control data identified cleanup system problems during the two initial fuel cycles that had resulted in specifications for the purity of feedwater and steam generator water being exceeded. The most significant had been "throw" of sodium, sulfate, and chloride from resin beds, regenerated with sodium hydroxide contaminated with these ions. The licensee had not been routinely analyzing bulk chemicals at that time; however, bulk chemicals were being routinely analyzed at the time of the inspection. The licensee suspected that sulfate ions were being thrown as the result of resin disintegration.

(5) AVT Chemical Injection

Both units began operation with all-volatile-treatment (AVT) chemistry control as discussed in Sections 10.3.5 and 10.4.9 in the FSAR. The operation of the injection systems used to add hydrazine and ammonia to the condensate polisher effluent, auxiliary feedwater, and steam generators during wet layup was reviewed. The use of replaceable, enclosed tanks for storage of hydrazine was considered to provide increased protection from possible leakage of this hazardous chemical.

(6) Feedwater Train

Through review of pertinent drawings, discussions with plant personnel, and walkdown of systems within the Unit 2 Turbine Building, it was established that the condensate/feedwater train of the as-built plant had been accurately described in Section 10.4.7 of the FSAR. In addition, the design and operation of this train, as well as the high-pressure components of the power conversion system (e.g., main steam lines, extraction steam lines, and high temperature drains) were reviewed to assess actions being taken to prevent transport of metal corrosion products to the stem generators. The presence of sludge, formed by solid corrosion products, has been considered to be a major contributor to the formation of localized corrosive environments on the tube sheet and in tube-tube support plate crevices. In addition, generalized corrosion, as well as erosion, has recently taken on considerable significance in relation to pipe thinning and loss of integrity of carbon steel pipe that provides flow for both single phase and two-phase systems. This subject is addressed in greater detail in section 7 of this report.

The following steps had been taken to minimize transport of oxidation products to the steam generators:

a. Prior to pre-startup testing, the condensate/feedwater train in each unit had been chemically cleaned to remove iron oxides that had accumulated during the extended pre-licensing period. A total of 4028 pounds of iron oxide (Fe_3O_4) and 130 pounds of copper oxide had been removed by dissolution in a 10 percent solution of

ethylenediaminetetraacetic acid (EDTA). This solvent had been extensively tested by EPRI and, under defined guidelines, had been recommended for chemical cleaning of carbon steel and inconel systems.

b. Prior to the second fuel cycle startup, all components (especially feedwater heater tubes) fabricated from copper alloys, had been replaced with stainless steel components. This action was taken to prevent the transport of copper oxidation products to the steam generators. Since this train contained copper alloy components during the first fuel cycle for each unit, the sludge removed during the first refueling outages contained copper as well as iron. Monitoring for copper in feedwater was continuing.

Removal of solid corrosion products from the low-pressure lines (condensate/feedwater) and from extraction steam lines and moisture separator reheater drains, before the water in these lines was pumped into the steam generators, had been incorporated into operating procedures. Feedwater purity specifications had been established in Operating Procedure OP 5-5A:II for the following modes of plant operation: Wet layup, hot standby, and power operation. As the result, during normal operation of both units, the concentration of copper was consistently < 1 ppb. However, the concentration of iron in the feedwater remained in the range of 10-30 ppb. The significance of these relatively high concentrations was discussed and the chemistry staff was encouraged to explore means of reducing this level to within the range (approximately 5 ppb) usually observed in PWR feedwater.

(7) Steam Generators

Because steam generator tubes represent a portion of the primary coolant pressure boundary, the actions taken to prevent formation of localized corrosive environments on the tubes and structural components of the steam generators was reviewed. Eddy current tests that had been performed on approximately 500 tubes in each Unit 1 steam generator during the first refueling outage failed to reveal any indication of tube damage. Increased numbers of the tubes in Unit 2 were eddy current tested during the first refueling outage (854, 831, 3388, and 855 tubes in steam generators 2A, 2B, 2C, and 2D). No evidence of significant damage was observed; however, very small (< 2 mils) indications of denting were observed. Also, two tubes required plugging because of damage incurred during the eddy current testing.

All steam generators were sludge lanced during the first refueling outages. Approximately 150-200 pounds of iron-copper oxide was removed from each of the Unit 1 steam generators and approximately 100 pounds of iron-copper oxide was removed from each of the Unit 2 steam generators.

Chemistry control data revealed that the purity of the steam generator water had routinely been considerably better than the requirements contained in Operating Procedure OP F.5:II (the criteria recommended by the SGOG). During March 1985, these limits were exceeded in both units as the result of feedwater contamination by impurities in the sodium hydroxide used to regenerate the condensate polishers. The result of hideout return measurements during unit cooldown, during power transients, and during end of cycle cooldown, showed that total concentrations of sodium, chloride, sulfate, and silica were much greater (5 to 30 times) than those measured when the plant was at 100% power.

As a consequence, additional actions to eliminate hideout return and to reduce the total amounts of corrosive ions to levels below the SGOG limits were begun. Some of these actions are summarized below:

- Blowdown during normal operation was maintained at > 40 gpm per steam generator (usually 80-100 gpm).
- 16-hour chemistry holds during cooldown had been proceduralized at 380°F and 340°F to maximize removal of hideout return.
- Blowdown was being completely or partially wasted to improve cleanup of the secondary system.
- Steam generator water had been continually cycled through demineralizers while the steam generators were in wet layup during the first refueling outages.
- Larger (2-inch) valves had been installed on the blowdown lines to facilitate blowdown and steam generator draining during outages.

(8) Conclusions

As a result of the significant research related to the prevention of corrosion in PWRs performed by the industry and EPRI during the period of the extended pre-licensing of the two Diablo Canyon units, the licensee was able to take additonal positive actions affecting corrosion control; such as,

a. the plant design was modified (e.g., water treatment plant and condensate polishers),

b. improved materials of construction were used in modifications to the condenser, feedwater heaters, and low-pressure turbines,

c. the control criteria and concept of action levels developed by SGOG/EPRI were incorporated into operating and chemistry procedures,

d. AVT chemistry control was adopted, and

e. startup and shutdown schedule holds were incorporated into operating procedures to facilitate cleanup of the secondary system.

Although these actions have not completely eliminated corrosive species in the steam generator environment, the chemistry of the steam generator water has been controlled well within SGOG guidelines. It was evident however that even this level of control had not prevented wastage of carbon steel pipe and formation of steam generator sludge.

The inspector established that the licensee was aware of the advantages to be gained by continuing to improve chemistry control and had been addressing the problems discussed in this section of the report through special task forces as well as through special projects performed by the chemistry staff.

B. Effectiveness of the Licensee's Water Chemistry Program

In Policy Statement No. 1.10 and in the response to Generic Letter 85-02, the licensee committed to an administrative philosophy and program to achieve optimum protection of plant systems through explicit chemistry related activities. Selected elements of the chemistry program developed to implement the licensee's policy, the guidance developed by SGOG/EPRI for PWR chemistry control, and the requirements of TS 6.8.4 were reviewed and evaluated.

(1) Documents Reviewed

a. Policy Statement No. 1.10, Chemistry Revision 0, October 7, 1986.

b. General Requirements for Chemical and Radiochemical Control Programs, NPAP C-201, Revision 7, October 7, 1986.

c. Administrative Procedure AP C-201 S2, Chemistry and Radiochemistry Sampling Schedules, Revision 0, July 13, 1983.

d. Administrative Procedure AP C-201 SI, Analytical Data Processing Responsibilities, AP C-201 SI, Revision 4, August 24, 1987.

e. Operating Procedure OP F-5, Chemical Control Limits, Revision 3, (not dated).

f. Operating Procedure OP F-5:II, Chemistry Control Limits and Action Guidelines for the Secondary Systems, Revision 1, (not dated).

g. Chemical Analysis Procedure CAP Q-1, Preparation and Use of Quality Control Charts, Revision 0, September 30, 1987.

h. Memorandum from Jeffrey E. Gardner to specified members of plant management entitled Unit 1 1986 Refueling Outage Steam Generator Hideout Return Report.

(2) Quality Control

Quality control charts maintained for all primary and secondary control parameters were reviewed. The charts had been maintained consistent with Chemical Analysis Procedure CAP Q-1. With very few exceptions, all daily control results were within the limits of two standards deviations (e.g., 95% confidence level). Fresh standard solutions had been prepared whenever the control limit was exceeded, and all repeat analyses had been within limits. The inspector discussed the advantages of redeveloping the control charts more frequently than once per year as a means of reducing the spread encompassed by the two and three standard deviation bands.

(3) Control of Bulk Chemicals

A draft of a new procedure relating to quality control of bulk chemicals had been written. As the result of problems previously encountered with bulk shipments of boric acid and sodium hydroxide, the chemistry staff was routinely testing these chemicals against specifications. The inspector was told that the sodium hydroxide that had caused contamination of feed and steam generator water in both units in March 1987 was known by the vendor to be impure before delivery but had escaped control by the vendor or testing by the licensee.

(4) Interface With Other Departments

Because of the increased responsibilities placed on the chemistry staff by the SGOG Guidelines, measures initiated by the chemistry staff to implement these responsibilities were evaluated. Some of these actions are described as follows:

- The chemistry staff collaborated with the Operations Department in the development of Operating Procedures OP F-5 and lower tier Operating Procedures OP F-5:I, II, and III, Chemistry Control Limits and Action Guidelines for the Primary, Secondary, and Plant Support Systems.

- The Senior C&RP Engineer and Outage Planning Coordinator maintained close liaison related to startup cleanup activities and hideout return blowdown periods during end of cycle cooldown.

- Shift chemistry foremen had maintained close liaison with operations personnel in the control room.

- Chemistry personnel had received timely response to requests for maintenance that could not be performed "in house."

- The chemistry staff had been instrumental in organizing training sessions related to the SGOG Guidelines.

No violations or deviations were identified.

7. Erosion/Corrosion Control and Surveillance Program

A. Introduction

Main feedwater systems, as well as other power conversion systems, are important to safe operation. Failure of active components in these systems, (e.g., valves or pumps, or passive complements such as piping) can result in undesirable challenges to plant safety systems required for safe shutdown and accident mitigation.

Failure of high-energy piping, such as feedwater system piping, can result in complex challenges to operating staff and the plant because of potential systems interactions of high-energy steam and water with other systems (e.g., electrical distribution, fire protection, and security systems).

The purpose of this inspection was to review the licensee's history of erosion/corrosion induced piping degradation, visually examine selected failed piping components and review the licensee's failure analysis results, interview the plant staff, and review the licensee's pipe wall thinning monitoring programs to ensure that proper techniques were used by qualified personnel for pipe wall thickness measurements and assure that adequate guidance was provided for corrective actions and other activities regarding repair and replacement.

B. History of Pipe Wall Thinning

DCPP piping was designed and fabricated to the following codes:

PG&E	Class A:	ANSI B31.1, 1967; ANSI B31.7 1969
PG&E	Class B:	ANSI B31.7, 1969 with 1970 Addenda
PG&E	Class C:	ANSI B31.7, 1969 with 1970 Addenda
PG&E	Class E:	ANSI B31.1, 1967 Dead Weight and Thermal
PG&E	Class F:	ANSI B31.1, 1967; ASME Section I, 1968

Piping material is ASTM A-106 Grade B and ASTM A-234 WPB carbon steel. This is consistent with the licensee's design commitment as stated in the DCPP FSAR Update Table 3.2-2 which was verified by the inspector.

The licensee initiated its pipe wall thinning inspection during the Unit 1 first refueling outage in September 1986. Since that was before the Surry 2 feedwater piping failure incident in December 1986, this inspection covered two-phase lines only. A baseline inspection of 29 fittings in selected two-phase systems (e.g., high-pressure (HP) turbine extraction, exhaust and high-pressure feedwater heater drains) was conducted using the ultrasonic technique (UT). Although some fittings had thickness measurements

less than the nominal, none were unacceptable and none were repaired or replaced. However, during plant surveillance of Unit 1 prior to the first refueling outage, blowdown piping at the inlet connections to the steam generator blowdown tank (downstream of the throttling valves) and that of the blowdown flash tank (downstream of the control valves), as well as portions of the tank wall and the internal wear plates were found to be severely eroded due to the effects of impingement. These affected areas were replace during the Unit 1 first refueling outage.

During the first Unit 2 refueling outage in April 1987, the licensee conducted baseline inspections. Severe thinning was observed in two branch connections off the HP turbine exhaust piping which supplies steam to the No. 2 feedwater heaters. The localized wall thickness was found to be as low as 70% of the nominal pipe wall thickness. Although the thickness was still above the code allowable minimum wall thickness, the branches were weld repaired during the outage. The inspector found that the licensee had taken a conservative approach and appropriate corrective actions to ensure safe operation of the system.

In response to the Unit 2 findings, the licensee also inspected the same portions of Unit 1 piping. Localized wall thickness as low as 68% of the nominal value was discovered. The licensee stated that, at the observed rate of wear, the wall thickness would not infringe on the calculated minimum wall thickness before the next Unit 1 refueling outage. It was therefore decided to leave the degraded piping in service. As an additional measure, the licensee indicated that wall thickness measurements were to be made during forced outages prior to the refueling outage. The inspector found that the licensee's approach might not be conservative and that an adequate margin might be lacking to ensure that the pipe wall thickness will remain above the code allowable minimum wall thickness. A conservative and more prudent approach would have been to use the Nuclear Management and Resources Council (NUMARC) Guidelines which recommends that degraded piping have a calculated wall thickness of at least 10% above the code allowable minimum value at the time of the next refueling outage. The inspector also considered, that if the secondary system operating conditions remained unchanged, the use of the following equation to estimate the remaining acceptable useful life of the secondary piping systems would be adequate:

$$\text{Remaining Life} = \frac{\text{Measured Minimum Wall} - \text{Minimum Allowable Wall}}{2 \times (\text{Observed Erosion/Corrosion Rate})}$$

where

$$\text{Minimum Allowable Wall} = \frac{\text{Pressure} \times \text{Pipe Outside Diameter}}{2 \times [\text{Allowable Stress} + 0.4 \times (\text{Pressure})]} + \text{Corrosion Allowance}$$

Results of the Unit 2 baseline inspection program for the remainder of the inspection points were still preliminary. The inspector agreed with the licensee that although the preliminary results indicate that some fittings in both two-phase and single-phase

systems have thickness measurements less than nominal but greater than minimum wall thickness, until another set of measurements is made, it would be difficult if not impossible to determine whether this variation was due to Erosion/Corrosion or manufacturing tolerance.

During a Unit 2 plant surveillance, a main steam and two HP turbine exhaust condensate drain orifice blocks and their inlet reducers and the HP turbine extraction line were found to be severely eroded. These components were all replaced with either stainless steel or chrome-moly alloy sections. Although the corrective actions taken by the licensee were effective in the short-term, the inspector considered that the potential for galvanic corrosion-induced piping degradation by the use of stainless steel or chrome-moly alloys in the carbon steel secondary systems should be evaluated for any long-term solution.

In addition to the above pipe wall thinning incidents, the licensee also indicated that wall thinning of straight sections of piping in the MSR shell drain and dumps, and the feedwater heater drain tank dump was also observed.

C. <u>Failure Analysis and Damage Mechanism(s)</u>

An internal visual examination conducted by the licensee on Unit 2 extraction steam elbows at the inlet connections to the No. 2 feedwater heaters revealed the signs of erosion/corrosion. Subsequent UT thickness measurements made in the affected areas of these elbows, however, did not show any significant wall loss. Since these elbows were determined to be safe for continued operation, destructive failure analysis could not be done to verify the results of visual observation.

The licensee also reported that blowdown piping at the inlet connections to the steam generator blowdown tank as well as portions of the tank internal wear plates adjacent to the inlet connections of both Units 1 and 2 were found to be severely eroded due to the effects of impingement. Independent examination by the inspector verified the licensee's analysis. Extremely localized deep penetration occurred on the surface of the wear plates which was indicative of the impingement-induced erosion damage mode. The inspector concluded that the licensee should conduct additional failure analysis on degraded piping components removed from the secondary systems to verify the damage mechanism(s) and to correlate the extent of wall thinning with chromium and copper content of the carbon steel piping components.

D. <u>Erosion/Corrosion Inspection Program</u>

Review of the licensee's pipe wall thinning monitoring program by the inspector revealed that prior to the feedwater line break incident at Surry 2 in December 1986, the licensee's inspection program covered only two-phase carbon steel lines. Since the Surry 2 incident, the licensee has established a multidisciplinary task force to formulate and implement an action plan to address

erosion/corrosion of carbon steel piping at DCPP. Initial efforts of the task force were directed toward creating the DCPP Unit 2 baseline inspection program, which was implemented during the first refueling outage. The task force recommended the most probable locations, based on available published data, incident reports and engineering judgement, for single-phase erosion/corrosion and the more familiar two-phase or wet-steam erosion/corrosion. The scope and extent of the Unit 2 baseline inspection program currently includes a total of 67 locations for ultrasonic inspection: 53 for two-phase erosion/corrosion and 14 for single-phase erosion/corrosion. These are in addition to the turbine cross-under piping where internal visual inspections of accessible areas were performed.

The inspector agreed with the licensee's approach to the establishment of the inspection frequency based on the erosion/corrosion rates derived from the measurements made or to be made during the second and third refueling outages for Unit 1 and the first and second refueling outages for Unit 2.

The licensee's Pipe Wall Thickness Measurements for the Erosion/Corrosion Monitoring Program, Instruction No. I-66 and the licensee's NDE Manual Procedure No. N-UT-2 were reviewed. The inspector determined that the scope of inspection was properly defined, organizational and individual responsibilities were clearly identified, and procedural instructions and documentation requirements were specified. In addition, the UT procedures for wall thickness measurements met the requirements of ASME Boiler and Pressure Vessel Code, Section V, Article 5. The digital readout UT instruments with a resolution of 0.001 inch were adequate for the intended purpose.

E. Inspector Qualification and Training Program

The licensee had established a rigorous training program. The instructors were certified American Society of Nondestructive Testing (ASNT) Level II or Level III inspectors. All pipe wall thinning inspectors were required to complete this in-house training program and pass a written and hands-on examination. Wall thickness measurements were made by these inspectors. However, in cases where wall thickness discrepancies were discovered, ASNT Level II inspectors were called upon to verify the findings. This approach was consistent with industry practice and was adequate for monitoring pipe wall thinning at DCPP.

F. Corrective Actions and Repair/Replacement Criteria

The DCPP Unit 2 inspection program was developed prior to the issuance of the Nuclear Management and Resources Council (NUMARC) Guidelines and therefore did not conform precisely to the NUMARC Guidelines. As discussed in Section 7.B., the licensee's current repair/replacement criteria did not appear to be conservative. However, in response to NRC Bulletin No. 87-01, Pipe wall thinning in Nuclear Power Plants, dated September 8, 1987, the licensee

committed to adopt the NUMARC Guidelines and the EPRI CHEC computer program to identify piping components likely to require corrective actions. The repair/replacement decision will be based on engineering evaluations of remaining life to minimum wall thickness, time remaining to the next planned outage, economics of repair vs. replacement, etc. The inspector determined that the licensee's future repair/replacement criteria was still unclear and should be explicitly expressed in the licensee's pipe wall thinning monitoring program. This matter will be examined further during a subsequent inspection (50-275/323/87-24-01).

G. Conclusion

In general, it was found that the licensee's overall efforts to address pipe wall thinning problems were above industry standards. It was commendable that the licensee had established an interdisciplinary task force, shortly after the feedwater line break incident at Surry 2, to develop a pipe wall thinning monitoring program for both two-phase and single-phase lines. However, the inspector found that although the licensee had committed to follow the NUMARC Guideline to monitor pipe wall thinning in the future, its current piping repair/replacement criteria might not be conservative.

Since the licensee replaced sections of the carbon steel piping with stainless steel or chrome-moly steel, the potential for galvanic type piping degradation in the long-term should be considered. In addition, in view of the fact that the feedwater line at the DCPP had been operating at 430°F, an average pH of 8.9, 3 ppb oxygen, and flow velocity of about 17 ft/sec, conditions similar to those observed at Surry 2, the licensee should consider raising the feedwater pH value to 9.2 to minimize the potential for severe pipe wall thinning in the long run. Since copper alloy components in the secondary system had been removed during the first refueling, raising the pH should not cause severe corrosion problems. The inspector also noted that a coolant chemist should be included in the licensee's task force, because coolant chemistry control has a significant effect on erosion/corrosion degradation of carbon steel systems.

H. Documents Reviewed:

(1) Response to NRC Bulletin No. 87-01, Thinning of Pipe Walls in Nuclear Power Plants. PG&E Letter No. DCL-87-217.

(2) Pipe Wall Thickness Measurements for the Erosion/Corrosion Monitoring Program, Instruction NO. I-66, Revision 0, effective date June 11, 1987, PG&E Co. Mechanical Engineering Department, Diablo Canyon Project Units 1/2.

(3) UT Thickness Measurement Examination Procedure, PG&E NDE Manual Procedure No. N-UT-2, Revision 0, January 1, 1983.

(4) UT Thickness Measurement Using a T-MIKE, PG&E NDE Manual Procedure No. N-UT-11, Revision 0, July 21, 1987.

No violations or deviations were identified.

8. Confirmatory Measurements - Radioactive Species

A. NRC Mobile Laboratory

The NRC Mobile Laboratory was brought on-site to perform gamma spectrometry intercomparisons with the licensee's Chemistry and Radiation Protection Laboratory. Five samples were obtained for the interlaboratory comparison. In the case of liquids and gas, the samples were split. Solid samples were exchanged between the licensee and the NRC.

The first analysis was performed on 10 ml of reactor cooling water stripped of fission product gases. Results of the intercomparison are presented in Table 3:

TABLE 3

Reactor Coolant

Nuclide	DCPP μCi/ml	NRC μCi/ml	NRC Counting Uncertainty μCi/ml	Ratio DCPP/NRC	Agreement Range*
Na-24	1.12 E-3	1.21 E-3	7.6 E-5	0.93	0.75-1.33
Mn-54	2.37 E-3	1.70 E-3	6.7 E-5	1.39	0.75-1.33
Co-58	-	4.72 E-4	5.5 E-5	-	0.60-1.66
I-131	3.48 E-3	3.57 E-3	9.6 E-5	0.98	0.75-1.33
I-132	7.54 E-3	8.04 E-3	1.8 E-4	0.94	0.75-1.33
I-133	7.18 E-3	7.59 E-3	1.0 E-4	0.95	0.80-1.25
I-134	1.31 E-2	1.39 E-2	4.6 E-4	0.94	0.75-1.33
I-135	1.02 E-2	9.71 E-3	3.6 E-4	1.05	0.75-1.33
Cs-134	3.56 E-4	4.36 E-4	5.0 E-5	0.82	0.60-1.66
Cs-137	5.31 E-4	4.36 E-4	5.3 E-5	1.26	0.60-1.66
Cs-138	3.03 E-2	3.23 E-2	2.2 E-3	0.94	0.60-1.66
Ba-139	4.87 E-3	4.31 E-3	6.7 E-4	1.13	0.50-2.00

*See Attachment 2.

Satisfactory agreement was obtained for the reactor coolant sample. The licensee did not detect Co-58 due to a lower sensitivity with respect to the NRC analysis.

Using the radioiodine activities presented in Table 3, an intercomparison of dose equivalent I-131 in reactor coolant was performed in accordance with the licensee's Chemical Analysis Procedure, CAP-14. The licensee measurements resulted in 6.77 E-3 µCi/ml dose equivalent I-131, while the NRC laboratory obtained 6.96 E-3 µCi/ml dose equivalent I-131. The ratio between the two results, 0.97, indicates good agreement.

Technical Specification 3/4.4.8 requires a determination of average beta-gamma energy of reactor coolant (E-Bar determination) on a semi-annual basis. The determination typically involves quantification of all beta and gamma emitters with half-lives longer than 10 minutes, excluding radioiodines. The most recent licensee E-Bar result per TS 3/4.4.8 was 0.41 MeV/Disintegration. This value is consistent with that observed at other facilities.

The activities of reactor coolant principal gamma emitters other than radioiodine obtained during the intercomparison test were multiplied by their respective beta-gamma energy emissions in MeV/Disintegration. These calculations were used to determine an average beta-gamma energy of principal gamma emitters in reactor coolant. The licensee measurements resulted in an average beta-gamma energy of 3.07 MeV/Disintegration. The NRC measurements resulted in 3.15 MeV/Disintegration. A ratio of 0.98 between the two results was obtained, indicating good agreement.

It is noted that a Technical Specification E-Bar determination requires additional measurements beyond the scope of the intercomparison tests, including quantification of dissolved gases and pure beta emitting radionuclides. For example, specific activities of tritium and Xe-133 determined during the licensee's most recent E-Bar analysis were 2.4 E-1 µCi/ml and 8.2 E-1 µCi/ml, respectively. When the licensee's tritium and Xe-133 values were included with the principal gamma emitters from the intercomparison, the average beta-gamma energy fell from 3.07 MeV/Disintegration to 0.25 MeV/Disintegration, which was consistent with the most recent licensee E-Bar result, 0.41 MeV/Disintegration. The remaining difference was chiefly attributable to other radionuclides not quantified in the intercomparison test.

The second sample analyzed was suspended solids from 1000 ml of reactor coolant deposited on a 47 mm filter. The results of the filter intercomparison are presented in Table 4:

TABLE 4

Reactor Coolant Suspended Solids

Nuclide	DCPP µCi/ml	NRC µCi/ml	NRC Counting Uncertainty µCi/ml	Ratio DCPP/NRC	Agreement Range*
Cr-51	3.61 E-4	4.23 E-4	2.2 E-6	0.85	0.80-1.25
Mn-54	6.36 E-6	7.00 E-6	1.3 E-7	0.91	0.80-1.25
Fe-59	5.66 E-6	6.27 E-6	2.4 E-7	0.90	0.75-1.33
Co-57	2.18 E-7	1.67 E-6	3.4 E-8	1.30	0.50-2.00
Co-58	1.11 E-4	1.21 E-4	5.0 E-7	0.92	0.85-1.18
Co-60	1.34 E-5	1.44 E-5	2.2 E-7	0.93	0.80-1.25
Zr-95	1.70 E-5	1.80 E-5	2.9 E-7	0.95	0.80-1.25
Nb-95	1.35 E-5	1.48 E-5	1.9 E-7	0.91	0.80-1.25
Mo-99	5.37 E-6	6.31 E-6	1.7 E-7	0.85	0.75-1.33
Ru-103	6.52 E-7	5.26 E-7	1.1 E-7	1.24	0.50-2.00
Sn-113	5.21 E-7	5.31 E-7	1.0 E-7	0.98	0.50-2.00
Sn-117m	9.61 E-7	9.27 E-7	6.3 E-8	1.04	0.60-1.66
I-131	1.59 E-6	2.16 E-6	1.5 E-7	0.74	0.60-1.66
Te-132	-	4.93 E-7	1.7 E-7	-	0.75-1.33
La-140	1.95 E-5	2.40 E-5	1.1 E-6	0.81	0.75-1.33
Ce-141	4.69 E-7	6.20 E-7	7.4 E-8	0.76	0.60-1.66
Np-239	3.01 E-6	4.40 E-6	6.7 E-7	0.68	0.50-2.00

Satisfactory agreement was obtained for the suspended solids filter measurements. Te-132 was not detected by the licensee due to lower sensitivity limits with respect to the NRC measurement.

The third measurement intercomparison involved 500 ml of liquid radioactive waste from a chemical drain tank. The results of the intercomparison are presented in Table 5:

TABLE 5

Liquid Waste

Nuclide	DCPP µCi/ml	NRC µCi/ml	NRC Counting Uncertainty µCi/ml	Ratio DCPP/NRC	Agreement Range*
Mn-54	3.52 E-7	3.47 E-7	7.5 E-8	1.01	0.50-2.00
Co-58	3.08 E-6	2.32 E-7	1.2 E-7	1.33	0.75-1.33
Co-60	1.39 E-6	1.10 E-6	1.1 E-7	1.27	0.60-1.66
I-131	6.45 E-7	5.41 E-7	6.7 E-8	1.19	0.60-1.66
I-133	1.47 E-6	1.52 E-6	1.1 E-7	0.97	0.60-1.66
Cs-134	5.38 E-7	2.27 E-7	8.6 E-8	2.37	0.40-2.50
Cs-137	3.95 E-7	3.49 E-7	8.3 E-8	1.13	0.50-2.00

The liquid waste measurement agreement was adequate.

A blank sample was also analyzed to test the sensitivity of the licensee's liquid waste measurements. In accordance with the licensee's standard liquid waste measurement procedure, a 500 ml marinelli beaker was filled with clean water and counted for 1200 seconds. Lower Limits of Detection (LLDs) were determined by software algorithm at each key energy for radionuclides of interest. LLDs were also calculated for several nuclides not detected in the actual liquid waste sample described by Table 5. The results of the LLD verification are presented in Table 6:

TABLE 6

Lower Limits of Detection for Liquid Waste

Nuclide	Technical Spec. Minimum LLD (μCi/ml)	Blank LLD (μCi/ml)	Sample LLD (μCi/ml)
Mo-99	5 E-7	1.66 E-8	1.04 E-7
Ce-141	5 E-7	4.12 E-8	1.83 E-7
I-131	1 E-6	2.65 E-8	-
Cs-137	5 E-7	1.93 E-8	-
Cs-134	5 E-7	2.26 E-8	-
Co-58	5 E-7	1.97 E-8	-
Mn-54	5 E-7	2.02 E-8	-
Fe-59	5 E-7	4.57 E-8	2.46 E-7
Zn-65	5 E-7	5.15 E-8	2.42 E-7
Co-60	5 E-7	3.07 E-8	-

All blank LLDs were an order of magnitude more sensitive than the TS limits. The verification and validation manual for the gamma spectrometry software was reviewed to determine LLD calculational methods. The approach used in the licensee's software was consistent with the TS LLD definition and NUREG/CR-4007 guidance.

The fourth sample obtained for intercomparison was gaseous waste from a waste gas decay tank. The results of the intercomparison are presented in Table 7:

TABLE 7

Waste Gas

Nuclide	DCPP μCi/ml	NRC μCi/ml	NRC Counting Uncertainty μCi/ml	Ratio DCPP/NRC	Agreement Range*
Kr-85m	9.16 E-6	1.47 E-5	4.2 E-6	0.65	0.40-2.50
Xe-131m	1.48 E-3	1.44 E-3	1.4 E-4	1.03	0.60-1.66
Xe-133	1.01 E-1	8.82 E-2	1.7 E-4	1.15	0.85-1.18
Xe-133m	1.09 E-3	1.03 E-3	4.7 E-5	1.05	0.75-1.33
Xe-135	4.09 E-4	3.68 E-4	9.4 E-6	1.11	0.75-1.33

The Agreement was adequate for the waste gas intercomparison.

The fifth sample obtained for intercomparison was a silver zeolyte cartridge sample of containment atmosphere halogens. The results of the analyses are presented in Table 8:

TABLE 8

Silver Zeolyte Cartridge

Nuclide	DCPP μCi/ml	NRC μCi/ml	NRC Counting Uncertainty μCi/ml	Ratio DCPP/NRC	Agreement Range*
Br-82	1.56 E-10	1.77 E-10	1.8 E-11	0.88	0.60-1.66
I-131	5.97 E-10	5.15 E-10	2.2 E-11	1.16	0.75-1.33
I-132	7.42 E-10	6.83 E-10	4.1 E-11	1.09	0.75-1.33
I-133	2.85 E-9	2.42 E-9	4.5 E-11	1.18	0.80-1.25
I-134	4.98 E-10	3.36 E-10	7.0 E-11	1.48	0.50-2.00
I-135	2.13 E-9	1.97 E-10	1.3 E-11	1.08	0.60-1.66

The agreement was satisfactory for the AgZ cartridge measurement. A positive bias may be present in the licensee's measurements with respect to the NRC laboratory due to the licensee's calibration and measurement methods for this sample geometry.

B. Quality Assurance and Quality Control of Radiochemical Measurements

The licensee's Administrative Procedure NPAP C-204/NOS-4.3.9 describes the radiochemical intracompany cross-check program for radiochemistry. Spiked samples were prepared by PG&E Division of Engineering Research and sent to the licensee under a predetermined schedule. Unknowns were prepared for the following sample types: Gross alpha/beta in water and particulates, mixed gamma emitters in water and particulates, and tritium in water. The intercomparison evaluation criteria were substantially similar to those used by the NRC. The inspector noted that the intracompany cross-check program did not provide unknowns for gaseous matrices and halogen sampling cartridges, both of which were important to effluent and radiation protection measurements. Also, radiostrontium unknowns were not provided to test strontium radiochemistry and measurement.

Intracompany cross-check records for the period 1986-1987 were reviewed. Cross-checks were performed in accordance with procedure and the results were acceptable.

Quality control procedures and laboratory records were reviewed for the following instrumentation: Gamma spectrometry, liquid scintillation and internal proportional counters. Appropriate quality control benchmarks and action levels were established according to procedure and instruments were checked against established criteria before use. The inspector noted that the licensee's QC criteria for gamma detector resolution was established in terms of KeV Full-Width-at-Half-Maximum. QC criteria in these units should take into account the expected decrease of detector resolution with increasing gamma ray energy.

No violations or deviations were identified.

9. Post-Accident Sampling System (PASS)

A. Introduction

Fuel damage resulting in the release of radioactive material can occur following a loss of coolant accident (LOCA) or following the loss of available heat sinks. Information obtained by the PASS supplemented by other emergency procedures enable a realistic assessment of the degree of core damage. The purpose of this inspection was to verify the extent to which the DCPP PASS meets the criteria for post-accident sampling presented in NUREG-0737.

B. System Overview

The Piping and Instrumentation Diagram (P&ID) for the DCPP PASS was reviewed. Each DCPP unit has its own PASS system. Each unit can

send a variety of liquid and containment air samples to its own grab sample panel. The liquid samples from a unit were cooled in a sample cooler rack dedicated to that unit. The containment air sample was conveyed in a heat-traced line to the Containment Atmosphere Sampling Panel (CASP). Within the grab sample panel, diluted and undiluted grab samples may be taken and hydrogen and total dissolved gas concentration in the liquid samples determined. Diluted containment air and diluted liquid off-gas samples could also be taken. The liquid sample from the Liquid Sample Panel (LSP) could be directed either to DCPP waste receivers or to the Chemical Analysis Panel (CAP) dedicated to each unit. Containment atmosphere samples were returned to the containment.

The CAP panel at each unit allowed determination of chloride, dissolved oxygen, pH, and conductivity. Analyzed samples leave the CAP and returned to the DCPP waste receivers.

Radioactive samples were contained behind shielding. Highly radioactive samples may be collected in shielded containers. Valve operation was predominantly by extension operated remote manual valves. Indication of sample pressure, flow rate, and temperature was provided. The panel was operated manually and could be used for normal as well as post-accident sampling.

C. Evaluation of NUREG-0737 Compliance

In this section, the DCPP's PASS was compared with the criteria and clarifications given in NUREG-0737. The licensee's compliance with each of the criteria and clarifications were evaluated in Sections 9.C.(1) through 9.C.(11).

(1) This inspection was to verify the licensee's capability to collect and analyze both reactor coolant sample and containment atmosphere sample within the 3-hour time limit. The following applicable licensee's procedures were reviewed:

Number	Title	Revision	Date
EP RB-15:E	PASS Liquid and Gas Sample Handling	3	August 27, 1985
EP RB-15:C	PASS Containment Air Sampling	3	June 21, 1985
EP RB-15:J	PASS Undiluted Liquid Sampling from Reactor Coolant	0	June 25, 1985
CAP G-4	PASS Liquid Sampling - Normal Operation	0	January 14, 1985

The above procedures had received extensive testing by the licensee during technician initial training and retraining and appeared appropriate and workable.

The licensee, using the above procedures, was observed collecting and analyzing reactor coolant samples and containment atmosphere samples. It required 40 minutes to obtain these samples. There were no indications of leakage or system malfunction. The results of quarterly tests of the PASS and the PASS analysis program established that sampling and analysis was successfully completed within the 3 hour time frame. The results were, in general, consistent with those obtained through the normal reactor coolant chemistry analysis. The containment air sample was not analyzed since no meaningful results were expected under the normal plant operating conditions.

An alternative backup power source was provided to assure the ability to meet the 3-hour sampling and analysis time limit. These provisions met the Criterion (1) of NUREG-0737.

(2) The PASS systems can provide diluted samples of liquid, dissolved gases, and containment air for analysis in an on-site counting facility. In addition, both on-site and off-site radiological and chemical analysis capability provide for the 3-hour time frame determination of radionuclides in the reactor coolant and containment atmosphere samples. In-line monitors were provided for pH, dissolved oxygen, dissolved hydrogen, and total gas analysis. Evaluation of analysis range and accuracy is given in Section 9.C.(10). The off-site radiological and chemical analysis facility is located within a few hours driving distance from the DCPP site, and the licensee also has two certified shipping casks. These arrangements meet the NRC requirement for providing post-accident transportion of samples to an off-site facility on a daily basis during the first week of an accident. Based on the above, the licensee met Criterion (2) of NUREG-0737.

(3) NUREG-0737 Criterion (3) requires that reactor coolant and containment atmosphere sampling during post-accident conditions not require placing an isolated auxiliary system (e.g., the letdown system, etc.) in operation in order to obtain samples. Review of the PASS P&ID established that post-accident sampling, including recirculation, from each sample source was possible without use of an isolated auxiliary system. The licensee indicated that valves, not accessible after an accident, were environmentally qualified for conditions in which they must operate. Independent verification was not possible during this inspection.

(4) The PASS determines total dissolved gas and dissolved hydrogen by analyzing the gases released from a cooled sample of liquid, obtained at full system pressure. Dissolved oxygen is measured in a stream of depressurized, cooled liquid.

The method for determining the reactor coolant hydrogen content and total gas content with the Sentry-manufactured system had been reviewed and accepted by the NRC staff. The dissolved

oxygen content was measured with a commercial Orbisphere dissolved oxygen analyzing system in which cooled, depressurized liquid sample flows past an oxygen sensing probe. This instrument provided measurements within minutes after flow through the sample cell had begun. The inspector concluded that the licensee's PASS system had the capability to determine dissolved oxygen in a reactor coolant sample well within the NUREG-0737 30-day requirement. Although this analyzer can measure from 1 ppb (0.001 ppm) up to 20 ppm, its actual accuracy was not verified during this inspection. However, a review of the licensee's administrative procedures and records indicated that the instrument was properly calibrated and within the calibration period.

(5) DCPP Units 1 and 2 have two barrier protection between the reactor coolant and the sea cooling water. The inspector found that it was acceptable for the licensee to complete chloride analysis within 96 hours of an accident. In addition, the chloride analysis does not have to be done on-site. The accuracy of the chloride analysis is discussed in Section 9.C.(10).

(6) The Criterion (6) of NUREG-0737 requires that the design bases for plant equipment for reactor coolant and containment atmosphere sampling and analysis must assure that radiation exposures to any individual do not exceed the criteria of GDC 19 (Appendix A, 10 CFR Part 50) (i.e., 5 rem whole body, 75 rem extremities). The design and operational review criterion was changed from the operational limits of 10 CFR 20 (NUREG-0578) to GDC 19 criterion as stated in the letter from H. R. Denton, NRR, to all licensees dated October 30, 1979.

The Sentry PASS system, installed at both units, was reviewed by the Chemical Engineering Branch, NRR, which determined that it met the NRC exposure guidelines. The basic man-dose analysis was included in Section 13 of the vendor's B10-01 specification. The source terms used were based on the worst case and conservative, in that 100 percent of the noble gas inventory was assumed to be in the reactor coolant volume and also in the containment atmosphere. The source terms were consistent with Regulatory Guide 1.4 for PWRs.

Several modifications had been made in the Sentry PASS systems by the licensee, such as replacing the L&N pH probe with a Beckman probe, the Beckman specific conductivity cell was replaced with a L&N specific conductivity cell, the YSI dissolved oxygen monitor was placed with an Orbisphere dissolved oxygen monitor, and all remote source isolation valves were replaced with Nupro valves, these modifications would not effect the staff's conclusion relating to exposure guidelines. The licensee had conducted an evaluation of shielding requirements for exhaust systems and components outside containment, located in or near the PASS stations, which could become source terms under accident conditions. The

licensee had also determined the tolerable leakage from the Sentry PASS and incorporated these values into leakage surveillance test procedure (STP-M-86 series) as acceptance criteria. The inspector determined that the PASS systems met Criterion (6) of the NUREG-0737.

(7) The PASS has the capability of providing both diluted and undiluted reactor coolant samples which could be used for boron analysis. This was confirmed by reviewing the licensee's weekly analysis reports using the PASS systems at both Units 1 and 2. In addition, the inspector witnessed the collection of reactor coolant samples using the Unit 1 PASS for boron and chloride analysis. The PASS met Criterion (7) of NUREG-0737. The accuracy of boron analysis is discussed in Section 9.C.(10).

(8) The PASS was equipped with in-line monitors for pH, chloride, dissolved hydrogen, oxygen, and total gas concentrations. Grab samples were also provided for liquid gross activity analysis, gamma spectroscopy, boron content and for containment air gamma spectrum.

Reactor coolant pH and chloride backup was provided by the undiluted grab sample. The inspector noted that diluted reactor coolant sample should not be used as backup for pH verification because of the high uncertainty introduced. In addition while a number of diluted liquid samples could be used as backup for chloride analysis, it would be undesirable.

Backup capability for gas concentrations in the reactor coolant could not be meaningfully verified by any grab samples obtained with the PASS. However, the containment air sample for isotopic analysis could be used for containment atmosphere hydrogen analysis.

To reduce possible plateout, crud buildup, and radiation exposure of components, the licensee provided in-line monitor flushing capability, and the panel tubing and monitors were thoroughly flushed after every panel exercise. The inspector verified that the licensee has the capability to ship and obtain offsite analysis, of one sample per day for seven days following onset of the accident and at least one sample per week thereafter. These provisions demonstrated that the licensee's PASS systems met the Criterion (8) of NUREG-0737.

(9) The design and hardware of the Sentry PASS system was reviewed by the staff and found to be capable of collecting reactor coolant samples for chemical and radiochemical analysis. The inspector observed the licensee collecting an undiluted reactor coolant sample from Unit 1 for activity determination and radionuclide analysis. The licensee demonstrated the capability of both collecting and analyzing the sample within the required 3-hour time limit. The inspector also verified that the sensitivity of on-site liquid sample analysis

permitted measurement of radionuclide concentration to 10^{-4} µCi/g. The sensitivity met the 1 µCi/g requirement of Criterion (9) of NUREG-0737.

The inspector verified that background levels of radiation in the radiological and chemical analysis stations from sources were such that the sample analysis provided results with an acceptably small error (approximately a factor of 2).

(10) Criterion (10) of NUREG-0737 required licensee's PASS system to have adequate accuracy, range, and sensitivity to provide pertinent data to the operator in order to describe radiological and chemical status of the reactor coolant systems.

- Gross activity and gamma spectrum (for core damage estimation).

  The licensee demonstrated an analytical accuracy within a factor of 2. This is consistent with the Criterion (10) of NUREG-0737.

- Boron (for shutdown margin verification)

  The clarification of NUREG-0737 Criterion (10) stated that, in general, the boron analysis should be accurate with ±5% of the measured value and for concentrations below 1,000 ppm, the tolerance band should remain at ±50 ppm. By letter dated July 24, 1984, the licensee indicated that its boron analysis was ±20% when greater than 100 ppm. The inspector further clarified with the licensee that this remained true of its current analysis. The licensee also stated that the boron concentration in the reactor coolant was kept routinely at about 2000 ppm, post-accident, while the calculated boron concentration for safe shutdown was about 1300 ppm, therefore, an accuracy of ±20% for boron analysis would be acceptable. In view of the fact that there was no assurance that 2000 ppm or more of boron would always be present in the reactor coolant, post-accident, to insure sufficient shutdown margin, the inspector determined that ±20% accuracy for boron analysis did not meet the latest clarification (June 30, 1982) of the requirement of NUREG-0737. The licensee's results on reruns of three standard boron samples provided by the inspector showed an accuracy of -1%, +5%, and -4% for 3 analyses, respectively. The results of the licensee's analysis of NRC standard solutions is addressed in Report Section 5.B, Table 2.

  The licensee letter of July 24, 1984, PG&E Letter No. DCL-84-271, stated in Table 1, "Initial Demonstration Acceptance Guidelines," with respect to boron that the analytical accuracy was ±20% when the boron concentration

was greater than 100 ppm. A footnote to the guideline with respect to boron stated that, "The ±20% guideline for boron analysis meets the intent of Criterion (10) of NUREG 0737, Item II.B.3, which states, 'Accuracy, range and sensitivity shall be adequate to provide pertinent data to the operator in order to describe radiological and chemical status of the reactor coolant systems.' Additionally, the stated accuracy of the carminic acid spectrophotometric method from a recognized evaluation of the method is ±15% with a footnote which states, 'In the procedure presented, uncertainty of the method was not included; based on professional judgment the uncertainty has been estimated at ±20%,' from 'Evaluation of GE & SEC Chemical Procedures for Post Accident Analysis of Reactor Coolant Sample, November 1981.' Prepared by Exxon Nuclear Idaho Company, Inc., Idaho National Engineering Laboratory, Idaho Falls, Idaho, for the Nuclear Regulatory Commission. Table 5 on page 30. A guideline narrower than ±20% will require installation of new hardware."

Supplement No. 31 to NUREG-0675, "Safety Evaluation Report related to the operation of Diablo Canyon Nuclear Power Plant, Units 1 and 2, Docket Nos. 50-275 and 50-323," addressed the PASS in Section 4.19, page 4-33. The report stated, "In SSER 14 (April 1981) the staff reported on its evaluation of the Diablo Canyon post accident sampling system (PASS) and found the system design acceptable." It further stated, "By letters dated July 24 and 26, 1984...PG&E informed the staff of the completion of tests, procedures, training and operability of the PASS for Unit 1." The report continued with discussion of the Unit 2 Sentry PASS referencing several letters related to the Unit 2 system. The report concluded with the statement, "The staff has reviewed the information above and has determined that the Unit 2 PASS meets the intent of NUREG-0737 Section II.B.3 and, therefore, is acceptable."

- Chloride (to assess the propensity for stress corrosion cracking)

For concentrations between 0.5 and 20.0 ppm chloride the analysis should be accurate within ±10% of the measured value. At concentrations below 0.5 ppm the accuracy remains at ±0.05 ppm. Analyses performed by the licensee on reruns of standard chloride samples provided by the inspector showed an accuracy of +7% and +6% for two analyses. The presence of high concentrations of hydrogen during an accident would keep the dissolved oxygen extremely low. Under this condition, chloride-induced stress corrosion cracking would be unlikely to occur. The results of the licensee's analysis of NRC standard solutions are addressed in Report Section 5.B.

- Hydrogen and Total Gas (for core damage estimation)

The Sentry PASS system was evaluated by the staff based on the vendor's calculations which showed that the system is expected to survive the radiation and chemical environment of an accident, and is therefore capable of providing analysis with an accuracy of ±20% between 50 and 2000 cc/Kg of H_2 or total gas.

- Oxygen (to assess the propensity of stress corrosion cracking)

  The licensee's PASS systems use the Orbisphere probe for dissolved oxygen analysis. This instrument was used in the TMI high radiation coolant environment and demonstrated good performance. Therefore, it was expected that the probe would perform satisfactorily in an accident condition.

- Standard Test Matrix

  The latest clarification of NUREG-0737 Criterion (10) (June 30, 1982) required that information be provided to demonstrate that the PASS procedures and instrumentation would achieve the required accuracies in a standard test matrix. However, the licensee stated that the test matrix had not been used in the evaluation of the PASS. The clarification of NUREG-0737, requiring the use of the Standard Test Matrix for Undiluted Reactor Coolant Samples in a Post-Accident Environment, was contained in letters to licensees dated June 30, 1982. Based on an examination of records, it cannot be demonstrated that the June 30, 1982, clarification of NUREG-0737 was sent to PG&E with respect to the Diablo Canyon facilities. In Supplement No. 14 of NUREG-0675, Safety Evaluation Report, dated April 1981, "Discussion and Conclusions - Postaccident Sampling - ALARA Evaluation," on pages 3-12, the report states, "Based on our evaluation, we find that the design meets the requirements of NUREG-0578, 0737 and Regulatory Guide 8.8 is therefore acceptable." Further in Supplement No. 31, NUREG-0675, Safety Evaluation Report dated April 1985, 4.19 Post Accident Sampling System (II.B.3), pages 4-33, the report stated, "The staff has reviewed the information above and has determined that the Unit 2 PASS meets the intent of NUREG-0737 Section II.B.3 and, therefore, is acceptable."

In an attempt to evaluate the representative nature of the Unit 1 PASS sampling, the licensee performed gamma spectrum analyses of a routine reactor coolant and a PASS reactor coolant samples. The comparison was not ideal in that the routine sample had been degassed while the PASS sample had not been degassed. In addition, the two samples were not collected concurrently, 12 hours having elapsed between the collection of the two samples. The results of the gamma analyses were

compared using the same methodology used to compare the licensee's and NRC analytical results. (See Attachment 2).

Gaseous Nuclides in Disagreement

Nuclide	Pass µCi/ml	Routine µCi/ml	Routine Counting Uncertainty µCi/ml	PASS/ Routine	Agreement Range
Xe-133	4.74 E-1	9.48 E-2	1.4 E-3	5.0	0.8-1.25
Kr-85m	1.13 E-2	2.55 E-3	2.4 E-4	4.4	0.6-1.66
Kr-88	2.20 E-2	4.86 E-3	8.6 E-4	4.5	0.5-2.0
Xe-135	6.45 E-2	1.51 E-2	3.4 E-4	4.3	0.75-1.33
Kr-87	9.00 E-3	1.42 E-3	6.0 E-4	6.3	0.4-2.5

Short-Lived Nuclides in Disagreement

Nuclide	Pass µCi/ml	Routine µCi/ml	Routine Counting Uncertainty µCi/ml	PASS/ Routine	Agreement Range
Rb-88 (17.8M)	3.02 E-2	8.35 E-3	1.6 E-3	3.6	0.5-2.0
Na-24 (15 HR)	1.43 E-3	5.75 E-4	1.4 E-4	2.5	0.5-2.0

Other Disagreements

Nuclide	Pass µCi/ml	Routine µCi/ml	Routine Counting Uncertainty µCi/ml	PASS/ Routine	Agreement Range
Co-58	4.02 E-5	2.25 E-4	9.1 E-5	0.2	0.4-2.5 (High counting uncertainty)
Mn-54	2.59 E-3	6.64 E-4	1.2 E-4	3.9	0.5-2.0

Nuclides Within Agreement Range

Nuclide	Pass µCi/ml	Routine µCi/ml	Routine Counting Uncertainty µCi/ml	PASS/ Routine	Agreement Range
I-131	2.91 E-3	2.94 E-3	2.4 E-4	0.94	0.6-1.66
I-133	6.33 E-3	6.03 E-3	2.6 E-4	1.16	0.75-1.33
Cs-137	4.37 E-4	2.95 E-4	1.3 E-4	1.87	0.4-2.50
I-132	6.81 E-3	6.85 E-3	4.1 E-4	0.99	0.75-1.33
I-134	1.08 E-2	1.03 E-2	1.1 E-3	1.05	0.6-1.66
I-135	9.35 E-3	9.31 E-3	8.7 E-4	1.00	0.6-1.66
Ba-139	4.76 E-3	2.94 E-3	1.6 E-3	1.62	0.4-2.50
Cs-138	2.87 E-2	2.36 E-2	2.7 E-3	1.23	0.5-2.00
Cs-134	5.40 E-4	3.09 E-4	1.0 E-4	1.56	0.4-2.50

Based on the comparison, it appears that the PASS reactor coolant sample was representative and comparable to the routine sampling system.

(11) The licensee's PASS systems were designed for purging of the liquid sample lines and heat tracing of the gas sample lines to reduce plateout. In addition, HEPA filters and charcoal absorbers were installed in the ventilation system. These provisions met Criterion (11) of NUREG-0737.

D. Conclusion

Based on the results of the inspection and an examination of applicable documents, it was found that the licensee's PASS systems meet the intent of NUREG-0737. The licensee had established acceptable training and retraining programs for the PASS technicians. The licensee also implemented several administrative control measures, such as the status boards displayed in both Unit 1 and Unit 2 PASS stations to identify instrumentation calibration status, etc., which the inspector felt that they would improve the reliability of the PASS systems.

10. Exit Interview

At the conclusion of the inspection, the scope and content of the inspection was discussed with the individuals identified in report section 1. At that time the licensee was informed that no violations or deviations were identified. However, the licensee was informed that an unresolved item had been identified in connection with Criterion (10) of NUREG-0737, concerning the boron analysis and the use of the standard test matrix (report Section 9.C.10). Subsequent examination of the NUREG-0737 clarifications applicable to Diablo Canyon, established that the criteria were not applicable to this facility. Therefore, no unresolved item has been identified with respect to these matters.

In the area of chemistry measurement control, it was noted that the laboratory was unable to identify some anomalies in the measurement systems used when NRC standards were analyzed. It appeared that full implementation of the laboratory QA/QC program would be effective in resolving these matters. It was noted that a significant improvement occurred when the NRC standards were rerun.

With respect to the erosion/corrosion evaluation program, the licensee instituted a program prior to the Surry 2 event and promptly added the surveillance of single phase systems to the earlier two phase system program following that event. With respect to the findings at Unit 1, the inspector believed that the actions taken when pipe wall thinning to 68% of the nominal pipe wall thickness was identified may not have been in the conservative direction (report Section 7.B). In general, the inspector found the program to be above the industry standard.

It was the consensus of the participating inspectors that the separation of the chemistry and radiation protection functions would provide a

lasting benefit in the area of quality and professionalism of the chemistry staff.

ATTACHMENT 1

CRITERIA FOR COMPARING ANALYTICAL MEASUREMENTS

This attachment provides criteria for comparing results of capability tests. In these criteria, the judgement limits are based on the uncertainty of the ratio of the licensee's value to the NRC value. The following steps are performed:

(1) the ratio of the licensee's value to the NRC value is computed

$$\left(\text{ratio} = \frac{\text{Licensee Value}}{\text{NRC Value}}\right);$$

(2) the uncertainty of the ratio is propagated.[1]

If the absolute value of one minus the ratio is less than or equal to twice the ratio uncertainty, the results are in agreement.

($|1\text{-ratio}| \leq 2$ uncertainty)

[1] $Z - \frac{x}{y}$, then $\frac{S_z^2}{Z^2} = \frac{S_x^2}{x^2} + \frac{S_y^2}{y^2}$

[1](From: Bevington, P. R., Data Reduction and Error Analysis for the Physical Sciences, McGraw-Hill, New York, 1969.)

ATTACHMENT 2

CRITERIA FOR ACCEPTING THE LICENSEE'S MEASUREMENTS

Resolution	Ratio
<4	0.4 - 2.5
4 - 7	0.5 - 2.0
8 - 15	0.6 - 1.66
16 - 50	0.75 - 1.33
51 - 200	0.80 - 1.25
200	0.85 - 1.18

Comparison

1. Divide each NRC result by its associated uncertainty to obtain the resolution. (Note: For purposes of this procedure, the uncertainty is defined as the relative standard deviation, one sigma, of the NRC result as calculated from counting statistics.)

2. Divide each licensee result by the corresponding NRC result to obtain the ratio (licensee result/NRC).

3. The licensee's measurement is in agreement if the value of the ratio falls within the limits shown in Table 8 for the corresponding resolution.