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SUBJECT: Board Notification 84-071:forwards draft investigation rept/ insp rept & draft summary of findings resulting from followup of IT Yin allegations & NRC independent overview.

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

APR 3 1984

Docket Nos.: 50-275
and 50-323

MEMORANDUM FOR: Chairman Palladino
Commissioner Gilinsky
Commissioner Roberts
Commissioner Asselstine
Commissioner Bernthal

FROM: Darrell G. Eisenhut, Director
Division of Licensing
Office of Nuclear Reactor Regulation

SUBJECT: DIABLO CANYON - INFORMATION ITEMS (BOARD NOTIFICATION NO. 84-071)

In accordance with current NRC procedures, the following information is provided to the Commission:

1. "Draft Investigation/Inspection Report," (Rev. 3-3/29/84) Prepared by I. T. Yin, NRC, Region III

2. "Draft Summary of Findings Resulting from Followup of Allegations and NRC Independent Overview (3/29/84), Prepared by I. T. Yin, NRC, Region III

The above Diablo Canyon draft inspection report and complementary draft summary are relevant to the concerns presented to the Commission during the Diablo Canyon meeting March 26-27, 1984 by Mr. I. T. Yin. They bear on issues being considered by the Advisory Committee on Reactor Safeguards (ACRS) at the request of the Commission.

The release of this draft inspection material is an exception to our normal policy with respect to issuance of draft inspection reports and is made without review of the documents. The documents are subject to possible revision during the normal staff review process. The Executive Director for Operations has authorized the release of the information for the narrow purpose of permitting the ACRS to advise the Commission on these matters on a schedule consistent with the Commission request.

N005

8403140266

By copy of this memorandum, we are also providing the Atomic Safety and Licensing Appeal Board and parties to the proceeding with this information.

Darrell G. Eisenhut, Director
Division of Licensing
Office of Nuclear Reactor Regulation

Enclosure:
As stated

cc: J. F. Wolf, ASLB
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J. Kline, ASLB
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DRAFT

DIABLO CANYON 1

SUMMARY OF FINDINGS RESULTING

FROM FOLLOWUP OF ALLEGATIONS AND

NRC INDEPENDENT OVERVIEW

Prepared by: I. T. Yin

3/29/84

Docket #50-275
Control #8403140266
Date 4/3/84 of Document
REGULATORY DOCKET FILE

Item Description (Affecting L/B, S/B, or Both)	Paragraph	Page No.
A. Against Criterion II		
There were inadequate provisions in the program for personnel indoctrination and training. The S/B pipe support engineers were not familiar with important elements in both the QA and technical programs.		
1. In the area of general technical and QA training, the program permits personnel performing safety-related design work w/o training up to 30 days. (L/B and S/B)	I.B.3.b	18-22 26
2. No measures or program provisions established to ensure adequate special training for the working staff on matters such as procedure revisions and problem trendings. (L/B and S/B)	I.B.3.c	22-25 26

B. Against Criterion XVI

QA program deficiencies and design nonconformances had not been identified and correctly promptly.

1.	Site design organization management was insensitive to staff concerns, and did not initiate timely corrective actions. (S/B)	I.C	27-29
2.	Lack of project timely response to PG&E QA findings. The delays were w/o justification. (S/B)	II.F.3.d. (1)(a)	92
3.	Lack of PG&E management attention to ensure timely responses to the audit findings. (S/B)	II.F.3.d. (1)(b)	92-93
4.	Bechtel audit finding corrective action scheduled completion dates were delayed without documented justification. (S/B)	II.F.3.d. (1)(c)	93
5.	Lack of PG&E audit finding corrective actions to identify the cause of the problem and the measures needed to prevent recurrence. (S/B)	II.F.3.d. (1)(d)	93

6.	Project corrective action only addressed specific problem areas identified in the PG&E audit findings and did not consider generic implication of the problems. QA concurred with this apparently inadequate corrective action. (S/B)	II.F.3.d. (1)(e)	93
7.	Inadequate Bechtel QA verification of OPEG corrective actions prior to close-out of audit findings. OPEG Personnel training continued to be inadequate. (S/B)	II.F.3.d. (1)(f)	94
8.	Lack of PG&E QA program measures to evaluate the effects of program efficiencies resulting in long delay of QA finding corrections prior to IDVP and CAP actions. (L/B and S/B)	II.F.3.d. (1)(g) II.F.3.d. (1)(h)	94 94-95

C. Against Criterion VI

Document control deficiencies were observed at the site design organizations.

1.	Engineers were using out-of-date procedures for performing calculations. (S/B)	I.A.3.b.	10-12

2.	Inter-office memorandums were issued in lieu of procedures that bypassed review and approval process. (S/B)	I.A.3.c.	12-13
3.	Site Quality Engineer and Support Group Leader maintained outdated listings of the latest work procedure. (S/B)	I.A.3.d.(2)	15
4.	Design personnel was performing calculations without having adequately controlled procedures for extended periods of time. (S/B)	I.A.3.d.(1)	14-15

D. Against Criterion V

There had been inadequate or lack of procedures for the design organizations.

1.	Lack of provision to handle and resolve field initiated design questions and requests by the PG&E home office. (L/B and S/B)	II.E.	76-79

2.	Lack of prescription of the limited conditions where piping thermal stresses could be released by installation of gaps within rigid restraints. (L/B and S/B)	II.B.2.b	63-66
3.	Inadequate stress walkdown inspection program to ensure freedom of interferences. Procedures did not fully incorporate IEB 79-14 requirements, and the acceptance criteria were relying on design piping movement predictions that were not always observed to be accurate. (L/B and S/B)	I.E.	39-47
4.	Ways that support joint loading can be reduced at structure connection were not prescribed. Unacceptable pin joint models were observed. (S/B)	I.D.3.b.(4)	34-35
5.	Lack of "Tolerance Clarification" procedural prescription on what could be "quickly fixed" at site without major revision of the existing calculations. (L/B and S/B)	I.G.	48-55

6.	Lack of sufficient references and engineering data for the site engineers to perform calculations that had resulted in personnel reliance on uncontrolled outside materials. (S/B)	I.A.3.c.	12-14

E. Against Criterion V

Deficiencies observed that could have been the results of personnel not following the procedures.

1.	Lack of S/B support calculation checks resulted in errors unrevealed. (S/B)	II.B.1.d. (1), (2)	57-60
		I.G.3.c.(4)	51-52 55
2.	"Preliminary" data identification and subsequent review of the calculation against final data were not done. (S/B)	II.B.1.(e) (1)	60-61
3.	Personnel Training was not requested by the supervisors in a timely manner. (S/B)	I.B.3.b.	18-22 26

4.	Stress walkdown inspections failed to identify all unintentional piping restraints. (L/B and S/B)	I.E.	39-47

F. Against Criterion III

There had been design control deficiencies identified during the program review and hardware inspections.

1.	Design criteria conflict in control of pipe support structural frequencies. (L/B and S/B)	II.A.	56
2.	Inadequate design evaluation of as-built deviations from design. (S/B)	I.G.3.c.(4)	51-52 55
3.	Lack of program provisions to control preliminary design data provided through telephone, and to verify the calculation against subsequent final data when made available. (S/B)	II.B.1.(e) (1)	60-61
4.	There was no design consideration for synchronizing loading between closely spaced rigid/rigid restraints, and rigid restraint/anchors. (L/B and S/B)	II.B.1.(e) (2) II.C.3	61-62 71

5.	Snubbers were inoperable due to placing them in close proximity with rigid restraints and anchors. (L/b and S/B)	II.C. II.D.	66-71 71-76
6.	Lack of ALARA considerations associated with the use of snubbers. (L/B and S/B)	II.C. II.D.	66-71 71-76
7.	Lack of documented design interface procedure for OPEG Piping Stress Group and Pipe Support Group. (S/B)	I.D.3.b. (5)	37-38
8.	Support field design change breakdown - Quick acceptance and fixes of design deviations bypassed measures including prior calculations made, review, and approval. There had been thousands of supports being "fixed" this way. (L/B and S/B)	I.G.	48-55

G. Against Criterion XVIII

Inadequate licensee technical QA audits and surveillances to identify and correct the design control and program deficiencies revealed during this inspection/investigation.

1.	When a QA audit item could not be evaluated due to a lack of project activities, followup of the item was not planned. (S/B)	II.F.3.d. (2)(a)	95
2.	Lack of QA audit documentation of specific materials reviewed that leads to closing out of the audit findings. (S/B)	II.F.3.d. (2)(b)	95
3.	Lack of QA documentation of materials reviewed during the conduct of the audit. (S/B)	II.F.3.d. (2)(c)	95-96
4.	Lack of technical QA audits to independently verify that OPEG calculation inputs were checked to be in compliance with engineering procedures. (S/B)	II.F.3.d. (2)(d)	96
5.	Auditor did not take the initiatives to investigate why there had not been any Discrepancy Reports issued by the site design group. (S/B)	II.F.3.d. (2)(e)	96-97

6.	Relative to a document control audit, the auditor discovered that, since March, 1983, the control of OPEG procedures was conducted at the PG&E and Bechtel, San Francisco offices. There was no attempt made to revise the audit checklist to cover these activities. (S/B)	II.F.3.d. (2)(f)	98
7.	Relative to the same document control audit, the checklist was modified to cover the subject OPEG activities, 10 mo. later, the benefit of timely audit to ensure program compliance had been compromised. (S/B)	II.F.3.d. (2)(f)	98-99

H. Against Criterion VII

Inadequate PE&E and Bechtel control of procured engineering services.

1.	Lack of procedure to ensure effective design interface between PG&E and W. (L/B)	II.G.4.b.	108
2.	Lack of DCP control of procedures to be used by the contractors.	II.G.5	108

a. Lack of measures to ensure that contractors had received required design criteria. (L/B)

b. Lack of justification on unrequired criteria and procedures being sent to the contractors. (L/B)

3.	Relative to DCP audit of contractors, technical audits of Imprell, Cygna and W had not been performed. (L/B)	II.G.6.a.	108
4.	Design procedures and instructions utilized by Imprell, Cygna, and W had not been reviewed and approved by the PG&E and Bechtel engineering and QA departments. (L/B)	II.G.6.b.	109
5.	PG&E did not perform QA program type audits of W in 1983, when most of the CAP analytical work was carried out. (L/B)	II.G.6.c.	109

6.	The PG&E QA program audit of W, No. 20506, "Seismic Re-Verification", conducted on May 25-28, 1982; did not include a review of piping analysis and pipe support calculation to ensure implementation of procedural requirements. (L/B)	II.G.6.d.	109
7.	Relative to contractor internal audits, Cygna technical review for design analysis and calculation was questionable. (L/B)	II.G.7.b.	111-112
8.	Relative to contractor internal audits, the W QA program type audit was considered to be inadequate and deficient. (L/B)	II.G.7.c.	112-113
9.	Relative to contractor internal audits, there had not been any technical audits conducted by W. (L/B)	II.G.7.c.	112-113

DRAFT

THIS REPORT IS INCOMPLETE

AND CONTAINS PRELIMINARY INFORMATION

DIABLO CANYON 1

DRAFT INVESTIGATION/INSPECTION REPORT

Prepared By: I. T. Yin

Rev. 0, 2/28/84

Rev. 1, 3/12/84

Rev. 2, 3/23/84

Rev. 3, 3/29/84

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INVESTIGATION AND INSPECTION EFFORT

Dates	Location	Inspector-Hours Spent
11/29-30/83	Site	20
12/1-3/83	Site	27
12/5-8/83	Site	40
12/14-15/83	Meetings w/NRR and PG&E at NRC, Bethesda, MD	8
1/5-6/84	Site	18
1/9-13/84	Bechtel, San Francisco, CA	40
1/23-25/84	Meeting w/NRR and Attending Congressional Hearing	24
1/31/84	Meeting w/licensee at PG&E, S.F., CA	8
2/1-3/84	Bechtel, S.F., CA	24
2/7/84	Meeting w/NRR at NRC, Bethesda, MD	8
2/15-17/84	Bechtel and PG&E, S.F., CA	24
2/22-24/84	Bechtel and PG&E, S.F., CA	26
3/5-8/84	Site	28
3/14-16/84	Bechtel, S. F., CA	12
3/26-27/84	Meeting w/NRR and Attending Commission Hearing	16
3/28/84	Meeting w/PG&E at NRR Office	5

PERSONS CONTACTED

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M. E. Leppke, Onsite Project Engineer, OPEG

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M. H. Lee, Piping Stress Group Leader

G. K. Wang, Staff Engineer

V. Juneja, Piping Support Group Leader

S. S. Chitnis, Supervisor, Plant Design

W. T. Kellermann, QA Manager, Programs and Audits

C. H. Nichols, Engineering Supervisor

R. W. Darcy, QA Supervisor, Training

C. W. Dick, Management

H. Friend, Project Management

R. Tinkle, Lead Mechanical Engineer, Unit 1

R. Nasadowski, Engineer

L. Mangoba, Pipe Support Group Leader, OPEG

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G. Spease, Onsite Quality Engineer

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Pace

L. Tripsianes, Stress Analyst

FUNCTIONAL OR PROGRAM AREAS INSPECTED

I. Followup on Allegations

A. Allegation No. 79, ATS No. RV83A063, BN No. N/A

1. Characterization

Site design engineers were not required to use controlled documents in the performance of their work. This resulted in different calculation bases, load ratings, and allowable stresses being used in small bore (S/B) piping analyses.

2. Implied Significance to Design, Construction, or Operation

Without uniform design bases, formulations, and acceptance criteria, the adequacy of plant system safety could not be verified and assured.

3. Assessment of Safety Significance

a. Individuals Interviewed

There were 30 hanger engineers and 25 piping stress engineers working at the site. Three engineers from each group were selected for interview. Length of employment at the site

was used as the criteria for selection. In each group the oldest engineer, the newest engineer and an engineer with an intermediate length of employment was selected for interview. The initials of the 6 engineers are:

Support Design Group

Names	Initials	Began Work
Moisey Shoikhet	MS	October 1982
Manmohan Durani	MD	April 1983
Shahran Aram	SA	September 1983

Piping Stress Group

Names	Initials	Began Work
Stan Jacques	SJ	April 26, 1982 (assigned as pipe stress engineer)
John Reas	JR	February 1983
Suresh Soorma	SS	November 1983

b. Maintenance of Out-of-date Work Procedures

(1) On December 2, 1983, the inspector interviewed MS at his work station and observed the following:

- PG&E Design Criteria Memorandum (DCM) No. M-9, "Guidelines for Design of Class 1 Pipe Support: Units 1 and 2 Diablo Canyon Power Plant." Both Revision 6 and Revision 8 (dated August 10, 1983) were being kept. At the time of this inspection the latest revision was Revision 9, dated November 18, 1983.

- PG&E Document No. 049243, "Piping and Mechanical Standard Pipe Support for Design Class 1 Piping 2" and Smaller." Revision 14, dated July 29, 1983, was the latest revision. MS was maintaining both Revision 14 and Revision 12.

(2) On December 2, 1983, the inspector interviewed MD at his work station and observed the following:

- PG&E Document No. 049243, "Piping and Mechanical Standard Pipe Support for Design Class 1 Piping 2" and Smaller." Revision 14, dated July 29, 1983, was the latest revision. MD did not have Revision 14. He was using Revision 12, dated January 12, 1972.

(3) On December 5, 1983, the inspector interviewed SS, the Piping Stress Group Deputy Group Leader, and

observed that there was only one set of controlled procedures being maintained for use by the Piping Stress Group. Six procedures were selected for review from the latest listing, dated October 28, 1983. Procedure Nos. P3, P11, and P19 were observed to be up-to-date. Procedure No. P1, Rev. 0 was in the manual, Rev. 2 was the latest revision. Procedure No. P2 was in the manual; however, it was listed as inactive. Procedure No. P9, both Rev. 0 and Rev. 1 (the current revision,) were in the manual. These controlled procedures were assigned to the Piping Stress Group Leader.

c. Maintenance of Unauthorized Technical Articles and Data

(1) On December 2, 1983, the inspector interviewed MS at his work station and observed the following unauthorized documents:

- Bechtel SFPSM-3.12.1, "Frequencies, Stiffness and Deflection Requirements," Revision 0, dated July 14, 1980

- Bechtel Inter-Office Memorandum (IOM) File No. 925, "Guidelines in the Design of Skewed Welds," dated March 21, 1983

- Westinghouse Nuclear Technology Division Data for calculating double cantilever deflections, no sign-offs and date

- Bechtel Gaithersburg STRUDL II Computer Program Users Manual, CE901, dated November 3, 1982

- Bechtel Gaithersburg IOM, from T. C. La Croix to Pipe Support Group Leaders, "GPD Pipe Support Group Newsletter No. 5, Proper Treatment of Beta Angle in STRUDL Input for Structural Analysis of Frames," dated November 11, 1980

- Uncontrolled Form, "STRUDL Input for Best Choice of 2 Loading Cases."

(2) On December 2, 1983, the inspector interviewed MD at his work station, and observed the following unauthorized materials:

- Control Data Corporation, Bechtel National Support Manager to Civil/Structural Projects and Staff, "Baseplate II Usage Aids," dated March 14, 1983

- Midland Nuclear Power Plant, "Pipe Deflection Formula"

(3) On December 3, 1983, the inspector interviewed SA, the Support Group Design Lead Engineer, and reviewed Calculation No. MP-1691 for Hanger No. 97-90 that was checked by SA for the as-built condition. The inspector observed that the hanger installation calculation was performed by Mr. V. Ghiya (VG), and checked by Mr. A. Ghose (AG). In the area of hanger deflection, the formula used by VG was based on a McGuire Nuclear Station "Deflection Formula," dated September 25, 1980. To check the design adequacy, AG used a United Engineers Pipe Support Design Standard, dated August 15, 1979.

d. Design Procedure System Deficiencies

The following findings were identified:

(1) DCM M-9, Control No. P-149 was assigned to MS, and Control No. P-126 was assigned to MD. Stress Manual Procedures (Control No. P-75) were assigned to R. R. Grey. Discussions with the On-site Project Engineering Group (OPEG) Quality Engineer, identified that these documents were controlled at the Project Administration Office in San Francisco. No record was kept as to when the first issue was sent to the site for use. The inspector was unable to determine how long the site staff was working without controlled procedures.

During a meeting held at NRC, Bethesda, MD on December 15, 1983, the inspector was informed that Control No. P-149, and Control No. P-126 were received by MS, and MD, respectively, on September 1, 1983. Since MS began work in October 1982, he accomplished his work without a controlled copy of procedure No. M-9 for approximately 11 months. Since MD began work in April 1983, he accomplished his work without a controlled copy of procedure No. M-9 for approximately 5 months. As for the manual with Control No. P-75, the complete manual was not available for the Piping Stress Group until May 2, 1983. People like SJ who started work at Diablo Canyon in April 1982 could have been working without controlled procedures for more than one year.

(2) The latest listing of all the procedures was dated October 28, 1983, and was maintained by Mr. M. Leppke. The listing of procedures maintained by the Quality Engineer, and by Leo Mangoba, the Support Group Leader, were dated September 15, 1983.

(3) Some confusion was encountered during the inspector's review, i.e., several procedures and drawings are maintained at PG&E Document Center, others are maintained at OPEG Document Center, and still others are maintained at the PG&E and Bechtel San Francisco offices.

4. Staff Position

The staff concluded that the administrative controls imposed on the site engineering activities have been inadequate and ineffective. The specific allegation items were substantiated.

B. Allegation No. 82, ATS No. RV83A063, BN No. N/A

1. Characterization

There was minimal training for onsite pipe support engineers.

2. Implied Significance to Design, Construction, or Operation

Without adequate indoctrination and training, piping stress and support design engineers may not effectively perform their assignments.

3. Assessment of Safety Significance

This issue was addressed through examination of training requirements, implementation records, interviews with engineers, and a review of engineering calculations.

a. Personnel Authorities and Duties

The staff interviewed five onsite design engineers selected from the personnel roster. In addition, managers/supervisors of the various design groups were interviewed. There were no written job descriptions available for the pipe stress and support group leaders, lead engineers, and engineers.

A followup inspection was conducted on February 15-16, 1984, at the PG&E corporate office, San Francisco, CA. The inspector reviewed the following documents:

- PG&E Engineering Manual, Procedure 1.3, Attachment A, Rev. 2, dated August 9, 1982. The Organization Chart did not show OPEG. The staff stated that the procedure was being updated.

- Bechtel NQAM Section I. No. 1, DCP Amendment dated July 5, 1983, Rev. 5-A, "Organization Charts."

- DCP Instruction No. 9, "Onsite Project Engineering Group," Rev. 0, dated September 17, 1982.

- Bechtel Personnel Requisition of 15 "Job Shoppers," dated November 1, 1982.

- Bechtel Personnel Requisition of 23 "Job Shoppers," dated February 14, 1983.

- PG&E Contract No. Z20-0023-84 with Code III Associates, Inc., dated January 13, 1983.

- PG&E Contract No. 5-75-82, Change Order No. 5 with Innova Corporation, dated October 20, 1983.

Subsequent to the review, the inspector concluded that the OPEG S/B piping design personnel authorities and duties were delineated in DCP Instruction No. 9; however, the site personnel were not familiar with the procedure, and as a result they were unable to address the inspector's questions during site interviews. Personnel qualifications and duties were prescribed in sufficient detail in Bechtel requisitions. PG&E requisitions require the contractor organization to submit the work force qualifications and capability for PG&E's review and acceptance. Both methods are considered to be acceptable by the inspector.

b. Personnel Indoctrination and Training - General

The general QA and technical training received by the engineers was not timely and consistent. The bases for this determination are:

Work Group	Began Work Mo/Yr	Engineering Manual Survey Training Date	QA Indoctrination Date
A (Support)	10/82	2/18/83	5/5/83
B (Support)	4/83	7/15/83	5/4/83
C (Support)	9/83	12/16/82	10/23/81
D (Stress)	4/82	6/9/82	5/5/83
E (Stress)	2/83	4/19/83	5/4/83

The staff reviewed several design calculations which are identified in Allegation No. 79. Among the calculations reviewed, the inspector identified that design verifications/checking were not being performed in sufficient depth to catch calculational errors. It is the inspector's view that this is an indication of a lack of procedural knowledge and training in project controls. This allegation was substantiated.

Subsequent inspections were conducted at the PG&E corporate office, San Francisco, CA on February 15-16, 1984. The following training records were obtained for evaluation:

Name	Date Reported to Work @ OPEG	Date Supervision Requested Training	Training Received
M. Shoikhet	10/19/82	2/8/83	EMS, 2/18/83, 4 hours
		---	SFPD QA Indoctrination, 5/5/83, 1 hour
M. Durani	4/83	7/7/83	EMS, 7/15/83. 3 hours
		---	SFPD QA Indoctrination. 5/4/83, 1 hour
S. Aram	9/83	12/15/83	*EMS, 12/16/83, 3 hours
S. Jacques	4/82	---	EMS, 6/9/82, 2 hours
		---	SFPD QA Indoctrination, 5/5/83, 1 hour
J. Reas	2/83	3/14/83	EMS, 4/19/83, 3 hours
		---	SFPD QA Indoctrination, 5/4/83, 1 hour
S. K. Soorma	11/1/83	12/15/83	*EMS, 12/16/83, 3 hours

*Since July 15, 1983, the EMS course included SFPD QA Indoctrination except on Design Drafting work modules.

The inspector also reviewed the pertinent portions of the following training procedures:

- PG&E Engineering Department Procedure (EDP) No. 2.1, "QA Program Training," Rev. 2, dated June 18, 1982, states in paragraph 4.2 "The Chief, Engineering Quality Control (EQC) shall arrange and have conducted specific training programs to assure that those engaged in nuclear safety-related work are knowledgeable in the applicable Procedures of this Manual.

  4.2.1 Personnel shall be appropriately indoctrinated, trained, and qualified prior to their performing quality assurance functions which may affect the final status of design or construction activities. Group leaders and supervisors shall send to EQC the names of all personnel, whether they be permanent or temporary, who are newly assigned to nuclear projects. EQC shall arrange and conduct training in Engineering Procedures for these personnel as soon as work schedule permits."

- DCP PEI No. 15, "Training," Rev. 0, dated August 5, 1983, states in the following paragraphs:

3.1.3 "The Project Quality Engineer (PQE) will identify project personnel required to attend EMS training or retraining and request EQC by IOM to schedule these individuals for EMS training in accordance with paragraph 4.1. Such individuals shall receive EMS training within 30 days of their assignment to the Project."

c. Personnel Indoctrination and Training - Specific

The staff also found that specific project group program training was not adequate. During the inspection conducted at the PG&E corporate office, San Francisco, CA on February 15-16, 1984, the following specific training records were obtained for evaluation:

Name	Date Reported to Work @ OPEG	Date Supervision Requested Training	Training Received
L. B. Mangoba	1/25/83	3/14/83	Engineering Manual Survey (EMS), 3/14/83, 3.5 hours

4/7/83	PEI Training, 4/13/83, 0.75 hour
---	SFPD QA Indoctrination, 5/5/83, 1 hour
---	PEI No. 16, Rev. 0, & EMP, 3.6 CN, 10/13/83, 1.5 hours

Mr. Mangoba is the OPEG Pipe Support Group Leader. During discussions project management stated that specific PEI training received by the supervisors/leaders should be passed on to their subordinates. It was subsequently determined that this practice was not carried out by the responsible supervisors.

- DCP Project Engineer's Instruction (PEI) No. 1, "Project Engineer's Instructions," Rev. 4, dated 2/1/84 states in Paragraph 4.6, "PEI Training will be conducted at the Engineering Group Supervisor (EGS) level. Training will be conducted in accordance with the training requirements for the Engineering Manual as described in procedure 2.1, Quality Assurance Program Training."

- DCP PEI No. 15, "Training," Rev. 0, dated 8/5/83, states in the following paragraphs:

3.2.1 "The Project Engineer(s) (PE) Unit 1 and Unit 2 are responsible for implementing the Project-Unique Training program on the Diablo Canyon Project. Training sessions will be conducted within 30 days of the identified need. The PQE shall assist in the development and presentation of the Project-Unique program(s) or other training as directed by the PE."

3.2.2 "The following personnel are responsible to attend Project-Unique Training as appropriate and/or necessary, in addition to specifically directed personnel.

- o Project Engineer (PE)
- o Assistant Project Engineers (APEs)
- o Group Supervisors/Group Leaders (EGS/EGL)
- o Project Quality Engineers/Quality Engineers (PQE/QE)"

On March 5, 1984, the inspector interviewed the following Pipe Support Engineers working under Mr. Mangoba:

Name	Date Reported for Work at OPEG
T. H. Cummings	11/15/82
T. B. Amin	11/15/82
M. C. Kewalramani	11/28/82
A. K. Ghose	11/21/82
Y. Igolnikoc	1/31/83
M. Durani	4/26/83

In response to the inspector's questions, all members of the above group indicated that:

- There had been no supervisor training provided by the group leader relative to procedure technical changes that could affect the quality of safety-related calculations performed by engineers.

- Training received by Mr. Mangoba on October 13, 1983, concerning changes made to PEI-16, "Design Changes for Nuclear Plant Under Construction," Rev. 0, dated October 10, 1983, and PG&E EMP 3.6 ON, "Operating Nuclear Power Plant Design Changes," Rev. 3, dated February 14, 1984, was not passed on to the working group personnel.

- The only specific training provided to the group pertained to administrative matters relating to calculation packages, such as how to handle page sequence revisions, and how to identify snubber numbers.

4. Staff Position

1. The failure to provide timely training for the newly employed or assigned site S/B piping stress and support design engineers was primarily the fault of supervision not requesting EMS training as required by EDP 2.1 and DCP PEI 15.

2. There was an apparent lack of PG&E QA training for the S/B piping group employees. Comprehensive QA training was not conducted until May, 1983.

3. There is an apparent program insensitivity for providing specific job related training for the working staff. No documented evidence exists to indicate that the Project-Unique Training required by procedure PEI 15 for site supervisory personnel had been passed on to the support design and piping stress engineers.

4. Since July 15, 1983, the EMS course was a part of the SFPD QA indoctrination training provided to the OPEG staff. The instructor for the EMS is a PG&E Quality Program Analyist who reports to the Sr. Quality Engineer who, through the PG&E organization, eventually reports to the VP of Engineering. The inspector considers that the indoctrination and training of QA program require-

ments is a part of the QA function. However, after review of the circumstances, the inspector stated that he had no further questions in this area. This conclusion is based on (1) since the formation of DCP in March, 1982, the PG&E Engineering Department was not responsible for costs or maintaining the established DCNPP construction schedules; but only to provide support personnel and other corporate resources, and (2) the text prepared for the EMS training appeared to be substantial and comprehensive.

C. Allegation No. 84, ATS No. RV83AD63, BN No. N/A

1. Characterization

Lack of management responsiveness to resolve the alleger's concern that he was not provided with controlled design procedures.

2. Implied Significance to Design, Construction, or Operation

The use of controlled design documents is to provide assurance that all work is performed to the requirements of current applicable design criteria, codes, and standards.

3. Assessment of Safety Significance

The staff interviewed the alleger onsite on December 7, 1983, to clarify his concerns in this area. The alleger referred to a memorandum written by line management to upper management relative to his concern about a lack of controlled design procedures.

The staff interviewed project team general construction personnel in relation to the memo purportedly written by supervision. In discussion with the pipe support group leader, on December 6, 1983, he denied that he had written a memorandum to Messrs. R. Oman and M. Leppke in December 1982 (the On-site Project and Deputy Engineers) relative to the lack of controlled design procedures being used in the pipe support group, in support of Mr. Stokes' concern.

Mr. Leo Mangoba agreed that he was aware of the subject concerns raised by a members of his staff, and that he had taken actions to obtain additional controlled design procedures.

In view of the task findings that are discussed in Allegations No. 79 and No. 82 concerning: (1) the large number of out-of-date procedures and drawings and the deficient document control system; (2) the lack of training for the personnel relative to the use of up-to-date procedures and revisions to design; and (3) that management did not respond in a timely manner to correct the problem and to prevent recurrence, the spirit of the allegation was substantiated.

4. Staff Position

The staff concludes that site management must improve its sensitivity in addressing safety concerns and improve communication with the workers.

D. Allegation No. 88, ATS No. RV83A063, BN No. N/A

1. Characterization

Means existed that would accept on-site design supports that were determined to be incapable of meeting the loading conditions.

2. Implied Significance to Design, Construction, or Operation

Management practice to compromise the system design safety margin by juggling calculations and designs to accept supports that had been rejected by calculations performed by the original reviewers could result in structures unable to perform their intended function.

3. Assessment of Safety Significance

a. The staff met with the alleger on site on December 7, 1983. Clarification and additional information concerning specific areas of his affidavit were obtained. A broad characterization of his concern references the following detail elements/ways the design group may compensate for unacceptable calculations:

(1) Revising pipe code break locations in order to reduce the number of safety-related supports and omitting many of the supports that failed in the review program.

(2) Assuming gaps that did not exist and vice versa.

(3) Assuming joint release for rigid connections. No attempt was made to remove the welds.

(4) Performing calculations to determine maximum support load carrying capacity. The results were then sent to the piping stress group for line model change to meet piping allowable stresses.

(5) Adding new supports within six inches of the unacceptable supports. The new supports consisted of an inaccurate assumption of restraint gaps. The new supports did not have control or document numbers.

b. During the inspection conducted at the site on March 5-7, 1984, the staff obtained the records, calculation logs and design calculations necessary to examine the above concerns.

(1) In response to the allegation that code break locations had been revised and failed supports were omitted in the review program, the inspector reviewed a number of

P&IDs, and determined that the code break locations were determined by the system engineers and could not be altered by the site support engineers. . OPEG practice is to protect the safety related piping that connects to non-safety related piping to ensure total system functionability during adverse plant conditions. . Seismic analyses are extended to an anchor or to include a number of restraints located on the non-safety related portion of the system. The rules are described in PG&E Mechanical and Nuclear Engineering Procedure No. P-11, "Procedure for Piping Stress Analysis, Diablo Canyon Units 1 & 2," dated October 15, 1983. Paragraph 4.4.11, "Code Breaks," states that "In cases where there is a change in code Class from PG&E Class I to Class II piping (seismic to non-seismic), it is necessary to include the Class II piping in the analysis up to a point on the Class II line at which an anchor or at least two supports in each perpendicular direction (vertical, horizontal-perpendicular) and at least one support in the axial direction has been included. A suggestion would be to install two guides around an elbow for adequate code break protection. Verify the feasibility of design with field personnel."

To verify that the site staff was implementing the procedural requirements, the following two S/B piping stress analyses were selected for review.

- Analysis No. 19-305, "Liquid Radwaste," Rev. 1, dated June 8, 1983.

- Analysis No. 3-313, "Piping System No. 3 - Feedwater Line No. 2477," Rev. 1, dated April 12, 1983.

Findings

Procedure Requirements	Analysis No. 19-305	Analysis No. 3-313
Vertical Restraint*	57-20(R) 22-423SL	20-401(SL) 2165-15(R)
Horizontal-Perpendicular Restraint*	57-11(R)	2165-32(R)
Axial Restraint	57-20(R)	22-400SL

*One of the two bi-lateral restraints

(R) - Rigid Restraint

SL - Snubber

Based on the above review, the inspector concluded that OPEG was handling code break analysis in an acceptable manner. The allegation was not substantiated.

(2) Relative to the allegations that "Gaps that did not exist were assumed and vice versa; New supports were added within six inches of an unacceptable support; New supports consisted of an inaccurate assumption of restraint gaps," the inspector had difficulty interpreting their specific meaning and the issues involved, even after discussions with the alleger. However, in view of the inspector's findings concerning OPEG's failure to consider load synchronization between closely spaced rigid restraints, and their failure to inadequately control the modeling of thermal stress relief gaps within rigid restraints, the inspector determined that the spirit of the allegation was substantiated.

(3) In conjunction with (2) above, it was also alleged that new supports were not assigned control or document numbers. During the period of the inspector's review that extended from late November, 1983 to March, 1984, all new or modified supports were observed to have assigned control numbers. On occasion restraints without a number were shown in a calculation. One instance observed was snubber 22-521SL for a valve in Analysis No. 19-305.

Subsequent review identified that a detailed drawing was made. This allegation was not substantiated.

(4) In response to the allegation of joint release for rigid connections, the inspector discussed the issue with OPEG engineering management. They indicated that there are three ways to reduce the loads on the flexible structures to which the restraines are attached. They are:

(a) Model the structure's physical properties and configuration in the support/restraint calculation.

(b) Calculate the structural attachment stiffness, then include the stiffness in the support/restraint calculation.

(c) Assume the joint connection as a pinned connection.

The inspector stated that he had no problem with methods (a) and (b) above, but that he had some reservations regarding method (c).

Calculation No. MP-583, "Pipe Support 2156-169," Rev. 5, dated November 9, 1983, with a pinned joint condition, was presented to the inspector as an example where joint

release was used. The following pertinent calculation revisions were reviewed:

- Rev. 3, dated August 22, 1983 - Final support evaluation completed. The Civil group requested that the hanger group to model the connection to the "double angle steel stiffener bracing structural member" as a pinned joint.

- Rev. 4, dated October 13, 1983 - Support complied with the civil group request.

- Rev. 5, dated November 9, 1983 - As-built evaluation made.

During discussions after his review of the above Rev. 3 and Rev. 4 calculations, the inspector stated that he felt it was unrealistic to remove all the structural joint bending moments, torsional moment, and all directional deflections. He requested the calculation be re-done with the attachment steel configuration and properties included. A summary of the outcome is as follows:

Loadings & Displacements	New Calculation w/Double Angle Steel	Rev. 4 Joint Release @ Node 3	Rev. 3 Fixed Joint @ Node 3
Fx (1)	-174	24	25
Fy (1)	54	32	57
Fz (1)	46	27	45
Mx (2)	-362	0	-501
My (2)	-372	0	-319
Mz (2)	393	0	-432
Δx (3)	.000103	0	0
Δy (3)	.003815	0	0
Δz (3)	.000058	0	0
θx (4)	.0086	.0042	0
θy (4)	.0006	.0015	0
θz (4)	.0023	.0118	0
Δ max (5)	.0105	.0097	.0095

where: (1) Local Hosgri seismic force in lb_f

(2) Local Hosgri seismic movement in $in\text{-}lb_f$

(3) Global linear deflection in inches under the Hosgri seismic condition

(4) Rotational displacement in radians under the Hosgri seismic condition

(5) Effective weight maximum frame deflection.

As a result of this review, the inspector stated that he felt that the modeling of pinned connection in support/structure design was an unacceptable practice. He further indicated that he recognized that the magnitude of the effect was small. How many other pinned joints are modeled in calculations is not known. Responsible OPEG personnel indicated they were aware of one additional instance where this condition existed. The allegation was considered to be substantiated.

(5) Relative to the allegation concerning back calculating pipe stresses using maximum support loads, the inspector was informed that the following practices were being utilized by the piping stress analyst:

(a) Gaps were provided in rigid restraints to eliminate thermal stresses.

(b) Pipe support stiffnesses were utilized in stress analysis.

(c) System temperatures were reduced by utilizing the latest revisions to procedures and DCNs.

(d) L/B piping system TAM was being re-evaluated.

(e) Additional supports and restraints were being utilized.

The inspector stated that all the above methods were considered to be acceptable, except caution should be exercised when method (a) is used. The specific problems observed regarding the utilization of "thermal gaps" within a rigid restraint is discussed in Paragraph II.B.2.b (Stress Calc. 8-314, Part A) of this report. The allegation was partially substantiated.

No written procedures existed that delineated an effective work interface between the Pipe Stress and Pipe Support groups. This could have been the cause of some confusion among the OPEG engineers, including the alleger.

4. Staff Position

The staff concluded that cases were identified where design conservatism had been compromised. While the effects of the deficiencies may be of minimal significance, the practices are considered to be in noncompliance with NRC regulations.

E. Allegation No. 89, ATS No. RV83A063, BN No. N/A

1. Characterization

Improper resolution of piping interferences.

2. Implied Significance to Plant Design, Construction, or Operation

Piping interferences or inadequate piping supports could result in piping systems being overstressed during operational or design loading conditions.

3. Assessment of Safety Significance

a. During a site inspection conducted on November 30, 1983, the pipe clamp for snubber 16-28SL that is installed on Line K3281-12 (a part of the Component Cooling Water system) was observed resting on the top of the floor penetration located on Fl. El. 115'-0". Subsequently, during the inspector's

review at Bechtel on February 2-3, 1984, the PG&E responsible staff stated that a Deficiency Report was issued, however, during a followup inspection, sufficient clearance was observed and so no corrective action was required. The inspector reviewed the Stress Walkdown package 4-102, "Component Cooling Water," dated 8/22/83, including several of the 21 Stress Walkdown Problem Resolutions (SWPR). One of the SWPRs reviewed was No. 4-102-3-Y-A, dated November 8, 1983. The inspector had no adverse comments. The report package identified 3 unintentional restraints and 13 out of approximately 145 supports on the piping system that had not been either installed or removed per the latest design revisions. The conflict between the inspector's and the licensee's observation was discussed. The conclusion was that perhaps the pipe clamp for snubber 16-28SL had been temperarily loosened to facilitate other construction activities in the area.

b. On February 2-3 and 15-16, 1984, the inspector reviewed the following PG&E DCP Mechanical and Nuclear Engineering design field walkdown inspection documents:

. Instruction (I) - 17, "NRC IE Bulletin 79-14 Field Reverification Procedure for Large Bore Piping Isometrics, Units 1 & 2," dated May 7, 1982.

- I-18, "NRC IE Bulletin 79-14 Field Reverification Procedure for Small Bore Piping Isometrics, Units 1 & 2," Rev. 1, dated September 2, 1982.

- I-50, "Stress Walkdown for Large Bore Design Class I Piping Systems, Units 1 & 2," Rev. 4, dated October 24, 1983. Also, Rev. 3, dated September 23, 1983; Rev. 2, dated August 22, 1983; Rev. 1, dated August 10, 1983; Rev. 0, dated August 2, 1983.

- Procedure (P)-36, "Walkdown of Piping During Initial Heatup, Unit 1," Rev. 1, dated January 27, 1984.

- P-37, "Procedure for Measuring Hot Gaps on Rupture Restraints, Unit 1," Rev. 1, dated February 10, 1984.

- P-38, "Walkdown of Piping During Power Ascension, Unit 1," Rev. 0, dated January 27, 1984.

c. <u>The review identified the following findings</u>:

(1) For I-17 and I-18, in the area of interference clearances (the only area that was reviewed), they do not meet the requirements delineated in the NRC IE Bulletin (IEB) 79-14, "Seismic Analysis for As-Built Safety-Related Piping Systems," dated July 2, 1979. The Supplement 2 of IEB

79-14, dated September 7, 1979, states "For exposed attachments and penetrations, licensees are expected to measure or estimate clearances between piping and supports, integral piping attachments (e.g. lugs and gussets) and supports, and piping penetrations. Licensees are not expected to do any disassembly to measure clearances." Contrary to the above, I-17 and I-18 do not require documented field measurements at locations such as pipe penetrations and where piping is near walls, near beams, and near large components. The procedures consider that pipe/structures with a clearance of 3/16" and above are without interference.

(2) To implement I-50 procedural requirements, the licensee stated, during a meeting conducted at Bechtel on February 23, 1983, that "The first of these programs, the Final Stress Walkdown, has already been completed. Every seismic category line was walked down in its entirety in the cold position to visually check for interferences of any kind. The walkdown was done by teams consisting of a piping analyst and a support designer. The team carried along records of the calculated displacements of the pipe for all loading conditions, including seismic, SAM, TAM, and all thermal operating modes. At locations of potential interference, the walkdown team calculated the range of predicted movements, subtracted them from the

observed clearances and determined whether an interference could occur. For each instance of insufficient clearance, a problem report was generated, which was forwarded to the appropriate organization for resolution. Approximately 800 problem reports were generated, and all of the problems were resolved."

(3) During the February 23, 1983 meeting, the licensee also addressed the implementation of the P-36 and P-38 procedures, stating that "To eliminate the possibility of an interference occurring due to differences between the actual thermal movements and those that were calculated, additional walkdowns will be done during initial heatup and during power ascension. Key points will be selected along the entire length of the system. At these points the cold position of the pipe will be measured, followed by the hot position, and the net displacement will be determined. The displacement will be compared against the predicted movements, and any discrepancies in magnitude or direction of significance will be documented in a problem resport. The problem report will be forwarded to the appropriate organization for resolution."

(4) After discussions with Bechtel and PG&E responsible engineers the inspector determined that the present inspection program, described in Paragraphs a, b, and c above, is deficient in the following areas:

(a) The minimum acceptance interference clearance of 3/16" used in I-17 and I-18 is not sufficient for all applications since many piping systems displace more than 3/16" during various thermal and loading conditions. Although I-50 inspection acceptance criteria does require the worst design condition piping displacements of (a) single directional for thermal expansion, SAM, and TAM; (b) double directional for all dynamic loads, there was no guarantee that the piping movements discussed above will be exactly as predicted by design. As a matter of fact, the inspector is aware of cases observed during system hot functional tests, conducted at other operating nuclear plants, where pipe lines moved in the opposite direction or sideways when compared with the predicted design movements.

(b) In conjunction with (1) above, the movements in the opposite direction are difficult and sometimes impossible to detect. The reasons for this conclusion are: (a) the few key points selected under P-36, and P-38 program do not correspond exactly with the possible interference locations, and (b) system hot tests do not cover all design thermal, SAM, and TAM displacements that result from all combined adverse plant operating conditions.

(c) Without establishing a data base for all potential unintentional restraints that includes (a) inspection of clearances for all directions exceeding the maximum piping displacements, and (b) documentation of the measurements at the concerned locations included in the IEB 79-14 requirements, any evaluation to ensure the absence of piping interferences during any given plant system operating condition would be difficult.

d. Additional site inspection was performed on March 6, 1984 in the Unit 1 Reactor Containment, the Auxiliary Building Area "L" (Fl. El. 115'-0"), and the Pipe Way Area (Fl. El. 121'-0"). The following piping and restraint interferences were observed:

(1) The movement of snubber 10-143 SL could be restricted by rigid restraint 1-32R in the tension loading direction.

(2) On line "Loop 4 FTD Manifold Return to Cold Leg 4, S6-1158-3," the non-safety related portion of the valve leakoff line interferred with by a guard rail. Since the non-safety related piping is connected to the safety related piping, the interference is considered to be unacceptable.

(3) The movement of snubber 22-61SL, installed in pipe axial direction, could be interferred with by piping insulation.

(4) The movement of snubber 22-65SL could be restricted in the tension loading direction. Insulation on the pipe elbow was touching the wall.

(5) The entire section of the horizontal run of piping for line 1-S6-51-2, where rigid restraint 2152-09 is located, is resting on the top of the pipeway.

(6) The pipe elbow below rigid restraint 2152-15 on line 1-S6-51-2, touches with the wall surface.

(7) The pipe insulation stated above is made of hard calcium silicate, with a metal cover.

e. On March 15, 1984, the inspector discussed the restraint interferences described in d above with the PG&E and Bechtel staff. The following conclusions were drawn:

(1) The 0.835" thermal movement observed at snubber 10-143SL represented the worst piping displacement condition. This condition is acceptable.

(2) The valve leakoff piping on line S6-1158-3" is not a part of the "code break" line extension. The thermal and seismic movements at the guard rail are small. This condition is acceptable.

(3) For snubbers 22-61SL and 22-65SL, and line 1-S6-51-2 Stress Walkdown Problem Reports (SWPRs) should have been written. This was an inadvertent error made by the walkdown personnel.

(4) There is little thermal and dynamic piping movements at the pipe elbow near rigid restraint 2152-15. This condition is acceptable.

4. Staff Position

The staff concludes that the site walkdown inspection program was unacceptable. In addition, the licensee's program to identify potential piping interferences was inadequate. The specific allegation item was substantiated.

F. Allegation No. 97, ATS No. RV83A063, BN No. N/A

1. Characterization

Site design engineers have not been required to work using

controlled documents. This laxity has resulted in the use of different design assumptions as well as other problems.

2. Implied Significance to Plant Design, Construction, or Operation

See Allegation No. 79.

3. Assessment of Safety Significance

See Allegation No. 79.

4. Staff Position

See Allegation No. 79.

G. Allegation No. , ATS No. , BN No.

1. Characterization

A "Quick Fix" design change program was being implemented. This program was not a part of the licensee's QA program.

2. Implied Significance to Design, Construction, or Operation

The use of a "Quick Fix" to accept pipe support design field changes bypassed the normal QA nonconformance reporting system

and circumvented the formal design change review and evaluation requirements.

3. Assessment of Safety Significance

a. On February 8, 1984, Mr. Charles Stokes executed a second affidavit that supplements and updated his initial allegations. One of the matters involved was OPEG's quick fix program for pipe support design changes. It was alleged that engineers were not informed of the proper procedures, yet they "completely redid the design of hangers, deleted hangers, deleted weld symbols from the drawings, and took similar actions without the benefit of any calculations." The normal quality assurance reporting system for nonconformances was bypassed, even with respect to significant hardware deficiencies recorded only on Quick Fix sheets.

b. On March 7, 1984, the inspector reviewed an DCP OPEG document titled "Guide for Issue of Pipe Support Quick Fix Design Changes," Rev. 1, dated January 7, 1983. The use of informal guidance in lieu of written procedures to perform safety-related design deviation evaluations is considered to be in noncompliance with NRC regulations. However, responsible site personnel pointed out that the PG&E QA Department Activity Audit No. 83341A, "OPEG Control of Design Changes - Criterion III" conducted on August 5

and 8, 1983, had identified this problem. The inspector reviewed the audit report, and determined that the licensee's corrective action was inadequate. The bases for this determination is discusses in Paragraph c below.

c. Subsequent to the PG&E internal audit finding, the "Quick Fix" guide was transformed into DCP Instruction No. 12, "Pipe Support Design Tolerance Clarifications", Rev. 1, dated August 5, 1983. The inspector reviewed I-12 and evaluated the records related to 3 L/B and 1 S/B Tolerance Clarifications (TC). The inspector considers this program is being improperly used based on the following:

(1) TC-1-11202, L/B Hanger No. 74-33R, approved on August 12, 1983.

The support base plate had been significantly altered. The alterations included major dimensional changes, an increase in plate thickness, a reduction in the number of stiffeners, and modified bolt hole locations.

(2) TC-1-11306, L/B Hanger No. 322-7R, approved on August 15, 1983.

The restraint design was changed from a double U-bolt configuration to single box beam type structure. The

design alternation also included changing from a steel channel and angle structure to a tube steel structure.

(3) TC-1-11369, 4B Hanger No. 18-7R, approved on August 18, 1983. This TC was superseded by TC-1-11777, approved on August 25, 1983. The as-built evaluation was dated September 14, 1983. The support base plate was revised significantly.

Original design: 2'-5" x 2'-5" x 1" thick; w/o stiffener; 8 - 1½" dia. bolts

Revised design: 1'-10 3/4" x 2'-5" x 1" thick; w/6 added stiffeners; 6 - 1½" dia. bolts

(4) TC-1-14057, S/B Hanger No. 57-15, approved on November 7, 1983.

This TC was used to evaluate PPP's Deficient Condition Notice No. 177-007, dated November 5, 1983.

The closeout of the Notice was dated November 15, 1983, and was based on OPEG S/B Support Design Group Calculation MP-1530, "As-built evaluation of Hanger No. 57-15", Rev. 2, dated November 9, 1983. The inspector reviewed

calculation MP-1530 and identified the following deficiencies:

(a) The PPP construction deviation relating to the included angles between several of the structural members had not been addressed in the as-built evaluation.

(b) Structural bracing members No. 48 and 49 shown in the STRUDL run dated November 9, 1983, were modeled in a different location than that shown on the as-built drawings.

(c) The 8½" long steel angle (2 x 2 x 3/8") that formed a part of the valve body restraint (STRUDL member Nos. 37, 38, 46, and 47) was not included as part of the computer input.

In addition to the Rev. 2 problems discussed above, Rev. 1 of the calculation dated September 8, 1983, "Per S/B Review Program", and Rev. 3 of the calculation, dated January 1, 1984, "Per Analysis 19-305 Rev. 1", had all been checked and approved by the responsible personnel. The deficiencies identified above were not documented and justified.

d. Followup on the three L/B hanger TCs listed above was conducted at Bechtel, S.F., on March 14-15, 1984. The purpose of the inspection was to determine if these TCs had received a timely and adequate review and were resolved properly.

(1) Hanger No. 74-33R (Bechtel Calculation No. S-45, Rev. 9, dated November 9, 1983

- The base plate evaluation showed that: (a) the maximum as-built condition and tension/shear stress interaction values (IVs) were within the program allowables, and (b) there was a significant increase in the IVs; from 0.958 at Node 27 and 0.974 at Node 28 for the as-built to 0.578 at Node 5 and 0.806 at Node 24 for the as designed.

- The support structural evaluation showed that: (a) maximum critical stresses were within AISC allowables, and (b) there was a maximum stress increase from 12,506 psi to 18,001 psi.

(2) Hanger No. 322-7B (Bechtel Calculation No. H-742, Rev. 3, dated January 24, 1984.)

- The base plate evaluation showed that: (a) the maximum as-built condition stresses and IVs were within the program allowables, and (b) the previous hanger calculation did not include a base plate analysis.

- The support structural evaluation showed that: (a) maximum critical stresses were within AISC allowables, and (b) the previous hanger hand calculation was not in accordance with approved design documention control provisions.

(3) Hanger No. 18-7R (Bechtel Calculation No. S-122, Rev. 15, dated December 21, 1983)

- The base plate evaluation showed that: (a) the maximum as-built condition stresses and IVs were within the program allowables, and (b) there was general decrease in the IV values.

The support structural evaluation showed that: (a) maximum critical stresses were within AISC allowables, and (b) there was a general decrease in stresses.

4. Staff Position

The staff concluded that, based on the findings identified, there appeared to be a breakdown in the licensee's QA program for site design change control. In view of the fact that: (1) there are thousands (more than 30 - 2½" binders full) of support "Quick Fix" or TC design changes that have not been subjected to design control measures commensurate with those applied to the original calculations, (2) a "guide" was used to perform safety-related design reviews, (3) QA and management actions to correct the apparent program breakdown including investigation of the causes, the effects, were not effective, (4) the TC procedure in effect at the time of this inspection did not delineate specific limitations on when it is appropriate to use the TC system, (5) OPEG S/B support calculations continued to include errors and (6) several L/B support original calculations were observed to be deficient, the allegation was fully substantiated. The inspector's review of the L/B support design alterations (the three TCs selected) indicate that sufficient reviews have been conducted by Bechtel. However, as this review was limited, an evaluation of the overall program and its implementation would require additional inspection.

II. NRC Overview - Outgrowth of Followup of Allegation Items

A. Review of Design Procedures

Among the design procedures reviewed in the followup of Allegation No. 79, the inspector observed conflict in design criteria. DCM M-9, Revision 8, Paragraph 3.1.1 states, in part, that, "A method that can be used for calculating natural frequency is to limit the deflection of the support in the restrained direction to less than or equal to 0.025" by hand calculation or STRUDL from analysis." This requirement was in conflict with the widely used uncontrolled Bechtel SFPSM-3.12.1, Revision 0 procedure, where it states in Paragraph 2, Table 2.1, "Support deflection in terms of support frequency should be limited to 1/16, or 0.0625 inch."

During the inspection conducted at Bechtel on January 11, 1984, the inspector reviewed Robert L. Cloud and Associates, Inc. Interim Technical Report (ITR) No. 60, "Diablo Canyon Unit 1 IDVP Review of Corrective Action Large and Small Bore Pipe Supports," Rev. 1, dated October 3, 1983. In Paragraph 5.7, this ITR identified an application of the incorrect 0.0625" criterion in DCP Calculation M-178, Rev. 2 for Supplement No. 2159/2.

B. Review of OPEG S/B Support Calculations and Piping Stress Analyses

During an inspection at the site on December 2-3, 1983, the inspector

reviewed 5 support calculations at the Support Group, and on December 5, 1983, reviewed 2 piping stress calculations at the Piping Stress Group. The following are the inspector's findings:

1. Pipe Support/Restraint Calculations

a. Calculation No. MP-397, "Hanger No. H21-226," Revision 2, dated August 18, 1983 - MS. No adverse comment.

b. Calculation No. MP-465, "Hanger No. 002-170," Revision 3, dated September 6, 1983 - MS. Even though an unauthorized double cantilever beam deflection formula was used, it did not affect the technical acceptability of the calculation.

c. Calculation No. MP-1691, "Hanger No. 97-90," Revision 1, dated December 1, 1983 - SA. Same comment as Calculation No. MP-465.

d. Calculation No. MP-942, "Hanger No. 99-20," - MS.

(1) A STRUDL run prepared on February 1, 1983, checked on February 2, 1983, and approved on February 12, 1983, included 19 errors in the 10 load cases.

The support utilized a steel angle structure to which six restraint members were attached. The Node point locations modeled in the isometric drawing were as follows:

- Center line of the steel angle structure: 10 | 8 | 7 | 5 | 4 | 3 |
- Center line of the pipe where loading imposes: 11 | 9 | 15 | 6 | 14 | 16 |

Load Cases	Loading Locations					
1A	11	9	15	6	--	16
1B	11	9	7	6	4	3
2A	11	9	15	6	14	16
2B	11	9	7	6	4	3
3A	11	9	15	6	14	16
3B	11	9	7	6	4	3
4A	11	9	15	--	14	4
4B	11	9	7	6	4	3
5A	11	9	15	--	14	16
5B	11	9	7	6	4	3

- There were 5 (7s) + 5(4s) + 5(3s) = 15 misplaced loading inputs. These incorrect inputs reduced the moments at the steel angle structure.
- There were 3(--s) = 3 missing load cases.
- There was one (4) that should have been a (16).

(2) A STRUDL run prepared on July 25, 1983, checked on July 26, 1983, and approved on July 27, 1983, for MP-942, Revision 3 included 30 errors in the 10 load cases.

Load Cases	Loading Locations
1A	11 9 7 6 4 3
1B	11 9 7 6 4 3
2A	11 9 7 6 4 3
2B	11 9 7 6 4 3
3A	11 9 7 6 4 3
3B	11 9 7 6 4 3
4A	11 9 7 6 4 3
4B	11 9 7 6 4 3
5A	11 9 7 6 4 3
5B	11 9 7 6 4 3

There were 10(7s) + 10(4s) + 10(3s) = 30 misplaced loading inputs. These incorrect inputs reduced the moment at the steel angle structure.

The design staff failed to follow PG&E Engineering Department Procedure No. 3.3, "Design Calculation," Rev. 4, dated June 25, 1982 (latest Rev. 5, dated July 15, 1983). The procedure states in Paragraph 4.2.4,

that "Computer calculations shall be checked for compatibility of the program and the design assumptions, correctness of inputs, and interpretation and application of outputs...."

e. Calculation No. MP-1621, "Hanger No. 2156-200," Revision 0, dated September 1, 1983, approved September 1, 1983, - MD.

(1) The support design load input was based on a piping stress preliminary run, dated August 24, 1983, that was telephoned to MD on August 27, 1983. During the site inspection conducted on December 3, 1983, the inspector compared the Calculation No. MP-1621 loading input against Pipe Stress Run No. 13-112, Revision 3, dated August 29, 1983, and found that the load direction signs for the 4 lb. dead weight loads were reversed. Although the inspector concluded that there would probably be no effect on the adequacy of the pipe restraint, it did bring up two issues:

- This simple error resulted in all ten load cases being invalid.

- There appeared to be a lack of provisions in the program to review and verify preliminary information provided over the telephone and to evaluate and document deviations from design.

The design staff failed to follow PG&E Engineering Department Procedure No. 3.3, "Design Calculation," Rev. 5, dated July 15, 1983. This procedure states in Paragraphs:

4.1.2 Calculation Sheets "For nuclear work, assumptions requiring verification at a later design stage shall be identified by marking the appropriate page or sections with an identifying symbol...and/or by labeling the Calculation Cover Sheet "Preliminary" until the verification is completed."

5.1.2 Nuclear Calculations, (a) "A preliminary calculation is an approved calculation which supports design but contains assumptions which need to be verified."

(2) The pipe riser was restrained by two rigid frames, one on top of the other, one foot apart. Forces in the X direction (South) were selected for review:

Load Cases	Upper Frames (lb$_f$)	Lower Frames (lb$_f$)
1A	-44	1546
1B	-54	-4
2A	1225	2934
2B	-1323	-1392
3A	1993	3838
3B	-2111	-2255
4A	808	950
4B	-902	-958
5A	811	2541
5B	-929	-958

The present support construction tolerance procedure allows, in the X-direction, a maximum 3/16" gap at the upper frame and no gap at the lower frame. For the load cases of 2A, 3A, 4A, and 5A, the applied loads will not be resisted by the upper frame. Any differences in upper and lower frame restraint gaps could cause one of the frames not to assume its portions of the design load.

2. Piping Stress Analyses

a. Stress Calculation No. 12-501, "Containment Spray," Revision 1, prepared on November 17, 1983, checked on November 20, 1983.

The response spectra developed by the Bechtel, San Francisco office was reviewed on November 17, 1983, and checked on November 22, 1983, but had not been approved for final calculation application.

During a followup inspection conducted on December 6, 1983, the correct values from Response Spectra 12-501, Rev. 1, dated October 4, 1983, was verified to have been utilized in the calculation.

b. Stress Calculation No. 8-314 (Part A), "CVCS: RCS Pump 4 Water Seal," Revision 6, dated November 10, 1983.

The modeling of 1/8" gaps at restraints 66-22, 2185-1, and 66-25 is allowed per Procedure No. P-11, "Procedure for Stress Analysis of Diablo Canyon Piping," Revision 6, dated October 5, 1983. Paragraph 4.6.2 of this procedure states, that "Initial thermal analyses are to be performed without support gaps modeled. As-built verification must be included in the documentation package for all modeled support gaps." It is the inspector's opinion that the assumption that the pipe will move to the designed gap location during system thermal expansion so that there will be no stress on the pipe and no load on the restraint is unrealistic. This opinion is based on (1) the records from startup tests observed at other nuclear plants indicate the actual piping thermal movements,

in many cases, differed from design, and (2) snubber cold position setting inspection results have been observed to differ under different conditions indicating that piping configuration and restraint gaps will not be maintained throughout plant life.

The generic issue related to the design control of thermal gaps within a rigid restraint was discussed during a meeting with PG&E and Bechtel personnel on December 15, 1983 at NRC office in Bethesda, MD. PG&E responsed to this issue, as well as other issues in two letters to the NRC titled "Diablo Canyon Unit 1, Response to Small Bore Piping Issues." Both letters were dated December 28, 1983. Their response stated, that "The (thermal gap) procedure was used on 59 supports, in 25 piping analyses, which accounted for 3.2% of the total small bore supports specifically analyzed....We have reviewed the 25 analyses and determined that there are 16 calculations below 200° F and 9 calculations above 200° F."

During a site inspection on March 6, 1984, the 19 small bore supports, where thermal gaps were remodeled in the 9 calculations, were observed and evaluated by the inspector (See Table 1). As to the systems below 200° F, including those with heat tracing, the inspector determined that the effect of thermal gaps would be minimal. No additional review is planned.

Table 1

Evaluation of Thermal Gaps within Rigid Restraints

Small Bore Piping Calculation No.	Small Bore Support No. for which Gap was Modeled	Thermal Gaps were Justified*
S118	63-7	Yes
	181-84	No
	181-96	No
3-302A	53-1	Yes
	53-1	Yes
	53-1	Yes
3-302B	53-1	Yes
4-302	42-6	No
8-310	2152-09	No
8-312	47-19	No
	47-24	
8-314A	66-22	Yes
	2185-1	No
	66-25	No
	66-24	No
	66-51	Yes
8-328	2157-14	Yes
9-309	181-20	Yes
	181-42	Yes

*The inspector considers that the thermal gaps were not justified if the piping between restraints had 4 or more directional changes after the nearest anchor or equivalent restraint, or if there was an extended length of pipe with 2 or more directional changes.

C. Observation of Large Bore and Small Bore Piping Suspension System Installations

1. On November 30, 1983, the inspector toured several areas in the auxiliary building. Many of the snubbers observed installed on large bore piping systems were in close proximity with rigid restraints. The snubbers observed are listed in Table 2. The functionability of these snubbers could be adversely affected. Mechanical snubbers require approximately 1/8" travel (less for small snubbers) to account for the play in the internal components and to close the gaps in the ball bushings installed in the structural and piping end connections and to assume the applied design load.

Under the existing installed condition the following problems could exist:

a. The operability of snubbers could be impaired by the close proximity of the rigid restraints and guides.

b. The non-functional snubbers could mean load increases at the affected rigid restraints and guides.

c. The piping system natural frequencies and the reactive support loading distribution could be altered.

d. The piping thermal movements at these locations are minimal. It is the inspector's opinion that the lines could be restricted without causing unacceptable increases in the secondary pipe stresses. The selection of these snubbers could be considered to be unjustifiable.

e. The radiation exposures received by plant personnel performing required Technical Specification visual inspection and functional tests for these snubbers with little or no thermal movement, could be avoided if the snubbers were replaced by rigid restraints that require only minimum ISI inspection and no functional testing. This use of mechanical snubbers inplace of rigid supports does not appear to give appropriate consideration to ALARA (ALARA design review guidance is contained in Regulatory Guides 8.8 and 1.70).

2. A During the inspection conducted on March 6, 1984, inside the Unit 1 containment, the following snubbers were observed on Line 1-S6-51-2SPL installed in between rigid restraints 2185-19, 2152-19, 2152-63, 2152-12, and anchor 23-2A. The operability of these ~~43~~ 45 pipe snubbers is questionable.

Snubbers	Max. Thermal Mvt. (in.)
22-326SL	0.172
22-62SL	0.016
22-63SL	0.472
22-61SL	0.211

Table 2

Large Bore Piping Snubbers Observed

Affected Snubber No.	Problem Description	Line/Location
4-2SL	Installed less than 2 ft. from Strut 98-16R	1-K-149-10 CCW/Safety Injection Rm. on Fl. El. 85'-0"
4-33SL 4-32SL	Installed on valve operator. The Piping connecting to the valve was rigidly restrained	1-S2-1984 SI/ Safety Injection Rm. on Fl. El. 85'-0"
16-49SL 16-47SL	Same as above	1-K16-572-3 Steam Generator Aux. FW Supply/Containment Penetration Area on Fl. El. 115"-0"
16-28SL 16-63SL	Snubber movements were restrained by 5-28R above & 5-5R below	1-K3281-12 Cont. Fan CLR Supply From HDR A&B/Cont. Penetration Area on Fl. El. 115'-0"
16-67SL	Snubber movements were restrained by 58S-33A & 58S-32R	1-S1-279-8 RHR Supply to Spray HDRs 1&3/Cont. Penetration on Fl. El. 115'-0"
16-79SL	Snubber movements restrained by 58S-33A, 58S-22R, & 58S-142R	1-S2-264-8 Cont. Spray PP1 Discharge/Cont. Penetration on Fl. El. 115' - 0"
16-68SL	Snubber movements restrained by 58S-126A & 58S-28R	1-S2-265 Cont. Spray Header/Cont. Penetration on Fl. El. 115'-0"
15-63SL	Snubber movements restrained by 58S-126A, 58S-159R, 58S-127R, & 58-160R	S2-2520-8 RHR PPS WTR Spray Headers/ Cont. Penetration on Fl. El. 115'-0"

Table 2 Continued

4-16SL	Installed on valve operator. The piping connecting to the valve was rigidly restrained	1-S6-48-3 CVCS/Let Down Ht. Exchange Rm. No. 11 on Fl. El. 85'-0"
22-401SL 22-400SL	These small bore branch pipes were restrained by the large bore pipe rigid restraints	K16-2477-3/4"/ Cont. Penetration on Fl. El. 115'-0"
16-77SL	Snubber movements were restrained by 5-14R	1-K2-316-12/Cont. Penetration on Fl. El. 115'-0"
16-80SL 16-81SL	Installed on valve operator. The piping connecting to the valve was rigidly restrained	1-S2-265-8 Cont. Spray/Cont. Penetration on Fl. El. 115'-0"
22-401 SL (Vert.) 22-400 SL (Hori.	S/B snubbers were installed in the same direction as rigid restraints on connecting L/B pipes	K16-2477-3/4"/ Cont. Penetration on Fl. El. 115'-0"
22-493 SL (Hori. on S/B pipe) 22-521 SL (Hori. on S/B valve)	Possible interaction w/rigid restraints 57-12 and the pipe penetration anchor	Stress Analysis No. 19-305, Rev. 1

3

2. Similar conditions also existed in anchor and rigid restraint installations. Anchors and rigid restraints with gaps were installed close to each other. An example is 58S-33A and 58S-32R. Unless the anchor is loaded to plastic deformation (beyond the design limit), the rigid restraint would probably not assume the design load.

D. Large Bore (L/B) and Small Bore (S/B) Snubber/Rigid Restraint Interaction Evaluations

1. Review of Bechtel Piping Stress Analyses

On January 9-11, 1984 and March 6-7, 1984, the inspector reviewed the subject material at the Bechtel office and at the site. The review and evaluation of piping stress analysis included analyses performed at the request of the inspector. In these analyses the questionable snubbers were omitted from the computer models. The results of the review and evaluation were summarized in Tables 3 and 4.

In Tables 3 and 4 the snubber operability acceptance criteria was based on the following manufacturer's test data:

Snubber Operability Acceptance Criteria

Snubber Type or Size	Pipe Frequency at 1st Vibration Mode (Hz)	Corresponding Snubber Dynamic Displacement, Tension or Compression		Test Load Tension or Compression (lb_c)
		Loss of Motion (in)	Total Deflection (in)	
PSA-⅛	9	.011 to .016	.025	350
PSA-½	9	.010	.0375	650
PSA-1	9	.003 to .010	.020	1,500
PSA-3	9	.012 to .016	.0625	6,000
PSA-10	8	.021	.052	15,000
A/D-41	9	.005 to .010	.030	422
A/D-71	9	.012	.031	767
A/D-501	9	.030	.051	5,000
A/D-5500	9	.021	.0585	60,392

2. Pipe Snubber/Rigid Restraint Interaction Evaluation Results

a. L/B Pipe Snubbers

(1) 8 out of 9 units or 89% will not function as required by design during the seismic event.

(2) 6 out of 9 units or 67% can be replaced by rigid restraints without causing a piping thermal stress problem.

Table 3

Large Bore Pipe Snubber/Rigid Restraint Interaction Evaluation

Affected Snubber No.	Designed by	Snubber Type & Size	Analysis No. (Bechtel Calculations)	Thermal Mvt. @ Snubber Loc. (in)	Seismic Mvt. w/o Snubber Modeled in Analysis			Test Data Snubber Lock up and Develop Load (in)	% Increase (+) or Decrease (-) @ Rigid Restr. or Pipe Stress	Design Evaluation		
					HOS (in)	DDE (in)	DE (in)			Justified per Thermal Mvt.	Justified per Pipe Stress & Support Leads	Operable During Seismic Event
4-2SL	PG&E	PSA-3	4-135/2	.009	.013	.002	.001	.0625	+16 (DE) +2.14(HOS)	No	No	No
4-33SL	Bechtel	PSA-1	8-109/2	.019	.159	.132	.066	.020	*	No	N/A	Yes
4-32SL	Bechtel	PSA-1	8-109/2	.011	.131	.112	.056	.020	*	No	N/A	Yes
16-47SL	Bechtel	PSA-½	2-105/2	.003	.376	.180	.090	.0375	*	No	N/A	Yes
16-49SL	Bechtel	PSA-½	2-105/2	.005	.298	.126	.063	.0375	*	No	N/A	Yes
16-63SL	Bechtel	PSA-10	4-102/4	.311	.169	.042	.021	.052	-8.5 (DE) -38.3(HOS)	Yes	No	No
16-67SL	Bechtel	PSA-1	8-117/4	.003	.099	.002	.001	.021	+11.6 (DE) -37.6(HOS)	No	No	No
16-79SL	Bechtel	A/D-71	8-116/2	.050	.011	.008	.004	.031	+ 6.8 (DE) +29.1 (HOS)	No	No	No
16-68SL	Bechtel	PSA-1	8-118/2	.104	.010	.002	.001	.020	- 4.9 (DE) + 9.9 (HOS)	Yes	No	No
15-63SL (a pair)	Bechtel	A/D-501	8-110/4	.019	.108	.030	.015	.051	+28.5 (DE) +39.3 (HOS)	No	No	No
16-77SL) (Hori.)	Bechtel	PSA-3	4-102/4	.043	.253	.162	.081	.0625))	+312 (HOS) Stress	No	No	Yes
16-29SL) (Vert.)	Bechtel	A/D5500	4-102/4	.191	.030	.018	.009	.0585))	@ Pene. No. 11	Yes Yes	No No	No No
16-80SL	Bechtel	PSA-½	8-118/2	.060	.017	.006	.003	.0375	*	No	N/A	No
16-81SL	Bechtel	PSA-½	8-118/2	.010	.374	.270	.135	.0375	*	No	N/A	Yes

* Snubber installed on valve operator for valve seismic qualification

Table 4

Small Bore Pipe Snubber/Rigid Restraint Interaction Evaluation

Affected Snubber No.	Designed by	Snubber Type & Size	Analysis No. (Bechtel Calculations)	Thermal Mvt. @ Snubber Loc. (in)	Seismic Mvt. w/o Snubber Modeled in Analysis			Test Data Snubber Lock up and Develop Load (in)	% Increase (+) or Decrease (-) @ Rigid Restr. or Pipe Stress	Design Evaluation		
					HOS (in)	DDE (in)	DE (in)			Justified per Thermal Mvt.	Justified per Pipe Stress & Support Leads	Operable During Seismic Event
22-401SL	PG&E	PSA-¼	3-313/1	.011	.089	.096	.048	.025	For most locations checked, no significant stress change	No	No	Yes
22-400SL	PG&E	PSA-½	3-313/1	.150	.266	.282	.141	.0375		Yes	No	Yes
22-493SL	PG&E	PSA-¼	19-305/1	.409	.393	.884	.442	.025	Valve component and bypass loop pipe were over-stressed w/o the snubbers	Yes	Yes	Yes
22-521SL	Bechtel	A/D-41	19-305/1	.701	.346	.772	.386	.030		Yes	Yes	Yes
22-543SL	Bechtel	A/D-71	S-045	.140	.046	.004	.002	.031	Insignificant pipe increase	Yes	No	No

(3) 9 out of 9 units or 100% can be removed without causing piping stress or support load that exceeds design limit.

(4) Maximum rigid restraint loading change due to inoperable installed snubbers in close proximity. + 39.3%; - 37.6%.

(5) There would be a significant pipe anchor stress increase if the nearby snubber failed to function as required.

(6) It is possible that the snubber is required because of large thermal piping movements; however, it would not be operable during a seismic event.

b. L/B Valve Snubbers

(1) 5 out of 6 units or 83% will function per design during the seismic event.

(2) 6 out of 6 units or 100% can be replaced by rigid restraints without causing piping thermal stress problem.

c. S/B Snubbers

(1) 4 out of 5 units or 80% will function per design during the seismic event.

(2) 1 out of 5 units or 20% can be replaced by rigid restraints without causing a piping thermal stress problem.

E. Review of PG&E Control of Field Problem Resolutions

1. Pullman Power Products Procedure ESD 223, "Installation and Inspection of Pipe Supports," dated August 23, 1983, states in Paragraph 6.7.1.2:

"Clearance dimensions specified as 0" on either side, top or side, top or bottom, and 1/8" on the opposite side shall have the following tolerances:

- 0" clearance on large bore supports must be maintained.
- For large bore supports 1/8" clearance shall be 1/8" within plus or minus 1/16" (from 1/16" minimum to 3/16" maximum).
- The gaps on all small bore supports shall be acceptable if the sum of the gaps on any axis is less than or equal to 3/16" except that the 0" gap in the negative-Y direction shall be maintained."

2. The following documents involved in PG&E engineering evaluations and approval of Hatfield questions concerning construction tolerances of 1/16", were reviewed by the inspector:

a. Diablo Problem (DP) Lot, Item H-1183, "Pipe Hanger Tolerances," General Construction to PG&E Headquarters dated February 14, 1977. PG&E Headquarters responded on February 18, 1977.

b. Intra-Company Letter, M. R. Tresler, Mechanical Resident Engineer to A. G. Walter (Supervising Engineer) "Pipe Hanger Tolerances," dated February 14, 1977. Items submitted for approval included:

Item 4. "A clearance gap of up to 1/8" between pipe or pipe attachment and the support is acceptable where 1/16" clearance gap is specified." The memo requested a return copy of approval with signature and date on the lower right corner.

c. Above letter was retyped, given a control number of DP-1-1183-M(H), and a new date of February 18, 1977. Item 4, "Total gap not to exceed 3/16"" was added. The acknowledgment was signed by R. E. Bancher (Senior Engineer), dated February 18, 1977.

d. DCP Engineering Office Special Instruction, "Design Questions Submitted by Steam Generation Department," dated November 22, 1977. This document was issued without review and approval signoffs.

e. Procedure Implementing Instruction, "Procedure for Handling DP's," by D. Polly (Licensing Engineer), dated August 12, 1978.

f. PG&E Co. Engineering Department, Nuclear Projects Department, Implementing Engineering Instructions, No. NPI-6.1, Supplement 1, "Design Questions," dated August 20, 1979. Approved by the Nuclear Projects Engineer.

g. PG&E Co. Nuclear Power Generation Department Procedure, No. D-444, "Design Question Administration," Rev. 0, dated June 3, 1981. Approved by Manager, NPS.

h. DCP Instruction No. 7, "Processing Diablo Problems," Rev. 0. dated August 10, 1982; Rev. 3, dated October 10. 1983.

3. Subsequent to the above document review, the inspector concluded that until August 12, 1978, there was no instruction on how to handle DPs. It was not until August 20, 1979, that a formal procedure was established on design question/problem evaluation by the design engineering organization. The problems concerning specific construction tolerance of 1/16" are as follows:

a. The February 14, 1977, field letter did not request an additional tolerance. The content of the letter was revised by the recipient and given a new date of February 18, 1977. Instructions on how the PG&E home office engineers can alter a field originated request is not specified in a procedure and as a result this alteration is considered improper.

b. The February 14, 1977, field letter requested PG&E Supervising Engineer's approval of the construction tolerance. The request was approved by a Senior Engineer. There were no provisions in procedures to permit a lower level of engineering approval of a field request. Furthermore, there was no document listing qualified reviewers who were designated to evaluate and approve specific field problems.

c. It was apparent that since August 10, 1982, (during the period of IDVP/CAP activities) control of the DP process had been upgraded. However, there was no evidence of any retroactive effort to retrieve all previously approved DPs to determine that (1) engineering dispositions and resolutions had been reviewed by qualified and designated engineers/departments, and (2) documentation was not maintained to substantiate that sufficient engineering evaluations had been made by the responsible individuals.

F. Review of Licensee and Bechtel QA Audits of OPEG

1. On December 6, 1983, during discussions with an OPEG QA Engineer, a Bechtel employee, the inspector requested audit and surveillance records covering the last 12 months. The areas of site design and document control were selected for review. The following audit reports were presented to the inspector:

a. Bechtel QA Audit No. 28.2-1, audit of onsite engineering in the areas of drawing control, conducted on November 5, 1982.

b. Bechtel QA Audit No. 28.4-1&2, audit of onsite engineering including personnel training, conducted on February 18, 1983.

c. Bechtel QA Audit No. 28.1-2, audit of onsite engineering including record retention, marking of SAR changes and superseded calculations, and verification of design assumptions, conducted on August 10, 1983.

2. During a meeting held at NRC Headquarters in Bethesda, MD, on December 15, 1983, licensee representatives presented the following additional QA audits:

	Audit	Date
a.	PG&E QA Audit 20703, "Approval of Implementing Procedures"	09/17/82
b.	PG&E QA Activity Audit 20917, "OPEG Drawing Control"	10/06/82
c.	PG&E QA Activity Audit 20813, "Incorrect Loads Used in Hanger Calc"	10/14/82

d.	Project QA Audit 28.1-1, "OPEG Design Calculations"	11/03/82
e.	PG&E QA Audit 83087A, "OPEG Control of Deviation from Design"	03/15/83
f.	PG&E QA Activity Audit 83159A, Maintenance of QA Records"	04/18/83
g.	PG&E Activity Audit 83161A, "Document Control: Indoctrination and Training Records	04/18/83
h.	PG&E QA Audit 83171A, "OPEG System Interaction Program - Inside Containment"	05/16/83
i.	PG&E QA Audit 83173A, "OPEG System Interaction Program - Outside Containment"	05/18/83
j.	Project QA Audit 28.2-2, "OPEG Design Change Procedure Compliance"	06/15/83
k.	PG&E QA Activity Audit 83259A, "OPEG Problem Report System"	06/20/83
l.	PG&E QA Audit 83187A, "Review and Approval Cycle of Drawings and Calculations"	07/27/83

m.	PG&E QA Audit 83341A, "Control of Design Changes"	08/05/83
n.	PG&E QA Audit 83339A, "OPEG Control of Design Documents"	08/08/83
o.	Project QA Audit 30.1-3, "OPEG SIP Activities	08/24/83
p.	PG&E QA Audit 83463A, "OPEG Audits"	09/12/83

3. On February 1-3, 1984, the inspector visited the Bechtel and PG&E offices and reviewed the following QA audit procedures, plans, and reports:

a. Audit Procedures and Plans

(1) PG&E QA Department QADP-18.2, "QA Audits," Rev. 2, dated October 3, 1983.

(2) Bechtel QA Department Procedure, Section C, Number 5, "Project Quality Audits," Rev. 7, dated September 24, 1982.

(3) PG&E QA Department - 1983 Activity Schedule for months of July to December.

(4) PG&E QA Department - 1982 Activity Schedule, approved on April 1, 1983 (as performed QA audits).

(5) Bechtel "QA Master Plan for DCP," Rev. 1, dated October 26, 1983.

(6) Bechtel "QA Quarterly Audit Schedule for DCP, August 30, 1982 through October 1, 1982," dated July 27, 1982.

(7) Bechtel "QA Quarterly Audit Schedule for DCP, October 4, 1982 through December 31, 1982." dated October 22, 1982.

(8) Bechtel "QA Quarterly Audit Schedule for DCP, January 3, 1983 through April 1, 1983," dated January 3, 1983.

(9) Bechtel "QA Quarterly Audit Schedule for DCP, April 8, 1983 through July 1, 1983," dated March 28, 1983.

(10) Bechtel "QA Quarterly Audit Schedule for DCP, July 5, 1983 through September 30, 1983," dated July 11, 1983.

(11) Bechtel "QA Quarterly Audit Schedule for DCP, October 7, 1983 through December 30, 1983," dated October 28, 1983.

b. PG&E Audit Reports

(1) No. 20703, dated September 14, 1982, "New OPEG Personnel Compliance with Approved Procedures," conducted on August 23-September 1, 1982.

Review included:

(a) Open Item Report (OIR) No. 147-82, dated September 17, 1982, stating that several implementing procedures were without required approvals. OPEG responded on December 21, 1982. QA close-out was dated October 6, 1983.

(b) OIR No. 148-82, dated September 2, 1982, stating that there was a lack of a controlled distribution system for site originated procedures. No project response was required. QA close-out was dated January 31, 1983.

(2) No. 20917, dated October 12, 1982, "OPEG Control of Velums per Procedural Requirements," conducted on September 23-October 5, 1982.

Review included:

(a) OIR No. 152-82, dated October 6, 1982, stating that superseded vellums were not marked and that there was a lack of controlled work procedures. OPEG responded on December 15, 1982, and a Discrepancy Report (DR) No.

82-184-S was issued. OPEG close-out of the DR was on April 18, 1983. QA close-out of the DR was dated May 17, 1983.

(3) No. 20813, dated October 19, 1982, "OPEG Support Modification in Compliance with DC1-EM-1090," conducted on October 14, 1982.

Review included:

(a) OIR No. 153-82, dated October 14, 1982, stating that there had been incorrect load data and deficiency document control and retrievability identified. OPEG responded on December 15, 1982, with DR 82-183-M. The DR was closed out on April 12, 1983 by OPEG. QA close-out of the OIR was dated May 9, 1983.

(b) OIR No. 154-82, dated October 14, 1982, stating that deficiencies had been identified in Pullman Power Product (PPP) as-built drawings. PPP responsed on November 3, 1982. QA close-out was dated August 17, 1983.

(4) No. 83087A, dated March 22, 1983, "OPEG Control of Construction Deviations," conducted on March 15, 1983.

(5) No. 83159A, dated June 2, 1983, "OPEG Quality Record Maintenance and Control," conducted on April 18, 1983.

(6) No. 83161A, dated May 28, 1983, "OPEG Personnel Indoctrination and Training Documentation Compliance with Engineering Manual Procedure 2.1," conducted April 18, 1983.

(7) No. 83171A, dated June 1, 1983, "System Interaction Program - Inside Unit 1 Containment," conducted on May 16-18, 1983.

(8) No. 83173A, dated May 5, 1983, "System Interaction Program - Outside Unit 1 Containment," conducted on May 10-17, 1983.

(9) No. 83187A, dated July 26, 1983, "OPEG Review and Approval of Calculations, Drawings, etc.," conducted on July 7, 13, and 14, 1983.

Review included:

(a) OTR No. 83-125, dated July 27, 1983, stating that approval of calculations by the Deputy Group Leader was not in accordance with work procedures. OPEG responded on August 4, 1983. QA close-out was dated August 16, 1983.

(10) No. 83259A, dated July 1, 1983, "OPEG Problem Report Process and Control," conducted on June 20, 1983.

(11) No. 83341A, dated September 15, 1983, "OPEG Procedures for Design Change Control," conducted on August 5 and 8, 1983.

Review included:

(a) OTR No. 83-185, dated August 17, 1983, stating that pipe support design tolerances were not approved properly and design changes were being made without documentation of calculations or assumptions. OPEG responded on September 30, 1983. QA close-out was dated October 17, 1983.

(12) No. 83339A, dated September 15, 1983, "OPEG Design Document Control," conducted on August 8-9, 1983.

(13) No. 83463A, dated September 27, 1983, "OPEG Internal Audit Planning, Performance, Reporting, and Followup Action Activities," conducted on September 12, 1983.

c. Bechtel Audit Reports

(1) No. 28.1-1, dated November 16, 1982, "OPEG Small Bore Pipe Support Calculation," conducted on November 3-5, 1982.

Review included:

(a) QA Finding (QAF) No. 1, dated November 4, 1982, stating that (1) calculation cover sheet incomplete, (2) sheet identification missing or incorrect, and (3) log indices incomplete. The scheduled correction completion date was

December 31, 1982. OPEG completion was dated January 11, 1983. QA close-out was dated April 28, 1983.

(2) No. 28.2-1, dated November 16, 1982, "OPEG Review of Contractor Developed S/B Piping and Support Drawings," conducted on week ending November 5, 1982.

Review included:

(a) QAF No. 1, dated November 4, 1982, stating that the P-10 procedure used was not approved. The scheduled correction completion date was November 30, 1982. OPEG completion was dated November 30, 1982. QA close-out was dated April 8, 1983.

(3) No. 28.4-1&2, dated February 28, 1983, "OPEG Personnel Indoctrination & Training," conducted on February 17-18, 1983.

Review included:

(a) QAF No. 1, dated February 18, 1983, stating that not all OPEG engineering personnel had received Engineering Procedure Manual training. The scheduled correction completion date was March 31, 1983. OPEG completion was dated March 14, 1983. QA close-out was dated May 10, 1983.

(b) QAF No. 2, dated February 18, 1983, stating that, "With one exception, no evidence was available to document training of supervisors to PEI's." The scheduled correction completion date was March 31, 1983. OPEG completion was dated April 20, 1983. QA close-out was dated April 21, 1983.

(4) No. 28.1-2, dated June 21, 1983, "OPEG Compliance with DCN Procedure," conducted on June 10-17, 1983.

Review included:

(a) QAF No. 1, dated June 17, 1983, stating incorrect use of DCNs had been identified. The scheduled correction completion date was July 1, 1983. OPEG completion was dated July 5, 1983. QA close-out was dated July 28, 1983.

(b) QAF No. 2, dated June 17, 1983, stating change reasons had not been given in DCNs. The scheduled correction completion date was August 1, 1983. OPEG completion was dated July 27, 1983. QA close-out was dated August 10, 1983.

(c) QAF No. 3, dated June 15, 1983, stating DCN sketches not been signed and dated. The scheduled correction completion date was August 1, 1983. OPEG completion

date was July 27, 1983. QA close-out was dated August 10, 1983.

(5) No. 28.1-2, dated August 24, 1983, "OPEG Calculation for DCP Unit 1 Compliance with Procedure," conducted on July 29 - August 16, 1983.

Review included:

(a) QAF No. 1, dated August 10, 1983, stating that preliminary and final calculations had not been entered into the Record Management System. The scheduled correction completion date was September 15, 1983. OPEG completion was dated October 27, 1983. QA close-out was dated December 20, 1983.

(b) QAF No. 2, dated August 10, 1983, stating where SAR change is required, no evidence of change was made. The scheduled correction completion date was September 15, 1983. OPEG completion was dated October 19, 1983. QA close-out was dated November 2, 1983.

(c) QAF No. 3, dated August 10, 1983, stating that inadequate references were stated in the final calculations. The scheduled correction completion date was September 15, 1983. OPEG completion was dated October 19, 1983. QA close-out was dated November 2, 1983.

(d) QAF No. 4, dated August 10, 1983, stating that Calculation No. 8-306 referenced incorrect design documents. The scheduled correction completion date was September 15, 1983. OPEG completion was dated October 19, 1983. QA close-out was dated November 2, 1983.

(6) No. 30.1-3, dated September 13, 1983, "OPEG System Interaction Program Implementation," conducted on August 22 - September 9, 1983.

Review included:

(a) QAF No. 1, dated August 24, 1983, stating that construction drawings were issued prior to approval of design calculations. The scheduled corrective completion date was October 20, 1983. OPEG completion was dated October 5, 1983. QA close-out was dated October 24, 1983.

d. Review Findings

Subsequent to the review, the inspector determined the PG&E and Bechtel QA audit programs and their implementation were deficient in the following areas:

Findings	Audits

(1) Inadequate Corrective Action

(a) Lack of timely (15 days was specified in the PG&E procedure) response to the QA findings from OPEG. The delays were without documented justification.

20703, dated 9/14/82
20917, dated 10/12/82
20813, dated 10/19/82

(b) The lack of timely response to an OIR was identified in a PG&E Nonconformance Report (NR) No. N005, dated Nocember 19, 1982. No documented evidence existed to indicate that QA had initiated actions against OPEG to ensure corrective actions. Instead, the NR was written stating that there was a lack of a tracking system within the QA Department and that the QA procedure should be revised. The development of a QA program revision was approved by management on September 21,

	1983. The revision had not been carried out as of the date of review (February 3, 1984).	
(c)	Bechtel audit finding corrective action scheduled completion dates were delayed without documented justification from OPEG.	28.1-1, dated November 16, 1982 28.4-1&2, dated February 28, 1983 28.1-2, dated August 24, 1983
(d)	Lack of PG&E audit finding corrective actions to identify the cause of the problem and the measures needed to prevent recurrence.	20703, dated September 14, 1982 20917, dated October 12, 1982 20813, sated October 19, 1982
(e)	Project corrective action only addressed specific problem areas identified in the PG&E audit findings and did not consider generic implication of the problems. QA concurred with this apparently inadequate corrective action.	20813, dated October 19, 1982

(f) Inadequate Bechtel QA verification of OPEG corrective actions prior to close-out of audit findings. OPEG Personnel training continued to be inadequate. 28.4-1&2

(g) Additional DDR's were reviewed at PG&E on February 15-16, 1984. A large number of DDRs show a close-out date many months after the problem disclosure. DDR No. 80-025, issued on October 16, 1980, was selected for review. The problem relates to engineering procedures do not require verification that only current documents are used. Engineering Department Procedure No. 2.4 was not revised to incorporate the requirement until Revision 2, dated February 22, 1982. Discrepancy and Departure Report (DDR) No. 80-025

(h) In conjunction with (g) above, on February 16, 1984, the inspector discussed the numerous late corrective action DDRs with the

PG&E Acting Senior QA Engineer. The inspector was informed that it was a PG&E management decision to place priority on closing out DCNPP Unit 1 DDRs. However, the inspector noted that there was as apparent lack of measures to evaluate the effects of the program deficiencies that were not corrected in timely manner and not covered by the IDVP and CAP.

(2) Inadequate QA Audits

(a)	When a QA audit item could not be evaluated due to a lack of project activities, followup of the item was not planned.	83087A, dated March 22, 1983
(b)	Lack of a QA audit verification that includes documentation of the material reviewed before an audit finding is closed out.	28.1-1, dated November 16, 1982
(c)	Lack of QA documentation of material reviewed during the	83161A, dated May 28, 1983

	course of the audit. The QA audit conclusions that stated "Indoctrination of training records are being maintained and controlled as required," and "Training and retraining have been conducted as required" were without basis and are contrary to NRC and subsequent Bechtel QA audit findings.	
(d)	Lack of technical QA audits to independently verify that OPEG calculation inputs were checked to be in compliance with engineering procedures.	83187A, dated July 26, 1983 28.1-1, dated November 16, 1982
(e)	An audit was planned to verify that OPEG issuance of Discrepancy Reports (DRs) was being implemented in accordance with procedures. DRs were not issued by OPEG until 1983. The DRs issued by OPEG to date are listed below. These DRs were issued during the NRC investigation.	Bechtel Audit No. 28.3 originally scheduled (w/e): December 17, 1872 1st postponement: August 5, 1983 2nd postponement: November 11, 1983

- DR 83-047-S, Procedures were not kept current, dated December 6, 1983

- DR 84-001-S, Support was modified for stress analysis, dated December 16, 1983

- DR 84-004-S, Base plate design was not per IE Bulletin 79-02, dated February 2, 1984

From late 1982 to Nov. 1983, there were hundreds of S/B piping stress analyses and support calculations performed by OPEG. The inspector considers that the Bechtel QA audits at the site were inadequate and that audits were not conducted or verifications made to determine the adequacy of OPEG actions taken to identify and correct design deficiencies

(f) An audit was planned to verify proper control of issuing and distribution of OPEG procedures. Two audit deficiencies were identified as:

Bechtel Audit No. 28.5
Originally scheduled (w/e) March 11, 1983
1st postponement: May 6, 1983
2nd postponement: August 2, 1983
3rd postponement: December 16, 1983
Conducted: January 9-February 2, 1984

- The auditor discovered that, since March, 1983, the control of OPEG procedures was conducted at the PG&E and Bechtel, San Francisco offices. There was no attempt made to revise the audit checklist to cover these activities.

- Approximately 10 months later the audit checklist was modified to cover the related OPEG activities. The inspector

considers that the benefits of timely audit to ensure program compliance had been compromised.

G. PG&E and Bechtel Control of Procured Engineering Services

During review of L/B snubber and rigid restraint interaction problems, the inspector was made aware that many of the L/B piping stress analyses were performed by outside consultants.

On February 21-23 and March 15, 1984, PG&E and Bechtel control of the procured engineering services was reviewed by the inspector.

1. Work Performed by the Consultants

Based on the Piping Stress Analysis Index as of January 6, 1984, the Bechtel engineers presented the following information:

a. Impell Corporation (Previously EDS, Nuclear Inc.)

Bechtel contracted with Impell in 1981. Most of Impell's work activities were conducted between October 1982 and August, 1983. The analysis performed included:

ANALYSIS NUMBER	SYSTEM SERVICE	REV NO.	ISSUE DATE
1-109	Main Steam Lead 3-Valve Bypass	3	06-06-83
1-111	Steam Generator Blowdown 1	2	05-06-83
1-112	Steam Generator Blowdown 2	2	05-11-83
1-113	Steam Generator Blowdown 3	2	05-11-83
1-114	Steam Generator Blowdown 4	3	07-29-83
1-116	Main Steam Isolation Valve 1	3	08-12-83
1-117	Main Steam Isolation Valve 2	*4	09-19-83
1-118	Main Steam Isolation Valve Bypass 4	3	08-12-83
2-115	Auxiliary Feedwater Supply	3	08-12-83
2-118	Auxiliary Feedwater Supply	3	08-18-83
2-119	Auxiliary Feedwater Supply	3	06-27-83
2-120	Feedwater Auxiliary Supply	4	06-23-83
4-109	CCW Return from PEN-20	2	06-06-83
4-110	CCW Return from PEN-21	3	06-03-83
4-110	CCW Return from PEN-21 Thermal Only	4	08-12-83
8-105	Cont. Spray Pump 1-1	0	11-17-82
8-118	Cont. Spray Suct. & Disch.	2	05-24-83
12-100	Fire Water Piping	2	07-29-83
12-101	Turbine Bldg Fire Prot.	2	07-18-83
12-102	Turbine Bldg North Fire Prot.	2	07-21-83

12-104	Fire Protection System	2	07-22-83
12-105	Fire Pumps 1 & 2 - Header	*5	10-21-83
12-106	Aux. Bldg Fire Protection	4	07-18-83
12-107	Aux. Bldg Fire Protection	3	08-15-83
13-104	Spent Resin Transfer System	0	11-05-82
13-109	Makeup Water Transfer Pumps	1	05-25-83
13-116	Makeup Water System	2	07-01-83
13-117	Makeup Water System	*2	12-24-83
13-118	Makeup Water System	*3	01-31-84
13-119	Cond. Stor. Transfer Pump	2	05-16-83
13-120	Makeup Water Trans Pump Disch	2	05-16-83
13-121	Makeup Water to Spent Fuel Pit	1	05-18-83

*Subsequent revision by DCP

b. Cygna Energy Services

Bechtel contracted with Cygna in 1981. Most of Cygna's work activities were conducted between October 1982 and August 1983. The analyses performed include:

ANALYSIS NUMBER	SYSTEM SERVICE	REV NO.	ISSUE DATE
2-109	Steam to Aux. Feed Pump Turbine	1	05-11-83

2-112	Aux. Feed-Steam Supply	3	05-26-83
2-113	Aux. Feed Pump Exhaust	1	06-01-83
2-114	Aux. Feedwater Pumps	*4	12-20-83
2-116	Steam Gen. 1-3 - Aux. Feedwater	*2	10-19-83
2-117	Aux. Feed Pump Turbine Supply	3	05-24-83
2-121	Make-up Water System	*4	10-21-83
2-122	Raw Water Storage Reservoir - Discharge	*1	12-30-83
3-104	Primary Water Support to PRT	2	05-10-83
4-113	CCW Header C	*2	12-07-83
4-115	CCW Branch Supply C	0	10-23-82
4-117	CCW Surge Tank Vent	1	05-17-83
4-118	Aux. Steam Drain Vent	1	06-16-83
4-119	Aux. Steam Drain vent-CCW Ret	1	06-17-83
4-120	CCW Evaporator-Condenser	1	02-14-83
4-121	Boric Acid-Concentrator Return	0	11-17-82
4-122	Evap. Cond. CCW Supply & Ret.	0	10-22-82
4-123	Component Cooling Water	1	01-12-83
4-124	Boric Acid Conc. Evap. Cond.	*1	12-29-83
4-125	Boric Acid-Concen Ret Hdr	2	07-27-83
4-126	Recip Charging PP-CCW Ret	2	07-27-83
4-127	Waste Gas Comp. CCW Hdr.	1	01-13-83
4-128	Waste Gas Comp. CCW Ret Hdr.	2	06-01-83

4-129	Waste Gas Comp. CCW Sup Hdr.	1	05-19-83
4-130	Water Gas Comp CCW Ret Hdr.	1	05-19-83
6-105	Boron Injection Line	3	08-08-83
8-104	Containment Spray Pump Suction	0	10-23-82
8-120	SIS Test Line RWST	3	06-14-83
8-122	Ventilation-Air Conditioning	1	04-07-83
8-123	Ventilation-Air Conditioning	1	07-27-83
8-124	Ventilation-Air Conditioning	0	11-16-82
8-125	Ventilation-Air Conditioning	0	11-17-82
8-126	Ventilation-Air Conditioning	1	02-08-83
8-127	CHPS. Exhaust Air Filter	2	07-27-83
8-128	Containment Hydrogen Purge System	2	07-27-83
8-129	CHPS Exhaust Air Filter	4	08-15-83
8-130	CHPS Exh. Air Fan Disch.	1	07-27-83
8-131	Ventilation-Air Conditioning	*4	10-07-83
8-132	Ventilation-Air Conditioning	*5	11-22-83
8-133	Ventilation-Air Conditioning	3	07-27-83
8-134	Ventilation-Air Conditioning	1	07-27-83
8-136	Ventilation-Air Conditioning	1	04-06-83
8-137	Ventilation-Air Conditioning	1	04-06-83
9-118	Charging Pumps Disch Header	*2	10-12-83
9-119	CVCS Letdown-Vol Control Tank	*2	12-20-83
9-120	Sealwater Heater Ret-Part 1	2	06-01-83
9-121	Seal Water Return	*5	02-08-84

9-122	CVCS-Seal Water Return	*2	12-08-83
9-123	Chem & Volume Control	2	05-19-83
9-124	Seal Water Return from Cont.	1	05-19-83
9-125	Condensate Storage Water	*2	02-09-84
9-126	Vol & Cont Tank-Vent & Relief	1	06-01-83
9-127	CVCS Letdown Line-Vol Cont Tank	2	01-05-84
9-128	RHR	0	02-14-82
13-103	Refueling Canal Rearc. Inlet	1	01-10-83
13-105	Refueling Canal Return	2	07-27-83
13-106	Service Air Penetration Header	2	07-29-83
13-107	Spray Additive Tank 1-1	0	10-29-82
13-111	Refueling Canal Rearc. Inlet	1	04-07-83
13-112	Service Air Penetration Header	*3	08-29-83
13-113	Refueling Canal Return	2	05-25-83
13-114	Primary Water Supply to PRT	2	06-08-83
13-115	Spray Additive Tank 1-1	2	07-06-83
13-123	CVCS Letdown Line	*2	12-02-83
17-100	Aux Saltwater Piping	4	06-29-83
17-101	Aux Saltwater Piping	4	06-29-83
17-102	Aux Saltwater Piping	0	06-23-83
17-103	Aux Saltwater Piping	0	06-23-83
21-100	Engine Crankcase Exhaust 1-1	2	07-19-83
21-101	Engine Crankcase Exhaust 1-2	2	07-18-83

21-102	Engine Crankcase Exhaust 1-3	2	07-18-83
21-103	Diesel Eng. Gen. Systems	0	10-31-82
21-104	Diesel Eng. Generator	1	04-27-83
21-105	Fuel Oil Transfer	1	04-27-83
21-106	Diesel F. O. Pump Discharge Out	0	11-02-82
21-107	Diesel F. O. Pump Discharge Out	0	11-02-82
21-108	Diesel Engine Gen. Systems	0	11-22-82
21-109	Diesel Engine Generator	0	11-11-82

*Subsequent revision by DCP

c. Westinghouse Electric Corporation (W)

PG&E has had a contract with PG&E since 1975. Most of the W work activities relative to the CAP were conducted between late 1982 and August, 1983. The analyses performed include:

ANALYSIS NUMBER	SYSTEM SERVICE	REV NO.	ISSUE DATE
ACC1/RHR1	Accumulator & Residual Heat Removal	1	08-24-83
ACC2/RHR2	Accumulator & Residual Heat Removal	1	08-01-83

ACC3/RHR3	Accumulator & Residual Heat Removal	1	08-01-83
ACC4/RHR4	Accumulator & Residual Heat Removal	1	08-24-83
FW1-4	Feedwater 1-4	2	08-24-83
SI-1-2	Safety Injection	1	08-01-83
SI-3	Safety Injection	1	08-24-83
P SURGE	Pressurizer Surge	1	08-24-83
RHR-4	Residual Heat Removal - Loop 4	1	08-24-83
MS1/MS2	Main Steam Leads 1 & 2	2	08-09-83
MS3	Main Steam Lead 3	1	08-09-83
MS4	Main Steam Lead 4	1	08-24-83
PSARV	Pressurized Safety Relief Valve	0	10-12-83

2. Review of Engineering Service Contracts

The inspector reviewed the following contracts and agreements and determined that the scope of work was properly defined:

a. Agreement for Technical Services, No. 7PE-TSA-2, Between Bechtel Power Corporation and EDS Nuclear, Inc. (now Imprell), dated February 5, 1981.

b. Agreement for Technical Services, No. 7PE-TSA-13, Between Bechtel Power Corporation and Earthquake Engineering Services (now Cygna), dated February 5; 1981.

c. PG&E Request for Services No. 5-24-82 to Westinghouse Electric Corporation, "Technical Support of Seismic Reverification, Unit 1 - Diablo Canyon Site", dated May 4, 1982, including Change Orders No. 1 to No. 6 from June 18, 1982 to October 20, 1983.

3. PG&E and Bechtel Acceptance of Contractor QA Manuals

The inspector reviewed the following correspondence and related conformatory review and commentary documentation and had no adverse findings.

a. W letter, No. PI&DA-82-639, Manager, PG&E Project to PG&E Chief Mechanical Engineer, "PG&E Co. Nuclear Plant, Diablo Canyon Site Westinghouse WRD QA Program", dated March 11, 1982.

b. Bechtel letter, Chief Plant Design Engineer to Inprell QA Manager, "Review of EDS QA Manual, Rev. 16", dated January 7, 1983.

c. Bechtel Interoffice Memorandum, No. 303QE101, 0020MCYGNA, Supervisor Quality Engineering to QA Manager, "Cygna QA Manual, Rev. 11," dated April 18, 1983.

4. Design Interface Control

a. The inspector reviewed DCP Instruction No. I-26, "Instruction for Control of Interfaces Between DCPO and outside Consultants", dated September 14, 1982, prepared and approved by DCPO, Cygna, and Impress and had no adverse comment.

b. There was no documented and proceduralized control relative to design interfaces between PG&E and W for performing seismic re-verification work as defined in the IDVP and Corrective Action Program.

5. DCP Control of Procedures to be Used by the Contractors

Inspection incomplete.

Preliminary findings:

a. Lack of measures to ensure that contractors had received required design criteria.

b. Lack of justification on unrequired criteria and procedures being sent to the contractors.

6. DCP Audits of Procured Engineering Services

a. Technical audits have not been performed by PG&E and/or Bechtel of the design and analysis activities conducted by Imprell, Cygna, and W.

b. Design procedures and instructions utilized by Imprell, Cygna, and W had not been reviewed and approved by the PG&E and Bechtel engineering and QA departments.

c. PG&E did not perform QA program type audits of W in 1983, when most of the CAP analytical work was carried out.

d. The PG&E QA program audit of W, No. 20506, "Seismic Re-Verification", conducted on May 25-28, 1982, did not include a review of piping analysis and pipe support calculation to ensure implementation of procedural requirements.

e. The inspector reviewed the following Bechtel QA program type audits of Imprell and Cygna, and considered them to be adequate.

- Bechtel QA Audit OE-332, audit of Imprell's implementation of the QA program for DCNPP, conducted on June 20-21, 1983.

- Bechtel QA Audit OE-331, audit of Cygna's implementation of the QA program for DCNPP, conducted on June 7, 1983.

7. Review of Contractor Engineering Company Internal Audits

a. Imprell

(1) QA program type audits included:

- Audit No. A04-1030, "DCPs" conducted on October 5-14, 1982.

- Audit No. A-83WR-13, "DCPs", conducted on May 31 through July 5, 1983.

(2) The technical audits included the following Engineering Division "Design Review Reports":

- "Pipe Support Design Project Instructions and Design Drawings and Calculations", dated October 15, 1982.

- "Pipe Support Design and Qualification," dated March 8, 1983.

- "Piping Analysis", dated April 8, 1983.

- "Pipe Support Verification Task", dated October 4, 1983.

. "Piping Analysis", dated November 25, 1983.

The inspector concluded that the audits and associated reviews conducted by Imprell were adequate and acceptable.

b. Cygna

(1) QA program type audits included:

. Audit No. 83-1, "Report of Audit of the San Francisco Office", conducted by Cygna, Boston office QA on January 17-21, 1983. Paragraph V contains areas related to DCNPP.

. Inspection/Surveillance Reports No. 1 to No. 17, conducted between September 21, 1982 and November 23, 1984.

(2) Internal technical program audits have not been performed by Cygna. Cygna management stated: (1) contractually, the technical audits are to be performed by Bechtel, (2) there had been a total of 142 informal "Design Verification Reports" prepared for various types of supports, and (3) piping stress computer runs were checked against the printout configuration plots. The isometric drawings that were plotted were discarded after use.

The inspector concluded that the Cygna QA program type audits were acceptable, but the adequacy of technical review for design analysis calculation was questionable.

c. Westinghouse

(1) QA program type audits included:

- Audit Report IA-83-03, "Design Control - Structural and Equipment Engineering", dated August 5, 1983. The audit areas involving DCNPP were contained in Paragrah 4.0 which indicated a review of as-built piping analysis packages of Safety Injection System (SIS) and Pressurizer Surge System (PSS) had been performed. The report found that there was a lack of a formal interface system. The audit concluded that the matter was insignificant because the NSSS contract had been completed.

(2) Technical audits had not been performed.

The inspector concluded that the W internal audits were inadequate and unacceptable in both the QA and technical areas. The QA program type audit was deficient in that: (a) there was no discussion on what specific areas of the SIS and PSS had been

reviewed, and (b) the original audit checklist findings/records had been systematically destroyed in accordance with W management policies.

H. Review of PG&E and Cloud IDVP Documentation

1. The inspector reviewed the IDVP conducted for S/B piping and piping suspension systems.

a.. A summary of data is included in Table 5 below:

Table 5

NRC Review of Licensee S/B Piping Design Verification Program

Piping Analysis	Support Calculation	Hardware Change
1. Total footage of pipe based on summation of average measurement on piping isometrics	1. Total estimated number of supports	
43,000	3,715	

2. Total ME-101 computer analysis 25,000'	2 & 3. Total pipe supports evaluated: a. Detailed analysis 1,800 b. Prequalified standard supports 415 Total: 2,215	2 & 3. Total support modifications including additions, deletions, and component upgrading 1380, or 1380/2215 = 62.3%
3. Total M-40 hand calculations 3,000'		
4. Total number of File cookbook type analysis that were without design documentation and were not verified by PG&E 15,000' or 34.9% of total S/B piping	4. Total pipe supports that have not been re-analyzed 1,500 or 40.4% of total S/B supports	4. None

b. NRC Concerns After Review of the Licensee's S/B Piping Design Verification Program Implementation:

1. The justification for accepting 15,000' of S/B pipe and the associated 1,500 safety-related supports, without further evaluation, is based on a review of a sample of piping analyses for 5,000' of pipe using the ME-101 computer program.

Analysis Methods Included in the 5,000' of Pipe

1,000' Hot Pipe	4,000' Cold Pipe
Thermal - MEL 40	600' - PIPSD
Seismic - PIPSD	3,400' - File 44

19 ME-101 Analyses were Performed on the 5000' of Pipe

10 ME-101 Included:	9 ME-101 Included:
4 active valves	Pure File 44 ?
4 Code Breaks	
5 SAM/TAMs	

PG&E, "Phase I Final Report Design Verification Program, DCPP, "Rev. 2, dated June 20, 1983.

Inspector questions that require response.

a. How many feet of pure File 44 piping was analyzed to determine that no further evaluation was needed?

b. Among the 62.3% of supports that required hardware modification, how many were installed on piping originally analyzed by the File 44 procedure?

Followup review and evaluation had not been conducted.

2. Robert L. Cloud and Associates, Inc., Interim Technical Report (ITR) No. 61, "Diablo Canyon Unit 1 IDVP Verification of Corrective Action - Small Bore Piping," Rev. 1, dated October 2, 1983.

The ITR reviewed: 8 ME-101 computer analyses
4 M-40 hand calculations.

Inspector question that requires response.

a. Why didn't the review include the adequacy of the File 44 span rule and its implementation and a PG&E "qualification by sample" methodology?

Followup review and evaluation had not been conducted.

3. Cloud ITR No. 60, "Diable Canyon Unit 1 IDVP Review of Corrective Action Large and Small Bore Pipe Supports," Rev. 1, dated October 3, 1983.

In the areas of engineering review, the ITR reviewed:

22 Large Bore Supports
8 Small Bore Supports

Inspector questions that require response.

a. Why weren't the L/B snubber/rigid restraint, rigid/rigid restraint, rigid restraint/rigid restraint interaction, and snubber ALARA problems not reviewed?

b. In conjunction with the large amount of computational errors that were identified by the NRC during the S/B support review and the ITR's own finding of similar problems, why did the Cloud S/B review conclude that the IDVP was acceptable without an additional sample review?

c. How did Cloud conclude that the "Corrective Action" was acceptable based on the small* sample size reviewed and with large number of errors identified?

* 8/3,715 = 0.22% Total piping population

8/2,215 = 0.36% Total IDVP evaluated

8/1,800 = 0.44% IDVP w/documentation

Followup review and evaluation had not been conducted.