TASK FORCE REVIEW OF OPERATIONAL HISTORY

FOR D. C. COOK UNITS 1 AND 2

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TABLE OF CONTENTS

1. SUMMARY

An evaluation was performed by a special five member Regional team on operational performance of the D. C. Cook Nuclear Plant. The time period for the evaluation was January 1983 to September 1985. The evaluation consisted of a selected review of NRC and licensee records related to regulatory performance, and interviews with licensee personnel and NRC inspectors. It also consisted of an evaluation of selected specific functional areas which impact regulatory performance. The results of these evaluations are documented in two sections of the report "General Regulatory and Operational Performance" and "Licensee Performance in Specific Functional Areas."

There were 84 total site violations over the 33 months included in the review with 40 issued in 1983, 24 issued in 1984, and 20 issued through September 1985. From an operational standpoint the number of trips for Unit 1 do not appear excessive (one in 1983, three in 1984, and none in 1985) but Unit 2 is much worse (five in 1983, nine in 1984, and three in 1985). There were 25 other ESF activations for Unit 1 and 33 for Unit 2 with 90% of these being containment purge isolations (21 for Unit 1 and 31 for Unit 2). There is no obvious explanation why Unit 2 is so much worse than Unit 1.

Both Units had approximately the same number of outages, nine for Unit 1 and 10 for Unit 2. However, only three of those for Unit 1 were forced outages whereas eight of the 10 for Unit 2 were forced. In addition, six of the eight for Unit 2 were due to leaks in the steam generator tubes but none of the Unit 1 outages were caused by this.

The plants appear to have two major problem areas; personnel errors (which includes some procedure violations) and missed surveillances. Other problems also were identified: excessive ESF actuations involving radiation monitors; excessive numbers of condition reports which must be reviewed, resulting in a time and work drain on management; failure to evaluate trending data; excessive number of open safety-related plant modifications; some failures to honor commitments; and unauthorized procedure changes.

The licensee is building an onsite training facility which will include a site specific simulator and training accommodations for crafts people as well as licensed operators. There are no licensing problems and NRR is satisfied with the licensee's performance in that regard. The licensee recently initiated a program to improve its performance in radiation protection. Plant morale is high and nearly all personnel expressed confidence and support for plant management.

2. INTRODUCTION

To further augment Region III's assessment of licensee performance, a special task force was formed to review the operational history of the D. C. Cook plant. The basic thrust of the review was to attempt to identify problem areas that have existed or now exist, and what has been done or should be done about them. The task force consisted of a Regional Project Manager as Team Leader, a D. C. Cook resident inspector, a former D. C. Cook resident inspector, and two Regional-based inspectors.

The methodology consisted of a review of NRC and licensee documents such as inspection reports, LERs, and condition reports and interviews with NRC and plant personnel. The time frame for the reviews was taken as January 1, 1983, to the present (September 1985) for both units.

3. DISCUSSION

The first section discussed below is the overall licensee performance in regulatory and operational matters. The second section is a discussion of specific areas which the team believed would help it to perform an overall licensee evaluation.

3.1 GENERAL REGULATORY AND OPERATIONAL PERFORMANCE

Regulatory and operational performance of D. C. Cook is discussed in the following sections.

3.1.1 NUMBER AND CAUSES OF VIOLATIONS

	Year	III	IV	V	Total
Unique to Unit 1	1983	0	4	1	5
	1984	0*	4	2	6
	1985	0	1	0	1
Total		0*	9	3	12
Unique to Unit 2	1983	0	8	3	11
	1984	0	3	2	5
	1985	0	0	1	1
Total		0	11	6	17
Common to Units 1 & 2					
	1983	0	16	8	24
	1984	1*	6	6	13
	1985	2	14	2	18
Total		3*	36	16	55
Total site violations					84

*3 violations (2 from Unit 1 and 1 common to Units 1 and 2) were combined for 1 Level III violation.

As is noted, from 1983 through about July 1985, 84 violations have been issued to the D. C. Cook plant by the NRC. These can be categorized as follows:

Category	Severity Levels III	IV	V
1. Failure to follow procedures	0	6	7
2. Inadequate procedures	0	6	5
3. Management (Nuclear Safety Design Review Committee) review problems	0	7	3
4. Surveillance problems	0	10	5
5. Communications (interface) problems	0	3	1
6. QA/QC problems	0	4	3
7. Switches/valves mispositioned	1	7	0
8. Inadequate corrective actions	0	7	1
9 Security	2	*	*
10. Miscellaneous	0	6	0

*The evaluation team did not evaluate the security functional area. Therefore, other than the two Level III violations listed, the above violations do not include any other security violations.

3.1.2 SUMMARY OF THE THREE LEVEL III VIOLATIONS

3.1.2.1.a Both of Unit 1 engineered safety feature ventilation trains were inoperable in excess of the time limit of technical specification 3.0.3. One train was inoperable for maintenance and the other train was inoperable because the control switch was in "off" which defeated the auto start features. (Inspection Report 315/84-18)

3.1.2.1.b Both of Unit 1 motor driven auxiliary feedwater pumps were inoperable because plant practice allowed the operators to place the control switch in neutral which defeated some of the auto start features. (Inspection Report 315/84-18)

3.1.2.1.c The Units 1 and 2 turbine driven auxiliary feedwater pumps had been inoperable for an unknown period of time because the setting of the governor valve controls defeated the automatic features of the pump. The setting would allow the pumps to achieve a discharge pressure of 900 pounds and then require operator action to establish the desired discharge pressure and flow. (Inspection Report 315/84-18; 316/84-20)

3.1.2.2 Three instances of failure to properly control vital areas were identified. Two of the instances were identified by the licensee and one was identified by the resident inspector. (Inspection Report 315/85018; 316/85019)

3.1.2.3 The licensee failed to comply with the appropriate reporting requirements when item 3.1.2.2 above was identified. (Inspection Report 315/85018; 316/85019)

3.1.2.4 In addition to the three Severity Level III violations discussed above, Region III currently is reviewing six recent Severity Level IV violations pertaining to surveillance testing to determine if they should be combined into one Severity Level III violation. None of these violations are reflected in any of the data above.

3.1.3 <u>CIVIL PENALTIES</u>

3.1.3.1 Item 3.1.2.1 above resulted in assessment of a $50,000 civil penalty. The licensee has paid the civil penalty.

3.1.3.2 Items 3.1.2.2 and 3.1.2.3 above each were assessed a civil penalty of $50,000 for a total of $100,000. The licensee's response to this civil penalty package is pending.

3.1.4 <u>ENFORCEMENT CONFERENCES</u>

3.1.4.1 March 16, 1983 (Glen Ellyn, Illinois): Enforcement Conference to discuss QA/QC controls related to the improper repair of a safety-related valve and the failure of the containment spray eductor to pass a surveillance test.

3.1.4.2 October 31, 1983 (D. C. Cook Plant site): Enforcement Conference to discuss a violation involving apparent inoperability of a diesel generator and valving error (diesel generator day tank and boron injection tank sample valve).

3.1.4.3 September 7, 1984 (Glen Ellyn, Illinois): Enforcement Conference to discuss three examples of inoperable safeguards equipment. Civil penalty of $50,000 issued/paid.

3.1.4.4 October 26, 1984 (D. C. Cook Plant Site): Enforcement Conference to discuss events involving an inoperable fire damper.

3.1.4.5 July 1, 1985 (Glen Ellyn, Illinois): Enforcement Conference to discuss three examples of degraded vital areas. Civil penalty of $100,000 issued. Licensee response pending.

3.1.5 MANAGEMENT MEETINGS

3.1.5.1 June 22, 1983 (Glen Ellyn, Illinois): Management meeting to discuss SALP - April 1, 1982 to March 31, 1983.

3.1.5.2 October 31, 1983 (D. C. Cook Plant site): Management meeting to discuss access controls, reportability of leakage in the containment closed cooling water system and the Licensee Regulatory Performance Improvement Program (RPIP).

3.1.5.3 December 8, 1983 (Glen Ellyn, Illinois): Management meeting to discuss RPIP.

3.1.5.4 January 31, 1984 (Glen Ellyn, Illinois): Management meeting to discuss RPIP.

3.1.5.5 February 27, 1984 (D. C. Cook Plant site): Management meeting to discuss RPIP.

3.1.5.6 March 28, 1984 (D. C. Cook Plant site): Management meeting to discuss RPIP.

3.1.5.7 May 3, 1984, (D. C. Cook Plant site): Management meeting to discuss RPIP.

3.1.5.8 June 21, 1984 (D. C. Cook Plant site): Management meeting to discuss SALP - April 1, 1983 to March 31, 1984 and to discuss RPIP.

3.1.5.9 October 26, 1984 (D. C. Cook Plant site): Management meeting to discuss RPIP.

3.1.5.10 March 5, 1985 (D. C. Cook Plant site): Management meeting to discuss RPIP.

3.1.5.11 October 3, 1985 (Glen Ellyn, Illinois): Management meeting to discuss Radiation Protection Program Improvement Plan.

3.1.6 REACTOR TRIPS

	Unit 1	Unit 2
1983*	1	5
1984	3	9
1985	0	3

*Data for 1983 may not be accurate because trips or challenges to the RPS system were not required to be reported until January 1984.

Two of the Unit 1 trips and six of the Unit 2 trips were due to failures of the vital bus inverters and all of these occurred while the reactors were operating at full power. The inverters failed when internal components (such as capacitors) failed because of overheating. The root cause or source of the heat was determined to be from the inverter power sources which were located inside the inverter cabinets. Three of the trips occurred in mid-1983, four occurred in mid-1984, and the last one occurred in January 1985. Temporary measures were taken to prevent such trips by installing air conditioners until permanent corrective actions could be taken. The permanent fix involves relocating the power sources outside of the cabinets. This has been completed for Unit 1 and will be completed for Unit 2 during the cycle 5-6 refueling outage. This should eliminate the problem.

Three of the Unit 2 trips involved no rod movements because the reactor was shut down. However, because they did involve challenges to the RPS, they were reportable pursuant to 10 CFR 50.73. None of the Unit 1 trips fell into this category.

There is no obvious explanation for the 9 trips for Unit 2 in 1984 as no more than two were caused by any one type of event (failure of vital instrument bus). The team could identify no reason why Unit 2 is experiencing more trips than Unit 1 (17 for Unit 2 compared to 4 for Unit 1).

Appendix A is a listing and brief description of each trip listed above.

3.1.7 OTHER ESF ACTUATIONS

Although the reactor trips were reviewed for the time period January 1, 1983 to August 1985, other ESF actuations were reviewed only for the time period January 1, 1984, to August 1985, because that is when the new LER reporting criteria became effective which required all ESFs to be reported.

Of the total of 58 other ESF actuations for both Units noted in Appendix B (not including reactor trips, which were discussed in the previous section) 90% were the result of inadvertent containment purge isolations. The actual breakdown by Unit is:

Unit 1

Cause	Containment Purge Isolations	Other ESFs
Deficient Procedure	7	2
Personnel Error	0	2
Equipment Malfunction	14	0
Totals	21	4

Unit 2

Cause	Containment Purge Isolations	Other ESFs
Deficient Procedure	6	0
Personnel Error	11	1
Equipment Malfunction	14	1
Totals	31	2

All 14 isolations for Unit 1 caused by equipment malfunction and nine of the 14 for Unit 2 caused for the same reason were the result of detector software problems that were resolved by the vendor. For Unit 2 these occurred during a one month period in March and April 1984, and for Unit 1 they occurred during a three day period in April 1985.

Most of the other containment purge isolations for both units were caused by deficient procedures involving radiation detectors combined in many cases with personnel errors. Procedurally at D. C. Cook the set points for these detectors are maintained no higher than twice background, and they must be adjusted daily during operation and continually during reactor startup. If they fail to do so, a containment purge isolation occurs. Historically this has resulted in many such events.

The issue of containment purge isolations bears further discussion because of what the team believes is an inadequate approach to correcting the problem. The basic issue relates to isolations caused by the radiation monitors.

As the team understands it, the type of radiation monitors used by the licensee for containment purge isolations, and problems caused by it, are not unique to D. C. Cook. These types of instruments are "noisy" in low background conditions. Nevertheless, Regulatory Guide 1.105 presents an NRC position that "setpoints should be established with sufficient margin between the technical specification limits for the process variable and the

nominal trip setpoints to allc for (a) the inaccuracy of the instrument, (b) uncertainties in calibration, and (c) the instrument drift that could occur during the interval between calibrations." Yet exceeding radiation monitor setpoints has caused, and continues to cause, the containment purge isolations at D. C. Cook. Furthermore, it appears that the licensee's approach to resolving the problem is not to fix the hardware but to change the reporting requirements. Following are specific examples taken from recent LERs:

Date	LER	Corrective Action
4/11/84	84007 (Unit 2)	"ERS-2405 had been set at the lowest suggested setpoint at the time of the incident. Due to the statistical variations in the detection of radioactive decay, coupled with the low ambient activity, normal statistical fluctuations in the detected activity account for the high alarm activation in this event. In order to prevent a recurrence, an alternate methodology for calculating the fixed background subtract has been developed that responds to the statistical fluctuations associated with very low levels of radioactivity."
4/18/84	84006 (Unit 2)	"Each Unit's procedure has been revised to identify expected situations which will prevent the need to report any similar incidents of this nature."
5/4/84	84011 (Unit 2)	"At the time of these occurrences, the containment purge procedures did not address expected results or preplanned sequences identified in NUREG-1022 Paragraphs 50.73 (a)(2)(iv). Each unit's procedure has been changed to identify this expected situation which will prevent the need to report any similar incidents of this nature."

6/23/84	84012 (Unit 1)	"The reason for the alarm setpoint being reached has been attributed to the normal increases in containment radiation levels associated with power ascension.... Procedural changes have been made in an effort to preclude recurrence."
1/29/85	85004 (Unit 1)	"Reactor power was being increased causing the containment airborne activity to trend upward.... To prevent recurrence a procedure change will be made by March 9, 1985, to identify expected results or preplanned sequences which will prevent the need to report any similar expected incidents of this nature."
8/19/85	85017 (Unit 2)	"Containment radioactivity was increasing during the Unit 2 startup causing the high alarms on the containment particulate, noble gas, and area monitors....To prevent recurrence the containment purge procedure has been revised to include increases in containment radioactivity due to reactor startup in a list of expected or preplanned sequences that could give high alarms and result in ESF actuations as identified in 10 CFR 50.73 (a)(2)(iv). Also, a containment particulate, noble gas and area monitor channel alert alarm will be utilized to provide an indication to the operators for the need of a high alarm setpoint evaluation and adjustment during power ascension."

In the approximate 18 month period covered by these six LERs, the licensee stated five times that the corrective action would be to change the procedures to preclude having to report future events. The team does not agree

with the licensee's "fix" of eliminating the problem by changing the reporting requirements. The purpose of 10 CFR 50.73(a)(2)(iv) is to preclude reporting planned events or events that are unusual but expected. The licensee's interpretation is a misuse of the non-reporting requirement. The team confirmed with the Office for Analysis and Evaluation of Operational Data (AEOD) that the licensee's interpretation is incorrect. The containment purge isolations may be expected, but they are not planned and therefore are reportable. The ultimate solution is to fix the problem.

The excessive number of ESF actuations at Unit 2 and failure to fix the problem also was recognized and discussed in a memorandum dated August 28, 1985, from C. J. Heltemes, Jr., Director of AEOD, to Harold Denton and Regional Administrators. (The discussions in the memo were not limited to Unit 2 of D. C. Cook but also included Fort Calhoun, LaSalle 1 and 2, San Onofre 2 and 3, Sequoyah 1 and 2, and WPPSS.) This memorandum concluded that repeated unresolved actuations could challenge continued equipment operability and proper personnel response. AEOD stated it would continue to monitor this item to determine if indicated corrective actions were being taken to resolve these actuations. (Corrective actions mentioned were reducing equipment failures during operation; reducing personnel errors, and revising actuation setpoints.)

In summary, 52 of the 58 other ESF activations were due to inadvertent containment purge isolations. There were two main causes for these: software problems, which accounted for 23 and which have been corrected; and personnel errors exacerbated by procedural deficiencies and equipment limitations and which still are occurring.

3.1.8 OUTAGES

The Unit 1 and Unit 2 forced and scheduled outages from January 1983 to September 1985 were reviewed to determine if any favorable or adverse trends were identified. A listing of all outages that required the licensee to remove the units from service is provided in Appendix C.

A review of the nine Unit 1 outages showed that only three of them were forced and none of these three were related. The Unit was shut down twice during fuel cycle 8 to perform ice condenser surveillance tests because during that cycle Unit 1 was required to test the opening force of the ice condenser door every six months and to weigh the ice every nine months. Amendment 83 to the Technical Specifications subsequently was issued to require that the opening force of the door and the weighing of the ice both be checked every nine months. This made Unit 1 Technical Specifications

consistent with Unit 2 Technical Specifications and with the Standard Technical Specifications. This therefore should eliminate one unnecessary shutdown during a normal operating cycle.

During the period covered by this report Unit 2 was removed from service 10 times and eight of these were forced including six to repair primary-to-secondary tube leakage. Three of the outages to repair steam generator tubes occurred during fuel cycle 4 and three occurred during fuel cycle 5. During the cycle 4-5 refueling outage the licensee performed 100% eddy current testing on all steam generator tubes. At that time all tubes with greater than 40% degradation were plugged (40% degradation is the Technical Specification limit). Approximately 12 months later, during the three forced outages in cycle 5, the licensee plugged approximately 95 additional tubes which had degraded more than 40%. Some of these tubes had 100% through-wall degradation and most of them had degraded greater than 40% since the cycle 4-5 refueling outage. A Region III specialist had been onsite for the eddy current testing performed during the cycle 4-5 outage and he identified no problems with the testing. Therefore, there may be generic implications of this accelerated degradation. The licensee has a program under way to try to determine the cause of the accelerated tube degradation and plans to sleeve tubes during the upcoming cycle 5-6 refueling outage. However, to date, the licensee has not determined the cause of the degradation.

3.1.9 CONFIRMATORY ACTION LETTERS (CALs)

There were three CALs issued to D. C. Cook since January 1983:

1. November 17, 1983 - A CAL issued to assure prompt and effective actions to correct problems with review, audit, and engineering design verification activities of the corporate Nuclear Safety and Design Review Committee.

2. August 21, 1984 - A CAL issued confirming that six senior operators who failed a written requalification examination would be prohibited from performing licensed activities until they satisfactorily completed an accelerated requalification program.

3. August 30, 1985 - A CAL confirming actions the licensee would take as a result of an inspection conducted by an NRC Headquarters Team from August 19-28, 1985.

3.1.10 MAINTENANCE REQUESTS

The licensee uses job orders as the mechanism to authorize, perform and document required maintenance work. The three classifications of job orders are: standard; emergency; and, supplemental. The supplemental job order is used when assistance from another department or section is needed to complete work reflected on an existing job order. The emergency job order is used in situations where there is an immediate or possible danger to the public, plant personnel, equipment or plant capacity. The standard job order is used for work other than supplemental or emergency.

The team attempted to take a "snap shot" of the control rooms and determine how many job orders were outstanding and to determine the significance of this number. This approach was abandoned since both units were in cold shutdown (Unit 1 for 10 year ISI/refueling outage and Unit 2 for repair of primary-to-secondary steam generator tube leakage). Instead the team interviewed plant personnel from the Maintenance department and Control and Instrumentation (C&I) department to determine how job orders are initiated, planned, tracked, worked, reviewed and closed out. The maintenance and C&I departments were chosen because these departments are assigned the lead for the majority of the job orders.

Once a job order is written (anyone can prepare/issue a job order) and assigned to the appropriate department, it is reviewed for completeness, entered on the computer and assigned to a foreman.

The foreman then schedules the work based on input provided by the department representatives at the daily morning meetings. The representatives are knowledgeable people and are able to provide input based an department needs. For example, representatives from the operations department each have a senior reactor operators license and are involved with the day-to-day operation of the plant. After the work is complete and the system or equipment declared operable about one to four weeks is required to complete additional reviews (if required) and close the job order on the computer.

The computer can track a job order, show workload for a foreman and provide machinery/equipment history. The maintenance department has been using it since 1980 and the C&I department since April, 1985. However, even though the computer can provide equipment history, neither department uses it routinely to trend this history.

The job order backlog was reviewed and the team was informed that the maintenance department has approximately 1600 job orders outstanding and C&I has approximately 600 job orders outstanding. The C&I department indicated that 600 was the manageable working level. Maintenance department personnel indicated they are working to reduce their backlog. The team was informed that during the recent refueling outage the maintenance backlog had reached approximately 2500. Personnel from both departments indicated that the status of job orders is a line item in the department head weekly status letter which is issued to the plant manager.

The backlog was discussed briefly with the plant manager who indicated that he has directed each department to determine its manageable backlog. He also indicated that mechanisms are being implemented to reduce the backlog by eliminating the need for certain job orders. For example, the maintenance department normally writes a job order to perform a surveillance. When this surveillance is done the maintenance department immediately will write another job order to perform the next surveillance. This mechanism assures that the surveillance will not be missed but it also contributes to the backlog. To eliminate the need for a job order for this case the plant is expanding the nuclear test scheduling program to include maintenance related surveillances.

To summarize, the licensee does not appear to have an unmanageable backlog of job orders. Furthermore, plant management is kept abreast of the backlog by requiring that the backlog be included as a line item in the weekly departmental status letters.

3.2 LICENSEE PERFORMANCE IN SPECIFIC FUNCTIONAL AREAS

In addition to reviewing general licensee performance in the areas noted in Section 3.1 above, the evaluation team reviewed the licensee's performance in the several specific functional areas which follow.

3.2.1 PERSONNEL ERRORS

Personnel errors are a continuing problem at D. C. Cook as is noted by discussion and observations in several sections of this report (e.g., see Sections 3.1.1, 3.1.7, 3.2.2, 3.2.3, 3.2.4, 3.2.5 and 3.2.7 and Appendix D). Of special note is Table 1 in Section 3.2.2 which shows that personnel errors related to procedure violations increased dramatically in each of the three years covered by this report, going from 34 in 1983 to 87 in 1984 and up to 129 through September of 1985. Furthermore, discussions with corporate personnel revealed that personnel error

condition reports currently are averaging about 30 per month. Some of this data also is contained in the quarterly trending reports discussed in Section 3.2.4 on "Trending Activities." The discussion in that section notes that the Shift Technical Advisors publish these reports but that few people apparently look at them.

The evaluation team inquired if any corrective actions are being taken to curtail these errors noting that there is a procedural requirement that when condition reports involve personnel errors, an attachment to the condition error must be sent to the AEPSC Vice President for Nuclear Operations and further requiring that a yearly analysis be performed. Corporate personnel told evaluation team members that as yet there is no formal mechanism to review this data. Individual members of the Nuclear Safety and Design Review Committee (NSDRC) Subcommittee on Corporate and Plant occurrences review it and may bring up for full committee discussion any anomalies they discover. But this review is not proceduralized and is not and cannot be construed as a formal review mechanism. The corporate personnel further stated that a problem they have in analyzing the personnel error data for root causes is that they have not been broken down into specific causes. The corporate personnel believe until that is done any analysis would not be useful. Currently, they are working on a computerized tracking program to do this but it is not operational and there is no firm schedule when it will be. Until that time a formal review and analysis of the personnel error data is "on hold."

The team disagrees with this approach and believes this is another example of the licensee missing the real issue (the other one was discussed in Section 3.1.7 on failing to fix the radiation monitors which are causing ESF actuations). With the increasing number of personnel errors action should be taken immediately to reduce them. It is not necessary to wait for a root cause system to be completed. Management has at its disposal other means until root causes can be determined. This can include, for example, general directives to all personnel that such errors will not be tolerated along with warnings that disciplinary action will be taken as necessary.

To summarize, personnel errors are a major problem area identified by the evaluation team and much of the data reviewed and documented in this report indicates the trend is getting worse instead of better. D. C. Cook management has in place systems or programs to identify personnel errors but the analysis and interpretation of the data and corrective action seems to be nearly nonexistent.

3.2.2 CONDITION REPORTS

D. C. Cook uses a system of Condition Reports to record and to report abnormal conditions (at some plants these are called Deviation Reports). Condition Reports are subdivided into 5 categories with only those in the first category (LERs) reportable to the NRC. All but the last category are required to be reviewed by the Plant Nuclear Safety Review Committee (PNSRC). This system generates tremendous amounts of paper that must be reviewed. For example, from January 1983 to September 17, 1985, approximately 6050 Condition Reports were written as follows:

Year	CRs
1983	1399
1984	2728
1985 (through September 17)	1926

The initial review, classification, assignment and reporting of Condition Reports are performed by the Plant Manager or an Assistant Plant Manager. Following this initial review, the Condition Reports are forwarded to the Quality Control (QC) Superintendent for an independent review and classification. Upon completion of this review they are distributed to assigned groups for action. All closeouts with the exception of the last category then must be reviewed by the PNSRC.

To give an example of one cause for the large number of Condition Reports, each time work is to be performed in an area protected by CO_2 or Halon systems, the system is isolated, a fire watch is posted, and a Condition Report is written. In 1984 there were 310 such reports and in 1985 (through September) there have been 240. Each of these must go through the review process. The licensee recently determined that planned or required entries into CO_2 or Halon protected areas does not justify issuance of a Condition Report. As such, administrative procedures recently were changed to delete this requirement.

The large number and required review of Condition Reports adds a big burden on management time, especially if and when they get behind and develop a backlog. For example, Inspection Report (315/85009, 316/85007) documented that there were 2131 open Condition Reports, of which 1213 were awaiting PNSRC review. The number of open reports was increasing at the rate of about 100 per month. All of this was impacting the timely review by the licensee. This also was recognized in the licensee's own internal

audits of December 1983; April 1984; May 1984; and July 1984. However, no corrective action was taken at that time to resolve those deficiencies.

As a result of the NRC inspection, the licensee committed to reduce the big backlog. Consequently the Assistant Plant Manager for Operations recently has been spending well over 50% of his time reviewing Condition Reports to reduce this backlog, time which detracts from his other responsibilities. He stated that he normally spends about one hour per day in the control room but recently has not been able to do so. At the time of the evaluation team review, the total number of Condition Reports remaining open were:

Year Initiated	CRs
1983	26
1984	212
1985	622

A summary of the Category E Condition Reports (events which occur at the plant requiring investigation but no reports required to any organization external to AEPSC and its subsidiaries) follows. Appendices E and F give a further breakdown of these numbers.

TABLE 1

Personnel Error Condition Reports

	1983	1984	1985 (through mid-September)	Total
Doors that were not operated properly	4	16	10	30
Radiation Protection related	22	51	46	119
Procedure Violation	34	87	129	250
Cardox Procedure Violations	9	33	17	59
Fire Watches/Security Guards performing the Fire Watch Function	2	8	10	20
Clearance Permits	9	34	15	58
Total	80	229	227	536

TABLE 2

Equipment Condition Reports

	1983	1984	1985 (through mid-September)	Total
Doors that did not operate properly due to equipment problems	15	79	58	152
Fire seals	4	5	16	25
Diesels	5	17	8	30
Auxiliary Feed Water	2	6	6	14
Ice Condenser	5	14	9	28
Control Rods/Rod Position Indication	6	14	8	28
Heat Tracing	30	13	8	51
Radiation Monitoring System	44	83	56	183
Auto Gas Analyzer	9	6	26	41
Turbine Room Sump Auto Compositer	1	4	12	17
P-250 Computer	1	12	5	18
Actual Fires	2	1	2	5
Total	124	254	214	592

3.2.3 WORK CONTROL ACTIVITIES

During a review of this area, the team reviewed three recent events which indicate the licensee may be having difficulty controlling work in progress.

3.2.3.1 On July 27, 1985, the licensee notified the NRC that a containment penetration isolation valve had been left open for approximately ten hours during refueling. The valve is an isolation valve on the containment ventilation drain lines to the clean waste holdup system outside containment. The valve had been opened during a break in fuel moves to drain water from a ventilation drip pan. However, the

operator repositioning the valve was distracted and did not close the valve. The mispositioned valve was found during shift change. The drain system has a water seal which prevented an atmosphere-to-atmosphere connection from inside to outside containment. Because of the water seal no violation of Technical Specification requirements occurred. (Inspection Report 315/85022; 316/85022)

3.2.3.2 On August 18, 1985, during the performance of the Unit 1 Containment Integrated Leak Rate Testing (CILRT) a region based inspector found a number of improperly positioned boundary valves. In response to this problem, the licensee reverified the CILRT valve lineup and found additional improperly positioned valves. (Inspection Report 315/85027)

3.2.3.3 On August 29, 1985, the licensee notified the NRC that the Unit 1 and Unit 2 control room ventilation systems were inoperable. Testing of the Unit 1 system revealed that the Unit 2 fresh air intake ventilation damper had been improperly positioned following testing on August 16, 1985. Unit 1 was in Mode 5 (ventilation system not required) and Unit 2 was in Modes 1-4 (ventilation system required). (Inspection Report 315/85029; 316/85029)

Since the team did not evaluate this functional area in much depth it cannot determine if the three events represent an improvement or a degradation over past performance. However, they are recent enough and close enough together in time that the team believes they may be indicative of a downward trend. Items 3.2.3.2 and 3.2.3.3 are being evaluated by Region III for possible enforcement action.

3.2.4 TRENDING ACTIVITIES

D. C. Cook has a procedural requirement that an annual analysis of Condition Reports be performed and that a report be prepared and issued. A recent Quality Assurance inspection noted that no such reports were prepared for 1983 and 1984, and therefore a Notice of Violation was issued. Furthermore, the report for the year 1982 was not issued until about March 1984. The licensee informed the QA inspector that the number of condition reports being generated prohibited their analysis.

The NSDRC Subcommittee on Corporate and Plant Occurrences also prepares graphs of the total numbers of condition reports, LERs and personnel error reports. Upon request, the plant QC department will perform a search of condition reports for specific types of repetitive occurrences.

However, none of these activities provide trending by cause, type of failure, manufacturer, or system affected. The licensee also received a Notice of Violation for this.

The corporate QA department is working on development of a corporate wide trending data base but this is a long term goal. In the interim, QA has developed cause and corrective action codes to facilitate trending of audit findings, surveillance findings, noncompliance reports and NRC inspection notices of violations. A manual trending effort on audit and surveillance findings has been initiated and the QA department currently is performing a historical cause and corrective action coding in order to build a data base.

There also are procedural requirements that the Shift Technical Advisors (STAs) prepare quarterly summary reports on a variety of plant parameters and that these be issued to each member of the Plant Nuclear Safety Review Committee (PNSRC). The evaluation team reviewed the latest copy of that report (dated August 7, 1985) and discussed its contents with several plant people. Most of the data contained in the report is extracted by the STAs from routine plant departmental reports. However, in some instances these departments were unaware that the report existed, or that their data was contained in it. The data in the report appears to be quite useable in trending the parameters because not only does it contain the current year's information, but it also presents the data from the previous year for the same time period.

An alternate chairman of the PNSRC stated there is no formal mechanism for reviewing the report or analyzing the trends. He stated that he believed the STAs would "flag" any obvious negative trends. The author of the report, on the other hand, stated that the STAs perform no analyses of the data. They simply gather, collate and publish it. When asked if he had ever received any comments from either the PNSRC as a whole, or from individual members, he stated he had not.

One reason the evaluation team pursued this area was that one of the trending curves is titled "Personnel Errors Resulting in Condition Reports" and through the 29th week of 1985 there was a dramatic increase over the same time period of 1984 for Unit 1 (132 errors in 1985 as compared to 45 in 1984). In the opinion of the evaluation team, this immediately should have raised questions by anyone reading the report. The next page of the report also is dramatic but in the opposite direction - the personnel errors resulting in Condition Reports for Unit 2 declined from 110 to 43 in the identical time frame. In still

another case, there is a figure on "Requalification Examination Performance" which purports to show that in January 1985, 50 persons took the requalification exam with 46 people passing; and in February 1985, 146 people took it with 130 passing. The team questioned the numbers since there are only about 80 licensed operators and senior operators at D. C. Cook. Further analysis by the licensee revealed that the numbers were incorrect.

Trending analysis can provide positive and immediate results as shown by the following example. During the recent past the licensee was experiencing what appeared to be a large number of minor skin contamination problems. Because of this, and after prompting by INPO, the licensee developed a radiation incident reporting system to track and to trend the problem to determine the root cause. Upon implementation of the system the trending program quickly identified that many of the contaminations involved the back of the neck. Further analysis revealed the cause to be a deficiency in radiation work permits (RWPs). Personnel were being allowed into containment with surgical caps instead of hoods. By changing the requirements to hoods, the frequency of skin contamination incidents was reduced by about 30%. During a management meeting with NRC Region III staff on October 3, 1985, the licensee stated that this trending program would be developed into a radiation incident reporting system which also would include other significant radiological incidents such as failure to adhere to RWPs and to radiation protection procedures (see Section 3.2.14 for more discussion on this).

In summary, the licensee apparently is gathering and publishing a considerable amount of data which could be useful to management in ascertaining plant performance. However, the "loop" is not closed because it appears few people are reading the material after it is published. There are no formal mechanisms for performing trending analyses.

3.2.5 LER REVIEW

LERs were reviewed to determine any major causes for the LERs and to identify any trends in plant equipment or systems. The data then was broken down by major cause and by affected plant systems.

	Number of LERs	
	Unit 1	Unit 2
1983	131	126
1984	35	37
1985	12	32

The number of LERs for 1983 is considerably higher because reporting requirements were changed in 1984.

3.2.5.1 CAUSES

3.2.5.1.1 PERSONNEL ERRORS

Personnel errors and activities were determined to be a contributing factor in 112 of the 355 LERs reviewed for the time period January 1983 to September 1985. The breakdown is as follows:

- 51 were the result of inadvertent actions such as inattention to details and poor judgement.
- 15 were the result of poor communications between personnel.
- 9 were due to lack of knowledge.
- 8 were due to personnel not following written procedures
- The remaining 29 were either miscellaneous or unknown causes.

A further analysis of these 112 personnel related LERs showed that:

- 11 involved valves incorrectly positioned
- 22 occurred where a fire watch was not on station or a fire door was left in an inoperable condition
- 20 caused surveillances to be missed
- 7 were due to failure to follow written procedures and drawings

Major plant activities involved in these errors were:

plant operations	18
maintenance	16
test/calibration	16

3.2.5.1.2 DEFECTIVE PROCEDURES

Defective procedures include conditions such as incomplete or incorrect procedures, and no written procedures. Of the 355 LERs reviewed, 45 were attributed to these causes and of these 45 the majority (20) were related to test/calibration activities. Eight resulted in surveillances being missed.

3.2.5.2 AFFECTED PLANT SYSTEMS

The following plant systems were identified in LERs as experiencing repeated equipment problems. (A further breakdown of these systems is listed in Appendix G).

LERs	System
39	Fire Protection
21	Containment Isolation
19	Radiation Monitoring
17	Engineered Safety Features
13	Emergency Diesel Generator
11	HVAC
10	Component Cooling Water

Of the LERs associated with the Engineered Safety Features, the majority were caused by the radiation monitoring system (for more information on this, refer to Section 3.1.7 on "Other ESF Actuations").

3.2.6 PLANT MODIFICATIONS

D. C. Cook has two types of plant modifications; request for change (RFC) and plant modifications (PM). A RFC is any design change determined to be safety-related or has a safety interface, and a PM is any design change determined to be non-safety related. Presently there are over 200 open RFCs with some dating back to 1976. The licensee noted that the backlog is not as significant as it appears because many of the changes are not mandated by regulation but rather were initiated internally.

The licensee explained that one reason for the backlog was because of a previous management system which assigned RFC responsibility to specific functional groups (for example, an electrically related RFC would be assigned to the plant electrical group). The actual work to be performed could involve several groups and in fact the assigned group may not necessarily have had the majority of the work. Nevertheless, it was their responsibility to coordinate the work efforts of all required personnel. In practice, this resulted in RFCs not being completed because the responsible groups concentrated on their routine work, and no single group had management overview.

The licensee recognized this problem and created a planning organization reporting to the Assistant Plant Manager for Maintenance. It is the responsibility of this organization to plan and to coordinate both scheduled and unscheduled plant outages and to implement the design change program. This includes scheduling and monitoring the progress of safety-related modifications at the plant. This should alleviate the problem of backlogs. To close out the approximately 230 open RFCs, the licensee has contracted for technical support with an outside organization. The goal is to eliminate the backlog by January 1987 for those RFCs for which the work has been completed.

3.2.7 SURVEILLANCE ACTIVITIES

In 1983 the licensee initiated a Regulatory Performance Improvement Program (RPIP) to improve the operation of the D. C. Cook plants. One of the topics of discussion in the RPIP deals with surveillance program controls. The objective was to reduce the possibility of not conducting a surveillance by required dates. To do this, the licensee was installing a computer-based tracking system which eventually would replace the manual tracking system. This has been completed.

However, the licensee's performance in actually conducting surveillance has been less than satisfactory and is one of the weak areas in the D. C. Cook operations. Surveillance tests still are being missed or being done late. Many of these are action or reaction type surveillances rather than routine ones.

For example, on June 5, 1985, the senior resident inspector notified Region III by memorandum that a review of 38 LERs dating from about October 1984 to May 1985, revealed 14 items that could be classified generically as failure to perform required surveillances. All but one were compensatory actions required for inoperable components. Seven of the 13 involved fire protection compensatory

surveillance (typically, missed area tours) while the other six involved various monitoring instrumentation. Most of the omissions involved failure to recognize, understand or communicate the compensatory requirement. Prior to this June memorandum, the resident inspectors monthly status report for March 1985, also raised the problem of licensee failure to recognize, understand and implement compensatory surveillances.

The June memorandum also identified other surveillance problems including two failures to recognize components not meeting acceptance criteria and surveillance testing using the wrong criteria or the wrong method. In summary, 20 of the total of 38 LERs reviewed were related to surveillance testing.

In August 1985, there was a mini-Performance Appraisal Team (PAT) inspection conducted by the Office of Inspection and Enforcement, and their principle findings dealt with missed surveillances. As a result of the inspection findings a Confirmatory Action Letter (CAL) was issued in which the licensee would review the surveillance program and verify that all required surveillances are completed prior to changing plant modes.

It is apparent that the issue of surveillance testing will require immediate and increased attention by the licensee and by the NRC. As the senior resident inspector noted in his June 5, 1985, memorandum, "These items are surely no cause for comfort and are ample cause for continued focus on surveillance matters."

3.2.8 PROCEDURES

Part of the RPIP deals with procedures. Prior to RPIP, procedure changes were made by reference to change sheets, but no changes were made to the body of the procedure. This caused the user to constantly flip back and forth from the procedure to the change sheet to determine what the changes were. As a result of RPIP a new policy was instituted such that when changes to procedures were made, a full page temporary change sheet was issued which then was incorporated directly into the body of the procedure, thus providing procedure continuity. In addition, word processing equipment was procured and new administrative controls initiated to reduce the number of temporary change sheets. These actions helped greatly to reduce the confusion when using the procedures.

A review of the procedures by the evaluation team indicated potential problems still may exist. In one case (a Plant Manager's Instruction) 16 change sheets had been issued including four changes on one page. All of the full page

inserts had been made as required, but the vertical "change bars" were confusing because only the last change was indicated thereby leaving uncertain the status of the previous changes. One page had been changed four times since the previous revision but only the last change had the marginal change bar. In general, there appeared to be inconsistency throughout the procedures on the use of the change bar.

Another problem involved the use of pen and ink changes. According to D. C. Cook policy and procedures such changes are not allowed except in "emergency" situations. Even in those cases the change must be approved by two members of plant management, at least one of whom holds a senior reactor operator license; and the change must be documented, reviewed, and approved by the plant manager within 14 days of the implementation. There were several cases identified by the mini-"PAT" team inspection and several others verified by the evaluation team, where such changes were made to surveillance test procedures by the Control and Instrument group without obtaining review and approval by plant management before implementation, or review and approval by the plant manager within 14 days. In addition, C&I supervisors did not initiate corrective action to revise these procedures during their review of completed surveillance tests.

There were other examples of procedure violations, some of which were identified by the licensee's QC organization and documented in Condition Reports, such as; cancellation of a procedure without the plant manager's approval; issuance of a change sheet with no senior reactor operator approval; issuance of a change sheet without the change being designated by either marginal markings (a vertical "change bar") or on the procedure change sheet.

In summary, the changes made as a result of the RPIP program were beneficial, but there now appears to be some laxness on the part of plant personnel when instituting procedure changes.

3.2.9 RELATIONSHIPS WITH AEPSC

Indiana and Michigan Electric Company (I&M) the owner and licensed operator of the D. C. Cook Nuclear Plant, is owned by the American Electric Power Company (AEP). AEP owns many utilities but the D. C. Cook plant is its only nuclear facility. The responsibility for administration and technical direction of the AEP system and its facilities is delegated to the American Electric Power Service Corporation (AEPSC). The D. C. Cook Plant Manager reports to the Vice-President of Nuclear Operations in AEPSC.

`though day-to-day operations of the D. C. Cook plant are .ie responsibility of the D. C. Cook organization, technical and engineering support is provided by AEPSC which is located in Columbus, Ohio. With regard to plant modifications involving safety-related equipment, AEPSC is responsible for among other things, engineering development, completion, and review; design development, completion and review; funding approvals; nuclear safety and licensing reviews and resolutions; material procurement; preparing "as-built" drawings; and specifying test requirements and acceptance criteria. In other words, AEPSC manages and directs the modification.

The evaluation team attempted to determine if this arrangement caused any operational problems. Of special concern was that the lead group may be too far removed from the site to be able to have the necessary information or knowledge to be able to "keep on top" of systems or problems.

Generally, most site non-management personnel interviewed stated that although they had no major problems with this arrangement, they believed that the cognizant AEPSC personnel did not spend enough time onsite and were not familiar with "the real world."

On the other hand, interviews with corporate personnel revealed that in addition to a Lead Engineer who is responsible for coordinating safety-related design changes, AEPSC also has Cognizant Engineers for Systems who are assigned complete responsibility for their assigned system. They "own" it and are on the review and approval chain for any work which will affect it. Every flow diagram is assigned such an individual. In addition, there are Cognizant Engineers for Equipment who act as resources for the Cognizant Engineers for Systems.

A recent NRC inspection (315/85026 and 316/85026) reviewed the issue of the offsite support staff and concluded that with the exception of design change and modification weaknesses, AEPSC was staffed adequately and their activities found to be acceptable. The weaknesses related to the fact that not all of the AEPSC engineering departments have a method to track Request For Change (RFC) packages.

The plant procedures describing responsibilities of the various groups specifically state that the final design package will be a closely coordinated effort between the AEPSC Lead Engineer and the plant staff. The same procedure also states that for safety-related items involving installation or modification of major items of equipment, the lead AEPSC engineer shall participate in a pre-production walkdown if specifically requested

to do so by the Design Change Coordinator (a plant staff member). Interviews with plant staff indicated this walkdown, normally done only by plant engineers, typically is done to ascertain whether the modification has any impact on other plant systems. There is little plant engineering evaluation of the modification per se, and relatively few requests for walkdowns by AEPSC personnel.

The evaluation team is aware of only one recent problem which may have been caused by the Lead Engineer having insufficient knowledge of the plant. When the Unit 1 station batteries were replaced, the design package (which was controlled by AEPSC) did not contain adequate detail to assure a seismically qualified assembly. The batteries were installed by site personnel and declared operational, but subsequently the NRC resident inspectors noted the installation was incorrect and issued a Notice of Violation.

The evaluation team discussed with corporate management the relationship of AEPSC design engineers with site personnel. In Corporate's opinion, the detachment of corporate design engineers may be beneficial because they will be more independent. They will perform their analyses strictly on safety considerations and will not be subconsciously influenced by operational expediency. Furthermore, corporate management stated there is much travel between Columbus and the site and travel is not discouraged. Two charter planes are on call at all times for this purpose.

In summary, much of the technical design work for D. C. Cook is performed by AEPSC engineers who are somewhat distant from the site and may not be fully cognizant of conditions at the site. Although this leads to some minor friction between plant personnel and corporate personnel, it does not appear to be serious and does not appear to result in any serious operational problems.

3.2.10 COMMITMENTS TO NRC

One of the sections of the RPIP deals with tracking of commitments to the NRC. The evaluation team became aware of several recent Condition Reports written by the licensee's QC organization identifying at least four incidents in the last three months where such commitments were not met. None of the incidents were serious but this may be indicative of a relaxation of management attention to this functional area.

3.2.11 TRAINING ACTIVITIES

The team reviewed the status of training in general, and the results of the recent history of licensed operator and senior operator examinations. Overall the D. C. Cook pass rate for senior reactor operators since mid-1983 has been 70% compared to a Region III overall pass rate of 81% and for operators the pass rate was 74% compared to a Region III average of 70%. There does not appear to be any significant trend in failure rates although in the last examination given in July 1985, six out of nine SRO candidates failed the written part of the examination. The licensee is contesting the results. The Operator Licensing personnel from Region III have visited the site to discuss the examination and the results. Final resolution still is pending.

The resident inspectors identified an adverse trend in June 1985, in contractor performance and noted that both the QA and QC departments also had identified job performance problems related to training on Unit 1 outage work. QC issued a "Stop Work" on one specific job, while QA negotiated an effective "Stop Work" with plant management on numerous jobs because of generic concerns in such areas as contractor employee training. The Senior Resident Inspector met with both plant and QA management and considers the corrective actions to be appropriate. Since that time there have been no instances of repeat problems.

The licensee's current training facilities are scattered over several temporary buildings and trailers and are geared primarily towards licensed operators. There is no simulator, thereby necessitating that simulator time be leased from Westinghouse at the Zion training facility. Since the D. C. Cook control room was customized when it was built and has received criticism from some NRC inspectors because of a "poor" layout, and because it is not similar to the Westinghouse simulator, the team was interested in trying to determine how D. C. Cook operators performed at the Westinghouse simulator. Interviews with NRC Region III operator licensing personnel indicated few operational problems are encountered by D. C. Cook personnel at the Westinghouse simulator. A very brief time is required for them to get "acclimated" but after that there is little noticeable difference between their performance and that of operators from sites with more standard designs.

The licensee has planned and designed an onsite training facility including a site specific simulator. The facility will have approximately 68,000 square feet of space excluding the simulator and will cost about $50 million. Construction will begin in the Spring of 1986 and is scheduled for completion in mid-1987, about the same time the simulator

will be completed. It is expected to be fully functional in early 1988. The training facility will include space and accommodations for training a wide range of personnel including, for example, chemistry technicians, rad protection personnel and maintenance personnel (such as mechanics). To staff the facility the licensee recently increased the dedicated training staff from 17 personnel to 49.

Simultaneously the licensee is pursuing INPO training accreditation. The senior reactor operator, reactor operator and shift technical advisor programs are scheduled to be submitted to INPO in February 1986, and the remainder of the programs are scheduled for June 1986.

Finally, the licensee is completing the implementation of a computer program called (HUREDIS) (Human Resources Education and Development Information System). This is a record keeping system which will track training programs, facilities, students, and instructors.

In summary, the licensee is committed to improving its training facilities and is allocating the resources to do this. The evaluation team found no major problems in its brief review of this functional area.

3.2.12 REGULATORY PERFORMANCE IMPROVEMENT PROGRAM (RPIP)

Initially, the evaluation team had some difficulty in determining when and how the Regulatory Performance Improvement Program (RPIP) was started. The following brief history should be helpful in aiding others to understand it.

The RPIP was started while the licensee's corporate offices were located in New York City. The program was formalized in a letter dated February 7, 1983. Shortly after that the corporate offices were moved to Columbus, Ohio, and many of the personnel involved with RPIP left the employ of the company. Consequently, the meaning and intent of some of the topics discussed in the February 7, 1983, letter was lost or uncertain. Therefore, on February 23, 1984, the licensee submitted an updated version of the RPIP in which it "clarified" some of the original topics, and listed in Appendix C of the letter those activities which were ongoing. It is this Appendix C which is for all practical purposes RPIP and the licensee meets monthly to update the progress on it.

A summary of the evaluation team's findings regarding specific RPIP activities is discussed in Appendix H.

An overall summary indicates that nine of the 11 formal functional activities involved in RPIP have been completed and the other two are ongoing; (Plant Procedures Revised per PMI-2010; and Management Review of QA Program.) Most of the completed items appear to have accomplished their goals but there is some question about the total effectiveness of the computerized surveillance program. As discussed in Section 3.2.7 of this report missed surveillances continue to be a problem at D. C. Cook although the cause for this is not related directly to the RPIP program, but rather is the result of not performing "reaction" type surveillances or because of misinterpretation of Technical Specification requirements. Two other areas show signs of laxness; temporary procedure changes and tracking of commitments.

3.2.13 LICENSING ACTIONS

The team discussed the operational evaluation with the Licensing Project Manager (LPM) and inquired if there were any licensing items of concern. The LPM stated that there were no major items of concern, that D. C. Cook has been a good performer in licensing matters. The LPM stated that the licensee is upgrading and clarifying its Standard Technical Specifications (STS). D. C. Cook was the first plant to get STS and since that time there have been four revisions to the STS, none of which were ever issued to D. C. Cook. The upgrading was initiated within the past year and will continue for several years. NRR believes this has been a good effort on the part of the licensee.

According to the LPM, all TMI items for which NRR is responsible are operable but all Technical Specifications have not yet been issued.

3.2.14 RADIATION PROTECTION PROGRAM

The NRC recently listed a number of concerns with the D. C. Cook radiation protection program:

1. Certain surveys not performed adequately
2. Need for increased contractor oversight
3. Reduction of radioactive materials storage areas
4. Procedure adherence appears to need improvement
5. Not responsive to certain NRC Region III NUREG-0737 items
6. Large number of minor skin contamination incidents

7. Apparent weak corporate/plant communications related to TMI items

8. Radiation protection technicians not paying attention to work

As a result of these concerns the licensee developed a list of goals and commitments to improve its performance in this area. These goals were presented to NRC management on October 3, 1985. They will be tracked through the routine inspection program. One of the commitments was to continue the trending of skin contamination problems which has resulted in identification and correction of a significant portion of the problem (see Section 3.2.4).

4. CONCLUSIONS

There were 84 total site violations over the 33 months included in the review: 40 in 1983, 24 in 1984, and 20 in 1985. However, there still are three months remaining in 1985 and there are several violations pending so 1985 probably will be worse than 1984, but better than 1983.

Operationally there appears to be a significant difference in performance between Units 1 and 2 as evidenced by: the number of trips, 17 for Unit 2 compared to four for Unit 1; containment purge isolations, 31 for Unit 2 and 21 for Unit 1; and forced outages, eight for Unit 2 and three for Unit 1. Furthermore, six of the Unit 2 forced outages were due to steam generator tube leakages whereas there have been none for Unit 1.

There appear to be at least two major problem areas at the D. C. Cook site which need immediate attention; personnel errors and missed surveillances. There were many examples found in both areas to indicate that the licensee does not have firm control (see Section 3.2.1 for personnel errors and Section 3.2.7 for surveillance activities). Furthermore, problems were identified in other functional areas such as: excessive number of ESF actuations involving the radiation montiors; excessive numbers of condition reports; some lack of control over work activities; failure to evaluate trending data; open safety-related plant modifications; unauthorized changes to procedures; and some failure to honor commitments.

Nine of the 11 RPIP functional activities have been completed and the remaining two are ongoing.

The team is concerned that the licensee at times does not appreciate the gravity of some situations and therefore is slow to take corrective actions. Two particular items caused this impression: (1) the licensee's decision to change the reporting requirements rather than to fix the problem when confronted with the continuing problem with containment purge isolations caused by radiation monitors; (2) the lack of effective action to correct an increasing number of personnel errors.

Although no problems were identified in the training area, the licensee plans to build a training center onsite which will include a site specific simulator for licensed operators. It also will include facilities for other plant personnel such as radiation monitoring technicians, chemistry personnel, machinists, and other crafts. This should improve personnel capabilities and performance.

Overall, morale at the site is high and nearly all personnel interviewed expressed confidence and support for the plant management.

In conclusion, the evaluation team identified no major safety concerns at D. C. Cook. However, several problem areas were noted and it appears that the licensee has many management tools in place to correct the problems, has made commitments to improve its performance, but has not or cannot "close the loop." Actions are started but not completed. Furthermore, much management time is taken up reviewing paperwork rather than managing work activities.

5. Recommendations

There are two activities which the evaluation team believes require immediate licensee attention; personnel errors and missed surveillances. A high but lesser priority also should be placed on fixing the radiation monitor-caused containment purge isolations, and setting up a formal program to review trending data and to implement corrective actions as necessary. Lower priorities should be placed on the remaining problems identified by the team. The licensee also should attempt to ascertain why Unit 2 performance and operation appears to be worse than Unit 1.

To accomplish these objectives the team recommends that this report be given to the licensee and a licensee management conference be conducted to discuss each of the issues if the licensee so desires. Following that, the licensee should be requested to commit to specific and measurable actions and schedules.

Finally, the team recommends that increased inspection effort should be placed on the specific topics discussed and that the status be included in the monthly status reports provided to Region III management by the Division of Reactor Projects.

APPENDIX A

SUMMARY OF REACTOR TRIPS - JANUARY 1, 1983 TO SEPTEMBER 30, 1985

Unit 1

11/23/83	Trip from power due to steams flow/feed flow mismatch.
01/23/84	Trip from 99.5% power due to indicated low flow on reactor coolant loop 2. This was caused by an instrument valve on a flow meter leaking when the meter was being returned to service.
06/17/84	Trip from 68% power during power ascension due to failure of the vital instrument bus. The bus failed because of a blown capacitor.
08/14/84	Trip from 100% power due to failure of a vital instrument bus inverter. The inverter failed because water-laden air was blown into the inverter cabinet by a temporary ventilation blower.

Unit 2

06/23/83	Trip from 100% power due to failure of vital instrument bus inverter.
08/22/83	Trip from 100% power due to failure of vital instrument bus inverter. The inverter failed due to a shorted electrolytic capacitor.
08/25/83	Trip from 100% power due to failure of vital instrument bus inverter. The inverter failed due to a shorted electrolytic capacitor.
10/15/83	Manual trip from 10% power due to primary to secondary leakage.
11/22/83	Trip from about 10% power (40 minutes after paralleling to grid) due to high-high level in No. 22 steam generator as a result of overfeeding.
2/18/84	Trip from 100% power due to a high level indication in the moisture separator reheaters while they were being put into service.
03/10/84	Manual trip from low power for scheduled outage.
08/5/84	Trip from 100% power due to failure of vital instrument bus inverter. Inverter failed due to blown fuse.
09/11/84	Trip from 100% power due to failure of vital instrument bus inverter. Inverter failed due to failed capacitor.
09/12/84	Trip from about 100% power (11 minutes after paralleling to grid) due to high-high water level in number two steam generator due to overfeeding. The overfeeding was a combination of operator error and level control problems.
11/11/84	Manual trip from 73% power due to increasing pressurizer pressure caused by a pressurizer spray valve that failed to fully close following partial cycling.
11/19/84	Trip from 96% power due to steam flow/feed flow mismatch concurrent with low steam generator level.
11/20/84	Reactor trip breakers opened while reactor was shut down.

01/11/85	Reactor trip breakers opened while reactor was shut down.
01/12/85	Trip from 2% power due to low-low level in number 22 steam generator.
01/26/85	Trip from 96% power due to failure of vital instrument bus inverter. The inverter failed due to a component short.
08/25/85	Trip breakers opened while reactor was shut down.

APPENDIX B

OTHER ESF ACTUATIONS - JANUARY 1984 TO AUGUST 1985

Unit 1

Date	LER Reference	Mode	Cause	Description
06/23/84 01/29/85	84-012 85-004	1	Deficient Procedure	2 containment ventilation isolations occurred when the radiation monitor exceeded the actuation setpoint
08/10/84	84-017	2	Personnel	An ESF actuation (feed-water isolation) occurred due to high steam generator level
04/08/85 to 04/11/85	85-015	3	Equipment Malfunction	14 containment ventilation isolations occurred due to a software problem that required resolution by the vendor
05/05/85	85-022	6	Deficient Procedure	Containment ventilation isolated 5 times because the suggested setpoint did not compensate for statistical fluctuation of the detectable activity
06/01/85	85-026	6	Personnel Error	A safety injection occurred when a low pressurizer pressure signal block was removed while a second channel was in test
08/03/85	85-037	5	Deficient Procedure	2 safety injections occurred while installing an approved design modification

Unit 2

Date	LER Reference	Mode	Cause	Description
03/11/84 to 04/24/84 05/04/84	84-003 84-008 84-011	5 6	Equipment Malfunction	Containment radiation monitor software problems caused 9 containment purge and exhaust isolations
04/05/84 to 04/21/84	84-006	6	-	-
a.			Personnel Error	A contractor placed radioactive trash near a containment detector which caused a containment purge isolation
b.			Personnel Error	A licensed operator improperly adjusted a setpoint for a radiation monitor causing a containment purge isolation
c.			Personnel Error/	Raising/lowering of the upper internals caused 13 containment purge isolations
d.			Personnel Error	Radiation levels reached the containment purge isolation setpoint while the containment ventilation was off for testing
04/11/84 to 05/01/84	84-07 84-10	6	Inadequate Procedure	Containment purge isolated 6 times because the lowest suggested setpoint did not compensate for statistical fluctuation of the detectable activity
05/08/84	84-012	6	Personnel Error/ Inadequate Procedure	Following performance of a surveillance, a safety injection occurred when the solid state protection system was placed on operate prior to resetting the SI blocks

Date	LER Reference	Mode	Cause	Description
12/13/84	84-34	5	Equipment Malfunction	A leaking RTD bypass valve caused 2 containment purge isolations
5/20/85	85-011	1	Equipment Malfunction	A leak in an RTD manifold resulted in 3 containment purge isolation signals
8/3/85	85-015	4	Equipment Malfunction	Leakage through an auxiliary feedwater valve caused a high-high level in a steam generator which resulted in an ESF actuation (feedwater isolation)
8/19/85	85-017	3	Personnel Error	5 containment purge isolations occurred due to increasing radition levels caused by reactor startup

APPENDIX C

SUMMARY OF OUTAGES, JANUARY 1, 1983 TO MID-SEPTEMBER 1985

Unit 1

1. March 25 to 27, 1983. Scheduled outage to perform Technical Specification required surveillance testing.

2. May 25,1983. Forced outage to perform Technical Specification required surveillance testing on the steam generator stop valves. This testing was not performed, as required, following the March 25 outage.

3. May 25 to 31, 1983. Forced outage to repair a leaking pressurizer spray valve.

4. July 16 to October 16, 1983. Scheduled outage for cycle 7-8 refueling/maintenance outage.

5. November 22 to December 12, 1983. Scheduled outage for pump and valve maintenance.

6. March 4 to 9, 1984. Forced outage to repair the trip/throttle valve for the turbine driven auxiliary feedwater pump.

7. July 27 to August 12, 1984. Scheduled outage to perform Technical Specification surveillance testing for the ice condenser.

8. January 11 to 31, 1984. Same as 7 above.

9. April 6 to Present (September 30, 1985) Scheduled outage for cycle 8-9 refueling/maintenance outage.

Unit 2

1. November 21, 1982 to January 23, 1983. Scheduled outage for cycle 3-4 refueling outage.

2. June 23 to July 9, 1983. Forced outage to repair primary to secondary tube leakage.

3. September 1 to 2, 1983. Forced outage to repair tie down features of the pressurizer enclosure ventilation system.

4. October 15 to November 7, 1983. Forced outage to repair primary to secondary tube leakage.

5. November 7 to 22, 1983. Forced outage to repair primary to secondary tube leakage.

6. March 3 to July 11, 1984. Scheduled outage for cycle 4-5 refueling outage.

7. December 12, 1984 to January 1, 1986. Forced outages to repair RTD manifold valves and retrieve loose split pins.

8. July 15 to August 2, 1985. Forced outage to repair primary to secondary tube leakage.

9. August 2, to 22, 1985. Forced outage to repair primary to secondary tube leakage.

10. August 24 to Present (September 30, 1985) Forced outage to repair primary to secondary tube leakage.

APPENDIX D

July 17, 1985

MEMORANDUM FOR: G. C. Wright, Chief, Reactor Projects Section 2A

FROM: B. L. Jorgensen, Senior Resident Inspector

SUBJECT: D. C. COOK EVENTS - TECHNICAL ASSESSMENT

At the request of Ed Greenman, I have performed a technical assessment on three D. C. Cook events of interest to him, focusing on proximate and underlying cause(s) The intent here is to try to establish what, if any, commonality may be present, and to take a "collective" view of significance should any relationship among the items be identified. I have referenced both my previous memo of June 5, 1985 concerning reportable events, and the October 27, 1983 report (50-387/83-20MM) of a Region I management meeting on Susquehanna Unit 1 involving repetitive surveillance testing problems, as a foundation in performance of this assessment.

EVENTS DESCRIPTION AND CAUSE

1. Two HPSI Pumps Inoperable: This event involved an equipment control error ("wrong train") during testing, such that one train was disabled from the control room by placing the pump in "pull-to-lock" (correct action), while the other was disabled in the pump room by closing local manual isolation valves (error). The proximate cause was a mistake by the operator performing the valve isolation. Underlying this were at least two other factors: a single procedure applicable to both trains, which distinguished between trains only by enclosing the valve designators for one train in parenthesis; and miscommunication (verbal) concerning which train/valves were to be manipulated. The quality of the local valve I.D. tags and the similarities in designations for similar valves in opposite trains may have contributed.

2. Containment Integrity Degraded: This event involved concurrent opening of small manual drain valves on the residual heat removal (RHR) system such that one valve was open inside and one outside containment (creating a potential vent path not protected by any automatic-isolation capability) at a time when containment integrity was still required. The proximate cause was failure to recognize, at the time of performance, that the valves should not be open simultaneously. The procedure neither required nor prohibited this simultaneity. Underlying this were previous failures to recognize this potential adverse situation during development, review, and approval of the applicable procedure. This, in turn, was probably related to several factors: RHR is designed as a closed system and receives no isolation signals (i.e., it is not normally considered to be related to "containment integrity"); the test (an infrequent hydro) itself rendered the subject train "inoperable," possibly de-sensitizing involved personnel as to the level of control or

attention to detail required; and, it was coincidental (rather than mandatory) that the activity was performed while containment integrity was still required.

3. Containment Spray System Mis-Valving: This event involved an equipment control error ("wrong unit") in placement of a "clearance," such that two of three suction paths to one train of containment spray in the operating unit (Unit 2) were closed (and an attempt made to close the third) when the intent was to perform this action on the shutdown unit (Unit 1). The proximate cause was a mistake by the operator performing the activity. No underlying causes are apparent, in that the individual was qualified to the task, was experienced, was given a specific pre-job briefing, and still managed to "just get turned-around." He apparently understood he was to go to a specific pump in Unit 1, he thought (even after manipulating two valves and reporting back his unsuccessful attempt on the third) he had gone back to Unit 1, and he was wrong. Less than optimum physical differentiation (i.e., no "color coding" of doors) may have contributed. Note that the operator went to the right pump in the wrong unit.

NRC Action Status

All the above events have some relationship to adequacy of equipment control, but each has a different relationship. None were significant in themselves; Item 3 was not even reportable. Equipment control has been and continues to be a primary focus on the D. C. Cook RPIP, which is ongoing. Specifically, the RPIP addresses such areas as accuracy of drawings and procedures, independent verification and equipment labeling (including color coding by Unit).

A Notice of Violation has been issued, responded to, and closed for Item 1. The LER remains open pending verification of separation of multiple-use test procedures (of which this was only one example) into single-use procedures. This has been done, but not yet specifically followed up by NRC. Resident inspectors have had discussions with plant operators concerning early experience with the new single-use procedures; the consensus being that the new procedures are greatly preferred.

The second-item (containment integrity) is a subtle one, and not readily recognizable beforehand. In fact, a certain amount of perspicacity was involved in its identification after it happened. I therefore consider it tenuous at best to impute generic implications. The associated LER also remains open, though the only open question I still have personally is whether the licensee should consider a "special" (i.e., unique color or shape?) I.D. tag for containment boundary valves or a special lock, as I have seen done elsewhere. Such a practice could sensitize the valve operator, whatever the reason he may be manipulating the valve.

The final item represents the only instance thus far in calendar year 1985 of a valve or control mismanipulation. This fact is significant in that fourteen such items were noted in 1984, primarily in the first half of the year. The licensee (and NRC) have been carefully following this as a measure of the effectiveness of the RPIP as discussed above. The data, in fact, suggest the

RPIP is working; the frequency of errors has been reduced (though not yet to zero); and the one error which has occurred this year was caught and corrected quickly, even before required "independent verification" (another RPIP matter) was begun.

CONCLUSION

My conclusion must by now be apparent. That is, there is not sufficient evidence of commonality to directly relate the events in my mind; at least not sufficiently to warrant any action we are not already taking (especially via the RPIP). Equipment control may once have been a generic D. C. Cook problem, but it is not apparent to me that it is any longer.

Finally, with specific reference to my previous memo and to the Region I meeting report, I would point out that inadequate corrective action (i.e., failure to prevent repetition) has been the basis for recent enforcement action at D. C. Cook. I continue to feel a straightforward Notice of Violation was appropriate to the circumstances (as opposed to a special Management Meeting) and may also be appropriate for continued repetitive problems in the fire protection area.

B. L. Jorgensen
Senior Resident Inspector

APPENDIX E

DETAILED BREAKDOWN OF PERSONNEL ERROR CONDITION REPORTS
(TABLE 1 in SECTION 3.2.2)

EXAMPLES OF DETAILED EVALUATION

NOTE: The total on the following tables will not in all cases agree with the totals as found on the summary. Some of the items did not fit into the categories mentioned below. The following examples are provided to show repetition and trend.

TABLE E.1

	1983	1984	1985	TOTAL
Doors that were not operated properly due to personnel error				
Door found unlatched or open	1	0	2	3
Door was tied, blocked, left or propped open	2	7	3	12
AFWP Room Doors closed. This is in violation of PMSO.064	0	3	0	3
Missed hourly door check	0	2	0	2
Latching mechanism taped over	0	0	2	2
Door inoperable, no fire watch posted	0	0	2	2

TABLE E.2

	1983	1984	1985	TOTAL
Radiation Protection Related Personnel Errors				
Exceeded exposure limits	5	2	5	12
Violation of the Radiation Protection Manual or Plant Procedures	3	20	20	43
Person without self reader or TLD	5	18	10	33
Person wearing another person's self reader or TLD	0	0	3	3
Contaminated equipment or trash where it does not belong	2	3	1	6

People locked inside of a High Radiation Area or Containment	2	0	0	2
Person in an RWP area but not on the RWP	1	4	0	5
Problems with RWPs or meeting the requirements of an RWP	3	3	5	11

TABLE E.3

	1983	1984	1985	TOTAL
Procedure Violation Personnel Errors				
Person doing work without obtaining permission from the Shift Supervisor or required permits	3	1	13	17
Procedure not followed	12	18	38	68
Paperwork not done correctly	3	7	16	26
Combustible material procedure violation	0	31	13	44
Housekeeping Procedure not followed	2	14	12	28
Procedure changes not reviewed by the PNSRC within 14 days	4	3	1	7
The plant was not operated according to procedures	3	3	19	25
Surveillance Procedure problem	4	2	2	8
Unapproved design or field change made	0	6	5	11

TABLE E.4

	1983	1984	1985	TOTAL
Cardox Procedure Violation				
A person entered a CO2 protected room without placing his or her name on the grease board	0	3	1	4
Cardox system isolated with no one present in the room or no name on the grease board	0	3	2	5

Name was left on the grease board after the person had exited the area	11	10	4	24
Cardox switch in the wrong position or no Fire Watch or Security person present with the switch in the isolate position	1	7	4	13
Personnel entry into a CO2 protected area without the CO2 system isolated	0	0	3	0
Violation of the Cardox Procedures	5	9	1	15

TABLE E.5

	1983	1984	1985	TOTAL
Fire Watches/Security Guards performing the Fire Watch Function				
Fire watch not posted when required	0	2	4	6
Missed fire inspection tour	0	4	1	5
Fire watch left or released and fire system not returned to service	0	2	4	6

TABLE E.6

	1983	1984	1985	TOTAL
Clearance Permit				
Valve or Switch in a position contrary to that indicated on the tag	0	3	2	5
Tag missing from the equipment	0	7	5	12
Work being performed with no clearance placed	0	0	3	3
Violation of clearance permit system	4	9	2	15
Tag placed on wrong valve or equipment	1	4	1	6
Paperwork not done correctly	3	6	0	9

APPENDIX F

DETAILED BREAKDOWN OF EQUIPMENT CONDITION REPORTS
(TABLE 2 of SECTION 3.2.2)

TABLE F.1

	1983	1984	1985	TOTAL
Doors that did not operate properly due to equipment problems				
Door would not close or close automatically	6	12	12	30
Broken or missing door knob or handle	2	6	3	11
Broken closure mechanism	2	11	0	13
Door would not latch properly	1	20	10	31
Tech. Spec. Door or Fire Door inoperable	2	21	10	33
Would not close due to air pressure in room	1	4	0	5

TABLE F.2

	1983	1984	1985	TOTAL
Fire seals				
Does Not Seal	0	2	1	3
Damaged	0	2	1	3
Foam Missing	0	1	3	4
Nonfunctional	1	0	11	12

TABLE F.3

	1983	1984	1985	TOTAL
Diesels				
Diesel Generator tripped or overspeed device tripped	1	5	1	7

NOTE: The totals on the following tables will not in all cases agree with the totals as found in the summary. Some of the items did not fit into the categories listed below. The following examples are provided to show repetition and trend.

TABLE F.4

	1983	1984	1985	TOTAL
Auxiliary Feed Water				
TDAFWP speed control	1	0	1	2
TDAFP low discharge pressure	0	1	1	2
TDAFP Trip throttle valve not latched	0	1	1	2

TABLE F.5

	1983	1984	1985	TOTAL
Ice Condenser				
Doors inoperable, frozen shut, or failed to meet the acceptance criteria	0	3	3	6
Problems with ice baskets	0	0	5	5

TABLE F.6

	1983	1984	1985	TOTAL
Control Rods/Rod Position Indication				
Rod Position Indicator has a difference greater than 12 steps from the demand position	0	11	4	15

TABLE F.7

	1983	1984	1985	TOTAL
Heat Tracing				
Temperature Low	11	6	1	18
Will not maintain temperature	4	2	0	6
Was de-energized	0	3	2	5

Inoperable	3	0	0	3

TABLE F.8

	1983	1984	1985	TOTAL
Radiation Monitoring System				
Failing High	0	3	3	6
Failed Low	5	4	4	13
Check Source	4	6	3	13
Erratic	3	4	1	8
Exceed Tech. Specs.	1	3	3	7
Control Terminal	3	11	2	16
Sample Pump	4	1	1	6
RMS Channel failed	6	22	14	42
Alarm Problem	6	6	5	17
Channel inoperable	10	19	17	46

TABLE F.9

	1983	1984	1985	TOTAL
Actual Fires				
Fire started on Auxiliary Building roof when tar was being melted over an open fire	1	-	-	1
Rags used for deconning caught fire	1	-	-	1
Fire in the Unit 2 Condenser Pit Cable Tray	-	1	-	1
Fire in Service Building	-	-	1	1
Trailer fire, south end of Unit 2 within restricted area, but outside of plant	-	-	1	1

APPENDIX G

PLANT SYSTEMS EXPERIENCING REPEATED REPORTING IN LERs

1. Fire Protection (39 LERs)

   - 25 caused mechanical problems with fire doors

2. Containment Isolation (21 LERs)

   - 13 involved repairs to containment isolation valves

3. Component Cooling Water (10 LERs)

   - 4 caused by valves out of adjustment

4. Emergency Diesel Generator (13 LERs)

   - 3 problems with lubrication and fuel oil leaks
   - 3 problems involving system valves

5. Radiation Monitoring System (19 LERs)

   - 5 failures due to problems with strip chart recorders
   - 3 software related problems
   - 2 cases of foreign material on circuit board

6. HVAC (11 LERs)

   - 6 caused by vent and fire dampers not opening or closing when required

7. Engineered Safety Features (17 LERs)

   - 14 caused by personnel errors and/or inadequate procedures
   - 3 equipment problems
   - 2 design errors

APPENDIX H

CURRENT STATUS OF REGULATORY PERFORMANCE IMPROVEMENT PROGRAM (RPIP)

A few years ago the licensee instituted a formal program to enhance the safe and efficient operation of the D. C. Cook Nuclear Plant. This program was identified as the Regulatory Performance Improvement Program (RPIP) and was formally documented by the licensee with a letter dated February 7, 1983. A major update was provided to the NRC on February 23, 1984, and the licensee meets monthly to discuss the status of the program.

The original eight major topics of the RPIP were discussed in the February 23, 1984 letter and those that remained open were combined with some other items to form the basis of the then current program. These were identified as Appendix C of the above letter and are the basis for the monthly meetings stated above. The topics and the current status is as follows:

1. DRAWING AND LABELING ACTIVITIES

   The licensee is involved in a joint effort between the plant and the AEPSC to confirm that flow diagrams accurately reflect the "as-built" configuration of systems; that components are uniquely identified; and that components are labeled appropriately.

   Field walks of Unit 1, Unit 2 and shared systems scheduled for walkdown have been completed. None of the drawing discrepancies found could have caused misoperation. Permanent or temporary tags have been installed on all components needing them to provide more functional information to the operator, including component name. All temporary tags are being converted to permanent ones and the program will continue until all temporary tags have been replaced. To date, 6146 new permanent tags have been installed.

2. PLANT PROCEDURES REVISED PER PMI-2010 AND THE CODES AND STANDARDS MATRIX

   PMI-2010 describes how all other plant procedures are to be written or revised, and the codes and standards matrix provides, for each PMI, an index of the regulations and standards with which the respective activities at the D. C. Cook plant must comply.

   To date, 44 of the 67 PMIs have been reviewed and 27 of these 44 have been revised and issued. Nine others are presently in the revision stage. The licensee said the review is on schedule with completion scheduled for February 1, 1986.

3. AUGMENTATION AND REORGANIZATION OF PLANT PERSONNEL

   A licensee review of the D. C. Cook plant organization revealed that the plant workloads would be more effectively and efficiently accomplished with the addition of 73 people and some reorganization. Additional

people were approved for hire and the Planning Department was reorganized to be responsible for all major planning activities such as outages and design changes.

This task was completed in September 1984, when the last of 82 new positions were filled.

4. TEMPORARY PROCEDURE CHANGES

The purpose of this function was to reduce the number of procedures which did not contain full page change sheet inserts. At the time RPIP was implemented there were 131 plant procedures with four or more temporary changes which had not been incorporated into the respective procedures. This backlog was eliminated early in 1985 and this part of RPIP therefore is completed. However, as is noted in Section 3.2.8 on "Procedures," the licensee may be getting lax on revising procedures even though the change process has been improved.

5. MANAGEMENT REVIEW OF QA PROGRAM

On July 1, 1983, the QA audit section of the D. C. Cook plant QA Department was transferred to the AEPSC QA Department, but it remains on site under the direction of the AEPSC QA supervisor. As part of the management review of the program a contractor was hired to provide a complete review and assessment of the adequacy and effectiveness of the QA program. The review was completed in August 1984, when the contractor issued 106 recommendations of which 76 were accepted by AEPSC. As of March 1985, 43 of these 76 were implemented. The remaining 33 are in various stages of implementation but corporate personnel to whom the evaluation team spoke could not provide a schedule.

6. ACTION ITEM COMMITMENT LIST

The objective of this function was to assure that corrective actions taken in response to internal and external inspections, evaluations and audits are timely, effective, and made known to all affected personnel, and that a followup system is employed to keep track of long-term commitments. To accomplish this a computerized program was established to track commitments made to the NRC. This system (known as the Action Item Tracking System) is the responsibility of the corporate office (AEPSC). The site recently received a computer terminal to be able to use the system but it is not yet operational. In addition to the corporate role, the site maintains a separate commitment tracking system. These systems appear to have improved the licensee's completion of commitments, because as of October 25, 1985, there were 313 open items on the list and only two of them were overdue. However, the evaluation team notes in Section 3.2.10 of this report there may be some minor laxness occurring because several other commitments were identified as missed.

7. INDEPENDENT VERIFICATION PROGRAM

The objective of the Independent Verification Program is to ensure that equipment is removed from service and returned to service without jeopardizing the safety of the plant. Various methods were used by the licensee to accomplish this but the method settled upon, effective in February 1984, was that the verification would be performed by persons acting independently of those performing the return to service (e.g., they would not be part of the same team). This method apparently is working because, in the one year period ending in January 1985, 5351 clearance permits were issued and 2026 valve lineups were performed with only 14 valve misalignments occurring. Of these 14 misalignments (all of which occurred early in the year) four were caught by the independent verifier leaving 10 missed by both personnel. Since June 1985, there have been no valve mispositionings directly attributable to incorrect independent verifications.

8. PROBLEM ALARMS IN CONTROL ROOM

The purpose of this activity is to minimize the number of control room annunciators/alarms that are problems, a problem alarm being defined as one that is lit or in an alarm condition during power operation. Of the approximately 3600 alarms in the two control rooms, 150 were identified as problem alarms. As of August 15, 1985, design work was completed on all previously identified problem alarms with 89 design resolutions having been implemented and 61 design resolutions to be implemented by the end of the Unit 1 outage. According to corporate personnel this task was completed and the control rooms now operate with clean (unlit) annunciators except for those which should be lit or which go bad in the future.

9. COMPUTERIZED SURVEILLANCE PROGRAM

The purpose of this was to develop a computer program to reduce the possibility of not conducting required surveillances. This was done and all Technical Specification surveillance schedules have been entered into the computer data base. Additionally, a measure is in place to control changes to these surveillance requirements. Fourteen enhancements were requested by plant personnel to make the program more user friendly with 13 of these already incorporated and the last one scheduled for completion in November 1985. However, even though this program has been completed, missed surveillances continue to be a major problem at D. C. Cook as is discussed in Section 3.2.7 of this report. This deserves immediate attention.

10. QA/QC ORGANIZATIONS AND FUNCTIONS

In July 1983, the QA audit section of the plant QA Department was transferred to the AEPSC QA Department, but the plant QC Department continues to report to the Plant Manager. One major task of the QC Department was to review and revise QC procedures to reflect the reorganization and to review all technical and operations procedures

for incorporation of QC hold points. Forty-six of the total of 50 QC procedures have been reviewed and revised as necessary. The licensee expects to meet its target date of December 1, 1985, for reviewing all fifty of these procedures.

Six hundred and seventy-three plant procedures have been reviewed for hold points, but it is not known by the evaluation team how many remain to be done. No schedule for completion was provided by the licensee in the RPIP.

The major task of the QA activity for this RPIP section was to revise 12 QA implementing procedures to reflect the transfer of the QA department to AEPSC. This task has been completed.

11. CONFIRMATORY ACTION LETTER RESPONSE SCHEDULES

This item was completed.