UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

Title: BRIEFING ON PILOT DIAGNOSTIC EVALUATION PROGRAM AND USE OF LICENSEE SELF-ASSESSMENTS IN INSPECTIONS - PUBLIC MEETING

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BRIEFING ON PILOT DIAGNOSTIC EVALUATION PROGRAM

AND USE OF LICENSEE SELF-ASSESSMENTS IN INSPECTIONS

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PUBLIC MEETING

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United States Nuclear Regulatory Commission

One White Flint North

Rockville, Maryland

Wednesday, December 7, 1994

The Commission met in open session, pursuant to notice, at 10:00 a.m., Ivan Selin, Chairman, presiding.

COMMISSIONERS PRESENT:

IVAN SELIN, Chairman of the Commission

KENNETH C. ROGERS, Commissioner

E. GAIL de PLANQUE, Commissioner

STAFF SEATED AT THE COMMISSION TABLE:

KAREN D. CYR, General Counsel

JOHN C. HOYLE, Acting Secretary

JAMES TAYLOR, Executive Director for Operations

WILLIAM RUSSELL, Director, NRR

EDWARD JORDAN, Director, AEOD

FRANK GILLESPIE, Director, Inspection and Support Programs, NRR

ELLIS MERSCHOFF, Director of Reactor Projects, Region II

P R O C E E D I N G S

[10:00 a.m.]

CHAIRMAN SELIN: Good morning, ladies and gentlemen.

The Commission is pleased to welcome members of the staff to brief us on the pilot special evaluation process that was conducted at Cooper Nuclear Station and on the use of the licensee self-assessment more generally as a possible alternative to region-based team inspections, at least in certain situations.

In your brief, we'd like you to not only talk about the results, but talk about the situations or the conditions that you think would point to a more streamlined regional inspection and more use of the self-assessment.

Just as background, in an effort to streamline the inspection scope and to make region-based team inspections more efficient and effective, and also to get the licensees to buy into the results a little more firmly, the staff has started an evaluation process that builds on region-based inspection. It builds the region-based inspections on licensee self-assessment. We'll hear this morning about the development and progress of the briefing.

The briefing comes in two parts. The first will discuss the specific staff activity carried out by special evaluation team to assess the effectiveness of licensee

activities performed by the licensee at the Cooper Nuclear Station. This assessment included an evaluation of findings made by the licensee's own diagnostic self-assessment team.

Then the second part will generalize from this experience and go into a discussion on licensee self-assessment as a generic question, as a possible alternative or supplement to region-based inspection.

In both presentations, the staff will discuss the experience with the approach, lessons learned and the plan for expanding use of this approach in the future.

Just looking ahead a little bit, this is, I believe, an example of a number of innovative attempts that we've taken to try to both be more cooperative where cooperation is called for and more efficient in terms of the economic impact we put on licensees. This may actually be a case where, we'll hear this morning, but we manage to get a better program in the sense of more likelihood for implementation at somewhat less overall cost.

Commissioners?

Mr. Taylor?

MR. TAYLOR: Good morning. With me at the table are Ellis Merschoff of Region II who led the special evaluation team at Cooper, Ed Jordan, who assists me in overseeing the diagnostic-type evaluation that the agency does, Bill Russell from NRR and Frank Gillespie. They will

talk about another inspection process where a licensee self-evaluation plays a part.

I would note that we decided at the last senior management meeting to field a diagnostic, full-scope diagnostic evaluation team to Cooper. We were in the planning process for this when Nebraska Public Power District advised us that they were planning and would carry out a self-evaluation. Ed Jordan and I reviewed that whole situation, decided it was a good idea on their part, and that we would adapt our process to what they had planned. We spent some time working to understand just exactly what they were going to do and they did, as Ellis and Ed will describe, carry out their own self-assessment.

I went to the exit with the Cooper Nuclear Station out in Nebraska where Ellis made the presentation. At that exit, Ralph Beedle, who had led the industry team, gave the results of their review. I must say, in my personal opinion they did a very effective broad-based review. In fact, they got into things that our normal diagnostic probably wouldn't get into and gave a very broad evaluation of the station. We were able, as Ellis will describe, to build out of that. In fact, at the exit, the two presentations, first by Mr. Beedle and then by Ellis, complemented each other.

So, with those opening thoughts, I look at this as a success, first at their coming forward and offering to do

it, and secondly, we were able to adapt to it in a reasonable fashion and carry out our mission.

I'll now ask Ed to continue.

[Slide.]

MR. JORDAN: Okay. Could I have slide 2, please.

We do have two objectives for this presentation on the special evaluation today. The first is to provide an understanding of the process that was defined by the staff as a special evaluation of the Cooper plant. The second is to discuss the lessons learned and the future plans for diagnostics based on that effort. We don't plan to dwell on the findings of the special evaluation at Cooper, but rather on the methodology that was employed, its effectiveness and efficiency when combined with the utility's self-assessment.

Could I have slide 4, please?

[Slide.]

MR. JORDAN: The initial communications we had with the utility regarding the NRC decision to perform a diagnostic evaluation identified concerns by the utility about the resource impact of the diagnostic evaluation. As Jim Taylor mentioned, in subsequent discussions the licensee indicated they plan to do a self-assessment using the NRC diagnostic methodology.

CHAIRMAN SELIN: This was pretty innovative on their part. Do you know how they came to this conclusion?

I mean that first of all it would be a good idea and did they have reason to believe we'd be receptive?

MR. JORDAN: There was a discussion with INPO along the way associated with that. So, it was an INPO suggestion as well to --

CHAIRMAN SELIN: Did we let it know that we would be receptive to this or did they just go on their own and catch us by surprise when they said this is what they'd like to do?

MR. JORDAN: I think the discussion with INPO was also one that led to the innovative approach.

CHAIRMAN SELIN: It was an INPO-Cooper discussion or an INPO-NRC or --

MR. JORDAN: INPO-Cooper, INPO-NRC.

CHAIRMAN SELIN: Thank you, Mr. Jordan.

MR. JORDAN: So, this opportunity for the innovative approach was recognized, discussed and Jim Taylor agreed. Discussions also included Region IV and NRR. We used the principles in an existing NRC manual chapter for utilization of licensee assessments. We discussed the necessary conditions with a licensee regarding the suitability of their effort by NRC direct observation and discussions with the team members of their assessment. We also identified that the team leader and the members of the team should be independent from the utility and that there

would be plans for a public exit meeting to discuss the findings of their team effort and the conclusions of a special assessment and that their assessment, their self-diagnostic, would be publicly available. So, those conditions were satisfactory to the utility as well and so we proceeded on that basis.

COMMISSIONER ROGERS: Just before you leave that, Mr. Jordan.

MR. JORDAN: Yes.

COMMISSIONER ROGERS: These are all good points, but if one is writing down "must haves" for something, I would be concerned about the mention of capability of the members of the team. Obviously, it goes without saying that we want a capable team. But the question is to what extent did we endorse the capabilities of the individual members of that proposed team before the process began or did we just let it take place?

MR. JORDAN: Okay. The initial team that was assembled by the utility contained a number of utility personnel that were subsequently replaced with people that were independent of our utility. That was based on our independence. The team members, the NRC did not review in advance of their selection by the utility. We reviewed their qualifications subsequently and Ellis will talk about that, but it was an impressive team that the utility

assembled for this purpose, with a great deal of industry experience. I don't think we would anticipate being in their selection chain. We would be looking after the fact.

COMMISSIONER ROGERS: Well, not as far as individuals are concerned, but perhaps as far as -- perhaps some kind of criteria or something.

MR. TAYLOR: They pick people with a broad range of experience across the plant.

COMMISSIONER ROGERS: Well, apparently it worked out very well.

MR. TAYLOR: Yes, it did.

COMMISSIONER ROGERS: I'm not questioning it.

MR. TAYLOR: Yes. I think at the outset --

COMMISSIONER ROGERS: I think one is a little uncomfortable about what that team composition is going to be and how they're selected if one is going to accept the process. But I was just curious as to what you thought about the future maybe as far as any guidance on what we would expect. This obviously worked very well. Again in the future, one would want to see that it worked as well.

MR. TAYLOR: Yes. I think we looked for the pattern of experience across the various elements of the plant, like maintenance, like ops. and so on.

Wouldn't you say?

MR. JORDAN: Yes.

MR. TAYLOR: They indeed, and Ellis will cover that, had a representation across major elements that concern us.

CHAIRMAN SELIN: I guess you would be looking not so much for individual members, but evidence of seriousness. If they just took all the fellows that were responsible for getting into the mess in the first place and said, "They're going to do the review," that would not leave the same kind of confidence as buttressing the team in some independent field.

MR. TAYLOR: Yes.

CHAIRMAN SELIN: Okay.

MR. RUSSELL: We'll come back and we'll also address your question as it relates to the broader aspects of how this is being done in other areas when we get to that discussion.

COMMISSIONER ROGERS: Okay.

MR. JORDAN: I think there's a concern about us becoming too prescriptive or get in the chain of decision as to the team members. We want to avoid that. But certainly the --

CHAIRMAN SELIN: If we're going to be responsible, we might as well do the review ourselves. The idea is to leave the responsibility where it belongs, but to have some assurances that it's being taken seriously.

MR. JORDAN: And I think the assurance that we have is by a team such as Ellis led making a determination that, yes, the team the utility employed was well qualified, did make good findings and was a powerful team. If, on the other hand, the determination was that it was a weak team that lacked experience and didn't make good findings, it would not be a basis for adapting or adopting those findings.

CHAIRMAN SELIN: But a key point is that a DT is not an inspection, it's an information gathering piece.

MR. JORDAN: Yes.

CHAIRMAN SELIN: And we already know there are problems. Now we're trying to figure out what the cause is.

MR. JORDAN: The extent and the cause.

CHAIRMAN SELIN: Our criteria for substituting licensee inspection for an NRC inspection would be different from the criteria we would have for how much reliance to put on the evaluation. We've got enormous promises on how terrific Ellis is going to be when he comes to -- we can hardly wait.

MR. JORDAN: Oh, boy. Maybe I should turn it over.

The NRC then scaled a special evaluation to a nine team member size, including the team manager, rather than a diagnostic that contained 16 to 18 persons. We expected to

attain the same scope and depth of evaluation by building upon the utility diagnostic self-assessment.

Could I have slide 6, please?

[Slide.]

MR. JORDAN: The goals of the special evaluation were the same as a full diagnostic with the added element of evaluation of the effectiveness of the licensee's self-assessment. The emphasis remained in determining the root causes of safety significant performance problems. Ellis Merschoff became involved very early in the evolution of this process and assisted in setting the ground rules for the special assessment, selecting the team, managing the effort and extracting the lessons learned.

Ellis, before I run into your presentation, why don't you proceed?

MR. MERSCHOFF: Yes, sir.

Slide 7, please.

[Slide.]

MR. MERSCHOFF: In order to accomplish this special evaluation, we formed and organized the team as shown. The special evaluation team included NRC employees with senior resident inspector experience, General Electric start-up engineering experience, regional, AEOD and NRR experience, as well as extensive diagnostic evaluation experience.

The functional areas chosen, operations, maintenance, engineering and management and organization, were analogous to the organization used for previous NRC diagnostic evaluations and the functional organization chosen by Cooper Station to organize its diagnostic self-assessment.

Slide 8, please.

[Slide.]

MR. MERSCHOFF: Now, in terms of the Cooper diagnostic self-assessment, that team consisted of 15 technical evaluators led by an experienced nuclear utility executive. The team members were independent of Cooper Nuclear Station line responsibility and reported to the Vice President Nuclear and President concurrently. The assessment plan and scope were developed to be consistent with an NRC diagnostic evaluation. A list of attributes were developed for assessment in each of the functional areas of operations, maintenance, engineering and management and organization.

The methodology employed for this diagnostic self-assessment was based on the NRC diagnostic evaluation program directives and handbook and employed a mix of field observations, of interviews, and programmatic evaluations.

The diagnostic self-assessment consisted of four weeks on-site by the full team, followed by two weeks of

report preparation accomplished by the team manager and his two assistants. The report was issued as planned on September 6th, 1994.

Slide 9, please.

[Slide.]

MR. MERSCHOFF: The diagnostic self-assessment team brought a considerable amount of experience to bear on the assessment of Cooper Station and, of course, this reflects directly on the conversation we were just having about the people. The team was led by a former executive vice president of the New York Power Authority with a consultant with NRC experience serving as the assistant team manager. The operations area was supported by the technical training supervisor from Farley, the Director of Nuclear Assessment from Clinton, the general manager of operations from Fitzpatrick.

The maintenance area included the mechanical maintenance manager from Pilgrim and the outage director from Fort Calhoun.

The engineering area consisted of an assistant team manager from INPO, the director of design engineering from Waterford, test and evaluation performance engineering supervisor from Fort Calhoun, the safety review group manager from Catawba and a program manager from INPO.

Finally, the management and organization area

included the offsite review committee chairman for Philadelphia Electric Company, a nuclear specialist from Virginia Power, a consultant with NRC experience and an assistant team manager from INPO.

Slide 10, please.

[Slide.]

MR. MERSCHOFF: The weaknesses that this group found, that the diagnostic self-assessment found, can be grouped into three main areas, management, programs and equipment. In the area of management, deficiencies were noted with planning, with establishing and enforcing high standards, with the effectiveness of independent oversight and with establishing a conservative operating philosophy.

In the area of program effectiveness, poorly defined and implemented programs were noted in design control, work control, configuration control, a corrective action program, industry operating experience and industrial safety. In the area of equipment performance and condition, weaknesses were noted with the quality of maintenance, long-term equipment programs and the potential for reduced margin of safety and important plant systems. As you can see, that's an extremely broad-based group of conclusions.

Slide 11.

[Slide.]

MR. MERSCHOFF: In terms of these weaknesses

found, the diagnostic self-assessment described the root causes of the problems at Cooper Station as described on the next two slides.

Slide 12, please.

[Slide.]

MR. MERSCHOFF: That's what the diagnostic assessment accomplished and who accomplished it and essentially how they did it. What I'd like to discuss now is the NRC's special evaluation, what we did.

Slide 13.

CHAIRMAN SELIN: Mr. Merschoff?

MR. MERSCHOFF: Yes, sir.

CHAIRMAN SELIN: Were the total resources in terms of people multiplied by time expended between the licensee's team and our team. Were they comparable to what we would have done in a DT ourselves?

MR. MERSCHOFF: Yes, sir.

Slide 18, please, Ola.

[Slide.]

MR. MERSCHOFF: If I can put this slide up, I can discuss it graphically.

If you go to your package to page 18, sir, you'll see we took a shot at describing the total effort in terms of person weeks assessment. If you add the DSA and the SET together, they come very close to the total assessment in

terms of people on site provided by a DET. In terms of impact to the licensee, we took a look at what we called the request for information. That's issues, questions that require a formal, thoughtful response. The total number of requests for information of the DSA and the SET were roughly equivalent to a DET. A DET runs around 13 to 1500, which is about what the combined total was. As you can see from this chart, in terms of NRC resources, the SET plotted alone, it comes up to a little more than half of what's normally invested in a DET.

COMMISSIONER de PLANQUE: You mentioned something. Let me make sure I understand this. Does this just include time on site or time for the total process?

MR. MERSCHOFF: No, ma'am. It's the total process. In terms of the DSA, it pretty much is only time on site. The 15 member team assembled day one on site, worked for four weeks on-site and then the team was released to their normal duties.

COMMISSIONER de PLANQUE: But then they had two weeks, I think you said two weeks --

MR. MERSCHOFF: Yes, ma'am.

COMMISSIONER de PLANQUE: -- for writing the report.

MR. MERSCHOFF: And that's included in this, the team manager and his two assistants. In terms of the SET,

that accounts for the work done here in Washington in preparation for the time on site and the report.

Okay. Slide 13, please.

[Slide.]

MR. MERSCHOFF: At this point, I'm describing the NRC's effort, the special evaluation. The methodology we chose attempted to evaluate the findings of the diagnostic self-assessment and to build on them to develop an overall assessment of performance of the Cooper Nuclear Station. That effort can be described in three phases. The first phase was an extensive review of licensee and NRC performance data for Cooper Station, including the SALPs, the inspection reports, the licensee event reports, Cooper Station's internal assessments and audits, their programs and their procedures. The second phase of the special evaluation consisted of on-site evaluation of the diagnostic self-assessment in its fourth and final week of the assessment. The observations that were accomplished by the special evaluation team were done by just half the team. The team manager and the four team leaders for that week of observing the DSA. We observed the diagnostic self-assessment team members performing their debriefs of licensee counterparts, their field activities, including their team meetings, their root cause assessment sessions and observation of the exit meeting that the diagnostic

self-assessment held with the utility at the last day of their four week on-site period.

The final phase, the third phase of the special evaluation entailed two weeks on-site with the entire NRC team for independent evaluation of Cooper Nuclear Station. This independent evaluation consisted of interviews of managers and staff, observations of plant activities and program assessment. Additionally a sample of the diagnostic self-assessment findings were reviewed to assess their validity and other areas identified during the preparation phase were reviewed that may not have been reviewed by the DSA.

Slide 14, please.

[Slide.]

MR. MERSCHOFF: The results of the special evaluation can be discussed in two parts. The first was the evaluation of the self-assessment and the second the evaluation of Cooper itself. With regard to the effectiveness of the diagnostic self-assessment, we found that Cooper Station had succeeded in organizing a large and experienced and sufficiently independent team to perform the assessment. The scope was sufficiently broad and deep to identify Cooper Station's significant strengths and weaknesses. While there were weaknesses in the process, in the DSA process, such as limited planning and evolving

methodology and changing team composition, the team nonetheless reached substantive conclusions that Cooper Nuclear Station recognized as valid descriptions of the station's performance problems and were supported by the NRC's independent assessment.

The root causes identified by the NRC's independent evaluation were consistent with and analogous to the diagnostic self-assessment identified root causes. The results of the diagnostic self-assessment were effectively conveyed during an exit meeting to a broad cross section of plant staff in a written report issued promptly after completion of the field work and at the first meeting of the licensee's board of directors following completion of the field work.

Slide 15, please.

[Slide.]

MR. MERSCHOFF: Now, with regard to the results of the special evaluation of Cooper Station, we found weaknesses in three key areas. We found that management did not provide the leadership and direction necessary to maintain appropriate corporate-wide standards of performance. We found that major programs and processes were poorly defined and as implemented did not assure the consistent and effective accomplishment of program goals and objectives. We found that independent oversight and self-

assessment were not effective in monitoring ongoing activities, detecting deficiencies or assuring that identified deficiencies were resolved.

Slide 16, please.

[Slide.]

MR. MERSCHOFF: These results, the results of the special evaluation, were presented in a public meeting following the presentation of the findings of the diagnostic self-assessment by the diagnostic self-assessment team manager.

CHAIRMAN SELIN: In other words, both presentations were made at the same public meeting?

MR. MERSCHOFF: Yes, sir. That was a very effective format. It was led off by the licensee's effort and the team manager presenting his results. Mr. Taylor provided opening remarks and then I gave the results of the NRC's effort.

CHAIRMAN SELIN: This was held at the station?

MR. MERSCHOFF: Yes, sir.

CHAIRMAN SELIN: And was there much public interest?

MR. MERSCHOFF: There was media interest there, only a very limited amount of public interest.

MR. TAYLOR: There were representatives of the state. Of course, the board members, a number of the board

members from the Nebraska Public Power District and media principally. Did I miss anybody? Those were the principal --

MR. MERSCHOFF: There were four or five members of the board there.

COMMISSIONER de PLANQUE: Did both groups know in advance about what the other side was going to say at this meeting?

MR. MERSCHOFF: Yes, ma'am. I had attended Mr. Beedle's exit and discussed with him before this exit the format, the general time and basically what would be said. But his report was out and so it was pretty clear what would be said on his part. He had less knowledge of what we would say.

As I said, the use of this public forum I thought was a very effective way to convey the results. It resulted in a commitment by Cooper Nuclear Station corporate management to addressing the problems described.

COMMISSIONER ROGERS: Do you have any idea who attended that public meeting that was not either associated with NRC or associated with the utility itself, who the independent observers might be that actually attended that?

MR. MERSCHOFF: Other than state members and media, no, sir, I don't believe we had more than one member of the general public. There's not a high degree of general

public interest or attendance in the public meetings out there. Plus, public meetings, there are a lot of public meetings occurring now at Cooper. We've established a restart panel, Manual Chapter 03 Cooper Restart Panel, and they hold their at least monthly or more often meetings as public meetings, either in Arlington or at the site. So, a public meeting at the site for this presentation would not be a very rare occurrence that might attract people.

MR. TAYLOR: This is a relatively rural area too in terms of location.

MR. MERSCHOFF: Slide 17, please.

[Slide.]

MR. MERSCHOFF: In terms of the lessons learned from this new approach, we felt that this special evaluation process was clearly an efficient use of resources. It was conducive to rapid buy-in by the licensee when their problems and deficiencies were identified by their peers early in the process. It provided the results much earlier in the process and reduced the regulatory impact on the licensee and the NRC resources necessary to accomplish the evaluation.

Slide 18 --

COMMISSIONER de PLANQUE: Hold on a second. When you say efficient, are you taking into account just the NRC resources or the combination of both? Because if you look

at your chart, the difference is not very much.

MR. MERSCHOFF: Well, we think it's both for a number of reasons. In terms of efficient, one, the results are available three months earlier in this process than they would otherwise. The licensee found that extremely useful to have the problems on the plate and solutions under development as the NRC process continued. Additionally, you should consider that when a DET, when a diagnostic evaluation is planned, a licensee will do some degree of self-assessment to prepare for that. So, a fraction of this DSA would occur regardless of a special evaluation process or a DET. Certainly not 17 people for four weeks, but perhaps half or a third of that. So, in terms of actual effort, it's efficient, we feel, from the licensee even more than this slide might show. And in terms of getting the results earlier and early buy-in, it's very efficient.

COMMISSIONER de PLANQUE: Did you or the licensee make any attempt to quantitate the reduced effort on their part?

MR. MERSCHOFF: No. Beyond what you see here on a broad approach, no, ma'am.

MR. JORDAN: We have had the experience that the utilities create -- we call it a shadowing team for diagnostics. So, during the three weeks on site for a diagnostic, there is essentially a matching resource the

utility provides tracking and monitoring what is being identified for their own self-diagnostic. It's my understanding that they did not have that level of effort in a shadowing manner. So, there are the order of 48 person days or whatever that would be different.

COMMISSIONER ROGERS: Well, I guess it's really asking sort of the same question, but whether you had any feeling about the licensee staff support that is required for these two methods of evaluation. Not what you have on your chart here, but what the staff's support for any of this work is that are not -- staff members of the utility that are not members of these teams.

MR. JORDAN: Yes, and that would be this shadowing effect. I said indirectly 48 person day. It would be something like 48 person weeks.

COMMISSIONER ROGERS: I think that's less.

MR. JORDAN: It would be probably half because there's still a shadowing of the special assessment team for the NRC, but I don't believe that there would be a shadowing by the utility for the self-diagnostic work. So, there would be -- if we asked the licensee, and I don't think we have, what their resources --

COMMISSIONER ROGERS: I think it would be useful to try to have a quantitative measure of that.

MR. JORDAN: That's a good question.

COMMISSIONER ROGERS: Yes. What their support for the effort outside of the specifically identified team members was in this particular case and I guess they don't have a basis for making a comparison. We have to get that from somebody else.

MR. JORDAN: Right. We would ask a recent other diagnostic a similar question.

COMMISSIONER ROGERS: Right.

MR. MERSCHOFF: One way to think about the level of effort of the administrative support is in response to the formal requests for information, for example, because a bulk of the work that a licensee inherits as part of this evaluation process is collecting information, Xeroxing that information, establishing essentially a technical library of that information and providing it to us. When we look at the numbers of requests, it's roughly equivalent. If we look at the time it takes for this combined DSA, SET process and the DET process, it's roughly equivalent. So, in terms of the administrative burden on the licensee, I would presume it's roughly equivalent.

COMMISSIONER ROGERS: I wonder if it would be useful to actually look in a little more detail as to -- you say the number of questions are about the same. But if you take the individual questions and look at see how this team asks that question versus how we would have asked the

question and to see if there's any difference there that is useful in guiding us either for our future or whether it reveals something that might be useful in perhaps streamlining the process.

MR. MERSCHOFF: Well, there are some differences. It's easier for the utility to work with an industry group in that in an industry group the diagnostic self-assessment can exchange written information, for example, where the NRC will not provide draft or written information in the course of an assessment. The level of rigor in a response to a regulator is necessarily higher in terms of material false statements and that regulatory arena then is in place for a self-assessment. So, the working relationship informality can't help but make things a little easier to work with on the self-assessment.

COMMISSIONER ROGERS: Yes. That's a very interesting point.

CHAIRMAN SELIN: But it's clear that the major -- although there will be some resource savings, the major impact is supposed to be in a more effective evaluation. So, what's your view as to how that actually turned out?

MR. MERSCHOFF: I think it was an extremely effective evaluation. I think the DSA team was comprised of very talented, knowledgeable people, that they used that experience well in the field, that they -- where we said

there was buy-in early, I think that's a very real effect when your peers tell you that you have problems, that your programs are not working and that at my station we do it this way and it works, that you get a very effective transfer of the findings. Additionally, the report for the DSA speaks for itself. It's a very comprehensive detailed report that lays out, we felt, the full spectrum of problems at Cooper Station.

MR. TAYLOR: I would second that. I read the full report before arriving at the station of the diagnostic self-assessment, a very effective report. It covered the broad spectrum of issues and it was very effective.

CHAIRMAN SELIN: So you didn't get the impression that punches were being pulled?

MR. TAYLOR: None. And not so in the exit. The exit discussion, the summary of the major issues, it was of course a summary of a rather extensive report. There were no punches pulled.

MR. MERSCHOFF: At the first exit on August 19th when the team was ready to depart the site. That exit was a two hour presentation done by the team leaders for each of the four areas and the team manager, Mr. Beedle. The attendance at that exit meeting was a broad cross section of managerial levels and organizational levels to hear an extremely detailed and powerful presentation of the problems

at Cooper.

CHAIRMAN SELIN: You know, Mr. Russell has reported earlier that we have found that a number of these diagnostics, on the one hand, are very nice, thorough statement of where we stand, but also a whole lot of things that either we knew or we could have known a lot earlier if we had just put them together. Did you find the same pattern here? Did the Cooper people say, "Gee, we could have figured that out ourselves if only we'd asked ourselves that question?" In other words, do you get the same feeling that there was information available earlier to reach many of these conclusions had somebody tried to piece it altogether?

MR. MERSCHOFF: The information was there. On the Cooper side, a number of self-assessments had occurred since early '92 that described almost all of the problems that were ultimately described by the DSA. So, the information was available.

CHAIRMAN SELIN: Did it take outsiders to catch the management's attention? If these reports had been made to Cooper management but not acted on, what was different this time?

MR. MERSCHOFF: Certainly the NRC's interest and a diagnostic level assessment caused the senior managers at Cooper Station to get involved and truly pay attention to

the findings. That's a big difference in itself in terms of the degree of regulatory involvement as a forcing function.

CHAIRMAN SELIN: What about our own understanding of the situation? Had we also failed to add two plus two to get four earlier having done these assessments in more of a piecewise fashion before this period?

MR. MERSCHOFF: If you look at the regulatory trail in this area, the SALP that was performed in '92 had drops in performance, in operations and radiological controls. The next SALP had dropped to a three in maintenance and a three in safety assessment. There were two trending letters issued after that. So, the slope of the response, regulatory response, would seem to be appropriate. What you could argue about is should it have happened a year or two or three sooner. Certainly based on the condition at Cooper, the answer would be yes, we could have and should have taken action sooner.

MR. TAYLOR: But the SALP process began identifying --

MR. MERSCHOFF: '92.

MR. TAYLOR: Yes, in the beginning of 1992. This began to focus our attention on Cooper, both at the regional level and at the senior management level. I guess the first trending letter was issued in this past January. As we saw, all of the results out there in '93 when we discussed this

and issued a trending letter last January, followed up by a follow-on letter this past summer for the teams.

MR. MERSCHOFF: Slide 19, please.

[Slide.]

MR. MERSCHOFF: In terms of the uncertainties and limitations of the special evaluation approach, we felt that the importance of the diagnostic self-assessment team qualifications and leadership to performing an effective assessment on the aggressive schedule that's chosen for DSA is clearly an uncertainty to be considered. Of course, that's the root of Commissioner Rogers' questions early on. The approach we took was in the performance and as opposed to monitoring the people selected first, rather did they achieve their goals. But that is certainly an uncertainty in the process.

The second is the potential for delaying corrective actions. If the diagnostic self-assessment and the special evaluation arrive at significantly different conclusions, the ultimate corrective action to those will necessarily be set back.

Finally, the public perception of NRC's partial reliance on a licensee's diagnostic self-assessment is a limitation of the process.

At this point, if there are no questions, Mr. Jordan will address the future plans.

COMMISSIONER ROGERS: Could I just ask one question? It's a detailed one that relates to Cooper itself, but the weakness -- this is on slide 15, the root causes for weak independent oversight and self-assessment. Does Cooper have a standing external nuclear oversight committee?

MR. MERSCHOFF: They have a corporate review board.

COMMISSIONER ROGERS: Well, that's the composition of that, do you know?

MR. MERSCHOFF: Yes, sir. There are nine and outside members. There are two to three outside members as well as corporate level and site level managers on that oversight board.

COMMISSIONER ROGERS: It sounds to me like they haven't done the greatest job then, which is exactly what you want an outside review board for, an outside oversight committee for.

MR. MERSCHOFF: And the DSA and special evaluation both identified that that organization had failed to detect declining trends in performance.

COMMISSIONER ROGERS: They're not getting their money's worth on that committee.

MR. MERSCHOFF: They've made some changes to that committee, by the way, in the past two months.

MR. JORDAN: Well, since Ellis is returning to Region II after completing this, I thought it was appropriate that I talk about future plans.

Could I have slide 20, please?

[Slide.]

MR. JORDAN: Based on the positive outcome of this special evaluation, we plan to establish a special evaluation in conjunction with a licensee self-assessment as an alternative that we may employ in the future. This Commission meeting, your support of the staff plan serves to convey NRC's willingness to accept this alternative. In the future, the early contact with the utility, once a diagnostic decision has been made, will offer this alternative approach for a utility to do a diagnostic self-assessment and for the NRC then to do a special evaluation in this matter.

We've learned a number of things in the process that will formalize. An example would be our special evaluation had four subteam leaders. That's really more than is required. Two subteam leaders would be appropriate to complement a team leader and give us more flexibility in the process. So, we have a lot of detailed things that we learn that will make us have a more efficient and effective, but the overall concept we're very happy with and would expect to provide it as alternative.

COMMISSIONER de PLANQUE: In doing this part of it, your evaluation, I would guess you were very conservative on this the first time around to make sure that the process is going as you would wish and you already indicated that you could do with a couple less people on the team. What about the total effort or the total person weeks, as you put it? Could that be reduced now that you've seen how it works?

MR. JORDAN: No, and I didn't mean to say we would reduce the total numbers of people on the team. We would reduce the numbers of people identified as leaders.

COMMISSIONER de PLANQUE: Okay.

MR. JORDAN: We had subteam leaders for each of the four functional areas. It worked out better or would work out better to have two team leaders with each two functional areas under them and give us more flexibility to shift to team members to an area that seemed to be lacking.

But at this point, from this experience, the sizing was in fact correct. We would expect to be able to proceed. If the outcome were that the self-diagnostic did not provide us the basic information we need, this same team could continue on site for about two more weeks and have an overall understanding that would be sufficient. That would be a resource much like a normal diagnostic would have been. So, we need to retain that flexibility and capability that

if the self-diagnostic did not provide us the necessary basis, that we could continue and obtain that information.

COMMISSIONER de PLANQUE: So the short answer is no?

MR. JORDAN: Yes.

COMMISSIONER de PLANQUE: Okay.

MR. TAYLOR: If there are no further questions on this portion, we'll ask Bill Russell and Frank Gillespie to continue. It's a separate area, but related.

MR. RUSSELL: I'd like to cover two items first as a follow-up to the Chairman's comment from the standpoint of programmatically what do we find from Cooper, special evaluation, and what does it tell us about our program. This is now the third DET in a row where we have found that the information was generally available prior to and could have been identified earlier.

We are working on a revision to the program to develop a more in-depth review of the record that exists on a facility, develop a hypothesis about the performance based on that record and then go in and explicitly test that hypothesis through an inspection activity.

The fifth pilot is underway now at Beaver Valley. We will be discussing the results and some improvements to that process from the pilots and will be coming back to the Commission probably right after the senior management

meeting with a recommendation to make changes to the program so that we can anticipate these sooner and not have to use a DET type tool to find these problems.

The second area I'd like to broadly cover is the approach to self-assessments and what we see from a program and policy standpoint as our real benefits. Just as you heard that there was a benefit related to early buy-in, I would characterize that really as an ownership of the problems that are identified.

In the case of a utility performing a self-assessment, it's actually utility staff who are performing the review. It's not a third party, so, even though it may be a peer that has credibility, it's still someone else identifying the problem. The process that we're talking about now is an assessment done by the utility by the utility staff so that they identify their own problems and as a result there is very early buy-in where problems are identified.

The second major feature is that it is a demonstration of the utility's ability to perform assessments of their own performance. That is, what did they plan to do, how did they do it, what did they find, and that process builds credibility on the part of the utility with the staff in their ability to perform assessments of their own programs.

And thirdly, we see it as a more efficient use of our resources overall. There are three distinct elements. I think we talked about them and there were parallels to this in the special evaluation.

That is, the first phase is preplanning, meetings with the utility where they describe what they're going to do, who's going to be doing it, and in fact the front end planning process.

Next is actually the conduct of the activity by the utility with observation in real time by the staff of the conduct of that assessment.

And then finally there is NRC follow-up that is independent evaluation to see whether we find the same types of things or whether we find weaknesses or whether there were areas that they didn't address that we want to address.

Overall, the results I think have been quite positive. I would like to have Frank Gillespie discuss it from a program standpoint, what we've learned to date.

MR. GILLESPIE: Let me go through what's -- this is what's in place in the program right now. In the last page of the presentation, when I get to it, I think we'll show that we've gradually increased the frequency of allowances for self-assessments to the point where right now on service water inspections there are 50 plants that fell into the category of, in our opinion, requiring service

water inspections and 23 of those are being performed by self-assessment, so we've progressed significantly over the last four years in the allowance of self-assessments to almost the 50 percent rate and we still have some other steps to go.

I'd like to emphasize this is disconnected from the DET which has a different objective than the inspection program, so I have different thresholds written into the program. We address both effectiveness and efficiency, so this is not, well, we're going to do 23 and that's going to save us six people each and therefore we can reduce. Coming at it as an overall program, I'll address the resources. It's a net effect of the performance of the overall industry which effects the number of inspectors, not just an individual piece we'll subtract this off.

[Slide.]

MR. GILLESPIE: On the first slide, licensee self-assessment in lieu of regional-based team inspections, you can see what we started with here was electrical distribution functional inspections, and these actually started in about 1991. The question came up about halfway through instituting those, "Gee," some licensee said, "what if we do it ourselves?" and we started then letting some licensees do it and we let four licensees do those themselves, had very positive results, so it led to saying

"Let's write a manual chapter in the inspection program."

[Slide.]

MR. GILLESPIE: The next slide starts to present some of the criteria out of the manual chapter. Just as a reference, it's manual chapter 4501 on self-assessment being substituted for team inspections. When we started this off it required the concurrence of the director of NRR being requested by the regional administrator. It met with enough success that as we've proceduralized it now we find that regional management can make the decision and they inform NRR once a decision is made.

Now, the planning for these is such that if we have a real problem with it there's no problem with calling up the region. I mean, we talk to each other. But procedurally it's a regional decision. They decide and then they inform us.

In considering it, and this is somewhat of a subjective consideration but it appears to be working at the rate we've kind of started shifting over, is the relevant NRC inspections already done, the plant performance reviews which are built into the program which requires each region to evaluate its licensees on about a six month basis and match them against each other to assure that our resources are being put in the most effective location in which each case each licensee's performance is kind of judged on a

microscopic basis every six months, and it's SALP ratings, the trends, exactly the kinds of things Ellis referred to when he was discussing the DET. If there's a long-term downward trend or a short-term indication of a problem at a plant, either one of those can interfere with the idea of approving a self-assessment.

If it's identified as a good performer at the senior management meeting, it it's specifically identified as a good performer, that in itself as a statement is enough for us to say okay. But to get named that, you would have gone through the same subjective judgments that we already have in the manual chapter on an individual basis anyway, so it really is not a different criteria. It's just recognition that if you've already gone through it for this reason over here it holds.

And licensees on the watch list are ineligible. Now, that's not that we can't make an exception, but when you're dealing programmatically the guidance is if you're there you don't do it.

[Slide.]

MR. GILLESPIE: Now in the steps we also have guidance as to what are the steps, and, as Bill mentioned, one of the steps is the licensee has to ask to want to do it. When the licensee asks to want to do it, we're looking for some compatibility with how we would have done it

because effectiveness is one of the objectives we're trying to maintain as well as efficiency.

There generally is enough experience when we do a team inspection. We would have done four or five pilots. We'll have four or five reports, so there is basic -- you know, you'd almost call it like there's a case load of information there on what the NRC would deem appropriate level of detail, types of people on the inspection and inspection size. So there is significant guidance available for any licensee who wants to volunteer to do it, so the licensees know exactly what their asking to do before they get into it.

We do look at the organizational capabilities, the experience of the assessment team. The scope of the effort is equivalent to the temporary instruction we've written and most of our temporary instructions that deal with team inspections are very detailed. It starts off with an objective. It's got a guidance section on the back and it's got a set of inspection requirements, so it's tiered and it gets broader as you go through the report.

So our expectations are generally very well worked out and again it's modified after we do four or five pilot inspections to become a final temporary instruction, so it's easy for a licensee to understand what we expect and that generally makes it easy for us to say, yes, you've met our

expectations.

And timing, if there is a particular reason we want to have service water inspections done within a certain timeframe to make judgments or as a prejudgment that we -- we have generally in team inspections a mid-point correction where we say do we want to stop here and put out a generic communication because we're finding the same thing over and over? Depending on whether we were going to use this plant or another plant, timing becomes a consideration.

These points are right out of our manual chapter that covers it and I think it's working extremely, extremely well. I was -- you know, it's when you start looking at these things programmatically you realize that you've got something that's working better than you thought. I didn't realize we were doing 23 out of 50 on service water inspections.

[Slide.]

MR. GILLESPIE: This caused us to then also look at the future of licensee self-assessments. The visibility many times is given to service water inspections, electrical distribution inspections as areas of emphasis, as kind of the team inspection of the moment.

We do actually have the equivalent of a team inspection built into our core inspection procedures, the core being a minimum we expect to be done at every plant in

the country, and it's in the engineering area. And while it's not listed as a team inspection, three out of our four regions actually conduct it as a team inspection, but it's an inspection that requires multiple disciplines on-site for multiple weeks.

And now we're looking at taking the criteria of 40501 and applying it to that area in the core inspection procedures themselves because we feel we've been reasonably successful in seeing how it's working on the area of emphasis team inspections, so now we're at least now asking the questions. Since we've got the criteria down, we have experience, the industry has experience, they understand it, we understand it, is it time now to really integrate it not into things that are exceptions or things that we do which are temporary, but we need to ask the question of integrating it into the permanent portion of the program.

[Slide.]

MR. GILLESPIE: Examples of resource impacts, you can't get away I guess in any programmatic discussion without talking about resources. I do have to emphasize we are looking at both effectiveness and efficiency. Efficiency isn't the overall goal, but to maintain effectiveness also is.

In the budget this year, maybe indirectly or directly, but in the budget we submitted as NRR going from

'94 to '95 was a reduction in the number of direct inspection hours that our little computer model generates per reactor unit. And this actually rolls up into total number of inspectors when you add overhead and other things on it, but it's driven by the number of hours you want on-site on the average, and there is no average site, eyeballing things.

And we did have a reduction this year, and the reason for the reduction I believe still holds. It was the overall improved performance of the industry, including its ability to do self-assessments, and this was in the budget documentation that came in to the Commission in the spring. And I know it's a small decrement, but nonetheless it's a decrement which is breaking with about ten years of history.

We were very, very stable over about the last ten years, oscillating around 2,800 hours, and this was a deliberate decrement to 27. That represents someplace in the range of 10 to 12 people, a real reduction in total inspection force.

Now what happens when you look at this as an individual inspection and you say, well, you know, we take Ellis', we're using 30 percent fewer resources on an individual inspection? What happens to those people?

Well, we still have inspectors and we expect them to inspect, and this gets to overall effectiveness. It's

that if you have a good performer who's capable of doing a good self-assessment which you feel will be credible, those resources which are not on a good performer now go over to someone with a performance problem. So there's two elements of savings. There's savings at the individual utility scale and then there's savings overall.

So far we've taken credit for a small savings overall, being relatively cautious as we get into this on what effects actual inspectors. But there has been a significant shift in gradation and it's this gradation between good and bad performers that we've been working on for years to try to show that good performance pays off in less inspection and poor performance is going to pay off in more inspection, so this is contributory I think to what we see as an increasing gradation between good and poor performers, which I think is very positive, and that's effectiveness of our resources, not necessarily a savings of our resources.

COMMISSIONER de PLANQUE: How does that play on the plant side? If they're obviously doing the inspections themselves, they require more personnel to do that. Is it a one for one?

MR. GILLESPIE: If I could, I think I'm going to fall back on -- we're putting a paper together right now to address basically our side of it which is going to come to

the Commission. I think we cannot underestimate and may go too far to try to quantify that 23 plants have said we want to do it after they've seen what it costs them and what it costs us to do it. So you could say to something the Chairman has told me, the market place is the proof.

Now when we're on site they shadow us. It's almost one for one. When they're on site maybe they do, maybe they don't, but they obviously see that this is beneficial to them.

Ownership is very important, ownership of the results. Timely resolution of the problems is extremely, extremely important, and not fighting with us over ownership is an increased effectiveness of our program, so I'm very hesitant to even want to take on trying to quantify what a utility thinks it saves by doing this. Because, if it was costing them more, they wouldn't be in here volunteering to do all these and they're doing a lot of work on them. Their team sizes are comparable. Their team experiences are comparable. Their preparation is maybe comparable or more, because the last thing they want is a regulator come in saying they did a poor job when they've committed to doing it. There's a lot of pride on the line and that goes a long way in the whole program.

[Slide.]

MR. GILLESPIE: That really finishes -- the last

slide is just a chart that shows how we've come from the EDSFIs, which were the first ones we did, to the service water inspections. And the number that's not on this slide so far is that the service water inspections were restricted to plants who were licensed before 1979 because they had older systems and different designs. The total number was 50 and we have 23 requests out of 50 eligible to do them.

So I think what we've done is integrated this in a very orderly way into the program. The licensees are recognizing the effect of integrating into the program and taking advantage of it and the results have maintained an extremely effective approach for the NRC, the safety of the facilities.

CHAIRMAN SELIN: Now, 23 have been approved, of which 14 have been performed?

MR. GILLESPIE: Performed, yes, actually performed.

CHAIRMAN SELIN: So none of them -- I mean, they will all be approved?

MR. GILLESPIE: So far they've all been approved, yes, but our criteria and what it takes for us to approve it is out there. You know what I mean? There's no ambiguity.

The level of detail is surprising and these utilities do read reports on activities of other facilities, so they know exactly what we're looking for, which is very

beneficial. They know exactly what we're doing, which gives us a very high approval rate.

CHAIRMAN SELIN: Well, I would say to you the same thing I say to utilities, that in an era of scarce resources this is attractive, but we have to make sure that we're not just using this to slough off shortages. Not so much that it's happened, but we will need a good strong self-assessment capability in-house to make sure that we're not -- you know, we don't fool ourselves, we don't let our wishful thinking lead to our results.

MR. GILLESPIE: I think when you see the resources, the oversight we're providing is very, very extensive. There is a savings of maybe in the range of 25 percent to us, but it's not one for one. This is not a drastic reduction so far in our effort at this early point, because we need to develop confidence that when someone says they're going to do something and we expect it to be carried out that in fact it is.

So, so far we've proceeded very very cautiously, which is why I'm saying in a net effect reducing the overall resources in the regions by 1/27th is really as far as we would have -- that's what we recommended, so it's as far as we considered going based on overall good performance in the industry of which this is one element. So I don't think you're going to find the staff wanting to over-extend and

reduce oversight too quickly until there's some real proven systematic evaluations done of the result.

MR. TAYLOR: I believe that concludes the staff's presentation.

COMMISSIONER ROGERS: A couple of observations.

One is I think that the staff's willingness to, in the Cooper case, Cooper situation, to accept their proposal and move ahead in this direction was a very wise move. I think it represents a state of maturity of the organization when we recognize that we can do something like this. The problem so often is of uncertainties that drive a regulatory organization into a kind of state of rigidity. It seems to me, as much as it's a credit to Cooper, it's a credit to the staff itself to have enough confidence that it knows how to look at these things, that it was willing to try this, and I really want to compliment you on moving ahead on it.

There are questions. There are some dangers, as have been discussed here, but I do think that it's really a credit to the staff's self-recognition that it could allow something like this and with some confidence that it could review it very carefully and feel good about the possible result, or, if not, we had a way of stepping in. So I think that I want to really compliment you for going ahead on this. It really looks like a very important step forward in how we might conduct our affairs in the future.

There are dangers, as the Chairman has I think alluded to already, that we have to be very careful that somehow we don't get down the road with a system that somehow starts to break down itself and we don't know what's happening, just as we're seeing -- we have the evidence from the SALPs that there were problems. It was all there and yet it took years to finally come to a point where this is really what must be done and we don't want that same thing to happen to ourselves that we see happening time and time again with licensees when all the indications are there that there's a problem and yet nobody somehow or other takes them seriously enough early enough to head off their further growth, so I think we have to be prepared to make sure that we constantly have a way of evaluating this approach ourselves to make sure that we're not allowing inadequate jobs to get done when we know that something more would have been done had we done it ourselves.

That brings me to the concern that may or may not be a problem, but, if one sees this self-assessment process extending further and further in the future and it looks good, do we run some danger of our own staff capability of doing assessments somehow or other atrophying for a lack of exercise? And I would say that's something to pay attention to, because as we are under the pressures that we've been under to reduce our size and our staff and so on and so

forth and something allows us to hand a capability or an activity over to a licensee where they have the capability to do it, are we eventually going to find ourselves in a position where we don't have the capability of doing it ourselves? I think that question has to be asked time and time again. You can't ignore that. That must always be there. Now it shouldn't be the basis for rigidity and just standing in place, but that same self-evaluation of our own internal professional capabilities of doing these evaluations must constantly be looked at as we go down this road.

I think the arguments for self-assessment are very powerful. The licensee buy-in, the ownership question, it's something I feel very strongly about and I've always felt strongly that when we say that the licensee has a responsibility we have to take that seriously. That doesn't mean that they have the responsibility but we do things that they really should be doing, but then we have to hold them accountable and we have to have a way to do that.

I'm encouraged by this trend, but I don't think it's one, for instance, that we probably could have done 15 years ago. I think that this represents a certain maturing not only of NRC but the industry itself that it's gotten to a point now that it's somehow or other grown up to the point that we can begin to treat it as a mature individual and

allow licensees to take on these things that they really should be doing all the time but in the past we didn't feel enough confidence that they would do correctly or at least to the detail that we want.

So I'm very much encouraged by the whole trend, but I do think it's one that we do have to provide some clear mechanisms for assessment of it as we proceed in this direction.

MR. RUSSELL: We agree and in fact there are activities underway programmatically to build on that and we're shifting from what I will characterize as inspection activity more toward assessment activity of what the inspection findings mean. Where in the past we may have done a lot of inspection, that is the specialist going out, inspecting in their area, making their findings, going on to the next plant, et cetera, and we were using other tools to help pull this all together, that is the SALP process, the senior management process, what we're trying to do now is to force that down to a lower level and get more assessment within the inspection program on a plant specific basis where we review and understand what it means, and there are a number of things that we'll be talking about to better address this.

And the evidence that this is a problem is in fact the findings from the last several diagnostic evaluations

where the information was there but it was not sufficiently focused, not brought forcefully to management's attention early to allow this to be identified and corrected before it degraded to the point where senior management was concerned and concluded the diagnostic was necessary. So the point is very valid and we have a number of programmatic and staff development activities, in particular the senior reactor analyst position, to help us pull this together and use safety insights in doing that.

COMMISSIONER ROGERS: Well, I just might return to this question of self-identification of problems. It's the hardest thing for every individual to do to identify their own weaknesses and it's the hardest thing for every organization to do.

I remember when we asked the question, I think, of Doctor Murley some years ago when one of the plants that had had a very good performance started to slip and it was going on for a fairly long period of time before we brought them up short and they had to take extensive measures to straighten themselves out and he sketched the classical scenario and, you know, the first period of one of denial. There is no problem. "You've got it wrong, NRC, there really isn't a problem." And then the recognition that there is a problem and then a conclusion that the problem has to be dealt with seriously and turned around and then

one has to climb out of that hole.

But the beginning part of it is usually a denial that there's a problem in the first place and that's where we have to have real confidence that the licensee has that capability of really doing a self-assessment in an objective way and recognizing that they have problems and that's the tough one that one has to always be worried about.

CHAIRMAN SELIN: Commissioner de Planque?

COMMISSIONER de PLANQUE: I have one detail question. Just out of curiosity, I would assume that the Cooper Station paid for the DSA? They bore the cost of that evaluation?

MR. JORDAN: Yes.

MR. TAYLOR: Yes.

COMMISSIONER de PLANQUE: Okay. Do we have any idea what that cost them?

MR. JORDAN: Do not. My understanding is they had consultants that were paid from the utility plus individuals from other plants that were paid by their own utility rather than by --

COMMISSIONER de PLANQUE: Okay.

MR. JORDAN: -- Cooper. Is that your understanding?

MR. MERSCHOFF: Cooper paid the travel costs for the other utility people, but of course they paid for the

consultants and there were about two consultants.

COMMISSIONER de PLANQUE: Okay. Well, in general I appreciate the philosophy behind what you're doing and I think you've done an excellent job of tracking this and analyzing it and I think you're well aware of some of the dangers and hazards as just revealed in the previous discussion, so I'm very pleased with the presentation and what you're doing and would encourage you to go forward.

CHAIRMAN SELIN: I'd like to associate myself with these remarks. I would just make a couple of small things.

One is to distinguish between the evaluation which is not an inspection function versus our participation in the licensee's self-assessment which does displace inspection and so we have different standards of review. In the first one the only question we really have to ask ourself, is the licensee serious or are they just trying to get us off their backs? You know, are they taking this as a real -- whereas, in the second one there's a lot of detailed information that must come out and the better -- the more we can be confident that they do it themselves the better it is all around.

The second is I just can't -- I haven't tried very hard, but I can't restrain myself from observing how ironic it is that all these cooperative efforts are going on just when the industry's consultants are complaining that there

isn't enough cooperation to go on. But good practice will continue in spite of some foolish observations about what is happening there, so I think that's very good and the crew deserved an award for going out and spending all this time at Cooper at this time of year. I'm sure Mr. Merschoff is anxious to get back to Atlanta.

MR. TAYLOR: He enjoyed it, sir.

CHAIRMAN SELIN: I'm sure he did.

Thank you very much for the material.

MR. TAYLOR: It's in the charter.

CHAIRMAN SELIN: You have to not only do it, but enjoy it.

MR. MERSCHOFF: Yes, sir.

[Whereupon, at 11:14 a.m., the above-entitled meeting was concluded.]

This is to certify that the attached description of a meeting of the U.S. Nuclear Regulatory Commission entitled:

TITLE OF MEETING: BRIEFING ON PILOT DIAGNOSTIC EVALUATION PROGRAM AND USE OF LICENSEE SELF-ASSESSMENTS IN INSPECTIONS - PUBLIC MEETING

PLACE OF MEETING: Rockville, Maryland

DATE OF MEETING: Wednesday, December 7, 1994

was held as herein appears, is a true and accurate record of the meeting, and that this is the original transcript thereof taken stenographically by me, thereafter reduced to typewriting by me or under the direction of the court reporting company

Transcriber: Carol Lynch

Reporter: Peter Lynch

THE SPECIAL EVALUATION

PROCESS USED

FOR COOPER NUCLEAR STATION

DECEMBER 7, 1994

Edward L. Jordan

Ellis W. Merschoff

Contact:
Ellis W. Merschoff, (301) 415-6954

PRESENTATION OBJECTIVES

- Describe the diagnostic level assessment process used for Cooper Nuclear Station which relied, in part, on a licensee Diagnostic Self Assessment effort.

- Discuss the lessons learned from the Cooper Special Evaluation and future plans for the Diagnostic Evaluation Program.

SELECTION OF COOPER NUCLEAR STATION

- Decline in performance noted in the last two SALP reports
- Significant and repetitive hardware problems
- Ineffective corrective action program
- Ineffective self assessment
- Organizational performance problems

DIAGNOSTIC vs SPECIAL EVALUATION

- Diagnostic level evaluation needed
- Opportunity for innovative approach
- Conditions for Special vs Diagnostic Evaluation

The Diagnostic Self Assessment must have:

- Scrutability
- Independence
- Public exit meeting
- Publicly available report

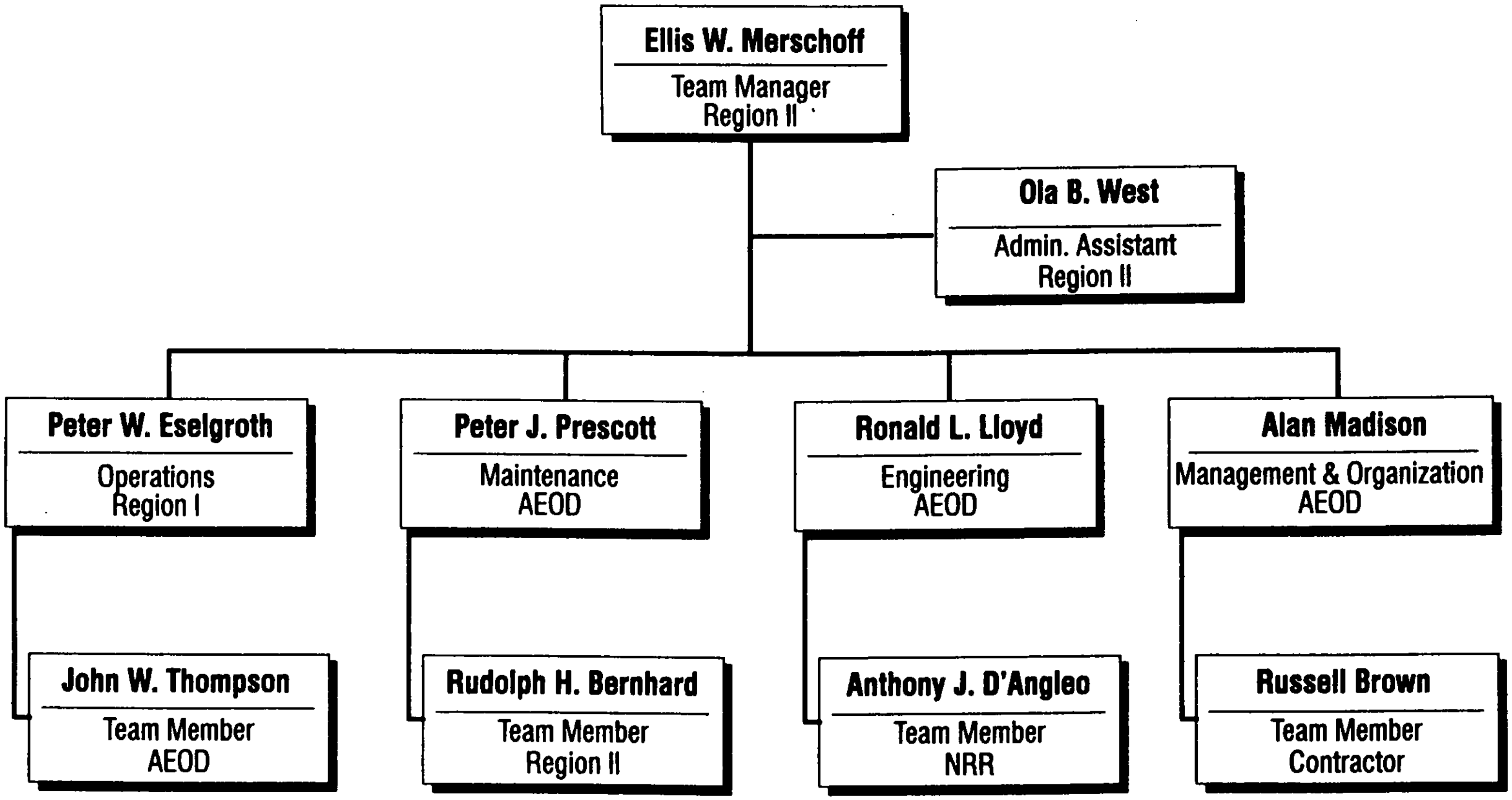
COOPER SPECIAL EVALUATION

- Small experienced team
- Diagnostic level evaluation
- Evaluate/build on results of Diagnostic Self Assessment
- Produce an NRC evaluation of Cooper

SPECIAL EVALUATION GOALS AND OBJECTIVES

- Provide information on Cooper's safety performance to supplement other assessment data available to NRC senior management.
- Evaluate the effectiveness of the licensee's Diagnostic Self Assessment.
- Determine the root cause(s) of safety significant equipment and performance problems.

COOPER STATION SPECIAL EVALUATION TEAM



COOPER DIAGNOSTIC SELF ASSESSMENT

- Assessment plan
- Scope
- Methodology
- Schedule

COOPER DIAGNOSTIC SELF ASSESSMENT TEAM

Team Manager – Consultant
Asst – Consultant

Operations and Training
- Farley
- Clinton
- Fitzpatrick

Maintenance and Testing
- Pilgrim
- Fort Calhoun

Engineering and Technical Support
- INPO
- Waterford
- Fort Calhoun
- Catawba
- INPO

Management and Organization
- Philadelpia Electric Co
- Virginia Power
- Consultant
- INPO

COOPER DIAGNOSTIC SELF ASSESSMENT
CONCLUSIONS

Significant weaknesses were found in the areas of:

- Management and leadership
- Program effectiveness
- Equipment performance and condition

COOPER DIAGNOSTIC SELF ASSESSMENT
ROOT CAUSES

- "Senior management has been ineffective in establishing a corporate culture that encourages the highest standards of safe nuclear plant operation."

- "Senior management did not establish the vision supported by adequate direction and performance standards to improve station performance."

COOPER DIAGNOSTIC SELF ASSESSMENT ROOT CAUSES (CONTINUED)

- "Ineffective monitoring and lack of critical self assessment have prevented management from recognizing program and process deficiencies and making the necessary improvements."

- "An ineffective management development program has resulted in a lack of management and leadership skills necessary to ensure that strong leaders and managers are available to fill key corporate and station positions."

NRC SPECIAL EVALUATION METHODOLOGY

- Extensive review of performance information
- Evaluate Diagnostic Self Assessment process and results
- NRC evaluation of Cooper

RESULTS OF NRC EVALUATION OF DIAGNOSTIC SELF ASSESSMENT

- Overall assessment was effective
- Minor process weaknesses were noted
- Results
    - Insightful assessment
    - Identified significant weaknesses
    - Effectively conveyed

RESULTS OF NRC EVALUATION OF COOPER

Root Causes:

- Management weaknesses
- Program and process weaknesses
- Weak independent oversight and self assessment

COOPER SPECIAL EVALUATION
PUBLIC EXIT MEETING

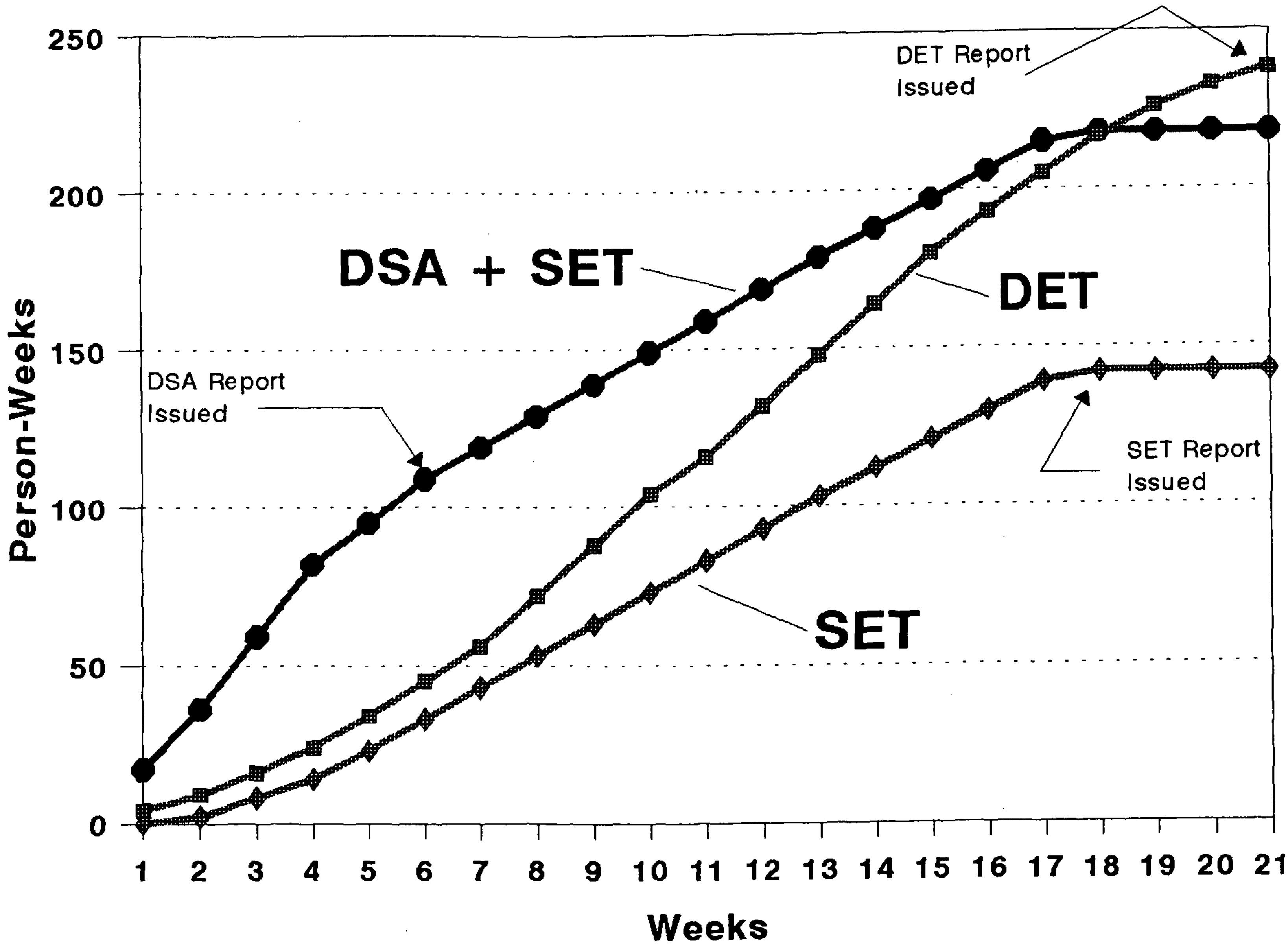
- Diagnostic Self Assessment Team leader presented results
- NRC Special Evaluation Team leader presented results
- Licensee senior management committed to addressing weaknesses

LESSONS LEARNED FROM COOPER SPECIAL EVALUATION

ADVANTAGES

- Special Evaluation process is an efficient use of resources
- Results conducive to rapid "buy in" by licensee
- Results available to licensee earlier
- Reduced regulatory impact on licensee
- Reduced NRC resources

DET vs SET STAFF UTILIZATION



LESSONS LEARNED FROM COOPER SPECIAL EVALUATION (CONTINUED)

Limitations of combined Diagnostic Self Assessment/Special Evaluation process:

- Importance of Diagnostic Self Assessment team qualifications and leadership
- Potential Diagnostic Self Assessment/Special Evaluation conflict could delay corrective actions
- Public perception of NRC's partial reliance on licensee's Diagnostic Self Assessment

FUTURE PLANS

- Programmatically establish the Special Evaluation approach as an alternative to an NRC Diagnostic Evaluation.
- A Special Evaluation may be conducted in conjunction with a licensee Diagnostic Self Assessment.
- Communicate NRC willingness to accept Diagnostic Self Assessment/Special Evaluation approach.

LICENSEE SELF-ASSESSMENT

AS AN ALTERNATIVE

TO A REGION BASED

TEAM INSPECTION

LICENSEE SELF-ASSESSMENT IN LIEU OF A REGION BASED TEAM INSPECTION

- THE NRC WILL RECOGNIZE A LICENSEE'S GOOD PERFORMANCE AND QUALITY SELF-ASSESSMENT

- REDUCED SCOPE EFFORT WILL APPLY TO SAFETY ISSUES INSPECTIONS:

  - SERVICE WATER SYSTEM OPERATIONAL PERFORMANCE

  - ELECTRICAL DISTRIBUTION SYSTEM FUNCTIONAL

  - SAFETY-RELATED MOTOR-OPERATED VALVE

CRITERIA FOR REDUCED NRC INSPECTION

- REGIONAL MANAGEMENT WILL CONSIDER:

  - PRIOR MAJOR SAFETY ISSUES INSPECTIONS

  - RELEVANT NRC INSPECTIONS

  - PERIODIC PLANT PERFORMANCE REVIEWS

  - SALP RATINGS, OR

- IDENTIFIED AT THE SENIOR MANAGEMENT MEETING AS A GOOD PERFORMER

- "WATCH LIST" LICENSEES NOT ELIGIBLE

NRC'S REVIEW OF LICENSEE'S REQUEST

IN REVIEWING A LICENSEE'S REQUEST TO PERFORM A SELF-ASSESSMENT, THE NRC CONSIDERS THE LICENSEE'S:

- ORGANIZATION CAPABILITY
- ASSESSMENT TEAM EXPERIENCE
- SCOPE OF EFFORT EQUIVALENT TO THE TEMPORARY INSTRUCTION
- TIMING - NRC PLANNING AND REVIEW

FUTURE USE OF LICENSEE SELF-ASSESSMENT

INSPECTION PROCEDURE (IP) 40501, "LICENSEE SELF-ASSESSMENT RELATED TO SAFETY ISSUES INSPECTIONS," WAS ISSUED AS A PILOT PROGRAM ON AUGUST 12, 1993. BASED ON INDUSTRY RESPONSE AND UTILIZATION OF THE PROGRAM BY LICENSEES, THE STAFF IS CONSIDERING BROADENING THE SCOPE OF IP 40501 TO INCLUDE OTHER TEAM INSPECTIONS, SUCH AS THE CORE ENGINEERING INSPECTION, IP 37550.

EXAMPLES OF RESOURCE IMPACTS

- DIRECT INSPECTION EFFORT WAS REDUCED FROM 2800 TO 2700 HOURS/REACTOR ANNUALLY

- ADDITIONAL RESOURCE SAVINGS ALLOWS INCREASED REGIONAL INITIATIVE INSPECTIONS

- A PAPER TO APPRISE THE COMMISSION ON THE RESULTS OF SELF-ASSESSMENT INSPECTIONS WILL BE ISSUED THIS MONTH

LICENSEE SELF-ASSESSMENT

STATUS OF SELF-ASSESSMENTS

TI	NRC INSPECTIONS PERFORMED	LICENSEE SELF-ASSESSMENT				
		REQUESTED	DENIED	PERFORMED	NRC REVIEWED	NRC RE-INSPECTED
SWSOPI 2515/118	24	23	0	14	14	0
EDSFI 2515/107	69	4	0	4	4	0

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

November 29, 1994

Docket No. 50-298

Nebraska Public Power District
Cooper Nuclear Station
ATTN: Ronald W. Watkins
P. O. Box 499
Columbus, Nebraska 68602-0499

Dear Mr. Watkins:

This letter forwards the Special Evaluation Team (SET) report for the Cooper Nuclear Station (CNS). The team assessed the effectiveness of licensed activities performed by Nebraska Public Power District (NPPD) in ensuring safe operation at CNS, and determined the causes of performance deficiencies. The team of evaluators, led by a Nuclear Regulatory Commission (NRC) manager, evaluated safety activities at CNS from August 15 through 19, 1994, and September 26 through October 7, 1994. Evaluations were also conducted at the corporate offices during these periods. Findings were discussed with you at an exit meeting on November 17, 1994. This exit meeting was open for public observation.

To gain an independent perspective, the SET was staffed with members having no recent responsibility for the regulation of NPPD. Safety performance was evaluated in the areas of operations, maintenance, engineering, and management and organization, and included an evaluation of findings made by your Diagnostic Self Assessment Team (DSAT).

A declining trend in performance had been noted by the NRC. This trend was documented in two letters to you dated January 25, 1994, and June 21, 1994. Further evidence was documented in recent NRC inspections conducted between May and August 1994. These inspections identified operability concerns effecting the primary containment system, the emergency diesel generators, and the control room emergency filtration systems which produced substantial concerns regarding inadequacies in management control and oversight, maintenance, testing, design control, and procedures. These conditions either existed or went undetected for years even though there were processes and programs in place that should have resulted in their identification and correction.

During July and August 1994, your DSAT found deficiencies in the areas of design control, configuration control, engineering experience, testing, quality of maintenance, long-term equipment reliability, procedural adequacy and compliance, industrial safety, conservative operating philosophy, training programs, human resource development, planning, management systems, self-assessment, and system functionality. The DSAT attributed these deficiencies to weak management, poorly defined programs, and ineffective self assessment. The SET efforts confirmed that the findings of the DSAT accurately characterized the station's performance deficiencies and their causes.

Additionally, the SET identified numerous significant equipment problems which led to the determination that operability could be affected for several safety-related systems, including the residual heat removal, standby liquid control, core spray and service water systems. Your staff was unaware of these deficiencies until they were identified by the SET.

I note that many of the findings of the DSAT and SET have been previously identified by your staff and by other assessment activities, and that previous corrective actions were not effective. I note that progress is being made towards addressing these issues in the newly developed performance improvement plan. I urge you to continue correction of equipment and performance issues. I acknowledge that you made a strong commitment to improve CNS at the public exit meeting held at the station on November 17, 1994.

It is important that you and other NPPD managers carefully review the enclosed report, and place special emphasis on the areas requiring additional management attention. Following this review, I request that NPPD determine the actions needed to ensure the long term resolution of CNS performance deficiencies. I also request that NPPD provide my office within 60 days of the date of this letter, its plans for addressing the root causes of these deficiencies which were identified by the SET and DSAT.

In accordance with 10 CFR 2.790(a), a copy of this letter and the enclosure will be placed in the NRC Public Document Room. Should you have any questions concerning this evaluation, we would be please to discuss them with you.

Sincerely,

James M. Taylor
Executive Director
for Operations

Enclosure:
Special Evaluation Team Report
for Cooper Nuclear Station

cc: (See next page)

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Vice President Nuclear
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P. O. Box 218
Brownville, Nebraska 68321

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Brownville, Nebraska 68321

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ATTN: Mr. Ron Stoddard
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Midwest Power
ATTN: James C. Parker, Sr.
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P. O. Box 657
Des Moines, Iowa 50303

OFFICE FOR ANALYSIS AND EVALUATION OF OPERATIONAL DATA
DIVISION OF OPERATIONAL ASSESSMENT

Licensee:	Nebraska Public Power District
Facility:	Cooper Nuclear Station
Location:	Brownville, Nebraska
Docket No:	50-298
Evaluation Period:	August 15-19, 1994, and September 26-October 7, 1994
Team Manager:	Ellis W. Merschoff
Administrative Assistant:	Ola B. West
Team Members:	Rudolph H. Bernhard Anthony J. D'Angelo Peter W. Eselgroth Ronald L. Lloyd Alan L. Madison Peter J. Prescott John W. Thompson, IV
Contractor:	Russell Brown

Submitted By:

Ellis W. Merschoff, Team Manager
Special Evaluation Team for
Cooper Nuclear Station

11/22/94
Date

Approved By:

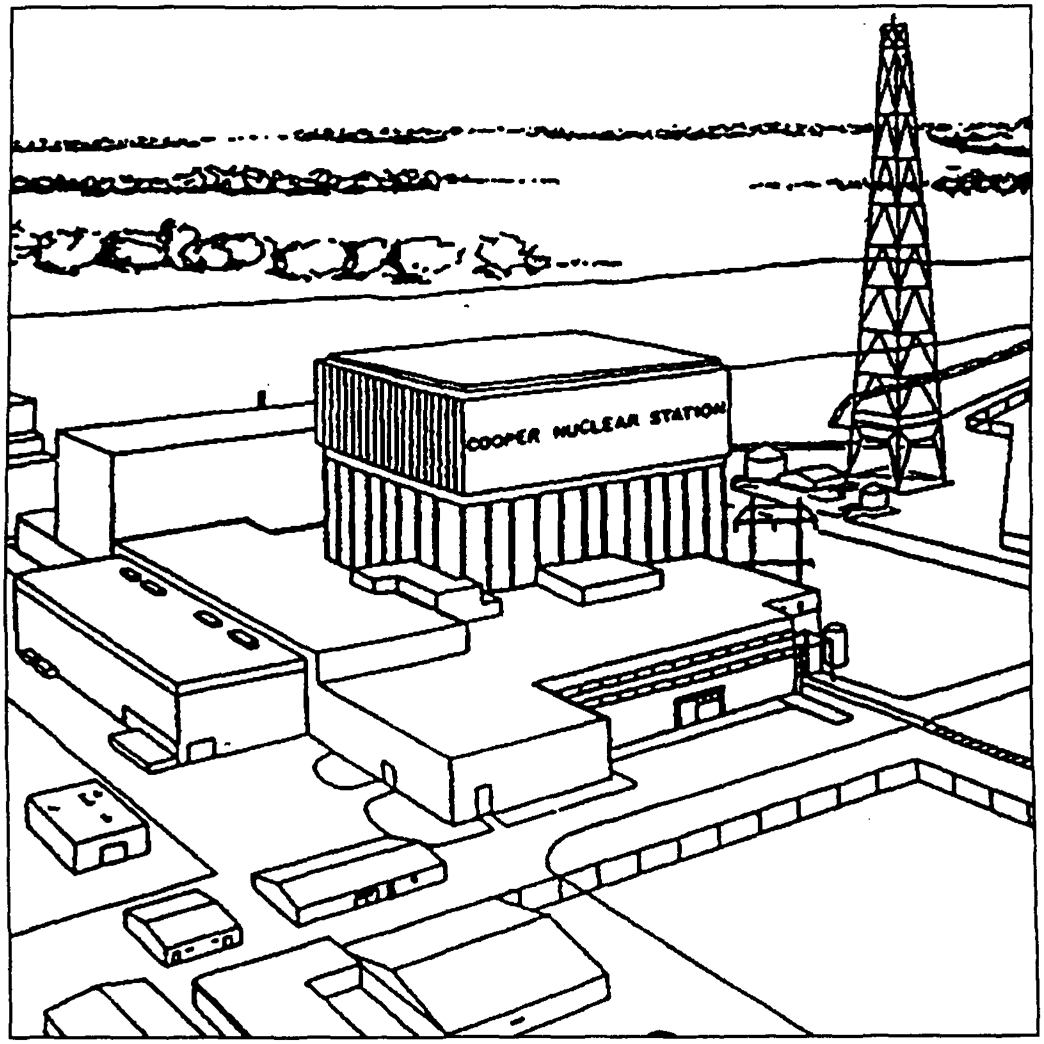
Edward L. Jordan, Director
Office for Analysis and Evaluation
of Operational Data

11/22/94
Date

Nuclear Regulatory Commission

Special Evaluation Team Report

Cooper Nuclear Station



August 15-19, 1994

September 26 - October 7, 1994

Public Exit - November 17, 1994

TABLE OF CONTENTS

ABBREVIATIONS

AOV	Air Operated Valve
CAP	Corrective Action Program
CIV	Containment Isolation Valve
CNS	Cooper Nuclear Station
CR	Condition Report
CRD	Control Rod Drive
CRG	Condition Review Group
CS	Core Spray System
DCD	Design Criteria Document
DEH	Digital Electro-Hydraulic
DG	Diesel Generator
DSA	Diagnostic Self Assessment
DSAT	Diagnostic Self Assessment Team
F	Fahrenheit
FME	Foreign Material Exclusion
GE	General Electric
GPM	Gallons Per Minute
HPCI	High Pressure Coolant Injection
HPES	Human Performance Evaluation System
IN	Information Notice
IST	Inservice Testing
LLRT	Local Leak Rate Testing
LSFT	Logic System Functional Test
MWR	Maintenance Work Request
NPG	Nuclear Power Group
NPPD	Nebraska Public Power District
NRC	Nuclear Regulatory Commission
PM	Preventive Maintenance
PRA	Probabilistic Risk Assessment
QA	Quality Assurance
QC	Quality Check
RCIC	Reactor Core Isolation Cooling
RHR	Residual Heat Removal
RHRSW	RHR Service Water
SALP	Systematic Assessment of Licensee Performance
SET	Special Evaluation Team
SLC	Standby Liquid Control System
SMM	Senior Management Meeting
SORC	Station Operations Review Committee
SRAB	Safety Review and Audit Board
SW	Service Water
TS	Technical Specifications

EXECUTIVE SUMMARY

From August 15 through October 7, 1994, a Special Evaluation Team (SET) from the U.S. Nuclear Regulatory Commission (NRC) evaluated the performance of the Nebraska Public Power District (NPPD) in ensuring the safe operation of the Cooper Nuclear Station (CNS). The evaluation included an assessment of the efficacy of the licensee's diagnostic self assessment (DSA) and use of the results of the DSA, as appropriate, to evaluate the performance of CNS. The evaluation was requested by the NRC Executive Director for Operations in order to obtain information needed to make an informed decision on overall performance at CNS and to determine the root causes of identified problems. The team, led by an NRC manager, consisted of eight technical evaluators and an administrative assistant. Areas evaluated included operations, maintenance, engineering, and management and organization.

The SET found that the DSA was an effective, comprehensive assessment which reached substantive conclusions that were supported by the NRC's independent assessment. The licensee assembled a large, experienced assessment team (DSAT) which was able to overcome the challenges of an evolving mission and approach, and produce an insightful assessment. The DSAT noted strengths in the areas of minimization of contaminated area in the plant, operations and training department teamwork and improved communications of on-shift operators. Deficiencies were noted in the areas of design control, configuration control, engineering experience, testing, quality of maintenance, long term equipment reliability, procedural adequacy and compliance, industrial safety, conservative operating philosophy, training programs, human resource development, planning, management systems, self assessment, and system functionality.

The conclusions of the SET were similar to and consistent with the root causes identified by the DSAT. Specifically, the SET found:

1. Management did not provide the leadership and direction necessary to maintain appropriate corporate wide standards of performance.

   Management exhibited low standards and expectations by its willingness to accept some degraded conditions without an aggressive effort to correct problems and in its acceptance of a lack of a questioning attitude. The number and individual significance of equipment problems represented a potential challenge to safe plant operation. NPPD senior managers did not develop and implement long range and strategic plans to provide guidance and direction to the Nuclear Power Group (NPG) in preparing and implementing lower-tier plans. In addition, senior managers did not effectively manage the backlog of work, avoid the use of excessive amounts of overtime, or ensure that important programs were completed in a timely manner. Weaknesses in internal and external communication also contributed to performance problems.

2. Major programs and processes were poorly defined and, as implemented, did not assure the consistent and effective accomplishment of program goals and objectives.

   Major programs dealing with surveillance of equipment and systems, engineering support of plant activities, assurance of operability of plant equipment, control of work, and configuration control were ineffective. For example, weaknesses in surveillance programs resulted in degraded equipment and poor assurance of the ability of safety related equipment to meet design basis requirements. Additionally, operability determinations and evaluations were limited in scope and at times non-conservative. Weak engineering programs affected the quality and availability of engineering support, including maintenance of the plant design basis and drawings. Further, an ineffective work control process resulted in essential equipment being unavailable unnecessarily and allowed poor work practices to exist. Poor configuration management resulted in instances when the CNS staff did not know the status of equipment.

3. Independent oversight and self-assessment were not effective in monitoring ongoing activities, detecting deficiencies, or assuring that identified deficiencies were resolved.

   Organizations responsible for providing independent oversight of station activities, programs and processes, including Quality Assurance and the Safety Review and Audit Board, were not effective. These organizations did not identify existing significant programmatic and process weaknesses despite numerous opportunities and information from outside sources, such as industry organizations and the NRC. Other organizations and programs having oversight responsibilities, such as the Station Operations Review Committee and the Condition Review Group, were also not effective. Self-assessment activities were weak, lacking in depth, and narrow in scope. Additionally, management did not take effective corrective action in response to these assessments. The corrective action program did not effectively support the recognition and resolution of plant problems because of weaknesses in problem identification, root cause determination, and corrective action implementation.

The SET noted positive findings in the areas of the effectiveness of the new management team in place at CNS and the cadre of experienced and qualified staff within NPG. The new management team brought diverse perspectives to CNS, and were open in their assessments of organizational weaknesses. The SET observed improved communications, increased standards and expectations, and an aggressive determination to resolve the causes of identified weaknesses.

1.0 INTRODUCTION

1.1 Background

The Nebraska Public Power District (NPPD), licensee for the Cooper Nuclear Station (CNS), has demonstrated a declining trend in overall performance at the plant since early 1992. The U.S. Nuclear Regulatory Commission (NRC) observed declines in the areas of operations and radiological controls during the Systematic Assessment of Licensee Performance (SALP) period ending January 1992 and observed a decline in the areas of maintenance and safety assessment/quality verification in the SALP period ending in early 1993. Since early 1993, the NRC has taken several significant enforcement actions involving civil penalties totalling $400,000. These enforcement actions involved the long term inoperability of certain safety systems, the failure to conduct required inspections of safety systems, and failures of the CNS corrective action system.

At the January 1994 NRC Senior Management Meeting (SMM), NRC senior managers discussed the regulatory and operating performance of CNS and concluded that the licensee's safety performance was declining further as evidenced by weak self-assessment and corrective actions. In a letter dated January 25, 1994 to the NPPD President and Chief Executive Officer, the NRC discussed these concerns and requested that NPPD take appropriate remedial actions.

After the January 1994 SMM, the NRC conducted a special NRC Operational Safety Team Inspection which found significant deficiencies in a number of areas. After this inspection, the licensee discovered a condition which rendered both diesel generators inoperable, requiring a plant shutdown on May 25, 1994. Before and during this unscheduled outage, significant deficiencies were noted by the NRC and NPPD both in the control room filtration system and with the assurance of primary containment integrity, indicating broad weaknesses in the effectiveness of the station's safety system surveillance program.

At the June 1994 SMM, NRC senior managers again discussed the continued decline in performance of Cooper Nuclear Station and the licensee's corrective actions. The senior managers recognized they would need additional information to make an informed decision on the overall performance of Cooper Nuclear Station. Consequently, the Executive Director for Operations directed the staff to obtain this information by performing an evaluation of the Cooper Nuclear Station.

Recognizing that significant deficiencies existed in the overall performance of Cooper Nuclear Station, the licensee initiated a formal independent assessment similar in scope and depth to an NRC Diagnostic Evaluation. In light of this extensive diagnostic self assessment (DSA), the licensee requested in a letter dated July 27, 1994, that the NRC consider using the DSA in lieu of the field work portion of the planned NRC diagnostic evaluation.

1.2 Scope and Objectives

The Executive Director for Operations directed the staff to form a Special Evaluation Team (SET) to assess the efficacy of the licensee's diagnostic self assessment through direct observation and independent assessment, and to assess the overall performance of Cooper Nuclear Station. This evaluation was to include an assessment of the licensee's DSA and, if appropriate, to build on any independently validated findings from the licensee's effort to arrive at an overall evaluation of the performance of CNS. The goals of the special evaluation were to (1) evaluate the effectiveness of the licensee's DSA effort, (2) evaluate the actions of licensee management and staff with respect to safe plant operation, (3) determine the root cause(s) of the safety-related hardware and performance problems and (4) obtain additional information on CNS safety performance to allow NRC senior managers to make an informed assessment of plant safety performance.

1.3 Methodology

The SET consisted of eight technical team members and an administrative assistant reporting to a team manager. The team members were further organized into groups for the areas of operations, maintenance, engineering, and management and organization, with a lead evaluator and team member assigned to each area. The team devoted several weeks to preparation that included an extensive review of CNS and NRC documents; team meetings; and briefings by representatives from Region IV, the Office of Nuclear Reactor Regulation, and the Office for Analysis and Evaluation of Operational Data.

During August 15-19, 1994, the team manager and four lead evaluators assessed the performance of the licensee's DSA at the Cooper Nuclear Station. This assessment was accomplished by reviewing documents; interviewing the DSA members; and observing the DSA's field work, team meetings, and root cause analysis. On September 26, the entire team returned to the site for two weeks to independently assess a sample of the DSA's results and to pursue possible performance deficiencies not addressed by the DSA. The NRC resident inspectors frequently observed SET meetings at the site. Representatives from the SET met daily with their licensee counterparts to discuss team activities and findings.

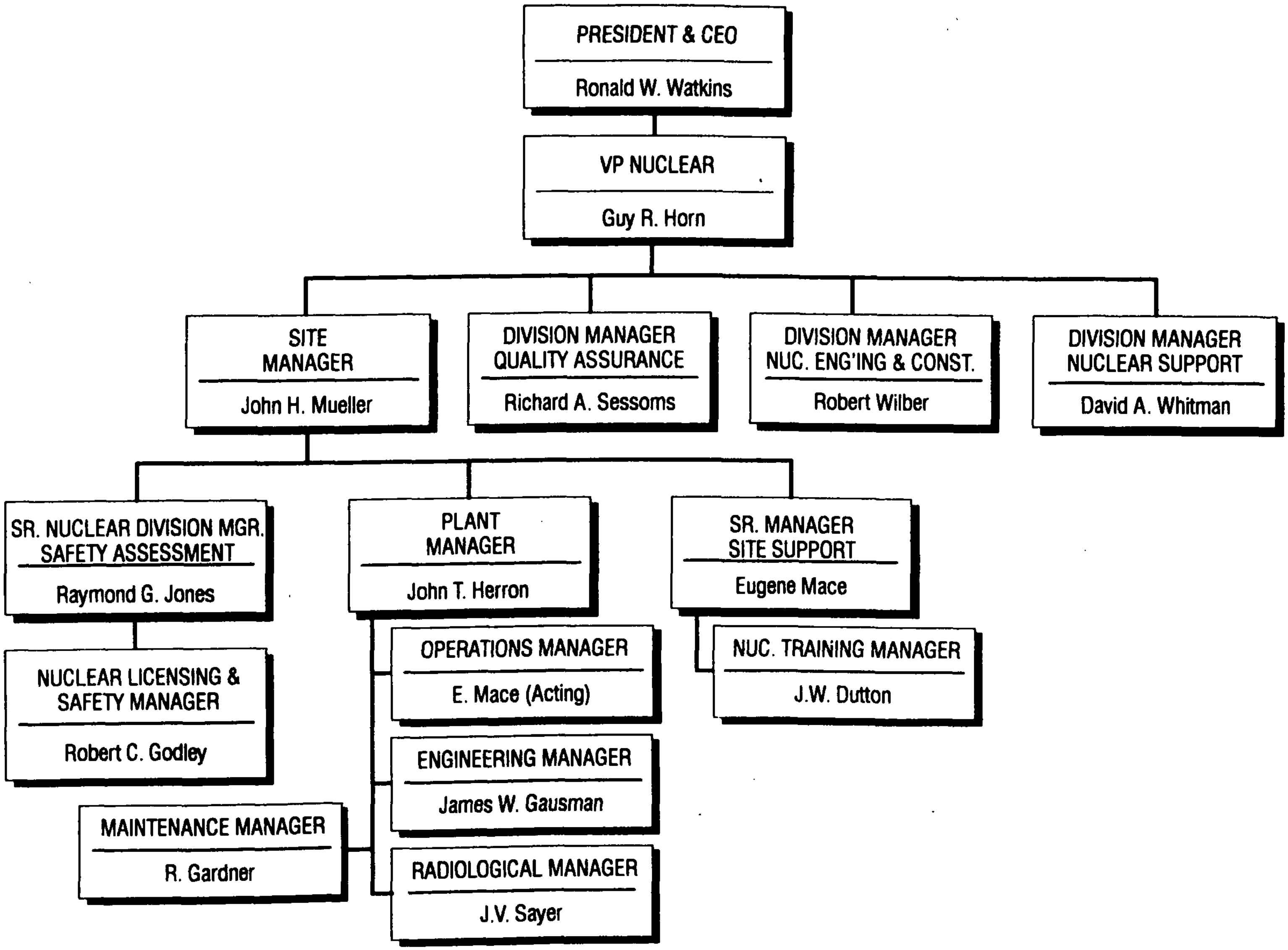
1.4 Facility Description

The Cooper Nuclear Station is located on the west bank of the Missouri River, near the town of Brownville, Nebraska. The plant consists of one General Electric (GE) boiling water reactor with a Mark I containment. The facility was designed and constructed by Burns & Roe.

1.5 Organization

The Cooper Nuclear Station is owned and operated by the Nebraska Public Power District. Several key management changes were made at Cooper Nuclear Station recently. Immediately before the evaluation, Mr. J. Mueller reported as the new Site Manager. During the evaluation, Mr. A. Sessoms reported as the new Division Manager of Quality Assurance, Mr. J. Herron reported as the new plant manager, and Mr. R. Jones reported as the new Senior Nuclear Division Manager of Safety Assessment. The following chart illustrates the NPPD organizational structure for management and support of the CNS at the close of the onsite evaluation.

NEBRASKA PUBLIC POWER DISTRICT
COOPER STATION



2.0 THE LICENSEE'S DIAGNOSTIC SELF ASSESSMENT

2.1 Scope and Mission

The licensee performed a detailed diagnostic self assessment to evaluate the performance of the Cooper Nuclear Station in the areas of operations and training, maintenance and testing, engineering and technical support, and management and organization. The licensee based the DSA on the results of previous NRC diagnostic evaluations and incorporated experience gained from other industry initiatives.

The Diagnostic Self Assessment Team (DSAT) consisted of 13 technical evaluators, two assistant team managers, and an administrative assistant, reporting to a team manager. The team members were organized into functional area teams for each of the areas described above. The team spent four weeks on site performing the assessment from July 25 through August 19, 1994. On September 6, the team manager and assistant team managers issued the final report.

2.2 Evaluation

During the final week of the DSA, the SET team manager and the four lead evaluators assessed the performance of the DSAT by interviewing both the DSAT members and their licensee counterparts, and observing DSAT walkdown inspections, interviews, team meetings, root cause assessments, DSAT/licensee technical debriefings, and the formal DSAT exit meeting. The SET independently performed a walkdown inspection of the drywell and observed a core spray surveillance test. Additionally, members of the SET observed the presentation of DSAT results to the NPPD Board of Directors.

2.2.1 Effective Overall Performance of the DSAT

The licensee assembled a large, experienced, and, with one exception, independent assessment team at the plant promptly after the NRC notified the licensee of an impending in-depth assessment of the performance of Cooper Nuclear Station. This team possessed substantial, germane experience in the design, operation, and maintenance of boiling water reactors, and used that experience in the assessment. The technical strength of the team enabled the members to overcome changes in the mission, approach, and composition of the team. The team assessed the plant in an insightful manner, finding strengths in the areas of minimization of contaminated area in the plant; operations and training department teamwork, which resulted in improved simulator fidelity; and improved communications between on-shift operators. Significant deficiencies were noted in the areas of design control, configuration control, engineering support, work control, corrective actions, use of industry operating experience, testing, quality of maintenance, long term equipment reliability, procedural adequacy and compliance, industrial safety, conservative operating philosophy, training programs, human resource development, planning, management systems, self-assessment, and system functionality.

2.2.2 Changes to the Process

The mission and approach of the DSAT evolved during the four week assessment period. This caused some confusion among the team members and prevented the team from fully accomplishing the initial scope of the assessment. Specifically, most of the team arrived at the site on July 25, 1994, with little advance preparation, shortly after a decision to change the team composition from half NPPD staff and half outside experts to a team totally independent of NPPD. The first week was largely spent formulating an assessment plan and obtaining outside team members to fill those positions originally staffed by NPPD personnel.

The lack of preparation time hindered each functional area team from fully using the assessment time at the site. This was particularly apparent in the engineering area. The DSAT performed a vertical slice assessment of the residual heat removal (RHR) system. However, the team did not have all of the system information necessary for this assessment until the final week on site, because the decision to perform this assessment was not made until well into the first week. Consequently, the vertical slice review was limited in scope.

During the DSA, the team twice changed the methodology used for the root cause determination. In the third week, the team replaced the originally planned Management Oversight Risk Tree type approach with a methodology familiar to one of the DSA team members. However, the team later abandoned the second approach for a symptom classification approach which was facilitated and employed effectively by one of the two assistant team managers.

2.2.3 Changes in Team Composition

The licensee's decision late in the DSA planning process to field a team that was independent of NPPD personnel resulted in team member identification extending into the second week of the on site assessment period. Additionally, an assistant team manager remained on the team in spite of recent involvement as a consultant for senior licensee management addressing problems which were also being identified by the DSA team. While this was not consistent with the intent of a completely independent assessment, it did not appear to have an adverse effect on the results of the assessment.

During the four week on site assessment period, team members in the operations, maintenance, and engineering areas joined the team after the assessment had begun; members in the engineering, and the management and organization area took personal time off during the assessment and also left before the assessment was completed. These changes in team composition throughout the assessment period created challenges for the team in completing the intended scope of the assessment and in assuring all members' findings and perspectives were accurately represented during the final root cause session.

2.2.4 Communication and Coordination between the Team and the Plant

In general, the communication of DSAT findings to and coordination with CNS personnel were effective. However, the in-process counterpart debriefs did not always occur daily, and in some cases were accomplished only two or three times during the course of the assessment. In order to facilitate understanding of the DSAT's issues in the absence of daily debriefs, the DSAT's written field notes were frequently provided to CNS personnel. The final counterpart debriefs which were observed by the SET were comprehensive, and accurately conveyed the substance of the DSAT's findings to the designated counterpart. The specific DSAT findings for Corporate Engineering were not provided to the responsible managers until two days before the exit meeting. The evaluator assessing Quality Assurance completed his efforts and left the site without providing a final counterpart debrief.

The final exit meeting was presented very effectively to a broad cross section of plant staff, and was video taped to allow additional access to the DSAT's findings by all levels of the organization. The report was issued promptly, and thoroughly developed the issues presented at the exit meeting.

On September 1, 1994, the DSAT's findings were effectively summarized and presented to the Board of Directors by Senior NPG Management. The DSA Team Manager was present at this routinely scheduled Board Meeting and answered the Board's questions regarding the DSA.

2.2.5 Conclusions

The DSAT reached substantive conclusions that were recognized by the licensee as valid descriptions of the station's performance problems. The root causes identified by the DSAT were broad in scope, supported by the conclusions, and confirmed by the SET's independent evaluation.

Although the fundamental causes identified by the DSA were confirmed, the SET found additional areas of concern not fully developed by the DSAT. These were the licensee's weaknesses in ensuring the operability of safety-related equipment, and inadequacies in the scope and implementation of the safety related surveillance programs. The SET found the RHR system had not been demonstrated operable as required, the standby liquid control (SLC) system was not operable because of inadequate heat tracing, loop A of the core spray (CS) system was inoperable because of excessive vibration, and the service water (SW) system was inoperable because of excessive silting at the inlet structure. The licensee was unaware of these deficiencies until they were found by the SET.

3.0 ROOT CAUSES

The findings and conclusions of the DSAT and the SET indicated that there were three root causes of the performance problems at CNS. First, executive and senior management of the Nebraska Public Power District responsible for the Cooper Nuclear Station failed to provide the policy, leadership and direction necessary to maintain appropriate corporate wide standards of performance. NPG managers had not effectively implemented appropriate standards and expectations for corporate and station personnel or provided appropriate direction and supervision. This resulted in the lack of a questioning attitude and a willingness to live with problems.

Second, performance of CNS had been characterized by major programs and processes which were poorly defined and lacked the comprehensive guidance necessary to assure consistent and effective implementation. This resulted in degraded equipment and poor assurance of the ability of safety-related components to meet their design basis requirements.

Third, with the exception of the DSA, NPPD's self assessment and independent oversight activities had been ineffective in promptly identifying significant deficiencies which were subsequently identified by regulatory or third party assessments and failed to assure that lessons learned from industry operating experience were appropriately applied at CNS. The Corrective Action Program did not effectively support the recognition and resolution of plant problems.

These root causes are stated and developed fully in sections 3.1, 3.2, and 3.3.

3.1 <u>Management did not provide the leadership and direction necessary to maintain appropriate corporate wide standards of performance.</u>

Management exhibited low standards and expectations by its willingness to accept some degraded conditions without an aggressive effort to correct the problems and in its acceptance of a lack of a questioning attitude. The number and individual significance of equipment problems represented a potential challenge to safe plant operation. NPPD senior managers had not developed and implemented long range and strategic plans to provide guidance and direction to the NPG in preparing and implementing lower-tier plans. Senior managers had not effectively managed the backlog of work, avoided the use of excessive amounts of overtime, or ensured that important programs were completed in a timely manner. Weaknesses in internal and external communication also contributed to performance problems.

3.1.1 Long Term Equipment Problems

Managers lived with acknowledged long term equipment problems without aggressive actions to correct them. The number and individual importance of equipment problems represented a potential challenge to the ability of plant staff to effectively monitor and operate the plant. Degraded material conditions and other long standing problems unnecessarily challenged operators responding to plant conditions and transients by requiring compensatory actions.

(1) CNS was not running the SW booster pumps during the shutdown cooling mode of RHR and was controlling reactor coolant system temperatures by throttling the RHR heat exchanger outlet valves, RHR 12-A/B, in lieu of SW system valves SW 89-A/B, because of concern with silting related SW system wear. This approach to controlling temperature required operators to manually close and open the valve's power supply breaker while they timed the partial stroke to approximate the gate valve's position. These actions also reversed the design basis SW to RHR differential pressure, which was intended to preclude contamination of the SW system from leakage across the heat exchanger boundaries, and the potential for unmonitored releases.

(2) Poorly designed and implemented engineering modifications to outboard RHR injection valves 27 A/B to minimize valve body erosion were made during a period of over four years. Following one valve trim modification, an outboard RHR injection valve was prevented from closing during a test because the modified trim became lodged in the valve seat. Even though valve position in the control room indicated closed, flow through the valve was almost 8000 gpm. The safety evaluation that supported the modification was weak in that it did not consider a scenario involving the collapse of part of the valve trim, which would prevent the valve from performing its containment isolation valve (CIV) function. After repeated attempts to modify the valve, the valve could not pass its local leak rate test (LLRT), and was abandoned as a CIV. The failed LLRT problem was then resolved in 1994 by reassigning the containment isolation function to inboard check valves RHR 26/27, and their bypass valves RHR 274 A/B. The RHR injection bypass valves were not powered by a safety-related source, and were to be maintained in the closed position pending further evaluations by the licensee. Maintaining the bypass valves in the closed position eliminated the system warm up design feature, subjecting the system to high thermal gradients upon initiation of shutdown cooling. Similar CIV boundary changes were being considered for the CS system due to nonredundant power supplies for the inboard and outboard valves.

(3) The licensee had not taken aggressive action to resolve increased pump vibration problems. During the SET assessment there were nine safety related pumps in the alert range because of high vibration readings, including the CS, high pressure coolant injection (HPCI), SW, SLC, and RHR service water (RHRSW) systems. A 1994 licensee audit report brought attention to the same issue. In September 1994, the SET questioned the rapidly increasing vibration readings for the SW and RHRSW pumps, and in October 1994, the B SW pump was disassembled due to high vibration. An inspection of the pump internals showed grooves in the impeller and bowl, indicating that the pump was damaged because of improper lift settings. The licensee stated that SW pump operation at the reduced impeller to bowl lift, which was less than vendor recommended values, was necessary to meet system flow requirements.

(4) Balance of plant problems induced unnecessary primary plant transients. Problems in controlling the condenser hotwell level prompted operators to use an abnormal operating procedure four times during the last eight

months of operation to prevent unnecessary plant scrams. Problems with the digital electro-hydraulic (DEH) system for the main turbine resulted in plant power oscillations three times with one plant scram in the last four months of plant operation. Numerous chronic DEH fluid and turbine lube oil leakage problems required an elaborate system of catch trays and hoses to gather the leakage in various containers.

(5) Coolant leakage from the mid-body flange joint of the A RHR heat exchanger had been a long term problem at CNS. The leakage was collected by a semi-permanent drain hose embedded in the heat exchanger's insulation. The licensee first found the leak in 1990 while completing a maintenance work request (MWR) that was cancelled later that year. Although the cancelled MWR was annotated to delay the repair until an outage of sufficient duration, no replacement MWR was created.

3.1.2 Lack of a Questioning Attitude

The licensee did not consistently have a questioning attitude. This resulted in a failure to identify some problems. In addition, when problems were identified they were not always adequately resolved. In some instances, management failed to ask the questions that would lead to thorough analyses to correct or avoid degraded conditions.

(1) CNS did not have assurance that, at minimum river water levels, sufficient water would be available to supply the SW pumps given the potential silting problems in the river and the SW bay. Specifically, silt had deposited near the SW inlet causing the bottom to be as much as 13 feet higher than the river bottom level assumed in the Updated Safety Analysis Report. Additionally, the contour of the channel bottom and the precise location of the channel were not known by the licensee, even though the major flood experienced in 1993 may have significantly affected the river bottom contour.

(2) The SET observed an inservice test (IST) of the CS 1A pump on August 17, 1994. During the test, the SET noted a cyclic sound, which the pump manufacturer later determined to be cavitation while water recirculated through the minimum flow line. This condition was not previously documented by the licensee. The pump manufacturer also recommended operating the pump no more than 60 hours on minimum flow without disassembly and inspection, however, CNS personnel were not aware of the recommendation and were not tracking this run time. The SET noted significant vibration that had caused support hardware to vibrate loose. In addition, Corporate Engineering later determined that a misoriented hanger combined with system vibration may have been sufficient to exceed the pipe design stress.

(3) The plant design had five sets of SW bay spargers for keeping silt in suspension. The licensee assumed operation of these spargers in its response to Generic Letter 89-13, "Service Water System Problems Affecting Safety Related Equipment." However, excessive wear or plugging prevented all but two of the spargers from operating. This

condition has existed for several years, but was not included in the current maintenance backlog.

(4) The SET determined that the diesel generator (DG) fuel oil tanks were not properly protected from missile damage. The DG fuel oil storage tank was located outside the DG building surrounded by an earthen surcharge and covered by two feet of concrete. However, access to the tank and equipment was provided by a manway with a 3/8-inch thick aluminum cover. Beneath the cover was a small compartment which contained the fuel oil transfer pumps, piping for the oil transfer system and tank level indication instruments. Although the probability of a tornado generated missile impacting this cover was low, the original design required a 3/4 inch thick steel cover to afford the required missile protection. The original 3/4 inch cover was removed in 1975 using Minor Design Change 75-44. Upon questioning by the SET the licensee concluded that the safety evaluation was inadequate. The Design Criteria Document (DCD) effort discovered the above design discrepancy, however the cover had been accepted based on an unapproved calculation using incorrect material constants, and did not meet the design requirements.

3.1.3 Poor Planning

An absence of NPPD Corporate level plans caused weaknesses in NPG long term planning which rendered these plans ineffective at addressing problems and making improvements. Executive and senior management had, by example, communicated the expectation that planning was not an essential element of management. Strategic planning and business planning at the NPG level had undergone changes on a frequent basis limiting their value as management tools.

(1) Senior site managers stated that they were unaware of any issued NPPD company wide strategic or business plan. The licensee had been preparing an NPPD Strategic Plan for about one year, but had not issued this district level plan.

(2) The licensee did not issue an NPG level integrated planning document as required by NPG Directive 1.4, dated September 1993. The licensee later cancelled the directive in August 1994. An NPG level Strategic Plan for Performance Improvement was issued in October 1993, was superseded by the NPG Integrated Enhancement Plan in early 1994 which was superseded by the NPG Business Plan in mid-1994. The NPG Business Plan included a requirement for monthly progress and status reports and branch business plans, none of which were issued. In August 1994, the Business Plan was superseded by the Performance Improvement Plan (PIP), which was under development.

(3) CNS outage planning was weak. The Outage Plan scheduled modifications, but only listed maintenance and surveillance activities to be performed within broad time periods. For the 1993 outage, work items were not frozen until two weeks before the start of the outage. Although over 25 percent of the modifications performed were added during the outage,

the outage master schedule was not updated after the begining of the outage. Maintenance and surveillance activities were listed for work during division outage windows, but did not account for resource, material or plant condition restraints. In addition, CNS only recently began a work planning process with a short term (2-day) look ahead schedule and was attempting to achieve a longer term (12 week) rolling schedule to include system window outage planning.

3.1.4 Backlogs Not Effectively Managed

Senior managers had not effectively managed backlogs, avoided the use of excessive overtime or ensured that important programs were completed in a timely manner. Problems caused by poor staffing management occurred despite findings from licensee sponsored studies which found weak practices in this area.

(1) The licensee slowed and twice stopped the Design Criteria Documentation (DCD) program because of new priorities and had not resumed the program at the time of the SET. The licensee began this program in 1987. The DCD was used by the site and corporate Engineering to help establish the design basis which a system or component must meet to perform its intended purpose. The program was not close to being complete. The SET reviewed a sample of closed DCD issues and determined that some were inappropriately closed in that issues were declared acceptable by Engineering which did not meet design requirements.

(2) System engineers were not effectively performing all the duties expected by management. Even though system engineering overtime ranged from 50 to 80 percent during June, July, and August 1994, with some individuals exceeding 100 percent on a weekly basis, very little time was spent performing system walkdowns to find plant problems, document system problems, enhance engineering programs, or to monitor and document system performance.

(3) Only one individual was assigned responsibility for both the Fire Safety and Industrial Safety programs. This individual was solely responsible for ensuring that these programs were maintained and effectively implemented. Duties included: touring the site to find problems; directly observing plant work activities for fire and industrial safety concerns; developing and giving training; developing and maintaining procedures; monitoring industry and regulatory standards; responding to employee, management, and regulatory concerns; and investigating and responding to condition reports in these areas. The backlog of work was large and increasing, resulting in limited direct observation of plant activities.

(4) Corporate Engineering work backlog items had increased almost 90 percent between January and September 1994. In response to SET concerns, the licensee stated that they had not yet fully quantified the post-start up engineering workload or resource loading to the extent that an assessment could be made of near term and long term resource requirements. The licensee planned to further quantify the workload to

be able to determine resource needs to assure that Engineering could support post-start up plant operation. A backlog of more than 100 safety related vendor technical manuals were awaiting evaluation for incorporation into the Preventive Maintenance (PM) program. In addition, the operations procedure change backlog was greater than 300, the corrective action report and MWR backlogs were each at about 2000, all increasing.

3.1.5 Poor Communications

Communication problems contributed to performance problems. Poor internal communication hampered the dissemination of important plant information. Coordination and accountability between disciplines were impaired by communication problems and sometimes resulted in equipment damage. Poor external communication resulted in incomplete information being submitted to the NRC.

(1) Poor communications resulted in operating DG 2 for approximately 15 hours in an unbalanced condition. On March 27, 1993, the system engineer and vendor representative had verbally requested that Operations not run DG 2 until March 29, 1993, at which time the required post maintenance adjustments, including balancing of the fuel racks, would be performed. However, on March 28 a decision was made to begin a 24 hour test run, and neither the system engineer nor the vendor representative were notified. The DG was run with the fuel racks unbalanced for approximately 15 hours, during which time the operators observed high cylinder temperatures, degraded peak firing pressures, and excessive engine vibration. In subsequent inspections, the licensee observed significant damage to several major DG components, such as pitted pistons, burned and pitted cylinder exhaust valves, and significantly worn, cracked, and rolled piston rings. During the SET evaluation, the licensee stated that operating the DG in an unbalanced condition potentially resulted in the observed damage.

(2) During a March 1994 Unusual Event, operations personnel failed to provide accurate information to the NRC. As corrective action, the licensee instructed operators and shift supervisors and issued procedural guidance to report accurate, but "only required" (NRC Form 361A) information to the NRC during initial event notification telephone calls. The SET raised the concern that this compliance oriented corrective action could unnecessarily restrict the flow of safety significant information between CNS and the NRC during events.

(3) The IST and Predictive Maintenance staff did not communicate well. Predictive Maintenance personnel were not notified before having pumps started which were experiencing vibration problems. Therefore, during post-maintenance testing, pumps had to be stopped and restarted after the vibration equipment was installed to obtain required performance data.

(4) Some control room supervisors were unaware of a standby plant temporary modification established to allow remote manual closure of the CS

minimum flow CIVs from the control room to establish containment isolation under certain operational conditions.

(5) CNS had not provided an environment which encouraged open dialogue at all levels. The SET saw evidence of this absence of an open dialogue.

3.2 Major programs and processes were poorly defined and, as implemented, did not assure the consistent and effective accomplishment of program goals and objectives.

Major programs dealing with surveillance of equipment and systems, engineering support of plant activities, assurance of operability of plant equipment, control of work, and configuration control were ineffective. Weaknesses in the surveillance programs resulted in degraded equipment and poor assurance of the ability of safety related equipment to meet its design basis requirements. Operability determinations and evaluations were limited in scope and at times nonconservative. Weak engineering programs affected the quality and availability of engineering support, including maintenance of the plant design basis and drawings. An ineffective work control process resulted in essential equipment being unavailable unnecessarily and allowed poor work practices to exist. Poor configuration management resulted in instances when the CNS staff did not know the status of equipment.

3.2.1 Weak Surveillance Program

Weaknesses in the surveillance program contributed to the licensee's inability to assure the operability of equipment or detect inoperable safety systems. Technical Specification (TS) required surveillances did not exist for some equipment and the surveillance requirements were poorly defined for others.

(1) The SET identified that TS surveillance testing had not been performed to demonstrate that the RHR pumps did not exceed the maximum flow rate of 8400 gpm against the TS defined backpressure. Upon further evaluation by the licensee, the RHR system was declared inoperable.

(2) The SET and the licensee identified several safety-related systems which had weaknesses in the testing of the system logic. Overlap did not exist between the various procedures to ensure that each system was fully tested. Many components had not been verified as part of a TS required surveillance since plant startup. In addition, the use of audible checks for relay pickup did not provide verification of relay contact performance.

(3) In mid-1994, both DGs were declared inoperable because the licensee discovered that several nonessential motor control centers were not verified as being tested as part of the TS load shed surveillance.

(4) Regional NRC inspections performed in mid-1994 found several weaknesses in the licensee's surveillance program, such as using inadequate procedures for testing the control room envelope, not performing required local leak rate tests on numerous containment penetrations as

required by TS, and not effectively addressing failures of secondary containment to meet its surveillance criteria.

(5) During observation of the monthly core spray surveillance test performed on August 17, 1994, weaknesses were noted in the prejob briefing. The operators were not attentive to the individual performing the briefing; the IST engineer arrived after the briefing was over, because he was not aware the test was about to be performed and had to be paged; and the test procedure was not reviewed in detail.

3.2.2 Poor Assurance of Equipment Operability

Equipment operability was not assured due to weak surveillance procedures, preconditioning of components before performance of their functional test, weak and nonconservative operability determinations and evaluations, and nonconservative interpretation of plant TS requirements. Weaknesses were also noted with the licensee's Limiting Condition for Operation tracking system, and with the thoroughness of equipment checks performed by operators during their rounds.

(1) During the course of the evaluation, issues raised by the SET resulted in the discovery that operability could not be assured for the core spray system, standby liquid control system, residual heat removal system and service water system.

(2) The SET determined that operability determinations and evaluations were technically weak and inappropriately used probabilistic risk assessment (PRA) and compensatory measures to justify equipment operability. For example, the operability evaluation performed to address a five gallon per hour leakage from each DG jacket cooling water system was based on inappropriate compensatory measures which would have required offsite power to add makeup water when the offsite power was not available. Licensee procedures did not permit use of PRA for operability determinations. However, the operability determination performed to address the potential for valve failure due to sudden motor reversal for several direct current powered motor-operated valves was based on the low probability of an accident occurring while stroking the valves during required surveillance tests or other infrequent valve manipulations.

(3) In May 1994, the NRC identified that preconditioning of components during testing prevented the identification of potentially inoperable equipment. In response to this concern, the licensee confirmed that numerous surveillances contained examples of preconditioning of components. As a result, the licensee revised 50 safety-related surveillance procedures and 13 surveillances were required to be reperformed.

(4) On November 9, 1993, upon discovery that DG 1 was inoperable, the licensee did not immediately demonstrate operability of DG 2, as required, due to a nonconservative TS interpretation. This error was first recognized by a licensee Quality Assurance (QA) audit. During the

SET, the licensee confirmed the conclusions of the QA audit, and determined that the TS had not been met.

(5) During the performance of station operator rounds, the SET observed that certain safety-related equipment functions were not routinely checked. Examples included, the lack of visual checks by the station operators of the DG governor control settings, and difficulty in checking oil levels in the reactor recirculation pump motor generator sets due to a painted over oil level indicator.

3.2.3 Weak Engineering Support

Programs and processes implemented by site and corporate Engineering were poorly defined, which decreased the quality and availability of engineering support to the site. Specifically, the system engineering functions were not well focused, the design basis information was not easily retrievable, and engineering was not sufficiently involved in testing programs and processes to ensure equipment operability.

(1) System walkdowns and system trending were not consistently performed by the system engineers, and the system report card program was not implemented. The vendor manuals were backlogged for review, and the corrective action and work control process requirements were consuming a large portion of the system engineers' time. Many system engineers were not qualified on their systems. The system engineers were not always aware of maintenance, modifications, or testing performed on their assigned systems. In some instances, technical, system specific, or job specific training was not adequate to support the required duties of the system engineers.

(2) Engineering walkdowns of systems did not always identify system deficiencies. The SET found that the SLC heat trace circuits had not maintained the suction piping at the required temperature. The SET later discovered that weak surveillance monitoring and poor system controls for the heat tracing circuits may have allowed this condition to exist for an extended period of time when the plant was operating. The licensee later declared the SLC system inoperable.

(3) Valves and pressure switches associated with the automatic closure capability of the SW crosstie/isolation valves were not tested. Failure of these valves to close would result in a loss of SW inventory for cooling during accident conditions. Additionally, the sensing lines for the pressure switches had experienced silting problems. However, when silting was found, the switches were not tested to determine if they were operable.

(4) Engineering did not assure that design basis information was easily retrievable, which contributed to the incorrect classification of safety related components and systems. For example, the licensee incorrectly classified the control room envelope as nonsafety-related, and over 150 SW valves had to be reclassified as safety-related.

(5) The lack of an accurate, easily retrievable design basis resulted in a loss of configuration control for several safety-related relief valves. The resulting errors included the installation of improperly sized valve springs, lack of tags for testing acceptance, seal wires that were not installed, and improper and inconsistent setpoints. The licensee identified that several of the deficiencies were long standing and affected several safety systems including CS, HPCI, RHR, and SLC. In at least one instance, a relief valve was installed which did not meet design requirements. The licensee concluded that undocumented and improper modifications had been made.

3.2.4 Ineffective Work Control Processes

The work control process was poorly defined and poorly implemented. The lack of effective work preparation resulted in short planning windows and poor communication between maintenance and other departments. These weaknesses resulted in equipment being taken out of service repeatedly for preventive and corrective maintenance. Poor foreign material control practices, and problems with the torque control program further exemplify weaknesses in the work control process.

(1) Observation of service water pump work performed while the SET was onsite showed weaknesses in the work control process and procedures. Neither the work package nor prejob briefing identified personnel fall hazards, resulting in a one day delay while adequate protection was provided after the SET expressed concerns. Maintenance was further delayed due to required procedure changes to add signoffs for torquing and to rewrite the pump reassembly portion of the procedure. The rewrite referred to three pump sections, but the pump had four casing sections. The pump had to be taken apart after its reassembly, because the procedure did not have guidance that would have allowed detection of an improper fitup of the pump shaft sections.

(2) During observation of SW pump reassembly, the SET identified that foreign material exclusion (FME) practices were not enforced. This resulted in the mechanical cutting and removal of a coupling over the open pump assembly, and a lack of covers over the open system piping and the open pump assembly when work was not in progress. The licensee had previously indicated that poor FME practices were a long standing work control problem which had contributed to instances of component failures. Examples included flow control valves for the reference leg backfill system becoming clogged with small metallic fragments, RHR 27 A/B valves found with seat leakage caused from foreign material damage, and PC-AOV-237 Local Leak Rate Test failure caused by welding slag and grinding debris found on a seating surface. The licensee recently formed an FME Task Force to resolve outstanding FME issues.

(3) Due to a poorly implemented torquing program, proper torque values were not included in MWRs. Some of the components which required rework due to incorrect torque values included the reactor equipment cooling (REC) pump casing bolts and the flanges associated with the CS orifices. The SET and DSAT identified other weaknesses associated with the licensee's

torquing program, including fastener torquing requirements not specified or implemented while performing maintenance on the DGs, RHR pump motors, and other safety-related equipment.

(4) The licensee implemented several changes in the work control process as a result of the DSAT findings. These changes were in the process of being implemented at the time the SET was on site. However, the SET observed continued weaknesses in the work control process. For example, a planning/scheduling group had been formed, depleting resources from the maintenance groups. The SET found that, in spite of the formation of this group, work control, coordination of PM activities, and assembly of the MWRs was still performed by the first line supervisors rather than the new planning/scheduling group. This negatively impacted the amount of time that first line supervisors spent in the field supervising the craft (approximately 10 percent).

3.2.5 Weak Plant Configuration Management

Programs and processes used for maintenance of plant configuration were poorly defined and did not ensure that system alignments and configuration were adequately controlled by the operations staff. Weaknesses in implementation resulted in clearance order deficiencies, mispositioned valves, and inadequate control of work boundaries. In addition, changes to plant configuration were not adequately reviewed or controlled to ensure that plant configuration accurately reflected station design.

(1) During the evaluation, the SET observed an evolution in which the control rod drive (CRD) system was operated with air in the system prior to being properly filled and vented. The licensee's subsequent evaluation of this event identified that the control room operator's reliance on the clearance order logs to maintain system status control resulted in the operators being unaware of the post maintenance status of the CRD system.

(2) A number of instances of undocumented modifications to the design of plant equipment were identified. For example, the licensee identified that DG starting air tank relief valves were not in agreement with the vendor drawings and were undersized. The DSAT found a temporary weld patch on the reactor equipment cooling system. Many of these alterations had been implemented through the maintenance work process without being recognized as modifications.

(3) The DSAT determined that configuration management of valve checklists was deficient. Over 700 valves had been identified as early as 1992 as not being included in valve lineup checklists. Criteria for performing lineup checks after maintenance or outages were not specified by procedure or policy. A check of valve lineups performed by the DSAT on seven systems revealed many mispositioned valves.

(4) Between 1986 and 1993, the licensee performed walkdown inspections of approximately 1600 drawings and found over 120,000 discrepancies, of which approximately 2400 remained unresolved at the time of the DSA.

These unresolved discrepancies were primarily problems in areas such as plant system labeling and equipment configuration. The DSAT reviewed a recently updated controlled drawing for the RHR system which was revised as part of the drawing upgrade program and found over 20 additional drawing discrepancies.

3.3 <u>Independent oversight and self assessment were not effective in monitoring ongoing activities, detecting deficiencies, or assuring that identified deficiencies were resolved.</u>

Organizations responsible for providing independent oversight of station activities, programs and processes, including Quality Assurance and the Safety Review and Audit Board (SRAB), were not effective. These organizations did not identify existing significant programmatic and process weaknesses despite numerous opportunities and information from outside sources, such as industry organizations and the NRC. Other organizations and programs having oversight responsibilities, such as the Station Operations Review Committee (SORC) and the Condition Review Group (CRG), were not effective. Self-assessment activities were also weak, lacking in depth, and narrow in scope. Additionally, management did not take effective corrective action in response to these assessments. The Corrective Action Program (CAP) did not effectively support the recognition and resolution of plant problems because of weaknesses in problem identification, root cause determination, and corrective action implementation.

3.3.1 Weak Independent Oversight

Independent oversight organizations were not effective. These organizations did not identify significant programmatic and process weaknesses because of a strict compliance orientation, lack of technical knowledge in some cases, and a lack of independence; did not effectively escalate significant findings to senior management; and did not adequately respond to criticism from senior managers, outside organizations, and self-assessments. Management did not take prompt and effective action when significant findings and concerns were identified by these organizations. Further, managers failed to establish and effectively monitor performance indicators.

(1) The SRAB was established by the TS to independently review and audit station activities and report directly to the NPG Manager. The DSAT and the SET found that SRAB had failed to effectively perform this function in that it did not identify declining performance prior to identification by outside groups. SRAB had not challenged QA or SORC when performance problems were found.

SRAB members were mostly senior NPG and CNS managers. A 1991 self-assessment and a 1993 internal memorandum criticized SRAB members for failing to differentiate their line and oversight roles. This failure had adversely affected SRAB independence. Minutes of SRAB meetings indicated that SRAB responsibilities were not given sufficient priority by members as exemplified by difficulties in gathering a quorum and failure to accomplish subcommittee duties in a timely manner.

As a result of recent management changes and observations by the DSAT, the non-NPPD members of SRAB performed an assessment of past SRAB performance. This assessment confirmed the problems noted above and recommended the addition of new members with experience in dealing with safety issues at other facilities and more non-NPPD members. The SET observed the September 1994 SRAB meeting and noted improved meeting participation.

(2) The QA organization had primary responsibility for independent oversight of station activities, programs, and processes. The DSAT and the SET found that QA had failed to perform this function effectively. The SET found that management had not established a supportive environment and, in some cases, had sponsored the performance of minimal compliance auditing rather than indepth performance based reviews.

The SET reviewed all 1993 and 1994 QA audits and found that QA findings were generally compliance oriented and missed significant performance based program and process weaknesses. For example, the 1993 QA Audit of configuration management identified nine findings and six recommendations. These findings and recommendations focused on procedural and documentary flaws and missed significant programmatic weaknesses found by the DSAT and the SET in this area. As a result, QA found the program "effectively implemented." Similarly, QA also missed significant issues in work control and procedural adequacy. QA auditors stated that they did not feel qualified to review for procedural adequacy, and therefore focused on procedural compliance.

QA monthly trend reports did not highlight significant, repeat, and overdue issues. Concurrently, management did not take prompt and effective corrective actions when QA identified issues. For example, in January 1994, QA found that CNS was taking credit for testing the alternate DG after discovering that one DG was inoperable, even though the validation test had been run before the failure was discovered. QA believed this to be contrary to plant TS and so informed station management. While CNS did the test only three hours before the discovery, Operations management reported to QA that they had always done it this way and that sometimes the test had been performed up to 24 hours before discovering a failure. Station management responded that no corrective actions were warranted. During the SET onsite evaluation, station management reversed this decision.

(3) Other groups and organizations charged with oversight responsibilities did not effectively perform their duties.

The SORC failed to rigorously carry out assigned duties and responsibilities as outlined in the TS. For example, the DSAT identified that SORC had failed to review nearly all safety-related special work instructions as required by TS. The SET found that the SORC had not established appropriate testing frequency for relays involved with the initiation of CS, HPCI, Low Pressure Coolant Injection (LPCI), and Reactor Core Isolation Cooling (RCIC) when they approved the associated surveillance procedure. The TS required that testing be

accomplished every 18 months. However, the SORC approved an eight year frequency.

The SET observed several instances of poor performance during the October 3, 1994, SORC meeting. For example, some items reviewed during the meeting were not given to members before the meeting and were not on the agenda. Members frequently exited and returned during discussions of items under review.

In response to recent criticism, the licensee reviewed the CRG and found it to be ineffective because of a lack of a questioning attitude. This group was charged with the responsibility to review, prioritize, and categorize Condition Reports (CRs). As a result, the licensee elevated the membership of this group to senior site managers.

The DSAT identified numerous concerns regarding the lack of quality checks (QC) and QC hold points in work requests. QA had also identified repetitive instances in which individuals performing QC were not fully independent of the job.

(4) The SET found that, with few exceptions, managers rarely used performance indicators to monitor or measure station and personnel performance. In 1992, the licensee published performance indicators quarterly. These became annual data points in 1993 and had not been published for 1994 at the close of the evaluation. The 1994 Business Plan listed performance indicators for each goal and objective area. However, the licensee did not publish these performance indicators. The Radiation Department routinely published radiation protection information, and recently, QA provided trending information regarding corrective actions as part of their monthly report to senior management. However, most managers stated that they had not found the QA trend reports useful. Operations, Site Engineering, and Maintenance managers stated that they did not monitor or trend performance indicators to determine the performance of their departments. Development of performance indicators was planned as part of Phase 1 of the most recent Performance Improvement Plan.

3.3.2 Weak and Ineffective Self-Assessments

The SET found multiple weaknesses in self-assessments and the self-assessment program including the absence of a self-critical attitude and poor followup of recommendations. Although a self-assessment guideline existed, it did not include good direction and clear expectations regarding criteria for conducting formal, systematic assessments. Further, the SET found an organizational environment that was not conducive to change. This attitude manifested itself in shallow evaluations, lack of ownership and acceptance of recommendations/findings, and failure to follow through with corrective actions. Consequently, CNS was unable to benefit from the results of self-assessments.

The self-assessment program was slow to develop. QA had lead responsibility for this program. However, no comprehensive plan for routine self-assessments

of CNS quality and safety was available to the SET on request. On August 2, 1994, the licensee issued a new NPG Directive to replace a "guideline" issued February 26. The new directive was intended to improve communication of management expectations regarding self-assessments, to provide for better formalization of results, and to improve corrective action follow through.

The first self-assessment of a nuclear quality or safety nature was the SRAB self-assessment performed in 1991. Six self-assessments have been performed since involving the corrective action program (twice), fire protection, radiation protection, SORC and a second but less detailed SRAB assessment. Although internal and external audits performed since 1992 have identified serious problems in Operations, Maintenance, and Engineering, comprehensive self-assessments that focused on these areas have not been conducted. Except for the Radiation Protection self-assessment, most self-assessments were lacking in depth and narrow in scope. When issues were identified, managers did not ensure effective corrective actions were taken.

(1) The 1992 self-assessment which compared CNS against issues identified in a 1991 NRC Diagnostic Evaluation (DE) of a similar facility missed many significant weaknesses. Of 75 DE findings, only one was judged applicable to CNS. However, many of the remaining issues were found to be applicable to CNS by the DSAT and the SET. For example, the licensee deemed the following not applicable: weak self-assessments, configuration management program deficiencies, poor root cause processes and results, inadequate management support, weak management information systems and performance indicators, and tolerance of degraded equipment. The SET found each of these weaknesses at CNS.

(2) In late 1993, the CNS staff reviewed findings from recent NRC Operational Safety Team Inspections at other nuclear power plants. Lack of a self-critical attitude and poor followup resulted in a weak assessment. Greater than 25 percent of the items identified as potentially applicable to CNS were dispositioned to programs and processes found deficient by the DSAT and the SET. Many of these were dispositioned to the new CAP which was not yet completed or implemented. Several others were dismissed as needing no action. The DSAT and the SET found deficiencies in many of these areas, such as repetitive maintenance, use of inadequate or wrong procedures, and QA effectiveness.

(3) The September 1991 SRAB self-assessment concentrated primarily on compliance issues. The assessment summary concluded that the activities of the SRAB were being effectively implemented. However, the full report and an attached report submitted by an outside contractor identified performance weaknesses and made several recommendations for improvement. For example, the full report stated that SRAB members rarely visited critical plant areas and had difficulty differentiating their roles as line managers from their SRAB oversight responsibilities. The contractor's report and the full report stated that SRAB subcommittees needed to be refocused on areas of concern, such as maintenance, operations, and training. The contractor's report noted that SRAB concentrated primarily on compliance issues rather than

performance and programmatic problems and recommended development and monitoring of performance indicators. The findings and recommendations from these reports were not closed out until September 1993. However, except for some minor revisions of subcommittee charters and some proposed changes to SRAB membership, no actions were taken to address the above concerns. A review of SRAB minutes for 1992 through 1994 showed that SRAB continued to be compliance oriented rather than focusing on program or performance issues.

(4) On August 2, 1994, the licensee issued NPG Directive 3.29, "Self-Assessment Programs," in recognition of concerns with self-assessment. However, this directive and the associated plans had not been implemented at the close of the evaluation.

3.3.3 Poor Application of Operating Experience

CNS application of outside operating experience was poor despite active participation in many industry organizations and a system that captured and tracked industry and regulatory information. CNS also did not always apply lessons learned from its own operating experience because of a lack of questioning attitude and evaluations that were not self-critical. Consequently, CNS experienced events and inoperable equipment, inadequate PMs, and repetitive and untimely identification of equipment problems which could have been avoided. CNS had numerous opportunities to identify and resolve many of the issues later identified by the DSAT and the SET.

(1) On May 25, 1994, the licensee declared both DGs inoperable because of inadequate surveillance testing of circuit breakers used for shedding non-critical equipment loads from DGs. This was the result of failure to follow vendor testing recommendations. NRC found concerns with other vendor recommendations for these circuit breakers, such as not performing recommended force margin testing, using higher than recommended amperage during testing, and exceeding the recommended operating lifetime of components.

(2) As a result of DG surveillance problems, the licensee identified that prior to June 1994, logic system functional testing (LSFT) of RHR and other systems did not comply with the TS. Multiple testing deficiencies were discovered in May 1994, which prompted the licensee to do additional testing in July and August. The licensee had several opportunities to correct this problem in the past. The licensee did a review in response to Information Notice (IN) 88-083, "Inadequate Testing of Relay Contacts in Safety Related Logic Systems," and found 190 essential relays and 856 essential contacts were not being tested. However, the licensee improperly concluded that the TS did not require testing of these contacts. The November 1988 LSFT enhancement program was not completed. A June 1992, internal memorandum questioned whether CNS was complying fully with the TS in its LSFT, and requested that the issue be re-evaluated expeditiously. The licensee also did not complete actions in response to IN 93-38, "Inadequate Testing of Engineered Safety Features Actuation Systems," May 1993.

(3) As a result of the licensee's recent efforts to review industry and regulatory notices, the licensee found that 354 control switches installed in the plant were susceptible to a generic failure identified in 1980. An Information Notice and a GE Service Information Letter written in 1980 stated that certain switches manufactured before 1976 could render safety related systems inoperable because of degradation of the Lexan cam. Both documents recommended inspecting or replacing safety related and important-to-safety switches manufactured before 1976. In fact, one of the events discussed in the IN occurred at CNS. A total of seven failures attributable to Lexan degradation have occurred at CNS.

(4) As a result of the licensee's failure to assure that deficiencies identified in IN 89-17, "Contamination and Degradation of Safety Related Battery Cells," were addressed CNS experienced multiple battery problems including a forced plant shutdown. IN 89-17 described copper contamination problems, identified the root cause as a manufacturing defect, and stated vendor-recommended corrective actions of increased surveillance frequencies and battery replacements. On December 18, 1991, February 7, and February 10, 1992, the licensee declared the station batteries inoperable because of low voltage in cells. The last occurrence resulted in both divisions of batteries being inoperable, forcing a plant shutdown. A visual inspection revealed copper contamination of the electrodes introduced during the manufacturing process.

(5) The SET found that the licensee had not established a preventive maintenance schedule for the DGs consistent with the manufacturer's recommendations. As a result, the licensee had not performed vendor recommended 10-year maintenance, which included partial disassembly and inspection of critical engine components.

(6) Vendor recommended maintenance had not been performed on the HPCI and RCIC steam traps until a 1993 HPCI steam trap failure. The licensee performed maintenance on the failed steam trap and found a clogged screen. As a result, the system engineer implemented an eighteen month PM for HPCI and RCIC steam traps. The vendor maintenance manual states that the bonnet should be removed once each year for cleaning and inspection of the screen. The engineer was unaware of this vendor manual requirement for annual cleaning until concerns were raised by the SET.

3.3.4 Weak and Ineffective Corrective Action Program

The SET concluded that weaknesses in the CAP were major impediments to improvement at CNS. The licensee did not prevent certain recurring equipment failures or effectively implement improvement initiatives in a timely manner because it did not promptly identify problems, categorize those found, determine the root causes, or take corrective actions.

(1) CNS failed to recognize multiple occurrences of excessive reactor pressure vessel heatup and cooldown rates. During a December 14, 1993, reactor trip, the temperature of the bottom head metal began cooling at a rate greater than the allowed rate of 100 degrees F in an hour as the reactor coolant was stratifying because of the loss of both recirculation pumps. When the licensee later increased the rate of depressurization to achieve cold shutdown, the resulting increase in natural circulation caused the temperature of the vessel bottom head metal to increase more than 100 degrees F in an hour. A similar event occurred on March 2, 1994. Neither event was recognized or reported until August 1994. In response to SET questions, the licensee reviewed all previous plant trips and determined that CNS operators may have exceeded the 100 degrees F temperature change in an hour 21 times during previous similar events. At the close of the evaluation, the licensee was reviewing these events and the consequences of exceeding the allowed heatup and cooldown rates many times.

(2) From December 1993 through January 1994, CNS experienced multiple failures of turbine building sump pump 1A because of a poor root cause evaluation. The licensee initially determined the root cause to be operator error in not maintaining adequate sump level to provide for net positive suction head. However, the licensee later found that the problem resulted from clogging of the suction line and not operator error.

(3) The licensee erroneously concluded that operator error caused a July 1994 event involving vessel level instrumentation spiking. A root cause investigation concluded that the vessel level had changed and operators had misinterpreted the increase as spiking. However, operators contested this finding and noted that other level instruments were being tested at the same time. Further investigation showed that level had not actually changed and that the most probable cause was the introduction of air into the instrument lines during a vessel level shroud instrumentation surveillance in progress at the time of the spiking.

(4) CNS had not taken prompt and effective corrective actions in response to silting problems. In 1993, the licensee reviewed the SW system piping configuration to identify line segments susceptible to silting. The basis for the review was an original silting study performed by the plant's architect engineer in late 1972, which included many recommendations to combat silting problems. Numerous silting concerns have affected system reliability and required the licensee to change system operation. Silting also resulted in many instances of plugged sensing lines and instruments. Further, accelerated SW and RHRSW booster pump replacement was a direct result of silting problems.

(5) Since early 1993, external organizations performed numerous assessments and found weaknesses in several areas, such as self-assessment, corrective actions, goals and objectives, management involvement and support, and problem resolution. Management did not take timely and effective corrective actions to resolve these issues.

A January 1993 outside assessment report described deficiencies in the areas of goals and objectives, performance tracking, management involvement, management effectiveness, and communications. This report recommended the establishment and communication of goals and objectives. However, the licensee only established goals and objectives in the June 1994 Business Plan and did not promulgate these goals and objectives throughout the organization. This report further recommended increased management presence in the field. However, the DSAT and the SET found that managers continued to spend little time in the field.

The November 1993 Common Cause Analysis included similar findings in the areas of goals and expectations, self-assessments, management support, communications, and human performance. This report also indicated that little improvement had occurred as a result of the January 1993 assessment. Additionally, this report recommended establishing a Human Performance Evaluation System (HPES) function because of weaknesses in human performance and human error evaluations. The licensee established a HPES function as part of the site organization. However, the SET found that this position had not been staffed and HPES assessments had not been performed.

CAP weaknesses were well known to licensee management since 1992 as a result of two self-assessments, three QA audits, and an NRC enforcement action. However, the licensee failed to respond effectively to CAP weaknesses until prompted by outside organizations. The licensee later determined that the CAP shortcomings resulted from a lack of a questioning attitude and managers' reluctance to encourage problem reporting throughout all levels.

The October 1993 Strategic Plan for Performance Improvement, the May 1994 Integrated Enhancement Program and the June 1994 NPG Business Plan all included actions to improve the CAP, but all three were superseded shortly after inception and before effective action was taken. Some efforts to improve the CAP process were undertaken early in 1994 with the establishment of a CAP review group. This group was disbanded in June 1994 with the establishment of a new CAP and a new organization. This new organization was disbanded in September 1994, and was replaced with another organization, which was not fully staffed at the close of this evaluation.

In September 1994, CNS took steps to improve problem identification and reporting by reducing the reporting threshold. There was some indication that problem identification and reporting had improved. However, backlogs rapidly increased beyond the capability of the available staff and continued to increase during the evaluation period because the licensee failed to effectively plan the implementation of threshold reductions. At the close of the evaluation period, the licensee added staff to address the CR backlog and changed the membership of the CRG to provide increased management oversight and improved prioritization by replacing the middle managers assigned with senior managers.

4.0 POSITIVE OBSERVATIONS

The licensee made several key management changes before and during this evaluation. Most of these individuals were recruited from outside NPPD in an effort to assimilate additional industry knowledge and experience from diverse perspectives. The resultant management team consisted of individuals with broad management backgrounds and pertinent experience with improvement initiatives similar to the one CNS was undertaking. CNS managers were open and forthright in their assessments of organizational weaknesses and cooperated fully with the DSAT and the SET. The SET observed improved communication and increased standards and expectations on several occasions, including SRAB meetings, management meetings to develop improvement plans, and one-on-one interfaces with managers and staff. The SET also observed that these managers were aggressive in their determination to resolve the causes of identified weaknesses.

The SET obtained much of its information and insights from the CNS staff. CNS personnel were dedicated to station improvement and included many knowledgeable and experienced individuals. However, CNS management had not fully benefited from this resource.

5.0 EXIT MEETING

On November 17, 1994, the Executive Director for Operations, the Deputy Director, AEOD, the Associate Director for Projects, NRR, the Region IV Regional Administrator, the Team Manager of the Cooper Nuclear Station Special Evaluation Team, and other NRC staff members met with the NPPD President and Chief Executive Officer, and senior managers and staff from CNS to review the results of the evaluation. During the meeting, results of both the DSAT and SET were presented by the respective team managers. This exit meeting was open for public observation and representatives of Midwest Power, Lincoln Electric Company, and members of the public attended. Briefing notes summarizing the team findings and conclusions are attached as Appendix A.

ATTENDEES LIST
For Exit Meeting on
November 17, 1994

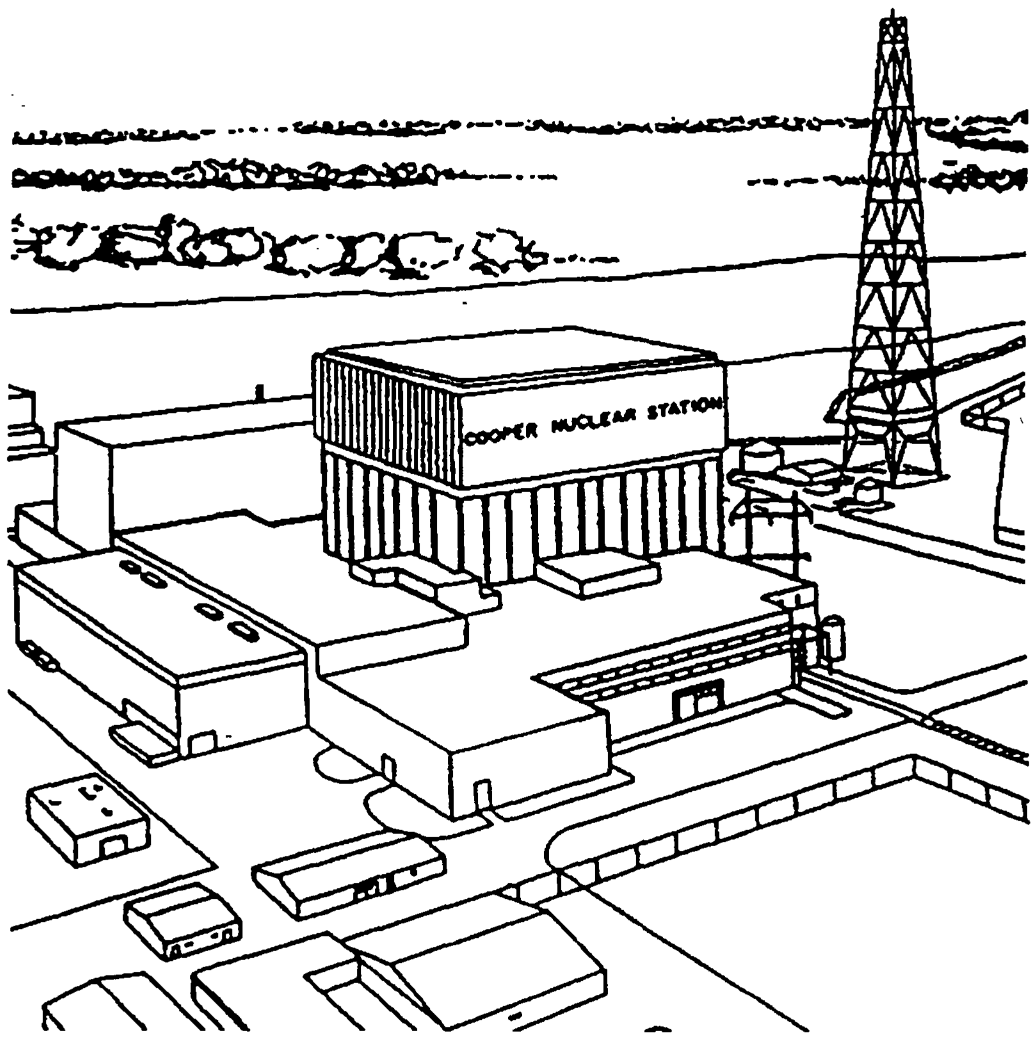
NRC	NPPD
A. Beach	S. Bowen
W. Beckner	M. Boyce
L. Callan	T. Bundy
P. Harrell	J. Dutton
R. Kopriva	R. Gardner
E. Merschoff	J. Gausman
J. Mitchell	R. Godley
T. Reis	J. Herron
D. Ross	R. Holzfaster
J. Taylor	G. Horn
W. Walker	R. Johnson
R. Zimmerman	R. Jones
	E. Mace
	S. McClure
	C. Moeller
	J. Mueller
	J. Parker
	R. Sessons
	R. Singer
	R. Stoddard
	G. Thompson
	G. Trouba
	K. Walden
	K. Ward
	R. Watkins

APPENDIX A - EXIT PRESENTATION

Nuclear Regulatory Commission

Special Evaluation Team Report

Cooper Nuclear Station



Public Exit - November 17, 1994

SELECTION OF COOPER NUCLEAR STATION

- Decline in Performance Noted in the Last Two SALP Reports
- Significant and Repetitive Hardware Problems
- Ineffective Corrective Action Program
- Ineffective Self-Assessment
- Organizational Performance Problems

SET GOALS AND OBJECTIVES

- Provide Information on CNS Safety Performance To Supplement Other Assessment Data Available to NRC Senior Management.

- Evaluate The Effectiveness of The Licensee's Diagnostic Self-Assessment.

- Evaluate Licensee Management Involvement and Effectiveness With Respect to Safe Plant Operation.

- Determine the Root Causes of Safety Related Equipment and Performance Problems.

SET METHODOLOGY

- SET Evaluation of DSA

  - Four Member Team

  - One Week on Site
    - . Interviews
    - . Observations
    - . Review Issues

  - Assess DSA Process and Results

SET METHODOLOGY
(CONTINUED)

- SET Independent Assessment of CNS

  - Eight Member Team

  - Extensive Review of Performance Information

  - Two Weeks On Site
    - . Observe Plant Activities
    - . Interview Managers and Staff
    - . Assess Validity of DSA Findings
    - . Develop Areas Not Addressed By DSA

  - Assess CNS Performance and Causes of Significant Safety Problems

RESULTS OF SET EVALUATION OF DSA

- Overall Performance Effective
- DSA Process Weaknesses
- DSA Results
  - Insightful Assessment
  - Identified Significant Issues
  - Effectively Conveyed

RESULTS OF NRC SPECIAL EVALUATION OF COOPER (CONTINUED)

Root Causes:

- **Management Weaknesses**
- **Program and Process Weaknesses**
- **Weak Independent Oversight and Self-Assessment**

MANAGEMENT WEAKNESSES

Management did not provide the leadership and direction necessary to maintain appropriate corporate wide standards of performance.

- **Acceptance of Long Term Equipment Problems**
- **Lack of a Questioning Attitude**
- **Poor Planning**
- **Backlogs not Effectively Managed**
- **Poor Communications**

PROGRAM AND PROCESS WEAKNESSES

Major programs and processes were poorly defined, and as implemented, did not assure the consistent and effective accomplishment of program goals and objectives.

- **Weak Surveillance Program**
- **Poor Assurance of Equipment Operability**
- **Weak Engineering Support**
- **Ineffective Work Control Processes**
- **Weak Plant Configuration Management**

INDEPENDENT OVERSIGHT AND

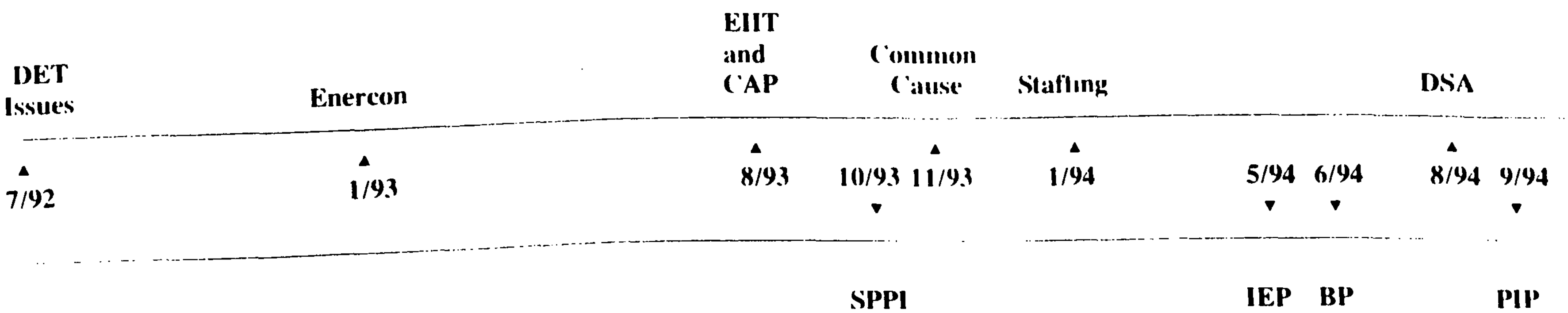
SELF-ASSESSMENT

Independent oversight and self assessment were not effective in monitoring ongoing activities, detecting deficiencies, or assuring that identified deficiencies were resolved.

- **Weak Independent Oversight**
- **Weak Self-Assessments**
- **Poor application of Operating Experience**
- **Ineffective Corrective Action Program**

Cooper Nuclear Station

Self-Assessments



Corrective Action Plans

Nebraska Public Power District

NEBRASKA PUBLIC POWER DISTRICT
P. O. BOX 499
1414 - 15TH STREET
COLUMBUS, NE 68602-0499

GUY R. HORN
Vice-President, Nuclear
(402) 563-5518

NLS940012
September 2, 1994

U. S. Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, DC 20555

Subject: Diagnostic Self Assessment Team (DSAT) Report
Cooper Nuclear Station
NRC Docket No. 50-298, DPR-46

Gentlemen:

Enclosed for your information and use is the Diagnostic Self Assessment Team (DSAT) report of the Nebraska Public Power District's (NPPD) Cooper Nuclear Station (CNS). This self assessment of CNS was conducted to provide an independent evaluation of CNS performance. The objectives of the DSAT were to determine the root cause(s) for the stations declining performance and to identify areas requiring improvement. The enclosed report provides the results of that effort.

If you have any questions concerning this subject, please contact me at this office.

Sincerely,

Guy Horn

G. R. Horn
Vice-President Nuclear

GRH/tja:dsat.rpt

cc: NRC Regional Office
Region IV
Arlington, TX

NRC Resident Inspector
Cooper Nuclear Station

NPG Distribution

NEBRASKA PUBLIC POWER DISTRICT

COOPER NUCLEAR STATION ♦ DIAGNOSTIC SELF ASSESSMENT TEAM

P.O. Box 98 ♦ Brownville, Nebraska 68321

September 6, 1994

Mr. Ronald W. Watkins, President
and Chief Executive Officer
Nebraska Public Power District
P. O. Box 499
Columbus, Nebraska 68601

Dear Mr. Watkins:

This letter forwards the Diagnostic Self Assessment Team (DSAT) report of the Nebraska Public Power District's (NPPD) Cooper Nuclear Station (CNS) assessment. This self assessment was conducted at your direction and that of the District's senior nuclear officer, Mr. Guy R. Horn, vice president - nuclear. The team members observed activities and reviewed records at CNS and the NPPD general office from July 25 through August 19, 1994. The observations were discussed with your staff throughout the assessment period. Concerns were discussed with you and a formal exit meeting with your staff was held on August 19, 1994.

In commissioning this team your goal was to obtain an independent review of the operation of CNS and to determine the root cause(s) for the station's declining performance. The sixteen-member team was drawn from nine nuclear utilities, the Institute of Nuclear Power Operations (INPO) and nuclear field consultants. The team possesses over 250 years of experience in the design, operation, maintenance and performance evaluation of nuclear facilities. Some team members have had recent experience at facilities where declining performance problems have been and are being addressed.

The team reviewed performance in the four broad areas of operations and training, maintenance and testing, engineering and technical support and, management and organization. A combination of station practices and procedures, federal regulation, INPO performance criteria, and experience are the basis for the team's observations. Concerns, observations and issues contained in this report represent a team consensus with regard to the nature and extent of the problem. Since this team is not a regulatory authority and is acting on your behalf, issues of a federal, state, or local regulatory nature must be considered by you.

A number of significant observations were developed by the DSAT. The team found weaknesses in several areas that prevented the plant from reaching high standards of performance. The significant items are listed below:

- Corporate and station management have not established or encouraged high standards for personnel and unit performance. Complacency and a philosophy of "do business the way it has always been done," contribute to the station's inability to keep pace with the nuclear industry's rising standards of excellence. Furthermore, a lack of self-critical review and weakness in the assessment of station and industry events has prevented the station from learning from their experience and that of the industry.

- Weaknesses in long-range planning and scheduling have contributed to the station's inability to address long-term problems and implement long range improvements. Current programs and management controls have not required or encouraged the use strategic or tactical planning. Non-routine activities are frequently planned orally and initiated without the benefit of a thorough plan.

- Independent oversight has been ineffective in that many of the current performance problems at the station were not recognized and corrected. Quality assurance audits, surveillance, and evaluations are generally compliance oriented and do not effectively assess performance beyond regulation.

- The SRAB and SORC have failed to aggressively challenge performance weaknesses when they are identified. These organizations are ineffective in raising problems and concerns to the appropriate managers for resolution.

- Several issues identified by the team have the potential to reduce the margin of safety in important plant systems. These issues include: inappropriately preconditioning systems prior to performance testing, uncertainties in the control of plant status, ineffective corrective actions, and weaknesses in configuration and plant design basis control.

In evaluating the performance of CNS, every effort was made to be as complete and accurate as possible in describing the problem areas. These

areas are representative of operations at CNS and should be combined with the results of other inspections, evaluations, and reports to develop a complete listing of all activities and programs requiring improvement.

During the period of this evaluation, the DSAT noted actions being taken by the station and corporate staff to address issues identified by the CNS staff, NRC, and this team. Recent changes in site management have introduced a heightened awareness of nuclear safety. New management has established a higher standard of performance for the CNS staff and clearly demonstrated the fact that the station will be accountable for adherence to these standards. Changes in programs dealing with surveillance testing, corrective action, work control and industrial safety are being implemented.

The fact that you have taken a more aggressive approach to problem identification and subjected yourself and your staff to this independent self assessment is a major and creditable first step. It will, however, only result in improved station performance if similar aggressive actions are taken in addressing the root causes identified in this report. While there is no regulatory or contractual requirement for you to respond to this report, I request that you provide me with a copy of your plans to address the root causes described in Section 3 of the attached report. I suggest that you provide the Institute of Nuclear Power Operations with a copy of this report and a copy of your corrective action plans when they are developed. The lessons learned at CNS will be of value to the nuclear industry in improving the level of nuclear performance.

The cooperation of your staff in identifying problem areas and the determination to improve performance expressed by many of the CNS staff is encouraging.

Sincerely,

Ralph E. Beedle
DSA Team Manager

cc: G.R. Horn
J.H. Mueller

COOPER NUCLEAR STATION DIAGNOSTIC SELF ASSESSMENT

CONTENTS **PAGE**

COOPER NUCLEAR STATION
DIAGNOSTIC SELF ASSESSMENT

EXECUTIVE SUMMARY

From July 25 - August 19, 1994, Cooper Nuclear Station conducted a Diagnostic Self Assessment (DSA) to assess the station's performance. The objectives of the DSA were to identify areas requiring improvement and to determine the root causes for the station's declining performance. The assessment was initiated by the President and Vice President, Nuclear of the Nebraska Public Power District. The team, led by an experienced former nuclear utility senior executive, consisted of 14 technical evaluators and an administrative assistant. Areas assessed included operations and training, maintenance and testing, engineering and technical support, and management and organization. The facility was shutdown throughout the self assessment.

Overall, the team found weaknesses in many areas that prevented the plant from achieving high standards of performance. Corporate and station management have not established or encouraged rising standards for personnel and station performance. Complacency, and a philosophy to "do business the way it has always been done," contributed to the station's inability to keep pace with the nuclear industry's rising standards of excellence. Furthermore, a lack of self critical review and weaknesses in the assessment of station and industry experiences has prevented the station from learning valuable lessons that could have corrected many station performance issues. Several issues identified by the team have the potential to reduce the margin of safety in important plant systems. These issues include: inappropriate preconditioning of systems prior to performance testing, uncertainties in the control of plant status, ineffective corrective actions, and weaknesses in configuration and plant design basis control.

The team found weaknesses in the implementation of many of the administrative programs and processes that support the operation of the station. Weaknesses were attributed to a lack of guidance from management in the form of clear expectations and standards for performance. Adherence to procedure and program requirements was weak. Frequently, when interpretation of a procedure or requirement was necessary, the interpretation was not conservative with respect to plant safety. There is a tendency to make decisions to expedite the completion of work rather than to conform to high performance standards. Weaknesses in the implementation of the clearance order and valve line-up programs have

resulted in occurrences where equipment and components were not in the condition intended or maintained under the positive control of the control room staff.

In the area of maintenance and testing, the team identified weaknesses in the control and performance of maintenance activities. Inadequate planning of maintenance has resulted in excessive out-of-service time. Emergency diesel generator and high pressure coolant injection out-of-service time has increased over the past three years due, in part, to poor coordination of maintenance and testing activities. Weakness in the quality of maintenance has resulted in degraded and nonconforming plant equipment. Verifications to ensure quality of repairs to equipment important to nuclear safety are not consistently made during maintenance activities. Specific problems found in the application of quality control to maintenance activities include: lack of foreign material exclusion and cleanliness control, use of improper materials, and lack of fastener torque requirements. A lack of a coordinated work control process has contributed to additional equipment outage time, increased outage risk, lost maintenance production hours, an increase in the backlog of maintenance, and over-reliance on the operations shift supervisor to coordinate maintenance on a daily basis.

The team determined that corporate and system engineering support of plant operations was deficient in several areas. The lack of well-defined roles and responsibilities of the two organizations, as well as interfaces between them, has resulted in inefficient use of engineering resources. Design basis information is not readily available to station engineers. Control of design activities is not sufficient to ensure the station's design basis is maintained and that analyses are based on correct design basis information. Some design changes and other station modifications had not been reviewed for design configuration prior to installation. Additionally, many system engineers are unfamiliar with the information that comprises the plant design basis. For example, due to a lack of understanding of the relationship among plant technical specifications, the Updated Safety Analysis Report, and the design basis, a test engineer specified incorrect limiting stroke times for motor-operated valves in the RHR system. Inadequate training on design and licensing basis information provided to the system and corporate engineers contributed to their lack of understanding of these issues.

The team identified several weaknesses in the station's corrective action program. Many events or adverse conditions at the station result from

failed or absent barriers that could have been provided through implementation of lessons learned from in-house and industry operating experience. Corrective actions sometimes do not adequately address the root cause. Technical evaluations of industry operating experience are often untimely, narrowly focused, or inappropriately conclude that an industry problem is unlikely to occur at the Cooper Station.

In the area of management and organization, the team identified significant weaknesses in many areas of the organization. Weak or uninvolved corporate leadership did not assist the station in areas where their expertise could have been beneficial. Corporate management has not insisted that the management practices in place support high quality operation. For example, the station does not have a strong self assessment culture. Independent oversight is similarly deficient in that most of the current performance problems at the station were not recognized and corrected. Quality assurance audits, surveillance, and evaluations are generally compliance oriented and do not effectively assess performance. The SRAB and SORC have failed to aggressively challenge performance weaknesses when identified. These organizations are ineffective in raising problems and concerns to the appropriate managers for resolution.

Weaknesses in long-range planning have contributed to the station's inability to address long-term problems and implement long-range improvements. Current programs and management controls do not require or encourage the use of strategic or tactical planning. Non-routine activities are frequently planned orally and initiated without the benefit of a thorough plan.

The team determined the following root causes of the station's performance problems:

- management's ineffectiveness in establishing a corporate culture that encourages the highest standards of safe nuclear plant operation

- failure of management to establish the vision supported by adequate direction and performance standards to improve station performance

- failure of management to establish effective monitoring and failure to direct critical self assessment activities that recognize program and process deficiencies and identify necessary improvements

- management's failure to develop corporate and station personnel with the management and leadership skills necessary to ensure that strong leaders and managers are available to fill key corporate and station positions

The team noted corporate and station management have taken action to address some of the issues identified in this report. Examples include:

- recent changes in site management have introduced heightened expectations and standards of performance
- improvements have been made to the corrective action program to better identify plant problems
- use of special instructions to perform safety related work has been reduced
- tighter controls on implementation of clearance orders
- preliminary development of long range business plans and schedules

Continued management involvement is needed to maintain the momentum for change that currently exists.

COOPER NUCLEAR STATION
DIAGNOSTIC SELF ASSESSMENT

1.0 INTRODUCTION

1.1 BACKGROUND

Prior to 1992, performance at Cooper Nuclear Station was generally considered satisfactory and consistent with industry standards. The station's scram rate was low and few significant events were reported. Few performance problems at the station were identified by outside agencies in 1991. Early in 1992 an Institute of Nuclear Power Operations (INPO) evaluation noted weaknesses in the communication and implementation of management expectations and management awareness of performance. The Systematic Assessment of Licensee Performance (SALP) review identified declining performance in plant operations and radiation protection. Weaknesses were also identified in the analysis and assessment of plant conditions.

In late 1992 and early 1993, several occurrences led to increased NRC scrutiny of the station. A temporary startup strainer was found in a reactor building closed cooling water pump. Although the station had previously evaluated the systems, in response to NRC Information Notice 85-86, and determined them to be free of strainers, additional strainers were found in safety systems by NRC inspectors. It was also discovered that the test method used to determine operability of the secondary containment did not insure operability under various plant conditions. The test had been used to verify operability for several years. Concerns were raised by the NRC concerning the effectiveness of the station's corrective action program after similar problems were noted to be recurring at the station.

Several key issues were identified in the 1993 SALP that indicated declining performance. These included: failure to aggressively pursue root causes of potentially significant equipment problems, a willingness to live with problems, a weak problem resolution and corrective action program and a lack of sensitivity to potentially degraded plant conditions. Similar problems were identified during other NRC inspections. Twenty-seven NRC violations were issued in 1993 compared to ten in 1992 and four in 1991. The station was assessed two civil penalties, totaling $400,000 in 1993, for issues related to the suction strainers and weaknesses in problem identification and resolution.

The station issued the CNS Near Term Integrated Enhancement Program document in early 1994 to focus management attention on issues that are important to improve overall performance in the near term. However, instances of inadequate problem identification and resolution, weaknesses in surveillance test performance, and events affecting safety equipment performance have continued to occur. Preconditioning of equipment and systems to optimal condition to increase the probability of passing the surveillance test, was also noted by the NRC. The station entered an unscheduled outage, in May 1994, to correct emergency diesel generator load shed deficiencies and resolve logic system test issues. Additional concerns have contributed to the length of the outage including untested containment isolation valves, untested actuation relays and programmatic issues. Plant restart has been further delayed pending resolution of NRC confirmatory action letter issues.

In June 1994, the Nebraska Public Power District met with the NRC to discuss the station's declining overall performance. During the meeting, the NRC indicated its intention to perform a Diagnostic Evaluation to better assess the station's safety performance. NPPD management, recognizing the need to enhance performance, initiated plans to conduct this Diagnostic Self Assessment (DSA) of the Cooper Nuclear Station. The DSA is intended to identify areas requiring improvements. Continuing discussions with NRC management indicates that the results of the DSA may be used by the Commission in their assessment of the station.

1.2 OBJECTIVES

The objective of the Diagnostic Self Assessment was to conduct an in-depth independent assessment of the performance of the Cooper Nuclear Station.

1.3 SCOPE

The DSA assessed performance in the areas of operations and training, maintenance and testing, engineering and technical support, and management and organization. The assessment included specific emphasis on assessment of CNS's performance history. The results of past NRC diagnostic evaluations and experience gained from other industry initiatives was used as a basis for the evaluation. Some of the significant problem

areas identified from these activities that were included in the scope of the DSA are:

- management's effectiveness in resolving underlying root causes and achieving improvement in overall organizational performance
- effectiveness of site and corporate management leadership
- effectiveness of the QA organization
- effectiveness of line organization performance (self) assessment activities
- ability and capacity of the organization to simultaneously support normal operations, deal with extraordinary plant problems, and respond to significant regulatory initiatives
- management tolerance of inadequate organizational performance
- management tolerance of equipment problems
- effectiveness of management processes and work control processes
- effectiveness and technical adequacy of engineering support
- understanding of the facility design basis and adequacy of conformance

1.4 METHODOLOGY

The DSA team used performance based evaluation techniques to assess both past and present NPPD performance. Most of the team members are INPO-trained peer evaluators and several team members are former NRC inspectors and managers who have experience in application of safety-oriented, performance based assessments. Appendix A provides a listing of the DSA team membership. The DSA also utilized the guidance from the NRC Diagnostic Evaluation Program Directives and Handbook in conducting the assessment.

The team's selection of specific issues and evaluation subjects was guided by its review of the plant history, including CNS performance information collected or developed by INPO. The team also included the information provided via NRC DET "requests for information" in their review. The DSA team reviewed plant event and problem histories, directly observed NPPD's handling of contemporary issues, evaluated plant and corporate NRC-licensed programs and their implementation, and conducted a vertical slice audit of one important safety system.

The DSA applied multi-level evaluation methodology used by the NRC in its performance of diagnostic evaluations. Level 1 of the evaluation focused on plant safety performance with respect to personnel, equipment and procedures. Level 2 of the evaluation concentrated on program adequacy and performance. Activities at Level 3 developed an understanding of effectiveness of management in directing the plant's activities and in responding to the problems identified in Levels 1 and 2. The DSA used the information developed in the Level 1-3 activities to identify root causes for significant verified problems identified at those levels.

1.5 FACILITY DESCRIPTION

The Nebraska Public Power District Cooper Nuclear Station, a 778-MWe (net) General Electric boiling water reactor, is located on the Missouri River south of Brownville, Nebraska. Commercial operations began in July 1974. The station was shut down throughout the assessment.

1.6 ORGANIZATION

The NPPD organization for support of the Cooper Nuclear Station consists of General Office and Station components of the Nuclear Power Group. The head of the Nuclear Power Group is the chief nuclear officer, titled vice president - nuclear. A chart of the organization is provided in Appendix B.

2.0 EVALUATION RESULTS

2.1 OPERATIONS AND TRAINING

The team found weaknesses in the implementation of many of the administrative programs and processes that support the operation of the station. Ineffective support programs have hindered the operator's ability to control and maintain systems and equipment in a manner that contributes to safe and efficient operation. In addition, oversight and control of shift routines and activities does not ensure the control room staff is fully aware of and in control of activities that may affect plant status and operation. Many of the weaknesses are attributed to a lack of guidance from line

management in the form of clear expectations and standards for performance. Management frequently failed to recognize program and personnel performance deficiencies. For those deficiencies that were identified, they failed to aggressively pursue the determination of root causes and corrective actions. Training was also not effectively used to provide the technical and professional skills necessary to enhance personnel performance in several key functional areas.

Positive observations included the station's aggressive cleanup effort to minimize contaminated areas in the plant. Areas of surface contamination have been significantly reduced in recent years resulting in ease of access for operation and maintenance in most areas. Operations and Training Department teamwork was noted in activities supporting control room simulator fidelity thereby ensuring operator training is realistic and relevant to plant operation. Improvements in operational communications to enhance shift watch standing effectiveness were also observed.

The team observed operations and training performance during an extended outage period. The areas observed included management planning and direction, implementation of management expectations through observation of on-shift activities and various program activities, equipment condition and control, and effectiveness of internal assessments. Support of operations by various site and corporate groups, including training, was also reviewed. A substantial number of interviews and document reviews were conducted. In addition, informal discussions, plant walkdowns, and control room observations were used by the team to evaluate operations performance.

2.1.1 Plant Status Control Is Not Rigorously Maintained

Administrative programs and processes intended to maintain plant status control are sometimes inadequate to insure that system alignments and clearance boundaries are known and controlled by the control room staff. Weaknesses in the implementation of these programs and processes have resulted in clearance order violations, valves and other components being found out of position, and inadequate control of work boundaries. Operation's ownership of the plant status control responsibility was not sufficient to ensure rigorous compliance to program standards. Additionally, the administrative programs for the control of seal wired valves and independent verification need strengthening.

(1) *Some aspects of implementation of the clearance order procedure* deviate from good industry practices for control of tagged equipment. Some of these practices reduce the ability of the control room staff to control the status of plant equipment and to remain cognizant of system status and availability. Other clearance order practices can desensitize operators and technicians to the importance of tagging requirements resulting in equipment damage or personnel injury. Additionally, some clearance order procedure requirements were bypassed through use of other processes. For example:

- CNS Procedure 0.9, "Clearance Orders and Caution Tag Orders," states that it applies to all equipment and work conducted at the station. However, work on safety systems is frequently performed using special instructions (SI) that establish work boundaries and isolation requirements. Frequently, these instructions do not use clearance orders and tags for equipment or personnel safety. Using SI work steps, instead of a clearance order, removes an important tool the shift supervisor has to monitor and control the condition of a system or component. A prerequisite for the shift supervisor to release a clearance order is the verification that the system is ready for service. Use of an SI removes this control from the shift supervisor.

- Until recently, test valves for local leak rate tests (LLRTs) were danger tagged as "no position." These danger-tagged valves were manipulated during performance of LLRTs with the danger tags still attached. This practice was used to shorten the time to complete the test and minimize the need for operator involvement. This practice is not consistent with the clearance order procedure or standard industry practice and is being eliminated.

- CNS Procedure 0.9 permits the control room operator to designate persons other than operators to implement a clearance order. Operators interviewed by the DSA team related occurrences when this has happened. This practice is not consistent with standard industry practice and is under review by operations management.

- Operators sometimes do not have the clearance order sheet specifying components to be tagged in hand while hanging and removing danger tags. This practice increases the likelihood for tagging the wrong component or removing the wrong danger tag.

(2) There is inadequate guidance on implementation of the valve line-up program. Action required for valves found out of the position specified on the valve line-up sheet, criteria for performing line-up checks after maintenance or outages, and requirements for periodic valve line-ups are not specified by procedure or policy. Components found mispositioned are typically not investigated to determine the reason for the mispositioning. Following the discovery of two mispositioned valves on the reactor recirculation system, valve line-ups were completed on six additional systems. More mispositioned valves were identified. As a result, a complete valve line-up was ordered and was in progress when the DSA team left the site. At that time 65 components, including valves, dampers, and breakers were identified as mispositioned. The high number of mispositioned components identified indicates a weakness in the station's ability to control and maintain system status.

(3) Drawing walkdowns conducted between 1986 and 1993 identified over 200 valves that are not included in valve line-up check lists. Operations personnel have not established a priority to include these valves in the line-up sheets. Considering the number of valves that have been found to be mispositioned that are listed on line-up sheets, the status of the unlisted valves is uncertain.

(4) Seven lead wire seals, used to prevent operation of critical valves associated with reactor safety without breaking the seal, have been found broken, missing or improperly installed in the past four months. Three of the deficiencies were discovered by the DSA team. The seals were replaced but no investigation was performed to determine the cause for the discrepancies. Missing or improperly installed seal wires remove a barrier to unintentional operation of valves important to safety.

(5) CNS Procedure 2.0.1, "Operations Department Policy," establishes numerous exceptions to the requirements for independent or

concurrent verification of valves, breakers and electrical leads. The aggregate effect of the exceptions is to prevent detection of misoperation or mispositioning of a component. For example, technicians land leads on sensitive equipment without concurrent verification that the lead and location are correct. This can result in the lead being landed on the wrong terminal, followed by an unintended actuation before the second person has the opportunity to detect the error. Typical industry practice is to provide concurrent verification for work on sensitive equipment and independent verification on component positioning that affects reactor or personnel safety.

2.1.2 Compliance to Standards and Procedures Is Frequently Not Conservative

The station has not established an expectation on adherence to standards, procedures and program requirements that conveys a philosophy accenting conservative compliance. Interpretations of technical specification requirements are sometimes inconsistent and are sometimes made to minimize the impact on the issue at hand. The requirements established in some programs are bypassed through the misuse of other processes.

(1) Some activities at the station are conducted in a manner that does not communicate a conservative approach toward the interpretation of the CNS Technical Specifications. The DSA team observed, and was informed of, several maintenance repair activities that were performed without SORC approved procedures as required by the technical specifications. Discussions with the CNS staff confirmed this was an often-used practice. Frequently these activities were performed using special instructions written by the work crew leader. Additionally, some work was observed to be performed on essential equipment, without written special instructions, relying instead on the skill of the craft. Recently, management guidance has been given to reduce the use of SIs for safety related work.

(2) A change was made to the quality assurance program that reduced the level of commitment to the NRC without processing the change in accordance with 10CFR, Part 50.54(a). QA audit frequency was changed for certain audits from annually to biennially without

obtaining prior NRC approval. Area audits deleted from the 1993 schedule included: station operations, repair maintenance, environmental, and SRAB/SORC activities. QA management did not interpret the change to be a reduction in the level of commitment to the NRC requiring prior approval, even though the previous auditing program is based on annual audits. Additionally, ambiguities as to which revision of ANSI N18.7 the QA program is committed have not been resolved by the station although the need to do so has been recognized by QA management.

(3) The CNS Emergency Plan requires the shift technical advisor (STA) position to be manned at all times. The technical specifications and station procedures contain provisions for not staffing the position during outages. During the current outage the STA position was left unmanned for several days before the discrepancy was recognized. A failure to ensure that different but interrelated programs establish consistent requirements resulted in securing the STA function without first recognizing the discrepancy.

(4) Procedure and program requirements are sometimes ambiguous. For example, the Conduct of Maintenance procedure allows the maintenance manager to make exceptions to that procedure but fails to establish controls or documentation requirements for exceptions that are authorized. The Temporary Design Change (TDC) procedure states that TDC's are not considered permanent while another step in the same procedure describes what to do when a TDC is considered permanent. Ambiguities in procedures can result in worker confusion regarding management's expectations and reinforce an attitude to interpret the requirements in a manner that expedites work completion rather than conformance to expectations.

(5) Decisions to postpone the Emergency Plan's 50 mile ingestion pathway zone (IPZ) dose assessment model conversion to EPA 400 requirements were made without modifying the Emergency Plan or the Emergency Plan Implementing Procedures. The emergency planning coordinator did not view this as a potential licensing issue and considered verbal NRC approval adequate.

(6) A well established procedure validation and walkdown process has been circumvented through the use of special instructions. While not

intended to be used as procedures, special instructions have sometimes been used in place of procedures. Since special instructions are neither validated or walked down, errors go undetected until they are actually being performed in the field.

(7) Proceduralized preconditioning of equipment, prior to surveillance testing, has resulted in the inability to determine the as-found condition of some equipment. A lack of rigorous investigation and response to a NRC identified concern regarding the testing of secondary containment integrity resulted in recurrence of a similar event and an undetected degradation of the emergency electrical system. Although station management considers this issue to be adequately addressed through recent management directives and procedure reviews, the DSA team found that little guidance has been developed for operability determinations in cases where preconditioning concerns were identified during the procedure reviews.

2.1.3 Training Is Not Effectively Used to Improve Performance

Training in some functional areas is inadequate to provide personnel with the knowledge and skills necessary to perform their assigned tasks. Training is viewed by some CNS management as an obligation instead of an opportunity to improve personnel performance. As a result, line management has not recognized the need for accurately determining core needs for competency in some areas. Additionally, a lack of line management ownership of their respective training programs has resulted in the training department receiving little or no oversight and feedback to improve the quality of training. Examples include:

(1) The initial engineering support personnel training program for station engineers provides limited overall system knowledge. Position-specific guidelines for selected engineering support positions were not incorporated into training as specified by the issuance of INPO ACAD 91-017, "Guidelines for Training and Qualifications of Engineering Support Personnel," due to inadequate follow-up by training management. System engineer training consists primarily of self study and a demonstration of their knowledge of their assigned system to their supervisor before being "certified" as system

engineers. There is limited cross training of engineers to improve the knowledge of the other (mechanical or electrical) aspects of system operations. Examples of training/knowledge weaknesses of observed include:

- Several system engineers interviewed were unaware of where the design basis for their system is located or how to identify the applicable design basis information for their system.

- System engineers currently prepare special instructions for maintenance work activities on safety-related components. Corporate engineers often prepare the special instructions for design change package implementation. However, neither group has received training in work planning or procedure preparation.

- Corporate engineering personnel do not receive plant systems training.

(2) Skill of the craft training needs are not understood and are inadequately defined. Many job performance measures (JPM's) are evaluated in the training shop environment to a generic skill. Few follow-up motor skill evaluations are conducted on specific in-plant equipment. Maintenance supervision relies on procedures and skill of the craft training to ensure maintenance activities are properly performed. The expectation is that journeyman need only basic skills of the craft training. Once this training is complete, maintenance supervision believes that the journeymen can handle most tasks in the plant using procedures or special instructions. Subsequently, maintenance supervision (with the exception of the operations manager who is responsible for the I&C training program) does not promote further training of maintenance personnel. However, weaknesses observed in the conduct of maintenance indicate additional training may be needed. Refer to section 2.2.2 for additional detail.

(3) The health physics (HP) technician continuing training program is limited in that it does not build an in-depth technical program following the fundamental training program. Although HP supervision

conducts continuing training during periodic meetings, the continuing training process needs to be defined from a Training Department perspective that includes a skills and needs basis and expanded to provide more technical detail and challenge for HP personnel.

CNS Directive 54, "Management Overview of Training and Evaluation Activities," issued in 1992, directed management to participate in periodic training observations and provide feedback on training quality and effectiveness. Maintenance management and supervision have not conducted any of the observations required by CNS Directive 54. Additionally, the engineering manager has not conducted any observations since 1992. The operations manager has provided feedback to the operations and I&C training programs. However, the DSA team observed that the operations manager's expectations for the shift supervisor maintaining a stand back overview during emergency events is not incorporated into simulator training indicating additional oversight and monitoring may be needed.

2.1.4 Degraded Material Condition and Long-Term Problems Have Potential to Affect Plant Operation

The overall number and individual importance of equipment problems represents a potential challenge to effectively monitor and operate the plant. The team does not consider this to be a significant issue at this time, as evidenced by a low number of significant events and complicated plant trips. However, degraded material conditions and other long standing problems may unnecessarily burden operators responding to various plant conditions and transients by requiring actions not identified in response procedures. The DSA team found a willingness by station management to accept some degraded conditions without an aggressive effort to correct the problems. Lack of action to correct material deficiencies and other long standing problems will result in an ever increasing number of operator work arounds and other problems that further challenge the operators ability to effectively monitor and operate the plant. Contributing to this problem is a lack of an integrated work control process that includes a mechanism for problem identification, prioritization, scheduling, status tracking and trending of recurring deficiencies. Examples include:

(1) The "B" reactor feed pump minimum flow valve leaks by its seat at 200 gpm, and as a result, is kept isolated by shutting a manual isolation valve. This is identified with a caution tag that was hung on 8/26/93. Isolating the leakage improves plant efficiency by avoiding heat losses to the condenser but requires operators to manually open the isolation valve if the minimum flow path is needed.

(2) Drywell "F" sump low level cutout switch doesn't reset until level is high. The reset under these conditions can cause a high fill rate alarm. This problem was identified in June 1993. Living with this condition could result in operators becoming less sensitive to drywell leakage annunciators and as a result take less than prompt action should actual leakage occur.

(3) The reactor vessel level injection solenoid isolation valve leaks past its seat. As a result, a manual isolation valve must be closed. This injection (fill) line is from the core spray system and would be used during emergency operating procedure conditions when reactor vessel level instrument reference legs are needed to be back filled. With it isolated, an operator would be sent to the reactor building, second level to open the manual valve.

(4) The demineralized water level control valve leaks by the seat. It has been isolated, requiring operators to manually open the valve prior to starting the mechanical vacuum pump from the control room.

(5) Long-standing problems in the service water systems due to silt accumulation have resulted in operational work arounds and increased maintenance on critical service water components. Examples include:

- Silting has resulted in problems with instrument sensing lines plugging and loss of the associated indication or control function. Silting concerns have caused the station to change the manner in which they operate the RHR system during shutdown cooling operations. The RHR system heat exchanger outlet valve, which is not designed to be throttled, is throttled to control cooling to avoid throttling of service water valves designed for this purpose. The concern the station has with throttling SW valves is the additional erosion caused by the presence of silt. In addition, instruments that indicate service

water d/p on RHR heat exchanger divider plates are pegged low due to problems with sensing line plugging. Loss of this indication prevents operators from being able to perform the precaution in an in-service test surveillance procedure that requires verification that d/p is less than 10 psid in order to prevent damage to the RHR heat exchanger divider plate.

- Spargers used in the service water bay for keeping silt in suspension have been in need of maintenance for several years. The plant design has five sets of spargers. The system is designed to work with automatic valves feeding the sparger header. Due to excessive wear of the spargers, only two spargers are in operation at any time. This condition has existed for several years but was not identified in the current maintenance back log.

- Service water pumps that are not in operation were rotated by hand at least once per every six hours by operators and prior to each time the pump is started in the non-automatic mode. This practice was stopped during the DSA.

- Service water booster pump maintenance is high considering the relatively low use of the pumps.

- Maintenance procedures for setting the impeller clearances on the pump require a one hour operation to ensure that the casing is clear of sand prior to work on the pump.

- Traveling screens are operated continuously to prevent binding from silt accumulation. Previous problems with screens require quick response from maintenance to avoid accumulation of silt preventing operation. If response is delayed, plant operation may be affected.

(6) Some long-standing equipment degradations noted during operation and maintenance are uncorrected and are not being tracked by the corrective action program or work control system for future resolution.

- Coolant leakage from the "A" RHR heat exchanger mid-body flange joint is being collected by a semi-permanent drain hose

embedded in the shell insulation. The leak had been first identified in 1986 via a maintenance work request that was subsequently cancelled in 1990. Although the cancelled MWR was annotated to delay the job until an outage of sufficient duration, no replacement MWR was created.

- A temporary patch has been installed on the REC piping from the reactor recirculation pump motor generator oil coolers in 1977 and apparently not considered as a temporary repair or modification. The patch was identified during a recent walk-down, removed and permanently repaired.

2.2 MAINTENANCE AND TESTING

Maintenance activities are not sufficiently controlled to adequately assure that equipment quality and availability are suitably maintained. Some controls for maintenance activities are inadequately established and are frequently not properly applied to work, resulting in nonconforming and degraded plant equipment. Improper maintenance work las resulted in an increase in out-of-service time and rework. Quality control verifications are not consistently incorporated in work instructions and are not consistently performed to ensure that the work meets established requirements. Lack of a comprehensive work control system using traditional scheduling and planning techniques also results in additional equipment outage time, increased outage risk, lost maintenance production hours, an increase in the backlog of maintenance, over-reliance on skill of the craft in the absence of comprehensive work packages, and over-dependence on the operations shift supervisor to provide close coordination of maintenance activities and plant configuration.

Maintenance and testing were assessed through interviews, observations of maintenance work, witnessing of testing, and review of related documentation.

2.2.1 Work Control Is Fragmented and Lacks Coordination

CNS does not have a comprehensive work control system that includes work package and work instruction development, parts and logistics planning

functions, nor centralized short- and mid-term scheduling and coordination functions. The lack of a comprehensive work control system has resulted in extended system outage durations, an increase in the duration and number of equipment outages, repeated challenges to the outage risk assessment process, and a reliance on the operations shift supervisor to manage the control and coordination of work and the configuration of the plant's systems. Additionally, lack of an effective work planning effort is affecting the quality of work being performed by failing to consistently provide written and/or properly reviewed and approved work instructions. The lack of a LCO tracking system adds additional challenges to the ability of the shift supervisor and line management to direct work activities and to assess the impact of emerging work items.

2.2.1.1 Work Planning

Work planning is not performed by a dedicated staff of planners but by the shop work crews. Craft personnel are assigned to determine the extent of the problem, develop repair methods including application of vendor or engineering information, arrange for parts and materials, and process the job related paperwork. System and corporate engineers may develop work instructions and procedures for modifications and other plant changes. Management has accepted the extensive use of skill of the craft as a substitute for written instructions and procedures that should contain information essential to the successful, documented completion of maintenance tasks such as critical work steps and sequences, quality requirements such as torquing, critical dimensions, and inspections. Reliance on the craft to arrange for their own job materials combined with weak planning of work package quality documentation and inspection requirements has contributed to installation of incorrect parts.

The station staff has also missed the opportunity to build their library of formally issued maintenance procedures by not converting special instructions into fully approved procedures.

2.2.1.2 Scheduling and Coordination

Each maintenance department generally controls its own work priorities with little coordination with other departments. There is little centralized direction for work item prioritization. The station does not use train-specific outage windows, rolling schedule or other similar scheduling techniques. This

reduces management's ability to collect, group, and coordinate work to minimize equipment unavailability, control room work loads, and increase craft productivity and has contributed to repetitive and excessively long system and component outages.

The shift supervisor spends a significant fraction of his time processing work requests as they arrive at the control room service window, generally on a first come first serve basis. The DSA team viewed this as an administrative burden on the shift supervisor that detracted from his ability to direct and monitor plant operations. Although there is a "daily work list," it does not accurately reflect ongoing work. In addition, the work scheduled on the list is frequently not worked as planned. Consequently, the shift supervisor has no viable list of scheduled or authorized work to assist the in decision making for the coordination of work.

Operations is not consistently involved in assigning priorities to work but acts as a processor of items proposed by the work groups. Even items of potential operational significance do not always receive sufficient priority. A number of the degraded material conditions identified by the team involved operational work-arounds that should be corrected, e.g., silting problems in systems carrying river water, malfunctioning "F" drywell sump low level cutout switch reset, and others as discussed elsewhere in this report.

Work is not routinely scheduled to optimize completion of backlogged corrective and preventive work while equipment is out of service. Backlog has increased from 1,023 open items in January 1994 to 1,392 in June 1994 and to over 1,600 in July 1994. Safety related systems and equipment are frequently removed from service for a single routine task, returned to service, and then taken out of service a few days later for another similarly routine task. For example, the "A" reactor recirculation pump was taken out of service and restored three times between June 2 and 9, 1994 for electrical maintenance. The "D" service water booster pump was out of service three times between March 1 and 11, 1994 for an oil change, a gland water piping repair, and an alignment check.

During outages, plant procedures call for designation of specific senior managers as Outage Directors. Because of the number and magnitude of issues being addressed by the plant staff, no senior managers were considered available for this position. Instead, two more junior staff members are assigned to the position of shift outage director. The

governing procedures were not clear regarding the shift outage directors' organizational reporting lines nor which line manager has the ultimate responsibility for outage scope identification, growth, and control; schedule adherence and accountability; and, information dissemination and communication.

The lack of centralized outage management and information was evident when the operations staff dealt with safety system train outages and restorations. During the assessment, the staff switched residual heat removal from RHR Division I to Division II but encountered a number of challenges. First, some actions needed to restore Division II's operability were being identified during outage schedule meetings but were not being captured in an action list for assured follow-up. Prerequisites for the divisional changeover were being identified until the initially scheduled changeover date and beyond. Secondly, some work items were sent to the maintenance shops but the paper work was misplaced. The jobs did not start and were not recognized as potential impacts to the changeover due to the lack of tracking information. Thirdly, several major jobs were not on the daily work list such as re-insulation of RHR piping, scaffolding removal, and battery testing. Lastly, a system readiness milestone certification process to establish and confirm RHR divisional readiness and operability did not exist.

2.2.2 Weaknesses in the Conduct of Maintenance

The following aspects of the plant maintenance program's performance contribute directly to poor quality maintenance. Low management expectations and performance standards for the maintenance program and correspondingly weak performance by several quality related aspects of the program were evident.

2.2.2.1 Nonconforming and Degraded Plant Equipment

The team found that inadequate maintenance controls or poor adherence to those controls contributed to improper or unsuccessful repairs and return of the equipment to service. For example:

(1) Safety related level transmitters for the scram discharge volume were installed using 1/4 inch mounting bolts instead of the 5/16 inch or larger bolts specified by the original system engineer-prepared special

instruction and the equipment vendor. The larger bolts were required to meet the seismic qualification requirements for the transmitter. The CNS system engineer changed the special instructions to provide torque requirements for the 1/4 inch fasteners. Although the system engineer subsequently wrote a condition report documenting the improper bolting condition, the transmitter was assembled, tested and returned to service.

(2) RHR pump motors had periodically experienced loose bolting following vendor shop repairs since at least 1988. In response to a 1993 loose bolting problem with the "C" RHR pump motor, the station determined that the vendor shop did not require quality control verification of torque in its shop. Corrective action was not taken to check the bolting on the "A", "B", or "D" RHR pump motors nor were the CNS work packages upgraded to specify and verify bolting torque. Subsequently, the "A" pump motor was found to have loose bolting and a related oil leak in July 1994. Maintenance items were then written to check the other pump motors.

(3) Other examples include:

- reassembly of the "A" service water pump coupling without using the vendor's recommended torquing pattern and values
- reassembly of the "A" service water pump impeller using clearance values about one-half those specified by the vendor manual (0.021 inches vice 0.056 inches)
- installation of a #2 EDG fuel injection pump and replacement of the exhaust manifold using special instructions that did not include torquing of the bolts per vendor manual requirements

2.2.2.2 Quality Control

Weaknesses in the quality control program result in inconsistent specification of quality requirements and rigorous quality verification of field work on safety related equipment. As discussed above, work instruction are prepared by the craft persons or system engineers assigned to the maintenance task. Quality requirements are normally to be input to the work instructions by work item tracking staff. Many of the work packages

reviewed by the DSA team contained no requirements for verification of key process steps or conditions to ensure the quality of the work performed.

CNS uses a peer quality control inspection process. A qualified craftsmen who did not participate in the work temporarily assumes the role of inspector. The team and recent NPPD quality assurance audits found occasions where this independence was not maintained. Peer inspector training was also found to be inadequate in that it does not include methods for performing checks or observations in the field but rather addresses only the administrative procedures and maintenance technical skills. Practical observation training and demonstration of field observation proficiency is not included. The above weaknesses result in relatively few problems being identified by peer inspectors. The team found that no deficiencies had been documented as condition reports by peer inspectors since the new corrective action program was implemented in April 1994. Little management oversight of the peer inspection activities was noted by the team, indicating a lack of line management ownership or concern for the quality of maintenance.

Specific problems found in the application of quality control to maintenance activities were:

(1) Multiple examples of failure to specify foreign material exclusion and failure to verify system cleanliness. CNS has experienced recent foreign material induced failures in a valve motor operator and multiple air system solenoid valves.

(2) Fastener torquing requirements not specified nor used for diesel generators, RHR pump motors, and other equipment.

(3) Correct parts and proper materials not being consistently verified at the point of installation, frequently resulting in questionable or nonconforming conditions. Examples include a HPCI auxiliary oil pump control relay with an incorrect voltage rating; an undersized EDG starting air system relief valve; and, various commercial grade check valves installed in the nuclear boiler, RCIC, RR, MS, and HPCI systems without proper dedication.

The aggregate issues of maintenance craft providing their own work planning (including specification of quality control requirements), the over-

reliance on skill of the craft of processes and procedures, and the peer QC program contribute to the inadequate quality of maintenance at CNS.

2.2.2.3 Rework

Station management does not effectively monitor rework (re-performance of corrective maintenance necessary because of unsuccessful or improperly performed repairs) as part of the existing performance monitoring process. Several plant practices tend to mask the occurrence of rework and degrade the effectiveness of work authorization and control processes. For example, maintenance work requests have been routinely held open for or re-opened after long periods of time. The team reviewed a number of examples of rework due to unsuccessful initial repairs. Examples include:

(1) Changes were made to 4160V breaker wheel and frame alignment using locally made tools and informal procedures that were not based on controlled drawings or vendor information. Those changes resulted in misalignment of and operability problems with auxiliary devices and subsequently affected breakers for an RHR pump, service water pump and service water booster pump, electrical bus ties and feeds.

(2) The "A" service water pump had been repaired in August 1994 and its impeller clearance adjusted. Over the next several days, the pump required impeller clearance readjustment at least twice more. No cause for the unstable clearances had been determined but the clearances used for assembly deviated from vendor manual values.

(3) Additional examples involved turbine equipment cooling pump mechanical seal leaks due to a missing O-ring, rework of diesel generator engine leaks three months after major overhaul, improper assembly of various containment isolation valves, and RHR service water booster pump motor-operated valves unsuccessfully overhauled during the refuel outage.

2.2.3 Deficiencies in Procedure and Instruction Content and Use

Management has not provided procedures for maintenance and testing that are adequately developed, reviewed and approved, and controlled in use. A great deal of reliance is placed on the "skill of the craft" that is assumed to derive from a very stable work force of crafts persons with unusually long incumbencies. In many cases, work is performed without specific work instructions, using only a maintenance work request to authorize and scope the work.

Administrative controls in procedures frequently have ambiguous or inadequate instructions and tend to weaken the local performance standards and management expectations for procedure adherence. For example, the determination of need for pre-test, post-test, and quality control requirements in Procedure 7.0.1.2, "MWR Generation and Review," are not clearly delineated. Section 1.2 of Procedure 7.0.4, "Conduct of Maintenance," states that the maintenance manager can make exceptions to the Conduct of Maintenance Procedure for non-safety related items but does not describe what exceptions are permitted nor how they are to be documented. The guidance for use of Interim Procedure Changes and Temporary Procedure Change Notices in Procedures 0.4, "Procedure Change Process," and 0.4.2, "Temporary Procedure Changes," are not explicit. Section 2.4.1 of Procedure 3.4.4, "Temporary Design Changes," states that temporary design changes are not considered permanent while Section 2.4.4 describes the steps to be taken when one is considered permanent.

Some work on essential equipment is performed in accordance with special instructions that are written by a variety of station personnel including managers, engineers, supervisors, and craft personnel. Frequently, these instructions are used without formal review and approval, including the SORC approval required by technical specifications. This has contributed to the use of maintenance work instructions that do not provide sufficient technical information to assure work is in accordance with vendor requirements or specifications.

The team found many examples where either skill of the craft or unapproved and inadequately controlled special instructions were used:

(1) A breaker contactor for core spray motor-operated valve 5A was replaced using a special work instruction written by the work crew leader but not approved by SORC.

(2) A complete overhaul of an RHR pump motor was performed on using unapproved special instructions. Subsequent problems involving loose RHR pump motor bolting were repaired on two MWRs in July and August 1994 using special instructions prepared by maintenance planning and system engineering.

(3) Various repairs were made to the emergency diesel generators without approved procedures, including:

- #2 EDG fuel injection nozzle overhauls in March 1993 using special instructions
- replacement of #2 EDG lube oil piping in March 1993 using skill of the craft
- removal and reassembly of the #2 EDG exhaust manifold in March 1993 using skill of the craft.

Even when procedures used for surveillances and field work are fully developed, reviewed and approved, they frequently result in inappropriate actions or work interruption due to unusable or incorrect information. For example:

(1) Testing in accordance with Surveillance Procedure 6.2.2.5.14, "RHR Initiation and Containment Spray Logic Functional Test," was suspended several times between July 24-26, 1994 due to errors in the procedure's treatment of relay logic. The errors were corrected by procedure changes. On July 26, the procedure caused an inadvertent trip of the 1A recirculation pump when the test shut the operating pump's discharge valve. The procedure had been extensively revised in the recent past but had not been subjected to verification and validation.

(2) The sensing lines for service water pressure switches which isolate the essential water sub-system from non-essential sub-system accumulate river silt and are routinely back flushed by technicians

prior to calibration. The back flush evolution is not included in the calibration instruction and discussions with I&C technicians, supervisors, and training instructors indicated no standardization of the practice. Further, the team found that, although the pressure switches were calibrated, the functional testing for the auto-closure feature was inadequate.

There is a lack of confidence by station personnel in the ability to revise and improve processes and programs in a timely manner due to an inadequate procedure revision and improvement program. As a result, both management and staff have become tolerant of procedure deficiencies and lax adherence. The backlog of unprocessed procedure changes has grown by about 65% since 1992. In the same period, the number of procedures which exceeded their biennial review time frames increased from about five to about thirty procedures per month. The number of open procedure change notifications has increased by about 60% and their average age has also increased. Although performance and status are reported monthly to station management, no comprehensive action appears to have been taken in response to these indicators. The team found that the inability to make expeditious improvements to procedures materially degraded the staff's attitude about procedure adherence and submittal of changes for improvement.

2.2.4 Weaknesses in Industrial Safety Practices

Standards for industrial safety are not consistently enforced by station management. Personnel frequently ignore station and corporate safety guidelines in the performance of work. Independent verification of clearances is not performed to provide for worker safety. Industrial safety practices of personnel performing work in the station are not in accordance with station guidelines and occupational safety standards. Examples include:

(1) Scaffold used for reactor equipment cooling piping was not equipped with toe boards, guard rails and/or mid-rails and had inadequate tipping protection. During the REC work, a welder was observed welding while standing on a steel rod pipe support with an improperly tied-off safety harness. Workers were periodically observed walking in overhead cable trays and duct work without fall protection.

(2) Inconsistent use of hard hats, eye protection, and foot protection were observed throughout the plant. For example, workers cutting pipe for the REC repairs were not wearing eye protection nor hard hats.

(3) Numerous problems were observed with clearance order administration and equipment status errors. Current practices for local leak rate testing allow operation of tagged valves and maintenance special instructions were used to isolate work boundaries instead of clearance orders and tags. The service water pump shafts were manually rotated using a bar on the coupling with the pump in pull-to-lock but without the protection of a clearance order.

Performance indicators for industrial safety accident rate at the station are well above the industry median. The stations industrial safety accident rate performance indicators have been above the industry average for the past four years and the station currently ranks 60th out of 71 plants in overall industrial accident rate performance. The team's observations were sufficiently numerous to indicate that management is not out in the plant observing activities and are not enforcing acceptable standards of performance.

2.3 ENGINEERING AND TECHNICAL SUPPORT

The control, use, and understanding of the station's design basis information was found to be weak. Station modifications are sometimes installed prior to receiving required design reviews. Inadequate training provided to the system and corporate engineers on design basis information, licensing basis and other station commitments contributed to their lack of understanding of the relationship between these issues. Some equipment performance monitoring programs are deficient and not effectively identifying degraded performance. Many of these programs have not been reviewed to identify weaknesses and areas for improvement. Corporate and system engineering support of plant operations is often weak and poorly coordinated. Roles and responsibilities for various engineering support groups are not well defined.

The team performed an in-depth review of the residual heat removal system and its associated electrical power supplies and support systems. The team also evaluated the effectiveness of the engineering and technical support functions by reviewing routine engineering support of the plant, resolution of

plant problems, plant modifications and design changes, configuration control and organizational issues. The team conducted numerous interviews with engineering support personnel, station and corporate management.

2.3.1 Design Control is Insufficient to Maintain Design Integrity

Control of design activities is not sufficient to ensure analyses are based on correct and current design information. Contributing to this lack of effective design control is a lack of readily available design basis information. Additionally, many system engineers were unaware of how to locate design basis information and what information comprises the plant design basis.

(1) The control of design calculations limits the ability of design engineering personnel to ensure that current calculations are being used as references when designing a plant modification. During interviews with engineering personnel, it was noted that there are over 24,000 calculations on file to support the station. However, it was found that the listing of calculations does not identify which calculations are current, such as identifying the calculation that superseded a previous calculation. During reviews of design change packages, it was noted that the supporting calculations seldom reference previous calculations, and none of the calculations reviewed identified any previous calculations as superseded. In one case, there were three different calculations to support a portion of a modification, and two of the calculations did not reference any of the other calculations associated with the modification. Additionally, a review of calculation control procedures identified the potential for a calculation to become approved and included in the calculation listing without the modification it reflected being installed in the plant. These activities can result in the incorrect calculation being used in station analyses.

(2) The control of plant changes that affect either physical station configuration or key plant analyses sometimes do not ensure the analyses are maintained current. During the 1993 refueling outage, the station used a process wherein a design engineer could prepare a set of design sketches to accompany an MWR, obtain SORC approval for the sketches as a design change, and authorize the change to be installed in the plant. A review of some examples of these changes noted that the calculations to support these design sketches would

sometimes lag as much as one year behind the installation of the change. Additionally, in the case of two of the SORC-approved MWRs reviewed, the design change that followed the SORC-approved MWR required some significant station work to ensure the completed modification would still comply with design requirements. For example, a damper in the standby gas treatment system was blocked open as a result of a SORC-approved MWR. However, when the design change was developed to finalize the design for blocking open the damper, it was found that there was a possibility that the purge flow from the containment could cause nitrogen and radioactive gases from the containment to back up into the reactor building exhaust plenum. As a result, the design change included system testing to establish the throttled position of another damper to ensure the flows would be limited and not allow containment nitrogen and gases to be drawn into the reactor building exhaust plenum.

(3) Controls over design information are not adequately established to ensure the correct information is provided for third-party analyses. For example, one engineering manager indicated he was not aware of any design engineering interface with GE regarding the fuel reload analysis and the control of design information necessary to support the various reload and transient analysis. During discussions of incorrect in-service testing valve stroke time requirements, one corporate engineer indicated the latest core reload analysis included a change to the stroke time for the LPCI injection valve. The analysis didn't identify the slower time as a concern. As a result, a documented basis for using the slower stroke as an acceptable testing value could not be identified. This lack of a basis is due to a lack of controls over the transfer of this design information.

(4) The understanding of design basis information is limited, with many engineering personnel unable to differentiate between the design basis for the station and the licensing basis. As a result, some aspects of plant testing and operation are not adequately addressed and design information may not be appropriately considered in some activities. For example, a lack of understanding of the relationship among plant technical specifications, the USAR, and the design basis, caused the in-service testing engineer to incorrectly specify the limiting stroke times for motor-operated valves in the RHR system. In another example, in response to questions concerning interactions between

the spent fuel pool cooling system and the RHR, engineers were unable to identify the basis for a USAR statement that the RHR system could provide fuel pool cooling if the fuel pool temperature were to approach 150 degrees Fahrenheit. Additionally, design basis information was frequently not identified as reference material when preparing design calculations. In reviewing approximately eight calculations that support design change packages, the team only identified two instances where the original design information was referenced.

(5) An additional indicator of a lack of understanding of design basis information is the use of tests to establish design input information. For example, when examining the possibility of back flows from the containment purge lines to the reactor building exhaust plenum, testing was performed to identify the correct setting for a damper that was placed in a throttled position. However, the testing did not verify that the system was capable of operating as intended in the design configuration. (i.e., verifying flows in portions of the system that were shown on process flow diagrams) when determining the "correct" throttled position for the damper. In another example, the system resistance of the RHR system was to be modified by replacing the flow trim in the LPCI injection throttle valve and the suppression pool cooling throttle valve. The system was verified to perform properly by measuring pump discharge pressure and flow rate, then using the original pump curve to determine whether the flows and pressures would meet technical specification requirements. This method of testing did not include considerations used in the original system design, such as system configuration for operations, or the changes in system configuration assumed in a post-accident condition. Typically these performance requirements are more complex that the values listed in the technical specifications.

2.3.2 Control of Station Configuration is Not Effectively Maintained

Changes to station configuration are not adequately reviewed or controlled to ensure the station configuration reflects station design. A number of items have been identified that are not consistent with design or licensing documents.

(1) A number of instances of alterations (undocumented modifications) to the design of plant equipment have been identified. These include: a semi-permanent leak collection hose attached to an RHR heat exchanger, a weld patch on the reactor equipment cooling system, and the removal of check valves from the standby gas treatment system. Many of these alterations have been implemented through the maintenance work process without being recognized as modifications. Alterations to plant equipment, through the maintenance work process, do not receive the in-depth analysis and review require to support changes to the design of plant equipment.

(2) The communication of design requirements to the station has not been effectively controlled to enable the station to establish the appropriate procedural controls to prevent placing the plant in an un-analyzed configuration. For example, it was recently identified that the reactor equipment cooling system could be cross-tied in a way that would prevent the system from performing its required function following a design basis accident. Similarly, corporate engineering personnel noted that the station procedures permitted some electrical loads to be cross-tied in a way that differed from the station electrical load analyses, and recently submitted a letter to the station manager to identify the need to revise these procedures to prevent these system alignments. Additionally, station procedures allow the shift supervisor to modify valve lineups from those shown in design change packages.

(3) The lack of readily available design basis information also contributes to difficulties in establishing the correct essential/non-essential system classifications. Some important station equipment has been incorrectly classified as non-essential, such as the control room envelope. Determining the correct classification to be used when performing maintenance or procuring spare parts is sometimes difficult to ascertain.

(4) A comparison of some drawings to procedures and valve lineup checklists identified approximately twenty-one valves on one drawing that were shown on the drawing in a position different than the normal valve position during plant operations. Further discussions identified that the station had taken a position that the procedures controlled valve positions, and the drawings identified the valve

locations. This undermines configuration control because the drawings are a principal design output document and, as a design output document, should reflect the normal system alignment used in the system analysis. Additionally, a limited scope drawing verification program identified several hundred discrepancies, including incorrect labeling of components, incorrect identification of some components, and incorrect references for continuation of systems.

2.3.3 Corrective Action Program Is Not Effective in Correcting or Preventing Problems

The station has experienced many recent events or adverse conditions that result from failed or absent barriers that should have been provided by effective evaluation and implementation of the lessons learned from in-house and industry operating experience.

2.3.3.1 In-House Operating Experience Program

CNS has not consistently demonstrated the ability to identify, aggressively pursue and permanently resolve their own problems occurring at the station. The inability to resolve recurring problems was attributed to failure to conduct thorough root cause investigation or implement the necessary enduring corrective actions. These deficiencies have been noted in the CNS Integrated Enhancement Program.

The DSA team recognizes that the station has made significant changes in the way problems are reported and evaluated. In April 1994, a single problem reporting system, having a low reporting threshold, was implemented. It is evident that aspects of the program have been embraced by station employees, particularly on the working level where over 95% of condition reports are being generated. (Problem reports are being generated at a rate of about 1,420 per year, as compared to about 138 per year in 1992.) Training has been given on the new program, thorough guidelines have been developed on root cause analysis techniques, and expert mentors/coaches have been provided to facilitate implementation of the new guidelines. A corrective action program manager has been assigned, and a group of root cause team leaders has been formed to improve the consistency of root cause analyses.

Notwithstanding these accomplishments, weaknesses continue to exist in the administration of the corrective action program as evidenced by the following:

(1) A growing backlog of problem reports is challenging the station to work on the important issues and avoid being distracted by the number of problem reports generated on events or conditions having lesser significance. Recent statistics show the backlog for significant condition reports (category 1 and 2 CRs) contain more overdue and older issues than the backlog of non-significant condition reports (category 3 and 4 CRs). This indicates that work on backlog items may not be appropriately prioritized.

(2) Root causes are continuing to be determined by an informal apparent cause process rather than rigorous application of the techniques contained in the CNS Root Cause Guidelines.

(3) Examples were found where planned corrective actions don't clearly focus on the root causes. For example, the root cause for failure of Westinghouse DB-50 undervoltage trip assemblies was lack of management commitment to operating experience review program implementation. However, the corrective actions primarily address prevention of the hardware failure and do not address such management commitment issues as performance monitoring and effectiveness reviews, resource and staffing, responsibility and accountability for program implementation, and performance of interface organizations.

(4) Accountability for the corrective action program is fragmented and the vision for the near-term and long-term program has not been finalized.

The DSA team identified the following recurring in-house events to be representative of continuing problems in this area:

(1) On February 1, 1994, while operating at full power, a core spray pump minimum flow valve unexpectedly closed and then automatically opened when the system test return valve was stroked open during valve operability surveillance testing. An

investigation was unable to recreate the anomalous equipment behavior. Because the core spray flow instrument had a history of problems associated with air in the sensing line and the flow transmitter had been removed from service and calibrated earlier that day, the most likely cause was attributed to instrument spiking caused by air in the sensing lines. Continuing evaluation of the event had subsequently dismissed air entrapment when the event recurred in April 1994.

The work history for core spray flow transmitters was then reviewed and numerous problems associated with erratic and erroneous flow indication dating back to 1985 were documented. As recently as March 1993, erratic flow indication had been noted while the core spray pump was running, and the pump minimum flow valve was found to be cycling. An operability determination completed in March 1994, concluded that the system was operable because, in part, unexpected cycling of the core spray minimum flow valves occurs only during testing (note the inconsistency of this statement with the March 1993, event described above). In July 1994, the station concluded that due to the effects of air on the flow transmitter, the minimum flow valve could cycle continuously, and that because the valve operator is not designed for this duty, it could fail in non-conservative position during an actual demand.

(2) In June 1993, the NRC identified a concern regarding the way secondary containment operability testing was being performed. The test was being conducted after substantial preventive and corrective maintenance had been performed, thereby precluding any opportunity to identify degradation that may have occurred prior to the maintenance. No as-found performance data was available. No action was taken by CNS management to address the generic issue of equipment preconditioning, and in May 1994, the NRC identified another case of preconditioning associated with the procedure for sequential load testing of emergency diesel generators. Some diesel generator loads were shifted before the test, and/or circuit breaker cleaning and lubrication was conducted prior to breaker functional testing.

(3) In March 1993, during a plant outage, the B RPS bus unexpectedly lost power resulting in several group containment isolations and a half scram. Investigation of this event was unable to determine the cause. In June 1993, the B RPS bus again lost power and the containment isolation signal resulted in a seven-minute interruption of shutdown cooling. Following this second event, a defective underfrequency monitoring unit in the RPS motor-generated control circuit was discovered and was attributed as the cause of both events. Further investigation of this problem revealed that an engineering work request had been written and approved in July 1990, recommending that the non-essential motor-generator output breaker trips be removed due to repetitive spurious actuations during the previous two refueling outages. The EWR was subsequently closed by mistake before a design change was initiated. The root cause analysis of the recent spurious actuations addressed only the defective underfrequency relay, not the previous similar events, the inadvertent canceling of the EWR, or the breakdown in control and tracking of corrective actions.

2.3.3.2 Industry Operating Experience Review

CNS has not benefited sufficiently from the experience of other stations in the industry. Performance in this area is weak because technical evaluations of industry operating experience documents are untimely, narrowly focused, based on incorrect assessments of the station equipment performance history, or inappropriately conclude that industry problems were unlikely to occur at the station.

The industry operating experience program relies primarily on a single manager to distribute industry operating experience (OE) documents to responsible departments for evaluation and development of corrective actions. The team found that the OE program manager and supporting department managers are not held accountable for carrying out their assigned responsibilities, and in-depth, independent technical reviews of the evaluations are not routinely performed. Further, periodic effectiveness reviews have not been effective in discovering the depth of the problems in the operating experience program (and the implication of these problems on the overall program adequacy) when individual cases of failed or absent

barriers were discovered. Due to the number and variety of recent station events that involve precursor industry events, the station is performing an extensive review of industry operating experience documents dating back to 1982.

The following example was judged by the team to be representative of problems in the industry OE area: In September, 1993, the station evaluated INPO SER 5-93, and NRC IN 93-62. Both of these documents address BWR thermal stratification problems and its consequences. The review concluded that existing station practices and training were adequate to address the concern, and that such an event was unlikely to occur at the station. During a reactor scram in December 1993, reactor vessel temperatures did stratify, and heatup/cooldown rate limits were exceeded. Although this condition was essentially identical to events described in the industry operating experience documents, it went unnoticed by the shift crew, and was also not detected during the subsequent post-scram review. It wasn't until February 1994, when reports of additional industry events were provided to the station, that the post-scram records were reviewed and it was identified that the limits violation occurred.

The following additional events (and their industry precursor documents) involve industry lessons learned that were not taken advantage of by CNS:

- Inadequate sequential load testing of emergency diesel generators led to undetected failures in the load shed logic on May 25. 1994. (NRC IN 991-13, NRC IN 88-83)

- Failure of Westinghouse 480 volt circuit breaker undervoltage trip assemblies led to unrecognized emergency diesel generator overload on June 14, 1994. (NRC IEB 83-08)

- Calibration inaccuracies in feedwater flow instrumentation led to non-conservative indication of reactor power and subsequent power by derating by 0.8 percent on March 11, 1994. (GE SIL 452 and 452 Supplement 1)

- Deficient abnormal operating procedure for loss of feedwater events resulted in unrecognized potential for placing the plant in the power instability region during a reactor water level

transient by tripping a recirculation pump on 12/14/93. (INPO SER 23-93)

- Multiple failures of GE type SBM control switches in August, 1994. (GE SIL 155 and Supplements 1 and 2)

- Control room habitability envelope test failure on April 11, 1994, due to excessive leakage and design deficiency. (NRC IN 86-76)

- Failure to control interfacing ventilation systems during secondary containment integrity tests led to undetected 10-inch penetration with no water loop seal since original construction on March 8, 1993. (NRC IN 90-02)

- Shifting emergency diesel generators loads as part of the test setup before load shed testing in May, 1994 - preconditioning issue. (INPO SER 27-93)

- High pressure coolant injection pump discharge valve failed on September 30, 1993, due to a dislodged motor pinion gear key. (Limitorque maintenance update, INPO SER 9-88)

- Primary containment declared inoperable and shutdown action statement entered on October 11, 1993, due to core spray dual-function valve (mini-flow valve) not meeting licensing basis. (NUCLEAR NETWORK OE 5033 on 1/10/92, and NUCLEAR NETWORK OE 5493 on 8/3/92)

The team recognizes that a change to the way industry operating documents are processed is being considered. The team feels that it is important for the station to study cases such as the ones above in order to determine the program breakdowns responsible for the problems.

2.3.4 Some Equipment Testing and Maintenance Programs Are Deficient

Programs for monitoring equipment performance to ensure safe plant operations have not been effectively developed or maintained to ensure the bases for the programs are adequate and the scope of the programs is appropriately defined. Many of these programs were developed at the time

of initial plant startup, or when the requirements for such a program were first established, and have not been reviewed since that time to ensure adequacy. During the last eighteen months, reviews of some programs have identified fundamental inadequacies in the programs. Examples include:

(1) The 10CFR50, Appendix J program for leak rate testing of containment penetrations and the associated isolation valves was recently identified to be insufficient. Following the identification of penetrations that did not meet expected requirements, a complete walkdown of containment penetrations identified approximately fifty penetrations that had not been previously tested as required. A further review of the adequacy of the testing processes applied identified a number of penetrations that had been tested improperly, such as not testing containment isolation valves in the direction they would be expected to prevent flow during post-accident conditions. Although the program was found to be deficient during this review, some individual testing problems had been previously identified, but had not identified the need for an overall program review. In one case, the boundary valves for a penetration that was not correctly tested had been identified in the technical specifications as the correct boundary valves for this system. Additionally, previous program reviews, including NRC inspections, had led the station staff to believe the program was adequate and problems identified were not indicators of significant program weaknesses. It should also be noted that the lack of available and controlled station design basis information limited the ability of station personnel to ensure the containment penetrations were correctly identified and tested.

(2) The in-service test program for testing important pumps, check valves, and motor-operated valves is deficient in its establishment of the bases for required stroke times for motor-operated valves. As a result of reviews of motor-operated valve stroke time acceptance criteria under the in-service test program, and a comparison with original system design requirements, a number of differences were identified. When questioned about the bases for the differences, station personnel indicated that this problem had recently been identified and a review was in progress at corporate engineering to ensure the valve stroke times were in accordance with design requirements. When asked about the bases for stroke times previous to this corporate review, station personnel indicated the acceptance

criteria were based on valve stroke time requirements identified in the technical specifications or the USAR. Generally, station personnel were unaware of the design valve stroking requirements established in the system design specifications. Additionally, monitoring of pump performance does not ensure that the pumps are operating within expected parameters. As a result of reviews of performance trends for the RHR pumps, unusual performance trends were identified, such as pump differential pressure readings that increased over four quarterly tests, although the normally expected pump performance would be stable or slightly declining. When questioned about evaluations to determine the causes of these unusual results, the program engineer and the system engineer indicated the causes for these results had not been analyzed because they did not fall outside the acceptable pump performance limits. Additionally, establishment of the appropriate pump and valve acceptance criteria is hampered by the lack of a readily available and controlled station design basis.

(3) The program for control of vendor manuals, which ensures these manuals are maintained current and reflect the latest vendor recommendations, does not sufficiently ensure the vendor manuals in use in the plant are the latest controlled copy. Currently, a controlled copy of the vendor manuals is maintained in the station library, but the copies of the vendor manuals available to the maintenance shops are not maintained current with the latest updates. As a result, workers in the field may be working with vendor manuals that do not reflect the latest approved information. Additionally, limitations on resources and conflicting priorities have resulted in backlogs of vendor manual changes awaiting engineering review and over eighty approved manuals for safety-related equipment that have not been reviewed to identify applicable preventive maintenance requirements.

(4) After finding cracks in the reactor equipment cooling system in 1979, GE recommended changing the chemistry in the system and establishing a program for ongoing monitoring for crack growth. At the time, a program was not developed to provide ongoing inspection of the weld joints. As a result, system leaks were not treated as indications of potential system degradation until the current outage when a sampling inspection program was undertaken to determine the extent of weld joint cracking.

2.3.5 Ineffective Engineering Support of Station Operation

A lack of clearly established roles and responsibilities for engineering organizations has resulted in an inefficient use of engineering resources and inadequate engineering support. Contributing to this problem is a lack of an effective management monitoring and assessment process to identify resource inefficiencies and where additional resources are required to maintain effective engineering support.

(1) Documented management expectations for system engineers include many typical engineering duties, such as system walkdowns, maintenance support, and system performance trending. However, assignment of additional duties to system engineers has resulted in an excessive workload for the current level of resources. For example, the majority of engineering work is focused on performing evaluations of condition reports under the relatively new corrective action program. Some engineers indicated that the program requirements result in an average of over forty hours of work for each condition report. As a result of the number of condition reports being prepared, the site engineering resources are unable to process the condition reports as quickly as new ones are being generated, resulting in a growing backlog of condition reports for review. Additionally, non-traditional work assignments to engineering are contributing to the excessive workload. Due to a lack of maintenance procedures and maintenance planning personnel, system engineers are called upon to prepare special work instructions for maintenance activities. As a result of these workloads, backlogs are increasing in a number of areas, such as industry operating experience reviews, NPRDS reports, vendor manual reviews, and procedure reviews. These backlogs are increasing despite system engineers typically working 50 to 110% overtime over the last eighteen months. Due to the increasing backlogs of various reviews and reports, the attention of the system engineers is being diverted from monitoring system performance and maintaining the necessary perspective when investigating the root causes of system performance problems.

(2) Due to the lack of clearly defined responsibilities between corporate and site engineering resources, determining work assignments is sometimes difficult and is currently in a changing condition. As a result, station demands on the corporate organization for support

during the current outage are resulting in significant delays in completing planned engineering activities, such as development of design basis documents, preparation of instrument setpoint calculations, and planned improvements in the modification process. Additionally, the lack of clearly established roles for the corporate engineering organization has resulted in difficulties in identifying the responsible organization for providing support for identified plant problems. For example, when problems were identified in the shutdown cooling and reactor equipment cooling systems, the expected role of the corporate engineering organization was not clear, resulting in one system engineer approaching a contractor for support that could have been provided by the corporate engineering organization. Similarly, corporate engineering personnel have been managing a drawing verification project, with the station role not clearly defined as part of the project planning process.

(3) Additionally, the lack of clearly established roles and responsibilities, as well as excessive system engineering workload and the lack of effective system training for system and design engineers, have contributed to plant modifications that do not correct the identified equipment performance problems, or may introduce additional problems to the system. For example, a modification to replace a core spray system flow transmitter resulted in the installation of a transmitter that is more sensitive than the transmitter it replaced, causing more exaggerated system response to air trapped in the instrument sensing lines. In another case, a modification to install a subsystem to provide backfill for the reactor vessel level instrument reference legs during post-accident conditions was attached to the high point vent piping for the core spray system without providing a vent for either system, resulting in air entertainment in both systems and indicated vessel level transients when the backfill subsystem is aligned to supply the reference legs.

Contributing to the above problems is the ineffective development and use of performance monitoring activities. Actions to monitor many of the current system engineering activities have recently been initiated, and demonstrate that the organization is struggling to keep pace with the inflow of work. Also, these indicators do not provide management feedback regarding completion of many of the formally assigned system engineering activities, such as performance trending and system walkdowns.

Additionally, the monitoring of corporate engineering performance is provided through a monthly report and schedule tracking activities. Currently, the monthly reports identify a number of areas where planned work is not being completed, and do not effectively track progress on short term work assignments in support of current station needs.

2.4 MANAGEMENT AND ORGANIZATION

Significant weaknesses were identified in many areas of the organization. This has been the result of lack of corporate leadership and support that fostered a management culture resistant to change, and inhibited the Nuclear Power Group from reaching for a higher level of performance commensurate with the rising standards of the rest of the nuclear industry. This manifested itself through a lack of self assessment and independent oversight, weak management systems for monitoring plant performance, lack of organizational discipline for planning and execution of plans, and failure to have in place an effective management development program to provide managers with the basic skills for managing systems/processes and leading people. These weaknesses have resulted in a reactive organization which has been unable to identify and correct declining plant performance.

The team drew it's conclusions by reviewing selected documentation and by conducting about three dozen formal interviews and many informal interviews from a vertical and horizontal cross section of the organization.

2.4.1 Impact of Management and Organizational Culture on Performance

Management/organizational culture at CNS has not provided an environment which encouraged open dialogue at all levels of the management and staff, and enabling effective identification and solution of long term problems with the plant, work processes and people. In the team's judgement this management culture, which has existed over a long period of time, has resisted change and has been one of the significant barriers preventing CNS from establishing rising performance standards for personnel and plant in partnership with the rest of the nuclear industry.

(One can define or describe organizational culture as a unique blend of values, beliefs, attitudes, norms, practices, myths, history and self image that becomes "the way things are done." It creates meaning and establishes reference points for determining the conduct of organization members).

The organizational culture that has existed at CNS affects performance in different ways and in many areas. For example:

(1) A welder observed what he thought was rust on a portion of REC piping. The rust was thought to be the result of a through wall leak in the piping. He didn't mention it to his supervisor until three weeks later, and then only after listening to a talk by the new site manager where the importance of the need for the staff to identify problems was emphasized. The timing was unfortunate however, since the REC system had been refilled. This required the system to be re-isolated and the piping drained to facilitate repairs. The initial reaction by the maintenance management was anger and frustration with the welder for not identifying it earlier. This type of management reaction represents a culture which discourages identification of problems. Reactions such as this have the potential for making employees feel they are placing themselves at risk for being an impediment to getting the plant back on the line.

(2) Several system valve mispositioning events were identified by operations. Operations management's proposed response was to re-perform all the valve lineups. The new site manager questioned the response and the overall policy for operating valves and why this policy has resulted in so many instances where valves were found to be out of their intended position. This raised the question regarding policy clarity, which was not very clear, and pointed to a need for changing the policy to establish better controls. This example represents a management culture in which the Operations management addressed only the symptom and failed to address the fundamental problem of why the valves were out of position in the first place.

(3) The station culture has created a worker's perception that they should refrain from proposing improvements that are beyond "minimum compliance" because they probably wouldn't be funded anyway. An example of this was the many missed opportunities to improve the control room emergency filter system (CREFS). This significant improvement, to provide the necessary design basis margin, was continually delayed over several years until it impacted system operability. The subsequent problems with the control room envelope, which was determined to be of marginal design and

unreliable, are well documented and has been one of the barriers to plant startup. This is a further example of the station culture and illustrates again it's impact through the inability or lack of willingness to pursue problems to resolution, that is to fully assure that the control room envelope would maintain an adequate supply of filtered air at the required pressure and beyond merely satisfying the vague technical specifications and USAR requirements. (compliance oriented).

In summary, the team concluded that the CNS has historically resisted change and improvement beyond minimum compliance, and have generally disregarded rising industry standards. Furthermore, management has tacitly or overtly approved of this isolationist approach for many years.

2.4.2 Ineffective Corporate Leadership and Support

Corporate leadership did not assist the site in areas where the presence of strong corporate leadership could have been beneficial. Corporate management has not assured that the management practices necessary to assure success in running a complex, high consequence operation are in place. These include high-level skills and practices, which are generic in nature and not all related specifically to the nuclear process. For example:

(1) A consistent system for the comprehensive monitoring of plant performance, comparing it against industry standards, then holding responsible management accountable for substandard performance has not been observed. Well thought out systems for management of plant activities were not in evidence. Direction was provided through extensive meetings, and accountability triggered mainly by unanticipated events, or prompting by external oversight observations. An example of an ineffective management system was the use of data generated by radiation protection performance. The report is distributed once per month via a single document that travels a serial route through the organization. No accountability forum appears to be used to assure that managers are aware when performance in their respective organization falls short. When corrective action is recognized to be necessary, such as the need for a cobalt reduction program, there appeared to be no clear planning or accountability for addressing the problem. Another example was the lack of monitoring of maintenance performance parameters. CNS does not

systematically track these parameters against performance standards. This results in a process that is managed mostly in a reactive mode. No strong role models for using a systematic approach to management were evident at CNS and no management training program toward this end appeared evident.

(2) Independent oversight has been conducted in a way that had a low probability of success. When problems occurred, they were not used as learning experiences. Corporate executive management did not ensure that these deficiencies were promptly addressed and corrected. The Corporate Board did not challenge SRAB regarding the absence of observations regarding deteriorating performance, in fact there is no evidence that SRAB meeting minutes were routinely reviewed and commented on by the corporate officers with the exception of the vice president, nuclear. Details and examples are provided in Section 2.4.4 of this report.

(3) Historically, comprehensive long-term planning has been insufficient to achieve substantial improvement in organizational performance. Recently plans have been put in place for an integrated business planning process. See details in Section 2.4.6 in this report.

(4) The Nuclear Power Group has not effectively utilized or developed more contemporary human resource and organizational development methods to assure strong management and supervisory performance. This has resulted in management performance weaknesses throughout the CNS organization, which has contributed to deteriorating plant performance. The Integrated Enhancement Plan/Business Plan currently contains some objectives toward this end and some actions, such as management development training, are ongoing. This program is however, separate from a program for management development under the sponsorship of vice president, finance and administration. Rather than use this program, NPG developed their own. This is another area where CNS could have benefited from strong corporate leadership. The example provided the team with further evidence that reinforced the view that CNS encouraged an isolationist approach with the rest of NPPD. See details in Section 2.4.6 of this report.

2.4.3 Weaknesses in Self Assessment

CNS does not have a strong self assessment culture. Although there is a guideline for the self assessment program, in some cases where a self assessment was done, it was ineffective due to a pronounced lack of a self-critical attitude. While the guideline does describe the methodology it does not include good direction and clear expectations regarding criteria for conducting formal, systematic assessments. A review of self assessment report files revealed only sporadic performance of self assessment. Also, during the DSAT review of maintenance, no reports existed when a request was made for the self assessments of MWRs and field observations required by section 8.10 of the Conduct of Maintenance procedure. When performed, the quality of the self assessments varied. Of the two reports reviewed in detail, the radiation protection effort was excelle. ι, however the SRAB assessment was marginal.

The SRAB self assessment, which was done in the third quarter of 1991, concluded that their activities were being "effectively implemented and the Board is making a meaningful contribution to the safe operation of CNS." Contrary to this conclusion, the Board did not detect or confront performance issues which were occurring at the station. A significant lack of ability to be self critical was evident. Poor conclusions not withstanding, the assessment report contained a number of comments and suggested improvements that would have improved the SRAB function had they all been acted on effectively, however they were not. A less rigorous self assessment performed in late 1993, and correspondence between the vice president, nuclear and the SRAB chairman indicated that SRAB performance issues had not been resolved.

Self assessment should also be initiated whenever a significant opportunity for learning presents itself. The CNS staff took such an opportunity by evaluating themselves against an NRC DET report for a BWR reactor facility similar to CNS. A review of 75 findings in that 1991 DET report was conducted and determined that none of the findings applied at CNS. Had the staff performed a more thorough study and taken action on some the findings, problems that are now being experienced at the station could have been identified and corrected. A close reading of the station's response revealed extensive rationalization of the seriousness of the issues and a shallow assessment of why they did not apply at CNS. One example was Item 70, where the issue was insufficient headquarters support and

oversight. The response cited several examples where this did not represent a problem, including one that the SRAB micromanages the SORC. The fact that the SRAB is micromanaging the SORC instead of assessing the effectiveness of SORC, supports the team's finding regarding the effectiveness of SRAB. That is, the SRAB and SORC lacked sufficient ability to be self critical and were not able to detect or confront performance issues which were occurring at the station.

2.4.4 Ineffective Independent Oversight

NPPD independent oversight was not effectively managed. When they had the opportunity to improve, they either missed the opportunity or, if learning occurred, (as in the case of the SRAB self assessment), follow through of the learning process was deficient. The result was an inability to assess station performance. NPPD independent oversight failed to detect the current performance deficiencies existing at CNS. Review of SRAB minutes and SORC minutes along with interviews indicated that these oversight functions believed that CNS performance was essentially strong. Unfortunately, this false sense of satisfactory performance appears to have been initially reinforced by external oversight organizations including the NRC. The performance problems subsequently identified by the NRC and the DSA are generally long standing and do not represent a rapid decrease in performance. In actuality, CNS may not have experienced a significant change in performance, but they have failed to keep up with improving industry standards. It's only the belated recognition of this that gives the appearance of a rapid decline in performance.

The quality assurance function however, differs from SRAB and SORC in that it is a standing organization charged with oversight and possessing true organizational independence. SRAB and SORC, on the other hand, are committees convened periodically, and composed largely of managers with line responsibilities. Because of these differences the causes of their respective failure to identify the performance issues also differ.

(1) The team's conclusion regarding causal factors for the SRAB/SORC failure, was based on SORC meeting observations, review of minutes, and structured interviews and include the following:

- The membership of both the committees was composed of a large component of plant line management. It is apparent that

they have been unable to succeed at differentiating their line and oversight roles. In late 1993, the vice president, nuclear communicated to the SRAB chairman commenting on this concern.

- The corporate management failed to apply the basic understanding of the role of oversight to the nuclear operation to ensure that common pit falls were avoided.

- Neither committee rigorously carried out their entire charter; SRAB's being the SRAB charter and SORC's being the technical specifications with emphasis on paragraph 6.2.1.A.4.e. In 1993, SRAB did a self assessment which identified important areas for improvement; however, there was little evidence that permanent change actually occurred.

- Neither SRAB nor SORC appear to have taken advantage of the opportunity to understand their performance deficiencies in light of and at the time of the earliest indications of the current problems.

- SRAB did not appear to have challenged the QA function when performance problems became evident.

- SRAB was not effectively challenged on its performance by executive management when problems became evident.

- SRAB minutes did not indicate that they ever seriously challenged SORC oversight performance.

(2) The QA problems were more complex. QA generally exhibited low performance combining a) a lack of vision of quality beyond compliance, b) an insensitivity to the need to evaluate performance vs. reviewing programs, and c) lack of management attention to the QA program. It was determined that QA performance may have been diluted by excessive use of their organization for performing staff duties. Additionally, the QA organization was called upon to perform the functions that will now be carried out by the independent review group function. While management had called on QA to perform these additional functions, QA did not adequately perform the

functions required by the regulations and did not uncover most of the performance deficiencies now evident in the line organization.

(3) The QA audits, surveillances and evaluations were generally compliance oriented and performance-based issues were generally superficial and caused QA's credibility with the plant staff to suffer. Further, senior management did not rely on QA as a meaningful tool for evaluation of performance-based technical matters. As a result, QA's effectiveness was significantly impeded. For example:

- The DSA team concluded that QA did not adequately follow up on open/overdue issues to ensure that they obtained senior line management sponsorship for appropriate response to their findings and concerns. This was evidenced by the large backlog of open QA findings, and the growing average days that a finding remained open. Since this is clearly a management issue, CNS management must determine what, in the way of QA follow up, works best for them. In either case, the bottom line is that response to QA issues has been deficient and must improve.

- Furthermore, QA had a weakness in identifying repeat findings to management. CNS performance has been characterized by repeat failures/events that have not been highlighted by QA even though they were identified in audit reports. If QA has pointed out repeat performance deficiencies to the line organization, their efforts were unsuccessful, and rather than emphasize the repeat nature of the deficiencies, QA has typically closed the finding if a previous finding or NCR was still open.

- As evidenced by the above, in the instances where QA identified poor performance in the line organization, response by the line organization was inadequate, and characterized by defensiveness, resistance to findings, and slow response.

- There was no evidence that SRAB challenged QA to achieve a higher level of performance nor did it bring performance deficiencies to the attention of executive management.

2.4.5 Ineffective Management Systems

Management systems appear to be weak at CNS. A consistent system for the comprehensive monitoring of plant performance, comparing it against industry standards, then holding responsible management accountable for substandard performance has not been observed. Neither collective nor individual department level indicators or management tools are available to routinely and systematically assess performance toward established goals. During many management interviews it was stated clearly that these management tools were not used. Similarly, initiatives for correction or improvement frequently languished due to a similar lack of control. Some examples include:

- Important programs, such as cobalt reduction identified by the radiation protection self assessment, Integrated Enhancement Program progress/updates, and initiatives stemming from the 1992 SRAB self assessment were not accomplished because the commitments are either not systematically tracked and/or managers held accountable.

- Important maintenance parameters are not tracked and controlled in a systematic way.

- Existing backlogs of CR's TPCNs, PCNs, PTMs, MWRs, would benefit from a systematic management approach to assure that management expectations on prompt processing and backlogs are being consistently met.

- Monthly radiation protection reports with important management control information is circulated serially, requiring time to complete the review and the distribution is followed by no clear accountability.

In summary, overall corporate performance monitoring was determined to be weak. Furthermore, the level of skills necessary to set up and manage these systems are not apparent nor is there any training being conducted to provide these skills. Strong role models, which would provide expectations regarding the need for these systems have also not been evident. Since these are universal business skills not unique to nuclear power, it could be expected that the corporate leadership would ensure that CNS is practicing them, but again that leadership was not evident.

2.4.6 Inadequate Use of Standard Human Resource Concepts

The Nuclear Power Group has not effectively utilized or developed more contemporary human resource and organizational development (HR/OD) methods to assure strong management and supervisory performance. This has resulted in management performance weaknesses throughout the CNS organization, and has contributed to deteriorating plant performance. Furthermore, the corporate HR/OD resources appear inadequate to meet the need. There are individual performance issues that have contributed to many aspects of the current performance problems at CNS, whether it has been workers choosing against their managers' expectations and not using procedures, or supervisors failing to plan, communicate, maintain accountability or follow administrative procedures; or managers choose to perform in the reactive mode, ignore industry changes or do not properly incentivize their organizations. HR/OD tools that could have helped correct this category of problems were not generally made available to the personnel at the site or, if present (such as the performance review program) not used with enough skill to affect improved performance.

Adding to the problem was that the corporate HR organization is located over 120 miles from the site with only one clerical person present at the plant. This in spite of the fact that one-third of the company's employees are at CNS. Further, interviews have indicated that the company does not to possess a significant OD capability.

Management and supervisory training was available from the corporate HR organization, but has not been utilized to a significant degree by the site organization. Interview data implied that HR assistance initiatives made toward the site were rebuffed, ignored, or given low priority. During an interview, an I & C foreman indicated that he has had three to four days of supervisory training since assuming his role five years ago. Most managers have not received any supervisory or management training.

Based on interviews, the selection process for filling management positions has been biased toward technical competence with no apparent strong analysis of management potential. In the case of supervisor selection, there remains a strong seniority component. Currently available technology for targeted selections for filling vacancies have generally not been used, reducing the likelihood of selecting the best talent for open positions from

either inside the District or, up until the most recent past, from outside sources.

Position incumbency appears unusually long. Rotation for career development is limited. During interviews, some managers stated that there were incumbents who were reluctant to assume their current positions in the first place and had made those concerns known in the selection process.

The team was informed that there is a performance review program in place, but interview feedback indicated that, while the forms are completed, real use of the program to improve personnel performance is scattered and ineffective. Discipline does not appear to be used as a tool in shaping performance.

2.4.7 Ineffective Planning and Prioritization

CNS is weak in the organizational discipline of planning and execution of plans. This has been a significant contributor towards their difficulty in achieving improvement and solving long term problems. In general, activities are not well planned, contributing to an observation that programs and corrective actions are initiated but not carried through to completion. Current programs and management controls have not required or promoted the use of strategic or tactical planning. Existing planning and scheduling systems have been ineffective. As previously noted, management has fostered an environment in which production and work accomplishment has usually been given the first priority with pressure on the staff to achieve results with minimal delay. Non-routine activities are frequently planned orally and launched without the benefit of a thorough plan. Activities were observed to "out run" plans before planning was complete or even begun. Examples include:

- Initially, there was inadequate planning and work instructions for correction of improperly engaged spade lugs in safety related terminal blocks.

- There was a poorly developed plan based on informal, verbal criteria for selection of operating experience items to review in response to an NRC Confirmatory Action Letter.

- The initial NPPD response to NRC concerns regarding preconditioning was not comprehensively planned. This resulted in ineffective field direction, communication of management expectations and management oversight. Examples of proceduralized preconditioning-conditioning were observed that were not properly nor expeditiously dispositioned in accordance with management's expectations.

- The new corrective action program was implemented in April 1994, however ownership, accountability, goals, and vision for the long-term program has not been clearly established.

- The CAP program manager and root cause team leader organization have been staffed but the group has not been institutionalized via charter statement or program plan.

- Indications are that the development of a new work control program is proceeding without a comprehensive, management accepted project plan.

- Task assignments and parameters for investigation and response to plant problems with valve lineup discrepancies and motor-operated valve testing discrepancies were unclear. The vice president, nuclear or the site manager had to intervene in both cases to ensure that safety issues were addressed and adequate plans developed.

- The absence of a centralized maintenance work scheduling process has resulted in additional equipment out of service time, lost maintenance production hours, and increased maintenance backlog. The lack of a work scheduling process also has placed a heavy administrative burden on the shift supervisor to coordinate work.

Strategic, or long-range planning, was also noted to be historically weak. Recently there appears to have been improvements in this area. In response to a growing awareness of performance problems management initiated a Near Term Integrated Enhancement Program IEP which represented a plan for near term improvement in specific areas identified as deficient. The program was published then updated in May 1994. In parallel to this effort, CNS management recognized the need for a more comprehensive, longer-term focus in today's nuclear environment, and developed a four-year business plan. The actions delineated in the IEP were integrated into the

Business Plan. In general, the new plan represented a good first step in long-range planning; however, it failed because:

- A systematic practice did not hold responsible managers accountable for timely completion of their respective actions.

- Branch Business plans, referenced in the Business Plan were not developed with appropriate staff involvement and buy in, and with sufficiently detailed tasks and responsibilities assigned to assure accountability.

- The "EXPECTED RESULTS" and "PERFORMANCE MEASURES" sections of the plan were not specific enough to enhance accountability.

- The plan did not get resource loaded along with the base line work load, and with the budgeting and control process firmly linked to the long range planning process to ensure that resources are available for improvement.

In summary, the team concluded that the IEP/BP was not fully successful due to the above factors. Further, it is the team's understanding that the business process is currently undergoing significant revision. The team did not have an opportunity to assess this new process.

2.4.8 Potentially Degraded Safety System Capability

Several issues identified by the station and the DSA team have the potential to reduce the margin of safety in important plant systems. Although some of these issues have been, or are currently being addressed by the station on an individual basis, they currently could represent a potential reduction in the margin of safety when viewed in the aggregate. The individual areas include the following:

(1) Preconditioning of equipment prior to performance testing may have corrected performance problems before they could be identified. In June 1993, the NRC identified a concern that prior to conducting secondary containment integrity tests, the station was performing preventive and corrective maintenance with the objective of passing the test, thereby precluding any opportunity to identify potential

degradation that may have occurred prior to the test. Subsequently, in May 1994, a similar situation associated with emergency diesel generator load shed testing was identified. In both cases, system performance deficiencies degradations were revealed when followup tests were performed in the absence of preconditioning. Since this time, additional examples of both procedurally established and unintentional preconditioning have been identified. Although actions have been taken to alert station personnel to identify and prevent preconditioning in the future, a review of station procedures is underway to identify additional cases, the DSA team found that insufficient guidance exists for evaluating these cases to determine whether the potential for reduced system capabilities exists due to past practices.

(2) Implementation and adequacy of the status control process does not ensure systems and components are controlled in the condition intended. Examples include the following:

- many examples of recently identified valve and switch mispositioning events
- valve lineup sheets have many known deficiencies
- clearance order program implementation problems have resulted in components being out of their required position and are violations of procedure requirements

In addition, in May 1994, a temporary blocking device (tie-wrap) was found installed on an undervoltage trip assembly of a non-essential 480 volt motor control center feeder breaker that rendered the load-shed function inoperable and could have potentially resulted in overloading of the emergency diesel generator. The blocking device was installed by procedure during the Spring 1993, refueling outage, but was inadvertently left in place due to lack of a procedure step to remove the device. The station conducted a special review of procedures that identified and corrected additional similar procedure deficiencies.

(3) There have been several recent events or adverse conditions at the station that indicate that lessons that should have been learned from

in-house and industry operating experience have not been incorporated into the station's operation. These situations have been caused by failure to conduct thorough root cause investigations, thoroughly evaluate industry operating experience, or implement enduring corrective actions. The station modified its problem reporting system, established a corrective action program manager, conducted root cause training, obtained the services of root cause analyses coaches/mentors, and is conducting a review of actions taken in response to some industry operating experience documents that date back to 1982. Nonetheless, there is a lack of rigor in recent root cause analyses, corrective actions that insufficiently address the root cause, unclear responsibility and accountability for the corrective action program, a large backlog of incomplete root cause analyses and corrective actions, questions regarding the adequacy of the industry operating experience review scope, and lack of management follow-through on the commitment to upgrade the corrective action program.

(4) The Station and corporate engineering organizations have not provided timely support to the station. Examples of issues that could potentially reduce the margin of safety include the following:

- Ongoing monitoring of the reactor equipment cooling piping had not been performed to detect continuing intergranular stress corrosion cracking (IGSCC) caused by previous system chemistry, resulting in the need for extensive system inspections when a leak recently developed.

- Only nine design criteria documents have been completed since a reconstitution effort began in 1986. In addition, activities to control station design are not sufficient to ensure analyses are based on correct and current design information; because, in part, many system engineers are unaware of how to locate design basis information.

- SORC approved MWRs were sometimes used to expedite modification to the plant. Instances were identified where the subsequent design change package corrected design errors in the MWR-implemented modification. Some design calculations were not prepared until the modification had been installed.

- The station identified deficiencies in the local leak rate test program that resulted in insufficient verification of the integrity of more than 50 containment penetrations. The DSA team identified lack of an adequate basis for acceptance criteria and valve stroke times contained in the pump and valve in-service testing program.

- Deficiencies were identified in the control of vendor manuals. In addition, about 87 safety related vendor manuals have not been reviewed to identify preventive maintenance requirements for associated components. A second review is required for about 30 additional manuals due to an inadequate first review.

- Some changes in station configuration control are not adequately reviewed or controlled to ensure the station configuration reflects station design. Examples include several hundred station-identified drawing discrepancies, relay settings that are not in accordance with current design calculations, standby gas treatment check valves that have been removed, drawings that do not identify expected valve positions, drawings that show valve positions that differ from valve lineup checklists, and procedures that permit shift supervisors to change valve lineups from those shown on drawings.

(5) Work activities on plant equipment are frequently started before a fully planned work package is available, and without first determining if other related work activities should be performed concurrently. This resulted in excessive system outage durations since systems are repeatedly removed from service because no work was able to be performed in accordance with vendor specifications due to insufficient procedural guidance and inadequate work plans. It was noted that these problems may be related to adverse trends over the last three years in HPCI system and diesel generator system unavailability.

(6) Maintenance is not consistently performed to assure equipment availability. Previous maintenance activities have resulted in nonconforming conditions, degraded plant equipment, increased out-of-service time, and rework. Examples include recent RHR pump overhauls using special instructions in place of approved procedures, replacement of emergency diesel generator components without a

procedure, 4160 volt circuit breaker misalignment problems, and rework to adjust the service water pump impeller clearance.

Some long-standing equipment problems have not been identified for corrective action. In addition, the team found a number of station-identified problems on important equipment that represent a potential challenge to plant operations. Examples include continuing problems with the main turbine bypass valves, excessive silt in the service water system that is compensated by operation of shutdown cooling with full service water flow and throttled reactor coolant flow (through a valve that isn't designed for throttling), silting that plugs instrument sensing lines, drywell sump level switch reset problem, excessive seat leakage on a reactor feedwater pump that necessitates closure of a manual valve and extra demands on operators, spurious actuations of the standby gas treatment system fire detector resulting in manual isolation of the deluge valve and the need for local operator action in the event of a fire, and unexpected opening of HPCI, RCIC, and core spray system pump minimum flow valves during surveillance tests.

2.4.9 Additional Observations

2.4.9.1 Resources

CNS appeared to have had the financial resources available to conduct a quality operation. Staffing has been appropriately studied and is adequate in most areas. Where deficiencies were noted, appropriate actions are being taken with the possible exception of short-term responses to needs generated by an accelerated event investigation program. Funding appears to have been adequate. The Electric Utility Cost Group (EUCG) three year rolling average O&M costs, less fuel, $/installed KW, placed CNS in the second quartile, slightly less than the industry median. Senior plant management stated that funding has been adequate. Interviews of corporate financial managers indicated that the budgeting process generally provided the nuclear operation with requested funding.

With regard to staffing, a recent study indicated that staffing tended to be slightly low in the site engineering group and in maintenance. This was based on steady state, non-outage expected staff levels reported in the "1994 Staffing Analysis Report" by Tim D. Martin & Associates, Inc. The engineering management indicated that engineering staffing increases were

in progress. Maintenance staffing was more complex however, since the study indicated that maintenance was low, and in the judgment of the DSA team, based on historic backlog performance and current planning and scheduling issues, there has been no apparent significant shortage of mechanics. On the other hand, staffing for the planning and scheduling function may not be sufficient. Recent expansion of the operating experience assessment function has locally stressed station and corporate staffing. In summary the team concluded that, although the staffing study indicated only localized shortages, the current performance improvement efforts will probably place significant additional stress on the organization. However, without the benefit of effective work planning and prioritization and good long range planning, resource utilization effectiveness could not be determined.

2.4.9.2 Budget and Control

The team concluded that the systems in place for budget and control are conventional and adequate to support improving performance if coupled to the new Business Planning process. Budget and control activities have been conducted in a manner not atypical to other facilities. Financial requirements are generated at appropriate levels within the organization and rolled up to the corporate level. Reasonable challenges are given throughout the process. Reports containing actual O&M expenditures, on a booked basis, versus budget are compiled monthly by a site accountant and forwarded to the responsible managers. Nuclear normally budgets an O&M annual contingency of approximately 4%.

Capital budgeting was also determined to be conventional. The budget was typically not fully spent due to limitations in the execution of spending plans. Carry over of unspent capital was practiced giving greater assurance that funding for necessary improvements and repairs was available.

As mentioned previously, funding for the nuclear program appeared to be adequate for normal activities but the budget and control process is not well tied to the long range planning process. Instead, it appears that resource planning has traditionally been based on historical performance with programmatic escalators added in.

3.0 ROOT CAUSES

3.1 Senior management has been ineffective in establishing a corporate culture that encourages the highest standards of safe nuclear plant operation.

Station and corporate management has been ineffective in fostering a heightened sensitivity and awareness to issues that affect nuclear safety. Weaknesses in nuclear safety consciousness have resulted in station programs and processes that do not promote the highest standards of nuclear plant operation. Key elements of a nuclear culture - continuous improvement, learning from experience, conservative decision making and a questioning attitude - were found to be lacking at CNS. The net result was that long-term performance became governed more by the bounding conditions of problems, often regulations, rather than being under the careful guidance of a management team with high performance standards. These weaknesses were evident in many of the performance issues identified during the assessment including:

- work processes and procedures that favor production over doing it in accordance with industry standards
- programs and processes that are intended to meet requirements rather than high performance standards
- a lack of critical review and oversight by all levels of station and corporate management.

Station and corporate management failed to establish rising standards for personnel and plant performance that is evident throughout the nuclear industry. Complacency, exhibited by programs and processes that "do business the way it has always been done," has contributed to the station's inability to keep pace with the nuclear industry's rising standards of excellence. Lack of corporate support in strategic business planning, engineering, human resources and critical assessment of performance further demonstrates weaknesses in senior management understanding of and sensitivity to nuclear plant operations.

3.2 Senior Management did not establish the vision supported by adequate direction and performance standards to improve station performance.

The team found that the CNS management was focussed on immediate, real-time issues and frequently did not apply longer range vision, provide the necessary levels of direction with clear ownership and strong contemporary standards of performance to plant programs and problems.

- Failure to establish and enforce high performance standards at the station contributes to many of the performance weaknesses observed. Low performance standards often led the CNS staff to make decisions that expedite the resolution of the issue at hand without full consideration of the long term impact on safe and reliable plant operation.

- Combined with these low standards, and a lack of vision and direction has helped perpetuate unsuccessful programs and weakly resolved problems. Managers, caught up in immediate activities, have failed to recognize the need for broader, longer range actions. Many issues were exacerbated by narrowly framed solutions. Lack of performance standards resulted in shallow technical evaluations and a lack of recognition of, or acceptance of, long-term problems. The team found high levels of maintenance re-work and excessive reliance on skill-of-the-craft for field problem solutions. In several cases, fundamental quality requirements such as torquing, foreign material exclusion, and vendor instructions were not applied to safety related maintenance. Ongoing problems with plant and system status control, procedure quality and adherence, the lack of a strong work control program, weak industrial safety practices, ineffective independent oversight and quality assurance program, and a general problem of inadequate programs that do not meet regulatory requirements, all reflect standards which have not kept pace with industry practice.

- Mid- and long-range planning has only occurred on a limited bases. The NPG Business Plan has articulated an organizational vision which emphasizes high safety standards, reliability, and cost effective production. Although management has had a growing awareness of a less than adequate performance and has begun to apply their vision of

desired performance by way of the Integrated Enhancement Plan and the NPG Business Plan, implementation of these plans have suffered from lack of accountability and have also been overtaken by plant problems and restart activities.

- Corporate management, except for the vice president, nuclear, has had little apparent involvement in helping set the direction for the NPG.. Corporate management has not demanded strong oversight of NPG activities, and has been ineffective in providing direction and support in areas where the corporate staff should be capable, such as human resources and organizational and management development.

- The lack of vision and direction has also extended into program development and implementation. For example, man, of the plant programs (ISI/IST, Appendix J, engineering programs for vendor manuals, equipment performance monitoring, etc.) have been identified as problematic by the station and were included in past improvement plans. Few of these have had extensive or structured input from management which reflects their published vision and expectations for performance. Insufficient management direction has been the primary cause for ineffective and untimely engineering support. Although existing programs contain management expectations for engineering duties, management's assignment of reactive workloads to engineers has effectively precluded the staff from fulfilling these expectations of dealing with the routine workloads and improvement efforts.

3.3 Ineffective monitoring and lack of critical self assessment have prevented management from recognizing program and process deficiencies and making the necessary improvements.

Many of the performance problems observed by the team and other external organizations could have been identified by effective management monitoring and self assessments of station performance. Examples of this include:

- Ineffective engineering support evidenced by their inability to recognize and correct system and equipment degradation, excessive backlogs and delays in completing important work such as design basis documents and vendor manual upgrades.

- Failure to recognize long-standing equipment problems noted during maintenance, such as the RHR heat exchanger primary water leak.

- Excessive rework, which contributed to increased system and equipment unavailability, caused by a lack of monitoring of work in progress, not providing adequate QC, and poor maintenance work procedures and practices.

- Lack of monitoring and feedback by the line organizations to the training department regarding the quality of, or lack of, training.

- Ineffective corrective action program monitoring and adjustment..

Independent quality oversight by NPPD has been similarly ineffective. The SRAB has failed to provide oversight by not challenging QA, not recognizing plant performance deficiencies, and not correcting recognized weaknesses in its own performance. Quality Assurance oversight has been ineffective because of its inability to detect performance deficiencies, inability to influence line management when weaknesses were identified, and an inclination toward compliance oriented performance.

3.4 An ineffective management development program has resulted in a lack of management and leadership skills necessary to ensure that strong leaders and managers are available to fill key corporate and station positions.

NPPD has not adequately addressed the management developmental needs of the organization and its employees. This is evidenced by:

- The lack of a human resources professional presence at CNS despite the fact that one-third of NPPD's employees work at the site.

- Supervisory and managerial selection is biased toward technical versus managerial abilities. Once placed into a supervisory position, minimal supervisory training is provided. The training that is provided is not based on any assessment of the individual's needs.

- Skills were lacking for conducting comprehensive monitoring of plant/departmental performance, comparison of this performance

against established standards, and holding the responsible management accountable.

- There is no apparent succession plan in place for developing a cadre of potential future leaders, managers, and supervisors.

4.0 EXIT MEETING

An exit meeting was held on August 19, 1994. The exit presentation material is provided at Appendix C.

APPENDIX A

COOPER NUCLEAR STATION
DIAGNOSTIC SELF ASSESSMENT
TEAM MEMBERS

Team Manager:	Ralph E. Beedle
Assistant Team Manager:	Donald A. Beckman President Beckman and Associates, Inc.
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Engineering and Technical Support:	Robert G. Azzarello Director, Design Engineering Waterford 3 Steam Electric Station
	Charles R. Brooks Program Manager Institute of Nuclear Power Operations
	Joseph L. Connolley Supervisor - Test and Performance Engineering Fort Calhoun Station
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	Steven B. Eisenhart Nuclear Specialist Virginia Power
	Harry Kister Senior Consultant Beckman and Associates, Inc.

Robert D. Ryan
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APPENDIX B

NPPD/CNS ORGANIZATION CHARTS

APPENDIX C

EXIT PRESENTATION

APPENDIX D
ABBREVIATIONS

AC	alternating current
ADAM	atmospheric dose assessment model
ADV	atmospheric dump valves
AEOD	Office for Analysis and Evaluation of Operational Data
AO	auxiliary operator
AOV	air-operated valve
ASME	American Society of Mechanical Engineers
BWROG	Boiling Water Reactor Owners Group
CAL	Confirmatory Action Letter
CAP	Corrective Action Program
CCW	component cooling water system
CEO	Chief Executive Officer
CFR	Code of Federal Regulations
CM	corrective maintenance
CNS	Cooper Nuclear Station
CO	clearance order
CRG	Condition Review Group
CRT	Condition Review Team
CST	condensate storage tank
CV	control valve
DBD	design basis documentation
DC	direct current
DE	diagnostic evaluation
DEH	digital electro-hydraulic
DG	diesel generator
DOG	deviation from outage guidelines
dp or d/p	differential pressure
DR	deficiency report
DSA	diagnostic self assessment
DSAT	Diagnostic Self Assessment Team
ECCS	emergency core cooling system
EDG	emergency diesel generator (DG)
EDSF	electrical distribution system functional inspection
EOP	emergency operating procedure
ESF	engineered safeguards features
EUCG	Electric Utility Cost Group

FO	fuel oil
FSAR	final safety analysis report
GE	General Electric (Corp)
GL	generic letter
HPCI	High Pressure Coolant Injection
HPES	Human Performance Evaluation System
HR	Human Resources
I&C	Instrumentation and Controls
IEP	Integrated Enhancement Plan
IGSCC	Intergranular stress corrosion cracking
IN	information notice
INPO	Institute of Nuclear Power Operation
IPE	individual plant examination
ISI	inservice inspection
IST	inservice testing
JCO	justification for continued operation
JPM	job performance measures
KW	kilowatt
LAO	licensed auxiliary operator
LCO	limiting condition for operation
LER	licensee event report
LLRT	local leak rate testing
LOCA	loss-of-coolant accident
LOOP	loss of offsite power
LPCI	low pressure coolant injection
MIS	management information system
MOV	motor-operated valve
MS	main steam (system)
MSIV	main steam isolation valve
MSLB	main steam line break
MWR	Maintenance Work Request
MSSV	main steam safety relief valve

NPG	Nuclear Power Group
NPPD	Nebraska Public Power District
NPRDS	Nuclear Plant Reliability Data System
NPSH	net positive suction head
NRC	Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation
OD	organizational development
OE	operating experience
OER	operating experience review
O&M	Operations and Maintenance
PCS	primary coolant system
PCN	procedure change notice
PM	preventive maintenance
PMWT	primary makeup water tank
PRA	probabilistic risk assessment
PTM	plant temporary modification
QA	quality assurance
QV	quality verification
RB	reactor building
RCM	reliability-centered maintenance
REC	reactor equipment cooling
RFP	reactor feed pump
RHR	residual heat removal system
RCIC	Reactor Core Isolation Cooling
RPS	reactor protection system
RPV	reactor pressure vessel
RR	reactor recirculation (system)
SALP	Systematic Assessment of Licensee Performance
SE	shift engineer
SER	Significant Event Report
SFHM	spent fuel handling machine
SGTS	standby gas treatment system
SI	special instructions
SORC	Station Operations Review Committee

SRAB	Safety Review and Audit Board
SRM	startup rate monitor
SS	shift supervisor
STO	switching and tagging order
SW	service water system
TBV	turbine bypass valves
TDC	temporary design change
TOL	thermal overload
TPCN	temporary procedure change notice
TS	Technical Specifications
UFSAR	Updated Final Safety Analysis Report
USQ	unreviewed safety question
UVTA	undervoltage trip assemblies
VM	vendor manual
VOTES	valve operation test evaluation system
VP	Vice President
WO	work order