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**Agency:** Nuclear Regulatory Commission
Advisory Committee on Reactor Safeguards

**Title:** Subcommittee on the Systematic Assessment of Experience, Proposed Power Level Increase for Indian Point Nuclear Generating Station Unit 2

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UNITED STATES NUCLEAR REGULATORY COMMISSION'S

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

DATE: February 6, 1990

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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

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SUBCOMMITTEE ON THE SYSTEMATIC

ASSESSMENT OF EXPERIENCE

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PROPOSED POWER LEVEL INCREASE FOR INDIAN POINT

NUCLEAR GENERATING STATION UNIT 2

Nuclear Regulatory Commission
7920 Norfolk Avenue
Phillips Building, Room P-110
Bethesda, Maryland

TUESDAY, FEBRUARY 6, 1990

The Committee met, pursuant to notice, at 8:30 a.m., HAL W. LEWIS, presiding.

ACRS MEMBERS PRESENT:

HAL W. LEWIS, ACRS SUBCOMMITTEE CHAIRMAN

CARLYLE MICHELSON, ACRS MEMBER

CHARLES J. WYLIE, ACRS MEMBER

DAVID A. WARD, ACRS MEMBER

IVAN CATTON, ACRS MEMBER

JAMES C. CARROLL, ACRS MEMBER

HERMAN ALDERMAN, COGNIZANT ACRS STAFF MEMBER

PARTICIPANTS:

DONALD S. BRINKMAN, NRC/NRR

CURTIS COWGILL, NRC/RI

PETER KELLEY, NRC/RI

ROBERT CAPRA, NRC/NRR

TIMOTHY COLLINS, NRC/NRR

ROBERT A. HERMANN, NRC/NRR

MARTIN R. HUM, NRC/NRR

BARRY J. ELLIOT, NRC/NRR

JAY L. LEE, NRC/NRR

JIN-SIEN GUO, NRC/NRR

ARNOLD J.H. LEE, NRC/NRR

DON R. LASHER, NRC/NRR

STEVE BRAM, CON EDISON

CHARLES JACKSON, CON EDISON

LOU LIBERATORI, CON EDISON

ROY KIM, INDIAN POINT

BARB SAMARDZICH, INDIAN POINT
GARY AMENT, INDIAN POINT
DON DURKOSH, INDIAN POINT
BOB MCFETRIDGE, INDIAN POINT
PETE SKULTE, INDIAN POINT
LARRY SMITH, INDIAN POINT
SEENA SRINIVAS, INDIAN POINT
PAUL MALIK, PMX INC.
BRENT BRANDENBERG, CON EDISON
TOM THOMAS, INDIAN POINT
JAY AKERS, INDIAN POINT
BILL BENNET, CON EDISON
ALBERT VAIA, INDIAN POINT
WALTER MOOMAN, INDIAN POINT
JUDE G. DELPERCIO, INDIAN POINT
GETACHEW TESFAYE, INDIAN POINT
ROBERT R. LAUBHAM, INDIAN POINT

PROCEEDINGS

[8:30 a.m.]

MR. LEWIS: Let's begin our meeting.

This is a meeting of the ACRS Subcommittee on the Systematic Assessment of Experience, and it's about a proposed power-level increase for Indian Point Nuclear Generating Unit Number 2. It's approximately a 10-percent increase that is being requested.

The meeting will come to order.

I am Hal Lewis, Chairman of the Subcommittee.

The other ACRS members around are Carl Michelson, Charlie Wylie, Dave Ward, Jay Carroll, and Ivan Catton, and the cognizant ACRS staff member for today's meeting is Herman Alderman, to my right.

The rules for the meeting have been announced as part of the notice in the Federal Register, January 23, 1990.

The meeting is being conducted in accordance with the provisions of the Federal Advisory Committee Act and the Government in the Sunshine Act, and we have received no written or additional oral statements from members of the public.

It would be helpful of everyone who spoke would (a) speak into a microphone, speak clearly and intelligibly so that the recorder can make a good record.

The general pattern we will follow be that during the first part of the morning, we will hear from the NRC staff about their views on the request for a power increase, then from the licensee, and then, heaven willing, we will take a short break, and then decide what we want to do.

Do any other members of the Subcommittee want to say something before we get cracking?

[No response.]

MR. LEWIS: Okay. In that case, my understanding is that our first speaker is Curt Cowgill from NRC Region 1, and I would request the people try to keep roughly on schedule, because I will get tough if we get very far off. Okay?

MR. CAPRA: Yes, Sir.

I'm Bob Capra. In my position in NRR, I am the project director responsible for Indian Point.

Prior to Mr. Cowgill's presentation, Don Brinkman, the Indian Point 1 project manager, will make a short presentation.

MR. LEWIS: That's fine. Sure. Go for it.

[Slide]

MR. BRINKMAN: Good morning.

My name is Donald Brinkman. I am the NRC project manager for Indian Point 2.

We are here today to provide you with a briefing on the licensee's proposal to increase the thermal power at Indian Point 2.

My project director, Bob Capra, is here with me.

Staff member, Curtis Cowgill, from Region 1, Tim Collins, and Bob Hermann will also be making part of the staff presentation.

We are accompanied by additional staff members who participated in the preparation of the staff safety evaluation. They will answer questions that you may have on the safety evaluation.

The licensee has representatives here, too.

[Slide]

MR. BRINKMAN: Our plans for today's presentation are that Mr. Cowgill will provide a discussion of operational experience at Indian Point 2. That will be followed by the licensee's presentation. Then I will come back and give an overview of the staff's evaluation. Assisting me will be Tim Collins, providing a discussion on the ECCS portion of the evaluation. Robert Hermann will give his discussion on the steam generators. And I will come back and give a final conclusion.

So, now, I'd like to introduce Mr. Cowgill, who will provide you with the Region 1 perspective.

[Slide]

MR. COWGILL: Good morning.

My name is Curt Cowgill. I'm currently a project section chief in Region 1, with responsibilities for both the Indian Point Unit 2 reactor facility and the Calvert Cliffs facility in Maryland.

I have just recently been assigned this project within the last month. I have the resident inspector from Indian Point Unit 2, Peter Kelley, here with me this morning to help me answer your questions.

My background -- I was an officer in the Navy nuclear power program until 1979. At that time, I came with the NRC. I have been senior resident inspector at two facilities. I was part of the NRC's staff that oversaw the cleanup of TMI-2 for some period of time. My most recent responsibilities, prior to Indian Point and Calvert Cliffs, I was the section chief responsible for the GPU nuclear plants and Duquesne Light.

[Slide]

MR. COWGILL: I would like to discuss with you a number of items this morning, associated with recent operating experience at Indian Point 2. I would like to talk about the 1988 steam generator dryout event, discussion of trips, operator professionalism, support, operating procedures, and the operator qualification and requalification program.

My understanding is that after the steam generator dryout event in 1988, the ACRS staff and Committee was briefed. So, I will keep my remarks concise in that area.

The most significant event that we have evaluated in the previous 2 years at Indian Point was the dryout event of the steam generator in January 1988, following a refueling outage, during the reactor startup.

During the plant heatup, a high rate of steam leakage through the steam generator and its associated MSIV, with the lack of normal makeup capability in the steam generator, resulted in a total loss of inventory, or dryout, in the steam generator.

The process was of a protracted nature. It took about 36 hours and existed for an additional 24 hours before being recognized by the utility management.

When plant management became aware of the event, appropriate analyses were conducted to assure that recovery actions were taken to refill the steam generator such that it would not result in equipment damage.

An NRC augmented inspected team was sent to the site to evaluate the event and the circumstances leading to the event.

The team noted that a tagged out auxiliary feedwater pump, coupled with a leaking MSIV, inappropriate use of emergency procedure analysis, inadequate communication and control of operations by management, as well as a number of procedural adherence problems, led to the event.

MR. MICHELSON: Question.

MR. COWGILL: Yes, Sir?

MR. MICHELSON: There must be a number of instruments that tell you how much water there is in the steam generator. What happened to those?

MR. COWGILL: Pete, why don't you come up to a microphone?

MR. KELLEY: I am Peter Kelley. I am the resident inspector at Indian Point Unit 2.

They were operating at the time, and the operators did recognize the fact that the inventory in the steam generator had gone away, but due to other actions going on and trying to start up the plant, this got kind of buried under some other jobs that the operators were doing at the time.

MR. MICHELSON: Well, there must be some kind of a redline on the meter or something that says don't operate below this level, and when you get down there, you'd better do something. Isn't there any -- there must be alarms, even, that says you're running on low water.

MR. KELLEY: They do have alarms, and they do have indications.

MR. MICHELSON: They ignore all these?

MR. KELLEY: They don't have a specific line on the chart recorders themselves that says don't go below --

MR. MICHELSON: "Redline" is sometimes, you know, just a commonly-used term.

MR. KELLEY: They do have alarms to indicate the level --

MR. MICHELSON: And they ignored the alarms, apparently. If the instruments were working, they would have gotten alarms.

MR. KELLEY: Alarms were in. At the time of the startup, when they are heating up, they have a lot of alarms in at that time, and it's believed that this was one more alarm that did come in, and due to other actions going on, somehow it was --

MR. MICHELSON: That's not a very comforting explanation, to be without water for so long. You know, water is one thing that's pretty important in a boiler, as you well know.

MR. LEWIS: The direct answer is the alarm went off, and they ignored it.

MR. MICHELSON: They ignored it, apparently.

MR. KELLEY: Well, the alarm was in. As Curtis had said, it took about 36 hours for this evolution -- for the complete dryout to occur.

MR. LEWIS: Well, is what I said wrong? The alarm went off, but they ignored it. It may not be a fair way to state it.

MR. KELLEY: I think that's a correct statement. I think that's correct.

MR. LEWIS: Could I ask another question, since you're interrupted?

I missed the words "inappropriate use of emergency procedure analysis". I am not quite clear what that means.

MR. COWGILL: Peter, can you help me a little bit there?

MR. KELLEY: I'm sorry. I didn't hear the question.

MR. COWGILL: The inappropriate EOP analysis that they performed during this event.

MR. KELLEY: In the basis for the EOPs, they have -- highly-developed EOPs is in this EOP guidance, and in the basis or in this guidance, it says just how many -- I believe it was how many cycles, thermal cycles, can a steam generator go through, and I believe it had in there how to recover from this event.

MR. LEWIS: What he said was something like inappropriate application or use or emergency procedure analysis. That means that the emergency procedure was wrong or that they used it wrong?

MR. KELLEY: They used the basis, the EOP basis, not the EOP itself. None of the action statements in the EOP was used. It was the actual basis that was used to develop the EOP was used.

So, the operators felt that using the -- if they can use the EOP basis, they would be okay.

MR. LEWIS: I don't understand that, because the point of an emergency operator procedure is that you are supposed to follow the procedure that somebody else has worked out in advance. Did they elect not to follow it because they didn't trust it?

MR. KELLEY: Well, there is really no EOP for this steam generator dryout. People were searching for a way to get out of this problem, and they found an EOP which had some -- a basis which had some guidance as to how to get out of it, and that's what they used.

MR. LEWIS: So, there was no EOP, and they improvised, and you are saying they improvised on an incorrect basis.

MR. KELLEY: That's correct.

MR. LEWIS: That's slightly different from what you said. Okay.

MR. CARROLL: Now, what were they trying to get out of? They were trying to figure out how to get water back into it?

MR. COWGILL: They were trying to recover from the dryout event. Initially, the shift began to perform a task to recover, independently. When management was made aware of the event, management told them to stop, and the utility developed a method for recovering level.

MR. CARROLL: How are you using the word "management"?

MR. COWGILL: I'm using the word -- management above the shift senior plant management at the facility. That is the "management" I am referring to.

MR. CARROLL: So the shift supervisor or whatever, he's called as management the way you're describing it.

MR. COWGILL: Not in the context that I used the term, sir.

MR. CAPRA: If I can clarify one point to put it in perspective. When this particular event happened, the plant was coming out of an outage. There was a lot of maintenance going on, a lot of systems being returned to service, a lot of systems being tested.

This wasn't a situation where the plant was shut down, all systems were returned to normal, and it was a normal plant startup. One of the problems was inadequate control of systems to bring the plant to startup and lack of contingency plans in the event things failed.

There were a lot of lessons learned out of this particular event.

MR. MICHELSON: Are the procedures for the plant symptom-based procedures now or event-based?

MR. KELLEY: For the EOPs?

MR. MICHELSON: Yes. The guidelines were written for symptom-based procedures. I just wondered if they have implemented those guidelines into procedures. The question is do you think they're symptom-based procedures?

MR. KELLEY: The EOPs are symptom-based.

MR. MICHELSON: Isn't one of the symptoms low water in the steam generator? Don't you go to the appropriate action statements for that situation?

MR. KELLEY: There is no EOP specifically for, say, just a dryout or a low level in the steam generator.

MR. MICHELSON: You mean there's nothing --

MR. KELLEY: They do have alarm or abnormal procedures for low levels in the steam generator.

MR. MICHELSON: Clearly, low water in the steam generator is an abnormal condition and that's a symptom of something. Don't you go to the procedures where it starts getting into low water in the generator and what to do?

MR. KELLEY: Not in the EOP.

MR. CARROLL: Strange.

MR. MICHELSON: Very strange. I thought that's what they were supposed to do.

MR. CARROLL: Is the distinction the fact that EOPs -- I don't agree with this -- but EOPs in general deal with events occurring during power operation as opposed to during shutdown or startup.

MR. KELLEY: That's true. During a startup evolution. During a startup; say, if they would have had a reactor trip and then, of course, that is an EOP itself and they were going through that EOP.

MR. CARROLL: Low level would have produced a reactor trip if they had been at a higher power.

MR. KELLEY: If they were actually critical.

MR. COWGILL: This event occurred, if I'm not mistaken, about 325 degrees Fahrenheit. Is that correct?

MR. MICHELSON: That's right.

MR. KELLEY: About that, yes.

MR. COWGILL: They were heating up on pump heat.

MR. MICHELSON: It's the old question of what do you do when you have an accident during shutdown; what procedures do you follow.

MR. CARROLL: Where was the steam going out of this generator?

MR. KELLEY: They had a main steam isolation valve --

MR. CARROLL: Valve open.

MR. KELLEY: -- seam leakage and it was leaking out there. Plus, also at the time, the auxiliary water feedwater pump that fed that steam generator was tagged out for additional maintenance. So due to the steam leak and not being able to add water to the generator, that's how it dried out within that 36 hour time span.

MR. CARROLL: So steam was going through the MSIV and through drains?

MR. KELLEY: I would imagine going through steam traps.

MR. CARROLL: I'm not totally clear on the 36 hours that's been referred to. That's how long it took to get to the dryout?

MR. KELLEY: That's correct.

MR. CARROLL: Then how long was the steam generator dry?

MR. COWGILL: Another 24 hours, sir.

MR. KELLEY: About another day after that.

MR. CARROLL: So now I get down to a dry generator. What happened during the 24 hours?

MR. KELLEY: During the 24 hours, Con Ed was trying to determine just how to refill the steam generator again, because they were --

MR. CARROLL: Worried about --

MR. KELLEY: They were heated up at the time and there were concerns about using -- this was in January. There were concerns about using the colder water in the condensate storage tank and just how fast it should be added.

What eventually happened was a sluicing operation from one of the other generators which had warm water in it, from one of those generators to the dried out steam generator. That's how they recovered from the event.

So it took that long to determine just what course of action to take.

MR. MICHELSON: What was the primary temperature, primary side?

MR. KELLEY: I would really have to look it up. It was probably about 350 or so.

MR. COWGILL: Yes. 325 to 350 is what we had, sir.

MR. CARROLL: Now, at what point did people realize they had a problem in this 36-plus-24 hour period?

MR. KELLEY: The operators at the time, they knew they had a problem just a little bit before the end of that 36 hour time span, before it completely got dried out.

MR. CARROLL: How about "management?"

MR. KELLEY: As was stated, it was about a day after, 24 hours after the dryout.

MR. LEWIS: They knew they had a problem, but they simply went to bed and didn't tell anybody?

MR. KELLEY: That's where the communications aspects come in. There were some problems with whether the operators had informed the senior watch supervisor or not that the dryout had occurred. Again, as was said, there were a lot of other activities going on at the time.

MR. LEWIS: There are always a lot of other activities going on at the time.

MR. KELLEY: This time, probably, they were going a little bit too fast.

MR. LEWIS: Please go on.

MR. CARROLL: I just have one more question. Whatever you call the most senior person on shift knew about this on a continuing basis. Now, who was he supposed to tell and when did he tell him, or is my first statement right?

MR. KELLEY: I would really like to look that up just to get who knew what when and who told who when.

MR. COWGILL: Peter, I've got a copy of the executive summary and the conclusions from the inspection report in my notes. So we could look that up for you. Would it be okay to answer that question a little later?

MR. CARROLL: Sure. That would be fine.

MR. COWGILL: Would you like me to continue now, sir?

MR. LEWIS: Yes.

MR. COWGILL: From the NRC inspection staff's perspective, we believe that in the recent operating history, the dryout event was really about the low point of the operation at the facility.

There was a confirmatory action letter issued. There was a management meeting in Region I to discuss the corrective actions taken by the utility prior to the Regional Administrator agreeing to restart of the facility.

Indian Point, in its early operating days in the middle 1980s, had a fairly high reactor trip rate. Over the last two SALP cycles, basically the 1986 to 1990 timeframe, we've seen a dramatic reduction in the operating trip rate.

There has been one reactor trip during this cycle. We see the utility continuing this trend and we believe this is a positive attribute.

As a result of the dryout event, there were a number of things done by the utility to improve their operation. Certainly, one of them was improving operator professionalism. After the dryout event, the operators themselves wrote an Operator Code of Conduct. It was developed by the operators. It was formally presented to Region I staff.

Indian Point operators on a 12-hour rotation. Recently, in the spring of 1989, after exams, they went to a six-shift rotation which improved a number of things, which included overtime usage.

We believe the operator control is good. We believe their interaction with other departments is generally good. We believe that shift turnovers, which were a problem associated with this event, have improved since that time. We believe they are formal and effective at this point.

We see a continuing trend of improved performance with respect to procedural compliance. There has also been --

MR. WARD: You said they went from -- they had been on 12-hour shifts?

MR. COWGILL: They are still on 12-hour shifts. They went from a five-shift rotation to a six-shift rotation, sir.

The operating shift itself consists of one shift supervisor, which is titled Senior Watch Supervisor, at the facility; one watch engineer, which is their shift technical advisor; a senior reactor operator who is assigned to the control room; two reactor operators; and, seven nuclear plant operators or auxiliary operators, non-licensed staff. That is their shift complement currently.

MR. CARROLL: During the steam generator dryout event, was that shift organization augmented because they were in a startup situation?

MR. COWGILL: I'm going to have ask Peter again, because I wasn't there.

MR. KELLEY: I believe at the time, in 1988, they were still on 12-hour shifts. I don't know how many rotations they had.

MR. WARD: They are on 12-hour shifts today.

MR. COWGILL: Peter, they say was the shift augmented, additional operators for the startup?

MR. KELLEY: Maybe the licensee would know about that at this time, but I don't.

MR. MICHELSON: Is the 12-hour shift a common thing in the industry or just an occasional? Most of the utilities, I thought, had less than 12-hour shifts.

MR. COWGILL: I can only speak for my most recent experience. I've now had experience with, I guess, about half-dozen utilities directly. This is the first utility I have had experience with that has a permanent 12-hour shift rotation.

MR. MICHELSON: I thought that was kind of unusual.

MR. COWGILL: I have not had any real time to evaluate how it works. It apparently works for them, but most other utilities don't use it as a general practice.

MR. MICHELSON: Does the staff know to what extent 12-hour shifts are used in this country?

MR. CAPRA: I don't have an exact count. I did see a listing of shift rotations and the longevity of shifts recently in a printout for all operating plants. I believe there were somewhere in the neighborhood of a dozen to 15 or so that had 12-hour shifts.

MR. MICHELSON: Maybe ten to 12 percent or so.

MR. CAPRA: Sure.

MR. WARD: Curt, we've heard perhaps more than we should have about this event of two years ago, but a number of actions have taken place since then and I guess the important thing today is what indications do you have that these actions have corrected whatever problems that existed two years ago?

MR. COWGILL: I tried to articulate those, but maybe I can do it again. One, we believe the shift turnover process, which was a contributor to the event, has improved. We believe that the formality of the operators is better.

The operators themselves have written a Code of Conduct. They adhere to it. We believe that the interactions with other departments is good. We have seen an improved communication within the shift and with plant management.

As a result of this event and in the SALP period for that period of time, and SALP was extended to include the steam generator dryout event, the utility was given a two-declining with some fairly strong words from the regional management and a recommendation for an improvement program.

The most recent SALP, which ended last year, Category II with no trend assigned, was assigned. Although inconsistencies were still noted, a number of improvements had been noted. In our most recent mid-cycle SALP, we identified to the utility that we saw continued improvement in the operations area. We are comfortable, at least at this point, that the indications we saw on the 1988 dryout event have not recurred and the utility has learned from that experience and has improved its operation in this area.

MR. WARD: So these are changes not only in the right direction, but you are convinced these changes have taken hold.

MR. COWGILL: Yes, we are. We are convinced that these changes have taken hold and are improving the overall operations.

MR. KELLEY: Plus, also, coming out of the last outage, we did do a restart inspection which concurred our findings that Con Ed is kind of on an increasing or improving trend with regard to operations.

MR. WARD: A restart inspection; what is that exactly?

MR. KELLEY: Basically, watching the startup.

MR. COWGILL: Observing activities associated with preparing the plant for restart and observing some aspects of the restart activity. Periodically, we do that.

MR. WARD: Was this after a similar shutdown? I mean, is your point that the situation during this inspection was similar to what existed in January of 1988 at the plant?

MR. KELLEY: Yes.

MR. COWGILL: The plant was coming out of its next refueling outage in the summer of 1989 and we conducted inspection at that time, sir.

MR. WARD: Thank you.

MR. CARROLL: What were the residents doing during the January 1988 36-plus-24 hour situation?

MR. KELLEY: We're not there all the time. We're not there 24 hours a day. We do make it a habit to go in to watch evolutions, such as startups and shutdowns and after-reactor trips, but myself and the senior resident inspector at the time were not in there at the time watching the startup. The startup from cold shutdown to actual criticality can take several days to do.

MR. CARROLL: You weren't there at any time during this 24-plus-36 hour period?

MR. KELLEY: We were there during the part when they were trying to figure out what to do.

MR. CARROLL: That was after they realized they had a dry generator.

MR. KELLEY: That's correct.

MR. MICHELSON: When a resident enters a control room routinely, does he sometimes look at the alarm board just to see what kind of alarms they're running with?

MR. KELLEY: On a routine basis, yes.

MR. MICHELSON: And he didn't, apparently, in this case, notice they were running with low water in the steam generator?

MR. KELLEY: As I said, at this time --

MR. MICHELSON: That's right. You said he wasn't there any time during the 36 hours when he would have noticed that; is that right?

MR. KELLEY: One would hope so, that he would see that.

MR. MICHELSON: But, normally, they do, at least occasionally, look to see what kind of alarms the plant is running with.

MR. KELLEY: That's right. As a matter of fact, that's part of our inspection program. Every day or every time you go into the control room, we observe to see what alarms are up and also to look at the chart recorders and see how they are tracking and trending.

MR. CARROLL: So you have a checklist of sorts.

MR. KELLEY: It's part of our inspection program.

MR. COWGILL: We're going to have to move on, but I would like to correct a checklist. We generally don't use, most of the residents anyhow, I know, don't use a specific checklist. We have an inspection plan and part of that plan is to observe control room activities. That includes observation of alarms.

Now, when I was up at the facility a week ago, we did enter the control room and there were maybe a half-dozen alarms lit in the entire control room. Probably 500 alarms, maybe more, in the control room itself.

During a startup -- just to put things in perspective -- you might have half of those alarms lit because systems are not operating in the condition that they would normally be in during power operation.

So conditions are somewhat different, sir.

MR. CARROLL: I have been in a control room.

MR. LEWIS: Could I just clarify one point? During the 36 hours, were the residents in the control room, though, during the 36-hour period? I'm fuzzy on what the answer was to that.

MR. KELLEY: The answer is no.

MR. LEWIS: The answer was yes?

MR. KELLEY: No.

MR. LEWIS: No.

MR. KELLEY: No. The residents were not there.

MR. LEWIS: So when you say you are not there 24 hours a day, I understand that. That's a long distance from not being there at all during 36 hours.

MR. COWGILL: There are possibly times over a 36-hour period we wouldn't be there, sir, particularly over certain weekends.

MR. LEWIS: I'm just interested in that 36 hours, and nobody was in there during that period.

MR. KELLEY: That's correct.

MR. CAPRA: Just to clarify something, sir. We may need to go back here and look at the inspection report anyway, but that 36 hours was the total time for dryout. That wasn't the time period that the steam generator was dry before anybody knew it. It took a significant amount of time even to get to the low water level mark, and then the steam generator to dry out.

The 24 hours prior to refill, both licensee management and NRC management were aware some short period of time into that 24 hours of the problem. The rest of it was working out the details of the recovery operation.

MR. LEWIS: But we've been told that they knew they were in trouble before the 36 hours began. Even so, we were just told that.

MR. COWGILL: I didn't try to imply that, sir. I said that -- at least what I was trying to say was that the dryout event occurred over a protracted period of time.

MR. LEWIS: I understand.

MR. COWGILL: About 36 hours.

MR. LEWIS: But I thought you said that they knew they were in trouble before the 36 hours began. Did I misunderstand that?

MR. KELLEY: I would have to check. I'd have to really look at the inspection report to answer that.

MR. LEWIS: Fine. Let's move on.

MR. CARROLL: During the 36 hours, the level was monotonically decreasing in the generator.

MR. KELLEY: Right.

MR. CARROLL: You could see it for most of the period, until you went below the wide range and then it dried out. That should have told somebody something bad was happening.

MR. KELLEY: Correct.

MR. MICHELSON: Along with the alarm that you should have gotten.

MR. CATTON: Don't they monitor feed?

MR. CARROLL: You don't have very good indication of this.

MR. MICHELSON: This is very small feed.

MR. CAPRA: Sir, the steam generator was bottled up at the time. They were not feeding the steam generator initially. They knew they didn't have the capability to feed the steam generator. I don't recall, again, without looking at the specifics of the inspection report, but I believe at some point in time, they believed that they would have the auxiliary feedwater pump back in service -- it was tagged out for maintenance -- to feed the steam generator.

MR. LEWIS: I'm going to rule out of order any more discussion of that event.

MR. COWGILL: I have got five more minutes. I think I need to move on.

MR. CARROLL: Is it going to be fair to ask the licensee questions about it, though?

MR. LEWIS: You bet you.

MR. COWGILL: I would note that we have observed increased, improved operations support. As a result of this event, again, an Operations Planning Group was formed. We believe that the Operations Planning Group and the improved support has aided in the decreased trip rate.

There is a Trip Response Group and we've noted during our last SALP cycle that the shift operations folks are relying more on this operations support group.

We believe that, based on our emergency operations procedures inspection conducted recently, that the procedures are technically accurate, that the procedures are structured so that with the equipment at the plant that actions can be implemented, and that the procedures can be effectively implemented as written.

MR. MICHELSON: Now, in their new way of doing business, how do they respond to alarms when they come in and they're logged and so forth so that you don't ignore an alarm that might be very important?

MR. KELLEY: What they have and which they had then, also, are what I'll call alarm response procedures, ARPs. Each alarm has specific procedures when it comes in as to what to do because of the alarm. Now, when alarms come in, we have witnessed that the ARP book does get pulled out and the procedure is followed as to what to do.

MR. MICHELSON: Apparently, that didn't happen before.

MR. KELLEY: That's correct.

MR. COWGILL: We also believe that the operator qualification and requalification programs are effective. As I said before, as a result of the examinations in April of 1989, the utility went to a six-shift rotation.

Our inspections have concluded that the operations requalification operator program was satisfactory.

MR. MICHELSON: When they go to six-shift operation and still have 12-hour shifts, what kind of a schedule is that?

MR. COWGILL: I'm not familiar enough with their schedule --

MR. MICHELSON: Why six? Why not shorten the shift time to give the people a little more energy on the shift?

MR. CARROLL: A lot of operators like the 12-hour shift.

MR. MICHELSON: I know that, but they don't mind sleeping even. Why go to six shifts?

MR. CARROLL: Six shifts gives you a shift that is always in training and shifts to cover days off and that short of thing.

MR. MICHELSON: And they give you more than that with six of them in 12-hour shifts.

MR. CARROLL: Slightly more than that, yes.

MR. MICHELSON: I would think it would be better to keep the people a little less on the job and a little more refreshed when they're working.

MR. COWGILL: I think that's a question you'd have to direct to the utility and their experience in operating their facility.

MR. BRAM: If I might just comment on that, maybe I could answer your question. The studies that we've done with independent consultants have suggested that it's more restful to the operators --

MR. LEWIS: Please identify yourself for the Reporter.

MR. BRAM: I'm sorry. My name is Steve Bram, Vice

President of Nuclear Power, Con Edison. We've had outside consultants come in and do a study of our shift schedule. The conclusion was not only do the operators prefer the 12-hour schedule, but it's actually more restful for them because they have fewer turnovers, which is really what becomes tiring, not the actual length of the shift.

MR. MICHELSON: If that were the case, I'm surprised more utilities don't use 12-hour shifts, it's really more restful.

MR. CARROLL: I think it's the trend, Carl. I think an awful lot of them are doing that.

MR. MICHELSON: Well, 12 percent, roughly.

MR. CARROLL: The other factor and I do not know how important it is at Indian Point but I know in my experience, commute time enters into it. If you have long commutes, it's a lot better to work less days.

[Slide.]

MR. COWGILL: If I could continue for a moment. We conducted a maintenance team inspection in May of 1989 and there were a number of weaknesses identified by that maintenance team inspection. Poorly defined program -- the team identified that there was not a conduct of maintenance procedure to formally define the program. There was also not a formal preventive maintenance program.

We indicated poor management support. That was principally based on the fact that the utility themselves had done a self-assessment, identified most of their problems, however, had not provided funds in their budget to correct a number of the items that they found in their self-assessment.

There were some material conditions problems, excessive number of work orders on certain pieces of equipment, some equipment had a history of being repeatedly out of service and there were some attention to detail kinds of problems with housekeeping such as leaving material at maintenance sites after completion of maintenance. However, the team did identify that there was excellent implementation of the actual maintenance tasks by the maintenance staff themselves principally because of their knowledge, skills, and dedication to their work.

The utility has taken this aboard, has produced a corrective action plan. They did present that plan to NRC Region I in December, 1989. The region was pleased by the program. We will wait to see about the long-term effectiveness but it included program and procedure upgrades. There's a procedure upgrade program including a number of dedicated procedure writers. The residents tell me that some procedures coming out of this program that they have reviewed appear to be good procedures. They've added staffing including some planners, system engineers, failure analysis engineers, added mechanics and I&C technicians.

They have some improved facilities to date with plans for more facilities in the near future.

MR. MICHELSON: Would any of these procedures they are now preparing make any difference for the situation that occurred in 1988?

MR. COWGILL: I'm not sure.

MR. MICHELSON: No, we're going to talk about it yet for a while. I just wondered, now you're giving us their corrective program.

MR. COWGILL: That's correct.

MR. MICHELSON: I'm asking, with this new corrective program, would it have been any different from the viewpoint of procedures available?

MR. CARROLL: You're talking maintenance procedures; aren't you?

MR. MICHELSON: Only maintenance? Oh, I thought I was talking operating.

MR. COWGILL: I'm talking only maintenance procedures.

MR. MICHELSON: Oh, okay. It won't make any difference. Thank you.

MR. LEWIS: There was an earlier comment that you're comfortable with the way that things are shaping up, the operating code and that sort of thing. That goes beyond maintenance procedures and if that had been in place at the time, would that have been an improvement?

MR. COWGILL: I'm sorry. I don't understand your question.

MR. LEWIS: Well, when you were asked what are all the changes that make you more comfortable, you cited the operator code, the fact that they appear to be taking it seriously. They're operating more professionally. It's hard to predict the past because it's over but would it have made a difference at the time?

MR. COWGILL: What? If they had had the code and some of the more formal things?

MR. LEWIS: Yes.

MR. COWGILL: It's really hard to tell. My gut reaction would be yes that it would but you know, on any rational basis, I really can't make that statement.

MR. MICHELSON: But there are no procedural -- no new procedures for taking care of these kinds of situations over and above what existed at the time; is that correct?

MR. COWGILL: I'm not sure, sir.

Back to maintenance --

MR. WARD: Are we going to get an answer to that? It seems like a pretty key point.

MR. KELLEY: Following the dry out of course and following the AIT that was sent up to the plant, several months afterwards, Con Ed has upgraded their operational procedures that they had in place at the time. These procedures were changed. A big review was gone into to improve these, to make them more user friendly, to get the bugs out of these procedures.

MR. MICHELSON: But did those procedures cover the situation they saw? I thought I got an earlier indication that maybe the procedures really don't cover this situation anyway. Now did they do anything different now that they do have procedures that would cover this situation or is it still the same? I'm not talking about normal accident procedures and what improvements they might have made there. I'm talking about this particular situation. Have they changed anything?

MR. LEWIS: For example, is there a rule that says once an hour, somebody should look at the alarms?

MR. KELLEY: They do their normal log taking activities which I think is every four hours.

MR. MICHELSON: You mean that even at the time of the event they were taking a log every four hours and they just logged in, no water in the generator?

MR. KELLEY: I'd have to take a look to see what they logged in.

MR. LEWIS: We're going to ask the licensee some of these questions.

MR. CAPRA: At some point in time that is correct. They did indicate the low level and circled it in red and did not take definitive action to correct that at the time. Again, without going back and looking at all the corrective actions, I know that the licensee did modify administrative controls and administrative procedures related to situations as occurred in 1988 coming out of refueling outages. As I recall, they made contingency plans as part of their normal process of coming out when they have a particular system out for maintenance. They did not have contingency plans in place before in the event they needed that system.

To what level of detail they went into, I'm not sure but there were significant changes in that area. There were also changes as I recall to the monitoring of the control boards in the control room with respect to operators walking down the boards and looking at all the indications, not only the log readings and that was done -- I forget the time. The licensee may be able to address that but that was like on an hourly basis and it was also done with the shift engineer or shift technical advisor as well at the time of shift turnover.

MR. LEWIS: The reason we're asking these questions -- I just want to be clear. We're here to review the request for a 10 percent power increase. We're not here to review the existence of a license but one of the important inputs to us is that the NRC staff seems comfortable with the situation -- reasonably comfortable as nearly as I can tell. We need to know why and we're trying to find out why and I must say, I'm having trouble but we'll learn more as the day goes on. Please, I'm making a -- you got it? It's your conclusion.

MR. CARROLL: I wanted to ask something about maintenance, if I may.

MR. LEWIS: I tried.

MR. CARROLL: As you probably know, ACRS has some views about the proposed maintenance rule. If a rule were in effect, would that have helped you in any way to assess or to help turnaround the bad things Con Ed was doing here?

MR. COWGILL: I'm really not in a position to say that. I really -- I really can't assess that for you, sir. I think that would be a hard statement.

MR. CARROLL: What did turn it around? Was it the NRC or was it INPO?

MR. COWGILL: We conducted a maintenance team inspection, identified a number of problems that had been previously identified by the utility which were not considered -- and they had not at the time of our inspection taken effective action to correct those problems. They had implemented a corrective action program to date. We are satisfied that that corrective action program if appropriately implemented should improve their maintenance. It's important to note in all this though that we identified that the maintenance staff itself was doing a good job. They had skilled, knowledgeable people and were conducting the maintenance properly although there were some weaknesses in their system.

MR. CARROLL: Had INPO identified many of these same things?

MR. COWGILL: I can't answer that question. I don't know.

MR. CARROLL: We'll ask the licensee. Okay.

[Slide.]

MR. COWGILL: In conclusion, we at Region I believe that Indian Point II operating experience and performance from 1988 to 1990 is adequate to support safe power operation at the higher power level requested by the licensee management.

That concludes my presentation unless there are other questions.

MR. CARROLL: I have one more question.

MR. COWGILL: Please ask.

MR. CARROLL: I guess lately I've become concerned at the number of things that suggest that the utilities, their architect engineers and the NRC staff has done a lousy job in letting glitches get through in the design of these plants. A lot of things are being turned up through SSFIs and where the utility does the same kind of thing where systems are just poorly designed. Somebody forgot something. Somebody put a hydrogen storage facility on the roof of a control building so that a leak in it would put hydrogen in the control room.

Somebody didn't provide a big enough suction pipe into the auxillary feedwater pumps, all kinds of electrical problems I'm seeing.

To what extent has SSFIs and utility programs doing the same kind of thing taken place at Indian Point? Do you feel good about Indian Point in terms of no design glitches anyplace?

MR. COWGILL: I don't think that anybody could ever say that there are no design glitches existing at any power plant. I can't speak specifically for Indian Point today because I haven't been with that facility very long but my experience with other utilities that I've dealt with is the fact that the utilities are embarking on a program to critically look at their systems and improve their design bases is a comfort to me that whatever design errors were made 15 or 20 years ago, the utilities are taking aggressive action to fix those problems.

I'd be more concerned if the utilities weren't taking the actions and finding the problems.

MR. CAPRA: I think the utilities are also looking harder these days in part of their design basis reconstitution efforts. Things that hadn't taken place in the past, just based on my limited scope of responsibilities with respect to -- I don't want to compare plants, but I've got 7 facilities in my project directorate. I would certainly say there are no more significant design deficiencies being found at Indian Point 2 than I see being found at other facilities within my directorate which includes some recently licensed facilities as well.

MR. CARROLL: My question is; has Indian Point, in your judgment, aggressively looked for these kind of things? Have they got a real program? Have you, the staff, aggressively looked for these things?

MR. CAPRA: The utility does have a program. As a matter of fact, it did do its own independent safety systems functional inspection on the auxillary feedwater system at one period of time a couple of years ago.

MR. KELLEY: The plant did have an NRC staff SSFI in 1988, and as Bob Capra has said, the plant has done their own safety system functional assessments on auxillary feedwater, and I believe it was also on service water. They take actions on those findings.

MR. MICHELSON: What did the staff look at in their SSFI? What system did they look at?

MR. KELLEY: In the SSFI, it was service water and component cooling water.

MR. MICHELSON: This was 1988?

MR. KELLEY: Yes.

MR. COWGILL: Unless there are any other questions, that concludes my remarks this morning, gentlemen; thank you very much.

MR. LEWIS: Thank you. Okay, who is next. Con Ed. Welcome. I imagine that you've gotten some idea of what some of the questions are going to be.

[Slide.]

MR. BRAM: Thank you. My name is Steve Bram. I am Vice President of Nuclear Power with Consolidated Edison Company of New York. I want to thank the Systematic Assessment of Experience Subcommittee for inviting us here today to make a presentation relating to Con Edison's stretch power application.

After a few brief introductory remarks, I will ask Mr. Charles Jackson, Manager, Nuclear Safety and Licensing to provide an overview of the stretch power program. Mr. Lou Liberatori, Manager of Safety Assessment, will then describe the results of our evaluations. I will also make myself available to answer some of your questions on the steam generator dryout event and the maintenance inspection, if you would like.

[Slide.]

MR. BRAM: I also have with me today a number of specialists from Con Edison's engineering organization, from Westinghouse and other consulting organizations which have contributed to our stretch analysis.

[Slide.]

MR. BRAM: My remarks today will provide you with an historical perspective on the siting and licensing of the Indian Point units and of the value of Unit No. 2 to Con Edison's customers and the area it serves.

Indian Point Unit No. 2, operating at a power level of 2758 megawatt-thermal, is located in West Chester County, New York, approximately 24 miles of the N.Y. City limits. The site also includes Indian Point Unit No. 1 which has been retired, and Indian Point Unit No. 3 which is operating at a licensed power level of 3025 megawatts-thermal.

Con Edison has had a long history of nuclear power generation at the Indian Point site. In fact, the first construction permit, CPPR-1 was issued for Unit No. 1 on May 4, 1956. Indian Point operated at a licensed power level of 615 megawatts-thermal until late 1974 and was retired because of economics and regulatory uncertainties as a result of the initial rulemaking on ECCS.

Many of the people currently working at Indian Point therefore have a long history of involvement with nuclear power. Con Edison received construction permit CPPR-21 for Indian Point Unit No. 2 on October 14, 1966. We applied for an operating license on October 15, 1968, and obtained a facility operating license No. DPR-26 to load fuel in the core and conduct subcritical testing on October 19, 1971.

On September 28th, 1973, we received Amendment No. 4

to the facility operating license to operate Unit No. 2 at a hundred percent steady state power. Indian Point Unit No. 2 was originally designed for an NSSS maximum calculated power level of 3216 megawatts-thermal and was guaranteed by the vendor for a core power level of 3071.4 megawatts-thermal.

That corresponds to the 3083.4 megawatts-thermal NSSS power, which is the subject of today's presentation. Indian Point Unit No. 2 was the first Westinghouse four loop plant of its design to be licensed for operation. The current power level of 2758 megawatts-thermal was based on extrapolations from previously licensed plants and to permit the accumulation of operating experience before operation at the vendor-guaranteed power level of 3071.4.

Even though other units that are of similar design as our's have been operating at higher power levels than what we have applied for, unrelated developments, both within our company and the industry at large, such as the backfitting programs imposed on all licenses as a result of the TMI-2 incident, and the Indian Point 2 special proceeding, forced us to put our ongoing stretch power program on hold on a number of occasions until this time.

The current phase of our stretch power program began in 1985 and culminated in our September 30, 1988 submittal.

[Slide.]

MR. BRAM: The average cost of generating a kilowatt hour of electricity with nuclear plants such as ours is significantly less than fossil plants. It is estimated that the additional energy that will be generated as a result of the increased stretch power rating will save our customers more than $15 million per year.

Of course, the actual value will depend on the specific mix of oil and gas and the cost of those fuels that would otherwise be burned to produce the equivalent energy.

I might note, very importantly, that all of the savings are automatically passed back directly through to our customers.

The additional capacity which results from the stretch power rating will also enable the company to defer installation or purchase of new capacity. On an annual basis, the avoided costs of the equivalent capacity is estimated to be at least $6 million.

Although Unit 2 generation and purchases of energy from other nuclear, as well as hydroelectric and coal plants, contributes to reducing the amount of fuel oil and gas that the company burns for energy generation, Con Edison, nevertheless, remains very dependent on foreign oil sources.

In 1989, the company burned 29 million barrels of oil and gas equivalent to another 15 million barrels of oil. The additional energy resulting from stretch power output of Unit 2 would save the equivalent of more than one million barrels of oil annually.

Finally, the additional energy from Indian Point 2, if it displaced oil fire generation, would result in a reduction of about one thousand tons each of sulfa dioxides and nitrous oxides each year.

That concludes my prepared remarks. I can turn the podium over to Mr. Jackson now to go into more detail on the stretch analysis that we undertook of, if you'd like me to entertain some questions relating to the dryout and maintenance and inspection, I'd be happy to do that.

MR. LEWIS: My inclination would be to go through the cycle of the licensee's presentations, asking only vital questions as we go along, and then we'll come back for a free-for-all. Is that agreeable?

MR. WARD: I think that would be appropriate.

MR. LEWIS: All right. Let's roll.

[Slide.]

MR. JACKSON: Good morning. My name is Charles Jackson. I'm the Manager, Nuclear Safety and Licensing up at Indian Point Station. I'd like to present to you this morning, briefly, an overview of the Indian Point stretch power program.

[Slide.]

MR. JACKSON: I will briefly describe some features of Indian Point principally, to set the stage for Mr. Liberatori's presentation on detailed evaluation results.

I will address the original concern on operating experience with a comparison of Indian Point with more recently licensed plants, a little bit of the additional background on licensing history, and some of the details of our schedule and implementation plan.

[Slide.]

MR. JACKSON: Indian Point, as Steve mentioned, was the first four-loop Westinghouse pressurized water reactor, Model 44 steam generators. Our core is a 15-by-15 fuel. We are in the first cycle of conversion over to what we term OFA, or the Optimized Fuel Assembly.

We are currently cycle 10. We are consistent with other reactors with what we refer to as an extended burnup fuel design. With the stretch application, we'll achieve a 6.33 kilowatt-per-foot, which is within the range of other previously licensed plants.

Two main features of the plant are; the Westinghouse main turbine, the low pressure rotors have been changed out and a modernization program, we have eliminated the disks and the problems associated with them.

We have also replaced the original generator with a General Electric generator, which is --

MR. CARROLL: Running backwards, of course.

MR. JACKSON: Excuse me?

MR. CARROLL: Running backwards.

MR. JACKSON: Yes. We had to change the fan orientation. GE and Westinghouse units are a little different, but we were able to make it fit. As you see, it has plenty of margin for the stretch condition.

[Slide.]

MR. JACKSON: I'm not going to read all these numbers, but the purpose of this slide is to compare typical numbers for the current cycle operation with the range and expected number to the stretch application.

I'd like to highlight both the Reactor T average, pressure, steam generator tube plugging, and RCS flow. We have performed the analyses, as Mr. Liberatori will explain a little further, for a range of parameters.

This will permit us operational flexibility, margin. We were going after a 90 percent flow. This would enable us to take increased steam generator tube plugging or conversely without the plugging to take additional degradation in service.

We felt it was prudent to do the evaluation for the range of parameters as a contingency in margin. This will keep us from having to come back in later for additional application.

[Slide.]

MR. JACKSON: The two slides that follow this one we will skip over because we are running a little bit behind. Basically, as Steve mentioned, Indian Point 2 application, the current application, the 3071, is still much lower than most newer licensed plants, most of the similar Westinghouse four-loop PWRs at the 3411 megawatt thermal level.

We have had a search done on the operating history of the U.S. plants and, as can be seen on the next two slides that are in the handout, we believe there are over 100 reactor years of experience. One of the original concerns for operation of the large reactors and why Indian Point 2 was originally licensed at the 2758 level was to permit the accumulation of the experience.

Obviously, such experience has been gained.

[Slide.]

MR. LEWIS: I'm always interested when people quote something like 100 years of experience as if it proved that you wouldn't have an accident for the next thousand years. It's just that you found that nothing obvious showed up in the first 100 years of four-loop experience at that power level.

MR. JACKSON: Certainly, I think we could characterize the experience as not seeing surprises. When you don't have experience, you're the first of the kind with an extrapolation, you do not know what certain unknowns might be. There was a concern that extrapolations not be made too great until the experience was gained.

We're not proposing that the experience demonstrates no accident potential, but what it's telling us is lessons learned from the other facilities. There aren't the surprises that may have been anticipated.

MR. LEWIS: Sure. It tells you that the plants can operate at that level, but the concern about higher power has always been that in the event of a malfunction, you just have a lot more energy to get rid of. This doesn't tell you really much about that. I'm not quibbling. Well, I am quibbling. Go on.

MR. JACKSON: There were certain unknowns associated with a large core, things such as xenon stability questions.

MR. LEWIS: Sure.

MR. JACKSON: They were calculated, projected, expected, but you didn't have the experience and --

MR. LEWIS: No. I understand that.

MR. JACKSON: -- we now have those and we have a much greater level of confidence than we did when we were here 17-18 years ago.

MR. LEWIS: That is certainly right. I'm just reacting against another agency. I'm reacting against NASA saying that 24 flights means that we have a safe system.

MR. MICHELSON: As I suspect the site had something to do with the level of conservatism, too, didn't it?

MR. JACKSON: Not originally. If you go back to the time period, we're talking the late 1960s or early 1970s, that wasn't particularly the issue that it was in the early 1980s, later time period with emergency planning.

It was generally a question of experience and there were other reactors at other sites that were also limited initially at that power level. It was not a siting issue, per se.

MR. MICHELSON: But it has become one.

MR. JACKSON: Certainly, there has been obvious increased attention and concern with siting. Indian Point 2, however, has several design features that a number of other plants do not have, which would serve to mitigate or counter those concerns.

I believe we've gone over most of this slide. I just wanted to highlight that although our original application was for 2758 megawatt thermal, all of the original evaluations for the engineered safety features were done at the 3216 level, which is higher than the so-called stretch application power that we're asking for now.

As part of that experience, Indian Point 3 that followed us a few years behind in the licensing cycle, although originally licensed at 3025, was restricted in operation to -- also at the recommendation of the ACRS -- to approximately the Indian Point 2 level of 2750, along with, I believe, Zion and Cook Plants had a similar early license restriction.

As we can see for the Indian Point 3 plant, which was originally an exact duplicate of Indian Point 2, that restriction was lifted in 1978. As Steve mentioned in his presentation, during this period, we had then initiated our stretch program, but we had to be put on hold as other events in the industry happened.

One of the features that we have been able to do, both with this application and over the last several years, as we are reanalyzing for reloads, we have been modernizing, if you will, the safety analyses and using more up-to-date techniques. We're not relying on a 22 year old safety analysis package.

As you can see from some of the material that will be presented, we have essentially updated most of the safety analysis chapter, if you will, in our FSAR.

[Slide]

MR. JACKSON: I would like to give a brief overview of our current plans and where we are, first, our schedule. With the assumption of a license amendment authorizing stretch in the near term, we have currently planned a mid-cycle inspection of our steam generator mid-cycle outage, and we would be on schedule to implement a power escalation to the higher power level on the return to service from that outage in March.

We believe that's an opportune time to do the stretch escalation. Why we are down, we can make the appropriate set-point changes. Although other plants have done them online, we would prefer, in our schedule, to do them while the plant is in cold shutdown.

In addition, we are on schedule for procedure changes, training, set-point changes that have to be made at that time.

On procedures --

MR. MICHELSON: Did you give a date for when you thought this change would occur, the time?

MR. JACKSON: We anticipate end of February, early March, the license amendment. Maybe Mr. Brinkman will be able to describe the staff's schedule. We are shutting down towards the end of February for our mid-cycle. We will be down to towards the end of March, and we would anticipate, if we have the license amendment, making the changes while we are shut down and starting up with the new license and power level.

MR. MICHELSON: In April then?

MR. JACKSON: At the end of March, our escalation would begin, and return to service is currently scheduled the end of March.

MR. CARROLL: Has all of this been programmed into your simulator, and have the operators --

MR. JACKSON: Yes. I will describe some of the procedure changes and the training scope that we're going through.

On procedures, virtually all of the plant procedures have been reviewed and changed identified for our operating procedures, a checkoff list, test and calibration procedures, any changes in our emergency operating procedures, some routine thing such as heat-balance procedure, and also, we have developed an onsite power escalation procedure to govern this whole process.

We get to the training --

MR. CARROLL: How about the emergency plan? Does this affect anything with respect to the way you'd analyze accidents in the emergency plan?

MR. JACKSON: No. Our emergency plan, protective action response, would not be affected by this change. The responses are based upon observed plant parameters exceeding certain limits and then recommendations based on those parameters.

We have revised our emergency plan and procedures to, as closely as possible, follow the symptom-based emergency operating procedures so that the things that the operator would have available to him to guide his actions in an emergency would also immediately trigger appropriate events in the emergency plan. We still have retained some of our event-based requirements, but we have moved to making those emergency plan procedures more user friendly for the operators.

In training, first of all, there is operator training, formal classroom. This will begin at the next cycle within the next, approximate, week, week and a half, so that the operators will be trained on the changes in the various set-points, procedures that are required, and we will catch all operators before return to service. The operators will be trained before they would have to go into the control room with any of the changes.

We also are programming the changes into our simulator, and those things that are affecting the simulator response, the operators will go through that training prior to being in the control room.

There aren't too many changes in terms of the actual plant simulator response, but we will be reviewing accidents, transients, everything from new reading on a megawatt meter to how various secondary-plant pieces of equipment respond.

Our training scope will cover all areas of the NSSS, as I mentioned -- accident transience, balance of plant systems, technical specification changes, and all of the plant set-point changes, which we treat very formally, as if they were modifications to the facility.

We have begun part of the training of some of the support staff in what we refer to as our "systems courses".

So, we are on schedule with the procedure changes, the review process, and the training program.

[Slide]

MR. JACKSON: The next slide briefly describes the areas where major set-point changes are required. Overpower over temperature Delta T will be described and the reasons for changes in the more detailed description by Mr. Liberatori, but they're all the key areas. They match closely where we have tech spec changes required and include such things as the normal operating range on secondary-plant support equipment.

Before I conclude, the NRC project manager, Mr. Brinkman, had indicated that there were some questions regarding biofouling, and although I don't have a specific slide, if it's appropriate, I'd just make a few remarks on some of our experience now.

Two areas of biofouling history at Indian Point: one called river grass and its potential for intake clogging, and also, microorganisms.

The grass is a brief seasonal experience, when we have temperature change in the river, and we get grass carried into the intake structure. We have fine screens, travelling screens, and our service water, in addition, has a Zurn strainer system. When we get into the periods of time, the few days each year, that we have grass, this requires additional attention on the part of our operators for more frequent cleaning of the intake structures.

Normally, we aren't getting grass carryover through the screening system, but on the couple of occasions when that has occurred, this requires that we go and inspect heat exchanger equipment to be sure we don't have any clogging.

MR. MICHELSON: Are you using full-flow backwash-type screens?

MR. JACKSON: Yes.

MR. MICHELSON: What's the mesh size, the finest mesh size the water passes through on the way to the service water?

MR. JACKSON: On the service water, I believe we're down to eighth-inch, now, screen size. We can double-check that dimension. I'm going on memory. We had been larger, and after our experience in 1980, one of the modifications we made was to go to a finer screen size. I do not know the screen size on our fine screens in front of the circulating water for the condensers.

MR. MICHELSON: What about the emergency core cooling systems? In other words, your emergency water systems -- what screening do you use on that?

MR. JACKSON: Our service water feed is the heat sink for the -- both directly for, for example, containment heat removal with our fan cooler systems, and indirectly, for our component cooling, which then serves the decay heat removal, RHR heat exchangers. Service water directly cools our diesel generators. Those are your key pieces.

MR. MICHELSON: And the screen size for that system?

MR. JACKSON: That's the --

MR. MICHELSON: Eighth-inch?

MR. JACKSON: That's what I have previously described. The water is taken in through the screens and then through strainers, the Zurn strainer system that we have. We have one strainer for each of the six service water pumps.

MR. MICHELSON: But the fine screen is one-eighth inch.

MR. JACKSON: The Zurn strainer is about one-eighth. I don't remember the exact size on the fine screen opening. It's probably something a little larger than that. The purpose of the fine screen is right at the river front, to catch large debris before it would get to a pump. It's principally pump protection. Then we have the fine mesh in the Zurn strainer system, which then has a backwash capability, as well.

So, I mentioned, the grass is a seasonal thing. We're prepared for it. It's just increased attention to cleaning.

Microorganism experience: Where we are located in the Hudson River, we're brackish water. We're not freshwater, if we were further up the Hudson, nor are we the salt content that we would see if we were down in the ocean. From certain perspectives, perhaps that's an ideal location. But we have had some minor barnacle problem that you see with brackish water, at the intakes, but it has not been a major problem with blockage. It's long term and removal of equipment such as screens for cleaning. It's not a problem we have as much. Our routine maintenance for corrosion inspection also takes care of anything that's necessary for barnacles.

In 1980, when we had an increased leakage experience with our fan cooler units inside containment, we believe that there was some microorganism attach that was a minor contributor to some of the leakage. We had particles that were getting through and being lodged in tubes, and in the crevice area, where those particles were lodged, we were seeing minor pitting, which we believe was associated with some microorganisms.

MR. MICHELSON: Which ones did you identify?

MR. JACKSON: I don't remember the specific names, but they were attacking -- either they or their byproduct were attacking the 90/10 copper tubes that we had installed at the time.

As a result of that, several actions were taken. We initiated chlorination, the service water system, and we are essentially on a continuous, during daylight, weekday hours. The fan coolers have been replaced.

Correction: The Zurn strainer is down to sixteenth-inch mesh.

MR. MICHELSON: Sixteenth mesh. Okay. Thank you.

MR. CARROLL: I knew there must be somebody in that cast of thousands back there that knew the answer.

MR. MICHELSON: Yes. Sixteenth is getting a little closer.

MR. JACKSON: Yes. We had originally been the eighth. We're down to sixteenth.

MR. MICHELSON: Yes.

MR. JACKSON: Part of our corrective action, of course, as I mentioned, was chlorination. We do that during daylight hours during the week.

MR. MICHELSON: You do it continuously in daylight hours.

MR. JACKSON: Continuously in daylight hours. That's correct.

MR. MICHELSON: Why do you choose the daylight hours?

MR. JACKSON: Well, it's a semiautomatic system. Also, sunlight as an effect on the consumption of the residual that then gets put into the discharge canal back to the river.

MR. MICHELSON: I see.

MR. JACKSON: Also, we want to closely monitor the concentration, and we have additional personnel during the daylight.

MR. MICHELSON: Go ahead.

MR. JACKSON: Additional things beyond the chlorination -- specifically, the fan coolers. They were originally redesigned. We replaced, of course, the leaking coolers, and we redesigned the water boxes to preclude the particles from being a potential plugging --

MR. MICHELSON: When you talk about "particles", are you talking about bi-valves --

MR. JACKSON: No. These were principally pieces of concrete.

MR. MICHELSON: Well, that's nothing to do with biofouling, necessarily, although it's also an important consideration.

MR. JACKSON: We really haven't seen -- there were a few barnacles we saw in inlet water boxes, but not anything significant that would have any measurable effect on flow.

MR. MICHELSON: No Asiatic clam contaminations in that area?

MR. JACKSON: No, we haven't seen any of that kind of --

MR. MICHELSON: No other types of clams?

MR. JACKSON: No, we have not seen any kind of a clam infestation.

MR. MICHELSON: Do you have a silting problem at all in that area?

MR. JACKSON: No, we don't have a significant silting problem. The river drops off very steeply at the side of the river, the Hudson River, where we are.

MR. MICHELSON: The easiest way to alleviate any of my questions is simply for you tell me that you have done certain tests of the flow capabilities of these systems in a fairly decent time and that you're seeing there is still full flow capability, and therefore, there is no reason to believe your cooling water systems are other than fully effective.

MR. JACKSON: We have just responded -- I'm about to send the response in to Generic Letter -- I believe it's 89-13, where we are proposing an extensive program on performance monitoring, but we have had for some time -- I'll give you two key examples of the service water-fed heat exchangers, diesel generators.

Flow is checked daily through the diesel generators, to know that we're still seeing adequate flow. Monthly, when we run diesel generators for a monthly test, we measure both the inlet/outlet temperature Delta T, and we trend that.

For the fan cooler units, every 4 hours, we're logging service water flow, and we have an action statement on minimum flow.

So, two of the key safety-related service water heat exchanger systems, which are at different elevations, are continuously monitored.

MR. MICHELSON: Okay. Now, in the case of your containment coolers, as an example, what degree, if any, of flow degradation have you observed over the last, say, 3 years?

MR. JACKSON: Essentially none.

MR. MICHELSON: It's still a design basis flow.

MR. JACKSON: We're still above the evaluated minimum. Approximately 1,200, I believe, is the number; 1,600 is the minimum for each of the fan coolers.

MR. MICHELSON: That's the number used in your safety evaluation?

MR. JACKSON: Yes.

MR. MICHELSON: Your safety analysis.

MR. JACKSON: Of course, there are a number of indirect measures such as the containment temperature during normal operation which is monitored and we're able to correlate that.

MR. MICHELSON: Direct measurement of the flow is a very good way of knowing if you've got any degree of plugging occurring in the system.

MR. JACKSON: We have a number of, as I mentioned, direct measurements on flow as well as indirect measurements of other parameters that are affected by the performance of the heat exchangers.

MR. MICHELSON: How about your component cooling water system? Do you monitor the service water side every four hours?

MR. JACKSON: Service water side is monitored and I don't have the frequency but we periodically monitor the closed cycle side of it as well.

MR. MICHELSON: I'm interested mostly in the open cycle side.

MR. JACKSON: On the service water side, I believe we're bounding that by the different elevations of what we're seeing on both the fan coolers and the diesel generators.

MR. MICHELSON: You mean you're not measuring your component cooling water flows occasionally?

MR. JACKSON: We are measuring them occasionally but I don't have off the top of my head the frequency. Maybe I can get some help.

MR. MICHELSON: Because that's of course in some respects even more important than the containment although they're both very important.

MR. JACKSON: Yes, it is important. I just don't -- I pulled two examples from our procedures and I didn't pull all of the heat exchangers out but we can get that answer for you.

MR. MICHELSON: Yes, if you could, and then indicate when was the last time you measured it and how close to design flow you might have been.

MR. JACKSON: I believe we did measurements during the last refueling.

MR. MICHELSON: By design flow, I mean the one you're using in your safety analysis because you're making an argument and the staff's making an argument that these systems are way oversized and they're still oversized and I just wanted to make sure we know they're oversized and that's why you measure the flow once in a while.

MR. JACKSON: Yes, as we mentioned, they were previously designed and evaluated for a much higher power level than the oversized but we'll get the specific number for you by the end of the morning.

MR. MICHELSON: Thank you.

MR. JACKSON: At this point, if there are no further questions, I'd like to introduce Lou Liberatori who will now go into the next layer of detail on the evaluations that were performed and some of the results.

MR. CARROLL: Out of curiosity, is the increased condenser delta T causing any problems? Who did you have to get approval to?

MR. JACKSON: When we originally licensed the plant, the environmental effects were evaluated at the full power level. In addition, the environmental effects were evaluated including Indian Point Unit I which is now retired. So we have plenty of margin in what was evaluated. We didn't have to go back and do re-reviews and get any additional approvals in that area.

MR. MICHELSON: Just while you're still here, just one brief question. You said you were working on your response to the service water system generic letter. Are you going to take any exceptions to the generic letter?

MR. JACKSON: I don't believe so. We're proposing a program that incorporates much of what we're already doing.

While we've been here in Washington, the final part of that letter has been prepared and I don't have a copy with me but as I recall --

MR. MICHELSON: You're not aware that you will take exception to any of the requirements.

MR. JACKSON: As I recall the graphs, we're proposing a program that I believe we think is consistent with what's being requested.

MR. MICHELSON: Thank you.

[Slide.]

MR. LIBERATORI: Thank you, Charlie.

Good morning. I'm Lou Liberator, manager of safety assessment at Con Edison's Indian Point Station. The purpose of my presentation this morning is to give you a brief overview of the results of our stretch program concentrating in both the analytical areas as well as the plant's equipment performance areas.

As Steve stated, there are many specialists in the audience today to support me in any questions or details that I might not be able to provide to you. First of all, as you can see from my first slide, I divided my program into four basic areas. I'd like to cover transients and accidents first describing both loss of coolant and non-loss of coolant accidents as well as off-site dose evaluations, touch on the technical specification changes that we requested of the staff, describe our plant equipment evaluations and then draw a conclusion.

Before I move to my next slide, I'd like to briefly describe the amendment process as we approached it. We had two processes going on in parallel. One was an effort to change over in fuel design from the standard Westinghouse fuel to the optimized fuel assembly and that was going on essentially in parallel with our restarted stretch program and to support the fuel design change, all the loss of coolant accidents and certain of the FSAR non-loss of coolant accidents required reanalysis.

What we chose to do was not only perform those analyses to support the fuel change but also to conduct them at the assumed higher power levels since we knew we had that effort going on in parallel and in effect, it prevented us from having to do analysis twice and also represented an efficiency on the part of the staff resources in terms of review.

What our stretch application did contain were the remaining FSAR transients which were not specifically reanalyzed as part of the fuel design package.

So at this point, we have as Mr. Jackson referred to earlier, effectively reanalyzed the required FSAR transients for entire Chapter 14 of our FSAR and those analyses packages bound current operation as well as the proposed stretch power operation and I'll give into more of that as I go on in my slide presentation. Next slide, please.

[Slide.]

MR. LIBERATORI: With respect to the loss of coolant accidents, as part of our upgrading to more recent approved models by the staff, we have performed the large break LOCA analysis using the BASH code technology and have performed the small break accidents using the NOTRUMP model and I've depicted the PCTs for both the large break and the small break on this slide and as you can see, both numbers are appreciably within the 2,200 degree acceptance limit of 5046.

MR. CATTON: What were those numbers before the power increase?

MR. LIBERATORI: The previous number for -- let's take the large break, for example. For the limiting break size, the number was approximately 1950 and I guess what I should point out is, if you recall Mr. Jackson's slide on the ranges of parameters that we've evaluated the stretch for, these numbers represent the peak clad temperature for the limiting values for each of those parameters.

So if you looked at where the plant will actually operate, we're probably talking a peak clad temperature that's approximately the same as what we have now at 2758, again, owing to the more sophisticated modeling and computer codes that are used today.

Again, just a point that the remainder of the 5046 criterion were demonstrated to be satisfied in our submittal to the staff and we also relooked at containment performance with respect to its response to a loss of coolant accident. Since original licensing of the unit, the containment response has always been evaluated assuming a core power level of 3216 and we were consistent with that in our reassessment with respect to the proposed power level and obviously it bounds it.

We did need to redo the analysis since at the upper range of the operating temperatures of what we've analyzed we would have a slightly higher hot lake temperature than was previously utilized. So we reanalyzed the containment again at 3216 but with the wider temperature range and the effects were about a half a pound higher than what we had calculated before so we're talking approximately 41.1 pounds versus the original FCR value of 40.6 pounds both of which are clearly within the containment design pressure of 47 pounds.

More importantly, in the staff's original SER, they defined a margin of safety with respect to containment as the design pressure should exceed the peak pressure by at least 10 percent and both the 40.6 and the 41.1 satisfy that original criteria so we're really not changing that margin of safety as originally licensed.

Otherwise, there was really no major effect in terms of containment performance. Next slide, please.

[Slide.]

MR. MICHELSON: Excuse me. In the case of containment performance, you're depending upon the heat exchangers there in part for keeping -- is that correct in this plant?

MR. LIBERATORI: That's correct. The analyses for the containment were done assuming heat input associated with a 3216 operating core and the fan coolant performance is based on being able to remove that heat and the --

MR. MICHELSON: A certain number of fan coolers were assumed to be functioning properly.

MR. LIBERATORI: That's correct and the flows that we used in terms of establishing operability for the fan coolers are based on their ability to remove a 3216 heating core.

MR. MICHELSON: Now in designing those fan coolers, there were certain fouling factors and so forth assumed in the design. Have you any test evidence of late to verify that these are still reasonable numbers?

MR. LIBERATORI: I believe we -- subject to correction by some people -- I believe we stuck with the same fouling factors. That appeared to be reasonable. I think as Mr. Jackson stated that the fan cooler performance certainly from our periodic inspections has been fairly good.

MR. MICHELSON: Does the fan cooler performance include a test estimate of the fouling factors?

MR. LIBERATORI: I don't believe I have the information to answer that.

MR. MICHELSON: Or do you just measure the fullness of the heat exchanger and leave it go at that, delta T?

MR. LIBERATORI: We'll see if we can get an answer to that question before the morning is over.

MR. MICHELSON: Okay.

MR. JACKSON: I can give a brief answer. It's flows delta T and of course indirectly, an expected performance on normal containment temperature. Of course, we do have new heat exchangers. We're not talking about 20-year-old heat exchangers.

MR. MICHELSON: These are new.

MR. JACKSON: After the 1980 event, we replaced and more recently, we replaced the heat exchangers from the 90/10 copper material to a AL6X material.

MR. MICHELSON: Were the new heat exchangers any more conservatively designed than the previous ones or the same?

MR. JACKSON: I think they were identical.

MR. MICHELSON: Thank you.

I would like to know why you believe that the heat transfer capabilities are approximately the same as the original design basis.

MR. JACKSON: Yes.

[Slide.]

MR. LIBERATORI: My next slide touches briefly on the non-LOCA transients. All of the SER required non-LOCA transients were reanalyzed. As I stated earlier, some were done as part of the fuel design change, some specifically associated with stretch.

In each case, we've demonstrated that the transients satisfy the various applicable criteria for each of the individual accidents. Again, as Mr. Jackson indicated, using currently accepted codes by the staff and each of the specific numbers for the various accidents are contained in our submittal.

MR. MICHELSON: Have you ever performed a natural circulation test from full power on this plant; either on purpose or by accident? Have you ever gone into natural circulation from full power?

MR. LIBERATORI: Well, we have had plant trips which have resulted from loss of offsite power, which put us into that.

MR. MICHELSON: Yes, that will put you into natural circulation.

MR. LIBERATORI: That's at least one that I can recall which was probably about ten years ago.

MR. MICHELSON: Did you ever analyze the subsequent performance to see if it met your expectations?

MR. LIBERATORI: I guess, to the best of my recollection, the plant behaved as expected in terms of offspeed, attaining and achieving hot shutdown, diesel generators picking up, you know, required loads. To my recollection, that was the case.

MR. JACKSON: If I may interrupt; I don't think the actual event would really lead itself to the analysis. We didn't go into a cooldown; we just maintained the plant briefly.

MR. MICHELSON: Have you ever, on purpose, performed some kind of natural circulation test, you know, as a test?

MR. JACKSON: I believe, if we go back 20 years, I believe that during hot functional, there may have been some verification.

MR. MICHELSON: This is in more recent times.

MR. JACKSON: This wouldn't have been in the more recent times.

MR. MICHELSON: The emphasis was put back on it in the early 80's, but I believe they allowed you to use a sister plant's results so you didn't -- I just wondered if you did your own, or if you used a sister plant result?

MR. JACKSON: I think we're relying on experiences with --

MR. MICHELSON: This tells you something about how much your predictions of margin really -- how much that margin is really there. You're going to lose a little bit of it now when you go up in power, another 10-12 percent, so that margin is going to disappear.

If you did a natural circulation test today, it will be different, the result, once you have elevated your power -- potentially different.

MR. JACKSON: It would be potentially different.

MR. MICHELSON: I just wondered if you had any old test results or not on this. I assum[illegible]erson -- I'd like to ask the staff; if you rai[illegible] 12 percent, are you required now to go back and [illegible]tural circulation test, or just show that somebody else had done one that looks close enough?

MR. COLLINS: My name is Tim Collins. I'm with the Reactor Systems Branch. A plant increasing its power by 10 percent would not be required to do a natural circulation test. They can depend upon the results of other plants if they'd like.

MR. CARROLL: What test is it, in point, relying on?

MR. COLLINS: I don't know the answer to that.

MR. MICHELSON: Well, has the staff asked them to demonstrate that they will have -- you have not asked them?

MR. COLLINS: No, we have not asked them.

MR. JACKSON: I believe the information we're relying on is Diablo Canyon which was performed at a much higher power level than we're asking for.

MR. MICHELSON: How about the loop configuration and so forth; identical?

MR. JACKSON: We're talking a similar design.

MR. MICHELSON: Similar pumps and so forth?

MR. JACKSON: I'm looking at Westinghouse to verify it. I believe it's a similar design and similar configuration.

MR. MICHELSON: So somebody has gone through the arithmetic and says that this is sufficiently identical that that test satisfies your need? I would hope that staff asked for that because I thought it was a requirement in order to elevate power, but maybe not.

MR. COLLINS: No, we do not require that.

MR. MICHELSON: It's been required in the past. You know, you required everybody to either go do it or demonstrate that somebody else has done it that's close enough and alike. That was in the early 80's -- '83 or '84 or somewhere in that timeframe, I thought. That was when we started getting very much interested in plants not seeming to do so well when they went on natural circulation.

Let's go back and look at it. Maybe I'm wrong. How about it, Jay, do you remember the history on that natural circulation as to when it was?

MR. CARROLL: Your timeframe is about right, I guess.

MR. MICHELSON: I thought it was a requirement that everybody had to meet and I would think that it's still a requirement to meet if you want to raise your power.

MR. CARROLL: I think that what they're arguing is that an identical -- essentially identical plant has demonstrated this --

MR. MICHELSON: No problem, but I think that it has to be documented. I think it's that much of a requirement that you either do it, or you document it.

MR. CARROLL: I'm surprised the staff hasn't put that in their safety analysis.

MR. CAPRA: Excuse me, sir. I'm not familiar with that particular requirement with respect to a power uprate. Now, around the timeframe in 1980 -- again, I don't have the details of it -- there was a generic letter that was issued in response to an event, I believe, at St. Lucie with the ability of a plant to cool down a natural circulation without drawing a bubble in the head, where generic requirements laid on all utilities to either perform an analysis or do a test, as I recall.

Indian Point was reviewed and evaluated for compliance with that particular generic letter, but that was not associated with this power uprate.

MR. MICHELSON: When you raise the power 10-12 percent, I think you need to go back and make sure that analysis done back at that time is still valid. I think that ought to be a standard check item for whenever you do any consideration of power upgrading of this magnitude.

I think there's no problem. I'm sure they've [illegible] sister that looks close enough alike and has the test results, but the fact that the staff didn't even ask or look at it bothers me a little bit.

MR. CAPRA: If you will recall, the original staff evaluation for this plant, with the exception of ECCS performance was done.

MR. CARROLL: That was before we understood these problems.

MR. LEWIS: There's a whole batch of generic things that are being asked here, centered around this particular one which is that part of the argument for the upgrade is that the plant was originally, in 1973 and in that period just before then, evaluated at the higher level, but there have been a number of things since then and presumably to justify an upgrade or an increase in power, one has to demonstrate that the plant would now, at the new power, comply with the current regulations for plants at that power, and that includes some of these -- not backfitting, but reanalysis items from the past.

I assume the staff is certifying that that's the case to us.

MR. JACKSON: I think, Dr. Lewis, if I might attempt an answer, -- this is Charles Jackson from Con Ed. I believe that are -- in consulting with Westinghouse -- that our evaluation and the acceptance by the staff of the SER was based upon experience with, particularly, Diablo Canyon, but others at higher power level than we are asking for now.

MR. LEWIS: That's for the specific issue?

MR. JACKSON: Yes, and also for the issue of our sister plant, Indian Point 3, which was also reviewed and evaluated at a very close level, the 3025, so that we think that we're well bounded by what has gone before and what has been evaluated, so that it did not become the subject of a need for a specific reevaluation in this application.

MR. CARROLL: Does the staff's SER deal with the issue of natural circulation?

MR. CAPRA: No, sir, it does not. We used the original licensing basis of the facility with exception of the revised ECCS analysis. I know that doesn't answer your question. I'm telling you what the staff did, in fact, review.

We did not take the delta between the original licensing basis of the facility and upgrade it to all current regulatory requirements on this particular power uprate and that's consistent with what we've done for other stretch power applications.

MR. LEWIS: Will the plant at the new power level, if it's approved, comply with all existing requirements for a plant at that power level? The staff is certifying that to us?

MR. CAPRA: Yes, sir, I believe it will do that with respect to --

MR. LEWIS: But with the exception of natural circulation?

MR. COLLINS: I am not sure exactly what you're asking. This plant -- we're not saying that this plant will meet all criteria for a plant that would be licensed today; we're not saying that.

We're saying that at the higher power level, it would meet the requirements that it was licensed to originally.

MR. LEWIS: Okay.

MR. MICHELSON: That's not good enough.

MR. LEWIS: No, not at all.

MR. COLLINS: That's what we're saying, though.

MR. LEWIS: That's what I was trying to pin down and that's what my friends have been trying to pin down on this particular point.

MR. COLLINS: That is what we're saying.

MR. MICHELSON: There have been a number of changed requirements from time to time since it was originally licensed. There have been generic letters and so forth. I assume that you review all of those kinds of newer requirements for comparable plants and make sure this plant meets the same requirements?

MR. COLLINS: Anything that was backfit since the plant was originally licensed; it still has to meet those requirements also, if something was backfit on the plant. But something which was not backfit into this plant; it would not now have to meet those criteria because they're upgrading the power.

MR. MICHELSON: Natural circulation wasn't a backfit. That was a requirement and that has always been a design requirement. They just went back and reminded people that you've got to make sure it works. I assume in this case that somebody has assured that, yes, it will work, also at this higher power level on this plant. I'm sure it's not a problem, but I'm a little concerned that somebody doesn't, you know, kind of check it anyway.

MR. CARROLL: Let me try: has it been specifically looked at?

MR. COLLINS: The natural circulation question; this one?

MR. CARROLL: Yes.

MR. COLLINS: I can't say for sure; I don't know for sure. Okay, we certainly didn't address it in the SER, but that doesn't mean that somebody didn't look at it in the process and decide it was a no-never-mind. I would have to check tnat. I just don't know.

MR. CARROLL: Do you believe that it should be looked at in a stretch application?

MR. COLLINS: Yes, yes.

MR. CARROLL: And documented in the SER?

MR. MICHELSON: It really should be in the SER.

MR. LEWIS: Let me ask the question in a slightly different way. Since --

MR. CARROLL: I didn't get an answer to my question.

MR. LEWIS: I heard the answer to your question, but let me broaden it a little bit. I just want to be very clear about this.

Since 1973, there have been a batch of things. There were the hundred-odd post-TMI action plan items and the plant presumably has complied with as many of those as everyone else has and has been reviewed in the normal course of events for compliance of those.

There have been a batch of generic letters and so forth. A few of those -- were those compliances based on the 2758 or on the original plant power analysis which was done at a higher level, on which we are now inquiring? That is to say; has all subsequent analysis been done at the 2758 license core level or at the original design basis level?

MR. CAPRA: All of the reanalyses that were done with respect to the transient accident analysis for this power uprate were done at the higher power level.

MR. LEWIS: That is not the question I asked.

MR. CAPRA: If your question is each individual requirement --

MR. LEWIS: I'm saying there have been many requirements levied since 1973 of which there were the hundreds of TMI and there are lots of generic letters and things like that. Those reviews were all done at 2758?

MR. CAPRA: I believe that's probably the case, if they were power dependent at all. I mean, many requirements --

MR. LEWIS: I'm aware that many of them are not power dependent but where there is power involved as there is, for example, for natural circulation, they were done at the 2758. That means that we do not have an assurance that those letters would have been complied with if the plant had originally gone to the original design level; is that correct?

MR. CAPRA: I can't give you a direct answer to that.

MR. LEWIS: I see.

MR. CAPRA: We have no evaluated that.

MR. LEWIS: Fine.

MR. CAPRA: Perhaps each individual requirement --

MR. JACKSON: Dr. Lewis, perhaps I can attempt to address that.

MR. LEWIS: You see why I'm asking.

MR. JACKSON: Yes, and we have already gone through that. The question really is much broader than the specific issues that might have been evaluated in part of an SER issued by the staff. We have attempted throughout the history of this unit to maintain modifications and evaluations on safety-related areas at the 3216 level and there are only a limited number of them that were specific where they were power level dependent specific to the 2758 and we believe we've identified those and we've incorporated the various modifications in the assumptions for the reanalysis work that has been performed for this application.

However, we have gone beyond that and there are provisions which you're probably aware of that a licensee is permitted to make modifications under 10 CFR 5059. We have conducted a review of the several hundred such modifications that we have performed to assure ourselves that there are none of the evaluations that we have performed that are power level dependent that, a set point or an assumption on some parameter such as flow or pressure is power level dependent in those safety evaluations.

We have not found any additional that have not been part of the reevaluation and we've completed that review ourselves to give us that assurance. We had a similar concern that we may have done something over the years that is specific to a given power level. I think as staff mentioned, most of the modifications evaluations are not power level dependent. There are only a few of them that are.

MR. LEWIS: Okay, I thank you, I must say for a direct answer. Let me make sure I understand it. You say that throughout the history of the plant, you've formed in the back of your mind that you might go again for the original design power level and therefore you've made all your mod's consistently with the originally designed power level and now you've gone back to make sure that you did that okay; is that essentially what you've said?

MR. JACKSON: That's correct.

MR. LEWIS: Thank you.

MR. CARROLL: I thought I heard you say there were a few that were done at the 2758?

MR. JACKSON: Yes. The principal area is the emergency core cooling system in which the staff evaluations were -- although we as licensee had formed a calculations and submitted them on the docket at higher power, the evaluations done by the staff and specific set points that resulted from that and technical specifications were at the 2758 so that was one of the major areas of our reevaluation was the emergency core cooling system performance and compliance with 5059.

MR. MICHELSON: This is an area that I'm surprised the staff didn't include in their SER. They should have said that there are a few things that might have happened that would be power dependent and here's the ones that did happen and here's how we evaluate them. I didn't find it anywhere in the SER but maybe I missed it, such things as the natural circulation test. It is an important consideration when you elevate the power this much, to make sure that these things are still monitored.

MR. CAPRA: Yes, sir. I understand your concern and you didn't miss it in the SER. It's not addressed.

MR. LEWIS: Please go on. We've not given you much of a chance to talk.

MR. LIBERATORI: If I might on a follow up slide, I think I have a good example of the situation that occurred after 1973. So I think I can give you a good example.

MR. LEWIS: How are you doing on schedule because my friends will shoot me if we're very late with our mid-morning break.

MR. LIBERATORI: I probably have about half left but I'll do the best I can.

MR. LEWIS: How many?

MR. LIBERATORI: About half of my presentation left.

MR. LEWIS: Which means?

MR. LIBERATORI: Maybe another 10 minutes.

MR. LEWIS: I'll hold you to that. Go.

MR. LIBERATORI: Okay.

Non-loss of coolant accidents, as I stated, have all been reanalyzed at this point. They meet the various non-LOCA acceptance criterion. With respect to containment performance, the transient of interest is the steam line break as opposed to the loss of coolant. Licensing up to this point has had the loss of coolant response bound, the steam break response.

We've reconfirmed that that continues to be the case at the proposed power level. There's no change with regard to that. Next slide, please.

[Slide.]

MR. LIBERATORI: Off-site dose evaluations, again the original FSAR performed all the dose consequences assuming a 3216 radiological source term. So that still bounds the situation we're talking about now. There were two specific events which we reassessed. The first one was to look at the dose calculations for the tube rupture accident which as I stated were done with a 3216 source term to get a feel for the sensitivity affect of again the parameter range that we've analyzed for here and we found that the effect of the parameter range really were insignificant in terms of the dose consequences of the tube rupture and in fact remained well within the guidelines for the accident.

The second accident which I referred to was a fuel handling accident in containment. There was a generic letter in the late 1970s which the staff requested all licensees to evaluate. That accident was not in our original FSAR and at the time we did it, we did it at the 2758 calculated power level. As part of our submittal to staff, we have recalculated that accident with a 3216 radiological source term making that now consistent with all the original FSAR accident analyses and in fact, one of our tech spec changes was a result of that. In order to maintain the same dose consequences for that event, we back-calculated it increasing the delay time prior to moving the first spent fuel assembly such that the consequences of the action would remain the same even though we assumed a much higher radiological source term now.

MR. CARROLL: What's the minimum time?

MR. LIBERATORI: The minimum time is currently 131 hours. It will be increased to 174 hours. So approximately 40 hours longer and that results in the same consequence for the accident, just in effect allowing more decay since we assume the higher source term. There is the case of an accident which in our review we did uncover as a post-licensing accident, then reanalyzed it.

MR. CARROLL: Isn't that hurting you in terms of real world schedules?

MR. LIBERATORI: Well, we've looked at it in terms of real world schedules and based on experience, when we normally start moving fuel, we did not see that as a tremendous economic restriction.

MR. CARROLL: Okay.

MR. MICHELSON: What was the feedwater maximum temperature and what is it now under the new power?

MR. LIBERATORI: The main feedwater temperature?

MR. MICHELSON: Yes.

MR. LIBERATORI: If my recollection is correct, it's going up about 10 degrees from about 415, 420 range to approximately 427, something in that range.

MR. JACKSON: A 15 degree increase, going up to about 430.

MR. MICHELSON: That's included of course in your analyses and so forth?

MR. LIBERATORI: That's correct. That's correct.

MR. MICHELSON: Thank you.

MR. LIBERATORI: So in summary, the limiting FSAR events are now consistently analyzed at the 3216 power level source term and the results remain below the Part 100 guideline limits.

Next slide, please.

[Slide.]

MR. LIBERATORI: Quickly, to touch on the technical specification changes we've requested of the staff, first change was the power level from 2758 to 3071.4. Changes we needed to bolt these T-average max as well as the T-average input to the overpower and overtemperature delta-T equations again based on the upper bound of the new operating temperature range.

The loss of feedwater flow accident assumed a higher minimum aux feed flow to take care of the higher decay heat levels. We revised the tech spec's minimum to match what we used in the current analysis. The basis of that particular tech spec happened to state what the full power steam flow was, so just that number physically has to change to the steam flow at the higher power level.

MR. MICHELSON: How much have you elevated the steam temperature for the new power?

MR. LIBERATORI: Not appreciably. Probably on the order of the same -- subject to check I guess on the order of the same 5 or 10 degrees.

MR. MICHELSON: What's your new steam temperature max of the generator?

MR. JACKSON: Remember, we're analyzing for a range. The current power steam temperature at steam generator outlet is 514 approximately and if we go to the upper range of the RCS temperature, we're just over 513. The lower temperature extreme would be 482.

MR. MICHELSON: That's the current.

MR. JACKSON: We're currently --

MR. MICHELSON: You've got a range currently, I assume.

MR. JACKSON: No, right now, we have a specific point.

MR. MICHELSON: Oh, you don't want to stick with one point.

MR. JACKSON: Okay. The revised analyses, if you'll recall one of my earlier slides provided for a various range of

RCS temperatures, pressure -- secondary pressures.

MR. MICHELSON: It's secondary I'm interested in. You're not going to exceed the 514 yet; is that correct?

MR. CARROLL: Pressure is dropping as the power goes up.

MR. MICHELSON: Uh-huh, but he's still starting out at the 514 as his peak.

MR. JACKSON: Yes. At the upper range of temperature, we're essentially the same, within a degree, the lower RCS temperature range, your temperature is dropped and of course, you're going to be limited based upon pressure in terms of stress analysis considerations. So depending on plugging level --

MR. MICHELSON: That takes care of it. Thank you.

MR. LIBERATORI: The last technical specification change that I just mentioned previously was the increase in the delay time prior to moving the spent fuel assembly to be consistent with the assumptions made in the fuel handling accident in the site containment.

Next slide, please.

[Slide.]

MR. LIBERATORI: Plant equipment review. We looked both at the nuclear steam supply systems and equipment in conjunction with Westinghouse, the original NSSS vendor. Likewise, we looked at all the balance-of-plant systems and equipment in conjunction with United Engineers, with the original AE.

The next slide.

[Slide.]

MR. LIBERATORI: This is in a sense a listing of key systems within the NSSS scope which we evaluated. In each case, we reviewed the equipment against the stretch conditions and determined that the design envelopes the anticipated operating conditions at stretch.

And as Mr. Jackson mentioned, there are normal control setpoints, alarm setpoints, and so forth, which will have to be adjusted to reflect where we will actually operate the plant, but again, within the capability of the existing instrumentation. It is just a matter of adjusting things. So there are no physical, you know, hardware changes necessary to support this evaluation. In effect, the design envelopes the anticipated operating conditions.

The next slide.

MR. CARROLL: Pressure safety valves. Do you have loop seals?

MR. LIBERATORI: No, we don't.

MR. CARROLL: Okay. What impact, if any, does the current flap about how to set safety valves and potential 10 percent errors in safety valve set-ins, and that sort of thing, have on the safety analysis that you've performed?

MR. LIBERATORI: We feel it doesn't have a significant impact on us. We don't have loop seals; we test our safety valves in a facility with saturated pressure.

MR. CARROLL: So you are actually testing them on saturated steam?

MR. LIBERATORI: That is correct. And we are part of the Westinghouse owners group, so obviously we are aware of the existing issue, and it seems to be concentrating on those plants with loop seals.

MR. CARROLL: Yes.

MR. LIBERATORI: But we will continue to follow the issue, and whatever comes out of that analysis, we certainly will follow it if it applies to us.

MR. CARROLL: Has your experience with pressurizer safety valves been good without them having loop seals?

MR. CARROLL: I would say our experience has been god, yes.

[Slide.]

MR. LIBERATORI: Balance-of-plant. As Mr. Jackson pointed out, originally designed and guaranteed at 3083.4, calculated capability of 3216 megawatts thermal. We did a similar review, evaluated the systems and equipment against stretch, determined that the design of the systems enveloped the anticipated operating conditions. Again, there are normal control setpoint changes necessary, heated drain tank levels, alarms, deviation alarms, et cetera, associated with normal operation.

In addition, for both NSSS and BOP, obviously there are changes to the facility necessary to accomplish the requirements of the proposed technical specifications. We've submitted, you know, reactor protection trips and aux. feed flow and so forth.

The next slide, please.

[Slide.]

MR. LIBERATORI: I would like to conclude by saying that we believe the Stretch Program has demonstrated compliance of the FSAR analyses with applicable acceptance criteria, that we have demonstrated compliance of the components and systems with FSAR functional and regulatory requirements. The Stretch Program has reconfirmed the capability of the plant to perform in its original guaranteed power rating, and, as our application states, we determined there is no significant hazards consideration involved as per 10 CFR 50.92C.

That concludes my prepared presentation.

MR. LEWIS: Thank you very much.

MR. JACKSON: Dr. Lewis, there were two questions that, if you would like our brief answers to the questions before the break, we can attempt to answer them now.

MR. LEWIS: Oh, why don't we do them after the break, when we are more prepared. Let me give us a 10-minute break, reconvene at quarter of, and then we will have those questions, the licensee conclusion, and the staff conclusion.

[Brief recess.]

MR. LEWIS: Okay. Let's come to order.

I think you had a couple of things to tell us before the summary. Is that right?

MR. JACKSON: That's correct.

MR. LEWIS: Okay.

MR. JACKSON: Charles Jackson.

MR. LEWIS: Are you ready?

MR. JACKSON: There were two questions, and if I understand them correctly, let me attempt an answer.

First was on the component cooling heat exchanger and what monitoring was being done and how frequently.

On the component cooling water side, the closed-cycle side, there is a monitoring every 4 hours of the header temperature and flows. On the service water side, we are also, on similar frequency, measuring header pressures, and then at refueling intervals, we put on special instrumentation for flow. We don't, right now, have instrumentation for flow to that specific heat exchanger but monitor the header flow.

MR. MICHELSON: Do you mean the header flow or the header pressure?

MR. JACKSON: The header pressure. Excuse me.

MR. MICHELSON: Header pressure doesn't tell you anything.

MR. JACKSON: We're measuring the --

MR. MICHELSON: The pressure will go up as you start to plug the headers.

MR. JACKSON: Well, we're measuring the temperature on the other side of the heat exchanger, and --

MR. MICHELSON: The downstream side of the service water, you're monitoring the temperature. Is that what you're saying?

MR. JACKSON: No. On the component cooling water side, we're monitoring regularly the temperature. So, if we had a decreased flow on the service water side of the heat exchanger, we'd see, for the normal operating condition, temperature would increase, and we have established a range of expected temperature that we would expect to see.

MR. MICHELSON: Okay. So, you monitor only -- you only monitor the header pressure on the service water side. I'm not quite sure what that's for. If it's dropping, that just tells you your pumping system isn't working as well. If it's going up, you think it's working well, but it's not; it's plugged.

MR. JACKSON: But we would expect the performance on the component cooling water heat exchangers to be similar to the heat exchangers that are also in that system on other safety-related equipment, such as the --

MR. MICHELSON: Do you monitor the downstream temperature at all on the service water side?

MR. JACKSON: I don't believe so, no. We do it indirectly, but it's a mixed flow in the discharge canal with other flows.

MR. MICHELSON: Now, did you find out when you last did any kind of test on that heat exchanger to confirm that it was functioning properly, and by that, I mean a real test of flow measurements?

MR. JACKSON: We did flow measurement, I believe, during the last refueling outage, which would have been last summer, with special test instrumentation that was put on the service water side, and of course, we are instrumented to monitor on the component cooling water side. Those heat exchangers are not the original 20-year-old heat exchangers. They have been replaced.

MR. MICHELSON: They're about 10 years old now.

MR. JACKSON: Seven or 8 years old, I believe. It was either the '82 or the '84 outage -- '84, I believe.

MR. MICHELSON: And you have no real biofouling problem on the heat exchanger.

MR. JACKSON: No. We haven't seen anything since we -- particularly since we have had chlorination on the service water for a number of years.

MR. MICHELSON: That's been a number of years that you've chlorinated?

MR. JACKSON: Yes. We instituted that -- I believe it was '81 -- '81-'82 time period.

MR. MICHELSON: What was the reason for replacing the heat exchangers?

MR. JACKSON: On the component cooling heat exchangers, there was degradation that was occurring on the surface of the tube sheet. It was, we believe, an erosion mechanism, and we replaced the -- we had attempted repairs of the surface tube sheet but finally replaced them.

One other quick question was on the fouling factor. I have asked Mr. Paul Malik, who was recently with Con Edison as the project manager for the stretch program, and he has also been our heat exchanger project engineer for various upgrades. He is now at PMX Corporation. He is consulting.

Paul, would you give a brief answer?

MR. MALIK: First, I'd like to thank you. You know, this is a great honor for me to address the distinguished members, who I see in the papers, the names. This is the first time I'm seeing all of them. It's a really personal satisfaction.

MR. LEWIS: Shall we assign the same credibility to the rest of what you say?

[Laughter.]

MR. MALIK: Yes, Sir. No, I say that as I feel it, and sometimes I get in trouble for that, but I would still say it.

Okay. Fouling factor, as we know, is a function of the water velocity and the river water conditions and temperature. Originally, when the plant was designed, since then the water hasn't changed. What we have done since 1982, I think, approximately, we have increased the flow to the fan coolers.

Originally, when the plant was designed, each fan cooler was supposed to have 570 gallons per minute going to the fan cooler, but presently, the flow through each fan cooler is roughly 1,200 to 1,400 gallons per minute. So, what we have done is we have increased the velocity to retard any buildup, any corrosion products, or any fouling, to improve on the fouling mechanism.

Number three is that originally, when the plant was designed, we were required to have 1,600 to 1,800 gallons per minute to meet the containment pressure criteria. In 1987, we did the reanalysis of the containment, and presently -- and that was based on 85 degrees -- we need only 1,600 gallons per minute and 95 degrees. So, we have a margin of 20 percent in the essential service water system for the fan coolers.

This gives us a great confidence that even if there was a slight seasonal change in fouling, it can be easily eradicated by the margin we have in the system.

MR. LEWIS: Thank you very much.

Okay. Now, I guess, we're on to hearing the licensee's conclusions. Is that the state of the art at the moment? After which, we'll hear the staff conclusions, after which we'll come to our conclusions. They may all be the same, but they may not.

MR. MICHELSON: Before we get to that, let me ask one more question.

What was, again, the reason why you decided to more than double your flow through the containment coolers?

MR. MALIK: Well, we found at that time, for many reasons, that we were not -- you see, 570 gallons per minute was part of the design. We are always trying to modernize and improve the plant, and we felt 570 gallons per minute was just not the right flow for the containment.

MR. MICHELSON: Apparently, then, the original design basis, which was 570 gpm, I assume, or thereabouts, was found to be inadequate for some reason.

MR. MALIK: I don't know if it was inadequate, Sir, but --

MR. JACKSON: Perhaps I can attempt to answer that.

You have two flow conditions. One is the normal operation flow for heat removal from containment and then a significantly increased flow for accident conditions.

What we found in the early '80s, we felt that a contributor to some of the corrosion mechanism was the reduced flow, and we felt that, in addition to the other changes that were made, increasing the normal flow would serve to have a benefit on sweeping the coolers clean of any material that might be depositing.

MR. MICHELSON: I don't know if you ever did tell me what the bio-organism was that you thought had caused the pitting attack. Do you know what it might have been?

MR. JACKSON: No, I don't, but I --

MR. MICHELSON: You apparently were upping the velocity to try to sweep it cleaner, but what was bothering you that you had to sweep?

MR. JACKSON: Well, it was a -- I don't remember the specific name of the organism. I believe it was a product from the metabolism of that organism that was causing --

MR. MICHELSON: Yes. Well, they attacked the tubes and that attachment point was where it occurred.

MR. JACKSON: It was really attacking in a crevice area, and we were seeing, I guess, minor pitting. It was not a significant contributor to the other events, the erosion type of attack we were seeing on the tubes.

MR. MICHELSON: It's enough to make you replace the heat exchangers.

MR. JACKSON: That, in itself, would not have been enough for us to replace it. The chlorination would have been more than adequate to cover that.

MR. MICHELSON: Why did you replace the heat exchangers?

MR. JACKSON: The heat exchangers had developed a leaking mechanism. The original design had braised joints, and those braised joints were subject to considerable corrosion and erosion type of things.

MR. MICHELSON: That was the heat exchanger header problem you were having. Is that right?

MR. JACKSON: Well, it was the heat exchanger itself. The heat exchanger design had a U-bend, and the U-bend section had what was typical, in those days, of an air-conditioning design, a braised joint, and we replaced with a new material that did not have the braised joints and have subsequently improved with a different tube material. We've had two replacements since that problem.

MR. MICHELSON: But you don't know what your biofouling problem was.

MR. JACKSON: I mentioned it because it was a minor contributor that we had some. I don't have the specific report here with me to give you the name of the species, but I think we could find it.

MR. MICHELSON: That's all right. Thank you.

[Slide]

MR. BRAM: Mr. Chairman, I'll be very brief in my concluding remarks, so that we can stay on schedule or get back to schedule.

Indian Point Unit Number 2 is being operated with the utmost concern for nuclear safety. The plant is being well maintained, and modernized of equipment has been ongoing through various betterment programs. This includes the main turbine, main generator, heat exchanger equipment, and pumps.

We have also, as previously described, upgraded many of the FSAR analysis packages to current technology. Additional equipment enhancements are planned for future years.

Indian Point Unit 2 is an important part of Con Edison's capacity base. We are committed to excellence in the manner in which we operate and maintain the plant.

Our corporate long-term strategic plan, in coordination with the industry at large, is to extend the current licensed life of the unit beyond 40 years. Stretch Power is an integral part of this strategic plan.

Our analysis and evaluations have reconfirmed the capability of the plant to perform at the original guaranteed power rating of 3071.4 megawatts thermal. We are currently on schedule to implement the Stretch Power escalation following the upcoming outage and request your concurrence to proceed.

Thank you.

MR. LEWIS: Thank you.

MR. CARROLL: Are you going to comment on the dry-out incident. or give us a little bit of perspective on it?

MR. BRAM: Well, if you'd like me to, I certainly would be happy to. I might say that the incident occurred, as we've discussed, a little over two years ago. I think, from the point of view of lessons learned and what we have done with those lessons learned, it has been a positive experience for us.

I think that we, as a company, have always stressed nuclear safety, and I think that we learned some things from this event, and consequently have, over the last two years, been able to make some very important, useful improvements in the way we do operate the plant and the umbrella of our desire for nuclear safety.

The actual event, as we've talked about, took place over a 36-hour period. Our own investigation, which I believe was supported by the NRC inspection, the AIT team, was that the operators did recognize the instrumentation. It gave them the indications that the generator was slowly drying out; it was not that they were caught by surprise.

What we believe happened, however, is that they were aware of the fact that the motor-driven aux feed pump was out of service for maintenance. They had been given a schedule that indicated that that piece of equipment was very soon to be returned to service, and they fully expected that that piece of equipment would be back before the steam generator actually dried out. For that reason, they did not take any action sooner.

When the piece of equipment did not return, that is really when, if you want to call it at the last moment, when they found themselves with a steam generator that was dried out.

The corrective actions that we took as a result of that event I think were far reaching. For one thing, we recognized that we had to have additional senior management involvement in plant operation, starting at my level, a vice president level, and going down to the general manager level, the operations manager level, right down to the actual shift watch supervisor.

At my level -- and I might say, by the way, from my point of view, this was a very interesting experience because I had only been in my job for two weeks when this event occurred, so it was an outstanding opportunity for me to learn every detail of operation of the plant, what we do well and what we don't do so well. It was also a golden opportunity to meet our regional administrator under circumstances that I'd prefer not to do so again.

But in any event, one thing that became very apparent to me was that the policies that were being set by senior management had to be communicated more effectively down to the operating level, and I don't know of any better way to do that then to get down and talk with the operators myself. So that is something that I have been doing routinely over the last two years. I insist that my general managers do that, and that my operations manager do that regularly.

I, periodically, make surveillances myself of control room operations, including the watch turnovers. I read the logs, and, as I said, I talk with the operators to ascertain what problems they have with the equipment and what their concerns are.

I think that healthy give and take has given senior management more credibility, and I think it has contributed to effective communications and an understanding by all operations personnel as to what our expectations are in the operation of that unit.

We did some other very concrete things, also. For one thing, although at the time of this incident we did have an STA, a shift technical advisor function, that function, below 350, was not required to be in the control room at all times. We made a change as a result of this, and the shift technical advisor is now required to be in the control room around the clock to provide additional technical guidance to the watch.

The shift watch supervisor, who is the ranking authority in the control room, has also been instructed to make sure that he or she does not get their attention diverted by small details that might give them a loss of oversight of the broader picture of what's going on in the plant.

We felt that, in part, during this event, the SWSes on duty were involved in some of the details of the start-up, and did not have an opportunity to pay as much attention to the broad picture of what was going on, and might have been able to handle the situation differently if they were focusing very specifically on that type of -- or had that type of perspective.

We identified some problems with log keeping as a result of this event. We modified the logs themselves. We felt that our watch turnover procedures could be enhanced as a result of that 36-hour period, where we felt that perhaps again the communications were not effective in highlighting that this was a concern.

We have increased the number of surveillances that are made by our independent QA organization. They are surveilling operations functions, both during the day watch and off watch and on weekends. They make surveillances of the log; they make surveillances of the watch turnovers; and they provide written reports to management in the plant, including myself, of what their observations are of the quality of the operators' work.

Very importantly, also what we have done is we provided an additional staff group to perform pre-operational planning. The purpose of this group is to review every evolution of the plant, to review the procedure that is applicable to that evolution, and to make a determination whether or not the plant is in a condition, materially, to initiate that evolution.

The purpose of this was to help the watch and be sure that the watch personnel were not the only people making a determination of whether a planned evolution could be carried through effectively and properly. So this group now reviews all the procedures before they're actually implemented to make sure that the initial conditions are as require in the procedures, and that those procedures can be implemented before they actually are implemented by the watch. Then, of course, the watch has the final decision as to whether or not to implement that procedure, but it's been pre-checked before the watch actually gets that procedure.

With regard to start-up procedures, one of the things that we saw as a result of this event, which, again, took place back two refueling outages ago, and I think it was mentioned that the NRC made an inspection of our more recent refueling outage startup, one of the things that we feel contributed to the dry-out event was the fact that we did have equipment out of service during the heat-up period, particularly that aux feed pump.

We now require that before we reach 200 degrees, all of our 350-degree holds are cleared, so that we have further assurance that our plant is ready to ascend in power. Any exceptions to that have to be approved by the highest levels of management.

So we think that we put in additional lines of defense, if you will. NRC, in their presentation, pointed to some other things that have been done. I think the training of our operators is excellent. I think the personnel that we have are highly qualified to operate the plant. I have the utmost of confidence in them, and I think now what we've done is close the loop to make sure that senior management's expectations are clearly understood and that there's adequate feedback to senior management to be sure that we're achieving what we want to achieve.

MR. WYLIE: Could I ask questions?

MR. LEWIS: Sure. Go ahead.

MR. WYLIE: In your subsequent inspections of the steam generators -- I believe in '89 -- did you notice any difference in the deterioration of the one that dried out compared to the others?

MR. BRAM: In what way?

MR. WYLIE: Well, I don't know. Normally -- you identified cracking and your girth cracks, and what have you, with those steam generators. Did you notice any difference in that particular steam generator and the others?

MR. BRAM: That steam generator is one of the two steam generators that did experience somewhat more cracking than the other two. We do have two steam generators that seem to have more -- I'm sorry -- the steam generators that had the most cracking were Steam Generators 22 and 23. I don't know that we saw any change, significant change, though, in that steam generator.

Charlie, do you recall offhand whether we saw any significant difference?

MR. JACKSON: No.

MR. BRAM: I don't believe so.

MR. WYLIE: You purchased four replacement steam generators, I believe.

MR. BRAM: That's correct.

MR. WYLIE: What are your plans for them?

MR. BRAM: Well, right now, those four steam generators are in storage. We have no specific plan to install those four steam generators, but they are available in the event that our evaluations would suggest that it's justified to install them. Right now, we do not believe that there is any immediate need to make that installation.

MR. WYLIE: Thank you.

MR. LEWIS: If there are no further questions, then thank you.

MR. CARROLL: Well, I did want to follow up on one other thing: the extent to which you're really looking at the design to make sure that this ancient plant -- that there aren't some glitches in the design, the SSFI kind of look.

MR. BRAM: Well, I think it was mentioned that there have been several SSFIs already undertaken. I believe three or four have actually been completed. I don't recall offhand the schedule, but there are more that are planned in future years.

MR. CARROLL: By Con Ed?

MR. BRAM: Yes, by Con Edison.

MR. CARROLL: Have you looked at electrical systems? That seems to be a place people are finding --

MR. BRAM: Yes, we did. Last year, in 1989, we undertook an SSFI of our electrical systems.

MR. CARROLL: And did that turn up anything startling?

MR. BRAM: Nothing startling. There were some enhancements that we made as a result of it, and we are doing a walkdown of our electrical systems, which will be a multi-year program, to make sure that we're satisfied that we understand the design basis of those systems.

MR. CARROLL: Okay.

Moving on to maintenance, do we need a maintenance rule to help you understand how to maintain your power plant?

MR. BRAM: I think not. I think we and others in the industry know how to maintain our power plants. I think that there are many examples of initiatives that have been undertaken in the industry, certainly by Con Edison.

I think, in some respects, a maintenance rule might just divert our attention from what we're otherwise doing. I think we have a sense of responsibility, and we want to maintain those plants as well as the NRC does.

MR. CARROLL: To the extent that the NRC found some negative things about your maintenance program in their maintenance team inspection, have those previously been identified by you and your self-assessment and by INPO?

MR. BRAM: Yes to all of that. The findings of the NRC inspection team really were very similar to the findings that we had made in our own self-assessment towards the very end of 1987. We had identified eight points in our self-assessment. Those points, in fact, were shared with the maintenance inspection team when they came into the plant. They've also been shared with INPO, and certainly the NRC and INPO are in agreement with our own findings. That, in effect, was, in large part, reflected in the NRC inspection report.

MR. CARROLL: So the problem is a matter of time to implement things as opposed to basic flaws in the program?

MR. BRAM: Yes, it is a question of timing. Actually, we had intended to -- first of all, let me say this. We have already, in many respects, implemented corrective actions that we had identified and that the NRC staff had identified in the self-assessment and in the maintenance inspection.

There are more to be done. We have a very detailed program that we have put down in writing. When Bill Russell was up to visit us about two months ago now, we presented a part of that program to him, and we are planning to sit down with the staff in large to go into more detail. Some of that has already been implemented, and you can see very definite improvements in the plant already.

MR. LEWIS: Thank you very much, Mr. Bram. I appreciate it and I think we'll now go on. I don't know who's going to speak for the staff. If I could beg and plead for the staff to try to hold itself to 30 minutes including our nasty questions, it would be a tremendous help.

MR. CARROLL: I thought we were being kind and gentle today.

MR. LEWIS: Indeed we are. We tend to get kinder as lunch approaches.

Please go on.

MR. BRINKMAN: Thank you, Dr. Lewis. There are three speakers left for the staff presentation, about 10 minutes a piece. We'll try to move along and maintain your schedule.

The staff in its safety evaluation and in its review of this application confirmed that the plant was in fact designed as the licensee has stated for the core power level, 3071.4. We also looked at the original license application and determined that the original operating license was requested at 2758. There was no technical reason for the derate. It was simply as was stated, to gain experience at the higher power levels than the previous plants.

In our 1970 safety evaluation report, the staff evaluated all the engineered safety features except the ECCS system and we did the environmental reviews. They were all done at 3216 and it was reported as such in the original safety evaluation. The state of the ECCS system was at 2758.

[Slide.]

MR. BRINKMAN: In our current safety evaluation, we looked at the core design and determined that yes, the core is adequate to perform at the 3,071.4 megawatt level. The licensee performed all the applicable FSAR Chapter 14 -- they were not in standard format but they did perform all the Chapter 14 events and the staff confirmed that the results are acceptable and they're bounded by the LOCA analysis.

We looked at ECCS performance which Tim Collins will give a further presentation on here in a few minutes. We looked at overpressure protection, determined that it is satisfactory. We looked at the anticipated operational occurrences. Their results are acceptable. We looked at non-LOCA events. Found them to be acceptable. We reviewed the auxillary feedwater and residual heat removal performance. We determined that with the increased flow in the auxillary feedwater system, it is acceptable.

We looked at the reactor coolant system to assess the stress and fatigue usage factors. We found them to be acceptable at the stretch power conditions. We also reviewed the containment integrity analysis. The original design pressure of the containment was 47 p.s.i. For the stretch power, we found the LOCA analysis to be bounding, 40.31 p.s.i.g. for the stretch power with the NSSS rating of 3,083.4. We found it to be 41.12 at the design level of 3216 megawatts. We looked at the analysis for containment integrity for the main steam line break. We found that it was bounded by the LOCA and for main steam line, we reviewed the calculation for 39.99 at the stretch power conditions.

MR. CARROLL: What's the pressure go to if one wants to postulate a catastrophic failure of the steam generator shell that takes with it the tube bundle which is a combination of those two.

MR. BRINKMAN: I don't believe we have any of that. Bob Herman, do you have anything to offer on that?

We have not analyzed that.

MR. MICHELSON: Have we not analyzed the blowing out of the manhole cover plate which is about how you would get into it, for instance, in a more easy fashion.

MR. CARROLL: No, I want to rupture the primary and secondary side.

MR. MICHELSON: Yes, okay. You want to get the whole thing. Well, there must be cover plates on the secondary side too; aren't there?

MR. CARROLL: Oh, yes.

MR. BRINKMAN: There are manways on the secondary side.

MR. MICHELSON: I know there's a manway on the primary side, too.

MR. CARROLL: I'm having the girthwell failure somehow or other.

MR. MICHELSON: That's an incredible failure.

MR. CARROLL: Oh, it is.

MR. MICHELSON: No, it's not a design basis failure.

MR. CARROLL: I understand.

MR. BRINKMAN: We have not analyzed that.

MR. CARROLL: It might be just twice.

MR. MICHELSON: I thought the manways had been analyzed but I guess not. On PWRs, you've never looked at the manway -- the cover plate blowing off?

MR. BRINKMAN: I don't believe we have. Does any of the staff have anything on that?

I don't believe we have. We also looked at the balance of plant systems including the steam turbine system with its -- the main steam system, the feedwater condenser, the condensate systems, circulating water systems and the rest of their support systems and determined that they are adequate for stretch power conditions.

We've talked about the service water system. We looked at the essential service water, the non-essential service water and determined it has adequate capability for the stretch power conditions. We looked at diesel generators. They have adequate capacity to support the stretch power. The auxillary feedwater system ends up with a slightly higher flow here but we've already analyzed it for the full flow of the capability of the pumps. So that was enveloped.

We looked at POP piping systems and determined they are satisfactory at the stretch conditions as well as the steam generators. The steam generators -- Bob Herman will give a further presentation on that in a few minutes dealing primarily with the cracking phenomenon that has been observed at Indian Point in the steam generators.

We looked at environmental qualification of the equipment and determined that the licensee did evaluate the effects of the stretch power and the equipment qualification and confirmed that the equipment in the EQ program is qualified for the temperature, pressure and radiation levels corresponding to the harsh environments which could be involved with a pipe break condition.

We reviewed the plant instrumentation and confirmed that no changes in plant equipment are required. The licensee is using approved methodology for calculating set point changes. We then reviewed the set point changes for true channels in some detail, the overpower Delta-T and the overtemperature Delta-T channels and we confirmed that the potential uncertainties have been properly considered.

We also looked at the environmental consequences of the power increase. The original environmental statement assumed a power level 3216 which bounds the proposed stretch power level of 3,071.4 megawatts thermal. We reviewed one of the accident analysis in the application for the steamline tube rupture accident and confirmed that the off-site doses remained well within the acceptance criteria of standard review plan 15.63.

The licensee's reassessment of the radiological consequences do not alter the conclusions stated in our original safety evaluation. They're well within the Part 100 guidelines.

MR. CATTON: If everything looked so good at 3216, why aren't they asking for more than 10 percent?

MR. BRINKMAN: I'll ask the licensee to respond to that.

MR. JACKSON: The original contract guarantee point was at the 3083 and that's the level that we're proposing to go to but we're not foreclosing subsequent analysis after experience at that level to go and ask the staff for increase to higher levels, whether it's 3216 or 3250, which is where I guess the similar generation plants are operating now but we picked the design point of the 3083 for this phase of an upgrade.

MR. CATTON: Sounds good to me.

MR. BRINKMAN: We've evaluated their request at the current 3,071.4 and these are the conclusions we have come to. They've certainly indicated they may request higher at some time in the future. We looked at the requested technical specification changes changing the value of rated power from 2758 to 3,071.4, would be accomplished in a change in the definition of rated power in the tech specs and changed the allowable Tavg in the limiting safety system settings, trip settings, and in the LCL set points and would require an increase in the minimum required auxillary flow rate to 380 gallons a minute. We agree with that change.

To be consistent with the fuel handling accident in containment, we would increase the fuel handling rate down to 174 hours.

Now I'd like to ask Tim Collins to come up and speak.

MR. MICHELSON: Before you leave though, I have a question. You told me about all the kinds of things you looked at in the process of reviewing this situation so let me ask you, did you look at the operating history of this plant for the last five years or so from the viewpoint of events that might have occurred that would be power-related for which you'd like to assure that appropriate corrective actions have been taken. So maybe you could tell me to what extent you've reviewed the licensee event report history on this plant for let's say the last five years to make sure that there haven't been events for which you might have some concern.

MR. BRINKMAN: I did not review them as part of this application per se, Dr. Michelson. However, I'd do that as a routine function in my position as project manager. I receive the licensee event reports. I review them. I have been in this position for about the past year. I do not recall any in the past year.

MR. MICHELSON: A year is fairly short.

MR. BRINKMAN: Yes, it is.

MR. MICHELSON: Well, did you ask, for instance, AEOD to give you a computer printout of certain kinds of things that might have occurred at Indian Point for the last five years?

MR. BRINKMAN: I did not.

MR. MICHELSON: Isn't that kind of what you would want to do to find out if there's anything in the operating history? We've looked at the paper. The paper looks good. The computations look good. How's the plant really working and have you asked at all or asked somebody else to look at or does AEOD -- wouldn't they normally respond to a request from NRR asking, give us a quick run-down on the operating history of

Indian Point II for the last five years. They'd give you some computer printouts and so forth and categorize the LERs according to the kind of events that have been occurring.

This is all automatically done on the sequence coding and search system. All you have to do is look at the output and decide if there's anything there that raises an interest.

MR. CAPRA: No, sir. We have not gone back to AEOD and asked them to do that in that methodological of a manner.

MR. MICHELSON: This isn't very much work for them, you know. It's all on computers. It's got to be used, of course, in order to be useful but it's all there and very easily searchable in a number of different ways. Just for my own curiosity this afternoon I'm going to ask them to give me the biofouling printouts for the last five years. It's something that's very easy for them to do. I know who to call and in about two minutes they'll come back and tell me how many hits there are and if you want the details, they'll print it out or give you categorizations of them or whatever, just as an interesting example.

I would have thought that the staff in the process of reviewing any application of this sort would inquire at least a little bit into how the plant's been operating as well as whether the papers are all in order.

MR. CAPRA: In NRR we do keep up on a day-to-day basis, with plant operations through the region. You are correct, we had not gone and listed specific LERs.

MR. MICHELSON: See, unfortunately, it is, you get hit so much by the day to day things that you kind of lose sight of what happened a year ago or two years ago that might be very important from the viewpoint of if you increase the power level, it might have been more of an aggravation than it was at the time. So it looks like it is a kind of a tidy check. As long as we are doing all these other good checks, why don't we ask how the plant has been operating?

MR. CAPRA: Yes, sir. Like I say, we have not done it in the method that you have so described, but we certainly participate, along with the region, in, you said we sometimes get caught up in the day to day events. We do go back, on a periodic basis, and review overall licensee performance on a periodic basis through the SALP process, which both us and the region have participated in. But we certainly go into a lot of detailed reviewing, all LERs and all events.

MR. MICHELSON: They are viewed at that time from a somewhat different interest viewpoint. You are more interested in the process now and how well is the process working. And that is important, too. But in this case I am interested in how well the mechanical equipment has been functioning, particularly as it may be related to increases in heat output.

MR. CARROLL: Related to that, do you look at NPRDS to see if there is anything in there that suggests that there may be problems with higher thermal output?

MR. CAPRA: No, sir. We haven't looked at NPRDS specifically related to this power increase.

MR. MICHELSON: There is a couple of obvious ones. One is the containment heat exchanger. I can pull that out of NPRDS and see what kind of maintenance record it's had, what kind of problems it has had, and so forth, without asking the utility, which is important to ask, too, but usually you like to kind of search out a little bit so you know which questions to ask. And it depends on how thorough you want to do the job. If it is a 2 percent power increase, I wouldn't be overly thorough. Ten to 12 percent, which I think this is in that range, begins to get more interesting.

MR. CARROLL: The utility did look at these kind of things.

MR. JACKSON: Yes, we have looked at these. The performance of equipment, specifically reliability issues associated with NPRDS data base. We have an expanded system engineer program at the plant and one of the functions of a system engineer in this particular system is to specifically review history, both of the maintenance experience, any failure history, as well as be cognizant of problem areas that exist for that system, for example, where members of the EPRI SWAT program on service water, and our system engineer routinely exchange information. We are keeping up to date with our data entry in that system. And we routinely use that for evaluation.

MR. CARROLL: Now, Joe's system engineer on the feedwater system specifically asked himself the question, does 10 percent more feedwater flow look like it is going to cause some grief with the existing equipment?'

MR. JACKSON: Yes. He will specifically look at that in part of his training, which is now, that was one of the first areas of training that had been reinitiated, was the system courses. And the system course training has been modified to include the additional stretch areas. Things, for example, in the secondary plant, in the condensate system, the drains, the feedwater system, we have directed by our system engineer an ongoing program looking at erosion, pipe thinning problems associated with high flow. We predict, we inspect and predict areas where we might approach a minimum wall thickness and schedule future corrective action, whether it be additional inspection or replacement of equipment, based upon that history.

It is the intent of the additional people, after they have been through their training, to routinely monitor these activities, be on top of it, anticipate.

MR. MICHELSON: You don't need to search your database, of course, you generated it, and you are the originators of the LERs.

MR. JACKSON: That is correct.

MR. MICHELSON: And you certainly ought to be aware of your own. I assume you look at Indian Point 1 and 3 as well.

MR. JACKSON: Well, yes, certainly. And we have cross membership on various safety committees and many of the people at Unit 3 are former ConEdison employees. There is a considerable exchange of experience at the site.

MR. MICHELSON: I didn't want to indicate in any way that I didn't think you were looking at it thoroughly. I just thought that the staff ought to be aware of this because they have to look at it from a little different viewpoint. And this is a check and balance process, anyway. And therefore, their view is important as well as yours, of the same information.

MR. BRINKMAN: Anything else?

[No response.]

MR. BRINKMAN: All right. Mr. Collins.

[Slide.]

MR. COLLINS: My part of the presentation today is the review that the staff did on the ECCS system.

Basically, there are two parts to the review that we did. The first one I call the "system overview." It is kind of a broad look at the system to see if there is anything particularly different about it, relative to other plants.

We also looked at the original design rating of the pumps in the system to see if the licensee was trying to squeeze more out of them than they were originally designed for.

We look at the s see how many high-pressure pumps, low-pressure pumps are in the ECCS, and compare it to other plants of similar size and similar design.

The second part of the review is really the LOCA analysis part, it is a performance analysis. And in this part of our review, we look at the methods used by the licensee to make sure we have approved them for the application that they are using them; the scope of their analysis; we verify that the inputs are consistent with the Appendix K requirements and that the technical specifications bound the analysis inputs; and then we just check to see that the results are consistent with the ECCS rule and any other Appendix K requirements.

[Slide.]

MR. COLLINS: As far as the system overview goes, the original system design was for 3216 megawatt plant, so we concluded there was no squeezing of any of the ECCS components as far as the power upgrading went.

The configuration is four accumulators, one on each cold leg. He has injected about 600 psi. And they are designed such that three of the accumulators will supply enough water to basically cover the core halfway with no other injection.

Three high-head safety injection pumps. Each one, they injected about 1700 psi, and about 400 gallons a minute is their design flow.

There are two RHR pumps which act as part of the safety injection system. They are 3,000 GPM pumps. They injected abouc 600 psi.

And then there are two recirculation pumps which draw on the emergency sump and they have a 3,000 GPM capability, and they deliver about 250 psi.

Basically, it is a typical mix of subsystems, high-and-low-pressure systems, and typical capacity for a plant of 3,000, 3,200 megawatts.

[Slide.]

MR. COLLINS: As far as the performance analysis goes, for the large breaks they use the BASH system of codes, which is the standard Westinghouse ECCS methodology for large breaks.

They use the NOTRUMP code for small breaks. Same thing, the standard approved methods.

The scope, the reviewed the full break spectrum and verified the size of the break, single failure considerations.

For inputs, they used 102 percent of the 3071.4 megawatts that they are asking for; 102 percent of peak linear power. They assumed a lot more steam generator tube plugging than they have experienced. I think their experience is like 8 percent, but they have put in a lot of margin by assuming 25 percent plugging. And they used all the required Appendix K inputs.

The results, they have already discussed, large break is 2039 and the small break was 1218, and the criterion is 2200.

MR. MICHELSON: When you redid the analysis, did you change the setpoint on the accumulator injection?

MR. COLLINS: I don't -- let's see if they changed it or not --

MR. MICHELSON: Did your analysis show you needed to change the pressure injection point for the accumulators?

MR. COLLINS: The Setpoint. Lou --

MR. JACKSON: Lou Liberatori, I think, can address that specifically.

MR. LIBERATORI: Yes. As part of the reanalyses, Westinghouse did some sensitivity runs upfront to in effect fine-tune the accumulator. So there is a different water volume now. And I believe we increased the overpressure about 15 pounds. I think it was from 600 to 615, within the capability of the accumulator. So we did finetune the accumulator to get the maximum benefit from it.

MR. MICHELSON: All right. Thank you.

MR. WARD: But Lou, you finetune that, then, to -- these are so-called evaluation model calculations. You had the option of going to best estimate model analysis. You didn't do that. I guess I understand why. But how do you feel about finetuning the instruments, or the systems, to an artificial analysis rather than to best estimate of the plant behavior?

MR. LIBERATORI: Westinghouse, correct me if I'm wrong, but I don't believe the best estimate evaluation model has been approved yet for four-loop plants. So we could not use the best estimate model. And in fact, we may very well use that for future considerations.

MR. JACKSON: I would like to add to that answer. We are currently working with Westinghouse and EPRI on an R&D project to use Indian Point II as a model for a four-loop best estimate plant. So that is why I hedged a bit on future uprates. There is the potential with the results from a best estimate model after review, and if accepted by the staff, to proceed further. But we are currently evaluating and we will be doing the analysis over the next approximately two-year period.

[Slide.]

MR. COLLINS: Our conclusions were that the component design rating had not been changed for the original rating. Where the component design rating hadn't been changed for the upgrade, they had used approved analysis methods for all their analyses; that the scope of the analysis was in compliance with the Appendix K requirements. The inputs and results satisfied

Appendix K and 5046, and we see that ECCS is acceptable for operation at the 3071 megawatt level.

[Slide.]

MR. HERMANN: Good morning. My name is Bob Hermann. I'm the Staff Section Leader in Materials Engineering. I've come to talk about the girth weld cracking, both at Indian Point, and we're going to talk a little bit generically about girth weld cracking.

With regard to actions to date, the problem started back in the 1982 timeframe with a leak at Indian Point through the shell. The staff has put out information notices 8237, 8565 and 9004, Indian Point 3 problems and Indian Point 2 and Zion problems. I think what I'd like to do next is to put up a slide of Model 44 Generator, so you get an idea of where things are in the generator.

[Slide.]

MR. HERMANN: The girth weld we're talking about is right here. The feed water ring is right here, and you can't see it in this one but I'll show you in a later slide that there's a baffle plate down in this area, too. I just wanted to give you a feel for where things are in the generator.

You have an area of discontinuity in the shell and an area of cold water impinging on the shell down in this area.

MR. CATTON: Is this thermal fatigue, then?

MR. HERMANN: It's a combination, but we'll get there. I just think what I will do then is, before I get into the discussion of overall experience, let me put up the other slide and make things a little easier.

[Slide.]

MR. HERMANN: Here is the girth weld on the generator. There was a downflow comer resistant plate with some holes in it at this area. The feed ring is up here and cold water was impinging in this area and the mixing area down around the girth weld.

MR. MICHELSON: How does the water come out of the feed ring in your plant?

MR. HERMANN: I believe, through the J-tubes.

MR. MICHELSON: You've got standard J-tubes on the outside?

MR. HERMANN: Yes.

MR. CARROLL: They're on the outside of the ring?

MR. HERMANN: Let me put it back up for you. Yes, they are; aren't they? I believe they're outside of that wrapper. There's a wrapper riser barrel wall.

MR. CARROLL: Okay, so they loop over the top of it; is that what you're saying?

MR. HERMANN: Yes.

MR. CATTON: Is it insufficient mixing?

MR. HERMANN: It's an area that -- well, let me get to the mechanism in a minute. I just wanted to give you a little bit of an idea of what things look like first. Everybody always likes hardware.

[Slide.]

MR. HERMANN: The experiences with cracking have been four domestic plants, one foreign plant, Models 44 and 51 generators. The cracks have ranged from severe to isolated and as I said earlier, Indian Point Unit 3 had a through-wall leak. I guess the experience in Indian Point 2 was comprehensive NDE done after the Indian Point 3 cracking.

Original repairs of some cracks were done in the Fall of 1987. I believe that was done between refueling outages 8 and 9. A year later, -- well, from the Fall of '87 to the Spring of '89, they came back and took another look and there were fairly severe cracks that had returned. I'm going to put up a slide of the cracking that was found at the two outages.

[Slide.]

MR. HERMANN: Correct me if I'm wrong, but it was the generator that dried out 23?

MR. KELLEY: Yes.

MR. HERMANN: These are the results for '89 and '87. The most severe cracking was in Generator 22 and not 23. I believe what the second most significant cracking was 23 or 24, Martin?

MR. KELLEY: 23.

MR. HERMANN: 23 was second. The earlier cracks; I guess the maximum crack in depth in '87 was on the order of a little over an inch and in 1989, one area was up to an inch and a quarter, and this was in one cycle's operation.

MR. CARROLL: The wall thickness is?

MR. HERMANN: It started around 3 and a half inches, I believe.

MR. CATTON: What are those?

MR. HERMANN: Those are the cracks that were removed by grinding -- the crack depths.

[Slide.]

Failure mechanisms; and this is probably --

MR. MICHELSON: Typically, how long were the cracks, if they were one and a half inches deep?

MR. HERMANN: Some of them -- they were fairly well around the circumference. They were separated by five of six inches or something like that.

MR. MICHELSON: They weren't that deep all the way around; were they?

MR. HERMANN: No.

MR. HUM: On Steam Generator 22, there is essentially a groove the entire circumference.

MR. MICHELSON: At a depth of 1.42? That's Zone 7.

MR. HUM: The groove was established in '87 and they are not at that depth. That is a low grind out. Bob will talk later about that.

MR. MICHELSON: That's about an average of at least a half to three quarters of an inch, though.

MR. CARROLL: It would help, I guess, if we knew what the zones meant, or generally what they meant.

MR. HERMANN: If the licensee would help me on the zones, I believe they were areas that the just picked for identifying where the cracks were.

MR. CARROLL: Around the circumference?

MR. HERMANN: Yes, circumferentially around it.

MR. JACKSON: We have a representative from Westinghouse and steam generators, Al Vaia.

MR. VAIA: Al Vaia, Manager of the Secondary Steam Generator Service Group. Basically for the zones, we divided the circumference of the steam generator into 12 equal zones. This was done from a logistics point of view in order to monitor where cracks were so that from a data point of view, we could continue to monitor where the cracks were.

The different zones; basically it's a 50-inch increment. Each zone is approximately 50 inches in length, and there are 12 around the circumference. The cracks that were found were basically a number of cracks associated with pits. Some of the cracks did connect, so the plot that Bob showed there was the maximum depth in any one zone.

It was not an indication that the crack was 360 degrees continuously; they were at different planes within each of the zones.

MR. CARROLL: So, roughly how long was a given crack? How long might it be?

MR. VAIA: Well, some of the grind out areas may have been as long as 5, 6, 7, 8 inches, but that could have been made up by a number of short cracks which had connected and during the grinding operation -- they may have connected, or during the grinding operation, that was the total length of the excavation.

MR. CARROLL: When I see for Zone 7, 1.42 and for Zone 8, 1.38; that doesn't imply that for 100 inches around the circumference, I've got a crack?

MR. VAIA: No, it doesn't. Also, between the '87 and the '89 results, that is not necessarily the same location.

MR. MICHELSON: It's the same zone, though?

MR. VAIA: Yes, it's the same zone.

MR. MICHELSON: The zones were the same in the two cases; isn't that correct?

MR. VAIA: Yes, we kept the same zone and the identification from '87 was maintained for '89 and will be maintained for all future inspections.

MR. HUM: I would like to point out that in the SCR, there is -- references a topic report that shows the length and depths of all grind outs, and what I was trying to emphasize about the '87 results was that, as a result of the grinding sa portrayed in this slide, there is a groove that is essentially around the entire circumference. That's not suggesting that this was one continuous crack. Obviously, they started and stopped. But I would also point out that I think that some of the cracks were quite long.

MR. MICHELSON: They were all well repaired back to the original surface, weren't they?

MR. HERMANN: No.

MR. MICHELSON: No? How much -- what's the condition presently, then, of this groove?

MR. HERMANN: I believe the first time the first time that the repairs were done on the plant in the '87 outage, there wasn't any welding done, so what you had looked at, especially in Steam Generator 22, were the depths of the grind outs and the zones as show up on the plot.

There were different profiles on the grind outs with tapers on them, so people didn't necessarily large stress razors in the area. It just wasn't somebody went in there with a pencil grinder and, you know, ground out a crack locally; it was an engineered grinding situation where they had specified tapers and so much allowable at the bottom.

MR. MICHELSON: And you filled in a portion of the depth and left the rest of it?

MR. HERMANN: No. In 1989, there was --

MR. MICHELSON: Well, in '87 you must have done that, because in '89, the depth was less than it was in '87 in some cases. So you must have done some filling.

MR. HERMANN: In some cases, but I believe the numbers you're looking at were probably numbers that may have been down in an area where there was a groove, so the actual well thickness could have been less in 1989 than it was in '87.

MR. VAIA: Yes. During the '87 evaluation, the various repairs were analyzed relative to the pressure integrity of the steam generator and also from a fatigue point of view. The area where you saw the 1.07 was a local grind-out area where we analyzed for one-inch uniform groove 360 degrees, and as part of the analysis, we superimposed a small local area on that location. So in 1987, there was no repair done of the steam generator, and that was based on the design and fatigue analysis that was performed.

In 1989, one steam generator, Steam Generator 22, because of the overall depth of the indications, there was a well repair performed, and all of the grooves were restored to a condition that was three-quarters of an inch, was the maximum depth left in Steam Generator 22 after the '89 repair.

MR. CARROLL: But the numbers in the table are before-repair numbers?

MR. VAIA: Yes, they are.

MR. CARROLL: So what Carl is saying is how can Zone 9 go from 1.01 in '87 down to .53 in '89?

MR. VAIA: That's a different location, and what is shown there is the maximum depth in '89 at that location. MR. MICHELSON: The 101 was still there --

MR. VAIA: One-oh-one was still there.

MR. MICHELSON: Okay.

MR. VAIA: The new indication in 1989 had a maximum depth of .58.

MR. MICHELSON: It's another groove they dug, but new cracks.

MR. VAIA: Those were new cracks, yes.

MR. MICHELSON: Those were new cracks that were removed.

MR. VAIA: Yes.

MR. MICHELSON: Okay.

MR. CARROLL: Very unclear table.

MR. WYLIE: Twenty-two is the steam generator that dried out?

MR. HERMANN: No, it's not.

MR. WYLIE: Twenty-three.

MR. HERMANN: Twenty-three was the generator that dried out.

[Slide.]

MR. HERMANN: Back to the discussion of the mechanisms. The mechanisms that are being postulated to date are corrosion assistant fatigue. This is not only true at this unit, but at some other units where people have done metallography to identify the mode of failures. In cases, there has been pitting in the generators, small cracks coming out of the bottom of the pits, and then thermal transients which are driving the cracks.

The other thing that's dependent, probably, on the crack growth rate is the -- well -- it is -- is the severity of the thermal cycling and the aggressiveness of the environment in terms of things like oxygen and alloys, contaminants like copper.

One of the other things that was being discussed with regard to Indian Point, originally, these were field stress relieved units, and there were some questions regarding the lower fabrication heat treatment. I don't really think that went anywhere in terms of the cracking mechanism.

The other issue that was thought to aggravate the situation at Indian Point was the downcomer location, and I'll put that slide back on again.

MR. LEWIS: Could I just interrupt for one second to say something about time? We really are running out of time because there is another subcommittee meeting here at one o'clock. Some of these people have to get out and have lunch. Otherwise, they'll be grumpy at one o'clock.

MR. HERMANN: I'll try to hurry up.

MR. LEWIS: So let's roll it off.

MR. HERMANN: Okay.

[Slide.]

MR. HERMANN: Anyway, the area that probably got aggravated by the thermal problems was because of the plate being right here. It tended to have the aux feed water splash up against the hot shell. During the transience, water level goes down, and it'll be filled with cold feed water.

[Slide.]

MR. HERMANN: Generically-corrective actions to date: Repairs were by grinding to establish profiles, which we talked about before with the tapers; well build-up and post well heat treatment of deep flaws; final excavation MP and mapping of the excavations; the downcomer plates have been removed.

MR. CARROLL: They were there originally to minimize carry over right?

MR. HERMANN: The downcomer flow resistance plates? I believe they were put in and taken out a couple of times for various and sundry reasons. They were in there for vibration purposes at one time.

MR. JACKSON: I'll try to answer that. They were there for control of the recirculation ratios stability control.

MR. CARROLL: So it's okay to take them out? No problems?

MR. JACKSON: Westinghouse has analyzed the sensibility of removing them and have given us an Okay on that

MR. HERMANN: The other things that have been done is water chemistry has been improved and flow conditions have been changed to try to minimize how much cold water is slugged up against the shell. Heat exchangers and other things have been replaced to get copper out of the system. I believe there is still some copper in the sludge in the generators, but they are trying to minimize that.

The last item --

MR. CATTON: Is their condenser copper?

MR. HERMANN: I believe it was before, but it's been replaced, I think.

MR. JACKSON: The condenser tube material -- originally Admiralty. We are in a phase change-out, and in the upcoming refueling, we will replace out one-third of the condenser and we will continue our replacement after that.

MR. CATTON: Replacing it with what?

MR. JACKSON: Titanium.

MR. CARROLL: Do you have polishers?

MR. JACKSON: No, we don't.

MR. CARROLL: And the feedwater heaters were copper alloy?

MR. JACKSON: The feedwater heaters were originally copper. They've been changed out. The only remaining feedwater heaters are those in the condenser neck at the very lowest low pressure. The moisture separator reheater tube bundles have also been changed out.

MR. HERMANN: The last item on here is "Replaced Steam Generators at Indian Point." There have been other people that have replaced generators that have had this problem. They are available at Indian Point.

[Slide.]

MR. HERMANN: The last slide is the possible generic future actions. Examination of these areas, we believe, can probably be done reliably now with ultrasonics from the outside. We've just had some early results from Zion where they're finding pretty shallow cracks and they've confirmed those depths in the last outage when they ground them out by MT, so it looks like UT is good a good tool in this case to be able to find this kind of cracking.

The code rules have changed. The 1974 edition of the code required a 20 percent look at structural discontinuities which could be spread over three different areas. The '77 edition of the code requires a hundred percent where you could do some distribution, but you're allowed to do a weld in one generator to satisfy the code. So, you're getting a much better sample by the routine inspections in this area for looking at problems.

The other thing is that people have voluntarily at a lot of plants been looking at these problems.

MR. MICHELSON: Apparently, the code does not require that you do a weld repair?

MR. HERMANN: You can look at the original designs and evaluate the wall and the discontinuity in the wall to see if it's necessary.

MR. MICHELSON: They apparently had a lot of excess metal in this design; is that the reason?

MR. HERMANN: Yes.

MR. MICHELSON: The code does prescribe the "as-left" condition though in order not to do the weld repair; is that correct?

MR. HERMANN: There's been an evaluation of the configuration of the grind out areas. I'm not sure if that came out of the code rules. I'm sure it meets the code rules for local discontinuities. I'm not sure if the establishment of what the tapers were specifically called out by the ASME code, but there are stress allowables you have to meet.

MR. MICHELSON: What's the reason that you don't do the weld repairs? You just don't do it if you don't have to?

MR. HERMANN: That's probably part of it, and it's a difficult thing to do, and you always have a problem when you're welding on a shell like this that you could get into more problems.

MR. MICHELSON: But you don't have a heat treatment problem.

MR. HERMANN: You do have a heat treatment problem. You have to post-weld heat treat.

MR. MICHELSON: To what extent do you post-weld heat treat in this case?

MR. HERMANN: These are -- in Generator 22 they did a post-weld heat treatment that was local to the shell area.

MR. MICHELSON: What temperature did they treat it at?

MR. HERMANN: I believe it was 1200 probably.

MR. MICHELSON: This is all relatively accessible, I guess; isn't it?

MR. CARROLL: You have some radiation problems in there.

MR. MICHELSON: If it's hot.

MR. JACKSON: Yes, it's accessible with scaffolding. You can get at the inside and at the outside, however, you do have a radiation field associated with the tubes that are in that area and obviously, you would lower water level to be able to gain internal access, and that reduces the shielding, so there is an exposure.

If we don't have to weld; meaning we meet minimum wall code requirements; we would not do that to save the radiation exposure.

MR. MICHELSON: To what extent, where you left a weld and just ground it out to get the proper configuration; to what extent did you find cracks in that type of as-left defect when you did your inspection the next time? I can't read that table and tell whether it's a new crack or an old crack.

MR. VAIA: In 1987, there was no weld repair. The 1989 outage, there was welding done on Steam Generator 22. At the mid-cycle inspection, we will go back in and reinspect that region and we'll be able to really answer your question after the mid-cycle outage.

MR. HERMANN: I think there was a concern that -- on the part of the staff and probably on the part of the licensee about the severity of the cracking that occurred essentially in one cycle after all the cracks were ground out. I think that's one of the reasons that --

MR. MICHELSON: Well, maybe I heard the answer, but maybe I heard too many words. To what extent -- what fraction of the welds that were ground out and left were found to have cracked again the next time you looked?

MR. VAIA: Okay, during the 1987 compared to the '89 results, there were a number of grindout areas that did show recracking, but it wasn't that all the cracking in '89 occurred in the previously ground out area. There was some additional cracking in '89 that occurred away from the grindout areas.

MR. MICHELSON: Now, in the case where it occurred in the same ground out area, how much additional cracking are we talking about and what depths?

MR. VAIA: I believe about 2/10ths to a quarter inch at the most.

MR. HERMANN: With regard to the questions earlier, though, on the integrity of the shells, one of the things in the evaluating operation later on, the assumptions that were made take the worst cracking to date and put them in an area where the shell was the thinnest, although the cracks had all been removed.

That was done as a conservative way of looking at, you know, what kind of performance could you expect out of the shell, should you get the same kind of degradation. The timeframe was cut for inspection essentially to a half a cycle rather than a cycle.

MR. VAIA: A number of the mitigating actions that Bob indicated, you know, were taken between the '89 -- well, during the '89 outage, and the effect of those mitigating actions will be determined during this mid-cycle outage.

MR. HERMANN: In conclusion, the staff is looking at whether we need to take any additional action in terms of generic communications on the subject. There are a couple of things that are going on. We just got the first results over the telephone of some samples taken at Zion which has the same mechanism.

There are two or three units coming down right now that we're trying to get some more information on the examination, voluntary examination of these girth welds.

MR. MICHELSON: What was the original design pressure for the shell?

MR. HERMANN: Around 1200, I imagine, 1250, something like that.

MR. JACKSON: I believe we're talking about around 1100 DU.

MR. HERMANN: The design is probably around 13.

MR. JACKSON: 1085 is the design.

MR. MICHELSON: I guess the staff looked at the degradation of the shell in terms of possible pressurization from the primary side under certain kinds of accident scenarios to make sure that even with these degraded wall thicknesses, we were still okay, and hopefully we are.

MR. ELLIOTT: Barry Elliott, Materials Engineering Branch. All design transients were looked at and the limiting transient happened to be a reactor trip.

MR. MICHELSON: You mean there weren't any possibilities of steam tube ruptures that might pressurize the shell side to some very high pressures? Of course, you've got relief capacity eventually, but I just wondered, under the particular accident at the time, what the scenario might be concerning the relief capability and so forth. That's the only time that you could get beyond what you might anticipate.

MR. LEWIS: I am going to stipulate that there are a lot of unanswered questions we all have. I will allow Mr. Ward one more question which he's burning to ask.

MR. WARD: The question is; when are you going to adjourn.

MR. LEWIS: Well, that's what I'm going to say. There are clearly many more questions we all have, but we have absolutely run out of time, so I'm going to call this quits. Let me not start a discussion among the Subcommittee members now, because that would do us in.

Let me ask the following: we are on the hook to write a letter about this. I still have a lot of questions and I think many of us do. We have a hunk of time scheduled at the full committee meeting on Friday morning.

MR. WYLIE: Not much.

MR. LEWIS: Pardon?

MR. WYLIE: We only have three quarters of an hour.

MR. LEWIS: I've already asked our Chairman whether we could perhaps have a bit more if it turns out to be necessary. It's right before noon, and I have no problem with that.

I do think that I would invite you all to put together your preliminary views on what we've heard today; get them to me Thursday morning and I will either draft a possible letter for us, or I will draft two or three alternative possible letters for us. We'll discuss it on Friday and decide where we come down.

I wish we had the rest of the day today to do this, but we simply don't. I'm going to be --

MR. WYLIE: Licensing?

MR. LEWIS: Yes, we do. We want as many people as you're willing to send, the same crowd, if you can or something like that; it's up to you, but we will have questions and, in particular, I believe our official metallurgist may have some questions.

MR. WYLIE: Do you plan to do the summary or let the licensee do the summary?

MR. LEWIS: Let me give it a try.

MR. WYLIE: You've got the staff and the licensee.

MR. LEWIS: What I don't want to do is repeat today on Friday, because there are six of us here now.

MR. WYLIE: But you could summarize.

MR. LEWIS: I will summarize as best I can, and you will decide how well I've done it by booing and the appropriate things. For the moment, for today's hearing, bang!

[Whereupon, at 12:12 p.m., the Subcommittee was adjourned.]

REPORTER'S CERTIFICATE

This is to certify that the attached proceedings before the United States Nuclear Regulatory Commission

in the matter of:

NAME OF PROCEEDING: ACRS Indian Point 2

DOCKET NUMBER:

PLACE OF PROCEEDING: Bethesda, Maryland

were held as herein appears, and that this is the original transcript thereof for the file of the United States Nuclear Regulatory Commission taken by me and thereafter reduced to typewriting by me or under the direction of the court reporting company, and that the transcript is a true and accurate record of the foregoing proceedings.

Marilynn Nations

MARILYNN NATIONS
Official Reporter
Ann Riley & Associates, Ltd.

Insert

# INDIAN POINT UNIT NO. 2 STRETCH RATING

## PRESENTATION TO THE

## SYSTEMATIC ASSESSMENT OF EXPERIENCE

## SUBCOMMITTEE OF THE ADVISORY COMMITTEE

## ON REACTOR SAFEGUARDS

FEBRUARY 6, 1990

Con Edison

## AGENDA

| | | |
|---|---|---|
| I. | Introduction | Stephen B. Bram |
| II. | Stretch Power Overview | Charles W. Jackson |
| III. | Stretch Program Results | Louis F. Liberatori |
| IV. | Concluding Remarks | Stephen B. Bram |

Con Edison

# INTRODUCTION

- o Historical Background
- o Economic and Other Benefits

Con Edison

# HISTORICAL BACKGROUND

- Location and original design
- Prototype four-loop Westinghouse design
- Stretch power historical perspective

Con Edison

## ECONOMIC AND OTHER BENEFITS

- Replacement Energy Savings
- Deferred Capacity Additions
- Fossil Fuel Dependency
- Emissions

Con Edison

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# STRETCH POWER OVERVIEW

- o DESCRIPTION OF INDIAN POINT UNIT NO. 2
- o COMPARISON OF INDIAN POINT UNIT NO. 2 APPLICATION RATING WITH PREVIOUSLY LICENSED PLANTS
- o BACKGROUND - LICENSING HISTORY
- o IMPLEMENTATION PLAN

Con Edison

# DESCRIPTION OF INDIAN POINT UNIT NO. 2

## Plant Configuration and Core Design

- 4-Loop Westinghouse Pressurized Water Reactor
  - Model 44 Steam Generators
  - 193 15x15 9-Grid Optimized Fuel and Standard Fuel
- Current Cycle 10 Core Design
  - Extended burnup fuel design
  - 5.7 Kwt/ft (6.33 Kw/ft at stretch)
- Westinghouse Main Turbine
  - FI low pressure rotors
- GE Main Generator 1439 MVA

Con Edison

# INDIAN POINT UNIT NO. 2

## KEY DESIGN OPERATING PARAMETERS

| Parameter | Current Operation | Stretch Operation |
|---|---|---|
| NSSS Power (MWt) | 2770 | 3083.4 |
| Core power (MWt) | 2758 | 3071.4 |
| Reactor Tavg ($^{o}$F) | 549.0 | 549 - 579.7 |
| Steam Pressure (psia) | 700 | 650 - 768 |
| Steam Flow (x$10^6$ lbm/hr) | 11.66 | 13.25 - 13.31 |
| S/G Tube Plugging (%) | 8 | 25 * |
| RCS Flow/Loop (gpm) | 89700 | 80700 * |

*Assumed

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## COMPARISON OF INDIAN POINT UNIT NO. 2 WITH PREVIOUSLY LICENSED PLANTS

- INDIAN POINT UNIT NO. 2 APPLICATION 3071.4 MWT
  - STILL LOWER THAN MORE RECENTLY LICENSED PLANTS
- SIGNIFICANT OPERATING EXPERIENCE FOR LARGE FOUR-LOOP WESTINGHOUSE PWRS BEYOND 3071.4 MWT

Con Edison

## LICENSE AND CORE POWER DATA
## FOR OTHER WESTINGHOUSE 4-LOOP PLANTS

| Plant | Core Power (MWt) | License Date |
|---|---|---|
| Zion No. 1 | 3250 | 1973 |
| Zion No. 2 | 3250 | 1973 |
| D. C. Cook No. 1 | 3250 | 1974 |
| D. C. Cook No. 2 | 3411 | 1977 |
| Trojan | 3411 | 1975 |
| Salem No. 1 | 3338/3411 | 1976/1986 |
| Salem No. 2 | 3411 | 1981 |
| Diablo Canyon No. 1 | 3338 | 1984 |
| Diablo Canyon No. 2 | 3411 | 1985 |
| Sequoyah No. 1 | 3411 | 1980 |
| Sequoyah No. 2 | 3411 | 1981 |
| W. B. McGuire No. 1 | 3411 | 1981 |
| W. B. McGuire No. 2 | 3411 | 1983 |
| Catawba No. 1 | 3411 | 1985 |
| Catawba No. 2 | 3411 | 1986 |

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# LICENSE AND CORE POWER DATA FOR OTHER WESTINGHOUSE 4-LOOP PLANTS

(CONTINUED)

| PLANT | CORE POWER (MWT) | LICENSE DATE |
|---|---|---|
| BYRON NO. 1 | 3411 | 1985 |
| BYRON NO. 2 | 3411 | 1987 |
| BRAIDWOOD NO. 1 | 3411 | 1987 |
| BRAIDWOOD NO. 2 | 3411 | 1988 |
| CALLAWAY | 3411/3565 | 1984/1988 |
| WOLF CREEK | 3411 | 1985 |
| ALVIN W. VOGTLE NO. 1 | 3411 | 1987 |
| ALVIN W. VOGTLE NO. 2 | 3411 | 1989 |
| MILLSTONE NO. 3 | 3411 | 1986 |

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# BACKGROUND - LICENSING HISTORY

- INDIAN POINT DESIGNED FOR 3083.4 MWT (3071.4 MWT CORE POWER)
- ORIGINAL LICENSE APPLICATION 2758 MWT CORE POWER (OCTOBER 1968)
- ENGINEERED SAFETY FEATURES ORIGINALLY EVALUATED AT 3216 MWT CORE POWER
- INDIAN POINT UNIT NO. 3 LICENSE AT 3025 MWT RESTRICTED TO 2760 MWT UNTIL MORE EXPERIENCE GAINED - RESTRICTION LIFTED JULY 1978
- UPDATED SAFETY ANALYSES FOR RECENT INDIAN POINT UNIT NO. 2 RELOADS AS WELL AS FOR STRETCH

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# IMPLEMENTATION PLAN

- Schedule
- Procedures
- Training
- Plant Setpoint Changes

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# PLANT SETPOINT CHANGES

- OVER POWER/OVER TEMPERATURE DELTA-T
- MAIN STEAMFLOW
- RCS FLOW CALIBRATION
- ALARMS
- AUXILIARY FEEDWATER
- FIRST-STAGE PRESSURE
- TAVG
- NORMAL OPERATION CONTROL SETPOINT ADJUSTMENTS SUCH AS HEATER DRAIN TANK CONTROL SYSTEM

Con Edison

## AGENDA

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# STRETCH PROGRAM RESULTS

- o Transients and Accidents
  - LOCA
  - Non-LOCA
  - Off-site dose evaluations
- o Technical Specifications
- o Plant Equipment Evaluations
- o Conclusion

Con Edison

# LOCA TRANSIENTS AND ACCIDENTS

- NRC LICENSED COMPUTER MODELS
  - BASH
  - NOTRUMP
- LARGE BREAK PCT RESULTS
  - 2039°F
- SMALL BREAK PCT RESULTS
  - 1218.5°F
- RESULTS SATISFY 10CFR50.46 ECCS ACCEPTANCE CRITERIA
- CONTAINMENT PERFORMANCE

Con Edison

# NON-LOCA TRANSIENTS AND ACCIDENTS

- o ALL FSAR NON-LOCA TRANSIENTS WERE REANALYZED
- o RESULTS MEET NON-LOCA ACCEPTANCE CRITERIA
- o CONTAINMENT PERFORMANCE

## OFF-SITE DOSE EVALUATION

- o TRANSIENTS AND ACCIDENTS
- o 3216 MWT POWER LEVEL
- o RESULTS REMAIN BELOW 10CFR PART 100 LIMITS

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# TECHNICAL SPECIFICATIONS

- Power level
- Tavg/Delta-T
- Minimum AFW flow
- Steam flow basis
- Minimum decay time for refueling

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# PLANT EQUIPMENT REVIEW

- o NSSS SYSTEMS AND EQUIPMENT
- o BOP SYSTEMS AND EQUIPMENT

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# INDIAN POINT UNIT NO. 2 STRETCH RATING PROGRAM

## NSSS SYSTEMS

- Reactor Coolant System
- Pressurizer and Steam Generator Safety Valve Systems
- Chemical and Volume Control System
- Residual Heat Removal System
- Emergency Core Cooling Systems
- Containment Cooling Systems
- Service Water and Component Cooling Systems

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# INDIAN POINT UNIT NO. 2 STRETCH RATING PROGRAM
# BOP SYSTEMS

- BOP SYSTEMS ORIGINALLY DESIGNED AND GUARANTEED AT 3083.4 $MW_T$
- BOP HAS A CALCULATED CAPABILITY OF 3216 $MW_T$
- BOP SYSTEMS AND EQUIPMENT WERE REVIEWED

# CONCLUSIONS

THE STRETCH PROGRAM:

- DEMONSTRATED COMPLIANCE OF FSAR ANALYSES WITH APPLICABLE ACCEPTANCE CRITERIA
- DEMONSTRATED COMPLIANCE OF PLANT COMPONENTS AND SYSTEMS WITH FSAR FUNCTIONAL AND REGULATORY REQUIREMENTS
- RECONFIRMED THE CAPABILITY OF THE PLANT TO PERFORM AT THE ORIGINAL GUARANTEED POWER RATING (3071.4 MWT CORE POWER -3083.4 MWT NSSS)
- DETERMINED NO SIGNIFICANT HAZARDS CONSIDERATION IS INVOLVED

Con Edison

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Insert

# NRC STAFF EVALUATION OF CONSOLIDATED EDISON'S PROPOSAL TO INCREASE LICENSED THERMAL POWER AT INDIAN POINT UNIT 2

PRESENTED AT

ACRS
SYSTEMATIC ASSESSMENT OF EXPERIENCE SUBCOMMITTEE
MEETING ON FEBRUARY 6, 1990

- INTRODUCTION -- D. BRINKMAN
- OPERATIONAL EXPERIENCE -- C. COWGILL
- LICENSEE PRESENTATION
- OVERVIEW OF STAFF EVALUATION -- D. BRINKMAN
- ECCS EVALUATION -- T. COLLINS
- STEAM GENERATORS -- R. HERMANN
- CONCLUSION -- D. BRINKMAN

# INDIAN POINT 2

## NRC REGION I STAFF

## OPERATING EXPERIENCE BRIEFING FOR ACRS

## FEBRUARY 1990

CURTIS COWGILL
SECTION CHIEF

# OPERATING EXPERIENCE

- JANUARY 1988 STEAM GENERATOR DRYOUT EVENT
- LOW NUMBER OF REACTOR TRIPS AND DECREASING
- IMPROVING OPERATOR PROFESSIONALISM
- IMPROVED OPERATIONS SUPPORT
- EFFECTIVE EMERGENCY OPERATING PROCEDURES
- EFFECTIVE OPERATOR QUALIFICATION AND REQUALIFICATION PROGRAMS

# MAINTENANCE EXPERIENCE

- WEAKNESSES IDENTIFIED MAY 1989 BY MAINTENANCE TEAM INSPECTION

  -- POORLY DEFINED PROGRAM

  -- POOR MANAGEMENT SUPPORT

  -- POOR MATERIAL CONDITION

  -- GOOD IMPLEMENTATION BY MAINTENANCE STAFF

- CORRECTIVE ACTION

  -- PROGRAM AND PROCEDURE UPGRADES

  -- ADDED STAFFING

  -- IMPROVED FACILITIES

# CONCLUSION

INDIAN POINT 2 OPERATING EXPERIENCE AND PERFORMANCE FROM 1988 TO 1990 HAS BEEN ADEQUATE TO SUPPORT SAFE POWER OPERATIONS AT THE HIGHER POWER LEVEL REQUESTED BY THE LICENSE AMENDMENT.

- **BACKGROUND**

  -- CONFIRMED PLANT WAS DESIGNED FOR A CORE POWER LEVEL OF 3071.4 MWT

  -- ORIGINAL OPERATING LICENSE WAS REQUESTED AT 2758 MWT

  -- NO TECHNICAL REASON FOR DERATE

  -- 1970 SER

    ENGINEERED SAFETY FEATURES (EXCEPT ECCS) AND ENVIRONMENTAL REVIEWS EVALUATED BY NRC STAFF AT 3216 MWT

    ECCS EVALUATED AT 2758 MWT

- **CURRENT SAFETY EVALUATION BY NRC STAFF OF LICENSEE'S ANALYSIS OF OPERATION AT 3071.4 MWT**

  -- CORE DESIGN

  -- ANALYSES PERFORMED

  ECCS PERFORMANCE (LOCA)

  OVERPRESSURE PROTECTION

  ANTICIPATED OPERATIONAL OCCURRENCES

  NON-LOCA ACCIDENTS

  AUXILIARY FEEDWATER AND RESIDUAL HEAT REMOVAL PERFORMANCE

  -- REACTOR COOLANT SYSTEM

- **CONTAINMENT INTEGRITY ANALYSIS**

  -- DESIGN PRESSURE = 47 PSIG

  -- LOCA

  40.31 PSIG FOR 3083.4 MWT

  41.12 PSIG FOR 3216 MWT

  -- MAIN STEAM LINE BREAK

  39.99 PSIG FOR 3083.4 MWT

- **BALANCE OF PLANT SYSTEMS**

  -- STEAM TURBINE SYSTEM INCLUDING MAIN STEAM, FEEDWATER, CONDENSER, CONDENSATE AND CIRCULATING WATER SYSTEMS AND SUPPORT SYSTEMS

  -- ESSENTIAL AND NON-ESSENTIAL SERVICE WATER SYSTEMS

  -- EMERGENCY DIESEL GENERATORS

  -- BOP PIPING SYSTEMS

  -- STEAM GENERATORS

- **EQUIPMENT QUALIFICATION**

- **INSTRUMENTATION**

  -- NO CHANGES TO PLANT EQUIPMENT REQUIRED

  -- USE APPROVED METHODOLOGY FOR CALCULATING SETPOINT CHANGES

  -- REVIEWED SETPOINT CHANGES FOR OVERPOWER DELTA T AND OVERTEMPERATURE DELTA T CHANNELS, POTENTIAL UNCERTAINTIES PROPERLY CONSIDERED

- **ENVIRONMENTAL CONSEQUENCES**

  -- RADIOLOGICAL AND NON-RADIOLOGICAL ANALYSES WERE ORIGINALLY PERFORMED AT 3216 MWT WHICH BOUNDS PROPOSED LEVEL OF 3071.4 MWT

  -- OFFSITE DOSES ARE WELL WITHIN ACCEPTANCE CRITERIA OF SRP 15.6.3

  -- LICENSEE'S REASSESSMENT DOES NOT ALTER OUR CONCLUSIONS STATED IN SECTION 11.4 OF ORIGINAL SER

- **TECHNICAL SPECIFICATION CHANGES**

  -- CHANGE VALUE OF RATED POWER FROM 2758 MWT TO 3071.4 MWT

  -- CHANGE ALLOWABLE $T_{AVG}$ LSSS AND LCO SETPOINTS

  -- INCREASE MINIMUM REQUIRED AUXILIARY FEEDWATER FLOWRATE TO 380 GPM

  -- INCREASE MINIMUM DECAY BEFORE FUEL MOVEMENT TO 174 HOURS

# IP-2 ECCS EVALUATION

* SYSTEM OVERVIEW
  - ORIGINAL DESIGN RATING
  - SYSTEM COMPOSITION
  - SIMILARITY TO OTHER PLANTS

* PERFORMANCE ANALYSIS
  - METHODS
  - SCOPE
  - INPUT
  - RESULTS

# SYSTEM OVERVIEW

* ORIGINAL DESIGN FOR 3216 MWt PLANT

* SYSTEM CONFIGURATION
    - 4 COLD LEG ACCUMULATORS
    - 3 HIGH HEAD SAFETY INJECTION PUMPS
    - 2 RHR PUMPS & HX's
    - 2 RECIRCULATION PUMPS

* SIMILARITY TO OTHER PLANTS
    - TYPICAL MIX OF SUBSYSTEMS
    - TYPICAL SUBSYSTEM CAPACITIES

# ECCS PERFORMANCE ANALYSIS

* METHODS
    - APPROVED BASH CODE FOR LARGE BREAKS
    - APPROVED NOTRUMP CODE FOR SMALL BREAKS

* SCOPE
    - FULL SPECTRUM OF BREAK SIZES EXAMINED

* INPUT
    - 102% OF 3071.4 MWt
    - 102% OF PEAK LINEAR POWER
    - 25% SG TUBE PLUGGING
    - APPENDIX K INPUTS

* RESULTS
    - LARGE BREAK PCT: 2039 F
    - SMALL BREAK PCT: 1218 F
    - PCT CRITERION: 2200 F

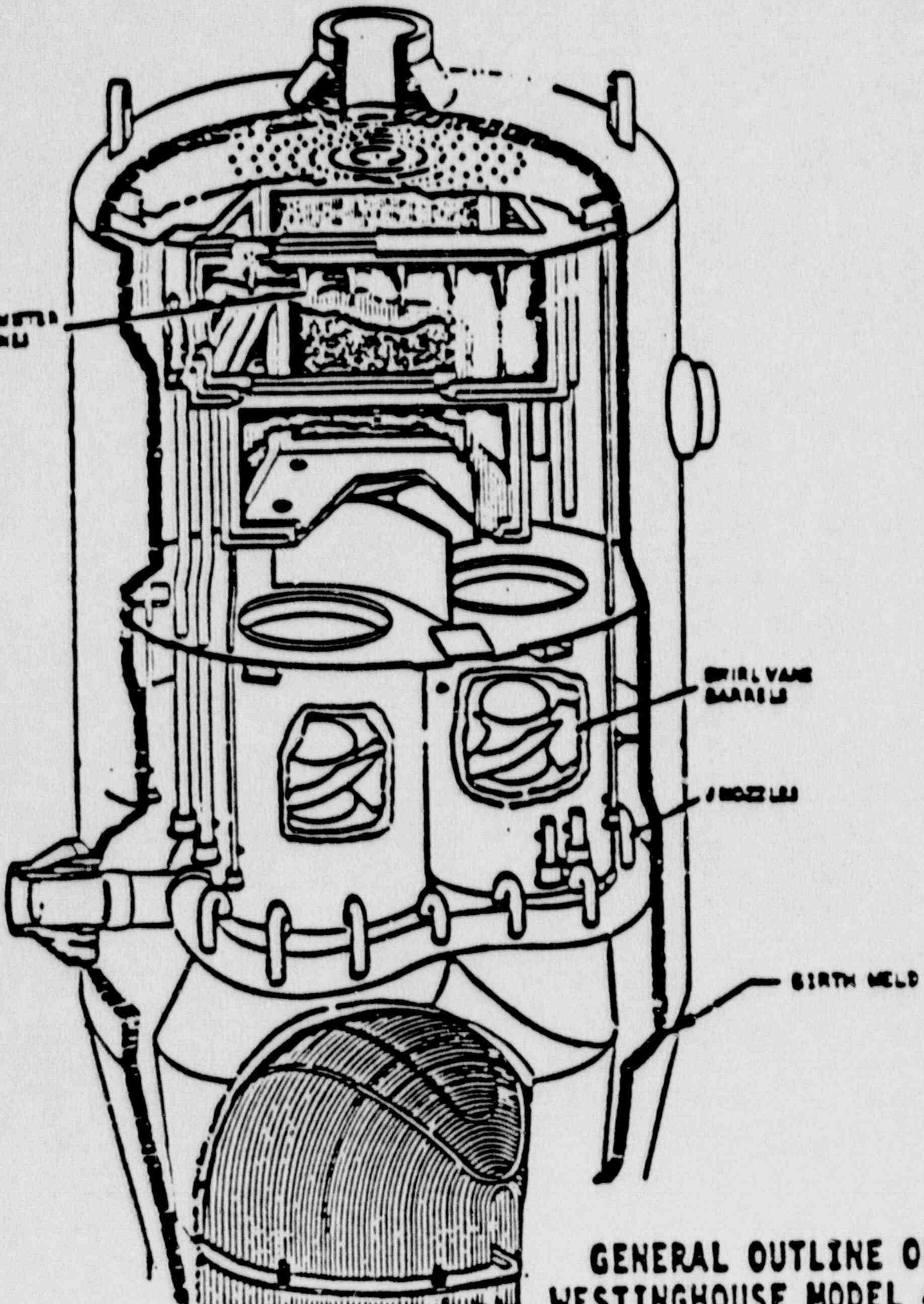
# ECCS REVIEW CONCLUSIONS

* ORIGINAL DESIGN RATING UNCHANGED
* APPROVED ANALYSIS METHODS USED
* SCOPE OF ANALYSIS ADEQUATE
* INPUTS/RESULTS SATISY REGULATIONS
* ECCS ACCEPTABLE FOR 3071.4 MWt OPERATION

# CRACKING OF THE UPPER SHELL-TO-TRANSITION CONE GIRTH WELD IN STEAM GENERATORS

## INFORMATION NOTICES AND PLANTS

| | |
|---|---|
| 90-04 | INDIAN POINT 2 AND ZION 1 |
| 85-65 | INDIAN POINT 3 AND SURRY 2 |
| 82-37 | INDIAN POINT 3 |



**GENERAL OUTLINE OF WESTINGHOUSE MODEL 44 STEAM GENERATOR**

Figure 2.1-1

# OVERVIEW OF INDUSTRY EXPERIENCE

FOUR DOMESTIC PLANTS - 18 SGs

WESTINGHOUSE MODEL 44 AND MODEL 51

WITH FEEDWATER RING DESIGN

ONE FOREIGN PLANT

CRACKS VARY FROM SEVERE TO ISOLATED

AND DISPERSED AT DIFFERENT PLANTS

IP-3 HAD THROUGH-WALL LEAK

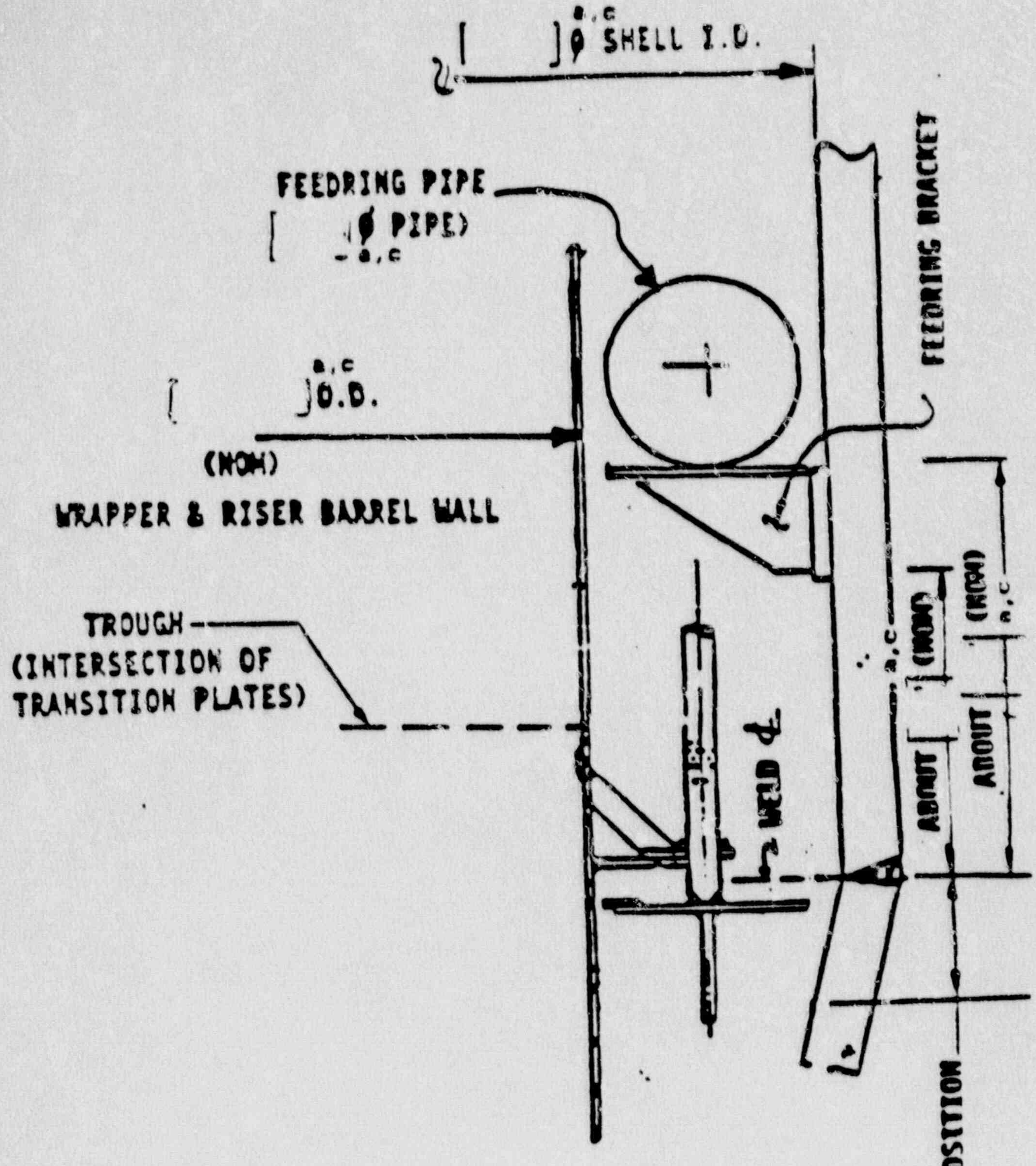
## SUMMARY OF EXPERIENCE AT IP-2

COMPREHENSIVE NDE AFTER IP-3 CRACKING

CRACKS DETECTED AND REPAIRED IN FALL 1987

ADDITIONAL CRACKS DETECTED IN SPRING 1989

MID-CYCLE EXAMINATION IN FEBRUARY 1990




GENERAL OUTLINE OF GIRTH WELD REGION

Figure 2.1-2

# INDIAN POINT UNIT 2

## FINAL MAX. DEPTH OF GRIND

## (COMBINATION OF 1987 AND 1989 DATA)

| | S/G 21 | | S/G 22 | | S/G 23 | | S/G 24 | |
|---|---|---|---|---|---|---|---|---|
| ZONE | 1989 | 1987 | 1989 | 1987 | 1989 | 1987 | 1989 | 1987 |
| 1 | .57 | .56 | .63 | .49 | .76 | 1.01 | .48 | .48 |
| 2 | .40 | .40 | .54 | .68 | .33 | .33 | .27 | .27 |
| 3 | .37 | .37 | .56 | .56 | .20 | .65 | .28 | .13 |
| 4 | N/A | | .51 | .88 | .49 | .49 | .28 | .00 |
| 5 | N/A | | .73 | 1.00 | .09 | .38 | .42 | .42 |
| 6 | N/A | | .58 | .76 | .34 | .34 | .33 | .57 |
| 7 | .28 | .28 | 1.42 | 1.07 | .11 | .42 | .26 | .36 |
| 8 | .36 | .36 | 1.38 | .89 | .36 | .16 | .51 | .51 |
| 9 | .32 | .32 | .58 | 1.01 | .79 | .65 | .16 | .00 |
| 10 | .36 | .36 | .71 | .51 | .58 | .58 | .33 | .33 |
| 11 | N/A | | 1.24 | .85 | .29 | .29 | .07 | .07 |
| 12 | .54 | .50 | .49 | .49 | .57 | .57 | .40 | .40 |

Table 2.3-6

PROBABLE FAILURE MECHANISM:
CORROSION-ASSISTED THERMAL FATIGUE

COMMON FACTOR: GENERAL CORROSION PITS
WERE CRACK INITIATION SITES

POSSIBLE CONTRIBUTING FACTORS:

THERMAL CYCLING DURING TRIPS AND TRANSIENTS

COPPER ALLOYS IN FEEDWATER SYSTEM AND CONDENSER

LOW TEMPERATURE FABRICATION HEAT TREATMENT

OXYGEN IN AUXILIARY FEEDWATER

LOCATION OF THE DOWNCOMER FLOW RESISTANCE PLATE

# CORRECTIVE ACTIONS TO DATE

REPAIR BY GRINDING TO ESTABLISHED PROFILES

WELD BUILDUP AND PWHT OF DEEP FLAWS

FINAL MT AND MAPPING OF EXCAVATIONS

REMOVE DOWNCOMER FLOW RESISTANCE PLATES

CHANGE PLANT OPERATING CONDITIONS
(FLOW AND WATER CHEMISTRY)

REPLACE COPPER ALLOY HEAT EXCHANGERS

REPLACE STEAM GENERATORS

# POSSIBLE FUTURE ACTIONS

## NONDESTRUCTIVE EXAMINATIONS

ENHANCED UT BY EXPERIENCED PERSONNEL CAPABLE OF DETECTING SURFACE-CONNECTED CRACKS

OLDER ASME SECTION XI SAMPLING COULD MISS CRACKS

NEWER ASME SECTION XI RULES INCREASE DETECTION

INTERNAL MT ONLY CONCLUSIVE NDE

ASSESS NEED FOR ADDITIONAL GENERIC COMMUNICATIONS

ZION METALLURGICAL RESULTS

ADDITIONAL VOLUNTARY EXAMINATION RESULTS

# CONCLUSION

**PROPOSED INCREASE IN LICENSED THERMAL POWER IS ACCEPTABLE**