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307TH GENERAL MEETING

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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

307TH GENERAL MEETING

Nuclear Regulatory Commission
Room 1046
1717 H Street, N.W.
Washington, D. C.

Friday, November 8, 1985

The committee met at 8:30 a.m., Mr. Jesse C. Ebersole, chairman, presiding.

PRESENT:

MR. JESSE C. EBERSOLE
MR. DAVID A. WARD
DR. ROBERT C. AXTMANN
DR. MAX W. CARBON
DR. WILLIAM KERR
DR. HAROLD W. LEWIS
DR. CARSON MARK
MR. CARLYLE MICHELSON
DR. DADE W. MOELLER
DR. DAVID OKRENT
MR. GLENN . REED
DR. FORREST J. REMICK
DR. PAUL G. SHEWMON
DR. CHESTER P. SIESS
MR. CHARLES J. WYLIE

PUBLIC NOTICE BY THE

UNITED STATES NUCLEAR REGULATORY COMMISSIONERS'

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

FRIDAY, NOVEMBER 8, 1985

The contents of this stenographic transcript of the proceedings of the United States Nuclear Regulatory Commission's Advisory Committee on Reactor Safeguards (ACRS), as reported herein, is an uncorrected record of the discussions recorded at the meeting held on the above date.

No member of the ACRS Staff and no participant at this meeting accepts any responsibility for errors or inaccuracies of statement or data contained in this transcript.

PROCEEDINGS

(8:30 a.m.)

MR. WARD: The meeting will now come to order. This is the second day of the 307th meeting of the Advisory Committee on Reactor Safeguards. During today's meeting, the committee will hear reports on and discuss the following:

First, the NRC's committee to review generic requirements. Second, we continue our discussion of the GSSAR II FDA application. Third, we'll hear ACRS subcommittee reports regarding EPA standards for disposal of high level radioactive wastes, seismic design margins in different power stations, the NRC incident investigation program, and ACRS effectiveness. And, fourth, Beaver Valley Nuclear Power Station Unit II application.

The meeting is being conducted in accordance with the provisions of the Federal Advisory Committee Act and the Government in Sunshine Act. Portions of the meeting may be closed to protect proprietary information or plant-specific security information.

Mr. Ray Fairly is the designated federal official for this portion of the meeting. A transcript of portions of the meeting is being kept and it's requested that each speaker identify himself or herself and speak with sufficient clarity or volume so that she or he can be

readily heard. We've received one written statement regarding the Beaver Valley application, and I think that's been distributed to the members.

However, there were no requests to make oral statements from members of the public regarding today's meeting; unless someone would like to say something that's not on the agenda at this time, we'll continue. We'll go ahead with the first agenda item this morning.

This is a briefing from the Office of the Committee to Review Generic Requirements. We thought it would be useful for the committee to learn more of the CRGR's activities. I think it's obvious they are playing a very important role in the regulation of nuclear power today.

The ACRS has not had a great deal of contact with the committee, which may be perfectly all right with Mr. Stello and others on the committee, but it may not be the best as far as our discharging our responsibility for our role.

So I think it will be helpful to us today to learn more about the committee's activities. One thing we should perhaps think about is whether we should establish more of an ongoing relationship and communication with the CRGR. It doesn't look like Mr. Stello is here. We have someone else, I believe, who will make the presentation.

So if you'd introduce yourself, we'll go ahead.

MR. SNIEZEK: My name is Sniezek. I am Director of Regional Operations and Generic Requirements Staff in the EDO's office. Vic had an unexpected conflict this morning and he won't be able to make it. I'll be giving the presentation. I gave you handouts but I'll also use slides at the podium.

Good morning, Mr. Chairman, members of the committee. We also thought it was important that we brief the committee on the functions of the CRGR; with the exception of a subcommittee briefing back in 1981, when we were being formed, there has been no formal interaction with the ACRS and the CRGR.

We believe and the staff believes that the CRGR is one of the more profound management tools in the agency for managing the staff's proposed generic requirements. This goes hand in glove with the Commission's recently-passed backfit rule.

With that in mind, and the committee's interest in the backfit rule, the prior version of it, the NRC Manual chapter on Backfitting, Manual Chapter 0514, I'm also going to bring you up to speed on the status of that work.

(Slide.)

Basically, when the committee was established by the Commission, the Commission had backfitting in mind. It

was established in October 1981 to review all proposed generic requirements for power reactors, and to make recommendations to the EDO for approval or disapproval of these generic requirements.

The committee by itself does not have any approval or disapproval authority. It is not a line function. It is advisory to the executive director of Operations. A very important factor here, when I mention the term "generic requirements", in that term, we include both the legal binding requirements, such as rules in that type plant, orders, as well as staff positions as expressed in the standard review plans, the regulatory guides, et cetera.

The committee's purpose is to ensure that we maintain an appropriate level of protection in public health and safety to, to reduce the exposure to workers in implementing NRC requirements whenever possible; conserve NRC resources and reduce unnecessary burdens on licensees.

The CRGR came about in the aftermath of TMI, when the staff issued a plethora of requirements on the licensees, as a result of our response to the TMI accident.

In 1980 and 1981, Jim O'Reilly had headed a task group of senior NRC managers, which included office directors and deputy directors at that time, and visited about a dozen utilities and sites to review firsthand the

impact our TMI response was having on the licensees. In his report he had concluded and the senior managers had concluded that, in spite of the good intentions of the staff, the plethora of requirements, they have been causing a safety problem of unknown magnitude. That was the foundation of the CRGR, to bring control to the staff's process for issuing generic requirements.

DR. MARK: Mr. Sniezek, perhaps sometime you'll come to it, and I hope so. To what extent does CRGR, which sits here in Washington with normal line authority, to what extent can it supervise and correct, if necessary, things that are done in the regional office?

MR. SNIEZEK: I will address that, but that will be more under the plant specific backfitting issue. I will cover that item.

The committee is composed of Vic Stello, who is the Executive Director for Operations, for Generic Requirements and Regional Operations, and six members. These six members are office directors, deputy office directors or division directors. And each of the major offices is represented by the committee.

In committee, the members are not to represent the views of their office. In general, we have found that to be true. Oftentimes, we will find a division director or office director or deputy director voting against a proposal

that's been forwarded by his office.

So, overall, we believe the members are really acting independently and as a collegial grou when they are on the committee.

I mentioned that the generic requirements are all to come before the CRGR. There are some exceptions. For example, if an office director determines he must take emergency action very promptly to correct an immediate health and safety problem, he can go forward in doing it without coming before the CRGR.

We average probably somewhat less than one of those types of actions a year. We just had a recent one on scram breaker failures this week, where an emergency bulletin went out issued by IE. That's been the only one this year.

We had one, the last one that we had was when we had the problem up at Salem with the scram breaker. That was an emergency bulletin that was issued and did not come before the CRGR.

I've been the staff director for a little over two years. Those were the only two events during that time where we issued an emergency bulletin.

DR. OKRENT: Is that good or bad? What do you think?

MR. SNIEZEK: I think that's good that they can

go without coming to the CRGR.

DR. OKRENT: But, only two in two years were issued before going through the formal CRGR review.

MR. SNIEZEK: I'm not aware of any others that should have been issued without going for the CRGR review. So I believe it's good.

DR. OKRENT: Have you gone back and looked over the last two years' experience at the seriousness of the events to see whether you think any of them might have warranted earlier action?

MR. SNIEZEK: We have not gone back and looked at that specific item. However, that decision on whether to go to CRGR review is the office director's decision. It's not a CRGR decision. It's the office director's. Once he decides it's important, he's just telling us he's doing it. Any time they have told us they're doing it, we've never said no or jumped in the middle of it. We have gone for it and done it.

DR. REMICK: Jim, while you're on organization, would you briefly mention the size and the function of the staff that you direct?

MR. SNIEZEK: I've got a very small staff. The impression is we want to be lean and mean. We don't want to get into areas we shouldn't be into. I have five people working for me associated with the CRGR activities, and

those activities are only about 25 percent of their function. There are a lot of other functions that we perform in the EDO's office. I will get into the process we go through when it comes over to the staff.

MR. EBERSOLE: May I ask a question?

Could you tell me your involvement with Davis-Besse?

MR. SNIEZEK: We've had zero involvement with Davis-Besse so far. Nothing on Davis-Besse so far. In Davis-Besse, that was a plant specific issue, so it would not come before the CRGR, Davis-Besse itself. If there were to be some generic requirements coming out of the Davis-Besse event, that would come before the CRGR.

MR. EBERSOLE: Really, isn't your office handling more than generic requirements, in that generic requirements, I think, constitute maybe half of our problems? The rest maybe affect one plant or two plants?

So why are you called "Generic Requirements" when in fact half the workload of fixing these plants is specific requirements?

MR. SNIEZEK: The CRGR only handles those requirements that are issued in a broad form to cover many reactors. One issues like a rule, a reg guide, a standard review plan; Manual Chapter 0514, which the committee commeted on earlier this year, is designed to handle plant

specific backfitting issues. If there is a plant specific backfitting issue, the staff has a procedure that they're to go through internally to decide what the impact on safety and the cost is, and they make a decision based on that.

So generic requirements, in fact, really, there are two types of requirements, generic and plant-specific. I agree with you 100 percent. And for a long time, in '81 to '84, we focused on the generic, we did not focus on the plant-specific.

The CRGR has visited about a dozen facilities also. And in those trips, we have been told by the licensees and utilities that the generic requirements are starting to make more sense now, and that's starting to be under control. We had to put effort on plant-specific.

As a result of that, the plant-specific Manual Chapter 0514 has been developed. It's ready to go out to the Commission within a few days, and that is our mechanism within the staff for controlling the plant-specific issues.

MR. EBERSOLE: Thank you.

(Slide.)

MR. SNIEZEK: Let me talk a little bit about CRGR reviews. The CRGR itself does not do the initial evaluation and analysis, it's the staff that is to do the initial evaluation and analysis.

The CRGR reviews the analysis to see if it makes

sense, whether the number is calculated the right way or, again, intentionally biased in a certain direction to support the staff. Or, has the staff missed an important safety consideration that isn't included in their analysis?

This is the collective judgment that the seven senior agency managers on the CRGR bring to the process. And then, my staff, when a package comes over, who reviews it and sees if there are issues that should be brought to the CRGR's attention, that the CRGR can focus on.

Many times, a package is six inches thick -- three to six inches thick. Obviously, the senior managers don't always have time to review it in specific depth. We have a small staff of five that takes apart the package to see what type of loopholes are in the packge.

Basically, what does the CRGR concentrate on in its review process?

There are five basic areas that are the focus of the deliberations. First of all, what's the specific objective the proposal is intended to achieve? What's the problem we're trying to fix? And, will our proposal fix the problem?

Oftentimes, we find the staff has come over with, "Here's what we want to do." We start to go into what problem are you trying to fix, and all of a sudden, we find the staff isn't sure what problem they're trying to fix.

So we really focus on that.

What's the activity that would be required of the applicant or licensee? And what category of licensees should it really apply to? Should it apply to all? Boiling water reactors, PWR's be a subset of the PWR's? Certain vintage containment?

Those are the type of things we bore in on there.

Are we articulating actually what the licensee needs clearly to the licensee?

So we hear them say later that, "We didn't know what they wanted us to do." Are we articulating what we want the licensee to do in an appropriate manner?

What's the potential change in risk? Are we decreasing the risk, at least with our action? Or at least maintaining it in neutral?

Those are the only two positions we can afford to be in. We don't want to take any action that may increase the risk. And there have been some proposals that have come before the CRGR where we're not sure that if we were to take the action, we would have increased the risk by the actions we propose to take. And a lot of times, those are arguable. You get a lot that are on the fence and they're really hard to decide.

It depends upon your assumptions many times.

DR. LEWIS: Just as a matter of curiosity, could

you say what you mean when you say "decrease the risk"?

MR. SNIEZEK: I've used the term erroneously here and just talked the term core melt. Have we increased the probability of core melt by the actions that we've taken, or are we decreasing the probability of core melt?

DR. LEWIS: So if one were to recalculate the probability of core melt without changing the plant, that would be decreasing the risk, or increasing as the case may be?

MR. SNIEZEK: That's correct.

DR. LEWIS: Thank you.

DR. MARK: You used the phrase "core melt". Why are you concerned about core melt rather than atmospheric release?

MR. SNIEZEK: We are equally concerned or more so concerned about atmospheric release.

DR. MARK: It seems to me you should be ultimately concerned with that. Core melt is a matter of concern to the utility, but if the containment works, what's the concern to you?

MR. SNIEZEK: No question on that. However, many times, we don't have a level three PRA conducted. It's a very cursory PRA and it doesn't go that far. So the core melt is used as a gauge more than anything else.

DR. MARK: I think it deserves some thought as

to whether that is the sort of term and the sort of thought that the agency should be using. They should be using the effects the industry deserves to use, needs to use and must use on core melt.

MR. SNIEZEK: Can I disagree with you on what you stated? I don't want to get into the safety goal today, but I agree with you.

DR. LEWIS: Let me just say that I'm delighted that Dr. Mark followed that point up. I was too shy to do it.

(Laughter.)

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MR. ETHERINGTON: I think core melt is important, particularly because we don't really know what is going to happen when you get a core melt. We know what the MARCH code says will happen, but we don't know that that is what is going to happen.

I think there are lots of questions on how it will behave.

DR. LEWIS: You are certainly right, Harold, but the point is that the original answer, which had to do with the calculation of core melt, said the risk was being evaluated in such a way that it had only a loose connection with the actual risk to the public.

Given that definition, one could triple the thickness of the containment and not change the risk at all, and that is surely overdoing the isolation of core melt as an objective.

MR. SNIEZEK: Another factor is the potential change in cost to the public, the worker, and the utility as well as the NRC.

What resources are being required, and how are we going to spend them?

MR. EBERSOLE: Thank you. May I ask a question?

When you calculate the cost to the utility, do you segregate the cost, which is really the cost to the corporation and stockholders versus that which is passed on

to the ratepayers?

MR. SNIEZEK: No, we do not, because from state to state that may differ. The cost to the utility is the downtime and replacement power cost. That is the cost to the utility.

MR. EBERSOLE: That is recovered, however, by assessing it to the public?

MR. SNIEZEK: It may very well be, but that is still a cost.

MR. EBERSOLE: It is a cost, yes.

MR. SNIEZEK: The relevance of other matters here, we are trying to make sure that the staff does not have on a pair of blinders and they are looking at the bigger picture, the integration of various issues together.

Will one fix solve many problems instead of solving individual problems piecemeal? What is the priority in light of the other ongoing activities in the industry?

Is there interim or final action? If there is interim action, why do we have to take the interim action?

What is the time on this? Are we allowing enough time for the facility to design, procure, to install, to train, develop procedures, et cetera?

Let's not have arbitrary dates anymore.

How about the coordination within the staff?

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Does the staff really have its act together? Does NRR know what IE or Research is doing in that area? They sure shoul1.

Those are the types of considerations the CRGR reviews when the package comes over.

Yes, sir?

DR. OKRENT: You mentioned timeliness. Do you consider timeliness from the point of view of the public; namely, is this something that needs to be remedied rather rapidly because of its potential impact on public health and safety?

If so, how do you do it? Give me an example.

MR. SNIEZEK: Let me give you an example. The recent one that went out was an emergency action. That was at D. C. Cook, where the scram breaker failed just recently. It did not have the shunt trip feature in it.

The staff looked at it. They went to D. C. Cook, examined it, and on tests the trip breaker didn't provide sufficient force again.

We found there were three utilities in the country that had the same type of problem, that did not have the shunt trip installed.

Within a day a bulletin was issued, saying we have got to fix it.

DR. OKRENT: Is this something that CRGR

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requested?

MR. SNIEZEK: No. Under the process, CRGR would not even step in on that.

DR. OKRENT: I am asking about CRGR because you mentioned the other side of the coin, that you think about how much time is needed by the utility to implement some change, and I am asking whether CRGR asks itself how much time is it appropriate from the public point of view to let this matter stay unremedied.

Have you ever given that consideration?

I would like an example.

MR. SNIEZEK: There are several, and I can't think of the examples right now.

VOICE: There is one on the station blackout, where the committee considered they were overtesting diesel generators. The committee recommended that they urgently take some prompt action to make sure that they are not overtesting the diesel generators.

Another item concerned a bulletin on breakers that did come through the committee, where they urged that the breaker be redesigned, that the problem was in the design, and patchwork, although it might be a temporary fix, would not totally correct the problem, and they urged action to correct that design problem.

Those are two that come to mind right now.

DR. OKRENT: I must say you leave me unimpressed with your examples.

Let me ask a different question:

Under the backfit rule, if I understand correctly, there are certain findings that need to be made before a backfit can be made, and these include the use of the word "substantial."

What is the CRGR's definition of substantial changes?

MR. SNIEZEK: The definition of substantial change at risk -- that is a question you asked the other day at the subcommittee briefing. We sent the same response down. It was sent to Congressman Markey. You should have that now.

DR. OKRENT: Can you tell me?

MR. SNIEZEK: I can tell you, in very few words, we have not applied a quantitative definition to the word "substantial," overall improvement. We use essentially a dictionary definition. It is a matter of engineering judgment whether or not you are having substantial additional deflection.

We say it is something that is not imaginary. It is of real value. That is what we say. We have not put a quantitative value on it.

DR. OKRENT: Let me pose a hypothetical example,

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for which I hope we can find a PRA which fits.

There are half a dozen important scenarios. One of these is calculated to be larger than the others by a factor of three. Some member or group from the staff comes in with a proposal to fix not the one that is calculated to be the dominant one but one of the other five. It says we can, we think, improve this one by a factor of two.

How would you treat that? Is that a substantial change in risk?

MR. SNIEZEK: The substantial change in risk also goes with the cost of change. You can't differentiate --

DR. OKRENT: I am sorry. The "substantial" has nothing to do with the cost.

MR. SNIEZEK: But the decision on whether or not --

DR. OKRENT: I didn't ask you about the decision. I am trying to find out how you interpret "substantial." We can find out about cost later.

I am trying to understand how you interpret "substantial."

MR. SNIEZEK: It depends upon where you are, as to what are your numbers to start with.

Are you in the 10 to the minus 7 realm, the 10 to the minus 3 realm?

DR. OKRENT: If you wish, I will give you a

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range. Your overall core melt frequency is a little larger than 10 to the minus 4, and these contributors in the second tier are all something like 10 to the minus 5, larger than 10 to the minus 5.

MR. SNIEZEK: That probably would be substantial.

DR. OKRENT: Overall risk would not be changed much because there is one dominant feature which is three or four times bigger.

Why would you call it substantial?

MR. SNIEZEK: Well, we are getting into a discussion of the dominant sequences, and there is no clear direction on dominant sequences in the agency at this time.

DR. OKRENT: Well, the CRGR, if I understand correctly, is the one that will be providing key advice to EDO on backfits. It seems to me they ought to have some kind of either philosophic approach or recipe or something which is disciplined -- is that the word that is proper these days -- in how they approach the term "substantial," and don't just say we will use engineering judgment.

MR. SNIEZEK: We basically do use engineering judgment, and when you get to individual sequences or 10 to the minus 5, the CRGR focuses on them. Whether the change is something that would be substantial depends upon the decisions that the individual policymakers make. It is not

a cookbook answer.

DR. OKRENT: One last question:

Are the meetings of the CRGR open?

MR. SNIEZEK: The meetings of the CRGR are open to all the staff. They are not open to the public.

DR. OKRENT: Why are they not open to the public?

MR. SNIEZEK: Because it is predecisional information that we are developing at that time, and we don't want to release it to the public, public interest groups or the industry, on the CRGR deliberations.

DR. OKRENT: Why do you think it is that this kind of pressure on the CRGR is adverse when the Congress has judged it is not adverse to have such pressure on the Commission or on the ACRS?

MR. SNIEZEK: I will tell you in a nutshell. Many times the staff comes before the CRGR with half-baked ideas. They want to come before them and get their advice, and we don't want the public to get the impression that the staff is wrong in a lot of instances. The staff action is not finished when EDO makes those decisions. It is all advisory to the EDO.

DR. OKRENT: So you want it to appear that there is a monolithic staff opinion when you are all done, or what?

MR. SNIEZEK: The staff opinion that comes out

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is the EDO's decision. You can poll 3600 people and get 3600 opinions. The staff opinion is the EDO opinion. That comes out of the process.

MR. WARD: Mr. Okrent is just jealous.

(Laughter.)

DR. OKRENT: I am not at all jealous. I would suggest that there is a loss of information to the public and, in fact, to the ACRS.

MR. WARD: Are the meetings open to ACRS?

MR. SNIEZEK: That is correct. They are open.

I would mention, also, that the staff proposals, the meeting minutes, and the resolution of everything eventually goes in the PDR, and a copy is provided to the ACRS.

DR. OKRENT: I have looked through these minutes.

MR. SNIEZEK: And all supporting documentation that goes with it.

MR. EBERSOLE: Mr. Sniezek, since someone took up an example here, may I reflect something I found?

We had an episode at Beaver Valley which bothers me. Can you mention the integration of effort so that this team knows what that team is doing?

I have suspected for a long time -- and I certainly confirmed at Beaver Valley -- that the team that

works on the materialization requirements for GDC-19 works in a different camp from the one that works on Appendix R because I go to the plant and I find at the outset a very expensive and quite substantial effort had been put in place -- and this is certainly generic to all plants -- to install switchboards which are in essence reproductions of the main control board, situated in places such that they don't share the atmosphere of the control room but which are backwired to the control room and thus subject to any of the physical events that occur within it.

Meanwhile, off in another camp there is another board being built to accommodate the physical disaster that might occur within the main control room.

These boards -- certainly the first one I mentioned -- are in essence extensions of the vulnerability of the main switchboard room, since whatever happens there can happen at the other place and they share the common consequence.

I regard this as disintegration of a design and construction logic and something that should be fixed because in fact all this expenditure has led to increased risk rather than decreased risk.

MR. SNIEZEK: I cannot disagree with you. Those types of things are still happening. It is the type of thing we are trying to correct on the front side, and we

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are not always successful.

MR. EBERSOLE: Thank you.

MR. WARD: Jim, I think the interchange is valuable, but how much more time do you need just for your presentation?

MR. SNIEZEK: I would need about 10 minutes.

MR. WARD: Okay, fine.

DR. KERR: You do think the interchange is valuable?

(Slide.)

MR. SNIEZEK: I will just throw this slide up for a second.

It shows you the type of generic issues that are in fact reviewed by the CRGR. I don't think it really needs any real discussion.

DR. REMICK: Just a question, Jim. You do not exclude power reactors, do you?

MR. SNIEZEK: We do not address nonpower reactors, just power reactors. Field facilities are not in our charter. That was a Commission decision.

The major problem that the Commission saw early on was with the power reactors.

DR. OKRENT: Before you take that off, what does standard designs imply?

MR. SNIEZEK: Standard designs would apply to

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something such as GESSAR, which, by the way, was not reviewed by the CRGR. Several years ago, before I even got there, a decision was made that it would not come before the CRGR.

I want to mention one thing that I forgot to mention upfront. The office directors are to bring all generic issues to the CRGR; however, the CRGR charter says that the CRGR will only review those things that are brought forward by the office directors.

So if the CRGR sees something going on that should have come to the CRGR again, our only avenue is to go to the EDO and have him direct the office again. Again, we are advisory to the EDO.

(Slide.)

Let me mention briefly the activities of the CRGR in a more statistical format.

Since its formation in 1981, there have been 82 meetings -- 11 of those were in this year -- 183 meeting agenda items for briefing or review, covering 129 different topics, 129 different generic issues.

I will mention that there is a difference between a briefing and a review. A briefing is when an office director wants to come over and just give CRGR advice, if we think we are going the right way in approaching a problem; whereas, a review is a formal review by the CRGR which ends

up in a recommendation to the EDO whether the staff should go forward with an action or not.

There 103 different issues that were reviewed, and for about three-quarters of them we recommended approval. Some of those were approval with comment. Right now on the long range agenda, generic issues that is on the staff's plate, there are about 150 items. Each year we publish a long range agenda, and the current one -- we have got about 150 items on it.

We believe that as a result of the CRGR the staff has been more thoughtful in their solutions to generic problems, and we have found that at least in the CRGR process the packages that are coming to us today are generally more well thought out than they were several years ago, more visits to the reactor sites. Our feedback from utilities is that the generic requirements today are starting to make a lot more sense than they did many years ago.

That is basically what I was going to say on the CRGR.

Because of the committee's interest in backfit, if you desire, I can go and talk a few minutes on the current status of the backfit issue within the staff, since backfit and CRGR are tied together.

(Slide.)

Backfit. Two types, as I mentioned, generic backfits that apply to more than one plant and plant-specific backfits.

CRGR is to handle the generic backfits. The NRC Manual Chapter 0514 is to handle plant-specific backfit.

In June 1983, the Commission directed that the staff take initiatives in the plant-specific backfit area.

In April '84, they approved the first version of Manual Chapter 0514, Control of Plant-Specific Backfit.

In May 1985, the Commission approved the staff revision of 0514. That is the version that the ACRS commented on in, I think it was, February of 1985.

Then, as you know, the Commission just recently approved 50.109, which is a backfit rule which covers both generic and plant-specific backfit.

What we are doing now in the backfit area --

(Slide.)

-- is, as I mentioned, the CRGR has met more than 80 times and discussed 129 generic backfitting topics.

We find that the plant-specific backfits are being primarily surfaced by NRR, but they are existing and they are happening out in the regions and in the Office of Inspection and Enforcement as well.

We have an agencywide plant-specific backfit monitoring system in place where we are tracking what is

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happening on the plant-specific backfits. It is a management tool for the agency managers. They pull out on the computer: here is what is happening, here is where backfit has been identified, here is the status of resolution, here is what is being done to fix it, and here is a final agency action.

Those type of activities are being tracked in all the plant-specific backfits.

Manual Chapter 0514 has been recently conformed to the backfit rule and is being sent down to the Commission within the next few days. We've held initial discussions with industry on having backfit workshops in the January-February '86 timeframe to make sure that industry understands the staff process and where we're going in the total backfit situation.

DR. CARBON: Question. Roughly how many backfits are in progress or to be in the mill at the present time, both generic and plant-specific? Can you give me some feeling?

MR. SNIEZEK: Generic backfits, as I mentioned, there are about 150 that are in the mill coming up.

DR. CARBON: I'm sorry, I missed that.

MR. SNIEZEK: In plant-specific, right now, the ones we know about, there's probably between 75-100 plant-specific. That does not mean that they're all identified yet. The plant is still in its learning process. We're changing a 15-year old culture as far as making sure that we know the total impact change in risk before we propose plant-specific backfits.

So we've got a long haul. I don't believe that that process will be fully implemented the way we were really satisfied with it for several years.

MR. WARD: Jim, do you have some involvement with

these plant-specific backfits?

MR. SNIEZEK: Let me tell you how the process works. It all flows from the backfit rule. The EDO Manual Chapter tells the offices, "Develop procedures to control it. If there's a backfit and it's consistent with the definition in the rules, here's the process you have to go through." The nine factors in the rule for the evaluation, that's what the staff has to go through.

If, at the end, they say, "Hey, this is still a worthwhile fix that we want to make," they then can impose it on the utility. If the utility says you didn't do your analysis right, or disagrees that it's really going to improve safety, they can appeal it. They submit the appeal and all these steps are tracked on the agencywide tracking system initiation of the steps.

MR. WARD: And who is doing that tracking?

MR. SNIEZEK: Each office submits inputs to the computer itself. Now, what we do on my staff, when there is an appeal submitted, a copy of the appeal is submitted to me. We monitor the agency's action on the appeal. We do not get involved until it is at the appeal stage.

Also, we'll be going out and auditing how well the agency is in fact implementing the procedures, that each office has in place.

MR. WARD: Okay, but this is something that your

staff does separate from your CRGR?

MR. SNIEZEK: That's right. Now, when we go out there, well, let me mention, we don't care whether the staff comes to the CRGR. Say, they want to buy a fixed facility. They can do it one of two ways. They can come before the CRGR and have it reviewed generically. Or, they can do it plant-specific on each one.

I would envision the staff would normally like to come to the CRGR route if they do one evaluation instead of 10 evaluations.

MR. WARD: Why do they have that option? If it applies to 10 plants, why isn't it under your procedures, generic?

MR. SNIEZEK: It is under. In actual practice, it won't make much difference. The same kind of objectives would be accomplished. The objective is to make sure that the staff does a disciplined analysis and review before they can impose a requirement.

Now what we do do if the staff has been doing the plant-specific instead of generic, and we pick that up, we go back to them and say, Hey, let's talk about your coming before the CRGR, since it is a generic issue.

MR. WARD: I hope so. It sounds like, if the staff chooses to do the same plant-specific action in 10 plants, that they would be bypassing the intent of the

agency.

MR. SNIEZEK: They are under the CRGR, but under the backfitting rule, they would be required to do the evaluation required by the backfitting rule 10 times for those 10 plants.

So, in the long run, I believe the overall objective of the agency would still be accomplished because the factors to be reviewed for plant-specific backfitting, with the exception of one factor, are the same as for the generic factor.

MR. WARD: Maybe you're giving an over-simplified example of something or I'm looking at it in too simple a way, but it sounds like, at minimum, this is wasteful of staff resources.

MR. SNIEZEK: I agree, and that's why I don't think we're going to find any or many of those happening. Now, it was happening before we had the plant-specific backfit, a circumspection to the CRGR process. Okay, fine. Then we ran them in. But, now, plant-specific backfitting, if we do it that way, we're accomplishing the same objective. You're right, doing it that way is a dumb way to do it.

DR. CARBON: Could I follow up what you just said here? To follow the same conversation or trend of thought, if a particular group leader, for example, has the idea that

he's going to push this through and he wants it, he can do it. Is that so? He can push this specific thing for one plant and he can take another?

MR. SNIEZEK: I oversimplified the steps. It's a very detailed process. You're right. He probably can push it through, only if his office director lets him. There has to be a plant-specific backfit analysis performed. That analysis has to be approved by either the office director or the deputy office director on a plant-specific basis. That's the control. We want management to manage their staff, and that's why we put in that specific step.

VOICE: Jim, could I make just a clarifying comment that might help you a little bit? The key is according to what the Commission asked through the Charter, the CRGR Charter. The Commission intended that the CRGR only get involved when an office director submits a proposal to the CRGR for review.

In some cases, an office director, for whatever reason, may not submit a proposal that really is generic. And then, plant-specificwise, he will do the same thing for a number of different plants.

The backfit rule literally makes him do this analysis for a plant and, therefore, is required for each plant.

I think the disconnect that you have is the

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problem where an office director does not submit a generic package to the CRGR but actually does go out and implement something at a number of different plants, and he thinks of it in terms of plant-specific.

I think that might help to draw the line for you.

MR. WARD: You mean, if somebody's subverting the agency. It seems to me the agency policy here, it's the office director.

VOICE: In the case you stated, that would be correct but I'm not sure it's direct subversion. It may be just not recognizing it as a generic action, thinking of it as a plant-specific action.

MR. SNIEZEK: Let me mention something else we did. We wanted to make sure that all levels of the agency, that we've got their attention. The Senior Executive Service Contract, the past year, it's the first time it's ever been in there, there's a specific element in there about backfitting and doing it in accordance with agency policy.

Through the monitoring we're doing, we're going to know which office directors and their staffs are doing it in the course of agency models. And it will be reflected in their performance evaluations. The EDO is very serious about this.

MR. MICHELSON: How do you do that? Is an office director going to admit that his people are not following backfitting policy? He's the one that reviews the SES regs and reviews, the contracts.

MR. SNIEZEK: We have it in the office director's contract that evaluates him.

MR. MICHELSON: Only if you believe that that office is so doing and you put it in his contract will it do much good.

MR. SNIEZEK: It's in his contract.

MR. MICHELSON: Well, it doesn't do any good to put it in the office member's contract. The director isn't going to admit to that.

MR. SNIEZEK: I disagree with you, Carl. If the office director is being paid on backfit, he's got a couple of division directors that are leading him down the path.

MR. MICHELSON: There are a lot of ways of fixing that problem.

MR. SNIEZEK: Sure, but we're serious about the controls.

MR. EBERSOLE: May I ask a question?

As I understand it, the regions are somewhat more autonomous than they used to be. Therefore, I would expect to find some backfits in some regions that I wouldn't find in other regions. How do you control that sort of thing?

MR. SNIEZEK: The same way. When I said "the offices", I included the regions. They're being treated the same way under the plant-specific backfit process.

MR. EBERSOLE: When you find backfits of a certain kind, perhaps one major backfit in one region, everybody's tried it everywhere else. What happens?

MR. SNIEZEK: First of all, backfit is not bad. Backfit is proper, but you've got to go about it in the right process. It's got to be evaluated. It's not bad to backfit. There are a lot of good backfits, but you've got to go about it in the right process. We're not worried about the backfit, we're worried about if the backfit was imposed and should not have been imposed and did not go through the process, there's arm-twisting of the licensees going on and that type of thing.

MR. EBERSOLE: What about a backfit that has been imposed in one place but never has been noticed for imposition on others?

MR. SNIEZEK: There's a question there where that should be reviewed generically for application for others. But, since the regions are really in the plant-specific backfitting mode, it may apply only to one plant and not other plants. It may be a specific problem on that plant but I agree with you, if there is a backfit imposed on one plant, a logical question is: Does it have applicability to

others?

MR. EBERSOLE: Is that a ritual that you want to dig up and follow through?

MR. SNIEZEK: That's not what we are monitoring from our office. That's the responsibility of the individual office directors and regional administrators.

MR. EBERSOLE: For instance, if I should find that if I had to put belated mechanisms on swing checks in one plant, I might not put them in any other.

MR. SNIEZEK: Let me mention one of the things that is in place. Under the Office of Inspection and Enforcement, they have it in their inspection program that the regions are to identify potential generic issues to the office director for consideration for application to all plants.

If an inspector finds on one plant that there's a problem that the region is acting to correct, then the regional administrator and his staff say, Hey, this may have broader applicability, it then is afforded to the Director of IE for evaluation for generic applicability. There is a process in place to do that.

DR. OKRENT: Correct me if I'm wrong. I came back here in the middle of the conversation, but I thought I heard that as part of the future evaluation of office directors, one thing will be how well was the process of

backfitting controlled by that office. Is that correct?

MR. SNIEZEK: That's correct. Was it done in accordance with agency policy?

DR. OKRENT: I have another question. I'll give an example so that this point is clear. The early Davis-Besse incident gave some information that in fact turned out, at least some of it, invalid. I recognize it was not generally recognized within the NRC, ACRS. Some members had concerns.

Is there somewhere in this evaluation of office directors a question of are they seeing and missing important safety issues?

MR. SNIEZEK: That is the very first thing in their performance appraisal -- safety. Their response to safety problems. The very first thing, right up on top.

DR. OKRENT: That's not the same thing, I'm sorry to say, and, obviously, what I have concern about is that this very considerable emphasis on backfit occurring within the agency now, much of which is needed, I'm not arguing that point, may have -- I'll call it a chilling effect, or maybe just a subconscious effect, or whatever, which leads to people in fact not being inquisitive about the things they should be. Okay?

And I gather, and I don't think your statement about evaluating the concern with safety necessarily gets

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to the point, are they sufficiently alert in following up clues of potentially important safety effects?

MR. SNIEZEK: As far as I know, there is not a specific item that says that in their contract. That's embodied under Safety Responsibility.

DR. OKRENT: If you're going to put a specific item on backfit, it seems to me you might put one on this, too.

MR. SNIEZEK: We haven't really seen a big problem in that area; whereas, we did have a problem in backfit.

DR. CARBON: A question of clarification. You said, had a comment, something about the regions operated in the plant-specific mode. I wasn't sure what that meant. If a region director mandates a change on all the plants in his region, that's generic. And that would come forth.

MR. SNIEZEK: You're correct, that would. We have not really seen that. Mostly more from the headquarters office.

MR. MICHELSON: How is the problem of informal backfitting handled? I think you probably understand what I mean by "informal backfitting". This is where the appropriate pressure is applied by the regional director to clean up the act at a given site, but he may also be exercising the same pressure at several sites. It's all

informal. It's not documented in the normal sense. When the licensee volunteers to do it because he's rather do that than face the unpleasant scene.

MR. SNIEZEK: Carl, that's what I mentioned earlier on. We're changing the culture here. That's going to take years to get that changed.

Cne of the things we have done, I personally have met with over 700 of the staff, seven hours in each of the regional offices and headquarters offices. We're talking a philosophy with respect to what we do or are supposed to be doing. There's no way up front that we're going to turn off all that informal backfitting and armtwisting that's going on. We're trying to ingrain the staff to what is expected of them in that area. And we believe basically that, over the long haul, if the managers, the reviewers and the inspectors reinforce this over the long haul, that issue will be fixed.

MR. MICHELSON: Some of this is good because it gets the little but perhaps important thing fixed without making a big issue out of it. So you can focus your attention on the real problems.

So how is that judgment? It's not an easy judgment to make.

MR. SNIEZEK: It's a difficult judgment. What we tell the inspector is, "Inspector, you know, if you're

forcing the licensee to do something, or if you're really requiring him to do something..." also, you know, "if you're really leaving it up to him to volunteer it, give the issue to him and let him think about it. It may be a good idea."

When we went out and talked to all the utilities, they said, "Don't knock off that interface, we want that interface, the individual reviewer telling us his views and his concerns is good. It makes us better. It makes us safer. We have a problem when he says you've got to do it my way, that's the only way you can do it."

That's what we're trying to control, but we want that dialogue to keep on. We want to even encourage that dialogue.

(Slide.)

The last slide I have here is on future actions. Basically, right now, as I mentioned, the backfit identifications, appeals and final dispositions are being monitored by the EDO shop. We will be providing periodic reports to the Commission on backfitting, on what's happening. We'll be having another round of meetings with the staff to explain the implementation of the rule.

This is a followup for our previous round of meetings, our original version of the Manual chapter. We'll be having the workshops with industry to make sure the industry understands the staff process and how the industry

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interfaces into that process, the appeal process, especially.

One of the things we're trying to do is, the industry, we recognize every plant manager, every vice president says I've only got so many chips to use in a battle with the staff. But if they're really being impacted by the staff or if they feel any intimidation from the staff and they're worried about retribution from an inspector or reviewer, that's something the agency won't tolerate. And that's the message we're trying to get out to the utilities.

We don't want the industry to do anything because of fear of retribution. We won't stand still for it. That's going to be a hard one to overcome.

DR. MOELER: I had a question, if you're near the windup.

As I recall, and please correct me if I'm wrong, the CRGR did review the proposal on how to prevent or try to control inadvertent PWR reactor cavity entrances with the in core detectors withdrawn. And in your early remarks this morning, I gathered that you looked at the staff analysis. You don't do the analysis but you look at it and see if there are errors, and so forth, in it.

We now have been asked to look at this item once again because I guess the staff considers it resolved. And

so I called and asked the staff members involved, and I said to them, You know, the proposal presented to us was to have a couple of sets of keys to the room, to the door entering the cavity, and to have another layer of administrative signoff to try to control this matter.

Well, I asked two questions. One was is there an indication in the control room of whether the in core detectors are withdrawn? If so, how much? And they said, Yes, indeed, that is displayed.

And then I said, Well that being the case, why couldn't you run a wire over to a light bulb, a red light above the door, the entry door to the cavity. And this light blinks if the in core detectors are in any degree of being withdrawn?

And they said, Well, we never had thought of that. Did no one think of that or is it not practical, or what?

MR. SNIEZEK: I can't answer that specific one. Remember, it was quite a while when that came before CRGR. There was discussion on the door interlocks, where you physically couldn't open the door if the detector was withdrawn.

There was a lot of discussion of the various types of hardware fixes that were to be made, also. I don't remember the exact rationale for each one.

But it is those types of things that do discussed at this hearing.

DR. MOELLER: Thank you.

MR. WARD: Maybe one more question.

Dr. Lewis.

DR. LEWIS: I wanted to follow up just for a moment what Dade was saying.

At least in one case that was really quite different -- Bill will remember this -- we had an indication in which there is a perfectly sensible idea for having a blinking light to show at all times that the scram system was working.

The NRC staff rejected it because they didn't want people tinkering with the system and felt that any permanent indicator that showed it was working would degrade the reliability of the system.

I had great difficulty following the logic, but

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that is what happened in that particular case.

I only wanted to make one other comment, and that is you are absolutely right, making the utility somehow feel free coercion is going to be an uphill struggle when coercion continues to exist.

MR. SNIEZEK: I will relate to you, we went out to a utility about three months ago. We had C. P. Nuclear in the front row, and all the department heads were behind him. We asked him, do you ever feel intimidated by inspectors and reviewers? And he said, absolutely not. Every one of his managers was just shaking his head the opposite way.

(Laughter.)

DR. LEWIS: Sometimes when you ask people if they feel coercion in front of the people from whom they are being coerced, they say "no." It is known to happen.

MR. SNIEZEK: Okay.

Anyway, the offices are in the process of revising the specific office procedures important to the manual chapter and the rule put out by the Commission. Right now we are in the process of revising the CRGR charter, which has to be brought in consistence with the backfit rule.

A few of our criteria were somewhat different than the backfit rule, so that is being revised, and that

should be done and sent to the Commission for approval within a couple of weeks.

That was the end of my prepared remarks.

If the committee has any further questions, I would be pleased to answer them.

MR. WARD: I think we have asked a good many.

Jim, thank you very much. It has been a very useful briefing. We appreciate your coming down.

DR. KERR: Mr. Chairman, I am not sure what the tone of the questions has been, but certainly following the activities of the CRGR, it seems to me it has had a positive influence on the Commission activities. I would hate for Mr. Sniezek to go away thinking that we are entirely negative about their activities. At least I, for one, am not.

DR. LEWIS: I would like to support what Bill said. One would have the impression from reading this transcript that we think CRGR is an abomination, and some of us don't.

MR. WARD: Thank you.

Let's take a 10-minute break.

(Whereupon, at 9:35 a.m., the meeting was recessed, to go into unrecorded session.)

AFTERNOON SESSION (2:30 p.m.)

MR. WARD: Let's go right into the next topic, then, which is Beaver Valley.

The next topic deals with the application for the license for the Beaver Valley Power Station. I will ask Mr. Wylie to give the subcommittee report.

MR. WYLIE: Thank you, Mr. Chairman.

The information concerning this meeting is contained in the handout as a blue cover agenda item, 13.1, and you have a notebook passed out by the applicant that covers his presentation today.

The Beaver Valley Subcommittee visited the site of Beaver Valley Unit 2 on October 31 and held a subcommittee meeting at the site -- at the Holiday Inn at the airport at Pittsburgh -- near Pittsburgh on November 1. The ACRS members present were myself, Mr. Jesse Ebersole, Bill Kerr, and Forrest Remick. Herbert Alderman was the ACRS staff member present.

The Beaver Valley site is on the south bank of the Ohio River in Beaver County, Pennsylvania about one mile from Midland, Pennsylvania and 25 miles from Pittsburgh.

On the site is one operating reactor, Beaver Valley Unit 1, which is an 810-megawatt electric Westinghouse PWR. The Beaver Valley site is adjacent to the Shippingport Atomic Power Station, which is scheduled for

decommissioning by DOE.

The applicant is Duquesne Light Company, which acts for itself and as an agent for the Ohio Edison and Cleveland Electric Illuminating Company and the Toledo Edison Company for a license to operate Beaver Valley Station Unit 2.

Beaver Valley Unit 2 is a duplicate design of Unit 1, with a number of enhancements, and is a three-loop PWR supplied by the Westinghouse Company, with a net calculated electric output of 836 megawatts.

Stone & Webster is the architect engineer/constructor.

The construction of Unit 2 is about 90 percent complete. The applicant presently plans hot functional testing in October -- let's see, October of '86, I believe it is -- and to load fuel in April of '87 -- in August of '87.

The containment is a cylindrical reinforced concrete structure designed to operate at subatmospheric pressures between 9 and 12 psia, maintaining an air ambient temperature of approximately 95 degrees Fahrenheit. It is tech spec'ed at 105 degrees Fahrenheit and to have access during operation.

I would like to call your attention to the design of the feedwater systems for the plant. There are two

60 percent capacity electrically driven main feedwater pumps. There is one 30 percent capacity electrically driven startup feedwater pump. There are two 50 percent capacity electrically driven aux pumps and one 30 percent capacity turbine driven auxiliary feedwater pump.

At the subcommittee meeting, we heard presentations by the applicant regarding the construction status and startup schedule, the organization and management, the training and staffing plans for Beaver Valley 2, the quality assurances differences between Unit 1 and Unit 2, and shutdown and decay heat removal capability.

The staff made presentations regarding technical issues, backfit items, confirmatory issues, licensing positions, and construction experience.

Two significant backfit issues -- the steam generator level control and protection system.

The Nuclear Regulatory staff maintains that it does not meet IEEE-279. The applicant originally disagreed and considered the issue a backfit and requested a backfit meeting.

The applicant has agreed to meeting any requirements which may come out of the resolution of Generic Issue A-47, which is the safety implications of control systems.

The second backfit issue had to do with the

cable spread room fire suppression system.

The Nuclear Regulatory staff was not satisfied with the carbon dioxide system as the primary fire suppression and the effectiveness of the CO-2 in the deep-seated congested cable areas and the accessibility to fight fires in that area.

The applicant has agreed to remove platforms and other constructions. It has purchased portable fog nozzles and plans to demonstrate the effectiveness of using the fog nozzles fire fighting system.

One significant open item has to do with Duquesne's proposal to cross-train supervisory personnel, SROs, operating personnel on both Units 1 and 2.

The Nuclear Regulatory staff of Region 1 is considering that proposal at the present time.

We heard a report from a representative of Region 1 that the experience to date, in his opinion, of quality assurance was indicative that the architect engineer/constructor, the applicant, and the subcontractors are all committed to building a quality nuclear power plant.

I believe that is enough for me to say at this time. I will ask any of the subcommittee members who were present if they have anything to add at this point.

DR. REMICK: Chuck, I might just add that we did

take a tour, and the licensee applicant has constructed a very extensive and elaborate emergency response facility.

Also, the combination training center and simulator center -- if I recall, the combination of the training center and the simulator were about 80,000 square feet.

So they have built some very nice facilities for emergency response, including the EOF center, technical support center, training center, and so forth.

MR. EBERSOLE: I would like to make one comment. I think that the ACRS should get a very warm feeling by finding out that this plant has electric main feedwater pumps, which are two 4000's in tandem per pump and they have 90 percent bypass, steam bypass capacity which they stated would not cause an undue financial burden to obtain.

DR. OKRENT: Are you satisfied that a very careful review of internal flooding has been done by the applicant and staff?

MR. WYLIE: Maybe the staff can respond to that.

DR. OKRENT: Let's leave it for something that they pick up.

Second, was there sort of a special look at the smaller items in connection with accomplishing decay heat removal in an earthquake that we have sometimes asked that special attention be given?

Do you know whether that kind of look has been done?

MR. WYLIE: The SER indicates that they have looked at that.

DR. OKRENT: I guess the applicant can tell us what they did in that regard.

Did they do a seismic systems interaction study, nonseismic versus seismic?

MR. WYLIE: I don't know. You can ask them.

DR. OKRENT: I have a question. I would just be interesting in hearing from the applicant.

My impression -- correct me if I am wrong -- is that Beaver Valley 1 -- that is a three-loop, is it -- it is like the plant that the French built first -- that the French made it as close as they could to Beaver Valley 1 except for the site. I believe the French made some changes in design from Beaver Valley 1, like a different containment design, and they may have even made changes -- well, I wonder if you had followed what the French had done and, if so, you could summarize what they thought was warranted or prudent or beneficial from a safety and/or reliability point of view and tell us how you evaluated what they did.

MR. EBERSOLE: Dave, I might call to your attention the responses to the ACRS concerns in the report here about the matter of the topic of our Wednesday

discussion. There is an elaborate response to that.

DR. OKRENT: There are, I think, a variety of things that the French may have implemented. I am just curious to see whether they have followed it and, if so, what comments they have.

MR. WYLIE: Any other questions or comments by members?

DR. SHEWMON: Are we going to have a presentation on this?

MR. WYLIE: Yes, sir.

Well, let me clarify that. The agenda under the tab agenda lists presentations.

Any other comments?

(No response.)

MR. WYLIE: If not, I will call on the applicants to begin their presentation.

MR. CAREY: Good afternoon, gentlemen. My name is Jack Carey, Vice President of the Nuclear Group for the Duquesne Light Company.

Beaver Valley No. 2 unit was contracted for in mid-1971. It was to be a duplicate of the No. 1 unit, which was under construction at that time. It was completed and went into commercial operation in 1976.

(Slide.)

The ownership of Beaver Valley No. 1 unit is

roughly 50/50 between the Ohio Edison Company and the Duquesne Power Company. In the No. 2 unit the ownership shares were established in accordance with a standard CAPCO ownership share.

CAPCO stands for the Central Area Power Coordinating Group.

The CAPCO companies are the ones shown on the board here, and the Pennsylvania Power Company is a subsidiary of Ohio Edison.

The CAPCO companies undertook to build several fossil and nuclear units with a standard ownership share.

Duquesne Light Company, even though a minor owner, 13.74 percent, in Beaver Valley No. 2 unit, was selected to manage the engineering, construction, and operation of No. 2 unit, since we were in charge of the No. 1 unit at the time that was contracted for, and we fully intend to utilize a common operating staff, and the plant will have a common control room.

There have been numerous modifications or changes to the original design, most of which are design enhancements based upon the experience that we gained in the startup and operation of No. 1 unit.

Just to answer a question that was asked, we are aware that Beaver Valley was basically the lead plant, the three-loop plant, for the French design, but we have not

followed closely the modifications that the French elected to put into their units, for two reasons.

One of them is that we have a subatmospheric containment device. So for the balance of plant equipment, most of those changes would certainly not be applicable. We rather elected to attempt to bootstrap on our experience with No. 1 unit and review each and every design modification that was installed in the No. 1 unit for its applicability and desirability for inclusion in the No. 2 unit.

DR. OKRENT: Excuse me, if I can make a comment.

I am a little skeptical that the changes the French have made are largely squeezed out by that difference in containment. Of course, I could think of some that would apply either way, but I don't know.

MR. CAREY: I didn't imply that they were squeezed out by that.

What I did imply was that since we had a completely different containment design, that all of the engineered safety features and the equivalent that is outside the nuclear steam supply system, that most of them would not have been affected by the changes to the nuclear steam supply.

We felt it was better to attempt to incorporate the experiences that we gained in operating our No. 1 unit,

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and we have followed very closely the changes that other United States utilities have incorporated in plants of similar design, such as Farley and the North Anna units.

(Slide.)

This is a view of the Beaver Valley facility. It is located on the Ohio River about 35 river miles and about 25 air miles west/northwest of the City of Pittsburgh. Beaver Valley is in the foreground.

We do have two cooling towers, one for each unit. The cooling towers again are slightly different. The No. 1 unit utilizes a Marley crossflow cooling tower. The No. 2 unit, on the basis of low bids, we have installed a CERN counterflow cooling tower.

It may be interesting to note that the Mansfield plants, which are in the background, are three cold-fired, 800-odd megawatt units, and these plants use a Research Cottrell counterflow cooling tower, and again I am sure that that was on the basis of the low bid.

(Slide.)

There is one other item that I may call to your attention.

If you will look at the Beaver Valley units, the cooling tower was installed on Beaver Valley No. 1 unit. A decision was made in late 1972, early 1973 to satisfy a federal water quality requirement on discharge temperatures

in the river. Beaver Valley was originally designed with a once-through cooling system. At the time we began the construction of No. 2 unit, we elected to rotate the entire plant 180 degrees. This was to shorten the length of the 108-inch cooling water lines between the cooling tower and the main unit generator.

Beaver Valley is different than many other two-unit facilities. We do not have common turbine buildings or common auxiliary buildings. The only common facilities between the two units are basically at the front end and the back end. We have got a common water treatment system, and we have some common facilities in both our gaseous and liquid waste facilities.

The main intake structure, which was originally designed to provide 500,000 gallons per minute, which is the cooling water requirement for the condenser, presently operates at about 42,500 gallons per minute, which is purely water that passes through our safety-related heat exchangers and other heat exchangers in the plant and is discharged to the cooling tower basin. This is about 7500 gpm more than our normal 15,000 gpm cooling requirements.

The cooling tower plume, I anticipate, is about 15,000 feet gpm, and the other 7500 gpm is forded over to the river to maintain a recirculation ratio of the water in the cooling tower.

(Slide.)

This is the layout of both facilities. The layout is essentially the same, with respect to the main structure -- reactor containment, a fuel building, and auxiliary building, service building and turbine building.

(Slide.)

The present construction of Beaver Valley No. 2 Unit is about 89.6 percent, as of 10-31. We are right on track with our schedule for fuel loading in April of 1987.

(Slide.)

This is a slide showing the construction completion with respect to the various buildings of the plant, and as you can see each and every building is approximately 89.5 percent complete. We see no major difficulty that we should encounter in meeting our existing schedule.

(Slide.)

This is called the Project Milestones. We have pulled the vacuum on the condensor. We wanted to be able to provide whatever the aeration that is possible on the water that we're utilizing for the steam generator hydro. We still hope to get the steam generator secondary hydro off prior to the end of 1985. Our reactor coolant system hydro is scheduled for mid-March of '86. All the indicators point to the successful completion of that activity as scheduled.

Hot functional testing is scheduled for mid-October of '86. We have fuel load to follow in April of '87. The major activity between hot functionals will be the containment structural integrity and heat testing, in addition to working down the punch list and closing out any open items that we may have with respect to nonconfirmance. We will be staffed with about 2300 craftsmen, and we feel that the remaining construction activities, we should certainly be able to successfully complete all activities in accordance with our construction schedule.

With that, I will turn it over to Roger Martin, who will describe the major design differences between Beaver Valley No. 1 and No. 2 Units.

(Slide.)

MR. MARTIN: My name is Roger Martin, Engineering Manager of Beaver Valley No. 2. My nuclear utility experience has extended over 30 years in the areas of operations, fuel management and design. I was the operations supervisor on duty at the Shippingport Atomic Power Station, when initial criticality was achieved. I wish to enumerate some of the more significant design differences between the Beaver Valley Unit 2 and Unit No. 1.

Beaver Valley Unit 1, as Mr. Carey has indicated, was designed to duplicate Beaver Valley 1, wherever

possible; however, certain modifications were made, in order to maximize safety and the reliability consideration gained from the continued study of the Beaver Valley 1 operating characteristics.

Beaver Valley 2 startup is scheduled approximately 11 years after Beaver Valley Unit No. 1 initial operation. Many lessons were learned from U.S. nuclear plant operations in the intervening period, and they have been incorporated in the Beaver Valley 2 design during its completion.

Beaver Valley

(Slide.)

The first item deals with the addition of the startup feed pump. This feed pump should enhance the generating unit capacity factor. This 900 gallon per minute motor-driven pump may be operated during hot standby or in light load conditions. In addition, if one of the two motor-driven main feed pumps is unavailable, startup pump may be operate in parallel with the remaining main feed pump. This arrangement will permit operation at 80 percent of unit capacity compared to a 60 percent of capacity limitation with a single made feed pump.

The next item is the alternate shutdown panel. Details of this panel will be presented later in this meeting. The panel design meets the requirements to bring

the unit to a cold shutdown following a single exposure fire in any one of five areas. It is possible that the fire could disable the safety-related control circuits in one of those selected areas.

A third item is the approach to cold shutdown. This topic will also be discussed in detail later in this meeting. While the safe shutdown design basis for Beaver Valley 2 was hot standby, the cold shutdown capability of the plant has been evaluated in order to demonstrate that the plant can achieve cold shutdown conditions following a safe shutdown earthquake, assuming loss of offsite power in the most limiting single failure, appropriate design modifications to both safety and nonsafety-related equipment were made to make it possible to achieve this condition.

An additional item is the full-flow condensate demineralizers. A condensate polishing system to remove ionic and other particulate contaminants utilizing powdered resin posited on three coat filters has been depositive. The system has its own air supply and the flow of condensate will be automatically converted around the demineralizaer filtering units upon high condensate depressurizing.

DR. SHEWMON: Have you decided whether or you'll use it full flow? Do you also have the option of not using it, if things are tightening up so you don't have to?

MR. MARTIN: We don't anticipate that it would be continuously operating at this time. The elimination of the boron ejection tank is an item I'm sure you're familiar with. The postulated main steam line break size has been limited to 1.4 square feet by installation of flow limiters in each of the steam generator discharge nozzles. The original design was at a larger break size and coolant reactivity during the primary cooldown was to be controlled by the initial injection of 20,000 ppm boric acid solution into the reactor coolant system.

The present design requires 2000 ppm. This can be obtained by using the charging system with suction from borated refueling water storage tanks or the boric acid tanks.

In addition, continuance filtration of the auxiliary building air exhaust is provided. This is done in order to reduce the potential for radioactive contaminated air being released to the atmosphere during normal operation. Redundant exhaust fans draw air through hepa filters and charcoal delay beds. Air is discharged at least 150 feet above grade at the top of the reactor containment.

Other locations served by this system are the main steam valve house in the main building, the housing pump, the cooling water pump and the solid waste areas.

In closing, several lesser design differences

might be mentioned. The main steam isolation valves are ball-type valves contrasted with the Beaver Valley Unit No. 2 design, which has nonreturn capability, consisting of two opposed check valves in series, digital radiation monitoring and rod position indications were provided in place of the analog equipment in Beaver 1. This modification was primarily done to provide more storage capacity for information as well as to expedite the retrieval of historical data.

The Beaver Valley 2 containment air compressor. Those compressors are located outside the reactor containment building for ease of maintenance and a mild environment.

All four recirculation spray pumps are located outside the containment building. In the case of Beaver 1, two were inside, two were outside.

Finally, an automatic update of the system bypass is in operable status through computer monitoring, is provided in the Beaver Valley to design. On clarifying point. I may have misunderstood the initial comments, but the steam-driven auxiliary steam pump, the single auxiliary feed pump is 100 percent capacity, a 700 gallon per minute capability. Two electric-driven auxiliary feed pumps are 350 gallons a minute each.

Yes, Dr. Okrent.

DR. OKRENT: I can't tell, my memory fails me, when you delete the boron injection tank, is there any effect whatsoever on the postulated ATWS event with regard to the way in which you can get boron into the power system?

MR. MARTIN: The boron injection tank was in the suction path. The boron injection tank was a small quantity. The water was injected initially in the 20,000 part per million boric acid. The cooling water storage tank is a continuous supply of 2000 parts per 1 million boric acid.

DR. OKRENT: I'm not sure, though, you've answered the question. Is the answer yes or no?

MR. MARTIN: Would you repeat your question.

DR. OKRENT: Assuming an ATWS -- you want to get boron into the primary system. When you don't have a boron injection tank in your particular design, does that change the rate at which boron is added to the primary system?

MR. MARTIN: Yes.

DR. OKRENT: What influence does that have then on peak pressures that you calculate in postulated ATWS', et cetera?

MR. GRADA: My name is Kenneth Grada, the Manager of Nuclear Safety at Beaver Valley. What we've done at Unit 2 is the elimination of the boron injection tank. In Unit 1, we previously had a 20,000 to 22,500 ppm system, and we

had a lot of maintenance problems with the heat trace and recirculation capability. So we had the steam break analysis reanalyzed at the lower boron concentration of 2000 ppm.

We found that we could still meet the NRC acceptance criteria for the Class IV accident.

Your question, as I understand it is, how has this affected ATWS. The answer is that it wouldn't have any effect, because what the procedures require is the utilization of the 7000-7700 ppm boric acid tank for emergency boration, and ATWS wasn't specifically analyzed.

DR. OKRENT: Does the Staff have an answer?

MR. NOVAK: This is Tom Novak of the Staff. My recollection of an ATWS would be that you basically depend upon the performance of the reactor coolant system itself for self shutdown mechanism and you do not depend on boron addition recovering early enough to help the pressure transient. Historically, the boron injection tank has been used to, in effect, bring the plant to subcritical following the steam line break.

That's been the historical use of it. So that you keep fuel failures and the return to criticality to a minimumin the event of a steamline break, but as far as the classical ATWS event, you depend on the system itself to self-shutdown.

DR. OKRENT: Are you telling me that when Westinghouse analyzes an ATWS for a plant with a boron injection tank, they don't have it enter into the analysis?

MR. GRADA: The primary system pressure comes up so fast that the injection -- you wouldn't be able to get boron injection into the system. You're above the shut-off head of the high-head injection pumps. You're depending on your power coefficients to insert negative reactivity and shut you down to turn that vent around, your Doppler and temperature coefficients.

DR. OKRENT: So you're saying there are charging pumps in some reactors of positives displacement that can put boron in. I'm still not clear on just what the Staff thinks the answer is. In fact, the answer is that their system response does not depend on the boron injection tank.

DR. OKRENT: And the analyses that lead to 2900 psi or 3200 psi have not taken any credit for boron coming in through the boron injection.

MR. NOVAK: That's correct.

MR. GRADA: The design of the boron injection tank was based strictly on the steam line break.

MR. MARTIN: Thank you.

MR. CAREY: I'd like to speak about the management philosophy of the Duquesne Light Company. We do

have a published policy that is on our bulletin board, and all of our workers are familiar with. We believe that our responsibility is to protect the health and safety of the public. Secondly, to protect the health and safety of the site workers, protect the plant and its equipment and fourth, to provide continuous electric service to our customers, and fifth, to operate and maintain the Beaver Valley Power Station at the lowest cost consistent with accomplishing the above priorities.

The keystones to accomplishing this philsophy are superior and comprehensive formal and documented training programs for all workers. The establishment of an effective preventive maintenance program and the establishment and implementation of an effective radiation control under our ALARA program, to mineralize and carefully monitor station effluents and maintain an effective emergency plan and insure that all workers are trained in their duties under the emergency plan.

We attempt to cultivate a spirit of professionalism among our employees. We expect our employees to meet all issues with an integrity and an openness in dealing with the regulators, as well as the general public. We expect the highest quality job performance of all personnel. We expect adherence to our administrative controls and our procedures. All employees

are instructed to perform their work in a thorough manner and pay particular attention to all details of the activities in which they're engaged.

We have been involved in nuclear power, as Roger Martin mentioned, for over 30 years, with the building and startup of the Shippingport Plant, and a good number of the people presently engaged in nuclear power activities at Duquesne Light Company, operated, managed and otherwise gained experience during the operation of the Shippingport facility.

With that, I would like to quickly go through our organization.

(Slide.)

Jack Sieber is here, but he was involved in an emergency tabletop meeting with, I guess FEMA, NRC and EPA. We weren't sure he'd be here, and since I looked it over, I'd better do this myself.

(Slide.)

The Duquesne Light Company has headquarter all nuclear personnel on the site. The organization that operates the nuclear plants operates under the chairman of the board, to whom I report. The chairman of the board is on-site at least once a week. He's on-site more than that, and we do whatever we can to try to make sure he doesn't have to come back more often than that.

The nuclear group, and this is the organization that will be utilized to operate the two-unit nuclear facility at Beaver Valley, is divided into four units -- a nuclear operations unit, a nuclear services unit, a nuclear engineering and construction unit and a quality assurance unit.

(Slide.)

Nuclear operations is responsible for plant operations, plant maintenance, testing, chemistry, outage planning, procurement and stores.

(Slide.)

We have in the nuclear operations unit, presently, 470 employees, 67 of whom have NRC operating licenses, about half of which are SRO and half are RO licenses. There is a total of 183 college degrees.

(Slide.)

Our nuclear engineering and construction unit presently has 81 employees. We anticipate -- we have 140 authorized, and we anticipate that, with the operation of both units, we will approach that authorization. Included are 66 college degrees.

Yes, sir.

DR. OKRENT: Would people, very knowledgeable in the analysis of severe accidents involving severe core degradation be found in either the nuclear operations or

nuclear engineering and construction unit or would it be some other part of the company organization?

MR. CAREY: I feel that we would have those kinds of individuals in at least three of these units -- nuclear operations, which includes the licensed operators, as well as the complement of shift technical advisers who receive special training in degraded core cooling and recognition and prevention of degraded core cooling.

Our nuclear services unit, under the manager of nuclear safety, has individuals who are thoroughly familiar with the accident analysis and the bases for it. And the nuclear engineering and construction unit has individuals who are more familiar with some of the nonnuclear accident analysis, but they have individuals who are experienced in fuel management, as well as accident analysis that is related to the nuclear core.

DR. OKRENT: Do any of these groups have people who have experience in reliability and risk analysis?

MR. CAREY: Yes, sir. The Nuclear Engineering and Construction Unit has individuals who have some experience, as well as Nuclear Services.

DR. OKRENT: Thank you.

(Slide.)

MR. CAREY: The Nuclear Services Unit consists of 483 individuals with 138 college degrees and six NRC operating licenses. The Nuclear Services Unit is responsible for nuclear safety, health physics and radiation control, licensing and compliance activities, security and adminstrative and office functions and training.

MR. WARD: Excuse me, Mr. Carey. When you have six people with operating licenses, are those people who have had them or are those maintained continuously up-to-date, requalified, and so forth?

MR. CAREY: Almost all of the people continuously maintain their license. Every once in a while, we have someone who may drop his license for a purpose or health reasons or other reasons. Almost all of our people continue to maintain their licenses and participate in the retraining program and stand watch in the control room at least once a month.

MR. WARD: Okay. They do. So these people in

this services unit would occasionally stand watch to maintain their license?

MR. CAREY: Yes, sir. We've demanded that every individual who wants to maintain licenses stand watch in the control room at least once a month.

MR. SIEBER: This is Jack Sieber. I am the General Manager of Nuclear Services. All six licensed people in my unit are current.

MR. WARD: And the 483 you have here, does that include your patrol force. Is that what you said?

MR. SIEBER: That includes the security force; that's correct.

MR. CAREY: That includes the security force, a large number of office and clerical workers. It's a lot of diverse activities are conducted in there, in support of the plant.

MR. WYLIE: Mr. Carey, how many people do you have on the security force?

MR. CAREY: Presently, about 120.

(Slide.)

The quality assurance unit is composed of 6[illegible] full-time Duquesne Light company personnel with 100 authorizations, which is the number that we expect to be able to function with for two operating units.

There are the 350 contract personnel, almost all

of which are quality control inspectors associated with the construction activities on the No. 2 Unit. We do have a smaller group of 30 or 40 quality control inspectors that are part of our quality assurance unit, that perform quality control activities on the operating unit.

There are a total of 58 college degrees and two SRO licenses. Although one individual has an SRO license on Beaver Valley No. 1 Unit, the second individual is a man that has had over 15 years of experience as a certified operating supervisor at our Shippingport facility. He does not have an SRO license.

MR. WYLIE: Mr. Carey, could I ask a question about the 350 contract personnel. That is in addition to your 2300 workers involved in the construction?

MR. CAREY: That's correct.

(Slide.)

Duquesne Light Company has over 28 years of nuclear operating experience. We have our entire nuclear staff on site. We have ample human resources, and we expect to maintain a minimal dependence on consultants and contractors to operate the two units at Beaver Valley.

With that, I will turn this over. The next speaker will be Mr. Tim Jones.

MR. REED: Mr. Carey, the numbers you show up there are certainly adequate in quantity.

My question has to do with quality.

MR. CAREY: I have used your elephant-horse story on many occasions, Glenn.

MR. REED: Then my question is, what do you do about quality? How do you get these operators that you are sure are not not all thumbs, even though they're educated?

MR. CAREY: We do have, I feel, in the 28 years of operating experience at the Shippingport facility, that has been for us a training experience for all of our maintenance personnel.

Now we do have a union contract that permits our maintenance people to rotate in jobs throughout the entire company. They are not confined to the nuclear activity, so there is always a certain rotation of personnel about the way we ensure that the people are fully qualified to perform their duties, are to first test the people prior to letting them enter.

MR. REED: What type of testing do you use? Natural ability testing to see if they can be trained?

MR. CAREY: Yes, we do. For all nuclear operators, for example, utilize a screening examination to be sure that people will be capable of absorbing training.

All personnel are tested by our personnel department at the time of entry into the company. We do the best we can to ensure that the personnel are not all

thumbs. They are required to pass tests which are a combination of written exams and demonstations, prior to being promoted to a first class mechanic or electrician's level.

I believe that our personnel currently have all of the physical skills and the mental skills necessary to perform their job duties and having worked -- I worked for about half of my career with the Duquesne Light Company in our fossil area, and I believe that we implemented a training program, so that the personnel we get are familiar with the tools of the trade and should have demonstrated some type of mechanical ability prior to progressing up the line in the maintenance organization.

Those who do not possess the necessary skills are demoted or promotions are withheld until such time as they demonstrate they can perform the work.

MR. REED: Just one last little question.

Are you familiar with the EEI POS natural ability tests?

MR. CAREY: Yes, we are familiar with them, and we have participated in a couple of programs with EEI, but we have not instituted on a formal basis, the establishment of those tests. The main reason for it, Glenn, is that our union naturally resists any new testing, and we do feel that our existing procedures for assuring that the people are

qualified prior to being promoted beyond the helper category protects us against getting someone who has no mechanical ability performing that kind of work.

MR. WARD: Boy, you really set this up, Glenn.

(Laughter.)

MR. REED: Now I'll be accused of collusion.

MR. JONES: Good afternoon.

My name is Tim Jones. I'm General Manager of the Nuclear Operations Unit.

I will discuss the Nuclear Operations Unit, the responsibility of the different sections and the experience of the people in these sections.

(Slide.)

As previously explained by Mr. Carey, the Nuclear Operations Unit is assigned three general functions: production, technical services, and third, planning and outage management. The production responsibility is assigned to the plant manager, who is responsibile for operations, maintenance instrumentation and control and testing.

I will discuss the operations and maintenance functions in more detail in a moment.

The Technical Services Department, the middle block, is responsible for the conduct of the chemistry program, requisitioning storage and issue of material and

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replacement parts, the preparation and upkeep of operations, INC, and maintenance procedures, the evaluation of events at Beaver Valley and at other power stations, the shift technical adviser function on each operating shift, and the last function, which was inadvertently omitted from the chart, the plant safety review process through the activities of the onsite safety committee or PORP, as it is called in some plants.

MR. WYLIE: Mr. Jones, could I ask a question about shift technical advisers.

How do you implement that requirement on shift? Are they on call, are they on shift?

MR. JONES: They are on each shift.

MR. WYLIE: These are what type of people?

MR. JONES: These are graduate engineers, who have gone through a training program, consistent with the INPO guidelines for shift technical advisers.

MR. WYLIE: Is there any experience level required for that position?

MR. JONES: There is, but I'm not sure what it is. We are in accordance with the minimum qualifications for the shift technical advisers from the experience standpoint.

MR. WYLIE: Is that one year, two years, five years?

MR. JONES: A year and a half, two years, or something. I'm not sure.

MR. WYLIE: One or two years out of college.

MR. LACEY: Excuse me. I think I can answer that for you, Ken. I'm Steve Lacey, the plant manager.

The engineers that we have on here, go through a one-year training program. Then they go through an on-shift training program for another six months, before they take over, say, the shift on their own.

MR. WYLIE: What is their role in an incident?

MR. JONES: Their role in an incident is to observe the critical safety functions and different parameters in the plant and to advise the nuclear shift supervisor of their observations and to give them his advice.

MR. WYLIE: Thank you.

MR. WARD: Another question on the STA. Some plants are using positions where a single person serves as both an SRO and an STA.

MR. JONES: We are not planning to do that at Beaver Valley.

MR. WARD: Do you have any comment on why not? How do you see the pluses and minuses of that?

MR. JONES: We have used the separate shift technical adviser for a number of years now, and we believe

that this is the best of the alternatives.

MR. WARD: You described his duties during an emergency, but, what are his or her routine duties?

MR. JONES: During normal operations, the shift technical adviser is involved in normal plant functions. He must be aware of the status of the engineering safeguards equipment and must concur in the removal of any equipment from service to ensure that we do have sufficient equipment available, if we need it.

He is also involved in walkdowns of the control boards at the start of each shift to provide a check that we do have the equipment in the proper configuration. He is involved in actual observing different operating activities and providing reports on that type of thing.

MR. WARD: Do the STAs participate? You have another group shown up there called advisory engineers.

MR. JONES: The STAs are part of that particular group.

MR. WARD: Thank you.

MR. JONES: Planning and outage management is responsible for planning and scheduling of plant activities, equipment history, preventive maintenance, scheduling, and work request tracking programs and the management of major outages, once Unit 2 becomes operational.

(Slide.)

I will return to the Production Department organization and discuss the operations and maintenance functions.

First, is operations.

(Slide.)

The Director of Site Operations is the Senior Operations Manager. His organization consists of support personnel, a shift complement, as well as day shift personnel. Support personnel are responsible for the preparation of shift schedules, review of shift activities and incident investigation follow up, coordination with other functional groups and for representing operations on the on-site safety committee.

(Slide.)

The shift complement consists of licensed supervisors and operators, as well as auxiliary or nuclear operators.

Each of the five operating shifts is headed by a nuclear shift supervisor, who is responsible to the Director of Site Operations for the operations of the station and is a senior company representative, in the absence of the plant manager and the director of site operations.

Each shift supervisor will have two nuclear station operating foremen for nuclear control operators and seven auxiliary operators, as well as an administrative

assistant assigned as a shift complement.

It is expected that the shift supervisor will be licensed on both units with the auxiliary operators maintaining qualifications for watch stations at both units through a rotating schedule.

In concluding my discussion of operations, let me emphasize the experience in this group. Presently, there are 39 licensed operators at Beaver Valley and a total of 268 years of nuclear experience, including 75 years in the control room. 12 of these operators have completed or are presently undergoing training on Unit No. 2 components and systems, with an additional eight operators expected to start this training in April of 1986.

There are 11 control room supervisors, who have been designated at this time for Unit 2.

Total nuclear experience of this group is 116 years, with 44 years experience in control room operations. Eight of these supervisors have more than one year of hot operating experience at Beaver Valley, and two of the went through the hot functional testing and the startup actvities on Unit No. 1.

MR. WARD: Before you leave that -- well, I've got it. Do all three of the foremen shown there hold SRO licenses?

MR. JONES: Two of them. The one in the middle

does not.

MR. WARD: What does he do? Supervise the balance of plant?

MR. JONES: He is basically an outside foreman, who is working -- there's one each of the shifts at Unit 2 right now. They have gone through the nonlicensed operator training program.

MR. WARD: So is this the complement you'll have after Unit 2 is up and operating?

MR. JONES: This is a two-unit complement.

MR. WARD: Now the ROs hold licenses on just one or the other unit.

MR. JONES: That's what we are planning right now. The ROs will not be licensed on both units.

MR. WARD: And the nuclear shift operating forman is just on one unit.

MR. JONES: Yes.

MR. WARD: Will you tell me something about the duties of the administrative assistant. Is that just a clerical job?

MR. JONES: The administrative assistant was put on shift to relieve the shift supervisor of a lot of paperwork and administrative activities. They are also the individuals who made the initial notification calls for the emergency preparedness plan.

MR. WARD: What is the career path for a person in that job?

MR. JONES: The career path that we've seen so far for the administrative assistant is basically into a foreman position. They're basically two-year engineers and some of them will complete their two years of education and get a B.S. degree, and then be considered for engineering positions within the organization.

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MR. REED: How many rotating shifts do you have or do you plan for the longer haul?

MR. JONES: Five.

MR. REED: I am a little surprised at that.

Do you think you can get in all the educational requalification requirements with five shifts rotating?

MR. JONES: We are at this time. If the training time expands, I guess we will have to look at a sixth shift that some plants have. But at this time five shifts is working.

MR. WYLIE: I guess I missed it. Which positions do you plan to cross-license?

MR. JONES: The nuclear shift supervisor.

MR. WYLIE: Thank you.

(Slide.)

The second area I will discuss is maintenance. This section of Beaver Valley consists of electrical and mechanical maintenance and is the second block from the left on this chart.

(Slide.)

The director of site maintenance has a mechanical and electrical senior supervisor responsible for directing the daily activities in these groups. The foremen report directly to the senior supervisor, and several maintenance engineers are available in a staff position to provide

technical assistance to the foreman and perform other technical assignments as directed by the senior supervisor.

Craftsmen will be assigned to each unit from a common pool as the workload dictates. They are members of the IBEW and obtained the position through a job bidding procedure and a qualification test.

Classroom as well as on-the-job training is provided for maintenance personnel.

(Slide.)

There are currently 470 persons in the nuclear operations unit, including a number of Unit 1 experienced engineers and supervisors assigned to Unit No. 2. Within this group are 67 NRC licensed reactor operators, senior reactor operators, 183 college graduates, and more than 1800 man-years of nuclear power plant experience.

In summary, I have presented an overview of the organization and structure within the nuclear operations unit. I have briefly described the function of the organization. I have noted the considerable amount of nuclear plant experience which exist within this organization.

That concludes my discussion.

The next speaker will be Mr. Fred Schuster.

MR. SCHUSTER: Good afternoon. My name is Fred Schuster.

The topic of my presentation is Beaver Valley emergency operating procedures, EOPs.

Beaver Valley Units No. 1 and 2 EOPs were based on emergency response guidelines, ERGs, for Region 1, developed by the Westinghouse Owners Group.

These ERGS are a significant improvement as a tool in dealing with plant emergencies. They are based on improved analyses of emergencies. Their format utilizes vastly improved impact and quality techniques and the scope of the procedures is much broader; that is, it covers more potential emergencies, than the previous procedures.

Duquesne Light Company has been an active participant in this development since its beginning, following the TMI accident, and strongly believes in the improvements that these procedures represent.

Beaver Valley's intent is to follow the generic guidelines as closely as possible in order to take full credit for the analysis efforts and human factors principles that form the basis for the TRGs.

The format of Beaver Valley EOPs has subsequently been made very similar to the generic guidelines.

(Slide.)

Beaver Valley 2 procedure generation package, the PGP, was submitted to the NRC in July 1984. Its purpose was to describe the process to be used in developing specific

EOPs from the generic ERGs. The PGP covers the major topic areas shown.

The first item, initial EOP development, and the third item, the training program, contain issues somewhat unique to Beaver Valley 2 and therefore warrant further discussion.

The first item, initial EOP development, covers the mechanics of procedure development.

(Slide.)

For Beaver Valley this consists of a series of coordinated but independent activities involving the Beaver Valley 1 EOP group and a separate Beaver Valley 2 EOP group.

The next three slides show how the two processes were coordinated to achieve the EOPs for Beaver Valley 1 and 2, which are similar except for where plant differences require procedure differences. This was done to support the philosophy of operating Beaver Valley 1 and 2 with some dual license operating personnel.

MR. WARD: Fred, wait a minute. I guess I haven't gotten the picture, why the two sets of procedures for the two units are different.

I mean, there are some plant differences. Is that the total reason for the difference in the procedures?

MR. SCHUSTER: Yes, sir. That had to be

considered. It couldn't be assumed that the procedures could be identical without actually evaluating these differences in the plants.

So the two processes were done independently to see where these system differences would create procedural difference requirements.

MR. WARD: Okay, go ahead.

MR. SCHUSTER: Both Beaver Valley 1 and 2 utilize human factor specialists as part of the verification and evaluation effort and coordinate with the EOP and designer efforts. This results in improvements to both control room indication and procedure flow and optimized EOP impact on quality.

(Slide.)

Some benefits of having two groups working toward essentially the same goal on EOPs are that with coordination we achieve an increased procedural review by a cross-check of the two independent efforts. It reduced Beaver Valley 1 operating experience into the Beaver Valley 2 procedures, and we simulated the use of Beaver Valley 2 validation for a portion of the Beaver Valley 2 effort.

MR. WARD: Is there an SPDS operational in Unit 1?

MR. SCHUSTER: It is, I believe, not quite operational at this point in time. It is very close.

MR. SIEBER: Perhaps I can amplify. It is functional, but it has not been accepted.

MR. WARD: Do the EOPs -- I guess they don't include use of the SPDS. Will they be modified to include that? How will you handle that?

MR. SIEBER: Yes, they will. That is part of the turnover process, and if you went over a piece of equipment, you have to have all the procedures for operating, it, maintaining it, and calibrating it in place at that time.

MR. MICHELSON: I am not sure that was the question that was asked. Maybe it was.

I had thought the question that was asked was: is the output of the SPDS being incorporated into the operating procedures, and not just how do you operate SPDS itself?

MR. SIEBER: That is correct. Yes, the output will be placed --

MR. MICHELSON: Before you put the SPDS into operation, you will have incorporated all of its features into your operating procedures?

MR. SIEBER: I don't think that we would say that we will incorporate all of the features, but with reference to them.

MR. MICHELSON: Basically, you put them in the procedure before you make the system operational, is that

correct?

MR. LACEY: My name is Steve Lacey, the plant manager. At the present time, it was my understanding that we are not going to incorporate those into the EOPs, that we would use installed instrumentation.

MR. MICHELSON: Equipment will be present in the control room but not used?

MR. LACEY: It will be used as a tool but not in the procedure. That was my understanding.

MR. MICHELSON: Is this a CRT type display, and so forth?

MR. LACEY: Yes, sir.

MR. SCHUSTER: Verification and validation of the EOPs is a subject also included in this section of PGP. It basically follows the guidelines published by INPO.

Verification provides a process to be followed in determining if each EOP is technically correct as written, like the PGP.

(Slide.)

Validation provides methods of assuring that the EOPs are usable; that is, that they can be understood and followed by trained operators without confusion, delay, or error, that they are operationally correct; that is, that there is a correspondence between the control room, plant hardware and EOPs, and capable of directing the operating

crew in managing the event.

This is accomplished at Beaver Valley 2 by a combination of three available methods.

(Slide.)

The Beaver Valley 1 simulator validation is utilized as input for evaluating such nonanalytical unit factors considerations as compatibility with operator training and clarity of procedure action steps.

Secondly, walk-through validations on a Beaver Valley 2 control board, full-scale mockup are utilized to evaluate specific Beaver Valley 2 control board layout and instrument impact on EOPs.

And table-top validation, having to do with plant-specific system differences between Beaver Valley 1 and 2 which cannot be simulator validated.

(Slide.)

The other topic of interest in the PGP is the EOP training program.

Initially, Beaver Valley 2 license candidates will first be trained at Beaver Valley 1 and trained on Beaver Valley 1 EOPs.

The EOP training was recently completed for all the current Beaver Valley 1 license personnel. It consisted of eight classroom and simulator training days plus a full day of evaluations of their ability to utilize the

procedures on the simulator.

Additional classroom training will be provided as part of the Beaver Valley 2 cross-training program. It will address the differences between Beaver Valley 1 and 2 EOPs.

Subsequent license candidates will receive training equivalent to that.

In summary, the current status of the Beaver Valley 2 EOP effort is that a draft of the procedures has been completed, including background documents. The only remaining activity is the table-top validation of the Beaver Valley 1 and 2 differences. This is to be performed when Beaver Valley 2 trained operators are available.

With this completed, we will have a set of EOPs based on the Westinghouse Owners Group ERG Round 1, with an improved analysis bases utilizing proved human factors techniques and covering a broader range of potential emergencies, and we will have taken full advantage in the Beaver Valley 2 procedures of the Beaver Valley 1 EOP efforts and the Beaver Valley 1 operating experience.

This concludes my presentation.

Yes, sir.

MR. REED: In your EOPs -- we hear a lot these days about auxiliary feedwater systems failing to deliver the water or being a little bit mixed up, but in your EOPs do you have provisions in the EOPs for backup cooling, say

by bleed and feed?

MR. SCHUSTER: Yes, sir. We have in the critical safety function restoration procedures under loss of heat sink the provisions for bleed and feed, using the steam generator and jets and charging.

MR. REED: You say the steam generator PORVs?

MR. SCHUSTER: Loss of heat sink for the steam generators. I am sorry.

MR. REED: What is the number and size, roughly, of your PORVs in the steam generator?

Now, you have got me.

(Laughter.)

MR. SCHUSTER: We have three pressurize PORVs. As far as their size --

VOICE: We can get that information for you.

MR. REED: That is good enough.

MR. WARD: I guess maybe if you can get an answer to the question. I am not so much interested in the size in inches, but I mean how many of the three are required for equilibrium removal of decay heat right after scram, let's say?

MR. SCHUSTER: I believe the Westinghouse ERGs require that two would fully satisfy that.

MR. MICHELSON: You probably covered this, but could you tell me just real briefly what significant

differences are there between Beaver Valley 1 and 2 as far as the systems and that sort of thing, ECCS in particular?

MR. MARTIN: Your question was what significant differences are there between Beaver Valley 1 and Beaver Valley 2?

MR. WARD: We did have that in an earlier chart.

MR. MICHELSON: I am sure we did. Is it possible to tell me within a minute?

MR. MARTIN: The significant differences are the startup feed pump, which I mentioned, also the condensate demineralizer, the ability to approach cold shutdown with low condensate demineralizers and all types of main steam isolation valves, radiation monitoring, and the outside containment air compressors.

MR. MICHELSON: Thank you.

MR. WARD: And no boron injection?

MR. MICHELSON: Auxiliary feedwater is identical?

MR. MARTIN: The feedwater is identical. The only difference, of course, is there is a startup feed pump on Beaver Valley 2.

MR. MICHELSON: The control layout is essentially identical?

MR. MARTIN: Yes.

VOICE: Fred, could you identify the differences in mark numbers from one unit to the other?

MR. SCHUSTER: I don't think there is significant system differences, but we have some physical system differences.

We have, for instance, on Unit 1 a turbine plant river water and a reactor plant river water -- safety grade river water, two separate systems; whereas, on Unit 2 we have one pumping system, a service water system that therefore has to be segregated during an accident. So there are valves that close off the turbine plant, the nonsafety-related portion of the system, and that posits some difference in the procedures.

We have some differences -- the lack of the boron injection tank was mentioned -- we have some differences in the flow paths. We have -- for instance, in the safety injection system we have on Unit No. 2 low head pumps which act in the injection phase to supply water from the refueling water storage tank directly to the system. Then when you go to the recirculation phase of safety injection they in Unit 2 do not take that suction; whereas, the Unit 1 low head pumps do. So there is a significant difference there.

MR. MICHELSON: The cross-license to operators, can they go from one shift to another between units?

MR. SCHUSTER: The only cross-licensing that we are anticipating, as was mentioned, is the nuclear shift

supervisor.

MR. MICHELSON: The others would not go across units?

MR. SCHUSTER: That is correct.

MR. MICHELSON: Thank you.

DR. REMICK: This might be an appropriate time for you to mention how you are going to assure that operators don't get confused between Unit 1 and Unit 2 if they are going to do maintenance or if they are going to pick up the EOP.

MR. SCHUSTER: We are going to have color coding of the procedures. We are using a blue color versus a white color on the Unit 1 procedures. We are also going to use some color coding in valve tagging in areas where there may be Unit 1 and 2 valve tags in the same area, some additional identification of the spaces on doorways accessing certain areas.

The tagging system -- as Gene was saying, the tagging and numbering system is somewhat different between the two units, with that being something that provides ease of identifying the two units.

DR. REMICK: Am I correct that your maintenance procedures will also be color coded so there is no chance that you will pick up the wrong maintenance procedure?

MR. SCHUSTER: I am not directly responsible for

that, but I do believe all the procedures are going to be color coded, yes.

MR. GRODA: Mr. Reed, this is Kenny Groda. I'd like to address your earlier question on the design of power-operated relief valves on the pressurizer design. They're designed for 210,000 pounds per hour at 2,250 pounds headpressure and 100 pounds downstream; and for water, 1,400 gallons a minute. That's at a thousand pounds per square inch differential.

DR. LEWIS: Is this a good time to take a short break?

MR. WYLIE: I think that would be appropriate.

DR. LEWIS: Why don't we do break for 10 minutes and come back at a quarter past.

MR. WYLIE: That will be fine.

(Recess.)

MR. EWING: My name is Gene Ewing.

(Slide.)

I'm manager of the Quality Assurance Unit. This afternoon, I would like to present an overview of the Quality Assurance and Quality Control.

As the Quality Assurance manager, I am responsible for maintaining and managing Duqesne Light Company's quality assurance program, and I'm authorized to report quality problems directly to any level of management necessary to ensure corrective action.

I report directly to the vice president of the

1 DAV/bc

Nuclear group, and I'm responsible for directing the activities of the Quality Assurance Unit.

This unit administers the quality assurance and quality control activities and the inservice inspection programs for both Beaver Valley Units.

The Duquesne Light Company is the owner and operator of two nuclear power units and recognizes its responsibility to operate these facilities with due regard for public and plant safety.

Our operations quality assurance program has governed the continual safe and successful operation of Beaver Valley Unit One since it began operations in 1976; because we recognized a close correlation between safety and plant quality, we abide by an ongoing program for quality achievement and assurance.

In both the design and construction and the operation of our nuclear power facilities, our design and construction and our operations quality assurance program define the requirements and specify the responsibilities for implementing these programs.

(Slide.)

The design, procurement, fabrication and construction of Beaver Valley Unit II has been carried out in accordance with Duquesne Light design and construction quality assurance program. This program complies with the

requirements shown as item 1 on this slide. I would like to point out that, with few exceptions, our contractors work under the Duquesne Light design and construction QA program. Ninety days prior to fuel loading, the Duquesne Light operations quality assurance program will be applied to Unit II.

This program complies with the requirements shown as item 2 on this slide. As stated previously, this program has been functioning for Unit I for 10 years. New and revised codes, standards and regulatory guides and regulations are continually reviewed and incorporated into the program as appropriate.

Duquesne Light personnel are required to act in strict accordance with the requirements of the Duquesne Light QA programs. Management gives full support to maintain an effective quality program.

Additionally, contractors who perform activities affecting quality on safety-related items are required to comply with the requirements of the QA program.

(Slide.)

The organization of the quality assurance unit is shown on this slide. Starting from the left side, the operating plant activities of Unit I are monitored by the director of Operations QA. This department is presently staffed with 12 employees, all of which have four-year

college degrees.

Moving to the next block, on the support activity such as engineering, construction, procurement and administrative functions are reviewed by the Director of Engineering and Procurement QA. This department is also staffed with 12 employees having four-year college degrees. The nondestructive examination, pre-service and inservice inspection activities are the responsibility of the director of Preservice and Inservice Inspection. This department is presently staffed with eight Duquesne Light employees and is being supplemented without side consultants.

Moving to the far right, the quality control activities for our operating plant, Beaver Valley Unit I, is the responsibility of our Director of Operations Quality Control. This department is presently staffed with 29 employees. These four departments which I have discussed are permanent Duquesne Light organizations which are staffed with Duquesne Light Company employees.

The quality control activities for the construction phase of Beaver Valley Unit II are the responsibility of the Director of Site Quality Control, shown as the remaining block on the chart. This is a temporary Duquesne Light organization which was developed specifically to support the construction of Unit II.

Ninety days prior to fuel load, the activities of

this organization will be assumed by the Operations Quality Control Department.

(Slide.)

The quality assurance unit is staffed with competent individuals who have the experience and knowledge necessary to assure that the Duquesne Light Company Quality Assurance Program is effectively implemented and maintained.

There are presently over 500 manyears of nuclear industry experience in the Quality Assurance Unit. We presently have two individuals who have been, or are presently certified reactor operators. As was pointed out earlier, one of those maintains an active license.

(Slide.)

Sixty-one Duquesne Light employees presently assigned to the Quality Assurance Unit can be classified at the following levels of management. Seventeen of these individuals are considered to be in supervisory positions and 23 are in engineering or auditing positions. And 21 are inspectors that are technical specialists.

Thirty-nine percent of these employees have one or more four-year college degrees, and 16 employees have received an associate degree.

In addition to this staff, which supplies support to both units, there are presently about 350 temporary

personnel who are responsible to the Director of Site Quality Control for performing the quality control activities for the construction phase of Unit II. This number does include supervision, QC engineering, inspection and clerical personnel necessary to support the quality control activities for the Unit II project.

One final program I would like to describe before I conclude is our quality control phone line. This program was established nearly two years ago to provide a means for all site personnel to report any quality concerns they might to an independent organization for followup.

The individual may remain anonymous if he wishes. All calls are received by the Quality Assurance Unit. They are recorded or logged, investigated, evaluated and closed out. The number of concerns received by this method have been small, which can be expected at this stage of the project. As the project nears completion and staffing reductions occur, it is expected that there will be increased activity in this area.

It is planned to give the program more visibility as we approach the end of the project.

In conclusion, compliance with the Duquesne Light Quality Assurance Program will provide assurance that the installed quality of the plant is maintained throughout its life. That proper administrative controls are in effect at

all times. And that decisions related to the operation of the plant are made at the proper level of responsibility and with the necessary technical device.

Effective implementation of this program provides assurance that Beaver Valley Unit II has been constructed and will be operated with a high degree of public and plant safety.

Yes...

MR. REED: You understand very clearly the difference between "quality assurance" and "quality control". I'd like to know, in operational quality control, who is going to be doing the improving, the inspecting, and this kind of thing. Will it be the line supervision with the craft, or will it be more of the noncraft?

MR. EWING: Doing the actual quality control inspection? Those will be inspectors in the Quality Assurance Unit. They will have no responsibility for the performing of the work.

MR. REED: You don't think that the real skilled person is a better person to make the judgment on whether or not the weld is appropriate?

MR. EWING: The skilled person has the responsibility to do the job right the first time. QC inspection comes in and verifies that he's done the job properly.

MR. REED: Does he really then have the equal to or better qualifications of the welder?

MR. EWING: They have been trained to inspect proper attributes. They probably would not be able to come in and make a weld, but they could come in and measure a weld size. Things of that sort, to evaluate the quality of the weld.

MR. REED: And they could judge other highly craft skilled operations without themselves been a craftsman?

MR. EWING: Yes, I believe so. With proper training, yes.

MR. REED: I might make a point here. We've had considerable discussion about perhaps an over-reaction of the industry to NRC rules, where the industry maybe didn't read the rules as clearly as they could have been read. And that is, the craft people -- not the craftsmen who did the work, or we'll say the craft foreman, not the foreman responsible for the work can do quality control inspections and approval.

MR. EWING: Some of our inspectors have worked in the maintenance areas. Some of them have had experience acting as foreman. So they are familiar with the maintenance activities.

MR. REED: So you don't regard your quality

assurance organization as just a paper trail checkout?

MR. EWING: Definitely not.

MR. REED: They have the skills necessary?

MR. EWING: Yes.

The next speaker will be Mr. Tom Burns, in the area of Training.

(Slide.)

MR. BURNS: Good afternoon. I'm Tom Burns, Director of Operations Training. I'll be discussing training facilities and programs.

(Slide.)

At Duquesne Light, we consider an effective training program to be essential for achieving excellence of nuclear operations. It's our policy to have properly trained individuals in responsible positions who operate, maintain and manage our nuclear facilities.

(Slide.)

We've been developing and implementing programs for many years that meet or exceed all requirements. These programs routinely receive high ratings from the NRC and INPO during audits, evaluations and inspections. Therefore, I'm very confident when I tell you that our training program facilities are among the best of any utility in the country today.

(Slide.)

Our commitment to training is evidenced by the obvious investment in our training center and available training tools provided to the staff.

(Slide.)

Including the Unit I plant-specific simulator and an I&C electrical training system.

(Slide.)

The training center provides a total available floor space of 42,000 square feet in the training building, and 28,000 square feet in the simulator building.

(Slide.)

A further indicator is our participation in the INPO accreditation program, and our efforts to ensure that the industry goal is met by completing the designated programs by mid-1986.

We have completed the job analysis and submitted the self-evaluation reports for the designated programs on the slide. You can see, in July 1984, we submitted the self-evaluation report for licensed and nonlicensed operator training and requal.

This year, we submitted the self-evaluation reports for shift technical adviser, rad protection technician, chemist and I&C technician.

In May 1986, we will commit the final three programs, for mechanical, electrical, tech staff and

managers.

I might add that after our first INPO accreditation visit, the team was particularly impressed with our instructional development program and our instructional presentations Also, our training administrative manual and our simulator exercise.

(Slide.)

Along with the accreditation effort is the implementation of the systematic approach to training.

(Slide.)

To support this effort, we are staffing the program development section within the training department.

(Slide.)

In keeping with our efforts to ensure that only the best courses are part of Beaver Valley's training program, our thermodynamics course for licensed operators has been evaluated by the American Council on Education and has been recommended for three semester hours in Nuclear Technology in the upper division baccalaureate category.

It is our intent to continue this evaluation.

I would now like to briefly describe our initial license operator program, and our license operator requal program.

(Slide.)

The licensed operator training program is

conducted in six distinct phases. Phase one consists of various theory courses, which prepares the trainees with a sound technical background for understanding plant systems and overall plant operations. Topics range from the fundamentals of mathematics and nuclear physics and chemistry to the more advanced subjects such as reactor theory, thermodynamics, accident and transient analysis and mitigating core damage.

Phase two consists of plant specific systems training in the form of a lecture series evaluated by written examination, used to track comprehension and progress.

MR. WARD: Tom, isn't that on pae 2 where you split between your Unit I and Unit II? Or, are those two sets of people maintained separately all along?

MR. BURNS: I will be covering that in the near future.

MR. WARD: I'll wait.

MR. BURNS: Phase three consists of actual system chasing in plant and completion of procedure review, followed by an oral examination administered by a qualified instructor who is guided by a system qualification standard.

(Slide.)

Phase four consists of simulator training, which

is intersperced throughout the program to allow hands on operation of various system controls, culminating with the startup certification in abnormal and emergency operation.

Phase five consists of on shift training, which is also interspersed throughout the training program. The trainee is assigned to an on shift program after qualifying on secondary and primary systems to complete OJT qualifications.

Toward the end of the program, he is assigned three months on shift as an extra operator.

In phase six, the trainees participate in an instructor-led review of technical subjects and are administered written and oral examinations, including a third party exam similar to the NRC exam.

(Slide.)

You can see the training program is laid out to reinforce what was learned in the classroom. Simulator training and on shift training. This really gives you an overview of how it's conducted.

MR. WARD: If you were to make an estimate of what fraction of the training effort is to train the person to run the plant and what fraction of the training is to train them to pass the NRC examination.

MR. BURNS: Fractions, I really don't have a number off the top of my head for that. We do both.

Training the operator to operate that plant in a safe manner, and we also train them to be able to pass the NRC exam. Not that we're not doing the same thing at the same time.

In other words, for instance, on our task analysis with licensed operators, we went beyond the control room assigned tasks to assure that that operator on the board who is directing the outside operators is also familiar and understands all of the tasks out in the plant.

DR. CARBON: Question. Do the NRC exams cause you to have or your operators to have a serious morale problem?

MR. BURNS: Are you referring to initial licensing exams?

DR. CARBON: Requalification.

MR. BURNS: Are you referring to a requal exam administered by the NRC or the annual exam that is administered as part of the requal program?

DR. CARBON: All of the above, I guess.

MR. BURNS: No, I don't think it's a big problem with our operators. We give them a good training program throughout the year to ensure that they are kept cognizant of all changes, plant changes, kept up to date on theory, the history of events, and so forth. And I do not think that there's a problem.

Also, our annual examination is based on the objectives as we conduct our requal program.

DR. REMICK: Have you had an NRC administered requalification exam?

MR. BURNS: We have not.

(Slide.)

Back to the additional training program. This program has been very successful. Our success rate is 88 percent.

(Slide.)

Individuals chosen to license on Unit II will be experienced licensed operators. On Unit I, individuals completing the initial training program and the Unit II cross-training program, all individuals presently planning to receive Unit II cross-training and licensing on Unit II or dual licenses are experienced Unit I licensed RO's and SRO's.

The Unit II cross-training program was developed to as a minimum meet the requirements of NUREG 1021; in accordance with these guidelines, a different analysis has been submitted to the NRC Region I for determination of licensing and the examination process to be followed.

(Slide.)

The license retraining program is designed to ensure that licensed personnel remain competent to operate in a safe reliable manner under normal, abnormal, and emergency conditions.

This program is conducted continuously for 24 months and is followed by successive 24-month programs. Each program is comprised of two retraining cycles, one year in length.

A typical cycle requires between 11 and 13 percent of an individual's normal working time to complete.

MR. WARD: Is that the same -- you have the shift supervisors are cross-trained. Do they end up spending more than that 10 or 12 percent, or whatever you said?

MR. BURNS: At this time I have not designed into the requal program that part of the requal for a dual license. We are looking at that. Of course, we are waiting to see what Region 1 will say about relicensing. That can be factored into the program, and I would expect it to increase some amount.

I can't tell you what that amount is now.

(Slide.)

Licensed retraining is conducted in five phases of instruction and evaluation. Phase 1 consists of the annual written examination, modeled in scope on the NRC

requalification exam.

Phase 2 consists of formal classroom training, based in part on the results of the annual written exam. It is also based on current industry events, operations feedback and the required subjects. This phase is presented in six modules of instruction, repeated six times to accommodate the operating schedule.

Additional classroom time is scheduled adjacent to this phase to provide retraining in other related areas, such as fire brigade, first-aid, CPR, emergency preparedness, plant training, and plant design change training.

Phase 3 consists of plant manipulations training, which is accomplished on the Unit 1, plant-specific simulator. This training meets and exceeds the requirements of NUREG-0737.

Phase 4 consists of review and self-study of significant operating experience reports, incident reports and design changes and procedure reviews.

Phase 5 consists of performance evaluations, which is a combination of performance ratings as observed during simulator training and actual performance on the job.

It is part of the accreditation effort that this program has been evaluated by the INPO accreditation team.

There were no concerns or recommendations noted.

(Slide.)

As stated previously, we have a Beaver Valley Unit 1 plant-specific simulator, which meets and exceeds the requirements of ANS 3.5 and Reg Guide 1.149. We began training on our simulator in February of this year, as planned. We have completed 2625 hours of successful training, as scheduled. This reflects an availability of 99 percent.

(Slide.)

The simulator has proven to be an invaluable training tool and has received excellent feedback from our experienced operators, operator trainees, and NRC licensing personnel who have conducted operational exams.

Also, to ensure the simulator maintains this type of training value, we have in place all required administrative procedures to track plant design procedures and update hardware and software.

(Slide.)

At this time I would like to briefly discuss a selected few of our nonlicense programs.

(Slide.)

General employee training at Beaver Valley consists of station orientation which provides instruction on industrial, radiological, and fire safety, security, and

quality assurance. Radiation worker training provides the background information and practical experience to allow individuals to perform their job duties safely in the workplace where radiological hazards may exist.

Our program was one of the first to be evaluated and incorporated into the INPO standardization program. General employee refresher training is required for all employees annually.

(Slide.)

Our radiation technician training program consists of academic and practical instruction in formal classroom settings and actual in-plant proficiency demonstrations. This training enables the technician to employ proper radiological controls during periods of maintenance testing and operations.

The course is approximately 45 weeks in length and provides health physics-related topics as basic plant system knowledge along with the study of emergency and casualty procedures.

Also incorporated into this program is an in-depth review and formal checkoff of radiological control manual procedures, dispersed accordingly throughout the program.

Program implementation is supplemented by the radiological operations staff who assists with the in-plant

practice and procedure training.

Concerning this program, our most recent NRC inspection of this training area stated the licensee's strength in the radiation technician program was demonstrated by the development and effective implementation of the radiation technician training and the continuing training program.

(Slide.)

Training for station maintenance personnel is conducted in three distinct levels of instruction. Maintenance orientation training is designed to provide newly assigned maintenance workers with instruction in general plant layout and various plant systems.

The program also addresses the specifics of maintenance and operations, administrative procedures. This enables the workers to identify the rules and practices affecting their duties and responsibilities.

The general maintenance training program is designed to provide maintenance workers with generic basic instructions concerning topics such as personal fire safety, basic and advanced rigging, measurement tools, and basic notification.

(Slide.)

Maintenance training is separated into topics particular to each maintenance section: I&C, mechanical

and electrical. This program is designed to build and improve skills necessary to perform routine and emergency maintenance and perform it correctly and efficiently.

The training for each discipline provides technically related classroom instruction, hands-on laboratory sessions, and a structured in-plant OJT program. Each discipline has a dedicated instructor, classroom, and laboratory area.

Specific training for the I&C technician includes basic and advanced training on the repair and installation of process control instrumentation; for the mechanic, basic and advanced training on repair and installations of various station system components, such as pumps and valves; and for the electrician, basic and advanced training in the repair and installation of station system electrical components, such as motor-operated valves and circuit breakers.

In conclusion, I would like to reaffirm that we fully recognize the importance of providing good training programs and are dedicated to this effort.

That concludes my presentation.

DR. MOELLER: On the GET program, you said, you know, that you train people to work where there were radiation hazards.

Does this include going into a contaminated area?

MR. BURNS: The radiation worker portion of that

program does, yes.

DR. MOELLER: And one other item: where in your training program do you make sure that there is the feedback of operating experience?

I don't think you mentioned that after all the SOERs from INPO and the LERs.

MR. BURNS: That is factored into our initial training program and our requal program. I did state that in the requal program that part of our training is industry events, and so forth.

For instance, we do factor in a certain amount of the SOERs our own reports that may have happened at our station or other stations.

DR. MOELLER: You have people specifically having that as an assigned task to be sure that the benefits are factored in?

MR. BURNS: Our technical advisory group reviews those, and they have their own subcommittee within that group that reviews those, and that is one way that we get those.

Another is through licensing.

DR. MOELLER: Thank you.

DR. REMICK: Am I correct that your training department does not report to your nuclear operations unit?

MR. BURNS: That is correct. The training

department reports to the general manager of nuclear services.

DR. REMICK: What do you do to assure that training and operations departments wholly cooperate to assure the best possible performance-based training for your employees?

How do you assure that training is not somewhere off in the clouds and it is really related to operations?

MR. BURNS: We have excellent communication with the operations group. We talk to the operations group almost daily. We get feedback from operations, particularly supervisor training or requal training. We provide evaluations from training to the operations group on any evaluations we make or perform on operations individuals, making sure they are aware of whatever.

We have a structured feedback system. We have evaluation forms for both simulator training and classroom training. We have post-training surveys. There are one or more administrative manuals that are issued within a few months after, say, an initial class was turned over to operations after licensing to get a response back, and also their supervisors.

DR. REMICK: Who checks off your OJT qualifiers? Are those the license people, or plant operations people I should perhaps say, or are they instructors in the training

department?

MR. BURNS: The operations personnel take care of the OJT. The specific OJT checkoffs may be signed by any qualified individual. However, each section within the OJT has a master signoff, which can only be signed off by the shift supervisor or the foreman of the shift.

DR. REMICK: Do you have any kind of training of the people who sign off on qualifiers on the important aspects or how they are to complete those qualifiers?

MR. BURNS: We do have as part of our instructor development program a phase that is not for our own instructors, but it has been developed particularly for on-the-job training of personnel in the station.

However, it is not feasible to have the entire operations group be out there qualifying an individual. This is aimed more at the maintenance and our specifics on our OJT.

DR. REMICK: Do you either encourage operations people to go at least temporarily into training, or do you have any impediments with which you keep good operators from becoming trainers for a couple of years? Is this encouraged, or are there impediments?

MR. BURNS: I would certainly encourage training personnel. At the present we have three operators who do license type training.

DR. REMICK: Do they suffer economically if they go from operations to training other than shift increments of some kind?

MR. BURNS: The shift from a nuclear station operating foreman to the operations and maintenance instructor is at the same step. Of course, if it were a shift supervisor, he would be monitoring probably.

DR. REMICK: Thank you.

MR. BURNS: The next presentation will be Mr. Eilmann on the shutdown panels.

(Slide.)

MR. EILMANN: My name is Irv Eilmann. I will be addressing the topic of emergency and alternate shutdown panels.

(Slide.)

Both the emergency and alternate shutdown panels have the capability to place Beaver Valley Unit 2 into a safe shutdown condition. The emergency shutdown panel, while satisfying the requirements of GDC-119, is utilized only in the unlikely event something should render the control room uninhabitable for the operators.

The emergency shutdown panel was designed into the plant in the initial stages in the 1972-1974 time frame.

The emergency shutdown panel is designed to

achieve hot standby conditions and has the capability to proceed to cold shutdown.

(Slide.)

MR. MICHELSON: Since this was designed in '72 to '74, are you using the same panel for both Units 1 and 2?

MR. EILMANN: No, we are not.

MR. MICHELSON: Unit 2 was designed that early?

MR. EILMANN: It was in the conception stages. We received our construction permit in 1974 for Beaver Valley Unit 2. So it was in the design phase.

MR. MARTIN: This is Roger Martin.

You might recall that originally Unit No. 2 was to be a duplicate of Unit No. 1. Many things were carried on at the same time.

(Slide.)

MR. EILMANN: The transfer of each component's control is accomplished by individual transfer switches at the emergency shutdown panel. This transfer electrically separates individual components from the control room without changing the status of the equipment.

This diagram here I have shown is a simplified diagram showing -- it indicates a typical transfer switch. It just indicates that the switch is in that particular room in which the panel is located in.

(Slide.)

The emergency shutdown panel contains both safety-related trains, orange and purple. The transfer electrically separates individual components from the control room without changing the status of equipment.

The alternate shutdown panel was committed to in 1982 to assure the safe shutdown capability in case of a fire in any one of five rooms in three fire areas.

(Slide.)

The three fire areas are shown here: the control room, the cable spreading room, cable tunnel, instrumentation and relay room, which is our normal switchgear, and the west communication room, which contains or houses the emergency shutdown panel.

In these rooms it was not possible to fully meet the separation requirements due to congestion of electrical cables and the raceways.

MR. EBERSOLE: These rooms contain the alternate shutdown panel you just mentioned, right?

MR. EILMANN: No, sir.

MR. EBERSOLE: The main control room?

MR. EILMANN: The five rooms I spoke of were the main control room, the cable spreading room, this room here is the instrumentation and relay room, and then the emergency shutdown panel room. The emergency shutdown panel is in the cable tunnel. The alternate shutdown panel is

located in the auxiliary building separate from these fire areas and precede these fire areas.

MR. EBERSOLE: With the construction of the alternate shutdown panel, doesn't what you call the emergency panel become superfluous?

MR. EILMANN: Yes. Once we go to the alternate shutdown panel and take control, the emergency shutdown panel becomes superfluous.

MR. EBERSOLE: As a matter of fact, it being an extension of the main control room functions, doesn't it really become then more of a burden than an asset?

MR. EILMANN: No, sir, it does not. The alternate shutdown panel is an essential aspect to assure safe shutdown during the case of a fire in any of those five fire areas.

MR. EBERSOLE: I know that one, but the other one.

Can I interpret that a fire renders the control room uninhabitable as well as needing protection from fire and thus work it down as a common facility for any condition?

MR. EILMANN: I am sorry, I don't understand your question.

MR. EBERSOLE: I am saying the uninhabitable aspect of what you call the emergency shutdown panel has

been overridden by the competence of the alternate shutdown panel; you can do anything necessary to shutdown the plant from the new alternate panel.

Am I correct?

MR. EILMANN: The alternate panel could also be used in case the control room becomes uninhabitable to shut the plant down.

MR. EBERSOLE: So you have two remote points of control now, one of which is competent for fire and one of which isn't?

MR. EILMANN: We have two capabilities. However, the emergency shutdown panel has both trains. It provides us a much better advantage in case the control room becomes uninhabitable. We would prefer to go there to gain control over more instrumentation in both trains.

MR. EBERSOLE: Just for the uninhabitability, whatever that is?

MR. EILMANN: Yes, sir. That was based in the early stages of what was required to comply with GDC-19.

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The later one, which is the alternate shutdown panel, evolved as a result of the Brown's Ferry incident and the requirement to meet fire protection. That was after the alternate RCIC shutdown panel was installed that we had to put in another panel to satisfy fire protection requirements.

MR. EBERSOLE: Thank you.

(Slide.)

MR. EILMANN: The alternate shutdown panel as it's shown here is in a totally separate fire area and electrically independent. As in the case of the emergency shutdown panel, transfer of each component is also accomplished by individual transfer switches at the alternate shutdown panel.

The alternate shutdown panel contains only the orange train and is also capable of bringing the plant to hot standby conditions, and capable of proceeding to cold shutdown.

In conclusion, the capabilities of Beaver Valley Unit II's emergency and alternate shutdown panels provide a safe means required to shut the plant down in the event of a fire or the loss of controlroom habilitability.

MR. EBERSOLE: In the logic of the alternate shutdown panel, does the rationale include consideration of inducing spurious actions as a result of damage in the main?

Or the emergency shutdown panels?

MR. EILMANN: Yes, sir, it will.

MR. ETHERINGTON: Can you transfer direct from the control room to the alternate panel?

MR. EILMANN: No, we have to go to the panels to gain control. There are switches located at the remote panels.

MR. MICHELSON: Are you going to tell us how you protect these alternate panels, for instance, from some local intervention that is unwanted?

MR. EILMANN: Are you referring to like a sabotage?

MR. MICHELSON: The inside sabotage scenario, for instance.

MR. EILMANN: We have a presentation on sabotage. We can get into that further. I will highlight one thing, and that is, if someone would enter the room and take control over a switch, it would alarm in the control room.

MR. WARD: I don't know if this should be in a closed session.

MR. EILMANN: Not this particular one. It would alarm in the control room, notifying the control room that someone has transferred control of a component or system. We would then proceed from there to our security efforts.

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MR. EBERSOLE: Are spurious actions derived from fires or other incidents in the alternate shutdown panel managed in some way that you could handle them? I'm not talking about disabilities but spurious actions derived from potential hot shorts in the alternate panel.

MR. EILMANN: The hot shorts in the orange shutdown panel, if that would occur, we would address or safely shut the plant down using the purple train.

MR. EBERSOLE: The purple train can cope with any artificially induced lineups that might be originating from that panel due to electrical faulting, right?

MR. EILMANN: I'd like to call on Operations. Fred Schuster.

MR. CAREY: This is Jack Carey. I'd like to respond to that because we've talked about it once before. On a hot short, after the hot short, we had to go to the alternate shutdown panel, because if you get a fire in the area where the emergency shutdown panel is located that contains both trains, it would take the control away from the control room. And now you couldn't enter the fire area and expect the operators to operate.

So then you go to the alternate panel, which would then transfer the control away from both the control room and the emergency shutdown panel, which took over controls in the hot short.

That's the only person of the alternate shutdown is to handle that hot short situation.

MR. EBERSOLE: It's unclear to me that a hot short in the alternate shutdown panel could not produce a plant condition which was undesired and could not be overridden by an alternate channel of functions.

MR. CAREY: Well, it really only takes one train of the safety function. You would still have your other train either from the control room or from the emergency shutdown panel. Certainly, the operators would not go to the emergency shutdown panel as long as the control room was habitable.

MR. SCHUSTER: I think, in addition to that, the circuits in the alternate shutdown panel are independent in that they have separate control power, and I think that would mitigate some of the hot short situations.

MR. EBERSOLE: You understand, I'm worried about spurious actions, not disabilities.

MR. SCHUSTER: I mean they are separate in that when you're controlling from the control room in emergency shutdown panels, those circuits are transferred out of interface with the other controlling circuits.

MR. EBERSOLE: You can isolate any spurious action on the alternate panel?

MR. EILMANN: Yes, sir.

MR. EBERSOLE: Thank you.

MR. EILMANN: We are also, Mr. Ebersole, undertaking a spurious signal analysis and whatever we find will be corrected.

DR. OKRENT: Are either the alternate shutdown panel or the emergency shutdown panel seismic class one with regard to whatever is essential?

MR. EILMANN: Both panels are, sir.

DR. OKRENT: Thank you.

MR. MICHELSON: It's safe shutdown, I understand, or cold shutdown? You used the word "safe shutdown" in your terminology.

MR. EILMANN: We can achieve hot standby and proceed to cold shutdown at both panels.

MR. MICHELSON: From the alternate alone, you can go to cold shutdown?

MR. EILMANN: Yes, sir, we can.

MR. MICHELSON: Thank you.

The next speaker will be Mr. Kenny Grata, Station Blackout.

MR. WARD: Mr. Wylie, we have about 25 minutes left and we haven't heard from the staff. What's your projection?

DR. WYLIE: The staff needs about 35 minutes.

MR. NOVAK: We'll do our best to abbreviate the

presentation, primarily issued here from the region regarding their views on construction. As far as the licensing activities, they're rather abbreviated and we'd only need to spend a few minutes except for answering questions.

DR. WYLIE: We've got two more items by the applicant before we go to the staff.

MR. WARD: You also had a closed presentation, did you?

DR. WYLIE: There's one on sabotage, but the staff has requested that we present theirs before we have a closed session so we won't have to reconvene.

MR. WARD: Could we just see are there any questions of the applicant?

DR. WYLIE: Why don't we just ask these questions of the applicant on the remaining topic on Station Blackout?

MR. MICHELSON: On station blackout, you're using I guess steam-driven auxilliary feedwater to ensure boiler water?

MR. GRADA: That's correct, sir.

MR. MICHELSON: Is the auxilliary feedwater all D.C. operated?

MR. GRADA: There's no D.C. requirements on the turbine-driven feedpump.

MR. MICHELSON: What kind of governor are you

going to use?

MR. GRADA: It's a Woodward UT-8 governor.

MR. MICHELSON: You don't have to have any power to it?

MR. GRADA: That's correct, sir.

MR. MICHELSON: It's manually operated?

MR. GRADA: It's self-contained. It has Black Star capability. There are six. For each steamline, you have two series, D.C. solenoid valves that fail open on loss of D.C. power to supply steam to the turbine driver.

MR. MICHELSON: You get to steam to the driver. My main concern is whether or not you can control the speed.

MR. GRADA: There are no external electrical connections.

MR. MICHELSON: Variable speed governor controls.

MR. GRADA: There's a three to fifteen air signal installed on it but it's not utilized. That's for the variable speed function.

MR. MICHELSON: You don't need any air for this plant either?

MR. GRADA: No, sir.

MR. MICHELSON: No air, no power and no ventilation to the room?

MR. GRADA: The ventilation from a preliminary

review, it was also in consideration to respond to any staff review under NUREG CR-3226. They found that just the ambient air losses, if you open the compartment doors between areas, that there wouldn't be an environmental problem.

MR. MICHELSON: What is your estimated equilibrium temperature for, say, several hours of operation?

MR. GRADA: Well, under loss of OEC conditions, we're going to lose a considerable portion of your heat input as well as your heat removal capabilities. We've procured under the Appendix R issue, we've procured gasoline-driven blowers that exhausted about 5,500 cubic feet per minute in the event that we would require it.

MR. MICHELSON: You mean exhaust from the compartment containing the feedwater turbine?

MR. GRADA: That's correct.

MR. MICHELSON: So you're going to depend upon gas-driven backups?

MR. GRADA: If we require it. We wouldn't anticipate that we would.

MR. MICHELSON: But you haven't made any calculations here.

MR. GRADA: No, sir.

MR. MICHELSON: Have you done any tests to see

how fast the room heats up with your normal heat up? There's quite a steam heat source from that turbine, of course, and the steamline; even if it's insulated, it is still a large heat source which doesn't normally exist in the room, as a matter of fact.

MR. GRADA: From our experience at Unit I, it's not a significant problem.

MR. MICHELSON: What experience is this? You've actually isolated this room at some time and watched the turbine run and the room heat up?

MR. GRADA: We've had fire dampers that went shut in this area and were unable to protect them until we did the annual load balancing when we ran that equipment.

MR. MICHELSON: I don't want to pursue it much further but there's a lot of difference in the heat input between the turbine lane by without running in one that's running.

MR. GRADA: As I did say, the staff, there was a contract in Contractor Report 3226 which stated that they analyzed it and they didn't see any problems in the eight-hour timeframe.

MR. MICHELSON: I guess, later on, the staff will fill us in with this analysis. Thank you.

DR. REMICK: Carl, on that point, although I agree with what you're saying, certification of the turbine,

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one thing we did find is that they have heated steamlines right down within a couple of feet of the turbines.

MR. MICHELSON: The steamlines should be well-insulated but the casing may not be. It doesn't normally happen.

MR. WARD: Okay. Any more questions on station blackout?

(No response.)

MR. WARD: Let's go to the next topic.

MR. GRADA: Excuse me. There were a couple of questions I was supposed to address from earlier discussions.

MR. WARD: Well.

MR. GRADA: Do you want to forego them?

MR. WARD: Unless people have the questions right now, let's skip over that. Charlie, it's up to you.

DR. WYLIE: Unless somebody wants to raise the issue.

MR. WARD: All right.

DR. WYLIE: Do we have any questions on the next subject?

MR. WARD: Leak befor break.

MR. MICHELSON: What is "alternate pipe rupture protection"?

DR. SHEWMON: That would apply to leak before

break in the nonhigh pressure primary.

MR. MICHELSON: Inside of containment or outside?

DR. SHEWMON: Both.

MR. MICHELSON: You can't cover that in two seconds.

MR. HULTZ: I'll quickly go through this.

MR. WARD: Let's see. Do we need to? The subcommittee spent a good bit of time with it. Are there any specific questions?

DR. SHEWMON: Tell me what you spent on it, Charlie?

DR. WYLIE: We heard a complete explanation on it.

DR. SHEWMON: We heard it. I would have a question then about what your plans are on how this will impact your schedule, and working in your plant in the completion of it over the next year.

MR. HULTZ: What we're requesting from the NRR is approval to proceed with this whipjet program that you heard about in the subcommittee. We would like approval. This is December 1985. Probably by the end of the first quarter of 1986 will be the point where any further relief will probably be of very little help to us.

So we're right now requesting a fairly rapid resolution by the staff on this issue.

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DR. SHEWMON: But is this a matter, since you haven't put the package into the staff yet as far as I've heard?

MR. HULTZ: We put the package in on October 10.

DR. SHEWMON: You told what lines?

MR. HULTZ: No.

DR. SHEWMON: That's what I mean by the package.

MR. HULTZ: That package will not be available until sometime in 1986.

DR. SHEWMON: Fine. Does that mean that you will bet that on certain lines or sets of lines, you'll say we'll leave these off until the first few outage, or what sort of schedule is in there?

MR. HULTZ: That's what we're asking for is a schedule or implementation program for those lines that ultimately may require restraints.

DR. SHEWMON: And when is the first guess as to what lines those are going to be likely to come forward from you people?

MR. HULTZ: That will start in early 1986. We're going to try and weed out first those lines that are essentially clear and present candidates for applying restraints. And we should have that completed in total by the end of 1986 for all lines.

But we can go through an early identification

phase of the lines that may be at risk.

MR. WARD: Okay. Thank you.

Let's see. Is there another topic then, Charlie?

DR. WYLIE: The staff would like to make their presentation at this time.

MR. WARD: Let's go ahead with that.

MR. SINGH: Good afternoon. My name is Braj K. Singh. I will try to finish my presentation within 10 minutes.

(Slide.)

Here is the licensing overview. We are giving the milestones, which I don't need to discuss; as a result of the review by the staff, SER has identified 11 open items, 44 confirmatory items and one licensing condition.

(Slide.)

I'm going to discuss in order open issues and estimated resolution date. The next one will be significant backfit issues. The third one, significant confirmatory issues. And then license condition item.

(Slide.)

Out of 11 issues, most of these issues are open because the applicant has not met the submittals as, for example, number one. Preservice, inservice testing. The submittal has not been made.

And based on the applicant's submittal date, I

have provided the estimated resolution date.

The next one is pump and valve leak testing. The submittal has been made and there has been a discussion in the CRGR and we have gotten guidance from them, and the staff will issue their position for the response.

The third one is inadequate core cooling instrumentation. The staff has reviewed it and asked for additional information.

The fourth one is the same like number one. The applicant has to make the submittal. The fifth one, safe and alternate shutdown, which you just heard, the applicant has not made any submittal yet.

Management and organization, that submittal has not come. And we have not received yet any submittal date, so I could not forecast estimated resolution date.

The cross-training program. The staff is reviewing. Eighth is the emergency preparedness plan. The applicant has to provide additional information.

MR. WARD: On the cross-training program, is this something you need from Beaver Valley, or are there other sides where individuals hold SRO's for Region II units?

MR. SINGH: Region I is reviewing that one and it's the dual training concept that might be unique, I think.

Lowell, do you want to answer that question?

DR. NOVAK: This is Tom Novak. The answer is we do encourage cross-training, obviously. It enhances the capabilities of the entire operating staff. The problem we have today is just one of getting the licensee to identify his program that he will use, the training program for cross-licensing the individuals.

Once we understand the program, I don't think it's that unique a test to go forward with it, so I don't anticipate any real problems.

(Slide.)

MR. SINGH: The initial test program. The staff has reviewed it and asked for additional information and full room design review. And safety parameter display system, the applicant has to provide the complete program.

(Slide.)

There were 16 backfit issues defined by the applicant under the generic letter, 84-S-12. Out of the 16 issues, 14 we have resolved as the result of technical discussions between the applicant and the staff. And the subsequent submittal of the additional informatioι , 14 issues were resolved.

These two issues, the steam generator level control and protection and fire suppression in the cable spreading room had to go to the appeal under the normal appeal process, and the Director of the Division of Licensing has made his decision.

The steam generator level control and protection, the basis issue was that the steam generator level design did not meet IEEE 279 Part 28, and the applicant's position was that they did not need to meet this criterion because it's not used for the protection.

The Director of the Division of Licensing has taken the position that they don't need to provide a response until the resolution of generic issue A-47. In

the interim period it does not impair the health and safety of the public.

Fire suppression in the cable spreading room, the applicant's position was that the main fire protection system was the CO_2 system backed up by manual hose. The staff wanted an automatic fixed water suppression system as a backup to the CO_2 suppression system.

And the decision was made. There was one particular corner, the northwest corner, where the manual hose could not be reached. So the applicant had to provide some sort of justification for that reason. They have provided a solution; they have removed some of the platforms. They have brought the Navy nozzles and the staff is reviewing that one.

Next, please.

(Slide.)

Out of 44 confirmatory issues, I consider these seven significant confirmatory issues. First, soil structure interaction analysis. That has been resolved. The basic disagreement was that the staff wanted the calculation at the foundation level, and the applicant wanted to provide it at the ground level. But that has been resolved.

We could not update in the SER because technical evaluation report by our consultant from Brookhaven could

not reach us in time.

Number 2, number 3 and number 4, the equipment qualification. The applicant has to provide the information. That's why these are the confirmatory issues.

Fifth, analysis of combined LOCA and seismic load. The results have been submitted to the staff and the staff has accepted the result.

The analysis has been performed using computer code multiplex 3, which is still not approved by the staff. So the staff is looking into the code itself and, after the verification of the code, there is no problem.

Number 6, the steam generator tube rupture. The Westinghouse Owners Group has not made the submittal yet. And after the submittal, this will be done.

The quality assurance program, again, some of the additional information has to come from the applicant.

(Slide.)

The last one is the license condition item. There is only one license condition, and that's the emergency response capability of Reg Guide 1.97. Basically, there were 23 issues. Twenty-two have been answered by the applicant. We have not updated that SER because this one was decided later on. Only one issue remains to be resolved. And that's on the accumulator tank.

Either they have to provide the qualified present

indicator or a level indicator.

That concludes my presentation.

Dr. Okrent, I'd like to answer your question first. If I understand correctly, you wanted to know about internal flooding, or external flooding?

DR. OKRENT: Internal flooding. Let me say what I have in mind. It's a draft staff position to be reviewed inside the staff concerning systems interaction. The staff, in hearing the draft, have the tentative solution that, at least among some class of plants that may not include Beaver Valley, seismic interactions and internal flooding may warrant a new look.

My question is has the e been a really good look at internal flooding at Beaver Valley II?

MR. SINGH: I can answer that about the internal. Do you want to?

So far, the internal flooding, the staff has evaluated and the flood level was calculated assuming a 30-minute leak duration. And that's allowing enough time for the operator to isolate the problem area before safety-related equipment is adversely affected. And all their safety-related equipment is above that flood level.

Now, to answer your question on the interaction. I don't think that we have got the proper information but it's my understanding that the applicant is doing a hazard

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analysis. Under that analysis, most probably, they are going to look into that.

Is there anybody amongst the applicant who can make the comment?

MR. GRADA: This is Kenny Grada. I thought the review for internal flooding was an SRP requirement. I can't reference the specific section.

MR. PROXLER: This is Kurt Proxler from Duesqne Light. We have evaluted the flooding aspect using either the full system volume dumping into any compartment where it could go, or the 30-minute criteria. And we are looking at the seismic-nonseismic interaction throughout the plant by taking each section of the plant and looking for all possible interactions between nonseismic and seismic systems.

DR. OKRENT: I'll accept that. At least the problem is getting attention. Can I ask whether you have looked at the margin you have for equipment, assuming there might be an earthquake larger than the safe shutdown earthquake equipment that you need to accomplish shutdown heat removal? Have you looked at this equipment to satisfy yourself that you have a rather significant margin?

MR. PROXLER: We have designed for our shutdown earthquake, but I do not believe that we have evaluated for greater than the design basis earthquake. Maybe somebody

can correct me on that but I believe that's so.

DR. OKRENT: Just one other question. If your steam lines were to be flooded, can you withstand the gravity load?

MR. PROXLER: The flooded steamline issue has been evaluated as part of ensuring that we can test those steamlines with the hydrostatic test.

DR. OKRENT: The answer is?

MR. PROXLER: Yes.

MR. MICHELSON: So without manual intervention, you put the anchors first?

DR. OKRENT: That's the point of the question.

MR. PROXLER: I'm not sure.

DR. OKRENT: That's the point of the question. This is not a flooding event for which you've been prepared. It's not the one I'm talking about.

MR. GRADA: You did say the gravity loading, right?

DR. OKRENT: I said the gravity loading. Assume you have the steam generator overfill due to some transient and steam line to some extent gets flooded. I'm not talking water hammer at the moment, I'm talking just about the gravity load.

MR. PROXLER: I don't know what the answer to that is.

VOICE: We can check on it real quick here.

DR. OKRENT: In other words, because when you're doing the test, you can prepare for it, we want to understand if you can accept this load.

VOICE: I believe so, but we're going to check.

MR. MICHELSON: I note that you do not have safety grade instrumentation to prevent a steam generator overfill. You probably do not have safety grade instrumentation to prevent a runaway of the feedwater flow rate. So I'm interested in the case of your auxilliary feedwater turbine; in the unlikely event that you should rupture the steamline in the compartment, where do you relieve to? This rupture of course is accompanied with the scenarios that you developed from steam generator overfill.

In the case of a rupture of the steam line, in the vicinity of the auxilliary feedwater turbine, where do you relieve the steam pressure to? What happens, in other words, if you break the steam line in that room? Does it blow the room apart or does it vent to atmosphere outside or go into the rest of the auxilliary building? Or where?

MR. MARTIN: What location?

MR. MICHELSON: The auxilliary feedwater turbine room. You keep the pressure on the system, I understand.

MR. MARTIN: That has been analyzed for the worst steam line break; the capacity of the walls have been

identified to be adequate.

MR. MICHELSON: If you don't vent it, I'm sure you'll blow the room apart. It's got to be vented to somewhere and that is my question. What is the steady state condition and how do you assure isolation and so forth?

It's part of your pipe break analysis that you must have done for this type of pipe break outside of containment.

MR. MARTIN: In the main steam valve area, we provided relief of the internal steam line pressure.

MR. MICHELSON: Of course, this is not in that area, I don't believe.

MR. MARTIN: I cannot address the auxilliary feedpump area. Let us get some information for the answer.

MR. MICHELSON: I'd like to know where it's vented to, what equilibrium conditions you reach and are you dependent upon isolation.

MR. EBERSOLE: On a related matter, I notice you have perfectly excellent ball valves for the main steam line, which must have cost you a pretty penny. They're bi-directional in competence. Am I correct?

Do you use valves of equivalent competence to isolate the aux steam feed break, which is what Carl's talking about.

MR. GRADA: There are three solenoid, D.C.

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solenoid valves.

MR. EBERSOLE: That's right, multiple D.C. solenoids.

MR. GRADA: Two in space.

MR. MICHELSON: Two in series.

MR. EBERSOLE: They have a whole bunch of them in series. This plant has an absolutely unique capability as far as I'm concerned to operate with zero D.C.

MR. GRADA: On turbine-driven feedwater.

MR. EBERSOLE: By solenoid valves, by springs, am I correct?

MR. GRADA: It's a pilot-assisted solenoid valve.

MR. EBERSOLE: Any failure on one of those solenoids, the machine cranks up, doesn't it? That's going to be interesting.

MR. WARD: Okay.

MR. EBERSOLE: They're sure going to crank up.

MR. WARD: Is that about all you need to know?

MR. MICHELSON: I think they said they're going to give us the information.

MR. WARD: Okay. We've got another presentation from the staff.

MR. MARTIN: As far as the filling of the steam lines, the gravity situation may need to be pinned before

the test. That is the arrangement we have. We believe they would be adequate. Specific calculations have been done for not pinning those supports.

DR. OKRENT: Now I'm confused. I have a question of the staff. We've had discussions on this issue in the past and, in fact, if I remember correctly, the staff said we've examined the plants in the field -- I think, meaning they looked at a couple. And the plants can take the gravity load.

And what I'm hearing now is maybe it can take it but it's not been analyzed for this plant, and I don't know for which plants.

Does the staff think this is an unimportant issue? If it's not an unimportant issue, why is not an evaluated one?

Would somebody on the staff please stand up and tell us?

MR. KNIGHT: This is Jim Knight from the Staff. I'm searching the recesses of my mind. That's a question that's been around for quite a while. I do recall having our folks look at a number of instances outside of the intervention, which wasn't independent work, but looking at materials and coming to the conclusion that in a number of instances, flooding of the lines would not result in catastrophic collapse.

Now, to the best of my knowledge, we don't impose -- I'm ready to stand corrected, but we dont' impose an explicit requirement that the lines be analyzed and shown to stay within code limits, or something like that.

DR. OKRENT: I wasn't talking about code limits but what we heard a little while ago was that regarding the degree of protection against steam generator overfill, someone had reached the position that this wasn't a safety matter, words something like this. And I don't know how you know it's not a safety matter if just the gravity load itself, right now, it might be -- you know, it probably takes it but, right now, they can't say yes.

And the staff apparently doesn't know it's yes. And we have what I would call sort of a soft basis.

MR. CURTIS: This is Gene Curtis. I think that, as was said before, it was not a safety concern pending resolution of A-47, which is addressing the overfill issue.

DR. OKRENT: But that's a bureaucratic answer. It's not a safety concern in fact if you can take overfill and nothing's going to happen.

MR. RUBINSTEIN: Les Rubinstein of the staff.

Again, it did this, as Jim said, searching the memory. We've had a couple of plants. And I don't want to say it's Yankee or Haddam Neck, where we've actually looked at and given credit for solid steam generator heat removal.

And we did look particularly in those cases at the loads. And this would have been in Maine perhaps or one of the Yankees.

Beyond that, I don't think we've got much to go on.

DR. OKRENT: Mr. Chairman, or Mr. Subcommittee Chairman, it seems to me that the combination of not having what I would call safety grade loop flow protection and the lack of knowledge that at least you can take the gravity load, we don't know enough about this water hammer yet to say whether that's a high probability problem or not.

Let me suggest that the staff or the applicant should do some looking.

MR. MICHELSON: And that looking should extend to the auxilliary feedwater steam line and a possible fix of ruptures there which might very well be associated with the water hammer and water-accelerated conditions that could exist on the steam generator overfill. If you're not going to use safety grade protection, at least you ought to think through what the consequences are so you can decide whether or not you'd really better invest in it now because, if I were the utility with that much money invested, I'd sure be looking awful carefully because I don't think it's that big a bucks to fix it.

MR. RUBINSTEIN: Les Rubinstein of the staff

again.

Not talking to Beaver Valley but on a number of plants, we usually look where the feedwater room contains certainly the electrical and the turbine unit because of EQ, and looked at the effect that they have a good system of isolation. Other steam to the pumproom externally from the control room.

I thought perhaps they might leap up and say they have an isolation valve.

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MR. CAREY: I would like to say we do have safety grade protection. The question is: do we need three or four channels?

Because you can postulate some conditions whereby you have got a failure of the channel associated with control systems and then an active failure postulated on another channel, and that will disable your two out of three.

MR. MICHELSON: I thought you said it was safety grade. If it is safety grade, then it is single failure proof. In other words, the failure that causes full steam or full feedwater flow will not also cause loss of overfill protection. That is a given if you have safety grade design.

So I think you don't quite have safety grade design. Perhaps you had better look into it. I wouldn't want to put the words in your mouth.

But you are certainly single failure proof if you are safety grade.

MR. CURTIS: This is Gene Curtis.

That was the purpose of the practice system, to identify the safety significance of this concern. Beaver Valley 2 operates with an acceptable level of safety. We have the same system incorporated in 33 operating Westinghouse reactors out there now with that same exact

design.

All we are saying is it will be pursued pending resolution of A-47, which the staff has agreed to and Duquesne has agreed to, to provide adequate resolution to determine that that is the correct way to go.

In fact, six of those plants that are out there operating have no high level protection at all.

MR. MICHELSON: So be a little careful in making your comparisons to also look to see what would happen on the overfill. There the scenario varies from plant to plant. Some is very bad, some is not so bad.

So look carefully. It is your judgment.

MR. HAUSNER: This is Wayne Hausner from the staff.

Let me see if I can't add some clarification on that.

I agree, Carl, with your statement that it either is or it isn't safety grade. But the staff's understanding of the system, the steam generator level control system is almost but not quite fully safety grade, with respect to the one provision of IEEE-279, which was uncovered by the staff review of the diagrams of the system during the course of the FSAR review. Everything they had said in the course of the PSAR and the CP review led the staff to infer that it would be fully safety grade, but I understand that the staff

really didn't know then what channel would be used for normal steam generator and level control at that point, and having given the applicant every opportunity and suggested that they address the question of the safety significance of the event, the response has been the type of thing that you have heard.

MR. MICHELSON: The instruments have all been upgraded now to full safety grade?

MR. HAUSNER: I don't think it was an upgrade. They were originally designed and installed the way they are on Beaver Valley Unit 1. That is my impression. And they meet Class 1E except for that provision.

MR. MICHELSON: They used to have power supply problems, for instance. I assume they fixed all of those.

MR. HAUSNER: I can't respond to that.

MR. EBERSOLE: In the present reporting structure, if these events were occurring, would we know it?

MR. HAUSNER: An overfill event?

MR. EBERSOLE: Either from INPO or our own.

MR. HAUSNER: I would think we would.

MR. EBERSOLE: On what basis? I don't know of any requirement in this context.

MR. GRADA: It would be 50/72, 50/73 anytime your protection system logic is activated, which it would be in an overfill event because at the 75 percent level the

steam generators gets a feedwater isolation signal which buttons up your main feedwater system.

MR. HAUSNER: He has just referred to protection system logic, and I understand their position is that this is not a protection system.

MR. GRADA: The issue, sir, was because it was referenced in Chapter 15 of the FSAR that we had this type of overfill protection, but the trip in fact is a turbine trip which directly produces a reactor trip. The turbine trip protection is not safety.

MR. HAUSNER: I understand.

MR. EBERSOLE: Then it induces a reactor trip. So you think it would be reported every time?

MR. GRADA: Yes, sir.

MR. WARD: Okay. Where do we stand now? This system is not fully safety grade?

MR. WYLIE: The applicant has agreed to comply with the resolution of A-47, am I correct?

MR. SINGH: That is right.

DR. OKRENT: There are a couple of multiple or mixed-up things here. We have been sort of assured in the past that all the plants could take a gravity load, but does one ask? It turns out one doesn't tell.

I am not talking about the fact that they meet the semi-cold limits, just that even if it is restored

somewhat --

MR. WARD: Is this a USI or has it been identified?

DR. OKRENT: If you think that nothing much will happen with steam generator overfill, you take the gravity water and you meet any water hammer that may occur, then you are a little bit less concerned about the quality of overfill protection.

On the other hand, you don't know where you led in that event, and I have seen in some vendor reports the statement that we don't know what happens if you have overfill, we had better vent it.

I think the staff ought to be asked to look a little more deeply into this on Beaver Valley. I don't know what is going to happen on A-47 because in fact each plant is going to [illegible] aving some peculiar characteristics. There may not be a single generic answer.

MR. HAUSNER: Just for clarification, USI A-47, is an unresolved safety issue. It is not a new one. It is my understanding that it is rather close to resolution, possibly within the next few months, maybe six months, something like that.

MR. KNIGHTON: My name is Knighton.

We are in the appeal process on this particular issue. It is a question of whether the pipe could stand

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hydraulic load. The answer at that time was it had been looked at.

DR. OKRENT: It has been looked at, you were told?

MR. KNIGHTON: If you look in the book you have here, the license has a question 2, and they indicated here:

"However, the main steam lines have
been designed and analyzed to
consider. The second item to be
considered was the water filled
main steam line to reflect hydro
testing conditions."

DR. OKRENT: During hydro testing is not the question.

MR. KNIGHTON: No. Your added question was: was there any manual addition to take away?

That is a good question, but as far as I understand, they have been able to say that, yes, it would take the load. That means on whatever hangers you have.

MR. WARD: This is without pinning? Do you understand from that, that that meant without any special precautions it could take the load?

MR. KNIGHTON: That is our understanding.

MR. WARD: Are you reading from the SER or what?

MR. KNIGHTON: This is the answer they provided

for you. That is the understanding.

MR. WARD: So the staff interpreted that anyway as without any special precautions?

MR. KNIGHTON: That was part of the decision process.

MR. WARD: Is that how that licensee meant the answer? Did you understand that?

MR. CURTIS: That item says, and I quote:

"Dead weight associated with
water filled main steam lines is
already under hydro testing
conditions."

MR. MICHELSON: People know what that means.

MR. WARD: Who knows what it means?

MR. MICHELSON: People who do hydrostatic testing of large lines know that you fix the hangers.

MR. WARD: There is a disconnect here. The applicant meant that the piping was pinned and specially prepared. The staff interpreted improperly that term.

MR. MICHELSON: Why isn't there any discussion of the auxiliary feedwater steam line as a part of the steam generator overfill consideration? Did you not think there was any way to generate problems in that line?

Because that has been well-documented and discussed as a part of the USI, yet it doesn't enter into

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the discussion here.

MR. HAUSNER: Wayne Hausner from the staff.

We didn't get that far. We asked the applicant to identify the potential safety significance of the overfill.

MR. MICHELSON: Auxiliary feedwater is certainly a safety-related system, so it might have potential safety significance.

MR. HAUSNER: That is correct.

MR. MICHELSON: And you just didn't get to look at it?

MR. HAUSNER: We just didn't get that far.

MR. MICHELSON: We need to go back and think about it for a moment.

MR. GRADA: This is Kenny Grada.

If we assume, okay, that the true function of the main feed system works on 75 percent, okay, the trip to main feed also starts the main feed pump if the main feed pump trips.

MR. MICHELSON: That wasn't the concern. The concern was the steam line overfill. With water in the steam line, you also have water entering the auxiliary feedwater steam line. It accelerates by gravity and by the opening of the valves. In fact, the worst thing that can happen is to start the auxiliary feedwater turbine now with

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a partially filled line and accelerate that water right into the turbine.

MR. CAREY: Then we may have to rely on our two AC driven pumps.

MR. MICHELSON: There is a little more to it. You have one steam and two electrics. The electrics, are they separated environmentally such that the break in the turbine now will not overpressurize the room and the steam will not enter into these other areas?

That is the question I raised originally. You haven't answered.

MR. MARTIN: Roger Martin. Let me answer your question.

The isolation valve -- the two solenoid valves that are in series and have cut off the steam to that individual, that turbine driven auxiliary feed pump, are in a separate cubicle from the pump itself.

MR. MICHELSON: They are exposed to the same accelerating water column that has damaged the turbine. This was quite a disturbance if you ever get into one. That is the concern, that you have lost the ability to isolate.

I would like your answer to simply be: if the compartment pressurizes, there is a blow-off panel to the outside atmosphere. In some utilities they have provided just that.

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I only originally asked, and I wonder now, did you provide a blow-off panel to the atmosphere, or are you depending on depressurizing with the rest of the auxiliary building?

I hope you have one to atmosphere.

MR. CURTIS: We are addressing that, and what happened is we are running late. We know there was some analysis done in that area; however, we don't have anybody in Boston at this time that can give us that information.

MR. MICHELSON: Thank you.

MR. EBERSOLE: There is a mystery here that I wish the staff would sort of look into. These events that we are talking about, notably the main steam line overfill, are apparently quite possible. The mystery is why haven't they happened.

I should hope we might find something out about this incongruous state of affairs. It is quite clear it can happen.

Is it that the operators are always so smart and alert that they stop this?

You know, I am bothered by the thesis that it can happen when it possibly could cause great damage, and yet apparently it hasn't happened.

I think we could profitably look at this enigma.

MR. GRADA: Sir, this is Kenny Grada.

We have had over 44 events in Unit 1 in the past 10 years, high level trips, and we have never had a failure of that almost safety grade instrumentation, in a trip of the main feed system, and there are several alarms that alert the operator to that event -- feed flow, steam flow, mismatched steam generator level alarms, temperature alarms, low pressure alarms.

The operators were right on those controls whenever we had them.

MR. EBERSOLE: I suspect that is it, that the case is that the operators are far more responsive than we think they are.

MR. GRADA: Where the staff had problems with it was that they wanted a 10-minute operator response time, and because we couldn't give that, given a wide open failure of the main feedwater regulator valve. As was said in the past, that is always a protection system that is not 100 percent IEEE-279 for the main feedwater pumps.

MR. REED: We have to be careful that we don't beat these steam generator blow-off controls and auxiliary feedwater things to death because there is another input possibility for overflow, and that is a serious large rupture.

So that the overfill issue, I am not so sure that it is very likely from auxiliary boiler feed or for loss of

the ability of the controls to back off, but it can happen from tube ruptures.

MR. CAREY: Jack Carey.

You are absolutely right, Glenn, and the plants that have it go out and pin the hangers. That is included in the emergency procedures.

MR. REED: Before we get too sad about that, let me point out that there is a lot of difference there in inventory capacity as well as normal operating water level in the various concepts of vendors' equipment. Some can overfill rather quickly, and there are others that take a long time, and we heard about one the other day in the Palo Verde discussion.

DR. KERR: Mr. Chairman, how much time are we going to spend on this issue? Can we resolve it tonight?

MR. WARD: It sounds like there is going to be at least one question hanging over, which we will have to deal with in the letter.

All right, are we ready to go on to the region presentation?

MR. TRIPP: Good afternoon. My name is Lowell Tripp, the Project Section Chief in Region 1 for Beaver Valley 2.

I have been Project Section Chief for three and a half years, both Beaver Valley Unit 1 and 2. Before that,

for about three years, I supervised the inspection program for mechanical, civil, and quality.

I also have with me Glenn Wellcome, of the NRC staff. He is the Senior Resident Inspector at Beaver Valley 2. He has been there since August '81.

Between the two of us, we have been associated with most of the Region 1 inspection program. The purpose of this presentation is to provide the basis of the ACRS for the current Region 1 staff conclusion that the overall licensee performance during construction for Beaver Valley Unit 2 has been satisfactory and in compliance with NRC requirements and safety objectives. It has been acceptable.

This conclusion has been reached after consideration of certain key factors. They include things like the corporate involvement by the licensee and the construction activities.

I think everybody heard that the chairman of the board is there frequently and the vice president is stationed onsite and spends most of his time on Unit 2.

Other factors, not the least of which is our NRC inspection for construction quality and licensee management attention to NRC concerns.

As a further point of introduction, I would acquaint you with about seven aspects of the Region 1

inspection program at Beaver Valley 2. I want to discuss inspection history, the enforcement record, special inspections like regional construction and NDE van inspections, construction deficiencies, allegations, and then systematic assessment of licensee performance, or SALP.

As you have heard, the construction permit was issued on May 3rd, 1984 -- I am sorry -- 1974.

Stone & Webster serves as architect engineer and construction manager.

Our inspection program actually started in 1972. It was performed by both the resident and regional-based inspectors, who obtained information through direct observation in the field, personal interviews, and review of procedures and records to determine whether construction and installation of safety-related components, structures and systems meet applicable requirements.

As I said when I introduced Glenn, he has been there since August of '81 as a senior resident inspector. The second resident inspector was assigned there in October '84, and in September of '84 the Unit 1 resident inspector was dedicated on a part-time basis to follow the pre-op test program at Unit 2.

First slide, please.

(Slide.)

The inspection history then can actually be traced from the initial inspection on July 11th, '72 until the present time. There has been approximately 130 inspections conducted.

We monitored activities, including soils and foundations, concrete work, safety-related structures, piping, welding, electrical activities, safety-related mechanical components and instrumentation.

We spent approximately 12,000 hours of direct inspection effort at Beaver Valley Unit 2. This -- by way of comparison -- this level of inspection effort is more than for other facilities at a similar stage of construction.

For example, Millstone 3 had about 6700 hours; Nine Mile Point 2, we had about 8300 hours; and Hope Creek had about 7600 hours.

Before you ask if this can be attributed to the longer period of construction, nearly 10 years or 11 years, we have actually been inspecting for 13 years, and we have also had a longer period of time when resident inspectors were assigned to Beaver Valley than these other sites that I used as examples.

Our inspection of the preop test program began in January of '85. Let me briefly address the enforcement record. As you probably have heard from other presentations, the inspection program uses inspection and enforcement measures to promote adherence to regulatory requirements, reduce repeated noncompliances and encourage self-identification and correction of nonconformances.

We issue notices of violation when necessary. Over the inspection history lifetime at this point, we have issued or identified 66 nonconforming conditions. We think, earlier, we said 65. We missed one in the count.

This compares very favorably with four other plants at a similar point in construction, especially in light of the amount of inspection hours conducted at Beaver Valley Unit II. For example, the total number of nonconforming conditions in other plants for Milestone III, 40; Nine-Mile Point II with 64; Hope Creek with 58 and Shoreham with 75.

More importantly than the actual number there are not any major outstanding enforcement items.

(Slide.)

Let me briefly describe two reactor construction team inspections that have been conducted at Unit II. These inspections provide a more indepth assessment of construction quality. We use a multi-disciplinary team.

It conducts a coordinated inspection of parallel ongoing functional areas to examine program effectiveness.

. The first inspection was conducted in April of 1983. We identified a weakness in the design control as a result of that inspection. There were no other major findings.

The second steam inspection was conducted in March of '85. While that inspection identified no major hardware problems there were some lingering problems which were identified persisting in the engineering and construction interface for electrical activities. This conclusion was reached during the inspection when certain capability and electrical termination procedures were conducted improperly.

However, that team inspection did note that the licensee had made significant overall progress in improving engineering and construction interface problems.

Could I have the third slide, please?

(Slide.)

We talked about independent and nondestructive examinations. I assume the ACRS committee knows that we have an independent MDE mobile lab in Region I. We conducted three independent nondestructive evaluations and verifications using that mobile lab.

The first one was conducted in July 1981 at the

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B&W plant in Mt. Vernon, Indiana. Their examinations were conducted on selected wells and base materials on the neutron shield tank, and included things such as thickness measurements.

We examined the laminations, magnetic particle and radiographic examinations. All results were acceptable. The radiographic examinations did cover some minor conclusions on two welds. Those were later resolved as acceptable.

The second and third inspections were conducted at the site in September and October 1984 respectively. Both of these inspections were conducted to provide representative samples of piping systems, components, pipe sizes, materials and ASME class one, two and three.

Shop and field welds. The items selected were previously accepted by the licensee based on vendor shelf and/or on site QA/QC records. The results of both of those inspections showed good correlation with the licensee's determinations. All items were found acceptable and especially noteworthy were the excellent records that we found on site by the licensee. Not only were they in good shape but they were readily retrievable.

(Slide.)

Let me mention briefly construction deficiency reports, or as they're also know, 5055E reports. They are

required to be reported to NRC. In the case of Duqesne Light, I've devoted appropriate attention to this reporting activity. It's not responsive to our requirements. I have a couple of examples on the slide.

Overall, the licensee, through September '85, had reported 62 significant deficiencies of which 48 were resolved either by fixing or just by analysis. Fourteen remain outstanding. Actually, some of those may be closed as far as the licensee is concerned; we haven't finished our inspection on those.

I think, in the interest of time, I'm going to skip through the examples on CDR's. They're in the report that was supplied to you.

Let me briefly mention allegations. Allegations received by NRC's Region I addressed both safety-related and nonsafety-related areas. When we receive an allegation, each one of them is reviewed by regional management. They decide on appropriate followups based on the potential safety significance.

Region I records for Beaver Valley II indicate that we've only had seven allegations over the life of the project. Of those seven, one allegation was substantiated while the other six could not be substantiated. There are currently no open allegations. We think the low number of allegations can be attributed to several factors, not the

least of which is the high regard for quality by the construction inspection and other project personnel.

We did confirm in our March 1985 team inspection, by interviewing approximately 20 QC and another 20 craft personnel selected at random, that those workers thought that it was a quality job, a quality project and maybe more importantly they did not feel inhibited from reporting quality concerns. And they thought they could get quality concerns resolved through their management, without reporting them to NRC.

And that's probably one of the reasons why NRC hasn't received very many.

Let me go on to slide 5, if I might.

(Slide.)

Let's talk a bit about SALP. The SALP program encompasses an integrated staff review of licensing performance over a 12-18 month cycle. We perform analysis of NRC-observed strong points and weaknesses of the licensee, construction and quality assurance efforts. This process serves to identify those areas which both licensee management and NRC should devote greater attention to, and to which greater NRC resources should be allocated. Or, conversely, if the area is going well, perhaps lesser NRC resources allocated.

It's prepared in Region I with input from

resident inspectors, regional specialist inspectors, NRR staff and regional management.

Since the start of the SALP program, we have addressed the performance at Beaver Valley II five times. The first three evaluations assessed the licensee performance from time periods from March 1, 1980 through November 30, 1982.

The licensee performance during this period was category one or category two in all functional areas with one exception. There was one category three in on site storage functional area. However, in the fourth SALP, NRC identified a decline in the overall licensee performance. The licensee's performance in three functional areas, namely, piping systems and supports, electrical power supply and distribution and engineering construction interface, was given a category three rating.

Significant weaknesses in the design and engineering effort were of most concern to NRC since it seemed to represent a root cause of many of the most significant project problems.

The design documents were not receiving adequate destructibility review, as evidenced by their frequent failure to contain sufficient or clear enough information for field use before they were sent to the field for implementation.

A large number of design changes and reinspections of piping supports were necessary because of such deficiencies. The licensee responded to these NRC concerns by taking various initiatives.

An engineering confirmation program was initiated. Also, organizational changes were made. There was a formation of constructability review groups to review drawings to make sure the information was clear and unambiguous, consistent with the criteria usable by construction and QC personnel in the field.

And there is a redrafting of drawings of especially complicated drawings, like multiple pipe rack drawings.

The fifth SALP is the most recent and it is assessed licensee performance through March 31, 1985. Improvement was shown in all three functional areas that received category three ratings in the previous SALP.

Those licensee initiatives I was just discussing implemented during that assessment period were effective in improving performance in the previously identified category three areas.

Furthermore, the licensee developed project mechanical and electrical plans to provide coordinated solutions to the significant mechanical and electrical items not yet completed.

As I said, it was evident that there was a need for such plans, especially in the electrical instrumentation area, because there were some lingering problems still evident at that time.

Since that SALP conc ıded on March 31, 1985, we've had several meetings w.ch the licensee to discuss their plans in progress in resolving problems, mainly in the electrical instrumentation area; problems such as cable support, separation, internal wiring, base plat shims, and so forth.

Region I has concluded that licensee plans in progress to date demonstrate that resolution of existing deficiencies such as the ones I just mentioned are proceeding in an acceptable manner.

(Slide.)

Let me summarize now. In summary, the Region I staff concludes that the overall licensee performance during construction for Beaver Valley Unit II has been satisfactory and combined with NRC requirements and safety objectives has been acceptable.

The basis for this conclusion is as follows:

There is positive corporate involvement in the construction project activities. Region I has confidence in the construction quality of Beaver Valley Unit II. And this conclusion is confirmed by the good results from three

inspections using the NDE mobile van, very few allegations regarding quality, and no significant problems identified in two regional team inspections.

There is a high level of licensee management attention to NRC concerns and the licensee and their major contractors have been very responsive.

These concerns are actively pursued to satisfactory resolution and as an example of that, this was evidenced by the licensee when various problems were identified, as I discussed. And for a SALP period specifically the licensee and their architect-engineer made constructive organizational changes and formed several new groups, such as the integrated construction support group, the constructability review teams; also, they blended two new programs into the project -- the quality improvement management program and the engineering confirmation program.

Overall, Region I finds that the construction program quality at Beaver Valley Unit II is acceptable. That does not mean that there have not been or will not be problems to be solved. While some electrical instrumentation problems must be resolved, the project electrical plan is in place to resolve these problems and we're satisfied with the progress under that electrical plan to date.

We will continue to monitor implementation of that electrical plan and of course we've already started, we will continue with the inspection in progress in the preop test program to ensure that the pressures of achieving in April '87 initial fuel load date are not allowed to adversely affec: the project quality.

That s the sum of my prepared remarks.

MR. WARD: Okay. Any questions?

Maybe...if we could have them only if they're very essential?

MR. MICHELSON: Just some information. Are you doing the Appendix R compliance inspections?

MR. TRIPP: We will be. We haven't done it yet.

MR. MICHELSON: Thank you.

MR. WARD: Charlie, do you have anything else? Is that all the staff presentation?

MR. NOVAK: That's correct.

MR. WARD: Now, there was scheduled a closed presentation for security. Is there anything new or unique therein that we need to hear about, or did you hear that at the subcommittee?

DR. WYLIE: No. We did not.

MR. WARD: Well, we didn't really see in the schedule enough time for all of this.

MR. CURTIS: Gene Curtis. We have one question.

We would like to get exactly Mr. Michelson's question.

MR. WARD: Could we hold that for a minute and decide whether we want to have the sabotage presentation or not, Charlie?

DR. WYLIE: I'll ask the members if they want to hear it.

MR. MICHELSON: I was a little interested in finding out the degree of protection to this alternate shutdown board, since apparently I can take over at least partial control of the plant from it.

DR. WYLIE: Maybe you just ought to ask questions.

DR. WARD: We'll have to close the meeting.

MR. MICHELSON: I asked the question before.

MR. WARD: Did you get an answer?

MR. MICHELSON: No, because it was said it was going to be covered later.

MR. WYLIE: We said that the condition would be enunciated in the control room.

MR. MICHELSON: That didn't leave me with much comfort at all, to think that the operator might know that somebody invaded. What kind of things can you do from there, and how quickly can you do them?

I don't know when you want to ask those

questions.

MR. WARD: You've asked it. Can it be answered in an open session?

MR. LUKEHART: Sir, I'm John Lukehart, Director of Security at Beaver Valley. I think that can be answered in open session. I don't have any problem with that.

I can anticipate any problem. The alternate and emergency shutdown panels are located in vital areas. The vital areas at Beaver Valley, because of the complexity and the sophistication I should say of the security computer system, we are able to restrict access to those vital areas to those persons predesignated only for those areas at predesignated times. And only when authorized by supervision above that particular person. And it is not automatically granted to all people in the plant.

For example, maintenance people have certain areas they can go to routinely and certain areas they can't. So since those panels are located in vital areas and they are tightly controlled, I don't anticipate any problems with activities at those panels.

MR. MICHELSON: You don't contemplate an inside then? Because he has the access. You gave it to him by definition.

MR. LUKEHART: Yes, sir, but that access has been granted to people who have demonstrated trustworthiness at

that plant, and access has been granted. It's not something that they can take on their own. It has been granted.

MR. MICHELSON: Let me ask you a different question to save some time. Is this panel in a sealed room or is it inside of a chain-link fenced area? I notice it was in a pipechase area of some sort. But how is the panel protected from people that are walking by?

MR. LUKEHART: Let's see, the emergency panel is in a separate room.

MR. MICHELSON: I'm talking now about the alternate.

MR. LUKEHART: It's in a separate room.

MR. MICHELSON: It's in a separate room, key-locked and monitored and all that other good stuff?

MR. LUKEHART: Yes, sir.

MR. MICHELSON: Having entered the room, how many relief valves on the primary side and the secondary side can I open if I wish without the control room being able to block me?

MR. LUKEHART: I'll defer that to Operations.

MR. SCHUSTER: Fred Schuster. You're speaking now of the emergency shutdown panel?

MR. MICHELSON: Yes.

MR. SCHUSTER: You have there of course only the one train.

MR. MICHELSON: But how about the relief valves for the entire plant? Since this is a fire protection feature, I think you have to prevent blowdown on the primary side, for instance.

And so I think you have certain control over all the relief valves from that point. I'm not putting words in your mouth.

MR. SCHUSTER: You just have. I believe it's one PORV.

MR. MICHELSON: And that would open the other two PORV's under your scenario and that's okay?

MR. SCHUSTER: Even opening that PORV, the consequences are going to be --

MR. MICHELSON: I'm a little surprised, in case of fire, that you are prepared to blow the primary side down as well. Okay, you can open one PORV on the secondary side; what can you open?

MR. SCHUSTER: You have control of two steam generator atmospheric dump valves.

MR. WARD: Does that answer the question?

MR. MICHELSON: That answers my question.

MR. WARD: Are there any other questions on the sabotage?

(No response.)

MR. WARD: I propose we dispense with that

presentation.

MR. CAREY: I'd like to comment on the question. In case of fire, the first short takes the control away from the control room and the second short does it for the PORV. And to say that we're prepared to do that, I would guess that our operators would respond to that. We certainly haven't designed it.

MR. MICHELSON: This is not the time to pursue it. You don't always...you're talking about getting into the control system itself. We're not out of the powering of the valves. I'm just surprised. I thought most utilities prevented this primary site blowdown in that location; maybe not. I stand corrected if not.

MR. WARD: Let's see. You wanted to answer the question about what? Aux feed?

MR. CURTIS: Yes, the question from Mr. Michelson on the aux feed. We had one question about over-pressurization.

MR. MICHELSON: We said we'd do it at the break. If you want to right now, the problem is very simple. In the unlikely event of a rupture in the auxilliary steam line in the auxilliary feedwater room, how is the pressure relieved?

There are various possible answers, and what are the equilibrium conditions under this relief condition,

assuming that you're unable to isolate because whatever caused the steam line to break also prevented the isolation.

MR. WARD: Any other questions?

Would the licensee like to make any final comment? Or the applicant?

MR. CAREY: I would just like to state that all of the presentations that have been made here today have been made by Duquesne Light Company employees. We believe that we have almost 30 years of nuclear operating experience, and we have a fully-trained and qualified staff, and we believe certainly that should we be granted an operating license, we will be able to successfully and reliably operate Beaver Valley No. II.

MR. WARD: Thank you, Mr. Carey. I guess I'd like to poll the members now. If Mr. Wylie recommends that we write a letter?

DR. WYLIE: Yes. I recommend that we do.

MR. WARD: Mr. Michelson, do you think we can write a letter?

MR. MICHELSON: I only have one reservation and that's on the steam generator overfill situation. And I think a paragraph in there is needed which says we would like to be informed later, when they come up with the solution, and so forth. And it doesn't prevent going to

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power.

MR. WARD: Dr. Okrent?

DR. OKRENT: I think we can write a letter. I agree with that point. And I want to note that they are going to do a seismic system interaction study, and the request has been done on several plants involving the A.C. and D.C. power on the small components, in which they do have margins above the SSE, something a little bit less likely.

Other than that, I'm relying on the pipe experts concerning whether or not it's okay to cope with this leak before a break concept, whether or not we want to see anything there.

MR. WARD: Dr. Carbon?

DR. CARBON: Yes.

MR. WARD: Dr. Kerr?

DR. KERR: Yes.

DR. WARD: Dr. Moeller?

MR. MOELER: Yes.

MR. WARD: Mr. Ebersole?

MR. EBERSOLE: Yes.

MR. WARD: Dr. Lewis.

DR. LEWIS: No problem.

MR. WARD: Dr. Seiss?

DR. SEISS: Yes.

MR. WARD: Dr. Mark?

DR. MARK: Yes.

MR. WARD: Dr. Shewmon?

DR. SHEWMON: Yes.

MR. WARD: Dr. Remick?

DR. REMICK: Yes.

MR. WARD: Mr. Reed?

MR. REED: Yes.

MR. WARD: Mr. Etherington?

MR. ETHERINGTON: I don't have a vote. Yes.

(Laughter.)

MR. WARD: Okay. That ends this agenda item. I would like to thank you gentlemen very, very much for being here.

(Whereupon, at 6:25 p.m., the committee adjourned, to convene in unrecorded session.)

CERTIFICATE OF OFFICIAL REPORTER

This is to certify that the attached proceedings before the UNITED STATES NUCLEAR REGULATORY COMMISSION in the matter of:

NAME OF PROCEEDING: ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

307TH GENERAL MEETING

DOCKET NO.:

PLACE: Washington, D. C.

DATE: Friday, November 8, 1985

were held as herein appears, and that this is the original transcript thereof for the file of the United States Nuclear Regulatory Commission.

(sigt) David L. Hoffman

(TYPED)

DAVID L. HOFFMAN

Official Reporter

Ace-Federal Reporters, Inc.

Reporter's Affiliation

DISCUSSION WITH THE ACRS SUBCOMMITTEE

ON

SAFETY GOAL POLICY

VICTOR STELLO, JR., DEDROGR

NOVEMBER 6, 1985

BASIC CONCLUSIONS FROM STEERING GROUP REPORT

- THE BASIC STRUCTURE OF THE SAFETY GOALS IS SOUND. THEY ARE NOT IN NEED OF RADICAL REVISION.

- THE CORE MELT GUIDELINE SHOULD BE GIVEN NEARLY AS MUCH WEIGHT AS THE INDIVIDUAL AND SOCIETAL RISK DESIGN OBJECTIVES.

- THE ONSITE COSTS OF CORE MELT ACCIDENTS SHOULD BE INCLUDED IN BENEFIT-COST ANALYSES.

- SAFETY GOALS SHOULD NOT BE USED WITHIN A FRAMEWORK OF STRICT ACCEPTANCE OR NONACCEPTANCE CRITERIA FOR REGULATORY DECISIONMAKING.

- THE USE OF SAFETY GOALS CAN STRENGTHEN DECISIONMAKING BY ADDING MORE OBJECTIVITY AND PREDICTABILITY TO THE REGULATORY PROCESS.

OPEN ISSUES IDENTIFIED FROM COMMENTS ON STEERING GROUP REPORT

- CORE MELT GUIDELINE NUMERICAL VALUE
- USE OF MEAN VS. MEDIAN IN CALCULATING CORE-MELT PROBABILITIES
- FACTORS ON BENEFIT SIDE OF BENEFIT-COST GUIDELINES
- USE OF SAFETY GOALS IN DECISIONMAKING
- DISTANCE SELECTED FOR CALCULATION OF INDIVIDUAL PROMPT FATALITY RISK
- DISTANCE SELECTED FOR CALCULATION OF LATENT CANCER RISK
- TREATMENT OF UNCERTAINTIES
- DEVELOPMENT OF A CONTAINMENT PERFORMANCE OBJECTIVE

SAFETY GOAL POLICY

RECENT PROGRESS AND CURRENT STATUS

• STEERING GROUP REPORT	EARLY MAY 85, INFORMATION TRANSMITTED TO COMMISSION
• CONCURRENT NRC MANAGEMENT AND ACRS REVIEW OF STEERING GROUP REPORT.	MAY THRU JULY 85
• ACRS LETTER WITH ADDED COMMENTS	MID JULY 85
• CONTINUED STAFF ANALYSES ON NUMBER OF OPEN ISSUES IDENTIFIED: -NEED FOR IMPROVED INTEGRATION IDENTIFIED (HEALTH EFFECTS, CORE MELT FREQUENCY, BENEFIT-COST ANALYSES)	LATE JULY THRU SEPT. 85
• FUTURE ACTIONS	
-ACRS DISCUSSIONS	NOV/DEC 85
-STAFF PROPOSAL TO COMMISSION	JAN/FEB 86

INTEGRATED SAFETY GOAL DECISION MATRIX

CORE MELT, HEALTH EFFECTS AND COST-BENEFIT)*

Large-Scale Core Melt Frequency (per RY)	Health Effects @0.1%/RY (Individual/Societal)	Cost Benefit ($1,000/p-r + Averted onsite cost)
$<10^{-5}$	Meet both Don't meet one	No fix Fix ($1,000/p-r)
10^{-4} - 10^{-5}	Meet both Don't meet one	Fix ($1,000/p-r + 1 → 0% AOSC) Fix ($1,000/p-r +100% AOSC)
10^{-3} - 10^{-4}	Meet both Don't meet one	Fix ($1,000/p-r + 10 → 1% AOSC) Fix ($1,000/p-r +100% AOSC)
$>10^{-3}$	Meet both Don't meet one	Fix ($1,000/p-r +100% AOSC) Fix (cost no limit)

*ALL VALUES ARE TAKEN AS MEAN VALUES

NRR STAFF PRESENTATION TO THE
ACRS

SUBJECT: BEAVER VALLEY POWER STATION, UNIT 2

DATE: NOVEMBER 8, 1985

PRESENTER: BRAJ K. SINGH

PRESENTER'S TITLE/BRANCH/DIVISION: PROJECT MANAGER,
LICENSING BRANCH NO. 3
DIVISION OF LICENSING

PRESENTER'S NRC TELEPHONE NUMBER: 492-8423

LICENSING OVERVIEW

CONSTRUCTION PERMIT ISSUED	MAY 3, 1974
FSAR DOCKETED	MAY 18, 1983
ENVIRONMENTAL REPORT DOCKETED	MAY 18, 1983
DES ISSUED	DECEMBER 1984
FES ISSUED	SEPTEMBER 1985
SER ISSUED	OCTOBER 1985
FUEL LOAD	APRIL 1987

- 11 OPEN ITEMS
- 44 CONFIRMATORY ITEMS
- 1 LICENSE CONDITION

ITEMS FOR DISCUSSION

1. OPEN ISSUES AND ESTIMATED RESOLUTION DATE

2. SIGNIFICANT BACKFIT ISSUES

3. SIGNIFICANT CONFIRMATORY ISSUES

4. LICENSE CONDITION ITEM

OPEN ISSUES

ISSUE	SER SECTION	ESTIMATED RESOLUTION DATE
1. PRESERVICE/INSERVICE TESTING	3.9.6	12/31/86
2. PUMP AND VALVE LEAK TESTING	3.9.6	3/31/86
3. INADEQUATE CORE COOLING INSTRUMENTATION (ITEM II.F.2 OF NUREG-0737)	4.4.7	3/31/86
4. PRESERVICE/INSERVICE INSPECTION PROGRAM	5.2.4.3, 5.4.2.2, 6.6	12/31/86
5. SAFE AND ALTERNATE SHUTDOWN	9.5.1	12/31/86
6. MANAGEMENT AND ORGANIZATION	13.1	NO RESPONSE FROM APPLICANT
7. CROSS-TRAINING PROGRAM	13.2.1.2	6/30/86
8. EMERGENCY PREPAREDNESS PLAN	13.3.3	12/31/86

ISSUE	SER SECTION	ESTIMATED RESOLUTION DTD.
9. INITIAL TEST PROGRAM	14	3/31/86
10. CONTROL ROOM DESIGN REVIEW	18.1	7/31/86
11. SAFETY PARAMETER DISPLAY SYSTEM	18.2	7/31/86

SIGNIFICANT BACKFIT ISSUES

1. STEAM GENERATOR LEVEL CONTROL AND PROTECTION

2. FIRE SUPPRESSION IN THE CABLE SPREADING ROOM

SIGNIFICANT CONFIRMATORY ISSUES

1. SOIL-STRUCTURE INTERACTION ANALYSIS
2. SEISMIC AND DYNAMIC QUALIFICATION OF MECHANICAL AND ELECTRICAL EQUIPMENT
3. PUMP AND VALVE OPERABILITY ASSURANCE
4. ENVIRONMENTAL QUALIFICATION OF MECHANICAL AND ELECTRICAL EQUIPMENT
5. ANALYSIS OF COMBINED LOCA AND SEISMIC LOADS
6. STEAM GENERATOR TUBE RUPTURE
7. QUALITY ASSURANCE PROGRAM

LICENSE CONDITION ITEM

LICENSE CONDITION	SER SECTION
(1) EMERGENCY RESPONSE CAPABILITY, RG 1.97, REV. 2 REQUIREMENTS	7.5.2.1

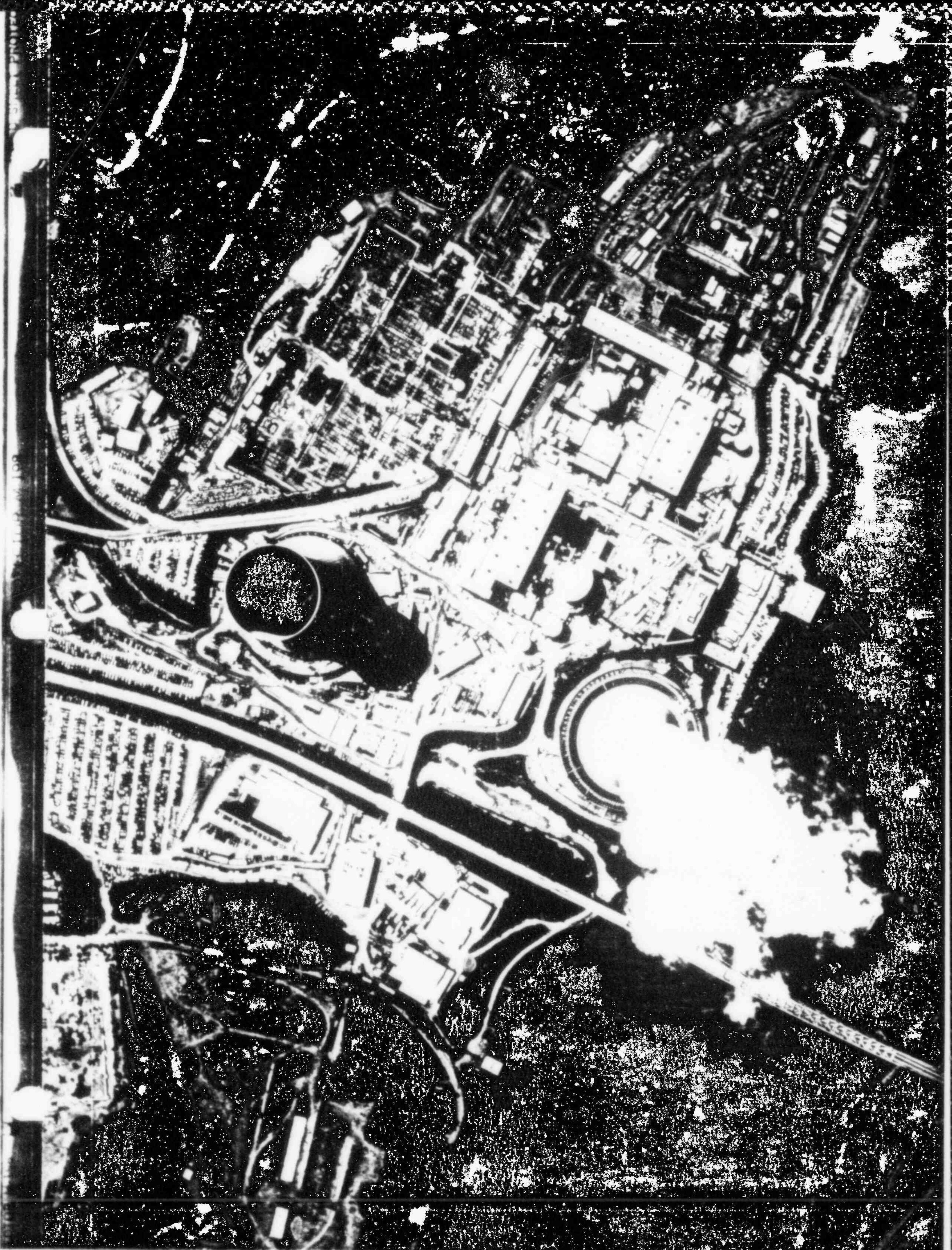
ADVISORY COMMITTEE
ON
REACTOR SAFEGUARDS

Full Committee Meeting

November 8, 1985

BEAVER VALLEY POWER STATION UNIT 2

Duquesne Light



A G E N D A
BEAVER VALLEY UNIT NO. 2
PITTSBURGH, PA
NOVEMBER 8, 1985

2:30 p.m.	Subcommittee Report	C. Wylie, Chairman ACRS Subcommittee
	APPLICANT PRESENTATION	
2:40 p.m.	Overview of Plant Layout	J. J. Carey
2:45 p.m.	Design Differences Between Units 1 & 2	R. E. Martin
2:50 p.m.	Construction Status and Plant Startup Schedule	R. J. Swiderski
	NRC STAFF PRESENTATION	
2:55 p.m.	Major Differing Technical Issues and Schedule for Resolution	
3:00 p.m.	Significant Confirmatory Issues and Licensing Conditions	
3:10 p.m.	Backfit Items and Resolution	
3:20 p.m.	Construction Experience	
3:35 p.m.	******* BREAK *******	
	APPLICANT PRESENTATION	
	Organization and Management	
3:45 p.m.	o Management Philosophy	J. J. Carey
3:50 p.m.	o Corporate & Nuclear Organization	J. D. Sieber
3:55 p.m.	o Plant Staffing	T. D. Jones
4:05 p.m.	Emergency Operating Procedures	F. D. Schuster
4:10 p.m.	Quality Assurance	C. E. Ewing
4:20 p.m.	Training	T. W. Burns
4:35 p.m.	Emergency/Alternate Shutdown Panels	E. T. Eilmann
4:40 p.m.	Station Blackout	K. D. Grada

AGENDA
BEAVER VALLEY UNIT NO. 2
PITTSBURGH, PA
NOVEMBER 8, 1985

(continued)

4:50 p.m.	Alternate Pipe Rupture Protection	J. A. Hultz
5:00 p.m.	Prevention of Sabotage	J. H. Lukehart
5:20 p.m.	Discussion	ACRS
5:30 p.m.	******* ADJOURN *******	

Duquesne Light

J.J. CAREY

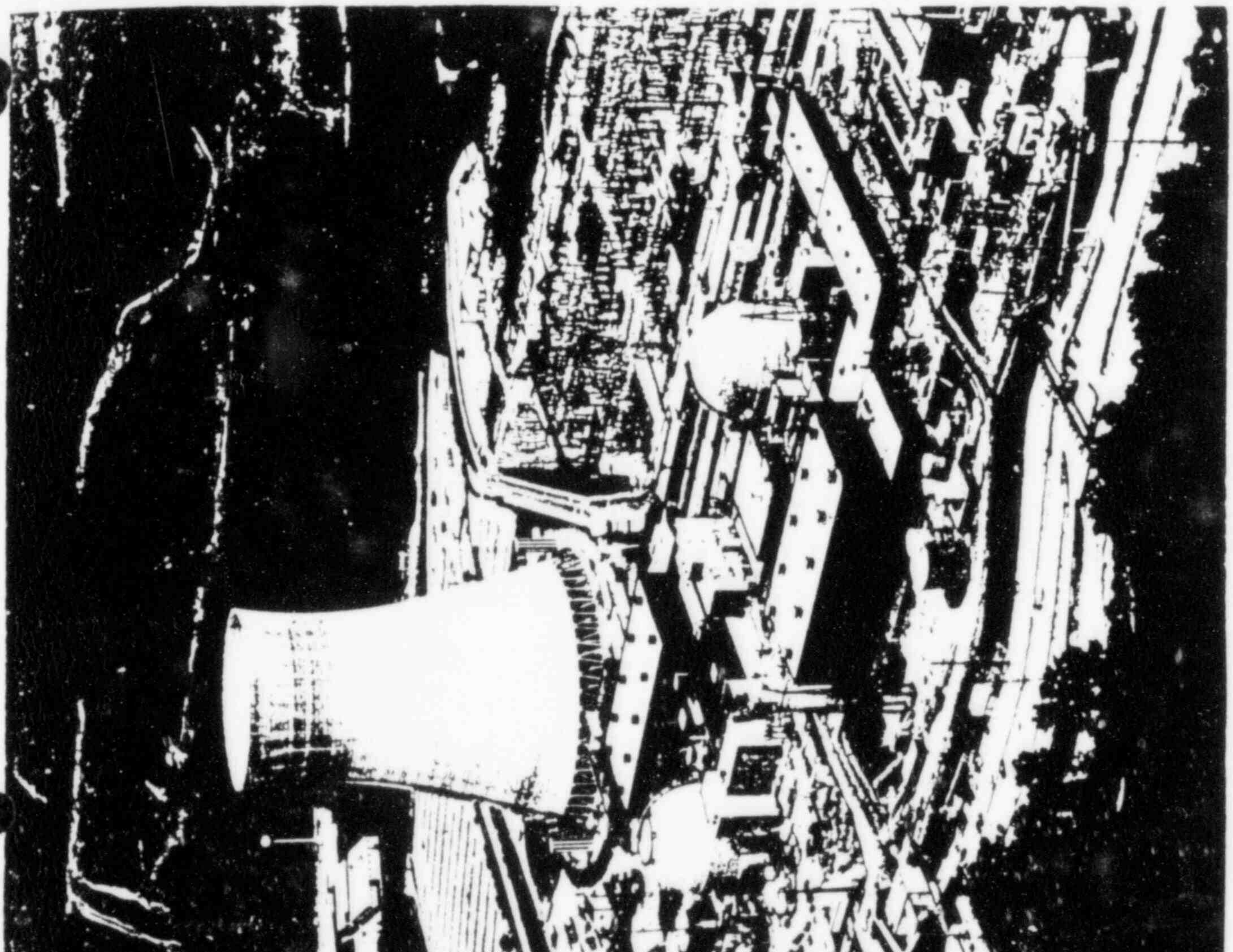
VICE PRESIDENT

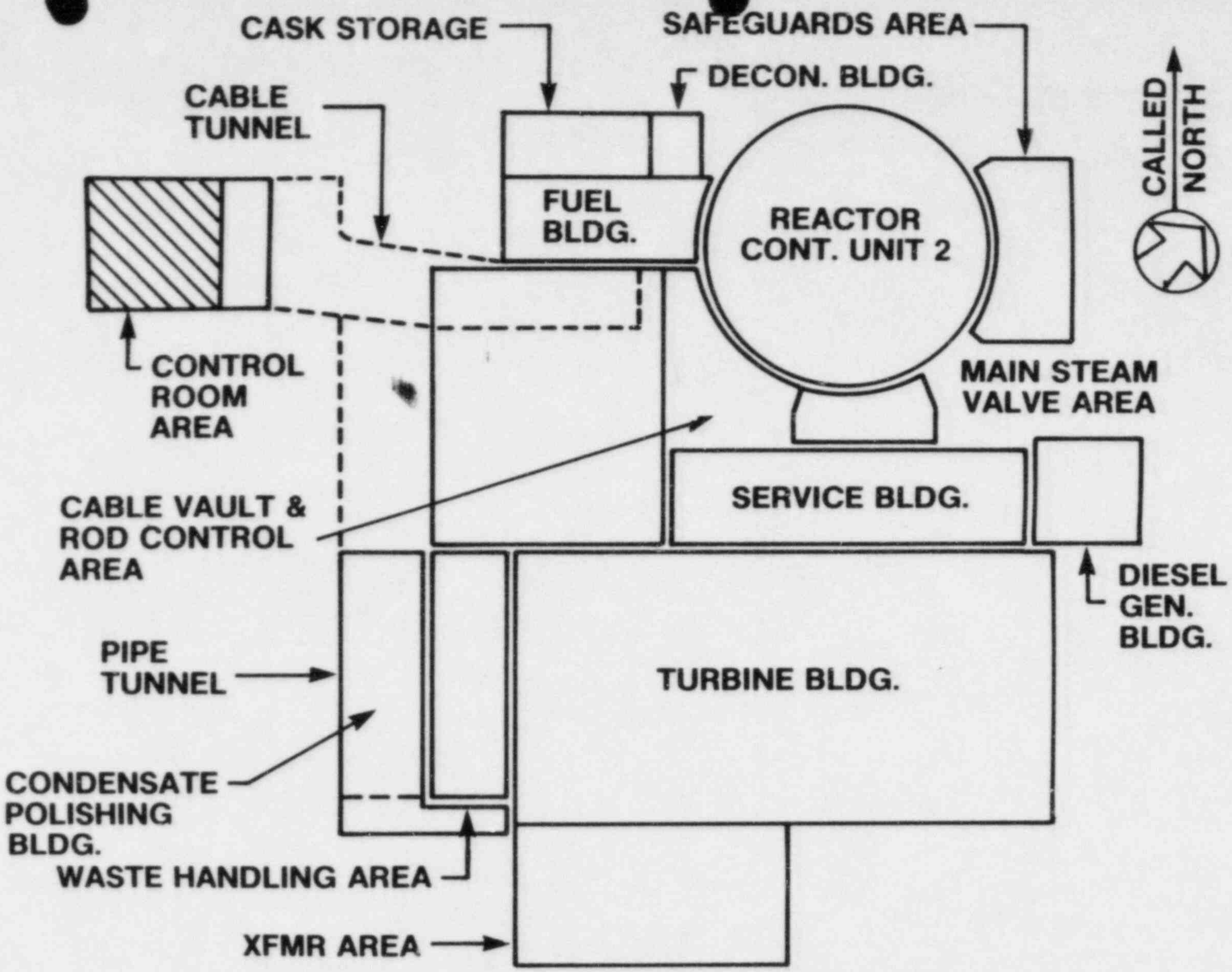
NUCLEAR GROUP

SITE CHARACTERISTICS

OWNERSHIP OF BEAVER VALLEY UNIT 2

COMPANY	SHARE
OHIO EDISON CO.	41.88%
CLEVELAND ELECTRIC ILLUMINATING CO.	24.47%
TOLEDO EDISON CO.	19.91%
DUQUESNE LIGHT CO.	13.74%





BVPS UNIT 2 PLAN

Duquesne Light

R. E. MARTIN

ENGINEERING

MANAGER

DESIGN DIFFERENCES

BV#1 vs BV#2
MAJOR DIFFERENCES

- START UP FEED PUMP
- ALTERNATE SHUT DOWN PANEL
- APPROACH TO COLD SHUTDOWN
- FULL FLOW CONDENSATE DEMINERALIZER
- NO BORON INJECTION TANK
- CONTINUOUS AUXILIARY BUILDING EXHAUST FILTRATION

Duquesne Light

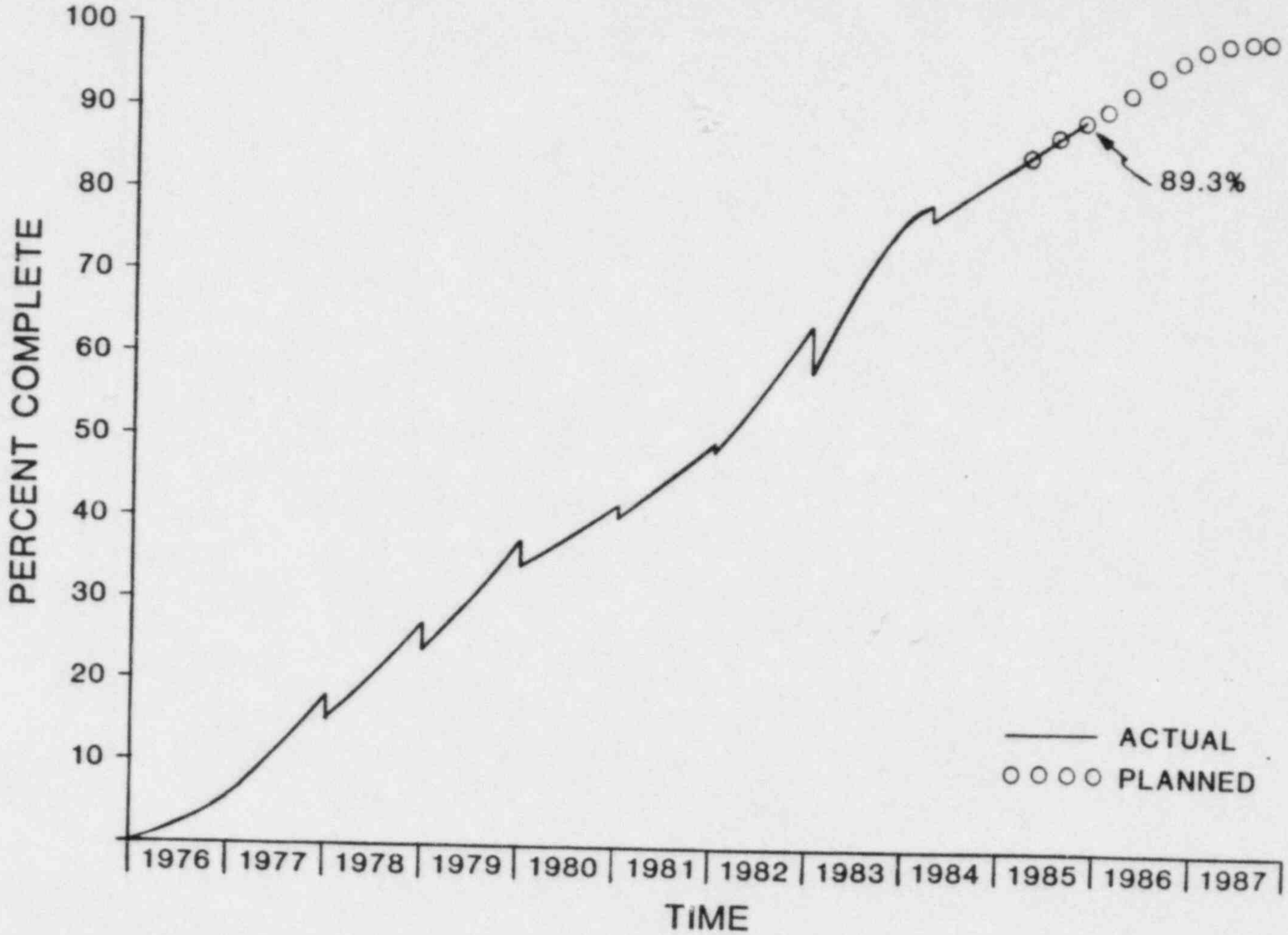
R.J. SWIDERSKI

MANAGER

NUCLEAR CONSTRUCTION

PLANT START-UP

BEAVER VALLEY POWER STATION - UNIT 2
CONSTRUCTION PROGRESS AS OF SEPTEMBER 30, 1985



BEAVER VALLEY - UNIT 2
BUILDING/AREA

BUILDING	BUILDING % COMPLETE
REACTOR	87.2%
TURBINE	91.9%
CONDENSATE POLISHING	90.2%
YARD	87.5%
COOLING TOWER PUMPHOUSE	94.2%
AUXILIARY	91.8%
MAIN STEAM & CABLE VAULT	88.6%
ESF	85.8%
FUEL & DECONTAMINATION	87.6%
WASTE HANDLING	83.3%
CONTROL	83.0%
DIESEL GENERATOR	89.7%
SERVICE	91.3%

NOTE: DATA IS THRU SEPTEMBER 30, 1985

BEAVER VALLEY POWER STATION - UNIT 2
PROJECT MILESTONES SCHEDULE

• JUL 1985	PULL CONDENSER VACUUM
• DEC 1985	STEAM GENERATOR HYDRO
• MAR 1986	REACTOR COOLANT SYSTEM HYDRO
• OCT 1986	HOT FUNCTIONAL TESTING
• 30 APR 1987	FUEL LOAD

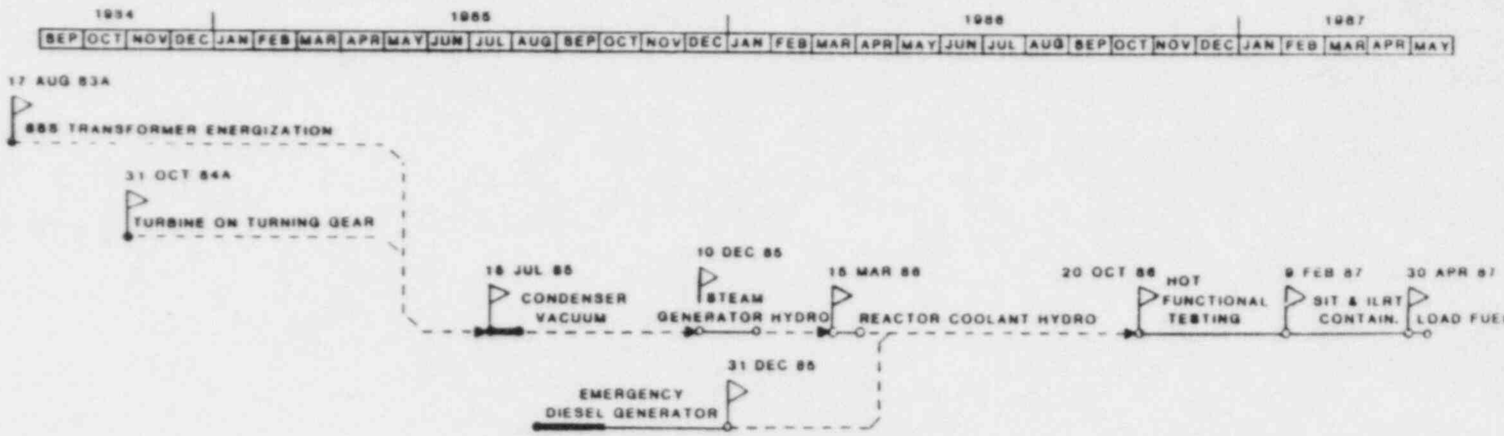
ADDITIONAL SLIDES

MECHANICAL COMMODITIES

INSTALLATION STATUS AS OF SEPTEMBER 30, 1985

COMMODITY	UNIT	ESTIMATE AT COMPLETION (QUANTITY)	ACTUAL TO DATE (QUANTITY)	PERCENT COMPLETE
SMALL BORE PIPE	LF	189,000	170,134	90%
SMALL BORE HANGERS	EA	24,000	19,469	81%
LARGE BORE PIPE	LF	191,150	190,880	99%
LARGE BORE HANGERS	EA	12,300	11,674	95%
INSTRUMENTS	EA	3150	2023	64%
SEISMIC INSTRUMENT SUPPORTS	EA	10,100	6,359	63%
STAINLESS STEEL TUBING	LF	75,000	63,817	85%
COPPER TUBING	LF	43,000	34,564	80%

ELECTRICAL COMMODITIES INSTALLATION STATUS AS OF SEPTEMBER 30, 1985				
COMMODITY	UNIT	ESTIMATE AT COMPLETION (QUANTITY)	ACTUAL TO DATE (QUANTITY)	PERCENT COMPLETE
CONDUIT	LF	738,600	640,783	87%
CONTROL & INSTRUMENTION CABLE	LF	5,040,800	4,120,995	82%
POWER SERVICE CABLE	LF	813,300	615,237	76%
CABLE TRAY	LF	65,830	60,353	92%



BEAVER VALLEY POWER STATION - UNIT 2
PROJECT MILESTONES SCHEDULE

Duquesne Light

G. L. BEATTY

LEAD LICENSING ENGINEER

SER ITEMS

Table 1.2 Open issues

Issue		SER section
(1)	Preservice/inservice testing	3.9.6
(2)	Pump and valve leak testing	3.9.6
(3)	Inadequate core cooling instrumentation (Item II.F.2 of NUREG-0737)	4.4.7
(4)	Preservice/inservice inspection program	5.2.4.3, 5.4.2.2, 6.6
(5)	Safe and alternate shutdown	9.5.1
(6)	Management and organization	13.1
(7)	Cross-training program	13.2.1.2
(8)	Emergency preparedness plan	13.3.3
(9)	Initial test program	14
(10)	Control room design review	18.1
(11)	Safety parameter display system	18.2

Table 1.3 Backfit issues

Issue		SER section	Status*
(1)	Snow and ice load	2.3.1	C
(2)	Underestimation of atmospheric dispersion conditions (χ/Q) at exclusion area boundary and consequences of radioactive release	2.3.4, 15.4.8	C
(3)	Potential for flooding from probable maximum precipitation and Peggs Run	2.4.2, 2.4.10	C
(4)	Steam generator level control and protection	7.3.3.12	A
(5)	Motor-operated accumulator isolation valve	8.3.1.12	C
(6)	Spent fuel pool maximum heat load	9.1.3	C
(7)	Fire suppression in the cable spreading room	9.5.1.6	A
(8)	Class 1E power for lighting and communication systems	9.5.2.1	C
(9)	Application of GDC 5 to communication systems	9.5.2.1	C
(10)	Application of GDC 2 and GDC 4 to communication systems	9.5.2	C
(11)	Application of GDC 4 to lighting systems	9.5.3	C
(12)	Illumination levels in excess of SRP criteria	9.5.3	C
(13)	Application of RG 1.26 to areas excluded by RG 1.26	9.5.4-9.5.8	C
(14)	Air dryers for emergency diesel generator	9.5.6	C
(15)	Alarm for rocker arm lube oil reservoir	9.5.7	C
(16)	Diesel lube oil fill procedure	9.5.7	C

*A - Issues were discussed in appeal meetings and resolutions are addressed in the SER.
C - Closed in SER.

Table 1.4 Confirmatory issues

Issue	SER section
(1) Operating procedures for continuous communication links	2.2.2
(2) Differential settlements of buried pipes	2.5.4.5
(3) Internally generated missiles (outside containment)	3.5.1.1
(4) Internally generated missiles (inside containment)	3.5.1.2
(5) Turbine missiles	3.5.1.3
(6) Analysis of pipe-break protection outside containment	3.6.1
(7) FSAR drawings of break locations	3.6.2
(8) Results of jet impingement effects	3.6.2
(9) Soil-structure interaction analysis	3.7.3
(10) Design documentation of ASME Code components	3.9.3.1
(11) Item II.D.1 of NUREG-0737	3.9.3.2
(12) Seismic and dynamic qualification of mechanical and electrical equipment	3.10.1
(13) Pump and valve operability assurance	3.10.2
(14) Environmental qualification of mechanical and electrical equipment	3.11
(15) Peak pellet design basis	4.2.1
(16) Discrepancies in the FSAR	4.2.2
(17) Rod bowing analysis	4.2.3.1(6)
(18) Fuel rod internal pressure	4.2.3.1(8)
(19) Predicted cladding collapse time	4.2.3.2(2)
(20) Use of the square-root-of-the-sum-of-the-squares method for seismic and loss-of-coolant-accident load calculation	4.2.3.3(4)
(21) Analysis of combined loss-of-coolant-accident and seismic loads	4.2.3.3(4)
(22) Natural circulation test	5.4.7.5

Table 1.4 (Continued)

Issue	SER section
(23) Reactor coolant system high point vents	5.4.12
(24) Blowdown mass and energy release analysis methodology	6.2.1.3
(25) Containment sump 50% blockage assumption	6.2.2
(26) Design modification of automatic reactor trip using shunt coil trip attachment	7.2.2.3
(27) Automatic opening of service water system valves MOV 113C and 113D	7.3.3.10
(28) IE Bulletin 80-06 concerns	7.3.3.13
(29) NUREG-0737 Item II.F.1, accident monitoring instrumentation positions	7.5.2.2
(30) Bypass and inoperative status panel	7.5.2.4
(31) Revision of the FSAR--cold leg accumulator motor-operated valve position indication	7.6.2.4
(32) Control system failure caused by malfunctions of common power source or instrument line	7 7.2.3
(33) Confirmatory site visit	
(a) Independence of offsite power circuits between the switchyard and Class 1E system	8.2.2.3
(b) Confirmation of the protective bypass	8.3.1.2
(c) Verification of DG start and load tests	8.3.1.8
(d) DG load capability qualification test	8.3.1.9
(e) Margin qualification test	8.3.1.10
(f) Electrical interconnection between redundant Class 1E buses	8.3.1.13
(g) Verification of electrical independence between power supplies to controls in control room and remote locations	8.3.3.5
(34) Voltage analysis--verification of test results	8.3.1.1
(35) Documentation of description and analysis of compliance with GDC 50	8.3.3.7.1
(36) Completion of plant-specific core damage estimate procedure before fuel load	9.3.2.2
(37) Training program for the operation and maintenance of the diesel generators	9.5.4.1

Table 1.4 (Continued)

Issue	SER section
(38) Vibration of instruments and controls on diesel generators	9.5.4.1
(39) Surveillance of lube oil level in the diesel generator rocker arm lube oil reservoir	9.5.6
(40) Solid waste process control program	11.4.2
(41) TMI Action Plan items	
(a) III.D.1.1	13.5.2
(b) II.K.1.5 and II.K.1.10	15.9.2, 15.9.3
(c) II.K.3.5	15.9.9
(d) II.K.3.17	15.9.11
(e) II.K.3.31	15.9.14
(42) Plant-specific dropped rod analysis	15.4.3
(43) Steam generator tube rupture	15.6.3
(44) Quality assurance program	17.4

Table 1.5 License condition item

License condition	SER section
(1) Emergency response capability, RG 1.97, Rev. 2 requirements	7.5.2.1

Duquesne Light

ORGANIZATION & MANAGEMENT

Duquesne Light

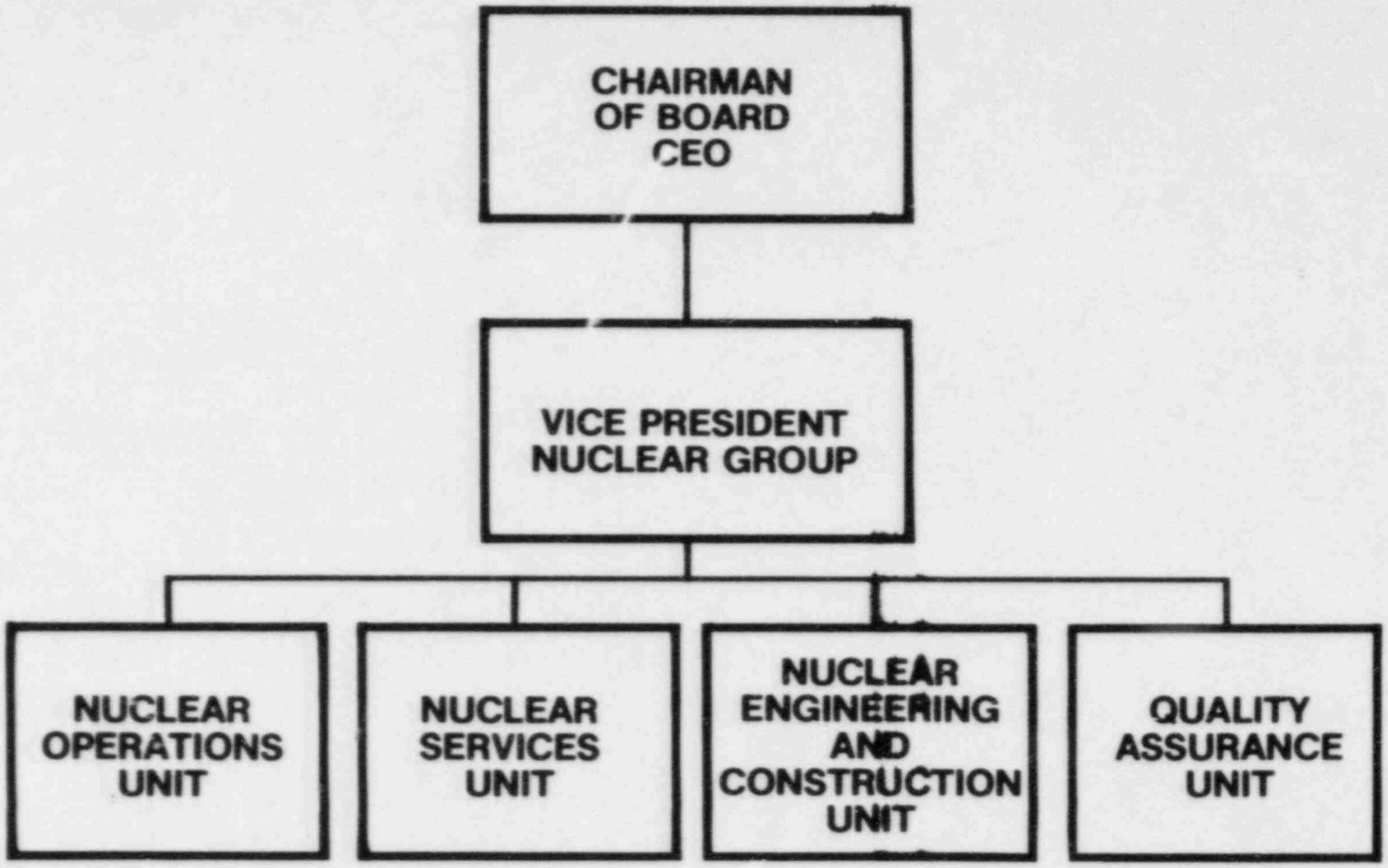
J.J. CAREY

VICE PRESIDENT

NUCLEAR GROUP

MANAGEMENT PHILOSOPHY

OPERATIONAL ORGANIZATION


CHAIRMAN OF BOARD CEO
VICE PRESIDENT NUCLEAR GROUP
NUCLEAR OPERATIONS UNIT
NUCLEAR SERVICES UNIT
NUCLEAR ENGINEERING AND CONSTRUCTION UNIT
QUALITY ASSURANCE UNIT

NUCLEAR OPERATIONS

- PLANT OPERATIONS
- PLANT MAINTENANCE
- PLANT TESTING
- PLANT CHEMISTRY
- OUTAGE PLANNING
- PROCUREMENT AND STORES

NUCLEAR OPERATIONS

- 470 EMPLOYEES
- 67 NRC OPERATING LICENSES
- 183 COLLEGE DEGREES

NUCLEAR ENGINEERING AND CONSTRUCTION UNIT

- 81 EMPLOYEES (140 AUTHORIZED)
- 66 COLLEGE DEGREES

NUCLEAR SERVICES UNIT

- 483 INDIVIDUALS
- 138 COLLEGE DEGREES
- 6 NRC OPERATING LICENSES

QUALITY ASSURANCE UNIT

- 61 EMPLOYEES (100 AUTH)
- 350 CONTRACT PERSONNEL
- 58 COLLEGE DEGREES
- 2 SRO LICENSES

DUQUESNE LIGHT COMPANY

- 28 YEARS NUCLEAR OPERATING EXPERIENCE
- STAFF ON SITE
- AMPLE HUMAN RESOURCES
- MINIMAL DEPENDENCE ON CONSULTANTS

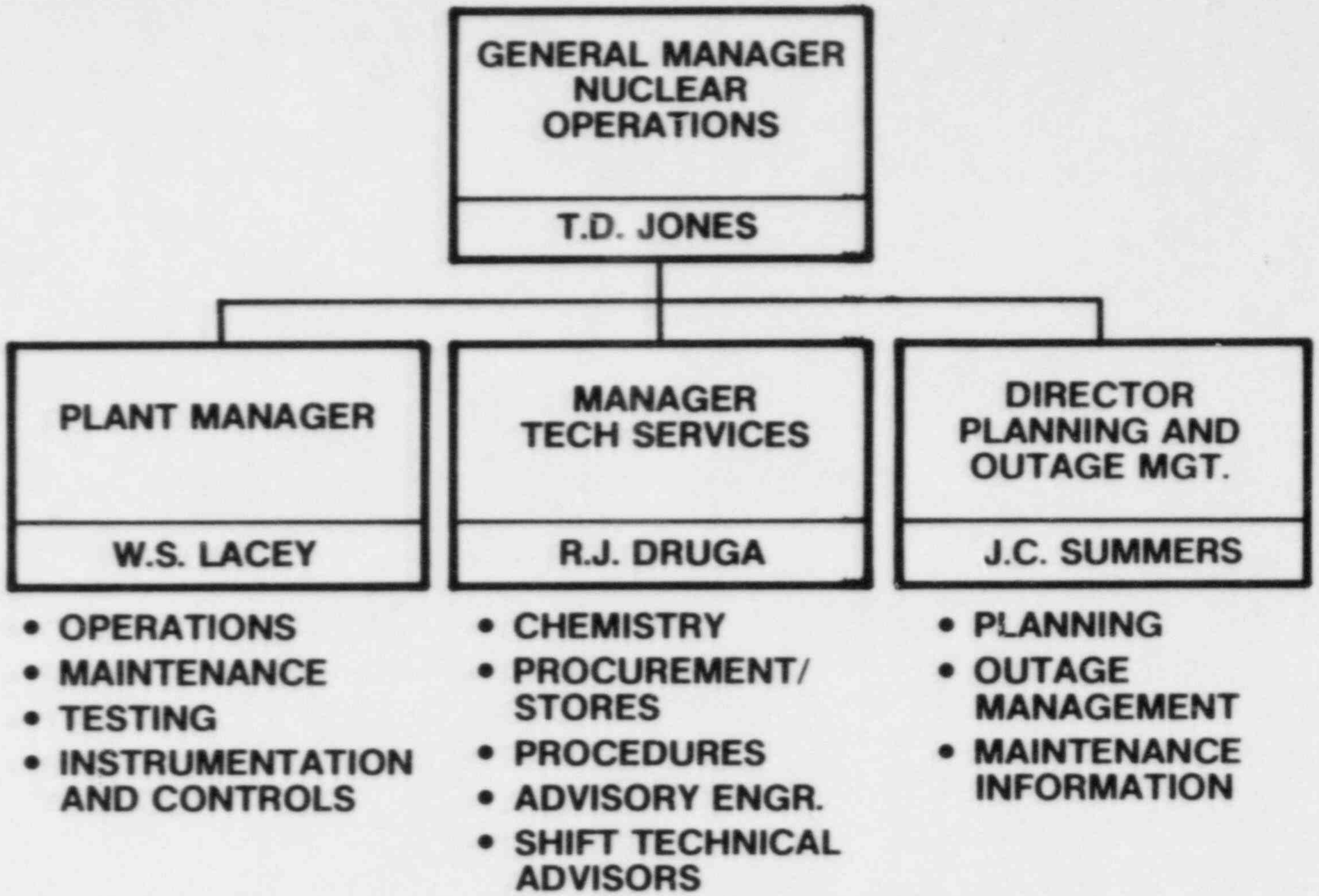
Duquesne Light

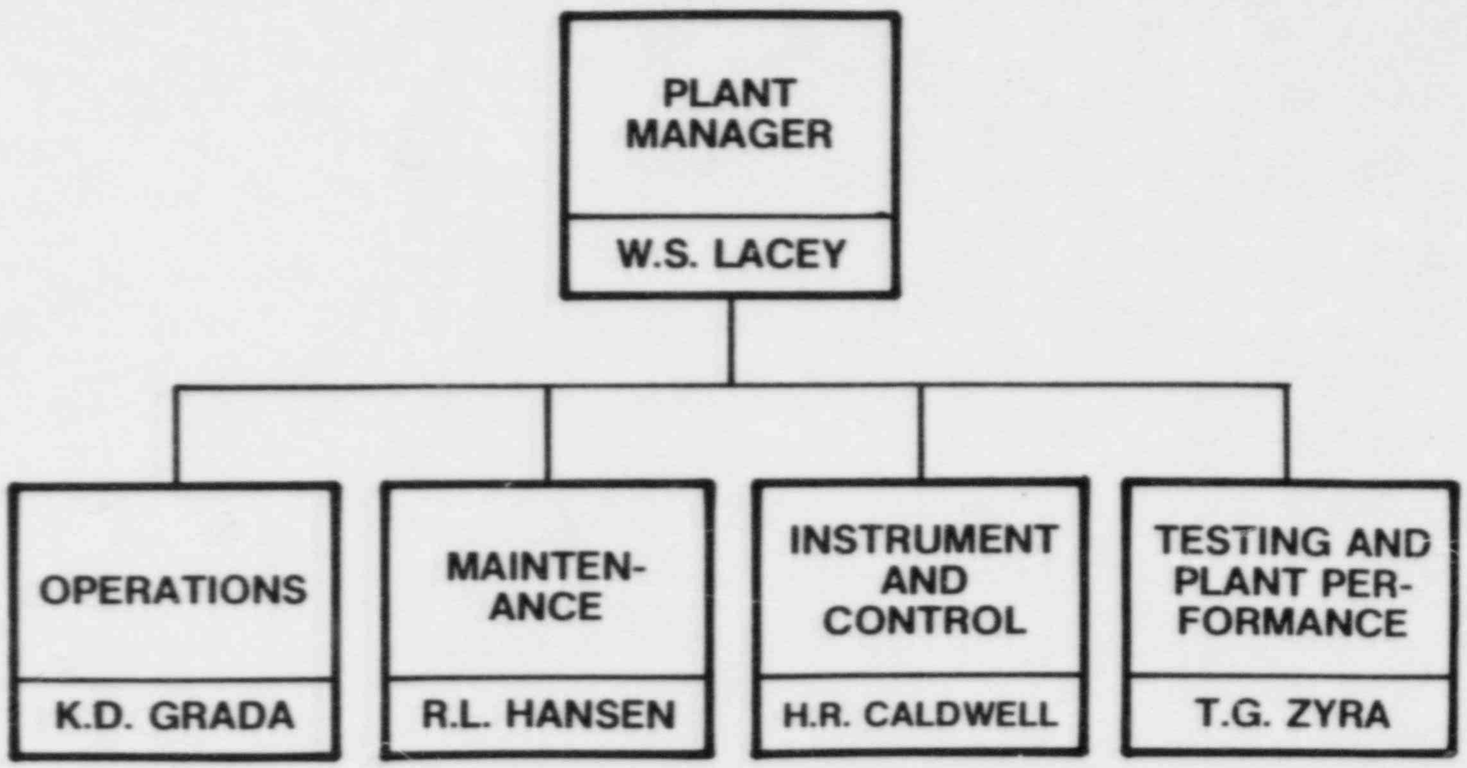
T.D. JONES

GENERAL MANAGER

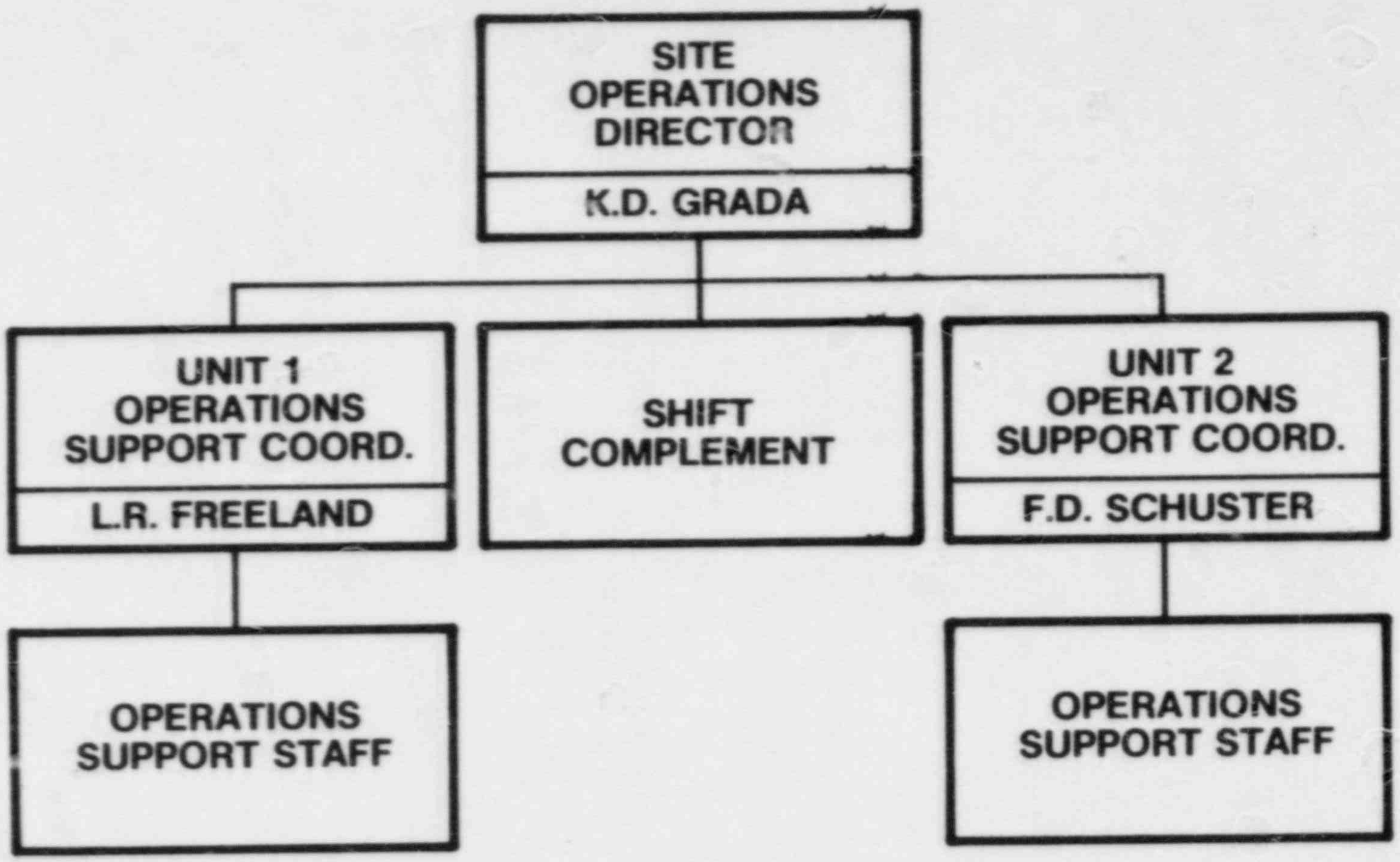
NUCLEAR OPERATIONS

OPERATIONS STAFFING

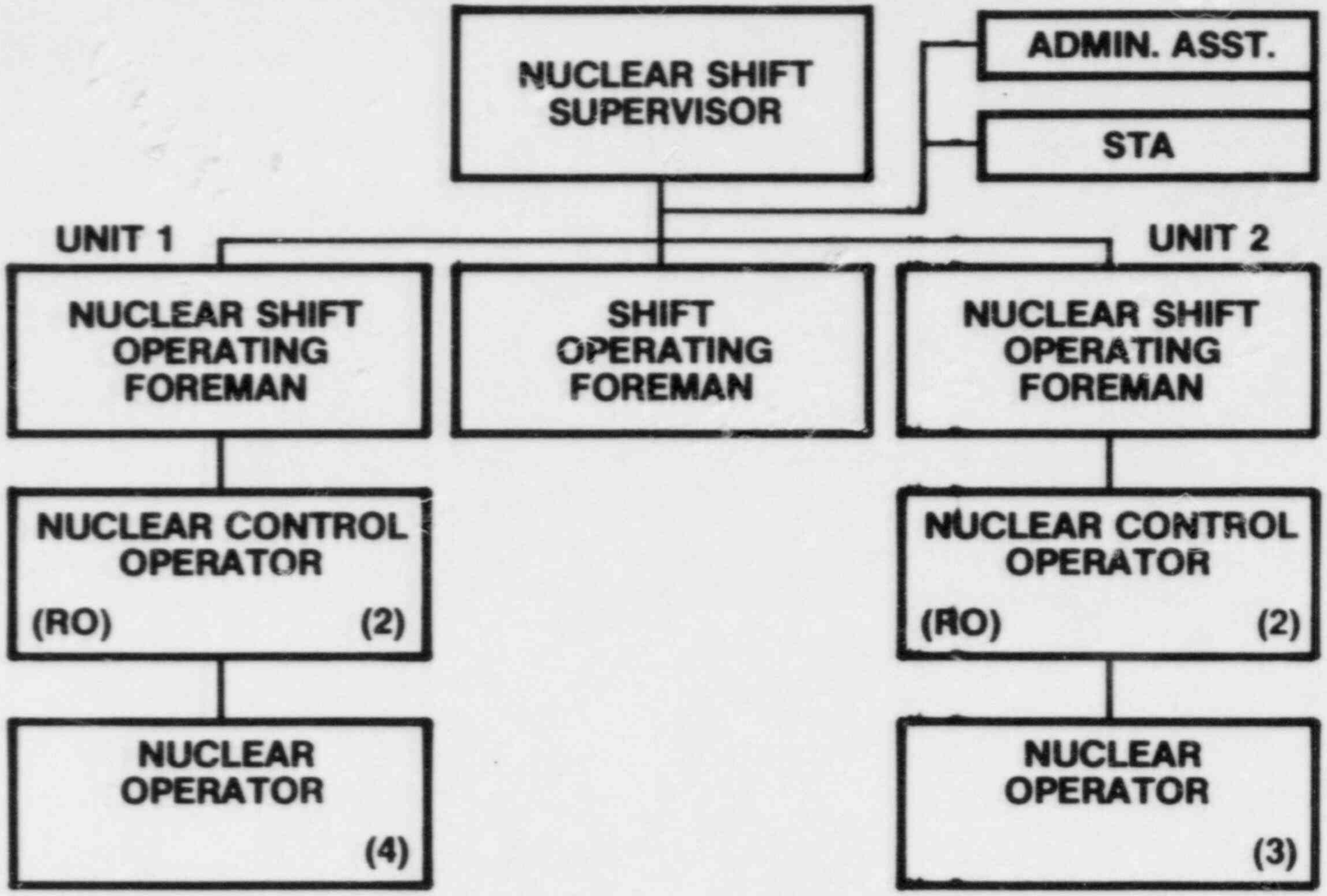

GENERAL MANAGER NUCLEAR OPERATIONS
T.D. JONES
PLANT MANAGER
W.S. LACEY
MANAGER TECH SERVICES
R.J. DRUGA
DIRECTOR PLANNING AND OUTAGE MGT.
J.C. SUMMERS
• OPERATIONS
• MAINTENANCE
• TESTING
• INSTRUMENTATION AND CONTROLS
• CHEMISTRY
• PROCUREMENT/ STORES
• PROCEDURES
• ADVISORY ENGR.
• SHIFT TECHNICAL ADVISORS
• PLANNING
• OUTAGE MANAGEMENT
• MAINTENANCE INFORMATION

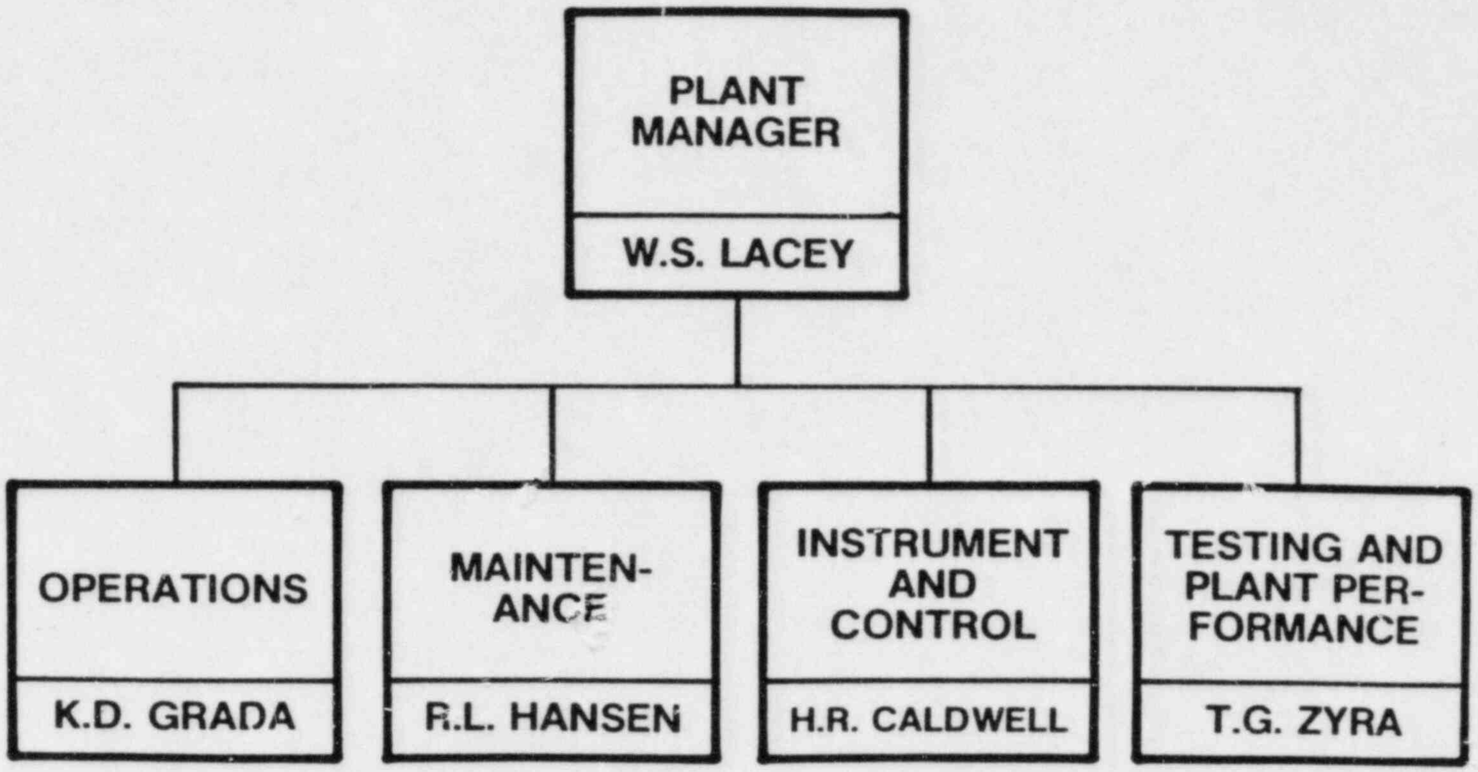

PLANT MANAGER
W.S. LACEY
OPERATIONS
K.D. GRADA
MAINTEN-ANCE
R.L. HANSEN
INSTRUMENT AND CONTROL
H.R. CALDWELL
TESTING AND PLANT PER-FORMANCE
T.G. ZYRA

PLANT OPERATIONS



SHIFT COMPLEMENT




PLANT MANAGER
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MAINTENANCE
R.L. HANSEN
INSTRUMENT AND CONTROL
H.R. CALDWELL
TESTING AND PLANT PERFORMANCE
T.G. ZYRA

PLANT MAINTENANCE

SITE MAINTENANCE DIRECTOR

R.L. HANSEN

SENIOR MECHANICAL MAINTENANCE SUPERVISOR

- 6 ENGINEERS
- 10 FOREMEN
- 72 MECHANICS

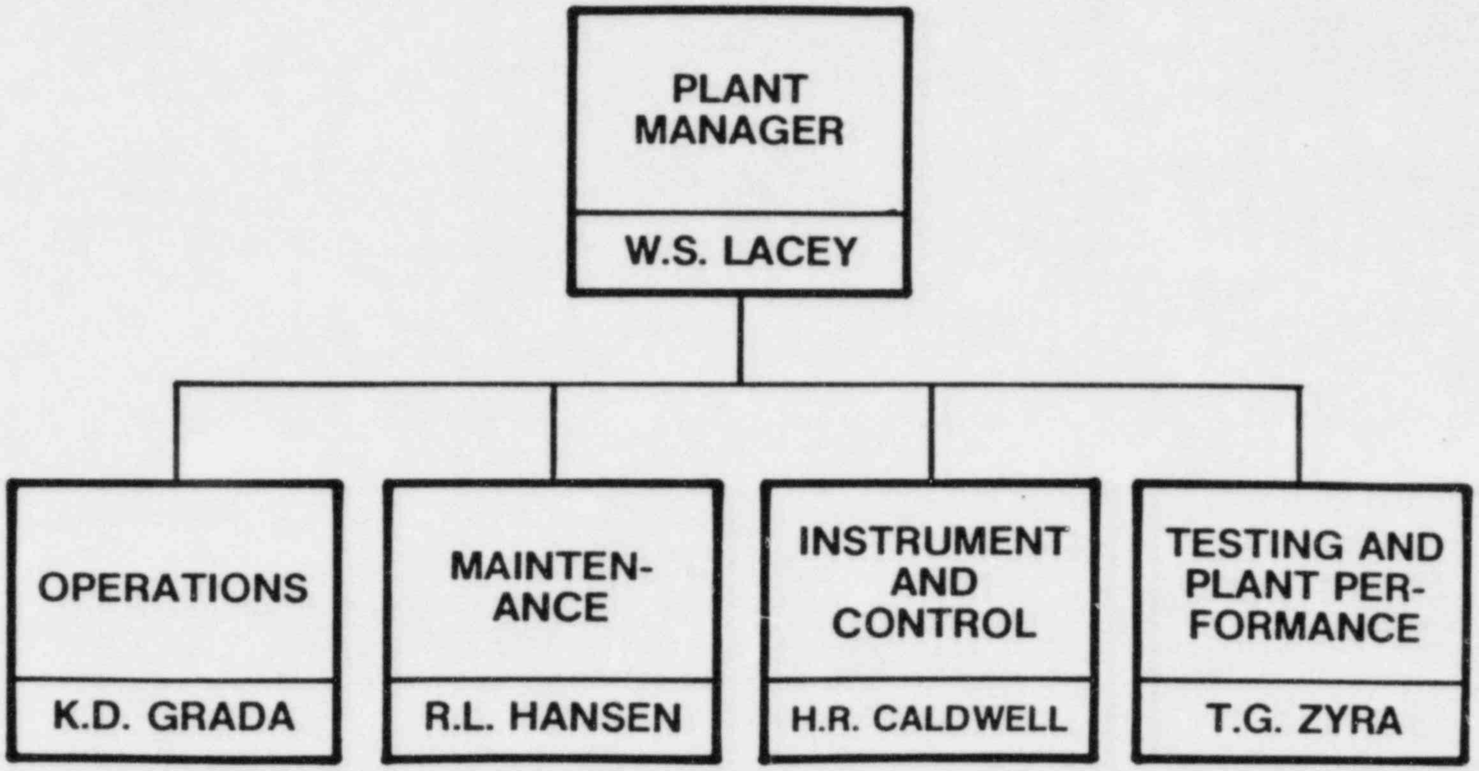
SENIOR ELECTRICAL MAINTENANCE SUPERVISOR

- 5 ENGINEERS
- 5 FOREMEN
- 30 ELEC-TRICIANS

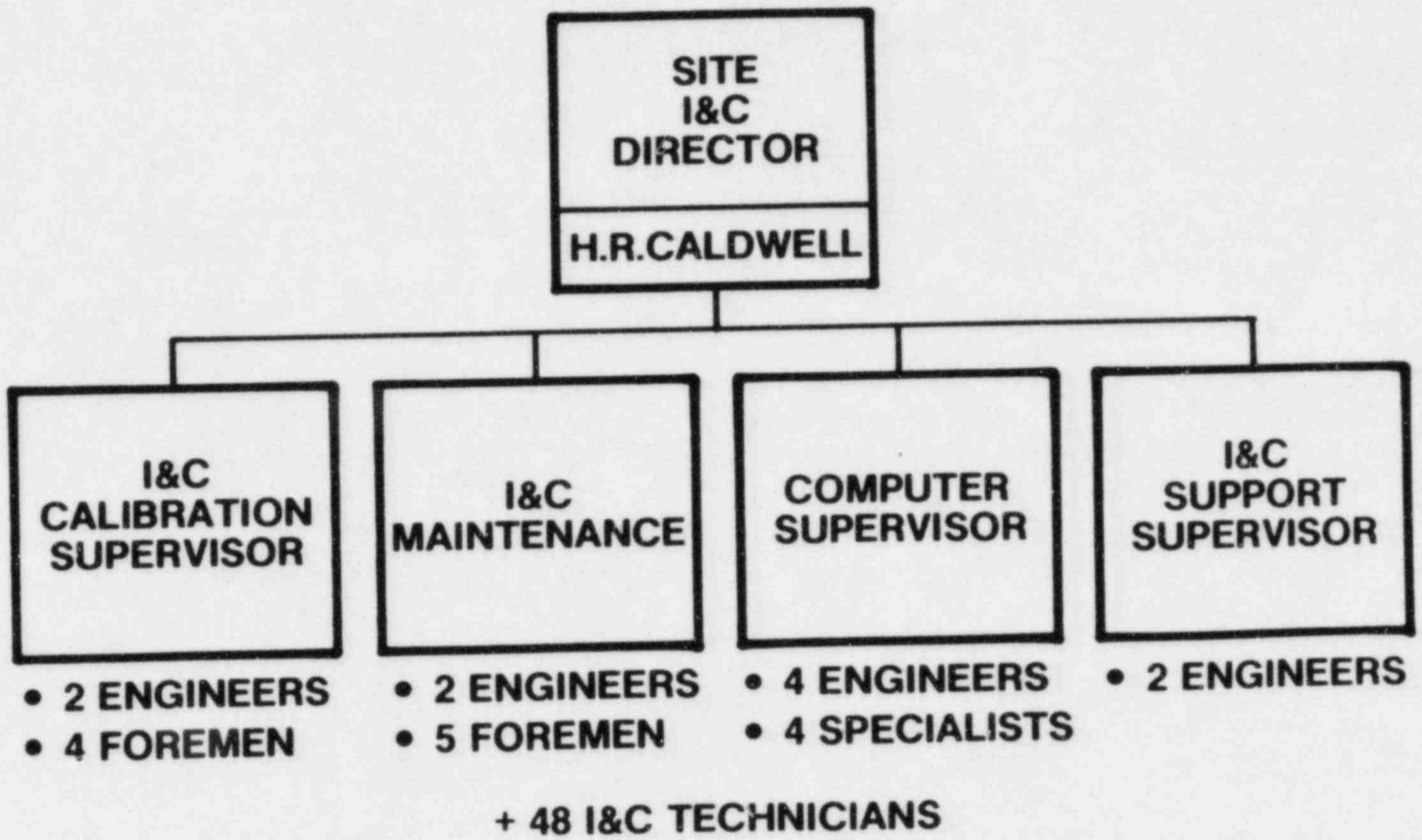
+ 43 LABORERS

MAINTENANCE SUPPORT COORDINATOR

- 3 ENGINEERS


PLANT MANAGER
W.S. LACEY
OPERATIONS
K.D. GRADA
MAINTENANCE
R.L. HANSEN
INSTRUMENT AND CONTROL
H.R. CALDWELL
TESTING AND PLANT PERFORMANCE
T.G. ZYRA

INSTRUMENT & CONTROL



NUCLEAR OPERATIONS

- 470 EMPLOYEES (531 AUTHORIZED)
- 31 SRO LICENSES
- 36 RO LICENSES
- 183 COLLEGE DEGREES

Duquesne Light

FRED SCHUSTER

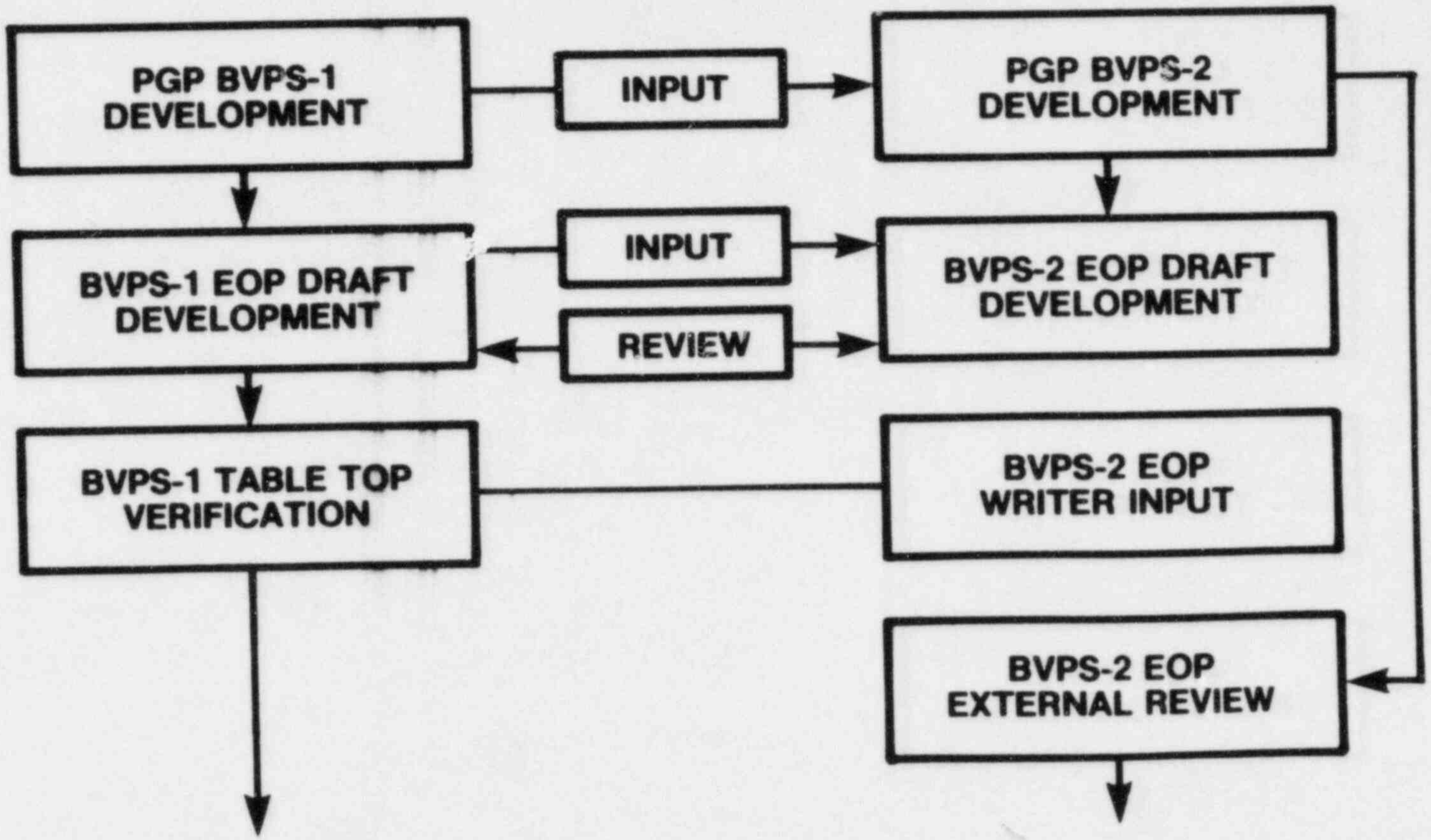
TECHNICAL ADVISORY ENGINEER

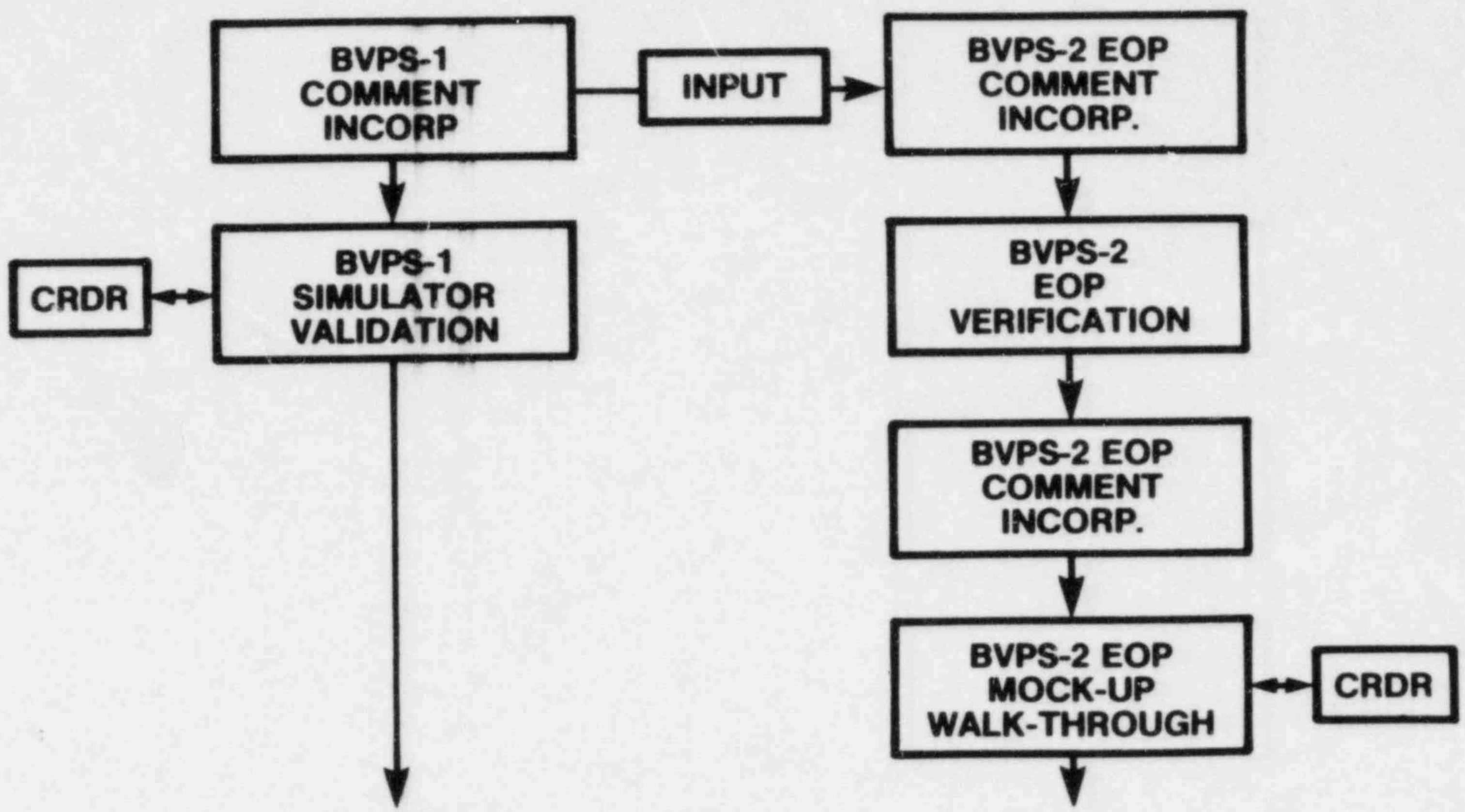
EMERGENCY OPERATING PROCEDURES

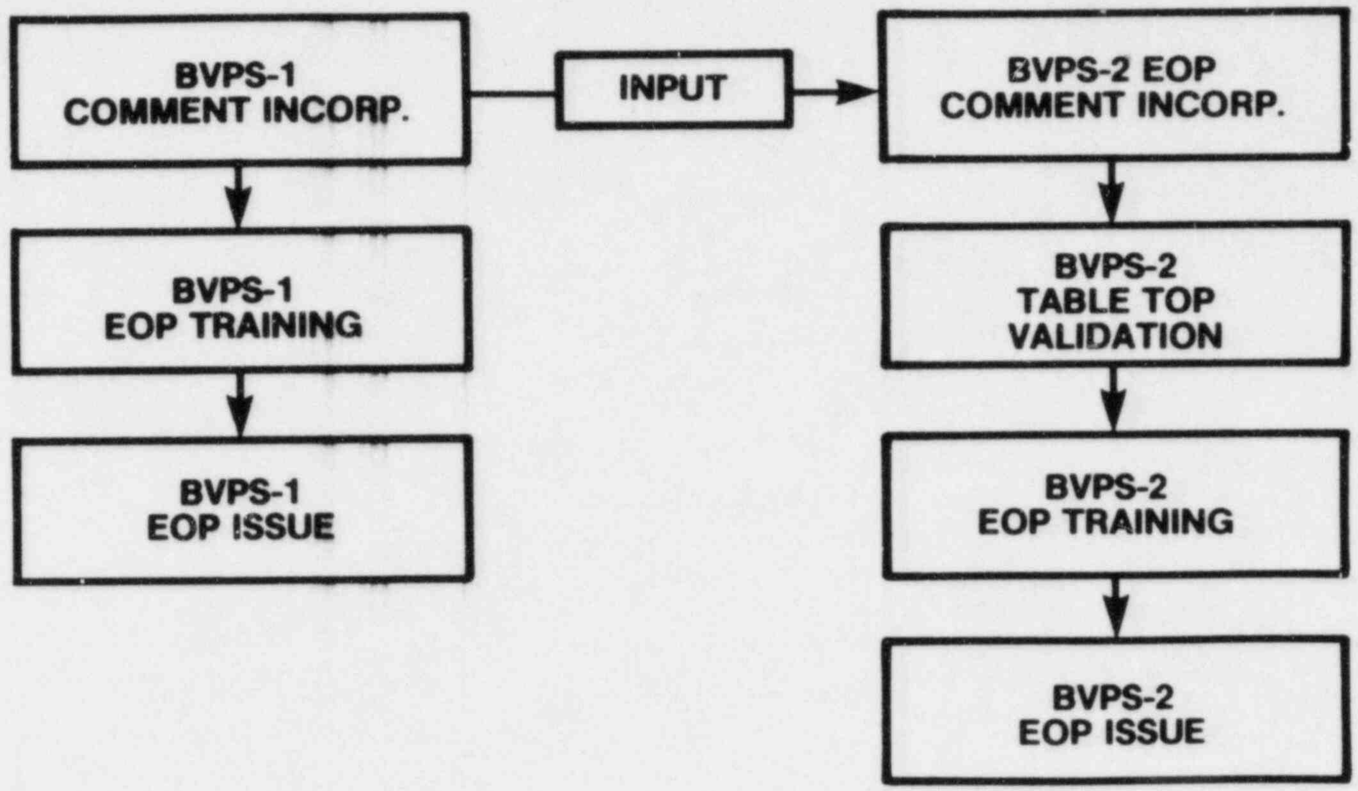
PGP TOPICS

- INITIAL EOP DEVELOPMENT
- ADMIN. CONTROLS FOLLOWING INITIAL IMPLEMENTATION
- TRAINING PROGRAM
- COMPARISON BETWEEN BV-2 AND ERG REFERENCE PLANT

COORDINATION BV-1/BV-2 EOP's




BVPS-1 COMMENT INCORP
INPUT
BVPS-2 EOP COMMENT INCORP.
CRDR
BVPS-1 SIMULATOR VALIDATION
BVPS-2 EOP VERIFICATION
BVPS-2 EOP COMMENT INCORP.
BVPS-2 EOP MOCK-UP WALK-THROUGH
CRDR


BVPS-1
COMMENT INCORP.
INPUT
BVPS-2 EOP
COMMENT INCORP.
BVPS-1
EOP TRAINING
BVPS-1
EOP ISSUE
BVPS-2
TABLE TOP
VALIDATION
BVPS-2
EOP TRAINING
BVPS-2
EOP ISSUE

E.O.P. TRAINING PROGRAM

- INITIALLY TRAINED ON BV-1 EOP's
- CROSS TRAINING ON BV-1/ BV-2 EOP DIFFERENCES

VALIDATION

- USABLE
- OPERATIONALLY CORRECT
- CAPABLE OF DIRECTING THE OPERATING CREW

VALIDATION METHODS

- TABLE TOP
- WALK-THROUGH ON BV-2 CONTROL BOARD MOCKUP
- BV-1 SIMULATOR

Duquesne Light

C. E. EWING

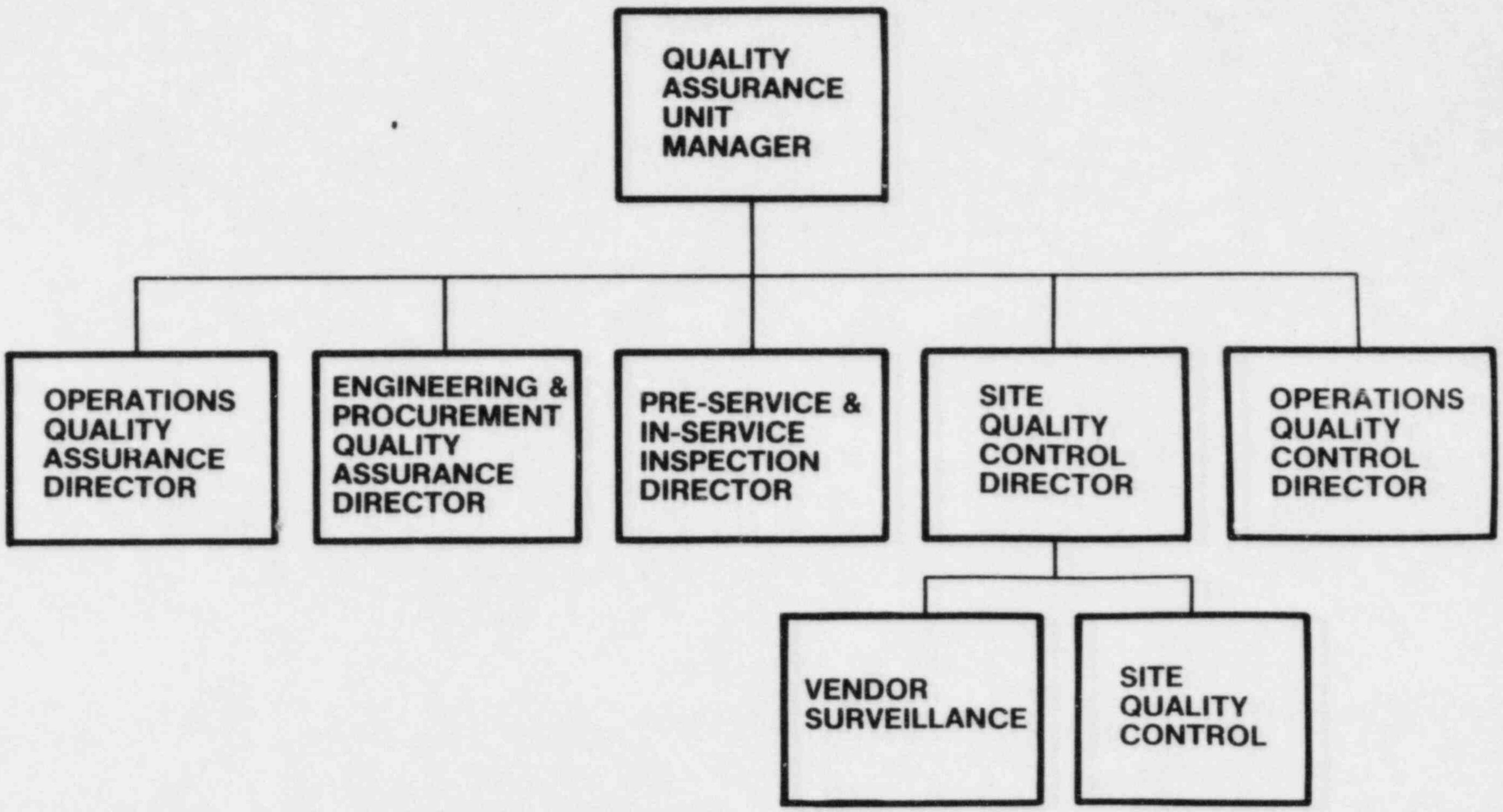
MANAGER: QUALITY ASSURANCE

QA/QC

DUQUESNE LIGHT COMPANY
QUALITY ASSURANCE PROGRAM COMMITMENTS

1. DESIGN & CONSTRUCTION QUALITY ASSURANCE PROGRAM
   - 10 CFR 50, APPENDIX B
   - REGULATORY GUIDE 1.28
2. OPERATIONS QUALITY ASSURANCE PROGRAM
   - 10 CFR 50, APPENDIX B
   - REGULATORY GUIDE 1.33
   - ANSI N45.2 SERIES

DUQUESNE LIGHT COMPANY
NUCLEAR GROUP
QUALITY ASSURANCE UNIT



DUQUESNE LIGHT COMPANY
NUCLEAR GROUP
QUALITY ASSURANCE UNIT

EXPERIENCE OF PERSONNEL

NUCLEAR INDUSTRY EXPERIENCE	510 MAN YEARS
DUQUESNE LIGHT COMPANY EXPERIENCE	570 MAN YEARS
REACTOR OPERATOR EXPERIENCE	30 MAN YEARS
REGISTERED PROFESSIONAL ENGINEER	31 MAN YEARS

DUQUESNE LIGHT COMPANY
NUCLEAR GROUP
QUALITY ASSURANCE UNIT

EDUCATIONAL ACCOMPLISHMENTS

MASTER DEGREES	2
BACHELOR DEGREES	40
ASSOCIATE DEGREES	16
WORKING TOWARDS DEGREE	8

Duquesne Light

THOMAS W. BURNS

TRAINING

EFFECTIVE TRAINING PROGRAM

ESSENTIAL
FOR ACHIEVING EXCELLENCE
OF NUCLEAR OPERATIONS

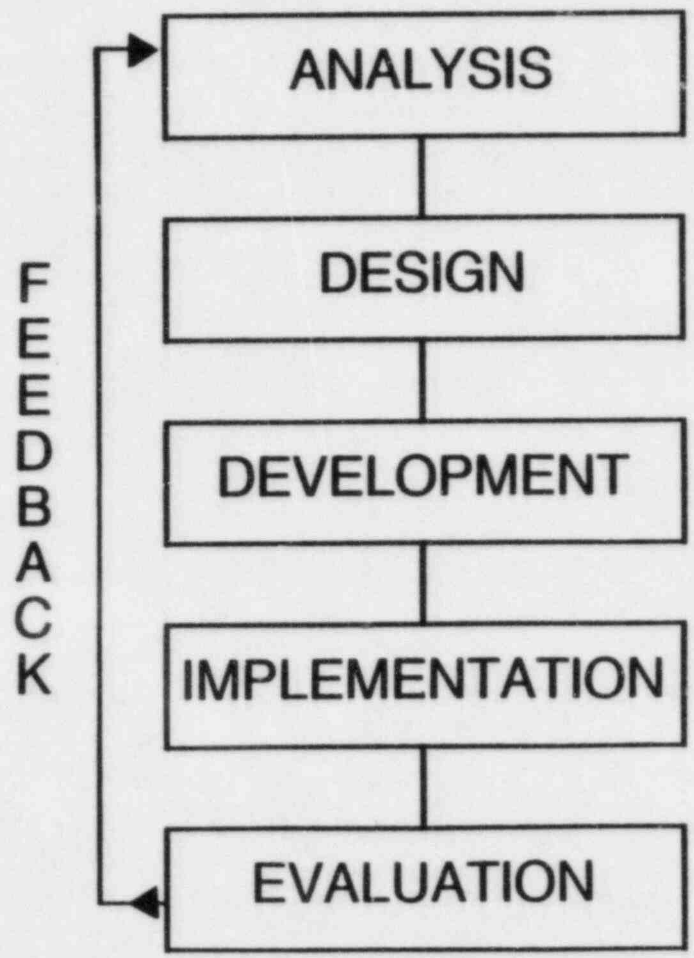
TRAINING PROGRAMS

- GENERAL EMPLOYEE TRAINING (INPO STANDARDIZATION PROGRAM)
- OPERATOR TRAINING — LICENSED AND NON-LICENSED
- SHIFT TECHNICAL ADVISOR
- RADIATION TECHNICIAN
- TECHNICAL PERSONNEL
- MAINTENANCE TRAINING
- EMERGENCY PREPAREDNESS
- FIRE BRIGADE
- ALCOHOL AND DRUG AWARENESS

INPO ACCREDITATION SCHEDULE
SELF EVALUATION REPORT
AND JOB ANALYSIS

- JULY 1984
  - LICENSED OPERATOR TRAINING
  - NON-LICENSED OPERATOR TRAINING
  - LICENSED OPERATOR REQUAL
- JULY 1985
  - SHIFT TECHNICAL ADVISOR
  - RADIATION PROTECTION TECHNICIAN
  - CHEMIST
  - I&C TECHNICIAN
- MAY 1986
  - MECHANICAL MAINTENANCE
  - ELECTRICAL MAINTENANCE
  - TECH. STAFF & MANAGERS

S.A.T. — SYSTEMATIC APPROACH TO TRAINING



TRAINING DEVELOPMENT

NEW TRAINING SUB-SECTION
TO SUPPORT THE S.A.T. EFFORT

THERMODYNAMICS

- EVALUATED BY A.C.E.
- RECOMMENDED FOR 3 CREDITS

LICENSED OPERATOR PHASES OF TRAINING

PHASE 1
ACADEMIC TRAINING

↓

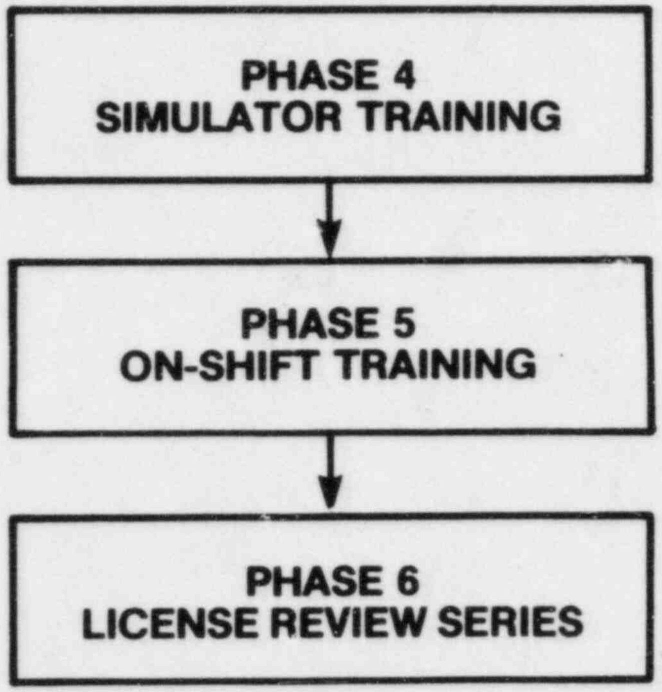
PHASE 2
PLANT SYSTEMS/
INSTRUCTION & STUDY

↓

PHASE 3
QUALIFICATION
STANDARDS CHECK-OFFS

↓

LICENSED OPERATOR PHASES OF TRAINING



TRAINING SUMMARY

- THEORY
- SECONDARY SYSTEMS
  - SIMULATOR
  - ON-SHIFT
- PRIMARY SYSTEMS
  - SIMULATOR
  - ON-SHIFT
- CONTROL SYSTEMS
  - SIMULATOR
- ACCIDENT ANALYSIS/MITIGATING CORE DAMAGE
  - Simulator
  - 3 MONTHS ON-SHIFT
- LICENSE REVIEW
  - SIMULATOR
- NRC EXAM

BEAVER VALLEY
SUCCESS RATE OF LICENSING
88%

UNIT II CROSS TRAINING

NUREG 1021

SYSTEM DIFFERENCE ANALYSIS

LICENSE RETRAINING PROGRAM

24 MONTHS

2 ONE YEAR CYCLES

PROGRAM 1983 - 1985

CYCLE 1	CYCLE 2
83 - 84	84 - 85

RADIATION TECHNICIAN TRAINING PROGRAM

ACADEMIC TRAINING

↓

RADIATION PROTECTION
FUNDAMENTALS/THEORY

↓

IN PLANT APPLICATION
OF
RADIOLOGICAL PROTECTION

MAINTENANCE TRAINING

BASIC TRAINING CATAGORIES

- MAINTENANCE ORIENTATION
- GENERAL MAINTENANCE
- SPECIFIC MAINTENANCE

MAINTENANCE TRAINING

- INSTRUMENT AND CONTROL
- MECHANICAL
- ELECTRICAL

RADIATION TECHNICIAN TRAINING PROGRAM

ACADEMIC TRAINING

RADIATION PROTECTION FUNDAMENTALS/THEORY

IN PLANT APPLICATION OF RADIOLOGICAL PROTECTION

MAINTENANCE TRAINING

BASIC TRAINING CATAGORIES

- MAINTENANCE ORIENTATION
- GENERAL MAINTENANCE
- SPECIFIC MAINTENANCE

MAINTENANCE TRAINING

- INSTRUMENT AND CONTROL
- MECHANICAL
- ELECTRICAL

Duquesne Light

ERVIN T. EILMANN

SENIOR PROJECT ENGINEER

EMERGENCY/ALTERNATE SHUTDOWN PANELS

EMERGENCY SHUTDOWN PANEL

- Assures for loss of Control Room habitability (GDC-19)

- Part of the original plant design (1972-1974)

- State-of-the-art of Industries compliance with GDC-19

  - redundant safety-related trains

  - single failure

  - LOOP

ALTERNATE SHUTDOWN PANEL

- Assures for safe shutdown in case of fire
  (BTP-CMEB - 9.5-1 & Appendix R)

- Result of Browns Ferry fire (1978)

- Committed to install panel in 1982 to comply with BTP & App R

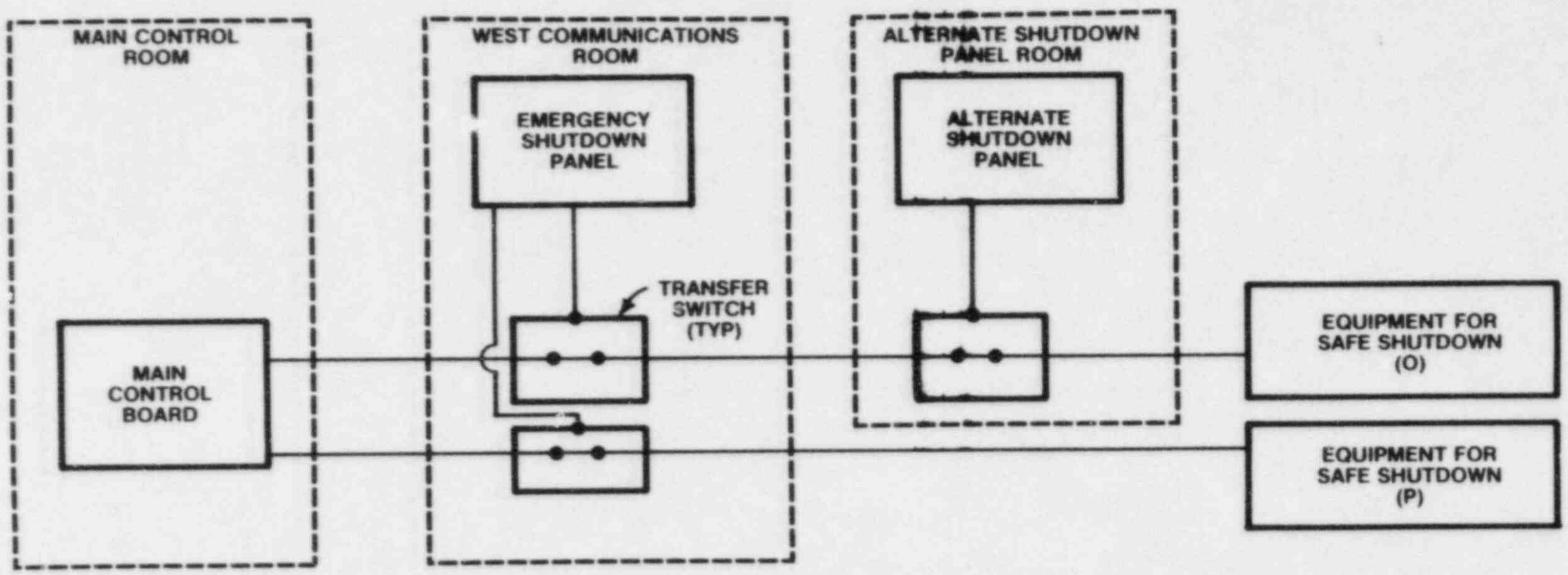
  - one safety-related train (orange)

  - LOOP

EMERGENCY SHUTDOWN PANEL (GDC-19)

- LOSS OF CONTROL ROOM HABITABILITY
- COLD SHUTDOWN CAPABILITY
- PURPLE & ORANGE TRAINS
- ELECTRICALLY INDEPENDENT FROM CR

SHUTDOWN PANELS



ALTERNATE SHUTDOWN PANEL

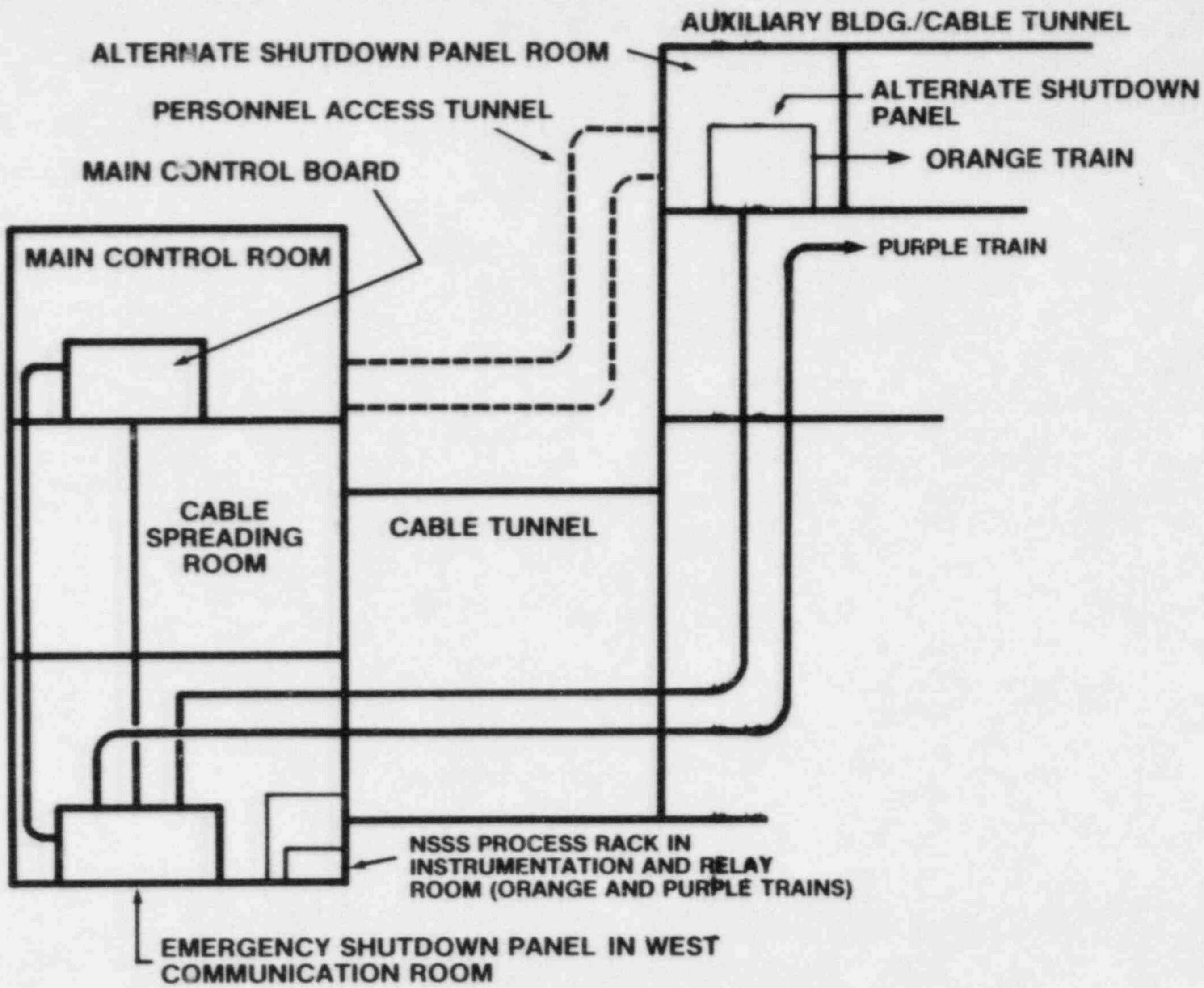
- FIRE IN AREAS (CB-1, CB-2, CB-6, CT-1, CR)
- COLD SHUTDOWN CAPABILITIES
- ORANGE TRAIN
- ELECTRICALLY INDEPENDENT

ALTERNATE SHUTDOWN PANEL

REQUIRED FOR FIRE AREAS:

- CONTROL ROOM
- CABLE SPREADING ROOM
- CABLE TUNNEL
- INSTRUMENTATION & RELAY ROOM
- WEST COMMUNICATION ROOM

SHUTDOWN CAPABILITIES



Duquesne Light

K.D. GRADA

MANAGER

NUCLEAR SAFETY

OFFSITE/ONSITE AC/DC POWER SYSTEMS STATION BLACKOUT

DESIGN FEATURES

- STEAM GENERATOR POWER OPERATED RELIEF VALVES
- TURBINE DRIVEN AUXILIARY FEEDWATER PUMP
- FLYWHEELS ON THE RCPs
- 25% DESIGN MARGIN ON STATION BATTERIES
- FLOATING RING SEALS
- SYSTEM CROSS TIES
- PEAKING UNITS
- SIX 345 KV and SEVEN 138 KV LINES
- COMBINED NUCLEAR-COAL COMPLEX GENERATING CAPACITY OF 4000 MW(e)

PRIMARY ACTIONS

- REACTOR TRIP
- TURBINE TRIP
- REHEAT STEAM and MSIV ISOLATION
- GENERATOR TRIP
- RCS ISOLATION
- AFW FLOW

FOLLOW-UP ACTIONS

- EQUIPMENT IN PULL-TO-LOCK
- LOCAL D/G STARTING
- ISOLATION OF RCP SEAL COOLING
- S/G ISOLATION
- ISOLATING AUXILIARY STEAM
- VENTING HYDROGEN
- SHEDDING DC LOADS
- DEPRESSURIZATION OF S/G TO 240 psig

NUMBER	TITLE
ECA-0.0	Loss Of All AC Power

A. PURPOSE

This procedure provides actions to respond to a loss of all AC power.

B. SYMPTOMS OR ENTRY CONDITIONS

1. Loss of normal control room lighting.
2. Emergency start of both diesel generators.
3. Reactor trip, turbine trip, and generator trip..
4. Zero voltage indication from voltmeters for the main and emergency AC buses.
5. Alarms associated with the loss of operating plant components.
6. This procedure is entered from E-0, "Reactor Trip Or Safety Injection," Step 6, on the indication that all AC emergency buses are deenergized.

NUMBER	TITLE
ECA-0.0	Loss Of All AC Power

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED

NOTE

- Circled numbers show immediate action steps.
- CSF Status Trees should be monitored for information only. FRPs should NOT be implemented.

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
1.	Verify Reactor Trip • Rod bottom lights - LIT - AND - Rod position indicators - AT ZERO • Reactor trip and bypass breakers - OPEN • Neutron flux - DECREASING	Manually TRIP reactor.
2.	Sound The Standby Alarm AND Announce "Unit 2 Reactor Trip" AND NSS Initiate EPP	
3.	Verify Turbine Trip a. Throttle and governor valves - CLOSED b. Reheat stops and interceptors - CLOSED	Manually or locally TRIP turbine.

NUMBER	TITLE
ECA-0.0	Loss Of All AC Power

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
4	Ensure Reheat Steam Isolation	
	a. DEPRESS reheat controller reset pushbutton	
	b. Verify closed or CLOSE main steam trip valves [2MSS*HYV101A, B, and C]	

NOTE

Generator trip will occur 30 seconds after reactor trip. Generator trip will occur immediately following a turbine thrust bearing or anti-motoring turbine trip.

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
5	Verify Generator Trip	
	a. Main generator output breakers - OPEN	a. Manually OPEN breakers from BB-C.
	b. Exciter circuit breakers - OPEN	b. Manually OPEN breakers from BB-C.
6	Check If RCS Is Isolated	
	a. PRZR PORVs - CLOSED	a. IF PRZR pressure less than 2235 PSIG, THEN manually CLOSE PORVs.
	b. Letdown isolation valves [2CHS*LCV460A and B] - CLOSED	b. Manually CLOSE valves from BB-B.
	c. Excess letdown isolation valve [2CHS*HCV137] - CLOSED	c. Manually CLOSE valve from BB-A.

NUMBER	TITLE
ECA-0.0	Loss Of All AC Power

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
7	Verify Total AFW Flow - GREATER THAN 360 GPM	Perform the following: a. Verify turbine-driven AFW pump running. IF NOT, THEN manually OPEN steam supply valves [2MSS*SOV105A - F] from BB-C. IF flow is less than 360 GPM, THEN dispatch an operator to locally: 1) Verify turbine trip throttle valve is reset. 2) Verify proper emergency alignment of AFW valves.

NUMBER	TITLE
ECA-0.0	Loss Of All AC Power

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED

NOTE

IF diesel generator operation is to continue for several days, ensure an adequate supply of lube oil and fuel oil is available.

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
8.	Try To Restore Power To Any AC Emergency Bus [2AE(2DF)]	
	a. Energize AC emergency bus with diesel generator:	
	1) Verify diesel generator running	1) Attempt manual start of diesel. Refer to Attachment 1, Section A. IF the the diesel does NOT start, GO TO Step 8b.
	2) Verify AC emergency bus [2AE(2DF)] automatically energized: a) Voltage normal - APPROXIMATELY 120 VAC b) Equipment listed on Attachment 2 - ENERGIZED AS REQUIRED	2) Manually energize AC emergency bus. Refer to to Attachment 1, Section B. IF bus can NOT be energized, THEN manually trip diesel and attempt to restore offsite power. GO TO Attachment 1, Section E.
	b. Check AC emergency buses [2AE(2DF)] - AT LEAST ONE ENERGIZED	b. GO TO Step 9.
	c. Return to procedure and step in effect	

NUMBER	TITLE
ECA-0.0	Loss Of All AC Power

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED

CAUTION

- When power is restored to any AC emergency bus, GO TO Step 26.
- IF an SI signal exists OR IF an SI signal is actuated during this procedure it should be reset to permit manual loading of equipment on an AC emergency bus.
- A service water pump should be kept available to automatically load on its AC emergency bus to provide diesel generator cooling.

9. Place Following Equipment Switches In PULL-TO-LOCK Position
   - Charging/HHSI pumps
   - LHSI pumps
   - CNMT quench spray pumps
   - CNMT recirculation spray pumps
   - CNMT air recirculation fans
   - CCP pumps
   - MD AFW pumps

10. Dispatch Personnel To Locally Restore AC Power, While Continuing With Step 11. Refer To Attachment 1

NUMBER	TITLE
ECA-0.0	Loss Of All AC Power

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
11.	<u>CLOSE Valves To Isolate RCP Seals</u>	
	a. Place RCP seal water isolation valve switches in the CLOSE position:	
	1) RCP seal return isolation valve [2CHS*MOV381] at BB-A	
	2) RCP seal injection supply isolation valves [2CHS*MOV308A, B, and C] at BB-A	
	3) RCP thermal barrier CCP return flow control valves [2CCP*AOV107A, B, and C] at BB-C	
	a) Verify valves [2CCP*AOV107A, B, and C] - CLOSED	a) Have operator CLOSE CCP return from CNMT outside isolation valves [2CCP*MOV156-1 and 157-1] locally.
	b. Dispatch personnel to locally CLOSE RCP seal injection valves:	
	1) RCP seal injection flow control valve [2CHS*HCV186] and inlet isolation valve [2CHS-480]	
	2) RCP seal return isolation valve outside CNMT [2CHS*MOV381]	

NUMBER	TITLE
ECA-0.0	Loss Of All AC Power

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
12.	Check SG Isolation	Manually CLOSE valves. IF valves can NOT be manually closed or their position verified, THEN locally verify closed or CLOSE valves.
	a. Main steamline isolation and bypass valves - CLOSED	
	b. Main FW control and bypass valves - CLOSED	
	c. Blowdown isolation valves - CLOSED	
	d. CLOSE auxiliary steam isolation valves [2ASS*AOV130A and B]	
	e. CLOSE auxiliary steam valves [2ASS-PCV118A and B]	
13.	START Black Diesel And Load Essential/Restore Air Systems In Accordance With Attachment 5	
14.	Dispatch An Operator To Vent Hydrogen Off The Main Unit While Continuing With Step 15	
	a. Perform procedure OM 2.35.4.I, "No. 2 Main Generator Hydrogen Cooling System Shutdown," to vent hydrogen from the Main Generator	
	b. Verify hydrogen vented off main unit	b. Continue to vent WHEN hydrogen is vented off, THEN, do Step 14.c.
	c. STOP air side seal oil backup pump [2GMO-P214]	

NUMBER	TITLE
ECA-0.0	Loss Of All AC Power

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED

CAUTION

A faulted or ruptured SG that is isolated should remain isolated. Steam supply to the turbine-driven AFW pump must be maintained from at least one SG.

15. Check If SGs Are NOT Faulted

ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
a. Check pressures in all SGs - • NO SG PRESSURE DECREASING IN AN UNCONTROLLED MANNER • NO SG COMPLETELY DEPRESSURIZED	a. Isolate faulted SG(s): • Isolate AFW flow SG-A [2FWE*HCV100E and F] SG-B [2FWE*HCV100C and D] SG-C [2FWE*HCV100A and B] • CLOSE steam supply valves to turbine-driven AFW pump SG-A [ ] SG-B [ ] SG-C [ ] • Verify SG atmospheric dump valves closed. IF NOT, THEN manually CLOSE.

ISSUE 1
REVISION 0

NUMBER	TITLE
ECA-0.0	Loss Of All AC Power

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
16.	Check If SG Tubes Are NOT Ruptured	Try to identify ruptured SG(s). Continue with Step 17. WHEN ruptured SG(s) identified, THEN isolate ruptured SG(s):
	a. Check radiation levels • Condenser air ejector radiation - CONSISTANT WITH PRE-EVENT VALVES	• Isolate AFW flow: SG-A [2FWE*HCV100E and F] SG-B [2FWE*HCV100C and D] SG-C [2FWE*HCV100A and B]
	• SG blowdown radiation - CONSISTANT WITH PRE-EVENT VALUES	• CLOSE steam supply valve to turbine-driven AFW pump: SG-A [ ] SG-B [ ] SG-C [ ]
	• Main steamline radiation - CONSISTANT WITH PRE-EVENT VALUES	• WHEN SG pressure less than 1035 PSIG, THEN verify SG atmospheric dump valves closed. IF NOT, THEN manually CLOSE.
	b. Dispatch Radcon personnel to sample alarming items	

NUMBER	TITLE
ECA-0.0	Loss Of All AC Power

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
17.	<u>Check Intact SG Levels</u>	
	a. Narrow range level - GREATER THAN 4% [44% ADVERSE CNMT]	a. Maintain maximum AFW flow until narrow range level greater than 4% [44% ADVERSE CNMT] in at least one SG.
	b. Control AFW flow to maintain narrow range level between 4% [44% ADVERSE CNMT] and 50%	b. <u>IF</u> narrow range level in any <u>SG</u> continues to increase in an uncontrolled manner, <u>THEN</u> isolate ruptured SG: • Isolate AFW flow: SG-A [2FWE*HCV100E and F] SG-B [2FWE*HCV100C and D] SG-C [2FWE*HCV100A and B] • CLOSE steam supply valve to turbine-driven AFW pump: SG-A [ ] SG-B [ ] SG-C [ ] • <u>WHEN</u> SG pressure less than 1035 PSIG, <u>THEN</u> verify SG atmospheric steam dump valve closed. <u>IF</u> <u>NOT</u>, <u>THEN</u> manually CLOSE.
18.	<u>Check DC Bus Loads</u>	
	a. Shed all large non-essential DC loads. Refer to 125 VDC Control System OM 2.39.5, Table 4	
	b. Monitor DC volts (VB-C) and amps(locally)	
19.	<u>Check PDWST Level - GREATER THAN 343 INCHES</u>	Makeup water to the PDWST. Refer to Attachment 3.

NUMBER	TITLE
ECA-0.0	Loss Of All AC Power

STEP | ACTION/EXPECTED RESPONSE | RESPONSE NOT OBTAINED

CAUTION

SG pressures should NOT be decreased to less than 140 PSIG to prevent injection of accumulator nitrogen into the RCS.

NOTE

- The SGs should be depressurized at maximum rate (NOT to be limited by the Technical Specification RCS cooldown limit of 100F/Hr) to minimize RCS inventory loss.
- PRZR level may be lost and reactor vessel upper head voiding may occur due to depressurization of SGs. Depressurization should NOT be stopped to prevent these occurrences.
- IF there is no station air, local operation of the equipment in Step 20 will be required.
- Depressurization of SGs will result in SI actuation. SI should be reset to permit manual loading of equipment on AC emergency bus.

20. Depressurize Intact SGs To 240 PSIG

ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
a. Check SG narrow range levels - GREATER THAN 4% [44% ADVERSE CNMT] IN AT LEAST ONE SG	a. Perform the following: 1) Maintain maximum AFW flow until narrow range level greater than 4% [44% ADVERSE CNMT] in at least one SG.

(Step continued next page)

ISSUE 1
REVISION 0

NUMBER	TITLE
ECA-0.0	Loss Of All AC Power

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
20.	(Continued)	
		2) Continue with Step 21 AND WHEN narrow range level greater than 4% [44% ADVERSE CNMT] in at least one SG, THEN do Steps 20b, c, d and e.
	b. Manually dump steam at maximum rate using SG atmospheric dump valves IF all SG(s) are intact THEN the residual heat release valve may also be used	b. Locally dump steam using SG atmospheric dump valves.
	c. Check RCS cold leg temperatures - GREATER THAN 272F [272F ADVERSE CNMT]	c. Perform the following: 1) Control SG atmospheric dump valves to stop SG depressurization. 2) Continue with Step 21.
	d. Check SG pressure - LESS THAN 240 PSIG	d. Continue with Step 21. WHEN SG pressure decreased to less than 240 PSIG, THEN do Step 20e.
	e. Manually control SG atmospheric dump valves to maintain SG pressures at 240 PSIG	e. Locally control SG atmospheric dump valves to maintain SG pressures at 240 PSIG.
21.	Check Reactor Subcritical • Intermediate range channels - ZERO OR NEGATIVE STARTUP RATE • Source range channels - ZERO OR NEGATIVE STARTUP RATE	Control SG atmospheric dump valves to stop SG depressurization and allow RCS to heat up.

ISSUE 1
REVISION 0

NUMBER	TITLE
ECA-0.0	Loss Of All AC Power

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
22.	Check SI Signal Status	
	a. SI - HAS BEEN ACTUATED	a. GO TO Step 25. WHEN SI actuated, THEN do Steps 22b, 23, and 24.
	b. Reset SI (both trains) if necessary	
23.	Verify Cotainment Isolation Phase A	
	a. Check all indicating lights with ORANGE CIA mark - LIT	a. IF CIA has NOT actuated, THEN manually actuate CIA (both trains) - OR - Manuallly align CIA valves IF valves can NOT be manually CLOSED, THEN locally CLOSE valves.
24.	Check Containment Pressure - HAS REMAINED LESS THAN 8.5 PSIG	Perform the following: a. Verify CIB and containment depressurization actuation has occured; Check all indicating lights with BLUE CIB mark - LIT. IF NOT, THEN manually initiate CIB (both trains). IF valves can NOT be manually closed, THEN locally CLOSE valves. b. Reset CIB signal (both trains).
25.	Check Containment Radiation - CONSISTANT WITH PRE-EVENT LEVELS	Manually CLOSE containment isolation valves as necessary. IF valves can NOT be manually closed, THEN locally CLOSE valves.

NUMBER	TITLE
ECA-0.0	Loss Of All AC Power

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
26.	Check If AC Power Is Restored	
	a. Check AC emergency buses [2AE(10F)] - AT LEAST ONE ENERGIZED	a. Continue to control RCS conditions and monitor plant status: 1) Check status of local actions initiated. 2) Check status of spent fuel cooling: Spent fuel pool level greater than 298 inches. IF level less than 298 inches, THEN dispatch personnel to initiate makeup to the spent fuel pool. Refer to Attachment 4. 3) Return to Step 19.

NUMBER	TITLE
ECA-0.0	Loss Of All AC Power

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
27.	Stablize SG Pressures	
	a. Manually control SG atmospheric dump valves	a. Locally control SG atmospheric dump valves

CAUTION

The loads placed on the energized AC emergency bus should NOT exceed the capacity of the power source. Diesel generators capacity is 4238KW.

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
28.	Verify Following Equipment Loaded On AC Emergency Bus	Manually load equipment as necessary.
	a. 480 volt buses 2N and/or 2P	
	b. Battery chargers 1 and 3, and/or 2 and 4	
	c. Vital instrument buses	
	d. Emergency lighting	
	e. Communications equipment	
29.	Verify Service Water System Operation	
	a. Service water pumps - RUNNING	a. Verify discharge valve closed and in AUTO, THEN manually START a pump.
	b. Service water flow - INDICATED	b. Align valves as necessary:

NUMBER	TITLE
ECA-0.0	Loss Of All AC Power

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
30.	Select Recovery Procedure	
	a. Determine if recovery can be accomplished without SI: • Check RCS subcooling based on core exit TCs - GREATER THAN 25F [190F ADVERSE CNMT] - AND - • Check PRZR level - GREATER THAN 4% [50% ADVERSE CNMT] - AND - • Check SI equipment - HAS NOT ACTUATED UPON AC POWER RESTORATION	a. GO TO ECA-0.2, "Loss Of All AC Power Recovery With SI Required," Step 1.
	b. GO TO ECA-0.1, "Loss Of All AC Power Recovery Without SI Required," Step 1	

- END -

NUMBER	TITLE
ECA-0.0	Loss Of All AC Power

ATTACHMENT 1

AC POWER RESTORATION TO EMERGENCY BUS

This attachment provides the procedure for performing the following actions.

A. Manual Start of the Diesel Generators from BB-C

B. Manual Loading of the Diesel Generators from BB-C

C. Local Start of the Diesel Generators at Diesel Building

D. Local Closure of the Diesel Generator Output Breaker

E. Restoration of Offsite Power

A. Manual Start of the Diesel Generators from BB-C

1. Place the Normal-Exercise Selector Switch in the EXERCISE position.

2. Depress START pushbutton.

3. IF a diesel did NOT start, THEN GO TO Step 8b of this preocedure.

4. Allow diesel to come to rated speed and then adjust speed to 514 RPM.

5. Depress manual field flash pushbutton and hold until voltmeter shows rapid increase.

6. Adjust voltage and load diesel on emergency bus.

B. Manual Loading of the Diesel Generator from BB-C

1. Verify open or OPEN emergency bus tie breakers:

- 4160V BUS 2AE(2DF) to 2A(2D) ACB [2E7(2F7)]
- 4160V BUS 2A(2D) to 2AE(2DF) ACB [2A10(2D10)]

2. CLOSE diesel generator output breaker.

ATTACHMENT 1

B. 3. IF manual loading can NOT be accomplished, THEN attempt local closure of the output breaker. GO TO Section D of this attachment.

4. Load required equipment listed on Attachment 2 on the emergency bus.

C. Local Start of the Diesel Generators at Diesel Building

CAUTION

- Some diesel generator auto trip features are bypassed when the diesel generator Auto-Local selector switch is in the LOCAL position.
- Auto-Local selector switch in LOCAL will block automatic or remote start signals.

1. Place the Auto-Local selector switch in the LOCAL position.

2. Depress the local start pushbutton and maintain it depressed until the diesel starts and is self-sustaining THEN release pushbutton.

   IF the diesel does NOT start, THEN manually actuate plunger on the air supply solenoid to the air start distributor to crank the diesel.

3. Adjust diesel speed using governor Raise-Lower control to establish an operating speed of 514 RPM.

   IF electric governor control can NOT be used, THEN use mechanical governor controls on the governor actuator face.

   a. Adjust speed knob to obtain 62-64 Hz to prevent hunting.

   b. Set speed droop knob at ZERO.

   c. Turn load limiter knob - FULLY CLOCKWISE

NUMBER	TITLE
ECA-0.0	Loss Of All AC Power

ATTACHMENT 1

C. 4. Notify Control Room operator of diesel status and have operator flash the diesel generator field from BB-C.

5. Attempt to restore diesel generator control to the Control Room.

   a. Place diesel Local-Auto selector switch in AUTO position.

   b. IF remote operation can NOT be maintained THEN return selector to LOCAL position and maintain control locally.

6. Attempt manual loading of the diesel generator. GO TO Section B of this attachment.

D. Local Closure of the Diesel Generator Output Breaker

1. Verify open or OPEN emergency bus tie breakers.

   - 4160V BUS 2AE(2DF) to 2A(2D) ACB [2E7(2F7)]

   - 4160V BUS 2A(2D) to 2AE(2DF) ACB [2A10(2D10)]

2. Strip the equipment listed in Attachment 2 from the emergency bus.

3. CLOSE the diesel generator output breaker by depressing the local close pushbuttons.

4. Load required equipment listed on Attachment 2 on the emergency bus.

E. Restoration of Offsite Power

1. **Verify main generator output breakers** [345KV BKR 352 and 362] and **exciter breaker** [ACB 42] OPEN.

2. **Place 4160V** breakers ACB 42A, 142A, 242B, and 342B in PULL-TO-LOCK at **BB-C.**

NUMBER	TITLE
ECA-0.0	Loss Of All AC Power

ATTACHMENT 1

E. 3. Establish communications with the systems operator.

4. CLOSE or verify closed OCB 85 and 81/94 to energize station service transformers 2A and 2B.

5. Energize bus 2A(2D) as follows:

   a. CLOSE 4160V breaker ACB 42A(342B) to energize bus 2A(2D).

6. Energize bus 2B(2C) as follows:

   a. CLOSE 4160V breaker ACB 142A(242B) to energize bus 2B(2C).

7. Energize emergency bus 2AE(2DF) as follows:

   a. CLOSE breaker 2A10(2D10) [4160V bus 2A(2D) to 2AE(2DF)].

   b. Select syncronizing selector switch for diesel generator 2-1(2-2) to 2E7(2F7) position for bus 2AE(2DF).

   c. Adjust diesel 2-1(2-2) speed to synchronize bus 2AE(2DF) to bus 2A(2D), THEN CLOSE breaker 2E7(2F7) [4160V bus 2AE(2DF) to 2A(2D)] to energize emergency bus 2AE(2DF).

   d. Reduce diesel generator load to 50 KW in preparation for taking off the line.

   e. OPEN diesel generator output breaker [2E10(2F10)].

   f. Place diesel generator in a standby status.

- END -

NUMBER	TITLE
ECA-0.0	Loss Of All AC Power

ATTACHMENT 2

DIESEL GENERATOR LOAD SEQUENCE

1. The following equipment should auto load in the specified start sequence

COMPONENT	POWER SUPPLY	RUN LOAD (KW)	START LOAD (KVA)	START STEP	CONTROL SWITCH
Charging/HHSI Pumps					
[2CHS*P21A]	[4KVS*2AE] Cu 12	522	3358	2	BB-A
[2CHS*P21B]	[4KVS*2DF] Cu 12	522	3358	2	BB-A
[2CHS*P21C]	[4KVS*2AE] Cu 15	522	3358	2	BB-A
[2CHS*P21C]	[4KVS*2DF] Cu 15	522	3358	2	BB-A
LHSI Pumps					
[2SIS*P21A]	[4KVS*2AE] Cu 8	229	1398	3	BB-A
[2SIS*P21B]	[4KVS*2DF] Cu 8	229	1398	3	BB-A
SWS Pumps					
[2SWS*P21A]	[4KVS*2AE] Cu 14	698	3992	3	BB-A
[2SWS*P21B]	[4KVS*2DF] Cu 14	698	3992	3	BB-A
[2SWS*P21C]	[4KVS*2AE] Cu 16	698	3992	3	BB-A
[2SWS*P21C]	[4KVS*2DF] Cu 16	698	3992	3.	BB-A
Stby SWS Pumps					
[2SWE*P21A]	[4KVS*2AE] Cu 19	825	6744	**	BB-A
[2SWE*P21B]	[4KVS*2DF] Cu 19	825	6744	**	BB-A
AFW Pumps					
[2FWE*P23A]	[4KVS*2AE] Cu 18	296	2248	4	BB-C
[2FWE*P23B]	[4KVS*2DF] Cu 18	296	2248	4	BB-C
CRDM Shroud FN					
[2HVR*FN201A1]	[Bus 2N] Bkr 9B	60	492	4	BSCP
[2HVR*FN201A2]	[Bus 2P] Bkr 9B	60	492	4	BSCP
[2HVR*FN201B1]	[Bus 2N] Bkr 9C	60	492	4	BSCP
[2HVR*FN201B2]	[Bus 2P] Bkr 9C	60	492	4	BSCP
[2HVR-FN201C1]	[Bus 2N] Bkr 9D	60	492	4	BSCP
[2HVR*FN201C2]	[Bus 2P] Bkr 9D	60	492	4	BSCP

ISSUE 1
REVISION 0

NUMBER	TITLE
ECA-0.0	Loss Of All AC Power

ATTACHMENT 2

COMPONENT	POWER SUPPLY	RUN LOAD (KW)	START LOAD (KVA)	START STEP	CONTROL SWITCH
Leak Cltn. Fltr. Exh. FN					
[2HVS*FN204A]	[Bus 2N] Bkr 8B	166	1068	5	BSCP
[2HVS*FN204B]	[Bus 2P] Bkr 8B	166	1068	5	BSCP
CNMT Air Recirc FN					
[2HVR*FN201A]	[Bus 2N] Bkr 11C	254	1912	5	BSCP
[2HVR*FN201B]	[Bus 2P] Bkr 11C	254	1912	5	BSCP
[2HVR*FN201C]	[Bus 2N] Bkr 11B	254	1912	5	BSCP
[2HVR*FN201C]	[Bus 2P] Bkr 11B	254	1912	5	BSCP
CCP Pumps					
[2CCP*P21A]	[4KVS*2AE] Cu 5	337	2428	6	BB-B
[2CCP*P21B]	[4KVS*2DF] Cu 5	337	2428	6	BB-B
[2CCP*P21C]	[4KVS*2AE] Cu 3	337	2428	6	BB-B
[2CCP*P21C]	[4KVS*2DF] Cu 3	337	2428	6	BB-B
Emer. Swgr. Sup. FN					
[2HVZ*FN261A]	[Bus 2N] Bkr 8C	58	550	6	BSCP
[2HVZ*FN261B]	[Bus 2P] Bkr 8C	58	550	6	BSCP
Emer. Swgr. Exh. FN					
[2HVZ*FN262A]	[Bus 2N] Bkr 8D	50	500	6	BSCP
[2HVZ*FN262B]	[Bus 2P] Bkr 8D	50	500	6	BSCP
Main Steam FN					
[2HVR*FN206A]	[Bus 2N] Bkr 10B	50	500	6	BSCP
[2HVR*FN206B]	[Bus 2P] Bkr 10B	50	500	6	BSCP

NUMBER	TITLE
ECA-0.0	Loss Of All AC Power

ATTACHMENT 2

COMPONENT	POWER SUPPLY	RUN LOAD (KW)	START LOAD (KVA)	START STEP	CONTROL SWITCH
Leak Sys. Htr					
[2HVS*CH219A]	[Bus 2N] Bkr 10C	250	1566	6	BSCP
[2HVS*CH219B]	[Bus 2P] Bkr.10C	250	1566	6	BSCP
Residual Heat Removal Pumps					
[2RHS*P21A]	[4KVS*2AE] Cu 4	277	1672	TD	BB-A
[2RHS*P21B]	[4KVS*2DF] Cu 4	277	1672	TD	BB-A
Misc. Equipment (Valves, Heaters and Fans)	Various	7-9	4178	2	Various

TOTALS

0-3 min. after start	4134 KW
Greater than 3 min. after start	4027 KW
Worst case (Stby Service Water Pumps Run)	4261 KW

** Starts only if Service Water Pumps are out of service.

NUMBER	TITLE
ECA-0.0	Loss Of All AC Power

ATTACHMENT 2

CAUTION

- The following maximum load conditions should be observed for each diesel generator

4238 KW	Continuous Rating (8760 hours)
4535 KW	2000 hours
4662 KW	160 hours
5086 KW	30 minutes

- Start only one additional load at a time.

2. The following equipment are additional loads that may be added to the diesel generator as required provided room exists on bus without exceeding diesel limits.

COMPONENT	POWER SUPPLY	RUN LOAD (KW)	START LOAD (KVA)	CONTROL SWITCH
PRZR Backup HTR				
[2RCS*H2A]	[Bus 2N] Bkr 7B	216	1595	BB-B
[2RCS*H2B]	[Bus 2P] Bkr 7B	216	1595	BB-B
[2RCS*H2D]	[Bus 2N] Bkr 7C	270	1990	BB-B
[2RCS*H2E]	[Bus 2P] Bkr 7C	270	1990	BB-B
Stn. Air Comp.				
[2SAS-C21A]	[480V Bus 2J] Bkr 2D	149	1192	BB-C
[2SAS-C21B]	[480V Bus 2K] Bkr 6C	149	1192	BB-C
Inst. Air Comp				
[2IAC-C21A]	[MCC*2-23] Bkr 6F	37.3	280	BB-C
[2IAC-C21B]	[MCC*2-26] Bkr 7F	37.3	280	BB-C
B.A. X-fer Pump				
[2CHS*P22B]	[MCC*2-E14] Bkr 4A	13.2	93	BB-A

NUMBER	TITLE
ECA-0.0	Loss Of All AC Power

ATTACHMENT 2

COMPONENT	POWER	RUN LOAD (KW)	START LOAD (KVA)	CONTROL SWITCH
Fire Wtr. Booster Pump				
[2FPW-P36]	[MCC*2-E04] Bkr 1F	29.8	224	Local
**Quench Spray Pumps				
[2QSS*P21A]	[4KVS*2AE] Cu 2	254	1982	BB-A
[2QSS*P21B]	[4KVS*2DF] Cu 2	254	1982	BB-A
**NaOH Chem. Add. Pumps				
[2QSS*P24A]	[MCC*2-E11] Bkr 9A	4.4	31	BB-A
[2QSS*P24B]	[MCC*2-E12] Bkr 9A	4.4	31	BB-A
**Recirc Spray Pumps				
[2RSS*P21A]	[4KVS*2AE] Cu 13	474	3012	BB-A
[2RSS*P21B]	[4KVS*2DF] Cu 13	474	3012	BB-A
[2RSS*P21C]	[4KVS*2AE] Cu 17	474	3012	BB-A
[2RSS*P21D]	[4KVS*2DF] Cu 17	474	3012	BB-A
Control Room Vent				
[2HVC*ACU201B]	[MCC*2-E10] Bkr 1F	25.4	210	BSCP
[2HVC*FN241B]	[MCC*2-E10] Bkr 2A	4.5	38	BSCP
[2HVC*REF24B]	[PNL*AC2-E4] Bkr E4-6	44	292	BSCP
[2HVC*FN265B]	[MCC*2-E04] Bkr 8C	36	258	BSCP
[2HVC*FN266B]	[MCC*2-E04] Bkr 8D	36	258	BSCP
Aux Bldg. Vent.				
[2HVP*FN264B]	[MCC*2-E04] Bkr 9F	26.5	225	BSCP
Diesel Gen. Vent				
[2HVD*FN270B]	[MCC*2-E08] Bkr 4F	44	292	BSCP

**Auto starts with Diesel Load Sequencing on a design basis accident.

- END -

NUMBER	TITLE
ECA-0.0	Loss Of All AC Power

ATTACHMENT 3

MAKEUP TO PDWST [2FWE*TK210]

A. WHEN the low level alarm for the PDWST (setpoint 343 IN.) Annunciator A6-4A alarms, THEN makeup to PDWST as follows:

1. Verify both demineralized water distribution pumps [2WTD-P23A and B] running or START pumps from BB-C.

2. Verify open or OPEN demineralized water supply valve to primary demineralized water storage tank [2FWE-LCV104A].

3. Observe PDWST level indication [2FWE*LI104A1 and A2] on VB-C for a stable or increasing level. IF level continues to decrease, gravity feed water from the demineralized water storage tank [2WTD-TK23] to the PDWST by locally opening the demineralized water supply isolation valve [2FWE*1165] in the primary demineralized water storage tank building, elevation 718'-6".

4. Return to Step 20 of this procedure.

B. IF PDWST level decreases to 24", THEN initiate service water into the auxiliary feed pumps suction at Safeguards Area elevation 718'-6" as follows:

NOTE

Service water should only be used IF no other source of water is available.

1. **CLOSE** the auxiliary feedwater pump recirculation isolation valves [2FWE*50, 51, and 52].

2. **OPEN** the auxiliary feedwater pumps service water suction isolation valves [2FWE*90, 91, and 92].

3. CLOSE the auxiliary feedwater pumps primary demineralized water storage tank suction isolation valves [2FWE*93, 94, and 95].

4. Return to Step 20 of this procedure.

- END -

NUMBER	TITLE
ECA-0.0	Loss Of All AC Power

ATTACHMENT 4

MAKEUP TO SPENT FUEL POOL

CAUTION

This procedure should NOT be used when other methods are available to maintain water level in the spent fuel pool. This procedure will direct unprocessed river water to the spent fuel pool.

1. Instruct Unit-1 Control Room to cross-connect Unit-1 river water system with Unit-2 service water system.

2. Place fuel pool purification pumps [2FNC-P24A and B] control switches in the PULL-TO-LOCK position.

3. Place fuel pool cooling pump [2FNC*P21A and B] control switches in the STOP position.

4. Verify closed or CLOSE the following valves:

   a. Purification suction cask area isolation [2FNC-1].

   b. Purification suction spent fuel pool isolation [2FNC-2].

   c. Spent fuel pool skimmer [2FNC-SKM22] suction isolation [2FNC-48].

   d. Filter return to cask area isolation [2FNC-30].

   e. Cooling pump suction header isolation [2FNC*105].

   f. Cooling water return to cask area isolation [2FNC*115].

   g. Discharge to spent fuel storage area isolation [2FNC*116].

   h. Fuel transfer tube isolation valve [2ICS*102].

   i. Isolation supply of "A" header to recirculation spray heat exchangers [2SWS*MOV103B].

NUMBER	TITLE
ECA-0.0	Loss Of All AC Power

ATTACHMENT 4

j. Control Room header "B" isolation [2SWS*MOV120B].

k. Service water pump [2SWS*P21B] discharge isolation "B" header [2SWS*MOV102B].

l. Service water pump [2SWS*P21C] discharge isolation "B" header [2SWS*MOV102C2].

m. Service water pump [2SWS*P21A] discharge isolation to "B" service water header [2SWS*22].

n. CCS heat exchanger backup isolation from "B" service water header [2SWS*MOV107D].

o. CCP heat exchangers [2CCP*E21B] and [2CCP*E21C] service water supply header cross-connection [2SWS*184].

p. CCP heat exchanger [2CCP*E21B] inlet valve [2SWS*MOV186].

q. Containment air coolers SWS cooling water inlet valve [2SWS*MOV160].

r. Standby service water pumps discharge to "B" header [2SWE*116B].

s. Chlorine injection isolation [2SWM*MOV564].

5. Remove the blind flange and install the spool piece downstream of [2SWS-122] located at (later).

6. OPEN the following valves:

a. Branch line isolation [2SWS*644].

b. Branch line isolation [2SWS*556].

c. Service water supply header to spent fuel pool backup [2SWS*124].

d. Service water supply header to spent fuel pool [2SWS*122].

e. Unit-1 river water and Unit-2 service water cross-connect [2FPW-807].

NUMBER	TITLE
ECA-0.0	Loss Of All AC Power

ATTACHMENT 4

7. Monitor spent fuel pool water level on VB-C [2FNC*LI102A and B] and throttle [2SWS-122] as necessary to maintain water level.

8. Return to Step 26 of this procedure.

-END-

NUMBER	TITLE
ECA-0.0	Loss Of All AC Power

ATTACHMENT 5

(LATER)

Duquesne Light

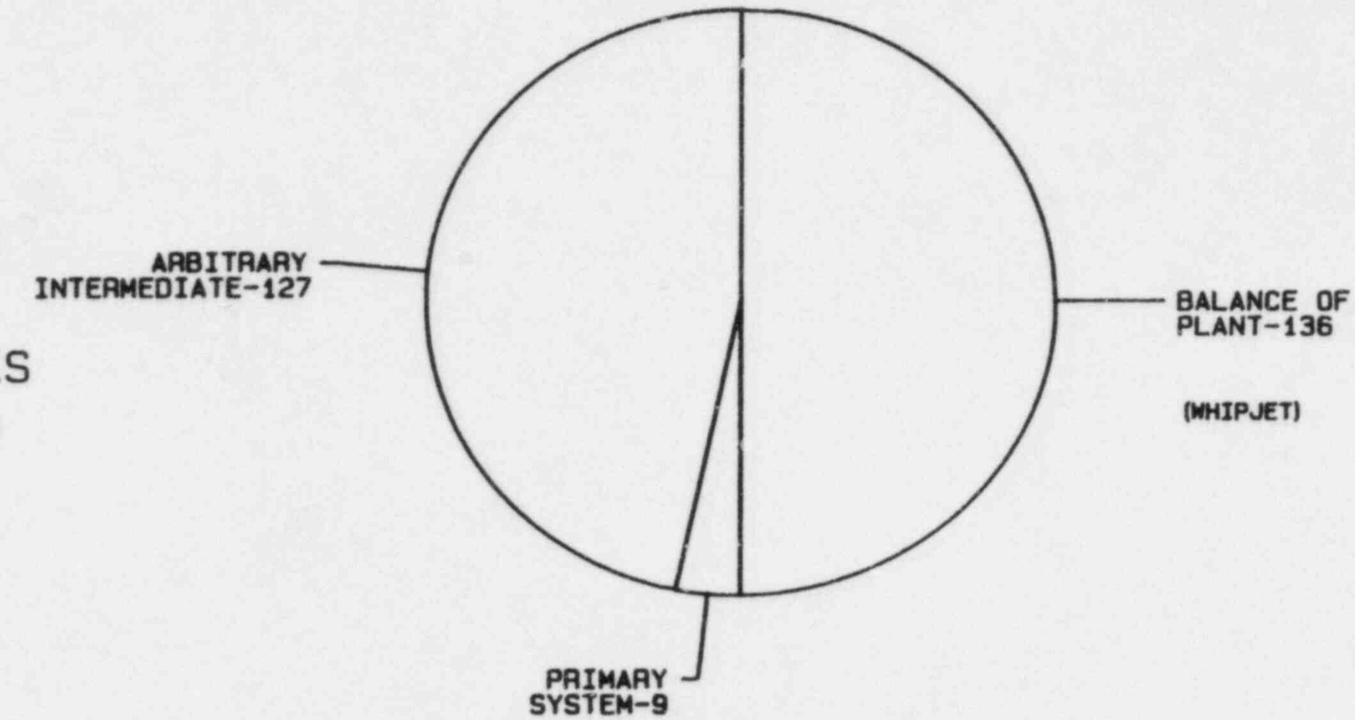
J.A. HULTZ

DEPUTY PROJECT MANAGER

ALTERNATE PIPE RUPTURE PROTECTION

LEAK BEFORE BREAK

SCOPE



BREAKS

(MEB 3-1)

(WHIPJET)

(GDC - 4)

THE NUMBERS REFER TO THE NUMBER OF RUPTURE RESTRAINTS.

EVENTS TO DATE

- WESTINGHOUSE R&D

- A-2 OWNERS GROUP

- CRGR A-2 (84-04)

- NRC APPROVAL OF AIPB AND GDC-4 EXEMPTION

- DLC MEETINGS WITH NRR AND ACRS ON WHIPJET

SUMMARY

- DECREASED WORKER EXPOSURE
- IMPROVED ACCESSIBILITY
- DECREASED CONSTRUCTION AND O&M COSTS
- DLC AWAITING WHIPJET APPROVAL

Duquesne Light

JOHN H. LUKEHART, JR.
DIRECTOR OF SECURITY

PREVENTION OF SABOTAGE

SABOTAGE PROTECTION

- PREVENTION
- PROTECTION
- OPERATION

PREVENTION

- SCREENING
- CONTINUOUS OBSERVATION

SCREENING

- EDUCATION VERIFICATION
- EMPLOYMENT VERIFICATION
- PERSONAL REFERENCE VERIFICATION
- NEIGHBORHOOD CHECK
- CREDIT CHECK
- CRIMINAL HISTORY RECORD
- MILITARY RECORD

CONTINUOUS OBSERVATION

- SUPERVISOR TRAINING
- EMPLOYEE ASSISTANCE PROGRAM

PROTECTION

- REDUNDANT SYSTEMS
- ACCESS CONTROLS
- COMPARTMENTALIZED VITAL AREAS
- INTRUSION ALARMS

REGULATORY EFFECTIVENESS REVIEW

- APRIL 1985
- NO ITEMS OF POTENTIAL SABOTAGE VULNERABILITY
- SAFETY SECURITY INTERFACE

OPERATIONS

INCIDENT DETECTION

- PLANT TOURS & LOGS
- BYPASSED INOPERABLE STATUS INDICATION
- INSTRUMENT RESPONSE
- OPERATIONS SURVEILLANCE TESTS
- MAINTENANCE SURVEILLANCE PROCEDURES
- BEAVER VALLEY TESTS

INCIDENT RESPONSE

- SECURITY RESPONSE
- OPERATIONS RESPONSE
- 2-MAN RULE
- CHECK LISTS
- EMERGENCY OPERATING PROCEDURES

PLANT HIGHLIGHTS

DESCRIPTION	FSAR REFERENCE
NSSS: 3 loop PWR; 2,660 MWt; 836 MWe net	Page 1.1-1 Section 1.1
Engineered Safety Features design based on 2,780 MWt	Page 1.1-1 Section 1.1
Containment design based on 2,713 MWt	Page 1.1-1 Section 1.1
Subatmospheric containment (9.5 psia)	Page 1.1-1 Section 1.1
Site: 509 acres on south bank of Ohio River; minimum exclusion radius = 1,500 ft.; distance to nearest residence = 2,300 ft.; low population zone area distance = 3.6 miles; population center distance = 17 miles	Page 1.2-2 Section 1.2.2
Containment: steel-lined reinforced concrete cylinders with hemispherical dome and flat base	Page 1.2-2 Section 1.2.3
Cooling tower: natural draft hyperbolic with reinforced concrete shell	Page 1.2-2 Section 1.2.3
Steam Generators: Westinghouse, vertical, U-tube units with inconel tubes. Integral dryers to provide steam with moisture $\leq$ 1/4%	Page 1.2-3 Section 1.2.3
Reactor Coolant Pumps: Westinghouse, vertical, single-stage, centrifugal pumps of the shaft-seal type	Page 1.2-3 Section 1.2.4
Reactor control by soluble boron and control rods	Page 1.2-4 Section 1.2.5
Charcoal beds and HEPA filters to control the release of radioactivity	Page 1.2-5 Section 1.2.6
Storage for 1,059 spent fuel assemblies	Page 1.2-6 Section 1.2.7
Turbine: 1,800 rpm, 888MW, tandem-compound, four flow, single reheat unit with provisions for six stages of feedwater heating	Page 1.2-6 Section 1.2.8.1
Generator: direct-driven, three-phase, 60Hz, 22kV, 1,800 rpm hydrogen inner-cooled, synchronous generator rated at 1,026 MVA at 0.90 power factor	Page 1.2-7 Section 1.2.8.1

DESCRIPTION	FSAR REFERENCE
Turbine bypass steam dump to handle up to 90% of full steam flow	Page 1.2-8 Section 1.2.8.6
Circulating water system: pumped, closed-loop system utilizing an air-cooled, natural draft hyperbolic cooling tower	Page 1.2-8 Section 1.2.8.7
ESF system: 1. Containment 2. Emergency core cooling 3. Quench and recirculation spray 4. Supplemental leak collection and release system 5. Post-DBA hydrogen control system 6. Containment isolation 7. Habitability system for control room	Page 1.2-9 Section 1.2.10
Main Steam System: 797 psia, 11.61×10^6 lbs/hr, 518°F	Table 1.3-1 Page 14 of 20
Full flow condensate polishing demineralizer	Table 1.3-1 Page 15 of 20
Hafnium control rods	Table 1.3-2 Page 2 of 19
No thermal sleeves in the reactor coolant loop branch nozzles to simplify the nozzle design	Table 1.3-2 Page 2 of 19
Steam generator integral flow restriction	Table 1.3-2 Page 3 of 19
Two-train dedicated residual heat removal system	Table 1.3-2 Page 3 of 19
Safety grade approach to cold shutdown	Table 1.3-2 Page 3 of 19
Reactor vessel head vent	Table 1.3-2 Page 4 of 19
Auxiliary feedwater cavitating venturies	Table 1.3-2 Page 4 of 19
Improved quench spray nozzle design	Table 1.3-2 Page 4 of 19
No Boron Injection Tank	Table 1.3-2 Page 4 of 19
Automatic transfer to recirculation on Safety Injection Signal	Table 1.3-2 Page 4 of 19

DESCRIPTION	FSAR REFERENCE
Positive displacement NaOH pumps for quench spray system	Table 1.3-2 Page 5 of 19
Alternate shutdown panel in auxiliary building (Appendix R)	Table 1.3-2 Page 6 of 19
Safety parameter display system	Table 1.3-2 Page 6 of 19
Reactor coolant system cold overpressure protection	Table 1.3-2 Page 6 of 19
Upgraded fuel transfer system	Table 1.3-2 Page 7 of 19
Refrigerant-type air dryer with desiccant filter bypass on containment instrument air	Table 1.3-2 Page 10 of 19
On-line pH and Na conductivity monitors for each steam generator	Table 1.3-2 Page 10 of 19
Filtration and exhaust system for gaseous waste storage and cask washdown area	Table 1.3-2 Page 12 of 19
Gland seal steam exhaust ventilation system to filter and monitor non-condensable gases prior to discharge	Table 1.3-2 Page 12 of 19
Fuel oil storage for seven days of full load operation	Table 1.3-2 Page 12 of 19
Motor-driven start-up feedwater pump	Table 1.3-2 Page 15 of 19
Two (2) motor-driven and one (1) turbine-driven auxiliary feedwater pumps	Table 1.3-2 Page 15 of 19
N-1 loop accident analysis	Table 1.3-2 Page 19 of19
Duquesne Light Company will build a plant simulator (BVPS-1 specific)	Table 1.10-1 Page 1 of 6
Emergency air lock in Containment Building is a subassembly of equipment hatch	Page 3.8-9 Section 3.8.1.1.3.2
Fuel assemblies: 17x17 rod array; 264 rods/assembly; 24 guide tubes; one thimble port; Zircaloy-4 clad; bottom nozzle-top nozzle Type 304 stainless steel; inconel grid straps	Page 4.2-9 Section 4.2.2

DESCRIPTION	FSAR REFERENCE
BVPS-2 fuel enrichment: 3.1%, 2.6%, 2.1%	Table 4.1-1 Page 4 of 4
Hafnium control rods (48); 149 lbs. each	Table 4.3-1 Page 2 of 2
Dedicated residual heat removal system inside containment	Page 5.4-30 Section 5.4.7
Pressurizer PORV's safety grade and used to achieve cold shutdown	Page 5.4-54 Section 5.4.13.2
BVPS-2 approach to cold shutdown	Appendix 5A
Containment subatmospheric (9-12 psia); design 45 psig; LOCA 44.6 psig	Page 6.2-2 Section 6.2.1.1.2
Refueling Water Storage Tank volume increase (BVPS-2 - 850,000 gal, BVPS-1 - 441,100 gal)	Page 6.2-4 Section 6.2.1.1.3.1
Each quench spray pump can deliver 3000 gpm	Page 6.2-46 Section 6.2.2.2.1
Recirculation spray pumps (4): 3500 gpm, outside	Table 6.2-57
Low head safety injection pumps (2): dedicated 3000 gpm each; used only for initial LOCA (page 6.3-6 first and last paragraphs)	Page 6.3-5 Section 6.3.2.2
Supplementary leak collection system: two 30,000 cfm normal fans; two 43,000 cfm emergency bus fans; four 29,500 cfm filters; two 13,000 cfm charging pump fans	Page 6.5-7 Section 6.5.3.2
Commitment to Reg. Guide 1.97, Revision 2	Page 7.5-1 Section 7.5
Automatic changeover from injection phase to recirculation phase	Page 7.6-6 Section 7.6.5
Interconnection of BVPS-2 to Mansfield, Hanna, and Sammis on 345kV (enhances reliability and availability)	Page 8.1-1 Section 8.1.3
Main transformer 21.5kV - 345kV; rated at 945 MVA; each 138kV bus supplies a 138kV - 4.36kV - 4.36kV transformer	Page 8.1-2 Section 8.1.4
Heat tracing alarms displayed on alarm CRT in control room (See Chapter 7 for more detail)	Page 8.3-7 Section 8.3.1.1.3

DESCRIPTION	FSAR REFERENCE
Swing 1E loads (i.e., 3 pumps available): charging/HHSI pump, service water pump, primary component cooling water pump	Page 8.3-7 Section 8.3.1.1.4
Interlocked swing loads on 480V emergency bus (2N or 2P) containment air recirculation fan (drops out on CIB); 480V "C" service water pump fan (trips if not running on SIS); residual heat removal suction valves (2RHS-MOV702A and 2RHWS701B) (drops out on SIS)	Page 8.3-8 Section 8.3.1.1.4
Each piece of safety related equipment contains an asterisk as part of its mark number	Page 8.3-12 Section 8.3.1.1.9
Onsite Emergency Power: two 4160 V, three-phase, 60 Hz diesel-generators, manufactured by Colt Industries; meet intent of Branch Technical Positions ICSB 7 and 8; diesel generator unit ratings are as follows:	Page 8.3-32 Section 8.3.1.1.15

Continuous duty:	(8760 hrs.)	4238 kW
	2000 hrs.	4535 kW
	160 hrs.	4662 kW
	30 min.	5086 kW

DESCRIPTION	FSAR REFERENCE
Standby service water system (alternate intake structure): provides heat sink if intake structure is disabled	Page 9.2-11 Section 9.2.1.2
Total demineralized water shared between BVPS-1 and BVPS-2 is 1.2 million gallons (BVPS-2 has 600,000 gal. storage tank [primary plant]; 140,000 gal. secondary plant)	Page 9.2-28 Section 9.2.3.1
Separate condensate polishing air system for condensate polishing building only	Page 9.3-5 Section 9.3.1.2
Safe shutdown: Chemical and volume control system capable of safety grade cold shutdown (refueling water storage tank is source of borated water)	Page 9.3-39 Section 9.3.4.1.7
Boric Acid Tanks (2) sized for cold shutdown (12,500 gal each)	Page 9.3-50 Section 9.3.4.2.4
Control Room HVAC: Control room pressurization initiated on detection of chlorine	Page 9.4-3 Section 9.4.1.1

DESCRIPTION	FSAR REFERENCE
Gland Seal Steam Exhaust Ventilation System: two 100% capacity charcoal and HEPA filters to reduce potential of turbine radioactive release	Page 9.4-61 Section 9.4.15.2
Condensate Polishing Building Ventilation: contains its own HEPA filters to minimize discharge of radiation to environment	Figure 9.4-17
Fire protection system meets intent of Branch Technical Position CMEB 9.5-1	Page 9.5-1 Section 9.5.1.1
Alternate shutdown capability (Appendix R)	Page 9.5-6 Section 9.5.1.2.4
Steam Dump: turbine by-pass system up to 90% full load steam to condenser	Page 10.1-1 Section 10.1
Turbine: 888 MWe, 1800 rpm	Table 10.1-1 Page 1 of 3
Turbine Control System: step load increase 10%; ramp load 5%/min. over a range of 15% to 100%; no reactor trip on turbine trip below 10%	Page 10.2-4 Section 10.2.2.1.1
Steam Generator Safety Valves: sized to pass steam flow for load rejection without reactor trip	Page 10.3-3 Section 10.3.2
Circulating Water Flow Path: from cooling tower base by gravity to condenser inlet (siphon effect) (vacuum prime system) to pump house to cooling tower fill	Page 10.4-13 Section 10.4.5.2
Condensate Polishing System: five filter/demineralizers; designed for full condensate flow; not for full-time operation; used to maintain chemistry	Page 10.4-19 Section 10.4.6.2.1
Primary Plant Demineralized Water Storage Tank (140,000 gal.) with connection to Demineralized Water Storage Tank (600,000 gal.)	Page 10.4-38 Section 10.4.9.2
Hafnium control rods utilized (reduces tritium source from Ag-In-Cd)	Page 11.1-5 Section 11.1.3.2.2
Gaseous waste system processes for BVPS-2; decay and discharge utilizes BVPS-1 systems	Page 11.3-1 Section 11.3
Air ejector charcoal delay beds accept effluent from BVPS-1 and BVPS-2	Page 11.3-5 Section 11.3.2.2

DESCRIPTION	FSAR REFERENCE
Digital radiation monitoring system (CRT, printer in control room)	Page 11.5-15 Section 11.5.2.6.1
Digital radiation monitoring system central processor functions and data files (trend, etc.)	Page 11.5-18 Section 11.5.2.7

Duquesne Light

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

J. J. CAREY

John J. Carey is Vice President of Duquesne Light Company's (DLC) Nuclear Group. DLC is a public utility incorporated under the laws of the Commonwealth of Pennsylvania and is engaged in the generation, transmission, distribution, and sale of electricity in the city of Pittsburgh and municipalities in Allegheny and Beaver Counties, Pennsylvania. Mr. Carey is responsible for all nuclear activities. These activities include management; administration of operation, maintenance, fuel, engineering, and capitol improvements; and construction at BVPS-2.

A native of Ambridge, PA, he graduated from the University of Pittsburgh with a B.S. degree in Electrical Engineering in 1956. Mr. Carey began his utility career in 1958 as a Test Engineer in the Power Stations Department. In 1960 he became Chief Electrician at Phillips Power Station in the Power Stations Department. He was appointed Electrical Maintenance Engineer in 1963, and in 1966 he became Superintendent of Elrama Power Station. In 1971 he was appointed Superintendent of BVPS-1 and then became Technical Assistant, Nuclear, in 1974. In 1979 he became Director of Nuclear Operations and was appointed Vice President, Nuclear Division, in 1981. He assumed his present position as Vice President, Nuclear Group, in 1983.

Mr. Carey is a registered Professional Engineer in the State of Pennsylvania. Jack and his wife Joyce have two children and live in Ambridge, PA.

Duquesne Light

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

R. E. MARTIN

Roger E. Martin is Manager of Duquesne Light Company's (DLC) Engineering Department. DLC is a public utility incorporated under the laws of the Commonwealth of Pennsylvania and is engaged in the generation, transmission, distribution, and sale of electricity in the city of Pittsburgh and municipalities in Allegheny and Beaver Counties, Pennsylvania. Mr. Martin is responsible to the Vice President of the Nuclear Group for the adequacy of engineering and design of BVPS-2.

A native of Springfield, OH, he graduated from Bucknell University with a B.S. degree in Mechanical Engineering in 1949. Mr. Martin began his utility career in 1949 as an Engineer in the coal fired generator stations. In 1972 he was named Nuclear Engineer in the Engineering and Construction Division, and became Director of Nuclear Engineering in 1981. He assumed his present position as Manager of Engineering in 1984.

Mr. Martin is a member of ASME, American Nuclear Society, and Atomic Industrial Forum. He is a register Professional Engineer in the State of Pennsylvania. Roger and his wife Joyce have two children and live in Gibsonia, PA.

Duquesne Light

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

R. J. SWIDERSKI

Richard J. Swiderski is Manager, Nuclear Construction, of Duquesne Light Company's (DLC) Nuclear Construction Department. DLC is a public utility incorporated under the laws of the Commonwealth of Pennsylvania and is engaged in the generation, transmission, distribution, and sale of electricity in the city of Pittsburgh and municipalities in Allegheny and Beaver Counties, Pennsylvania. Mr. Swiderski is responsible for site construction activities, the startup and test program, and construction modifications for BVPS-2, and assigned maintenance and construction proof-testing for BVPS-1.

A native of Pittsburgh, PA, he attended the University of Pittsburgh and Point Park College studying mechanical and electrical engineering. Mr. Swiderski began his utility career in 1958 in the Substations and Shops Department. In 1963 he was assigned as Automatic Controlman in the Substations and Shops Department. In 1972 he was assigned as Construction Inspector in the General Construction Department, and in 1973 he became Chief Construction Inspector at BVPS-1. He assumed his present position as Manager in 1982.

Mr. Swiderski is a member of the EEI Construction Committee and Labor Relations Subcommittee. He served in the Army from 1961 to 1963. He left the Army as a Specialist E5. Rich and his wife Rose have three children and live in North Hills, Pittsburgh, PA.

Duquesne Light

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

E. F. KURTZ

Eugene F. Kurtz, Jr., is Manager of Duquesne Light Company's (DLC) Regulatory Affairs Department. DLC is a public utility incorporated under the laws of the Commonwealth of Pennsylvania and is engaged in the generation, transmission, distribution, and sale of electricity in the city of Pittsburgh and municipalities in Allegheny and Beaver Counties, Pennsylvania. Mr. Kurtz is responsible for developing, implementing, and maintaining the total regulatory program for BVPS-2 to assure the project's compliance in all regulatory aspects.

A native of Pittsburgh, PA, he graduated from Penn State in 1968 with an Associate degree in Electrical Engineering, from Point Park College in 1973 with a B.S. degree in Electrical Engineering Technology, and from Carnegie-Mellon in 1980 with an M.S. degree in Nuclear Engineering. Mr. Kurtz began his utility career in 1970 as an Associate Engineer in the Power Stations Department. In 1973 he became a Nuclear Shift Foreman in the Nuclear Division, and in 1976 he was appointed Senior Quality Assurance Engineer. In 1980 he became Supervising Engineer, Nuclear, in the Engineering and Construction Division. He assumed his present position as Manager, Regulatory Affairs, in 1982.

Mr. Kurtz is a member of the American Nuclear Society and held an Operator's License on BVPS-1 in 1976. He served in the Army from 1968 to 1970. Gene and his wife Chris have one child and live in Scott Township, PA.

Duquesne Light

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

G. L. BEATTY

Gary L. Beatty is Lead Licensing Engineer of Duquesne Light Company's (DLC) Regulatory Affairs Department. DLC is a public utility incorporated under the laws of the Commonwealth of Pennsylvania and is engaged in the generation, transmission, distribution, and sale of electricity in the city of Pittsburgh and municipalities in Allegheny and Beaver Counties, Pennsylvania. Mr. Beatty is responsible for the primary interface with NRR during the safety review.

A native of Pittsburgh, PA, he graduated from Carnegie-Mellon University with a B.S. degree in Electrical Engineering in 1975. Mr. Beatty began his utility career in 1975 as an Engineer in the Quality Assurance Department. He assumed his present position as Lead Licensing Engineer in 1982.

Gary and his wife Kathy live in Hookstown, PA.

Duquesne Light

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

J. D. SIEBER

John D. Sieber is Senior Manager of BVPS-1 and General Manager of Nuclear Services Unit of Duquesne Light Company's (DLC) Nuclear Group. DLC is a public utility incorporated under the laws of the Commonwealth of Pennsylvania and is engaged in the generation, transmission, distribution, and sale of electricity in the city of Pittsburgh and municipalities in Allegheny and Beaver Counties, Pennsylvania. Mr. Sieber is responsible for operation, maintenance, and modifications of BVPS-1 and for radiological control, security, nuclear safety, personnel and industrial relations, records, budget, and fuel management for BVPS-1 and for BVPS-2 when BVPS-2 becomes commercial.

A native of Pittsburgh, PA, he graduated from Carnegie-Mellon University with a B.S. degree in Mechanical Engineering in 1961. He has completed special courses in Nuclear Physics at Purdue University and Nuclear Safety at Massachusettes Institute of Technology. Mr. Sieber began his utility career in 1961 as a Test Engineer at the Shippingport Atomic Power Station. He has held the positions of Instrument Engineer, Nuclear Training Engineer, Care Analysis Engineer, Superintendent of Licensing, and Manager of Nuclear Safety and Licensing. He assumed his present position as Senior Manager on January 1, 1985.

Mr. Sieber served in the Army from 1961 to 1963. He left the Army as First Lieutenant, Signal Corps. Jack and his wife Carol have two children and live in Franklin Park, PA.

Duquesne Light

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

T. D. JONES

Thomas D. Jones, II, is General Manager of Duquesne Light Company's (DLC) Nuclear Operations Unit. DLC is a public utility incorporated under the laws of the Commonwealth of Pennsylvania and is engaged in the generation, transmission, distribution, and sale of electricity in the city of Pittsburgh and municipalities in Allegheny and Beaver Counties, Pennsylvania. Mr. Jones is responsible for operation, maintenance, and testing of BVPS-1 and -2.

A native of Western Pennsylvania, he graduated from Lehigh University with a B.S. degree in Mechanical Engineering in 1960. Mr. Jones began his utility career in 1960 as an Engineer in the Power Stations Department. In 1970 he was named Maintenance Supervisor in the Shippingport Atomic Power Station and became Superintendent in 1974. He assumed his present position as General Manager in 1984.

Mr. Jones is a member of the EEI Nuclear Operators Committee. Tom and his wife Anita have three children and live in Sewickley, PA.

Duquesne Light

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

F. D. SCHUSTER

Fred D. Schuster is Technical Advisory Engineer of Duquesne Light Company's (DLC) Nuclear Start-Up Group. DLC is a public utility incorporated under the laws of the Commonwealth of Pennsylvania and is engaged in the generation, transmission, distribution, and sale of electricity in the city of Pittsburgh and municipalities in Allegheny and Beaver Counties, Pennsylvania. Mr. Schuster is responsible for shift operating personnel and generation of operating procedures and manuals.

A native of Youngstown, OH, Mr. Schuster began his utility career in 1970 as a Station Operating Foreman at the Shippingport Atomic Power Station. In 1975 he was named Nuclear Shift Supervisor at BVPS-1 and transferred to the BVPS-2 Start-Up Group in 1978. He assumed his present position as Technical Advisor Engineer in 1984.

Mr. Schuster served in the Navy (Nuclear Program) from 1960 to 1967. He left the Navy as an ET-1 responsible for the Reactor Control Division of the Submarine "Seawolf." Fred and his wife Linda have two children and live in Liberty Township, OH.

Duquesne Light

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

C. E. EWING

C. Eugene Ewing is Manager of Duquesne Light Company's (DLC) Quality Assurance Unit. DLC is a public utility incorporated under the laws of the Commonwealth of Pennsylvania and is engaged in the generation, transmission, distribution, and sale of electricity in the city of Pittsburgh and municipalities in Allegheny and Beaver Counties, Pennsylvania. Mr. Ewing is responsible for the Quality Assurance and Quality Control Departments for both BVPS-1 and -2.

A native of Elkton, MD, he graduated from Lehigh University with a B.S. degree in Mechanical Engineering in 1959, and a M.S. degree in Business Administration from Robert Morris College in 1985. Mr. Ewing began his utility career in 1959 as a Test Engineer at the Shippingport Atomic Power Station. In 1976 he was named Senior Quality Assurance Engineer in the Quality Assurance Department, and he became Quality Assurance Supervisor in 1977. He assumed his present position as Manager in 1981.

Mr. Ewing is a member of ASME and ASQC. Gene and his wife Blanche have three children and live in Moon Township, PA.

Duquesne Light

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

T. W. BURNS

Thomas W. Burns is Director Operations Training of Duquesne Light Company's (DLC) Nuclear Training Department. DLC is a public utility incorporated under the laws of the Commonwealth of Pennsylvania and is engaged in the generation, transmission, distribution, and sale of electricity in the city of Pittsburgh and municipalities in Allegheny and Beaver Counties, Pennsylvania. Mr. Burns is responsible for the development, conduct, and administration of the nuclear license training and license retraining programs to provide skilled operating personnel for BVPS-2 in a safe, efficient, economical manner.

A native of Pittsburgh, PA, he attended Penn State University in the Credit Acquisition Program for SROs. Mr. Burns began his utility career in 1971 as a Station Operator at Shippingport Atomic Power Station in the Power Stations Department. In 1972 he was named Operator at BVPS-1. He became Operating Foreman in 1973 and licensed SRO in 1975. In 1977 he became a training instructor in the Training Department. He assumed his present position as Director Operations Training in 1985.

He served in the Navy from 1965 to 1971 in the Nuclear Program. He left the Navy as an EM-2. Tom and his wife Armandina have two children and live in Brighton Township, PA.

Duquesne Light

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

E. T. EILMANN

Ervin T. Eilmann is Lead Licensing Support Services Engineer of Duquesne Light Company's (DLC) Regulatory Affairs Department. DLC is a public utility incorporated under the laws of the Commonwealth of Pennsylvania and is engaged in the generation, transmission, distribution, and sale of electricity in the city of Pittsburgh and municipalities in Allegheny and Beaver Counties, Pennsylvania. Mr. Eilmann is responsible for technical and administrative supervision of the Licensing Support Services Section which includes such activities as environmental protection, equipment qualification, fire protection, nuclear safety, permits, and licensing scheduling and planning.

A native of Cleveland, OH, he graduated from Valparaiso University with a B.S. degree in Civil Engineering in 1974, and an M.S. degree in Civil Engineering from Akron University in 1984. Mr. Eilmann began his utility career in 1974 as an Associate Engineer in the Mechanical Engineering Department of Ohio Edison Company. In 1976 he was named Engineer on the Erie Nuclear Plant Project. In 1982 he was loaned to DLC and assumed his present position as Lead Licensing Support Services Engineer.

Mr. Eilmann is a registered Professional Engineer in the State of Ohio. Erv and his wife Linda have one child and live in Beaver, PA.

Duquesne Light

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

K. D. GRADA

Kenneth D. Grada is Manager, Nuclear Safety, of Duquesne Light Company's (DLC) Nuclear Group. DLC is a public utility incorporated under the laws of the Commonwealth of Pennsylvania and is engaged in the generation, transmission, distribution, and sale of electricity in the city of Pittsburgh and municipalities in Allegheny and Beaver Counties, Pennsylvania. Mr. Grada is responsible for interfacing with the NRC on licensing and safety issues, fire protection, and independent safety evaluation group.

A native of Pittsburgh, PA, he attended U.S. Maritime Academy, Penn State University, and Rennsaylaer Polytechnic Institute in the Mechanical and Electrical Engineering programs. Mr. Grada began his utility career in 1969 in the High Tension Meter and Test Lab. In 1970 he became a Radiation Technician at Shippingport Power Station. In 1971 he became Nuclear Station Operator at Shippingport Power Station. In 1972 he was appointed Operating Foreman at BVPS-1 and to Shift Supervisor in 1974. In 1981 he was appointed Superintendant of Licensing at BVPS-1. He assumed his present position as Manager Nuclear Safety in 1983.

He served in the Army from 1967 to 1969. He left the Army as Staff Sergeant. Ken and his wife Linda have two children and live in Pittsburgh, PA.

Duquesne Light

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

J. A. HULTZ

James A. Hultz is Deputy Project Manager of Duquesne Light Company's (DLC) Construction Liaison Group of the Project Controls Department. DLC is a public utility incorporated under the laws of the Commonwealth of Pennsylvania and is engaged in the generation, transmission, distribution, and sale of electricity in the city of Pittsburgh and municipalities in Allegheny and Beaver Counties, Pennsylvania. Mr. Hultz is responsible for construction and engineering interfaces on BVPS-2.

A native of Bethel Park, PA, he graduated from Penn State University with a B.S. degree in Nuclear Engineering in 1971. Mr. Hultz began his utility career in 1971 as a Junior Engineer in the Nuclear Engineering Department of Ohio Edison Company. In 1972 he became an Associate Engineer in the Nuclear Engineering Department. In 1975 he was promoted to Engineer and in 1978 he became the General Project Engineer for the Erie Nuclear Project. In 1982 he was loaned to DLC as Deputy Project Manager for Engineering and Licensing in the Nuclear Construction Division. He assumed his present position as Deputy Project Manager in 1984.

Mr. Hultz is a member of the American Nuclear Society and is a register Professional Engineer in the States of Ohio and Pennsylvania. Jay and his wife Linda have two children and live in Beaver, PA.

Duquesne Light

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

J. H. LUKEHART

John H. Lukehart, Jr., is the Director of Security of Duquesne Light Company's (DLC) Beaver Valley Power Station. DLC is a public utility incorporated under the laws of the Commonwealth of Pennsylvania and is engaged in the generation, transmission, distribution, and sale of electricity in the city of Pittsburgh and municipalities in Allegheny and Beaver Counties, Pennsylvania. Mr. Lukehart is responsible for directing the nuclear and industrial security of the Beaver Valley Power Station.

A native of Punxsutawney, PA, he graduated from Indiana University of Pennsylvania with a B.A. degree in Social Science in 1970. Mr. Lukehart began his utility career in Babcock and Wilcox's Nuclear Materials Division in 1966 as a Health and Safety Technician, progressing to Internal Compliance Officer in 1969, Licensing Officer in 1971, and Division of Security Officer in 1973. In 1976, Mr. Lukehart became the Supervisor of Safety and Security for Cerro Metal Products, Inc., and in 1978 the Security Chief for Crucible, Inc. He assumed his present position in DLC as Director of Security in 1981.

Mr. Lukehart is a Major in the U.S. Army Reserve. John and his wife Virginia have two children and live near Beaver Falls, PA.

Duquesne Light

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

W. S. LACEY

W. Steven Lacey is Plant Manager of Duquesne Light Company's (DLC) Nuclear Group. DLC is a public utility incorporated under the laws of the Commonwealth of Pennsylvania and is engaged in the generation, transmission, distribution, and sale of electricity in the city of Pittsburgh and municipalities in Allegheny and Beaver Counties, Pennsylvania. Mr. Lacey is responsible for all operative, maintenance, and testing activities at BVPS-1 and -2 and assures the stations are operated in accordance with Technical Specifications and applicable regulations and procedures.

A native of Pittsburgh, PA, he graduated from Allegheny Community College with an Associates degree in Electrical Engineering in 1971 and Cornell University with a B.S. degree in Electrical Engineering in 1973. Mr. Lacey began his utility career in 1973 as a Test Engineer in the Nuclear Group. In 1974 he was named Nuclear Operating Foreman at BVPS-1 and became Nuclear Shift Supervisor in 1977. In 1980 he became Technical Advisory Engineer, and in 1982 he was assigned to the Chief Engineer position at BVPS-1. He assumed his present position as Plant Manager in 1983.

Mr. Lacey served in the Navy (Submarine Service, Nuclear) from 1963 to 1969. He left the Navy as an E-6 Electrician. Steve and his wife Susan have two children and live in Moon Township, PA.

BVPS-2 ACRS
Subcommittee Questions

Q1: What percent of annual low level waste volume will come from secondary full flow demineralizer resins?

Response: All resin from the condensate polishing demineralizers will be disposed of as industrial waste. Therefore, there is no contribution to solid waste (high or low level).

If BV-2 operated with a tube leak and dumped one expended demineralizer charge per shift, this would contribute approximately 300-500 cu/ft of resin per month to the solid waste system.

BVPS-2 ACRS
Subcommittee Questions

Q2: Have water-filled Main Steam Lines been considered in the BV-2 design?

Response: Transient events considered in the design basis for piping systems at BV-2 were established on the basis of the system design and an extensive review of nuclear operating experience as reported in NUREG-0582 and other industry documents. Such a review resulted in elimination of the steam generator overfill transient. Consequently, the capability of the main steam lines to sustain the loading associated with steam generator overfill has not been uniquely addressed in the pipe stress analysis and support design.

However, the main steam lines have been designed and analyzed to consider:

1. Thermal expansion associated with maximum steam temperature

2. Deadweight associated with the water-filled main steam lines during the hot hydro testing condition.

The current BV-2 steam generator feedwater control and protection system is the standard Westinghouse 3 channel system and it is the same design that is now being used in 24 operating nuclear pants. The BV-2 design is safe and will maintain an acceptable level of safety as shown by the BV-2 FSAR and as demonstrated by the many operating reactor years of the Westinghouse designs currently in use.

A steam generator overfill resulting from an SG level control malfunction requires the coincidence of all of the following conditions:

1. Steam generator feedwater must be supplied by the main feed pump(s) (BV-2 has an electric driven startup feed pump).

2. The main feedwater regulating valves (not the bypass valves) must be controlling feedwater.

3. The main feedwater regulating valves must be in the automatic mode.

4. Steam generator level channel C must fail low.

5. Either SG level channel A or B on the same steam generator must fail in a very specific manner.

6. The operators must not take appropriate action to terminate the event.

7. The reactor must not trip prior to filling the steam generator.

The control channel (Channel C) must fail low. The failure must be in the level detection circuitry. Failures in the feedwater regulating valve or in the controller would not reduce the number of signals available to perform the 2-out-of-3 coincidence turbine trip/feedwater isolation protective function.

A second steam generator level channel (Channel A or B) on the same steam generator must either fail-as-is or its high level bistable must fail. If the channel failed high or failed low feedwater isolation would occur. Loss of power, opens, or shorts in the detector/indicator circuitry would result in feedwater isolation. The industry operating experience has been that instrumentation faults resulting in fail-as-is are not the highest probability failure modes.

The reactor must not trip prior to filling the steam generator since a reactor trip in coincidence with a low T_{AVG} shuts the feedwater regulating valves (SOV in the air supply fails shut).

Finally, the operator must not take action to terminate the event. However, the operators are provided sufficient information to take appropriate corrective action. A low SG level alarm and a steam flow-feed flow mismatch alarm promptly attract the operator's attention. Three narrow range level, one wide range level, two steam flow, and two feed flow indicating channels are provided for each steam generator. Operators are trained to use steam flow and feed flow indications in evaluating the adequacy of and controlling feedwater flow rates. BV-2 has performed an analysis which established that the operator has ten minutes to take appropriate corrective action if this event is postulated to occur at full power. The available time for operator action is reduced at lower power levels. DLC experience at BV-1 and planned operation of BV-2 indicate that nearly all power operation will occur at or near full power. The appropriate operator actions can and would be performed promptly. Within a matter of seconds the operator would:

1. Identify which SG is receiving excess feedwater
2. Place the respective feedwater controller in manual
3. Reduce feed to the affected SG

All the required indications and controls are located in the same area on the control room panel. Operator training and experience indicate that these actions would be taken. In the unlikely event that an operator decided to trip the reactor rather than analyze the readily available information, the transient is terminated. The SG level shrink provides a prompt reduction in SG level. Shortly following the trip, the main feedwater control valves shut

without regard to level demand signals, when RCS temperature falls to the low T_{AVG} setpoint.

This combination of conditions, particularly the different, yet very specific failures on a single steam generator, is highly improbable. No operator action to terminate the feedflow-steamflow mismatch is also highly improbable. DLC believes that the combined probability of these events is only a very small contributor to the probability of SG overfill from all causes. Since NUREG-0844 (resolution of USI A3, 4, 5 Steam Generator Tube Rupture) states that overfill events resulting from SGTR events will be addressed by USI A-47, this conclusion should soon be confirmed. Staff recommendations to resolve A-47 are due in November 1985.

This issue was addressed as a backfit in accordance with Generic Letter 84-08. In the BV-2 PSAR, the Commission approved the BV-2 feedwater control and protection systems and indicated that IEEE-279 was addequately considered. No changes to this 1971 regulatory criteria or to the feedwater design have occurred since. However, the staff proposal implied that this same feedwater design was not acceptable.

Clearly the NRC had changed its interpretation of an existing unrevised regulation for which major modifications to BV-2 systems and components would have been required to meet this new interpretation.

10CFR50.55a(h) provides the regulatory basis for application of IEEE-279 to the protection systems of nuclear power plants. Part 50.55a, which became effective on July 12, 1971, applies to all plants which received construction permits after January 1, 1971.

At least 12 other Westinghouse plants, which have received construction permits since 1971, use two out of three logic for the high steam generator water level turbine trip. The staff must have determined that these 12 plants comply with 10CFR50.55a(h) and IEEE-279, since no exemptions to 10CFR50.55a(h) have been required.

BV-2 FSAR has shown in Section 15.1.2 for excess feedwater events that the fuel limits for departure from nucleate boiling are not exceeded at any time, radiological doses are within 10CFR20 limits and the reactor coolant system pressure boundary is not breached.

Section 15.1.2 of the BV-2 FSAR meets the current Standard Review Plan acceptance criteria for increase in heat removal events. NRC action to resolve unresolved safety issue A-3, steam generator tube integrity, was recently issued through Generic Letter 85-02 and NUREG-0844 by the NRC director of licensing. Steam generator overfill was addressed in that NUREG. However, no NRC actions were recommended at this time, but instead as stated in Section 4.3.1 of NUREG-0844, the NRC study on steam generator overfill is

being performed as part of the unresolved safety issue A-47, control system failures, safety implications of control systems.

Thus, an addition of a fourth steam generator level channel now on BV-2 to address control system interaction with steam generator overfill would be premature and at best would be considered only an interim change pending resolution of unresolved safety issue A-47.

If the NRC believed that adding a fourth steam generator level channel to this standard design was truly required to maintain a minimum level of safety, then a generic order would certainly have been issued to operating plants with the 2-out-of-3 feedwater level design rather than awaiting the outcome of unresolved safety issue A-47.

In fact, the Commission continues to allow, we believe, nine plants to operate without any form of high steam generator water level turbine trip function.

Duquesne Light Company believes that a backfit to address this very specific scenario would only slightly reduce the relatively small probability of steam generator overfill from all causes. However, even if the addition of a fourth steam generator level channel to BV-2 was postulated to provide a minimal increase in the protection, it would not be cost beneficial. The addition of a fourth steam generator level channel would result in a cost of over $1 million an may well result in a delay in the startup of the plant. Duquesne Light Company sees no justification for imposition of an interim solution now when the final resolution of A-47 is scheduled to be available in 1986.

Duquesne Light Company will meet any requirements that evolve from the resolution of A-47 to allay steam generator overfill concerns.

Since further analysis is beyond the current licensing design basis and the staff's resolution to unresolved safety issue A-47 is incomplete, staff requests for such analyses would fall under 10CFR50.54.

In summary, IEEE-279 is not required for a control function such as the high steam generator water level turbine trip as per Standard Review Plan 7.7.

However, Duquesne Light Company believes their current standard Westinghouse-designed feedwater control and protection system maintains an acceptable level of safety as demonstrated by the BV-2 FSAR and the many operating plants using the standard Westinghouse design systems.

An addition of a fourth steam generator water level channel will not provide a substantial increase in the protection of the public health and safety.

As a result of the use of the GNLR 84-08 Backfit Procedures, NRC staff management focused additional staff attention on this issue. After an appeal meeting at the division director level, NRR determined that no undue risk to the public existed and agreed with the DLC position that additional response to these concerns is not warranted prior to the resolution of USI A-47. One area that the staff is still evaluating is the question of applicability of 10CFR50.55a(h). If the staff determines that an exemption to 10CFR50.55a(h) is required, it appears that the exemption would be required of all plants with CP dates after January 1, 1971, unless those plants had backfit their SG level instrumentation.

BVPS-2 ACRS
Subcommittee Questions

Q3: How do you stop destruction of room from full CO_2 discharge?

Response: Refer to subcommittee Question No. QE2 received from J. Ebersole.

BVPS-2 ACRS
Subcommittee Questions

Q4: From the experience at BV-1, what have been the number of challenges on the Auxiliary Feedwater System?

Response: The following signals auto-start the Auxiliary Feedwater Pumps:

Motor Driven (2):

1. 2/3 Low-Low Steam Generator Levels (2/3 signals per steam generator)

2. SIS (Safety Injection Signal from any of the following: low pressurizer pressure, high containment pressure, low steam pressure rate, or manual)

3. Start failure of Turbine Driven Pump (low discharge pressure time delay with start signal present)

4. Trip of Main Feedwater Pumps

Turbine Driven Pumps (1):

1. 1/3 Low-Low Steam Generator Levels (2/3 signals per steam generator)

2. 2/3 Low Reactor Coolant Pump Bus Voltage

Above 10% power, all of these conditions (except Item 3) will produce a reactor trip signal. Since at-power reactor trips also cause the steam generator levels to decrease (shrink) below the auto-start point of the Auxiliary Feedwater Pumps, through strict interpretation of a "challenge," the number of AFW challenges can be determined by the table below:

Year	Number of At-Power Reactor Trips
1976	43
1977	47
1978	25
1979	15
1980	4
1981	11
1982	9
1983	11
1984	7
1985 (to date)	8
TOTAL	180

For purposes of further evalutating and reducing this data, we will define a challenge as a transient which results in a sustained loss of the main feedwater system such that there is a continued need for the AFW System to perform its primary safety function. All other transients which auto-start the AFW pump will be classified as demand signals.

It is important to make this distinction between challenges and demands because unlike some facilities, both BV-1 and BV-2 employ motor driven Main Feedwater Pumps which do not auto-trip on all reactor trip signals as do the steam-driven feed pumps at other units. This allows the operator to perform a number of actions quickly to restore main feed to the steam generators under various circumstances. These actions would include the following for feedwater restoration under emergency conditions if the AFW system was not available:

1. Restoring main feedwater by resetting the SIS signal.

2. Restoring main feedwater by resetting a high level condition in the steam generators which causes a feedwater isolation signal.

3. Utilizing manual control on the feedwater bypass valves if there was a sustained loss of air at the station.

4. Restart of the Main Feed Pumps post-trip where an automatic low suction pressure trip condition would be corrected at the lower flow condition to the steam generators.

Since the above conditions can be easily corrected by the operator, the number of demands on the AFW system can be reduced from the 180 reactor trip baseline by subtracting all trips attributable to any of the following conditions to determine the real number of challenges to the AFW system:

1. Transient conditions which caused a direct reactor trip due to a low-low level condition in one steam generator.

2. Transient conditions which caused a safety injunction signal with offsite power available.

3. Transients which caused a loss of station air to one or more components resulting in a reactor trip.

4. Transients which resulted in a trip of the Main Feed Pumps due to a high steam generator level condition.

5. Transients which caused a reactor trip but did not affect the ability of the main feedwater system to supply the steam generators post-trip for decay heat removal.

6. Power-dependent secondary side transient conditions which are corrected after the plant trip (by the trip itself) and would permit the main feedwater system to be used to supply the steam generators at the reduced flow rate.

All 180 at-power reactor trips in the data base were reviewed and excluded from the count if the transient fit one or more of the criteria (1-6 above).

Results: Four events, described below, remained after the data base was reduced to determine which transients resulted in a condition whereby the AFW system was challenged to perform its safety function under post-trip conditions.

Event 1:

On June 15, 1976, a reactor trip occurred from 22% power due to clogged strainers in the suction line of the condensate pumps.

Event 2:

One June 16, 1976, a manual reactor trip occurred from 3% power due to clogged strainers in the suction line of the condensate pumps.

Event 3:

On October 5, 1976, a manual reactor trip occurred from 17% power due to a leak on the 1B Main Feed Pump seal cooling line with the second Main Feed Pump out of service.

Event 4:

On July 28, 1978, the main transformer faulted resulting in a reactor trip and safety injection at 99% power. Offsite power was lost for 17 minutes.

Conclusion:

For Events 1-3, inclusive, it is possible that the feedwater system could have been capable of supplying the steam generators under the post-trip condition for decay heat removal. Since this could not be ascertained, they were not excluded and the challenge frequency under post-trip conditions for the AFW System was determined to be four events in 10 years or 0.4 events per year.

There are a number of balance of plant and protection electrical, control, pneumatic, and fluid systems that can interact with the feedwater systems. For this reason, there are more start demands on the AFW System than any other safety related fluid system. Moreover, the feedwater system is one of the principle contributors to reactor trips industry-wide as detailed in WCAP 10405.

Additional Information Requested by the ACRS on the AFW System

The turbine-driven Auxiliary Feedwater Pump is supplied steam through six in-line solenoid valves; these valves operate on 125v dc and fail open. On loss of 125v dc, the valves will open by means of a spring and pilot operation thereby providing steam to the feedpump. The taps for these valves are upstream of the MSIVs.

The turbine-driven Auxiliary Feedpump throttle valve is a manual valve which must be in a latched condition to allow steam to the turbine. This latched condition is monitored by the plant computer and is an input to BISI (Bypassed and Inoperable Status Indication).

The pump discharge valves (six in total) are electrohydraulic valves and are operated by 480v ac. These valves are normally full open and their position monitored by the BISI system. In case of failure of a control signal, the valves fail open; and on a loss of motive power, fail as is. The valves can be moved manually on a loss of power.

References:

DLC Letters ND1SLC:1072, ND1NSM:1850, and WCAP-10405

BVPS-2 ACRS
Subcommittee Questions

Q5: Is the PORV block valve qualified?

Response: These valves (mark nos. 2RCS*MOV535, 536, and 537) are Limitorque motor operated valves supplied by Westinghouse. The Westinghouse generic IEEE 323-1974 program (WCAPs 8587 and 8687, EQDP HE-1) contains the qualification for these valves. This qualification envelopes postulated normal, abnormal, and accident (LOCA) conditions for inside containment at BV-2 as determined by engineering review. The valve proper is a three inch gate valve (model 36M88) manufactured by Westinghouse Electro Mechanical Division (ASME Code 1 Valve).

BVPS-2 ACRS
Subcommittee Questions
Received from J. Ebersole

QE1: Question of Applicants absence of analysis of consequence of steam generator overfill.

Response: Refer to subcommittee Question 2 response.

BVPS-2 ACRS
Subcommittee Questions
Received from J. Ebersole

QE2: Discussion of control of carbon dioxide distribution into safety areas in context of potential overpressurization.

Response: BV-2 utilizes a ten-ton capacity low-pressure carbon dioxide storage tank to protect several safety related fire areas within the plant. A redundant ten-ton storage tank is connected to the system by piping and associated valves that must be manually opened to align the redundant tank. All of the areas that are protected by carbon dioxide utilize a total flooding system that is connected to the storage tanks by seismically supported welded steel pipe.

The pressure buildup in any area during a carbon dioxide discharge is a function of the discharge rate and the free vent area provided. The rate of discharge to any area is determined by controlling the sizing of the supply piping and by the use of orifices installed at the discharge nozzles. The amount of free vent area for each fire area has been calculated; and it has been determined that the normal leakage paths that presently exist, i.e., under doorways and through the dampers in the ventilation system, are sufficient to prevent pressure buildup through extended discharge. The possibility of excessive pressure buildup has been postulated for each area with the most adverse affect identified being bulging of the fire doors. However, in all cases, redundant systems necessary for safe shutdown of the plant would not be affected.

After the permanent penetration seals have been installed, each area will have a functional test of the carbon dioxide system to verify the adequacy of design. Factors that will be monitored will be the actual levels of concentration obtained during the discharge and soak periods and verifying that sufficient natural vent area has been provided to prevent overpressurization. Therefore, any system malfunction, such as a malfunctioning timer, which would cause a potential discharge of the total ten-tons of carbon dioxide, would not cause overpressurization.

BVPS-2 ACRS
Subcommittee Questions
Received from J. Ebersole

QE3:

a. Clarified difference between safe and alternate shutdown panels.

b. Justified presence of emergency shutdown panel (ESP) after satisfactory completion of alternate shutdown panel (ASP).

c. Discuss negative aspects of emergency panel that cannot accommodate damage situations in main control room.

d. Discuss design and operating logic regarding ASP.

Response:

a. Safe shutdown can be accomplished from either the main control board, ESP, or ASP. There is not a panel specifically called the safe shutdown panel. Safe shutdown capability is defined as one train of systems available to achieve and maintain hot shutdown conditions. Controls and systems are also available to achieve and maintain cold shutdown within 72 hours. The ESP will be used to obtain safe shutdown if the main control room experiences a loss of habitability. Safe shutdown can be achieved from the ESP for fires anywhere in plant except in the instrumentation and relay room, cable spreading room, west communications room (ESP station), the cable tunnel, and the main control room. In these five rooms safe shutdown could not be assured due to inadequate electrical separation. For these five rooms an ASP (remote to these rooms) was installed to assure the safe shutdown capability (Section C.5.c to BTP CMEB 9.5-1).

b. The presence of the ESP was required by General Design Criteria-19 and Standard Review Plan Section 7.4 and was incorporated into the BV-2 design in the 1972-1974 time frame, significantly before the ASP. The ESP will be used to achieve a safe shutdown condition in the event the main control room experiences a loss of habitability. The ESP has an advantage over the ASP in that the ESP can control both safety-related trains as well as the necessary non-safety related systems, where as the ASP can control only one train (orange). The ASP was required to comply with Section C.5.c to BTP CMEB 9.5-1 only. Both of the panels are necessary in order for BV-2 to meet the aforementioned regulatory requirements and guidelines, and neither the ESP or ASP can be deleted from the design of BV-2.

c. The ESP can accommodate any damage situation in the main control room. The design of the ESP is such that any spurious or unwanted control signals will not inhibit an operator's capability to control those circuits which are on the ESP. Transfer to the ESP allows complete electrical independence of this panel regardless of previous or ongoing spurious or unwanted signals. The same design exists for those circuits on the ASP.

d. The ASP is a manually controlled panel with no automatic signals available. Its controls, instrumentation, and safe shutdown equipment is powered by the Class 1E orange train emergency diesel generator. In the event of a single exposure fire in any one of the five fire areas (see response to question 3.a), the ASP will be used to transfer its circuits required to obtain a safe shutdown by electrically isolating them from the fire area.

If an exposure fire occurs in the ASP room, only the orange Class 1E train is impaired and the safe shutdown can then proceed from the unaffected purple Class 1E train in the main control room. In accordance with the guideline of BTP-CMEB 9.5-1, the ASP must consider a loss of offsite power.

BVPS-2 ACRS
Subcommittee Questions
Received from J. Ebersole

QE4: Describe operation of turbine driven auxiliary feedpumps without direct current.

Response: The turbine driven auxiliary feed pump does not require DC power to operate.

- The steam suply valves will fail open
- The flow to the steam generators will be controlled manually at the auxiliary feedpump discharge valve.

BVPS-2 ACRS
Subcommittee Questions
Received from J. Ebersole

QE5: Discuss logic of allowing key locked manual transfer to redundant electrical supply in light of potential common mode failure. What checks preclude transfer and what alternate controls prevent cascade failure?

Response: BV-2 design does not require the loading of redundant equipment on a single safety related bus to safely accommodate any design basis event. In a limited number of cases, a third piece of equipment is supplied as a replacement for redundant equipment which is dedicated to a particular emergency bus. These replacement loads can be powered from either bus through a key interlock transfer scheme, which prevents interconnecting the busses as shown on the attached figure.

If a faulted piece of equipment causes failure of one emergency bus, failure of the redundant bus as a result of transferring that piece of equipment is highly unlikely. The following aspects of plant design and operating practices assure this event will not occur.

1. Since only a single train of safety related systems is required for any design basis event and each train is powered from a single emergency bus, loss of one bus does not create an unsafe condition. Therefore, transfer of replacement loads to the energized bus is not necessary.

2. Likelihood of plant conditions existing which could set the stage for an unfortunate operator action is low because all the following conditions are necessary:

    a. A piece of replacement equipment must fail in such a way as to cause a power source failure. Only a few pumps and fans are provided as replacements.

    b. The faulted equipment must have been connected to one of the two power sources.

    c. The circuit protection equipment associated with the first power source for the replacement load must fail to protect the power source.

    d. The circuit protection equipment associated with the other power source for that replacement load must also be defective. (Note that each replacement load has a separate breaker dedicated to each power source.)

    In addition to these specific circumstances, the operator must recognize an additional plant condition requiring transfer of the replacement load.

3. Operating practices would generally follow actions similar to the following:

    a. Upon loss of one bus, verify availability of the redundant bus.

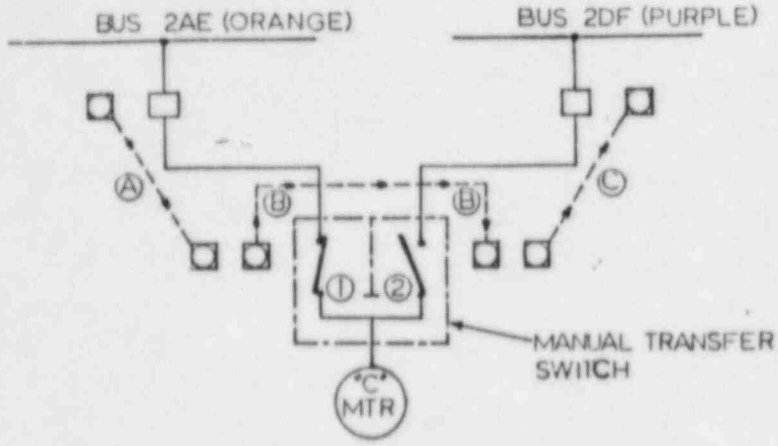
    b. Verify that safe plant conditions exist with one power source available.

    c. Determine the cause of power source unavailability.

    d. After indication of cause is found, the affected bus will be stripped of all loads, re-energeized, and manually reloaded as necessary.

These types of operating controls would assure that replacement equipment is not transferred unless it is desirable and that faulted equipment is not transferred.

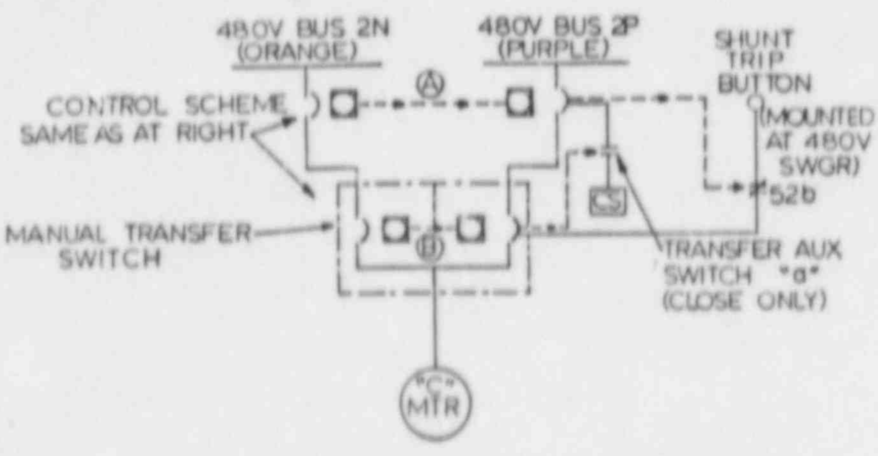
KEY INTERLOCKS 4160V SWING MOTORS



DESCRIPTION OF OPERATION

1. BREAKER ON BUS 2AE RACKED IN; "A" KEY HELD CAPTIVE. SWITCH "1" LOCKED CLOSED WITH "B" KEY HELD CAPTIVE. SWITCH "2" LOCKED OPEN WITH "C" KEY HELD CAPTIVE. BREAKER ON BUS 2DF LOCKED IN RACKED OUT POSITION.
2. TO TRANSFER POWER SOURCE FROM 2AE TO 2DF; RACK OUT BREAKER ON 2AE, REMOVE "A" KEY & INSERT IN SWITCH "1". OPEN SWITCH 1, WHICH HOLDS "A" KEY CAPTIVE & RELEASES "B" KEY. INSERT "B" KEY IN SWITCH "2" & CLOSE SWITCH "2". "B" KEY IS HELD CAPTIVE & "C" KEY IS RELEASED. USE KEY "C" TO RACK IN BREAKER ON BUS 2DF.

KEY INTERLOCKS 480V SWING MOTORS



DESCRIPTION OF INTERLOCKING

1. ONLY ONE 480V BUS BRKR & ONE TRANSFER SWITCH BRKR MAY BE CLOSED AT A TIME. ONE "A" & ONE "B" KEY WHEN BRKR IS CLOSED, KEY HELD CAPTIVE.
2. TO CLOSE 480V "P" BRKR, "P" TRANSFER SWITCH BRKR MUST BE CLOSED. TO TRIP "P" TRANSFER SWITCH BRKR, P 480V BRKR MUST BE TRIPPED. THIS INSURES TRANSFER SWITCH DOES NOT OPERATE UNDER LOAD. SIMILAR SCHEME FOR "O" BRKRS.

OPERATING SEQUENCE

1. TO TRANSFER POWER SOURCE FROM 2N TO 2P TRIP "O" BRKR WHICH ALLOWS "O" TRANSFER SWITCH BRKR TO BE TRIPPED & ALLOWS KEYS "A" & "B" TO BE REMOVED FROM "O" BRKRS.
2. INSERT KEYS "A" & "B" INTO "P" LOCKS. CLOSE MANUAL TRANSFER SWITCH BRKR "P" ALLOWING "P" BUS BRKR TO BE CLOSED.

BVPS-2 ACRS
Subcommittee Questions
Received from J. Ebersole

QE6: Discuss real challenge frequence and auxiliary feedpump system vs. reliability as expressed in Table 10.1.

Response: Refer to subcommittee Question 4 response.

BVPS-2 ACRS
Subcommittee Questions
Received from J. Ebersole

QE7: Discuss consequences of loss of all AC power including potential leakage for main current pump seals.

Response:

- WCAP 10541 discusses coolant pump seal leakage.
- Procedure ECA00 discusses the consequences of seal leakage and is included in the station blackout procedure.

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