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NUCLEAR REGULATORY COMMISSION

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NUCLEAR REGULATORY COMMISSION

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BRIEFING ON OPTIONS FOR ADDRESSING SHUTDOWN AND LOW POWER RISK ISSUES

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PUBLIC MEETING

Nuclear Regulatory Commission
One White Flint North
Rockville, Maryland

Tuesday, July 20, 1993

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

COMMISSIONERS PRESENT:

IVAN SELIN, Chairman of the Commission
KENNETH C. ROGERS, Commissioner
FORREST J. REMICK, Commissioner
E. GAIL de PLANQUE, Commissioner

STAFF SEATED AT THE COMMISSION TABLE:

SAMUEL J. CHILK, Secretary

JOE SCINTO, Deputy General Counsel for Hearings, Enforcement and Administration

JAMES TAYLOR, Executive Director for Operations

WILLIAM RUSSELL, Associate Director for Inspection and Technical Assessment, NRR

ASHOK THADANI, Director, Division of Systems Technology, NRR

ROBERT JONES, Chief, Reactor Systems Branch, NRR

MARK CARUSO, Reactor Systems Branch, NRR

P-R-O-C-E-E-D-I-N-G-S

10:00 a.m.

CHAIRMAN SELIN: Good morning, ladies and gentlemen.

The Commission is meeting at this time to receive a briefing from the staff on the status of the shutdown risk program. This is an agency-wide program that was begun as a result of international studies on shutdown risk, as well as the specific concerns that were raised by the incident investigation team that reviewed the 1990 loss of all vital AC power at the Vogtle Nuclear Plant. We were last briefed on the status of the program September of last year.

Today's meeting serves as a means for the staff to update the Commission and the general public on the status of the program by presenting technical findings, propose generic requirements and recommendations.

Of course, copies of the viewgraphs, as usual, are available at the entrance of the room.

Do we have any comments?

Mr. Taylor, would you proceed?

MR. TAYLOR: Good morning. With me at the table are Bill Russell, Ashok Thadani, Bob Jones and Mark Caruso, all from the Office of NRR.

As you mentioned, Mr. Chairman, really emanating from the Vogtle event several years ago, through various work that the staff has been doing, we've attempted to concentrate on the subject of risk during shutdown. Today we presented, first a few weeks ago, a paper to the Commission and today we believe, as you will hear in the presentation, that after a thorough study of the subject that the staff believes that rulemaking is probably the most appropriate way to establish generic requirements which address shutdown risk issues.

We will discuss the reasons for recommending that approach this morning and the Office of NRR will continue to have the lead in developing the rule and supporting documents with support from the Office of Research and the Office of the General Counsel.

With those opening remarks, I'll turn to Bill Russell to continue.

MR. RUSSELL: Okay. I would like to highlight just a little bit from the background because it relates also to the recommendation for rulemaking that we are going to. That is that the staff has been addressing decay heat removal during shutdown or issues broadly related to shutdown events

since about 1980. Between the time frame of 1980 and the Diablo Canyon event in '87, we actually issued five generic letters addressing these issues. After the Diablo Canyon event and the Vogtle time frame we issued three additional generic letters addressing these. We do feel that the generic letter following the Diablo Canyon event addressing mid-loop operation was the most significant of those and it did identify some new insights as to the risk associated with that particular mode of operation of mid-loop.

You'd mentioned that we've had bilateral discussions. The two that I'd like to highlight that were early on were discussions with the Swedish regulators and the French regulators, principally the conclusions that they had reached from doing safety assessments using probabilistic techniques and addressing shutdown events. Those assessments indicated that the core damage frequency associated with shutdown events was approximately comparable to that associated with events from power and that shutdown events were a significant contributor to core damage frequency when weighted on average over the year.

Those findings, along with the Vogtle event, led to the decision to do a reassessment of the

approach we had taken to shut down events. We concluded early on that this was not an issue that raised questions regarding adequate protection, but rather this would be clearly in the mode of enhancements to our regulations and we viewed this as necessary to take a comprehensive review of both the foreign information, our own event information.

To that end we had a task activity that was made up of participants from each of the offices, Nuclear Reactor Regulation, AEOD, Research and the regions, and we addressed operating experience broadly. We visited plants and we looked at accident sequence precursor events as they related to shutdown. We looked at PRA techniques and did a level 1 PRA. It's a screening and did not have all the uncertainty or sensitivity analyses. We did special studies on loss of decay heat removal. The particular event of concern which was identified by the French, which was a boron-dilution event during start-up, was looked at. And then we reviewed carefully our current regulatory requirements.

In addition, this issue was receiving a lot of international attention as well. Through the OECD Nuclear Energy Agency, the Committee Nuclear Regulatory Activities conducted a special review with

a meeting that was held in June of '92. That meeting included participants from utilities worldwide and it was at that meeting NUMARC was represented by Mike Wallace from Commonwealth Edison Company.

That report was completed in November of '92 and I believe copies were provided to the Commission. It is a restricted information because it was provided in confidence and, in fact, the comparative type of analysis is held closely by the countries that have participated. I would like to characterize though that essentially each country views the issues from the same perspective, from a safety standpoint. Others have gone further in their regulatory requirements as it relates to permissible activities during shutdown and in particular controls on mid-loop operation. But it does indicate what is the current status, at least amongst the Western Countries.

CHAIRMAN SELIN: Why did they hold this information tightly?

MR. RUSSELL: There have been cases in the past where there have been comparisons one country to the next and that raises questions. Taken out of context and without knowing the regulatory process that exists within a country, it is not deemed

appropriate. So, one of the ground rules associated with the information exchange was that this information would be held in confidence. It is not releaseable outside of the government's --

CHAIRMAN SELIN: So it's not based on proprietary --

MR. RUSSELL: No, it is not.

CHAIRMAN SELIN: -- insensitivity.

MR. RUSSELL: It's sensitivity to program comparisons country to country. I would point out that the comparison for the U.S., we would be near the bottom of the list with respect to regulatory requirements as it relates to shutdown risk. The actions that we are proposing are comparable to actions that have already been taken in many of these countries.

The program we initiated was a three phrased program.

(Slide) Could I have the first slide, in fact?

The three phased program was essentially a program of technical studies. We have promulgated the results of that work. It's in NUREG-1449. It was issued in February of '92. We've had a number of technical meetings on it. It's been reviewed by the

ACRS and we've received two ACRS letters. In addition, we've had numerous workshops and discussions both with inspectors and with industry. We have also issued a temporary instruction, which is guidance to the field for the purposes of conducting inspection activities, focusing on issues related to shutdown risk and it provided guidance to the field in that area.

We've interfaced heavily with industry. NUMARC has prepared guidelines which we feel are from a broad policy level and approach level. They are quite sound. We encourage the implementation of those guidelines.

(Slide) If I could have the next slide, please.

The staff last briefed the Commission in September of '92 and we basically covered those technical studies and the requirements that we had under consideration. In just a moment I'll have Bob Jones summarize both the technical findings and the recommendations. That is the specific technical recommendations that we're proposing. But I would note that the Commission requested us also to address our preliminary regulatory analysis, which has been provided in the SECY paper, and to address

specifically the pros and cons of rulemaking as compared to a generic letter. That has been completed and I will be addressing the staff's rationale for recommending rulemaking and I'd like Bob Jones now to summarize the results of the study and our technical findings.

COMMISSIONER ROGERS: Just before you move on, Bill, you mentioned that the requirements that you are recommending would bring us more closely to the practices in other countries. How long have they had those requirements in place and could you comment as to --

MR. RUSSELL: Yes. The process --

COMMISSIONER ROGERS: -- how it is that we're behind them because we try to stay in touch with general practice worldwide? Was there a flurry of activity that led to those over a short period of time and we're just catching up to that or what?

MR. RUSSELL: Well, it varies from country to country. I would say that in general the approach in France, for example, was more advanced and developed with interaction between the regulator and EDF, addressing issues of shutdown risk and they had been essentially addressing these issues from about the 1985 time frame on, with specific technical

requirements early on. It was enhanced as a result of their PRAs which were comprehensive and addressed shutdown risk. This is in the 1989/1990 time frame, and there were additional requirements that were imposed as a result of those findings.

In other cases, the countries, Sweden in particular, had done work and was leading. In fact, that's why we started on our work in 1990. Between 1990 and 1992, I would characterize there was a lot of activity. In some countries the mechanisms by which they implement requirements are based upon discussion and mutual agreement as compared to the processes that we use in this country. I don't think that there has been a significant difference in time frame with respect to recognizing the issues or taking interim actions. We just have not completed our formal processes. I would characterize that processes in the United States are somewhat unique both from the standpoint of required regulatory analysis and backfitting and the process we go through.

So, the technical studies were nearing completion about the same time. The report does indicate that some countries are continuing to study. There is an update to that report.

MR. TAYLOR: Bill will be mentioning the

NUMARC guidelines and other actions that will come out of this whole area as a result of the staff's generic letters and discussions with industry. So, the industry has not itself stood still.

DOCTOR THADANI: If I may just add to what Bill was saying, the process, even internationally, is an evolving one. Over the years you do see changes in various countries in terms of the way they deal with shutdown risk. Some countries, France for example, has actually made a number of changes in the more recent years as a result of their studies. There are countries out there wherein they have paid attention to shutdown conditions for many, many years in terms of requirements for redundancy and diversity of available equipment. So, what you see generally is better understanding over time, an increased set of requirements in most European countries certainly.

MR. RUSSELL: Okay, Bob.

MR. JONES: As part of our evaluation, the staff went and tried to estimate the core damage frequencies during shutdown and low power operations. To a large extent, the analyses that we performed confirmed the findings we found from the international studies, that is that shutdown risks are comparable to those of power operation. We further confirmed that

the BWR core damage frequencies are approximately a factor of ten lower than PWRs primarily as a result of unique vulnerabilities present in the PWR as associated with mid-loop operation.

One of the findings that we came to early on in NUREG-1449 and we worked with the industry on is that effective outage planning and control is extremely important in controlling shutdown risk. The outage plans determine what conditions the reactor coolant system can get into and i t also dictates the available equipment to mitigate any events that might occur. Along these lines, one of the items that we confirmed was that when the reactor cavity is flooded, the risks are essentially minimal.

As a result of the outage planning and control activities, we worked very hard with NUMARC and NUMARC-initiated and issued guidelines, NUMARC-91-06 which helps guide utilities in performing outage planning.

Another -- we also found that for both reactor types, the PWRs and the BWRs, similar to the Vogtle event, losses of off-site power can be significant contributors to core damage frequency in shutdown modes. With the current requirements in general that is out there in the industry for one

diesel or one on-site power source, we estimate that a loss of off-site power leads to about 40 percent of the core damage frequencies that we're seeing. As a result, we have concluded that redundant on-site power capabilities appear necessary when in reduced inventory.

CHAIRMAN SELIN: Does that mean safety level or do you want to talk about that later?

MR. RUSSELL: We'll talk about that in a moment, but we are looking at alternatives as long as it's capable of performing the functions. So, it would not necessarily require two safety grade on-site AC sources, but it would, for example, allow the use of a station blackout alternate AC source if they're adding a gas turbine or bringing in a portable diesel particularly for the outage to support diesel work in parallel. I'll talk about how we're proposing to implement that.

CHAIRMAN SELIN: Was there any more to that fire observation than what you have here?

MR. JONES: Well, I was going to get to that later, but I can do it now. Basically what we've found in the area of fire is we walked down at one plant and did a look see as to how the decay heat removal systems are routed through the plant and what

kind of vulnerabilities might exist if there was a fire. What we found is you can actually reduce or eliminate the redundant ones, redundant capability for decay heat removal in some plant areas and additionally, since many of the plants only require one RHR in certain modes, you can eliminate all of the residual heat removal capability at that time.

Additionally, we looked at some of the history over about a year period. We had about eight fires that we noted. Seven of these occurred during shutdown.

CHAIRMAN SELIN: That was really my interest, was the second point, did you look at the probability of fire, because you've got a lot of junk floating around and a lot of people who maybe are less sensitive than your normal --

MR. JONES: We didn't really look in a quantifiable way, but we did look at just generally the transient combustibles and types of vulnerabilities and the fact that there are no regulatory requirements in this mode for fire and we determined that that was a significant vulnerability in that mode that needed to be addressed.

MR. TAYLOR: Particularly on one RHR.

MR. JONES: Particularly on one RHR.

DOCTOR THADANI: Right. Let me expand on that a little bit. The frequency of fires during shutdown, as Bob noted, is higher. The severity of fires is not very significant. On the other hand, the current regulations really don't require that once you go below hot shutdown condition towards cold shutdown or refueling, they don't require availability of the two trains of decay heat removal in terms of if you have a fire in a certain location. It could be that during that mode you have a train unavailable for maintenance purposes or something, and the single fire will knock out total decay heat removal capability.

So, while we didn't quantify risk, I would expect it could be significant, just when you considered those facts.

MR. TAYLOR: It could be a motor.

DOCTOR THADANI: Yes, indeed.

CHAIRMAN SELIN: You know, when I read the fire protect -- you want to talk about fire protection later on?

MR. RUSSELL: I'm going to come back to that when we talk about the approach to implementation.

CHAIRMAN SELIN: Fine. Okay. We'll do that later.

MR. JONES: Okay. Finally, the other item noted from our review was that many of the operations that go on during shutdown are performed without the containment closed. That is with the containment open to allow for equipment to be moved then out. If you do not close containment and have a core damage event, we calculate that the off-site and on-site releases would be quite large and, in fact, comparable to those that would occur from a core meltdown event at power with a containment failure.

COMMISSIONER REMICK: Bob, two questions on that viewgraph, which by the way is not on the screen.

MR. JONES: Oh, excuse me.

COMMISSIONER REMICK: But the first one you give a range of core damage frequencies and I think, Bill, you mentioned they were weighted. Could you elaborate a little bit more? I'm not quite sure I appreciate the way you're weighting it.

MR. RUSSELL: We're talking about two different things. My comment toward weighting was based upon the analyses that were done overseas where they looked at a typical profile of the number of days in shutdown, the number of days in start-up and the number of days at power and then they weighted it to

come up with an overall core damage frequency and then they looked at what the contribution was associated with shutdown periods, transient start-up shutdown periods and steady state operations.

COMMISSIONER REMICK: And my question --

MR. RUSSELL: So, in that context, that's what I was discussing by weighted.

COMMISSIONER REMICK: Yes.

MR. RUSSELL: We did in our regulatory analysis weight the shutdown periods based upon time in various modes and that's contained in the regulatory --

COMMISSIONER REMICK: And how did you weight it? Does it mean that the risk was greater during the actual shutdown and if spread out over the year it was less or -- I'm not quite sure I understand the weighting in this case.

MR. RUSSELL: That is correct. There are short periods of time when the risk, if you averaged it over -- if you averaged over a year, the risk would be on the order of 10^{-4} per year, but the risk at that time is higher even though it's a shorter period of time. So, yes, typically if the core damage frequency associated with shutdown is on the same order as at power and you are shutdown for a month to two months

and you're at power for ten or eleven months, the risk associated with shutdown from a time standpoint is higher than the risk during power operation. That's principally because of the controls we have put on availability of equipment, containment for example, decay heat removal equipments that do not exist when you're in the shutdown modes.

COMMISSIONER REMICK: Right. Now, these numbers on the viewgraph, are those weighted so I can compare them with core damage frequencies in general during operation or is this during the period of shutdown?

MR. RUSSELL: This is the period of shutdown, but it is per reactor year, not per day.

DOCTOR THADANI: This is appropriate. You can compare them, although I will add one thing, that the uncertainties in estimates here are clearly much larger because they're controlled by human actions, essentially all these estimates. So, I would expect much larger bands about this.

COMMISSIONER REMICK: The question I was going to ask later, but I'll ask it now, and that is the PRA, shutdown risk PRAs are not complete. Are you going to look at your regulatory analysis once you have the PRAs complete? Will you revisit that because

you're making certain assumptions now about the risk?

MR. RUSSELL: I would characterize that I believe we've carefully documented the bases for the assumptions and we've performed some sensitivity studies. We have not carried through on certainty type analyses and it's essentially looking at the reliability of decay heat removal. So, there are insights that we've gained from the screening PRAs, et cetera. But to do it in a more quantifiable manner may be difficult and it may not be achievable in the near term. We have gotten to the point where we've done a fairly significant amount of work. We've looked at sensitivity studies. We've attempted to quantify it. They are point estimates with sensitivity studies, but it's fairly well documented as to what the assumptions were and we think that they're reasonable assumptions based upon the site visits and the other work that we've done.

COMMISSIONER REMICK: And that's okay if the PRA indicates in the range. But suppose they aren't. Would you revisit the regulatory analysis?

MR. RUSSELL: Clearly if it turns out to be substantially different than what we have reviewed here.

DOCTOR THADANI: I guess again, and let me

go back, there are two -- as you know, there are two PRAs being done for Grand Gulf and Surry. What you will end up when those studies are completed, I think, is truly an exceptional understanding of those two plants and risk during shutdown for those two plants. We utilize the -- as Bill was saying, from earlier scoping analysis what kinds of scenarios may be important. But if you look at the regulatory analysis here, every attempt was made to make as realistic an assessment as we could. I would be very surprised that you would come up with different conclusions. But what you would have once those studies are done would be a much better understanding of those two plants clearly.

MR. JONES: If I could add to that, we do have some point estimate numbers for the Surry analysis. They indicate for the $3x10^{-5}$ roughly for the core damage frequency due to internal events and a $2E^{-5}$ for the fire. They have done a fire analysis point estimate. These are recently made available to us. We are still following that study. We will incorporate the findings if new information becomes available. That work is ongoing and should be pretty much through with the internal events, a level 1 PRA, by the end of this year on both plants.

COMMISSIONER REMICK: Okay. Another question -- yes, Bill.

MR. RUSSELL: I think the important thing to recognize though is that really these issues have been driven, as Ashok mentioned, by human error. That is, in fact it's even more so recently. In April, AEOD forwarded their review of events and their conclusion was that better than 80 percent involved human error and were avoidable. The earlier studies had indicated it was on the order of 60 percent of the events. When you think about an outage and how it's conducted, you may do initially good planning for the outage, but if the outage gets behind, if something's not done properly, you can lose control of equipment configuration or get into modes where you don't have the defense in depth of the redundancy or the contingency plans. Those are generally the kinds of issues that we've seen.

These are generally avoidable with better planning and we feel that there needs to be a floor described regarding minimum equipment availability and we'll get to the rationale for that. But we don't see that this is one that significant additional study is going to change the view regarding the importance of this issue and the fact that there is some need for

regulatory control. We do see it as an enhancement. These are relatively low probability events, but they are also avoidable events and the way you can control that is by controlling equipment availability administratively, either through tech specs or through other mechanisms.

COMMISSIONER REMICK: Another question I had is on containment. How important is it to button up the containment from the standpoint of withstanding pressure versus just buttoning up so you don't have diffusion of any possible fission product? How important is it with an accident at shutdown that it be a pressure closure?

MR. JONES: We believe you need to button it up for pressure retention. You could clearly get into hydrogen issues with the containment closed or just buttoned up and not pressure retaining, which could lead to a large pulse should you have a fire. Also, low pressurize the containment. There have been some studies done as part of the research PRA which looks at the pressurization rates in containment. I don't remember the exact numbers now. I think it's like one and a half PSI or two PSI a minute type pressurizations, but as I said I don't want to be quoted on that. But it is significant. It can get

quite large given one of these events.

COMMISSIONER REMICK: Now, I assume that both of us were talking there about PWRs.

MR. JONES: Yes.

COMMISSIONER REMICK: How about BWRs?

MR. RUSSELL: We'll get to that in just a moment. But the BWRs essentially do not have a containment and if you do not maintain subcool and decay heat removal, if boiling occurs because of the specific volume of steam when you're at atmospheric pressure the quantities of steam are basically going to make it difficult to recover. You would probably fail the secondary containment fairly quickly, on the order of half an hour or so failure or less.

COMMISSIONER REMICK: Fail from what?

MR. RUSSELL: Steam pressure generation up in the spent fuel pool area, the top of the --

COMMISSIONER REMICK: Even if you had the standby --

MR. RUSSELL: Yes.

COMMISSIONER REMICK: -- control?

MR. RUSSELL: Standby gas treatment.

COMMISSIONER REMICK: Standby gas treatment, yes.

MR. RUSSELL: Standby gas treatment or

refueling area cooling. It's not sufficient to accommodate the kinds of heat loads that you would get from decay heat. So, the -- and the heat sinks are not there and it's a relatively small containment, so that there's not the volume to dissipate it. The analyses showed that secondary containment failure would occur and I recall numbers on the order of 30 minutes. It may have been less.

MR. JONES: That's about the right time.

COMMISSIONER REMICK: But in a BWR you have a lot of water usually normally there when you're --

MR. RUSSELL: That's correct. The advantage you have with a BWR is that you do have time and it looks like they have more mechanisms for maintaining subcool decay heat removal.

DOCTOR THADANI: Much lower core damage frequency estimate.

MR. RUSSELL: By about an order of magnitude.

DOCTOR THADANI: An order of magnitude lower.

COMMISSIONER REMICK: Well, thank you.

MR. JONES: Could I have the next slide?

CHAIRMAN SELIN: This is very important

and I want to make sure I understand. You're saying, roughly speaking, that on the order of half of the risk that comes in a power plant cycle comes during shutdown, maybe a third, even though the shutdown is obviously a much smaller share of the time.

MR. RUSSELL: That's correct.

CHAIRMAN SELIN: And you're saying that roughly 40 percent of the risk that occurs in shutdown is related to fire, at least in these two -- I mean this is not a generic thing, but you've done the two samples. Not necessarily caused by fire, but exacerbated by fire or --

DOCTOR THADANI: I think it was about 20 percent, I believe, for fire.

MR. RUSSELL: Bob quoted the preliminary results from Surry and it would be about 40 percent based upon Surry. We have not quantified it for other -- in the regulatory analysis we incorporated the approach to fire protection with the broad regulatory analysis as it related to controls.

CHAIRMAN SELIN: So, even if there were no risk of fire in normal operations, the fire risk during shutdown is still a major contributor --

DOCTOR THADANI: Yes.

MR. RUSSELL: That is correct.

CHAIRMAN SELIN: -- to risk.

DOCTOR THADANI: That's correct.

CHAIRMAN SELIN: Okay. So, a part --

DOCTOR THADANI: Our regulations on fire don't cover that mode.

CHAIRMAN SELIN: Right. So, we've got some work to do even after we're done --

DOCTOR THADANI: Oh, yes.

CHAIRMAN SELIN: -- with the work that's done in here.

DOCTOR THADANI: Yes.

CHAIRMAN SELIN: And we're not talking about fire barriers, we're talking about the broad question of fire prevention.

DOCTOR THADANI: That's right, exactly.

MR. RUSSELL: I'm going to cover that in just a moment as to what the issues are and the approach we're recommending.

CHAIRMAN SELIN: Fine. Thank you.

MR. JONES: (Slide) Next slide, please.

As a result of the technical findings, we have done a regulatory analysis which we provided a draft version of, which we will be upgrading to reflect our option or conclusion to go to rulemaking. I'd just like to go through what we came out as our

proposed requirements.

First off, as noted, outage planning and control is just absolutely critical in defining and mitigating shutdown risk. We believe that licensees should have a program for this that is a controlled program which would be similar to those requirements in NUMARC-91-06 which would include such things as having safety principles for outages, define roles and responsibilities for plant personnel during the outages, contingency planning for responding to events, along with appropriate procedures and operator training.

We believe, however, that the NUMARC-91-06 guidance needs to be enhanced in the area of fire protection, as Bill mentioned he will talk more about our proposed requirements for fire. But basically what it is is allows plants to perform realistic assessments of fire hazards during shutdown operations and to provide appropriate controls to limit fire loadings during the planning of the outage.

In addition --

COMMISSIONER de PLANQUE: A quick question. Are you looking at an assessment that's done on a one time basis or for each outage?

MR. JONES: We're leaving that option up

to the licensees.

Finally, we have had experiences in the recent years on use of instrumentation, available instrumentation in the plant where you can control or we desire to maintain temperature indications in PWRs while in lower loop inventory and yet they have to be disconnected when you go and put on and take off the reactor vessel head. We would like to have procedures on the use of that instrumentation to minimize the time period that you would have such instrumentation not available.

COMMISSIONER REMICK: To what extent -- what's the staff's assessment of to what extent these things are being done now as a result of the interest over the last couple of years in shutdown?

MR. JONES: We are seeing the NUMARC guidance is being implemented out in the field. We have done five shutdown team inspections. Clearly people are starting to plan their outages better. However, we are also seeing problems with maintaining safety principles throughout an outage as part of those inspections such that the controls in place as emerging work comes into the outage is not necessarily very well done. In addition, we are continuing to see events out there and we are still seeing licensees

plan outages wherein they are not, for example, maintaining redundant on-site power supplies during mid-loop operation, which is what was recommended in the INPO guidances, for example. We are seeing them all the time. In fact, we may have one today that we're going to be discussing with the licensee.

MR. RUSSELL: I would characterize it that the NUMARC guidelines are at a top level. Below that are some INPO guidelines that are more specific. We have seen cases where utilities believe that they are following the guidelines broadly and we have looked at those and have concluded that they were not and have asked to have management meetings to understand how the conditions that they're proposing are acceptable in fact meet those guidelines. This is continuing. It has been identified through our inspection activities. Some have been escalated to discussion with Headquarters.

The issue that seems to be the most contentious is the redundant on-site AC power availability, whether it be a portable diesel that's brought in or using a gas turbine. It's not redundant safety-related AC power, but that appears to be an issue for some utilities. It's not even consistent within a company. We've seen cases where one plant of

a company's organization takes a very aggressive approach to it and controls it well and another facility within the same organization basically hadn't gotten the word and was planning its outage and we concluded that they weren't consistent with the guidelines.

So, we do feel that it's necessary to establish a floor level. Operators and others understand technical specifications. These are clearly modes which have some significance to risk and we feel should be controlled at that level.

CHAIRMAN SELIN: I actually had a couple questions for you now. One is a very general one, one's a specific one. The specific one is when we do an analysis of the potential contribution of a third safety-related diesel to risk, is that just done in the operational modes or does that include shutdown risk? I've often asked why do we stop at two diesels and the answer is the third doesn't contribute much for risk. But does that include giving a second diesel when a third is under maintenance?

MR. RUSSELL: I can address that from the standpoint of what we're doing now on the new designs because that is an issue that's being looked at and we are specifically addressing shutdown risk. In

general, they have proposed three trains of decay heat removal with on-site sources. That gives them significant flexibility from the standpoint of being able to do maintenance. Essentially they can meet the goals with two available. There is not a built in spare that could be used. So, with a three train system you have significant flexibility. But essentially you would need, we believe, two. What we're saying is we're not going to require those be safety related, but we are looking at functional capability to have sufficient power.

CHAIRMAN SELIN: That two sources be available at all times even when maintenance is going --

MR. RUSSELL: That's correct. The only time we would allow less than two sources is when you're flooded up to 23 feet above the vessel flange when the canal is flooded and then you don't have the same timing requirements. In that instance we would allow them to go to a single decay heat removal --

CHAIRMAN SELIN: What about any existing diesels. I mean existing --

MR. RUSSELL: Most plants have -- because of the GDCs, they have redundant RHR capability with on-site as well as with off-site. That's from the

general design criteria. So they have generally two methods of doing that. Some overseas facilities have made modifications such that spent fuel pool cooling could be used in addition to the two trains to give them some capability. But in general, U.S. facilities do not have that kind of capability. So they're generally two train.

DOCTOR THADANI: If I may add to that though. As a result of the station blackout rule some facilities in this country did add an additional either diesel generator or a combustion turbine safety grade or, in many cases in fact, not safety related. So, there are a number of plants that have, in fact, three on-site sources of power for single unit sites. And they do take credit during power operation in terms of the third source of power. What we're saying during shutdown condition is that for a limited time period, a period where we're most concerned because if something goes wrong the available time is limited. For that period, we want to be sure that there are at least two sources of on-site power, safety or non-safety, and off-site power should be available. This is driven by trying to get an understanding of risk significance of what we ought to do.

That's the focus, this approach.

CHAIRMAN SELIN: There's a small number of plants that have fewer than two diesels per unit, two sources per unit. Oconee has got that funny hydro --

DOCTOR THADANI: That's correct.

CHAIRMAN SELIN: Have we done the shutdown PRA for these?

MR. RUSSELL: We've not looked at shared systems. It's been essentially for single unit sites. But shared systems generally have sufficient capacity to handle with one diesel both units at power or one at shutdown and one at power. So, it does relate. In fact, a shared diesels because they have to be available to support operation of the unit at power may be beneficial. Generally we would encourage and have through the station blackout rule the additional -- adding additional sources to those, either where there's a swing diesel that is shared between two units or where there are only two diesels for two units that are larger diesels.

DOCTOR THADANI: Except for Oconee, I believe, if I remember correctly, all plants where they have, for example, two unit sites with three diesels, shared diesels, they're all adding additional sources of power.

CHAIRMAN SELIN: They are? Okay. Now, on

the general question, I understand why a licensee might want to cut corners and not keep the redundant energy source, but I don't understand why they don't want to plan their outages in detail anyway. My general understanding was that very carefully planned and controlled outages are cheaper and faster and not just safer. Am I missing something or are you just trying to get people to do what in a better world they would realize is in their best interest anyway?

MR. TAYLOR: Well, our outage planning covers specific aspects of protection during the shutdown condition, whereas more broadly what you say is true, good outage planning usually means the utility --

CHAIRMAN SELIN: Part of Mr. Jones' comments --

MR. RUSSELL: This is, in fact, a win-win situation. By doing better outage planning we've seen that the outages have been shorter, which is an improvement from what has been the case in the past where they've not been as effectively planned, and it also improves the safety because they're able to manage equipment configuration and equipment availability during the outage.

COMMISSIONER ROGERS: That isn't so clear

to me though, that the outage planning has included the safety aspects.

MR. RUSSELL: It has not in the past.

COMMISSIONER ROGERS: And that, in fact, it is cheaper. I mean because they're more limited when they take into account the loss of certain functions during the outage from a safety point of view. They may not be able to turn off two different pieces of equipment to work on them at the same time and that may, in fact, result in a more costly outage than if they could do that. So, it isn't clear that it's cheaper necessarily, but it's certainly safer.

MR. RUSSELL: But we've also found in some cases that, for example, offloading the core such that you can conduct activities in parallel --

MR. TAYLOR: May be the answer.

MR. RUSSELL: -- may be part of the answer and more utilities are proceeding to offloading the core rather than staying in mid-loop for extended periods of time. There are things that can be done to plan around them. We do feel it's appropriate to ensure that there is minimum equipment available during particular modes of operation that have risk significance.

So, there clearly are tradeoffs, but in

general we've not seen that this program has resulted in lengthening outages. It requires better preplanning for the outages and then when they are better planned they are generally executed. In fact, the overrun of the outages are generally less. That is if you look at days planned versus days accomplished and how much overrun you have, a well planned outage has had generally less overrun.

CHAIRMAN SELIN: I've heard rumors you actually have a prepared briefing. I apologize for that.

MR. JONES: I think the technical specifications in the area of operability of redundant equipment we've covered pretty much already in our comments. The other item that we are adding would be the PWR containment integrity requirement, which we would put in only to early in the outage to have the containment close when you have basically lost the steam generators as a heat sink. So you have a fission barrier should you have a core damage event.

CHAIRMAN SELIN: Would you be kind enough -- I'm sorry, I should know this, but I don't. What's the background for saying that you have a containment during PWR but you don't during BWR during shutdown?

MR. RUSSELL: You have to open the top of the dry well on the BWR, which is a breach of containment, in order to do a refueling. So, the BWR is open. Basically you have the secondary containment and --

CHAIRMAN SELIN: And the BWR you can keep closed except for the convenience of just opening hatches if you want to get --

MR. RUSSELL: Basically, yes. The large dry has much more capability. In fact, we have requirements to have containment integrity set when you're handling fuel in a PWR. There are ventilation systems, et cetera, that are required for BWRs for the same fuel handling accident, but there you don't have the forcing function driving it to require the pressure integrity. But if you lose decay heat removal and you have boiling in the BWR, that same small volume above the refueling floor would be quickly pressurized and would fail.

CHAIRMAN SELIN: I see. Okay. Thank you.

MR. JONES: Finally we have identified the need for an additional level instrument for PWRs for mid-loop operation. Effectively what we are finding in spite of our enhancements as a result of Generic Letter 88-17 to add level instruments to more

accurately measure water level to control mid-loop operations, we are continuing to have problems. It's primarily related to use of a DP cell and the delta Ps around the system because of the way they're arranged. We believe that a diverse level indication is needed, primarily something like an ultrasonic device we believe is a means of accomplishing this. Some licensees have implemented it already in response to Generic Letter 88-17. Or additionally, we have had some licensees actually put in a system such that they cannot drain the system down below the mid-loop elevation that would be a -- we would consider that on a case by case basis.

CHAIRMAN SELIN: Do I perceive that what you would really like to do is to tell people not to do mid-loop operations at all and just offload or are there so many special factors from one reactor to another that --

MR. RUSSELL: That's an option for a planned outage for refueling when you're otherwise going down where you can offload the core. But if you were to have a reactor coolant pump seal problem or if you had an unplanned outage associated with steam generator tube leakage, it's really not practical or prudent to do that.

CHAIRMAN SELIN: How about just refueling outages?

MR. RUSSELL: For refueling outages it is an approach. We have not specified "Thou shalt not go into mid-loop," because there are activities that can be done and can be done safely as long as you maintain equipment availabilities, et cetera. The ones that I'm more concerned about from a safety standpoint personally is the unplanned outage where you've got a contingency where you're going into mid-loop, you're in a hurry to get there because it's not planned, you want to get down quickly, you've got a high decay heat load, it has not had the same degree of planning and those are the conditions under which we'd like to maintain the redundant decay heat removal capability, containment closure set in advance, et cetera.

So, it's that mode that I believe has risk significance as compared to where they've got a longer outage because you can manage the steps earlier in the outage, maintain the equipment available and potentially just offload.

CHAIRMAN SELIN: But you're also not doing diesel maintenance during unplanned outages, et cetera. I mean by definition they're unplanned outages, so you're not doing --

MR. RUSSELL: Our guidance would indicate that they should not. Whether that's happened in the past or not, we have had that issue come up.

CHAIRMAN SELIN: I see. Thank you.

MR. RUSSELL: Let me shift now to the bases for the staff's recommendations.

(Slide) If I could have slide 5, please.

The first point I'd like to emphasize is that we are continuing to see significant precursor events, loss of decay heat removal. They are continuing. We feel that there is a lack of control both by licensees and regulatory control on entering circumstances which are likely to be a challenge and those circumstances have often had minimum equipment and containment integrity has not been established. I mention that this has been reaffirmed in an April '93 AEOD report.

We've also talked about core damage frequency. We have not talked about consequence from the standpoint of radiological release. This similarly is comparable in magnitude to a severe accident from power initiation. This is true where the containment is not available. It's even more of a concern for the PWRs because if you do not have containment you're likely to have a ground level

release and the near field consequences are, in fact, somewhat more severe. But these are fairly significant person REM exposures comparable to that which you'd get from a severe accident from power.

The regulatory analysis that we've done, I'd like to point out, would support either approach to implementation. That is we chose to do the regulatory analysis to support either rulemaking or a generic letter approach so that the regulatory analysis itself is not determinative as to which approach you would take.

We did conclude that the activities associated with outage planning and administrative controls and fire protection were cost beneficial for the PWR and even with the sensitivity analyses we're still very cost beneficial, on the order of $52.00 per person rem avoided. For the PWR instrumentation, it was $280.00 per person rem avoided. For the BWR it was above the threshold of $1,000.00 per person rem when you only considered core damage. It was at $1600.00, but again this is an issue for which you do not have a containment and so we don't feel that that's appropriate by itself. You ought to look at --

CHAIRMAN SELIN: Would you stop for a second?

MR. RUSSELL: -- large release.

CHAIRMAN SELIN: You don't have a containment if you're refueling.

MR. RUSSELL: That's correct.

CHAIRMAN SELIN: But if you have unscheduled outages you normally keep containment integrity in a BWR?

MR. RUSSELL: It depends upon the activities that you would go into. It is possible, yes, that in an unplanned outage for a BWR if you had primary leakage in excess of, say, three to five gallons per minute and you needed to make a dry well entry to find that. You could go in and find a problem and repair it.

The issues that were most significant for the BWR were essentially loss of inventory when you were on decay heat removal. By losing inventory you lose the capability of maintaining subcool decay heat removal. That gets back to maintenance activities. For example, maintenance on drain lines on the vessel associated with reactor water cleanup system have the potential for draining inside the jet pump shroud area and so you can actually drain the vessel in those circumstances. So, it's more loss of inventory, loss of AC power are the dominant ones for the BWR and it's

not as much an issue of containment integrity. If containment integrity were there in an outage, it would clearly be a benefit for the BWR.

COMMISSIONER REMICK: In fact, any unplanned outage that was of short duration, a BWR you would probably --

MR. RUSSELL: It would be unlikely to do that because you would not want to lift the shield plugs, pull a containment head, et cetera. So, an unplanned outage --

COMMISSIONER REMICK: By definition it's all an outage?

DOCTOR THADANI: I think that's right.

MR. RUSSELL: I think we're really talking about longer outages for BWRs.

CHAIRMAN SELIN: So your remarks about what makes you most nervous are really more toward PWRs?

MR. RUSSELL: That's correct. The risk for Ps are higher because of the concerns for mid-loop operation. The advantage you have with the P is that containment, if containment integrity is set you essentially have a non-problem from the standpoint of public risk. You do have still a significant problem as it relates to core damage.

CHAIRMAN SELIN: Okay.

MR. RUSSELL: The staff is recommending rulemaking. We evaluated both implementation by generic letter and by rulemaking. The approach we looked at for generic letter was essentially a voluntary submission of information that is a commitment to a program that would address outage management, a voluntary request for technical specification amendments to implement model technical specifications, to perform a fire hazard analysis and look at contingency plans and how they would manage decay heat removal in light of fires during shutdown conditions, and for PWRs to address the reliability of existing instrumentation and to propose an additional diverse instrument for mid-loop operation.

This process, while it may be somewhat quicker to get a generic letter out, would result in significant case by case reviews. We feel it would be more resource intensive and it would likely take longer to implement for all plants in that you're always going to get to a few plants at the end where you have a lot of debate and it may even require the staff going to 50.109 with a plant-specific backfit analysis and implementing by order and, of course, there are rights when you get into ordering such

activities.

We also felt it was not as formal and, in fact, we feel that the risk significance associated with shutdown operations or its formal treatment through a regulatory process in the long-term.

CHAIRMAN SELIN: I actually happen to think that this is almost a red herring, that this is a standard case for rulemaking. It's not emergent, it's not et cetera. But I do have a question about interim activities because this is a long --

MR. RUSSELL: That's my next slide.

MR. SCINTO: I just wanted to indicate that the General Counsel's Office supports rulemaking in this case. We really think this is a rulemaking case and we would make the notation that orders in this case, if for example you went through the generic letter process and you did get recalcitrant licensees and you went to an order process, it would mean -- the way some of this stuff has been characterized, it would be very difficult to get immediate effective order. It didn't sound like the stuff you're talking about immediate effective order. Indeed, sometimes some of the language used sounds like we're talking about enhancements and sometimes it sounds like adequate protection. But if we're really talking

about enhancements, it can be very difficult to sustain an order for a safety enhancement if we concede that it is not necessary for adequate protection. That's a tough order to sustain.

MR. RUSSELL: I would also point out that, as I mentioned earlier, we've had eight earlier generic letters that we've issued related to this and the problems have continued. So, we think it's time to now formalize it by rulemaking.

We think it's important though to allow for flexibility and implementation in the rulemaking. What I'd like to do is discuss the approach that we would recommend. We are envisioning essentially two rules. The first rule would be a rule which would require outage planning, would establish broad requirements for redundancy of decay heat removal capability when in shutdown modes.

COMMISSIONER REMICK: Excuse me, Bill. You say you would require outage planning. Do you mean that or that in outage planning you would consider the safety of the risks and so forth?

MR. RUSSELL: Yes. I used the shorthand. When I talk about outage planning I'm talking about outage planning as it relates to safety as we've described.

COMMISSIONER REMICK: I don't want the perception to be left that people aren't doing outage planning.

MR. RUSSELL: No. The issue is a safety perspective on that outage planning to control equipment configuration and availability during various modes which have been shown to be significant to risk.

We would envision a broad rule with a regulatory guide which we feel that the regulatory guide may, in fact, be based upon, if not endorse, many of the items that are within the NUMARC guidelines at this point in time. We think we would also have to have a generic letter that would forward model technical specifications for the equipment availability during shutdown. To that end we have developed model technical specifications as a part of the technical specification improvement program. We have corresponded with the owners' groups and we are going to start the dialogue on those technical specifications at the end of this month.

COMMISSIONER REMICK: Bill, that's something I didn't understand. Why a generic letter to give model tech spec changes versus a reg guide giving model tech spec? I'm not quite sure I

understand the significance there.

MR. RUSSELL: Okay. At the point we're at right now we have been using basically model tech specs which have been issued as NUREG documents and have been under the staff's control. Now that we have shifted with the tech spec improvement program we have done basically the same thing. We have a set of model specs which are in the process of implementation that we have interacted back and forth with the industry on those model specifications. I would characterize that probably the bulk of the language within those specifications is language, in fact, proposed by industry which the staff has found acceptable.

In the advanced reactor approach we will have the equivalent model specifications as a part of the design certification in what we've called tier 2. So, in each case there has been a set of model specifications that you would then tailor to a particular design, put in your set points, et cetera, or address availabilities of equipment.

COMMISSIONER REMICK: But my question is why do that through a generic letter versus a reg guide or a NUREG? I don't understand why the emphasis on generic letter to provide people with model tech specs. If there's significance in the generic letter

in this case, I don't understand it. I'm not again it, I'm trying to understand.

MR. RUSSELL: I would say that the basis is just past practice. I'm not sure that the -- at least I'm not aware that the question has come up before. Generally regulatory guides have not addressed tech specs. Tech specs flow from 50.36 and the requirement in an application for an applicant to submit proposed tech specs which we have then reviewed and evaluated and we've had standard tech specs for years that provide a model that an applicant can use in proposing technical specifications.

COMMISSIONER REMICK: But you're not helping me because you said we did it by NUREG in the past and I thought reg guides were a way of conveying to people one way of doing it. I interpret that's what you're saying for the generic letter, but maybe there's more into it than I understand. If there's no answer, let's just drop it at the moment.

MR. SCINTO: If we have a regulation basis, which we're planning to have, to require people to carry out this function, then a use of a regulatory guide to give them guidance as to how to fulfill that regulation or to refer to a NUREG as another document giving guidance as to how to carry it out or a generic

letter, those are all reasonable alternatives. They're all guidance as to how to carry out a regulatory requirement which is framed in a rule.

COMMISSIONER REMICK: Right or wrong, I give some special significance to a generic letter over a reg guide. It's just consistency in my mind, I guess.

MR. RUSSELL: In any event, we do feel a need to provide model specifications. We were going to follow the practice that we had followed with the owners group. In this case we have identified the minimum equipment availability based upon safety-related equipment because we do not know the specifics of what alternative equipment they may have at their facilities that is not safety related. So, we are specifically encouraging the owners groups to identify alternative approaches to the safety-related equipment.

We've had discussion of what we'll call contingent tech specs with some licensees. Philadelphia Electric is an example where they are putting in a tie to Conowingo Dam and going to use the Conowingo facility as the alternate AC source for a station blackout. This would provide them relief on their limiting conditions for operation for their

diesels. That same contingency being available could be factored into the shutdown specs so that it could be written that either Conowingo is available or on-site safety-related source is available. But that's the approach we're taking and we're looking at a demonstration that it's capable of performing the function, but not necessarily requiring routine surveillance on these non-safety equipments. That is showing it's capable of performing the function prior to relying on it at the time it's needed. So, if you had a portable diesel you brought in, you would need to demonstrate that the portable diesel is capable of performing the function providing power to the buses, but there would not be a surveillance activity that would be continuing.

The other area that we're looking at rulemaking is in the fire hazards analysis and in instrumentation. I said that we would get back to the fire hazards analysis or the scope of the fire protection program. We think that there needs to be an analysis of fire hazards with respect to decay heat removal during cold shutdown and refueling with some modifications from what we've done in the past. We believe it should be a realistic fire based upon combustibles in the area, transient materials and

ignition sources.

We think that only -- you need not consider a loss of off-site power except in those cases where the loss of off-site power results from the fire in the area. We think that there ought to be repair capability to restore decay heat removal within about 72 hours. So that means that you have to look at the capabilities to implement that restoration. We think alternate methods of decay heat removal must be available during that 72 hour period of repair. This is a contingency approach that would be taken.

You'd asked the question earlier, Commissioner de Planque, regarding whether this could be a one time review or an each outage review. I think that's a function of the type of analysis that a license would propose. If they propose hard equipment or physical separation and they modify the facility to accommodate that, then that would not require them to do an outage by outage evaluation. If on the other hand they have not taken that approach and they address what they're going to do by way of control of transient material, ignition sources and contingency planning and the contingency methods of decay heat removal vary from outage to outage based upon what work is going on, then they would be in the

latter mode. Either option would be available under the rule.

We think that they need to consider such things as how they would make up to the reactor coolant system by way of water makeup, what decay heat removal functions are available, electrical power needs and instrumentation needs. We think that these issues would be covered with the minimum allowed equipment by technical specification so that there is a tie between this and the redundant decay heat removal capabilities. We'd like to have a fire only impact, a train during this period of time. So, if there are fire areas that impact redundant capabilities, whether it be service water or decay heat removal, then there would need to be some contingency set so that if there were a fire in that area you're still able to perform the function.

This is not proposed to be a change to Appendix R. We feel that these approaches are more realistic and it provides flexibility in planning activities during outages and we are not proposing that there be a physical separation required, which would be the case if you were to apply it to Appendix R.

CHAIRMAN SELIN: Is there anything to just

try to prevent the fires in the first place, good housekeeping and control of combustibles?

MR. RUSSELL: That's clearly a part of the program, what they're going to do by way of controlling. But, in fact, that part of the program should be in place now.

DOCTOR THADANI: That should be in place now.

MR. RUSSELL: They establish fire watches for hot work and they have requirements to have fire watches or take other action when the barriers are breached. The problem is that the design essentially looks at the capability of removing decay heat when you're hot. Our events started from power and this is an area where our regulatory framework did not require an evaluation of the capability to remove decay heat when in shutdown, when you're in subcool modes.

DOCTOR THADANI: And, Mr. Chairman, if you look at the data, what you find is that the frequency of fires is actually going down, significant fires is clearly going down over the years.

CHAIRMAN SELIN: In shutdown or across the board?

DOCTOR THADANI: No, across the board. Frequency during shutdown is higher, but across the

board the frequency is going down.

MR. RUSSELL: (Slide) If I could have slide 6, please.

COMMISSIONER REMICK: Bill, I guess I had a question before you go onto that. On page 4 of the SECY document you indicate an option for dealing with fire protection in shutdown modes by revising existing regulations to include detailed supplemental requirements. The word "detailed" caught my eye because to me that might mean prescription and it reminds me of Appendix R, which from a biased viewpoint I don't think was our shining hour. How detailed?

MR. RUSSELL: That's why I tried to describe some of the approach that we had in mind.

COMMISSIONER REMICK: Those were the approaches you had in mind.

MR. RUSSELL: This is the approach that we have in mind.

COMMISSIONER REMICK: Okay.

MR. RUSSELL: We are not down to specifying fires in fire zones of mechanisms that would be very severe. We're proposing realistic. So, this is a modification from the approach we've taken in Appendix R.

COMMISSIONER REMICK: Yes. So, by details were the things you just went over. That's what you had in mind?

MR. RUSSELL: That's the scope of what we're proposing to address.

COMMISSIONER REMICK: Okay.

MR. RUSSELL: What I'd like to do now is address essentially the rationale for why the staff believes that there is time to implement rulemaking given that this is going to stretch out for a couple of years.

First we have seen improvement in the implementation of the industry initiative, NUMARC-91-06. There are a few isolated cases where it's still raising questions regarding minimum equipment availability during shutdown for particular modes. We are addressing that through our inspection activities. We have issued a temporary instruction and that enhanced activity is in place basically looking at the conditions that are present and what type of outage planning has been put in place and contingency planning.

CHAIRMAN SELIN: The thing I had in my -- the idea I had in my question was roughly speaking you're talking about two kinds of things in the rule.

One is a set of operational steps you'd like to see taken. The second is a set of material, capital steps you'd like to see taken. Is there a convenient way to encourage the operational steps to be taken faster? Obviously we wouldn't want to force people to make capital investments on a rule that might be changed significantly in the process. But the control steps and the planning steps, which are relatively low cost steps, do you think your plan adequately takes account of the desirability of these being implemented somewhat earlier than the major capital cost things?

MR. RUSSELL: I believe that in fact the answer to that is yes. In fact, some of it is going on now on a voluntary basis by industry as a result of their initiative. Their activities in 91-06 essentially address the issues of outage planning and control, contingency plans to ensure minimum equipment availabilities. It does not have a floor level and it does have a regulatory base. That is there are not clear, specific minimums that have been established.

The areas where there are weaknesses are in fire protection and the redundant hardware instrumentation for mid-loop operation that Bob mentioned for the PWR. Those would be new areas to be addressed.

CHAIRMAN SELIN: My own personal view is it's not appropriate to try to get people to put in instruments until you've gone through the rulemaking. That's the whole idea of a rulemaking, et cetera. I'm not clear on the fire protection, how much of that is better operations and planning and how much of that is capital investment.

DOCTOR THADANI: Essentially all planning basically. I would be surprised if there's any significant hardware modification.

MR. RUSSELL: But there are choices. They could go through the planning process for each outage and address it on an outage-specific basis or they could do it one time with some capital improvements and --

CHAIRMAN SELIN: Oh, I see.

MR. RUSSELL: -- provide physical separation. So, that's an option that's available. What we would encourage would be better addressing of fire hazard and risk administratively in the interim period, looking at control of combustibles, alerting people to the importance of this and the significance of some fire areas.

CHAIRMAN SELIN: Through information notices or --

DOCTOR THADANI: And the key is maintenance.

CHAIRMAN SELIN: Is this basically through information notices as opposed to a generic letter or something?

DOCTOR THADANI: It would be information notices.

MR. RUSSELL: We have, in fact, provided this information in that the NUREG with the technical rational and the concerns has been available for some time. We've had a number of workshops that we have participated in on shutdown risk. We've had regional briefings, et cetera. So, I believe that we've done a reasonable job of getting the word out.

CHAIRMAN SELIN: But you don't have a document that says that the Commission would encourage this or something. I mean there is no such document. I mean it's not appropriate to have such a document.

MR. RUSSELL: The guidance in the past has been that we should ensure the soundness of our regulatory base before we arm-twist, et cetera.

DOCTOR THADANI: I would go back and say information --

MR. RUSSELL: We are cautious in doing that.

DOCTOR THADANI: -- notices is the level at which we could go.

CHAIRMAN SELIN: Okay.

MR. RUSSELL: I would like to point out though that we also believe that the regulatory analysis, which this I think is a good test case where we have looked at the Commission safety goals in making judgments about screening and that is addressed in the regulatory analysis. These events are not 10^{-3} events. We would not be at this table proposing this kind of a schedule if we were looking at something that was a 10^{-3} per reactor year event.

It is in the range of 10^{-4} to 10^{-6} when you address the sensitivity studies and the uncertainty. It is very dependent upon human error probability. But from a risk perspective, we think it's one that warrants going forward on a reasoned basis and would support rulemaking. So, we feel that the combination of the industry initiative, what we're doing by way of inspection and our findings regarding risk, would say that we do have time and should proceed in an orderly manner to rulemaking.

(Slide) If I could have slide 7, please.

We have received all of the comments on the NUREG. We're going to revise that and issue it

final with our recommendations to proceed to rulemaking. We expect to issue that in August of '93. The actual development of the draft rule, associated regulatory guide and supporting information we think will take us to about December of 1993. We anticipate that this will take more than one CRGR meeting and it may take more than one additional ACRS meeting. But following CRGR review and ACRS review and Commission approval, we anticipate that we would be able to issue a proposed rule for public comment in May of '94.

Following that, we would conduct a workshop with industry and the public to receive comments on the proposed rule in addition to the written comments that normally come in in response to a rulemaking. We're anticipating it would take about a year from the time of the proposed rule to the final rule and it's principally based upon the technical information having been available for some time and the approach having been identified such that we would be able to proceed relatively quickly with a rulemaking.

That completes the staff presentation and we're ready to take additional questions.

CHAIRMAN SELIN: Commissioner Rogers?

COMMISSIONER ROGERS: Does the EPRI

requirements document address these issues, the advanced light water reactor requirements document?

MR. RUSSELL: In the context that they have additional requirements on systems and those additional requirements have resulted in additional redundancy, principally for flexibility and operations, yes, it does. We have had dialogue with the evolutionary plant vendors and we provided them copies of the draft NUREG report and we have been performing analyses to look at the capability of the new designs to handle shutdown events. We have also sent to General Electric the model specifications for shutdown events and it appears at this point from the analyses they've done that they are able to meet the goals of essentially assuring highly reliable decay heat removal during shutdown. That is maintain subcool and decay heat removal and that they have sufficient and significantly better equipment for doing that from the standpoint of redundancy and additional capability.

COMMISSIONER ROGERS: That's all.

CHAIRMAN SELIN: Commissioner Remick?

COMMISSIONER REMICK: I agree that rulemaking is the proper route, but just a question of curiosity. In a country like France when they have

something like this do they impose these by license condition or through change of regulations? I'm just picking out France as one example because you said there, or Sweden is another.

MR. RUSSELL: Possibly the best thing to do would be to give you the comparative analysis that was done for each country because it describes the approaches that were taken and how they were implemented. It is a combination. They did have technical specifications that addressed shutdown conditions, but then they also have requirements that are essentially in each outage requirement where information is submitted to the regulatory authorities prior to the outage that addresses both the planned activities, modifications to be made and what are the significant safety aspects associated with the outage.

In France, for example, for mid-loop, each time mid-loop is entered it requires a specific approval of the regulator.

COMMISSIONER REMICK: But did they do this by equivalent of a condition on the individual plant licenses or is it done as a regulation?

MR. RUSSELL: I would characterize it varies from country to country. Generally it is not done at the level of a regulation. It is more of a

cooperative relationship that exists between the regulator and the regulated.

COMMISSIONER REMICK: I would expect that in Japan too.

MR. RUSSELL: That's very much the case in Japan. It's mostly a consensus process and then the action is taken.

COMMISSIONER REMICK: Now, the SECY document refers to low power operation, but we really haven't discovered low power operation. Is there anything unique in low power operation that we haven't discussed in the shutdown risk area?

MR. RUSSELL: The issues that were of concern associated with low power operation were essentially some boron dilution events due to losses of power during start-up that could result in pure water slug in a loop with the subsequent initiation of recirculation by recovering AC power. We found that those events were not as significant, but we did address the entire scope and there are conditions when draining down, for example, and going into mid-loop. That's of concern. But we addressed the entire scope, but most of our focus has been on mid-loop and decay heat removal during modes 5 and 6 or 4 and 5.

COMMISSIONER REMICK: One time I

thought -- a year or so ago when you started you were looking up to 15 percent power or something like that.

MR. RUSSELL: Yes, we were.

DOCTOR THADANI: Yes, we were.

MR. RUSSELL: That was more for completeness.

COMMISSIONER REMICK: Yes.

MR. RUSSELL: We did not find significant issues that required additional action on our part.

DOCTOR THADANI: If I may go back to your earlier question.

COMMISSIONER REMICK: Yes.

DOCTOR THADANI: I've been looking at the table that we have for various countries. It looks like most of the countries are imposing these requirements through technical specifications, most countries.

COMMISSIONER REMICK: I see. Okay. Thank you.

CHAIRMAN SELIN: Commissioner de Planque?

COMMISSIONER de PLANQUE: Just one question on the containment integrity issue. You mention in the paper the possibility of installing containment closure manifolds. This is rather costly. How many plants would you expect might have to do

that?

MR. RUSSELL: I think we'd have to get back. It is one of the possibilities. I personally believe it's probably easier to set containment integrity. That's done now for handling fuel and to set it in advance rather than to go to significant design modifications. We'll have to get back to you to give you that estimate.

COMMISSIONER de PLANQUE: Okay. That's all.

CHAIRMAN SELIN: Well, the Commission thanks you for the presentation. Obviously this is not a topic which I personally and some of the rest of us are familiar as some others. So, it was particularly educational in going through the discussions. This is an information meeting, although there's some significant policy issues. It's pretty clear that the sense is that if there's action to be taken, it should be taken through a rule. I mean as the General Counsel's deputy said, this is a pretty standard case.

I'm still personally interested in the operational questions because although you've all correctly stated that the contribution to risk isn't very large, the cost isn't very large either. So,

those seem to be ideal questions for the industry to move out smartly and just take care of and not let the discussions concentrate on the higher cost items.

So, anyhow, we thank you very much for the presentation. Very well done. It does continue to show the importance of the overall fire program. You know, it's a general risk of getting involved between fire barriers and fire protection, the one being something we have to clean up our act on, but it's not essential. The other is really a central issue on what we do and I would hope that the attention that goes to fire barriers doesn't detract from the real attention on protecting against fire in power plants.

DOCTOR THADANI: No. In fact, Mr. Chairman, the program that we have does look at all aspects, where we have perhaps gone too far and where we may not have gone far enough.

CHAIRMAN SELIN: Right. Fine. Thank you very much.

(Whereupon, at 11:20 p.m., the above-entitled matter was concluded.)

CERTIFICATE OF TRANSCRIBER

This is to certify that the attached events of a meeting of the United States Nuclear Regulatory Commission entitled:

TITLE OF MEETING: BRIEFING ON OPTIONS FOR ADDRESSING SHUTDOWN AND LOW POWER RISK ISSUES

PLACE OF MEETING: ROCKVILLE, MARYLAND

DATE OF MEETING: JULY 20, 1993

were transcribed by me. I further certify that said transcription is accurate and complete, to the best of my ability, and that the transcript is a true and accurate record of the foregoing events.

Carol Lynch

Reporter's name: Peter Lynch

NRC STAFF PRESENTATION
TO
THE COMMISSION
JULY 20, 1993

SHUTDOWN RISK PROGRAM

WILLIAM T. RUSSELL,
ASSOCIATE DIRECTOR, INSPECTION AND TECHNICAL ASSESSMENT
OFFICE OF NUCLEAR REACTOR REGULATION

ROBERT C. JONES,
CHIEF, REACTOR SYSTEMS BRANCH

SHUTDOWN RISK PROGRAM
BACKGROUND

- BROAD AGENCY–WIDE PROGRAM INITIATED IN 1990

  - VOGTLE EVENT AND INTERNATIONAL STUDIES RAISED NEW CONCERNS
  - PREVIOUS REVIEWS HAD ADDRESSED ISSUES INDIVIDUALLY

- THREE PHASE PROGRAM

  – COMPLETE TECHNICAL STUDIES
  – IDENTIFY AND EVALUATE ISSUES
  – RESOLVE ISSUES

- INTERFACED WITH INDUSTRY

- TECHNICAL FINDINGS DOCUMENTED IN NUREG–1449 DRAFT FOR COMMENT FEBRUARY 1992

SLIDE 1 (W RUSSELL)

BACKGROUND

- STAFF BRIEFED THE COMMISSION 09/17/92
  - REQUIREMENTS UNDER CONSIDERATION
  - PRELIMINARY REGULATORY ANALYSIS

- COMMISSION REQUESTED:
  - PROs AND CONs OF RULEMAKING VERSUS GENERIC LETTER
  - BASIS FOR STAFF'S COST/BENEFIT EVALUATION

- STAFF REQUIREMENTS MEMORANDUM ISSUED 09/30/92

- COMMISSION PAPER SUBMITTED IN RESPONSE TO SRM (SECY-93-190)

TECHNICAL FINDINGS

- CORE DAMAGE FREQUENCY ESTIMATED TO RANGE FROM 1E-4/RY (PWRs) TO 1E-5/RY (BWRs)
- VULNERABILITIES:
  - PWR--LOSS OF RESIDUAL HEAT REMOVAL SYSTEM
  - BWR--LOSS OF COOLANT VIA DRAINING
- EFFECTIVE OUTAGE PLANNING AND CONTROL CAN SUBSTANTIALLY REDUCE SHUTDOWN RISK
- RESIDUAL HEAT REMOVAL SYSTEM MAY BE VULNERABLE TO FIRE
- REDUNDANT ON-SITE POWER CAPABILITY SIGNIFICANTLY REDUCES RISK DURING REDUCED INVENTORY OPERATION
- RISKS ARE MINIMAL WHEN REACTOR CAVITY FLOODED
- CORE DAMAGE WITHOUT CONTAINMENT CLOSURE RESULTS IN LARGE OFFSITE AND ONSITE RELEASES

PROPOSED GENERIC REQUIREMENTS

SUMMARY

OUTAGE PLANNING AND CONTROL

- REQUIRE THAT LICENSEE HAVE PROGRAM
- PROGRAM SHOULD COVER:
  - NUMARC 91-06 GUIDANCE
  - FIRE PROTECTION
  - PROCEDURES FOR USE OF INSTRUMENTATION

TECHNICAL SPECIFICATIONS

- REQUIRE OPERABILITY OF REDUNDANT DHR, ECCS, EDG WHEN REFUELING CAVITY NOT FILLED (PWR & BWR) (INCLUDING REDUNDANT SUPPORT SYSTEMS)

- REQUIRE PWR CONTAINMENT INTEGRITY WHEN DECAY HEAT HIGH OR NORMAL DHR UNAVAILABLE

INSTRUMENTATION

- PWRs ADD DIVERSE LEVEL INDICATION FOR MID–LOOP

STAFF RECOMMENDATION

- STAFF RECOMMENDS RULEMAKING
  - SHUTDOWN OPERATIONS NOT FULLY ADDRESSED IN CURRENT REGULATIONS
  - RULEMAKING FACILITATES IMPLEMENTATION OF GENERIC REQUIREMENTS AND ENSURES THEY ARE LEGALLY BINDING

SHUTDOWN RISK PROGRAM
STATUS

- IMPLEMENTATION OF INDUSTRY INITIATIVE (NUMARC 91-06 COMPLETE)

- TEMPORARY INSTRUCTION FOR ENHANCED INSPECTION DURING EACH OUTAGE REMAINS IN PLACE

- DRAFT REGULATORY ANALYSIS COMPLETED WHICH SUPPORTS IMPOSITION OF COST-JUSTIFIED SAFETY IMPROVEMENTS

SLIDE 6 (W RUSSELL)

SHUTDOWN RISK PROGRAM
FUTURE ACTIVITIES

- ISSUE NUREG-1449 IN FINAL FORM WITH PUBLIC COMMENTS ADDRESSED (AUGUST 1993)
- DEVELOP DRAFT RULE AND ASSOCIATED REGULATORY GUIDE (DECEMBER 1993)
- FOLLOWING COMMISSION AND CRGR + ACRS APPROVAL, ISSUE PROPOSED RULE FOR PUBLIC COMMENT (MAY 1994)
- CONDUCT WORKSHOP WITH INDUSTRY AND PUBLIC TO RECEIVE COMMENTS ON PROPOSED RULE
- ISSUE FINAL RULE WITH APPROVAL OF ACRS, CRGR AND COMMISSION (MAY 1995)

SLIDE 7 (W RUSSELL)

CALCULATED RELEASES AT POWER AND SHUTDOWN

PLANT	OPERATING CONDITION	PERSON-REM AT 50 MILES	PERSON-REM ONSITE
SURRY	SHUTDOWN	3.1E+06	2.0E+05
SURRY	POWER	1.7E+06	
GRAND GULF	SHUTDOWN	8.0E+05	2.0E+05
GRAND GULF	POWER	3.1E+05	
ZION	POWER	5.0E+06	
GENERIC	SHUTDOWN	2.0E+06	2.0E+05

BACK-UP SLIDE 1

OUTAGE PROGRAM
DESIRED ELEMENTS

- <u>COVERED IN NUMARC GUIDANCE TO UTILITIES</u>
  - CLEAR SAFETY PRINCIPLES
  - CLEAR ORGANIZATIONAL ROLES AND RESPONSIBILITIES
  - CONTROLLED PROCEDURE FOR PLANNING PROCESS
  - PRE–PLANNING FOR ALL OUTAGES
  - STRONG TECHNICAL INPUT FROM ANALYSIS
  - INDEPENDENT SAFETY REVIEW OF THE PLAN AND MODS
  - REAL TIME SAFETY INFORMATION DURING OUTAGE
  - CONTINGENCY PLANS AND BASES
  - REALISTIC CONSIDERATION OF STAFFING NEEDS
  - TRAINING
  - FEEDBACK OF EXPERIENCE TO PLANNING PROCESS

- <u>NOT COVERED IN NUMARC GUIDANCE TO UTILITIES</u>
  - FIRE PROTECTION
  - PROCEDURES FOR USING EXISTING INSTRUMENTATION

BACK-UP SLIDE 2

July 12, 1993

POLICY ISSUE
(Information)

SECY-93-190

FOR: The Commissioners

FROM: James M. Taylor
Executive Director for Operations

SUBJECT: REGULATORY APPROACH TO SHUTDOWN AND LOW-POWER OPERATIONS

PURPOSES:

(1) To respond to the Commission's request for a discussion of the advantages and disadvantages of rulemaking to impose, versus a generic letter to request voluntary adoption of, new staff positions in the area of shutdown and low-power operations in advance of completing the staff's internal review of the proposed new staff positions; and

(2) To update the Commission on the projected schedule for completing the Shutdown Risk Program.

BACKGROUND:

On September 17, 1992, the staff briefed the Commissioners on the status of its evaluation of shutdown and low-power operations, including potential actions on the part of licensees to resolve shutdown risk issues. During the meeting, the staff (1) summarized the on-site evaluations, analysis of experience and other studies leading to the conclusion that the public has been adequately protected and (2) described safety enhancements under consideration in the following areas: outage planning and control; technical specifications; fire protection; and instrumentation. The staff also summarized the results of its draft regulatory analysis of the actions being considered, including its cost/benefit analysis. On September 30, 1992, the Commission issued a Staff Requirements Memorandum (SRM) requesting (1) a brief description of the pros and cons of rulemaking versus a

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NOTE: TO BE MADE PUBLICLY AVAILABLE AT THE JULY 20, 1993 COMMISSION BRIEFING

generic letter to address shutdown and low-power risk issues and (2) a detailed description of the basis for the staff's cost/benefit evaluation supporting a requirement for action on the part of licensees.

The staff's discussion of the pros and cons of rulemaking versus a generic letter is provided in this paper. The detailed description of the basis for the staff's cost/benefit evaluation is provided in the enclosed draft regulatory analysis. The draft regulatory analysis has not yet been reviewed by the Committee to Review Generic Requirements (CRGR) or the Advisory Committee for Reactor Safeguards (ACRS). However, the staff did meet with the ACRS in September, 1992 and discussed an earlier draft of the regulatory analysis at that meeting. We expect to meet with the ACRS again in October, 1993 to discuss the issue further.

DISCUSSION:

The areas in which the staff is considering actions on the part of licensees to improve safety during shutdown operations are described briefly below, followed by a discussion of the pros and cons of rulemaking versus a generic letter.

Outage Planning and Control

Because the role of outage planning and control is central to safety during outages, the staff is currently evaluating the need for legally binding requirements to ensure that licensees implement and maintain a program for the planning and control of outages that:

(1) includes specific administrative controls that address areas important to operational safety during outages;

(2) uses technical specifications to specify limiting conditions for operation (LCOs) for important plant equipment;

(3) is documented in a controlled procedure subject to inspection by the NRC and summarized in an update to the safety analysis report; and

(4) can be revised without prior NRC approval, within predefined limits, with the approval of an onsite safety review organization.

Such a requirement for outage planning and control could be established through rulemaking or through an amendment to the license that the licensee proposed voluntarily in response to a generic letter. However, if a rulemaking approach were followed, a generic letter would still be needed to transmit guidance to licensees in the form of model technical specifications for use

in establishing LCOs required by the new rule.

Fire Protection

The principal regulation covering fire protection is 10 CFR 50.48. It requires all plants to have a fire protection plan that satisfies General Design Criterion (GDC) 3 of Appendix A to 10 CFR Part 50. Appendix R to 10 CFR Part 50 provides specific requirements to be satisfied in meeting the regulation for plants licensed before 1979. Additionally, guidance for satisfying the regulation is provided in the branch technical positions referenced in the regulation. However, this guidance was developed to ensure that the plant could be brought to a hot shutdown condition from power operation during a fire and does not address the condition of being in a shutdown or refueling mode at the time of a fire. Further, fire protection criteria established by the regulations only require that at least one train of those systems important for ensuring an adequate level of decay heat removal during cold shutdown and refueling be capable of being restored to service within 72 hours of a fire. In addition, NRC guidelines for performing a fire hazards analysis do not address shutdown and refueling conditions, or the potential impact a fire may have on the capability to maintain shutdown cooling. In light of this, the staff is evaluating the need for licensees to take the following actions:

(1) Conduct an assessment of the potential consequences of a fire during the cold shutdown and refueling modes of operation. The focus of this assessment would be on ensuring that effective decay heat removal (DHR) during shutdown conditions can be maintained in the event of a fire in any plant area. The severity of fires assumed in the assessment may be based on actual conditions in fire areas during shutdown with regard to (a) amount and location of combustible material and (b) the existence of ignition sources or temporary electrical wiring.

(2) Should the assessment indicate the normal DHR function could be rendered inoperable by a fire, develop a DHR restoration contingency plan and document the plan for use by the plant staff in an emergency. Plant staff must be trained in the use of the contingency plan.

(3) Document the results of the assessment including the bases for contingency plans and any necessary plant modifications in an update to the safety analysis report and make the specific details available for inspection by the NRC.

With respect to the actions on the part of licensees described above, it is the staff's intent to supplement current requirements for fire protection with additional requirements to ensure that the capability to remove decay heat is not lost because of a fire during cold shutdown or refueling conditions. This could be done by revising existing regulations to include detailed supplemental requirements. However, the requirements being contemplated by the staff would allow for realistic assumptions regarding the threat of fire and therefore be inconsistent with the more conservative requirements given in Appendix R and recommendations of the branch technical positions that apply to power operation. A second approach would be to include fire protection during outages as part of the licensee's program for the planning and control of outages that could be affected through rulemaking or a generic letter, as discussed above.

Instrumentation

On the basis primarily of a review of operating experience and inspections, the staff is considering the need for the following actions on the part of licensees with regard to instrumentation used during outages:

(1) All licensees should review existing operating procedures and make any changes necessary to (a) improve the availability of existing instrumentation used to monitor temperature, pressure, and water level in the reactor vessel and (b) provide accurate guidelines and training for operation when existing temperature indications may not accurately represent core conditions.

(2) Licensees of pressurized water reactors (PWRs) should provide an additional means of accurately monitoring water level in the reactor coolant system (RCS) during mid-loop operation. This additional instrumentation should not be affected by errors induced in the other level measurements because of changes in pressure in the RCS or connected systems. Normally, ultrasonic devices or other local measurements such as pressure differential across the hot leg would be necessary to meet this criterion. The installed instrumentation should include visual and audible indications in the control room to alert operators to an inappropriate condition. The instrumentation should be placed in operation before a reduced inventory condition is entered.

The first action regarding instrumentation stems from the need for operators to be able to monitor critical safety parameters during an outage. The staff considers this to be a necessary

item in an outage program. This action would be included in the administrative controls portion of the program for the planning and control of outages.[1]

The staff believes the proposed action regarding installation of new water level instrumentation, including an alarm, in a PWR is a cost-justified safety enhancement.[2] This action stems from a desire to eliminate losses of the residual heat removal system due to air ingestion caused by operator error when lowering water level to achieve a mid-loop condition. The additional level instrumentation would supplement the improved level instrumentation adopted voluntarily by all affected licensees in response to Generic Letter (GL) 88-17, "Loss of Decay Heat Removal." Generic Letter 88-17 recommended important improvements in several areas related to instrumentation, but did not address the specific problems caused by system pressurization.

The principal regulation covering instrumentation requirements is GDC 13 of 10 CFR Part 50, Appendix A, which requires that instrumentation be provided in nuclear power plant designs and sets forth general design requirements encompassing all instrumentation. The adequacy of specific plant instrumentation, e.g, instrumentation for measuring water level, has always been reviewed and approved on a plant-specific basis. Modifying the regulations to incorporate the requirement for a specific water level instrument to be used in a specific shutdown mode would be inconsistent with the regulatory treatment accorded other instrumentation. It would be more appropriate to modify Regulatory Guide 1.97, "Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident," to cover the water level instrumentation recommended by the staff here and in GL 88-17, or to cover this instrumentation in a new regulatory guide for

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[1]This assumes that licensees would voluntarily adopt the plan, including this element, if a generic letter were used.

[2]The staff's draft regulatory analysis documented in the enclosure includes the assumption that BWR water level instrumentation will be operable during cold shutdown and refueling operations in accordance with standard technical specifications. The results of the analysis support the conclusion that improvements in BWR water level instrumentation used during shutdown operations are not warranted. Recent concerns with the accuracy of BWR water level instrumentation are being addressed by utilities with actions in response to NRC Bulletin 93-03, dated May 28, 1993. Those actions will ensure that BWR water level instrumentation will function as assumed in the draft regulatory analysis.

implementation of a rule regarding shutdown operations. In a generic letter, the staff would request that licensees voluntarily submit their plans to adopt the staff's recommendation, make the appropriate facility modification, propose technical specifications to ensure system availability and update their safety analysis report.

In addition to the actions being considered by the staff to improve safety during shutdown operations, it is also important to note that the staff is currently considering the interrelationship of GDC and technical specifications, in general, and in particular with regard to shutdown and low-power operations

Pros and Cons of Rulemaking Versus Generic Letter

The pros and cons of rulemaking versus a generic letter are discussed below. In evaluating these pros and cons, the staff has considered policy and legal issues.

(1) A new regulation to address shutdown issues would effect programmatic improvements in several areas important to safety and is expected to be a prescriptive rather than a strictly performance-based rule like, for example, the maintenance rule.[3] Use of a prescriptive rule to address outage planning and control would be similar to the way some other programmatic requirements have been treated, that is, with a specific regulation calling for a program and specifying the key program elements. Those elements would be addressed with a combination of administrative controls specified in the rule and limiting conditions for operation (LCO) in technical specifications. The need for new limiting conditions for operation to be incorporated into the plant technical specifications would be specified in the rule, and guidance for developing these technical specifications would be provided by a generic letter. The rule and the technical specifications would provide legally binding requirements. While performance-like goals for the availability of equipment would be established through technical specifications, the lack of a clear quantitative indicator on which to base an overall performance goal for shutdown operations would make it difficult at this time to write a strictly performance-based rule.

[3]In a March 8, 1991, directive to revise the CRGR Charter, the Commission directed that when considering generic requirements, the staff evaluate the feasibility of defining a performance-based regulation which merely specifies the objective or result to be obtained, rather than prescribing to the licensee how the objective is to be obtained.

In a purely generic letter approach, the administrative controls portion of a program for outage planning and control could be added to the administrative section of each plant's technical specifications through a license amendment request submitted voluntarily by the licensee. This would provide a mechanism for enforcing compliance with programs established by licensees and deemed acceptable by the staff. Administrative controls are called for in 10 CFR 50.36 as "provisions relating to organization and management, procedures, recordkeeping, review and audit, and reporting necessary to assure operation of the facility in a safe manner." The enhanced LCOs for plant equipment would also be effectuated by license amendment requests submitted voluntarily in response to a generic letter. Any licensee that did not adopt the staff's new positions by applying for a license amendment in accordance with the guidance, or proposing acceptable alternative actions, could have its license amended by order to impose the guidance in the generic letter. However, in accordance with 10 CFR 50.109, such an action would have to be supported by a plant specific backfit analysis as opposed to the generic backfit analysis that supported issuance of the generic letter and would support a rule.

Effecting the actions discussed above by rulemaking has the advantage of making them legally binding on all licensees. Historically, this mechanism has facilitated resolution of safety issues and implementation of changes. Accepting alternative proposals is somewhat more complicated and may require an exemption depending upon the form of the rule. A generic letter can solicit a commitment from a licensee; it cannot impose other requirements. Compliance with the recommendations in generic letters that go beyond what the existing regulations or other legally binding requirements currently require is optional. Historically, this mechanism has initiated a process of soliciting and evaluating licensee proposals aimed at satisfying the safety issue through alternative means. However, in the generic letter approach, regulatory authority regarding shutdown operations would be sought in the form of (a) technical specifications covering administrative controls and operability of safety equipment and (b) commitments from the licensee in the areas of instrumentation and fire protection. As requirements, technical specifications are enforceable because they are a part of the license. As discussed above, technical specifications would be implemented through license amendment requests submitted voluntarily in response to a generic letter or, if necessary, through orders issued by the Commission in accordance with 10 CFR 2.202.

(2) In the past, one important administrative difference between rulemaking and a generic letter approach has been the degree to which the public and the Advisory Committee on Reactor Safeguards (ACRS) have been involved in the process. The Administrative Procedure Act and the Commission's regulations generally require that proposed rules be issued for review and comment by the public. In addition, the Commission, as a matter of policy, requires that proposed rules undergo peer review by the ACRS, and be approved by the Commission for implementation. In addition, a regulatory guide or branch technical position (BTP) for implementing the regulation would be developed and issued for public comment. In the recent past, these formal activities have resulted in periods of a few years to develop and impose a new regulation. This can delay implementation of safety improvements compared to a generic letter approach. However, this difference between rulemaking and a generic letter approach is expected to decrease in the future. Indeed, as directed by the Commission, the staff now normally follows a procedure for issuing generic communications that includes review and comment by the public, review by the ACRS, and Commission approval. This procedure incorporates public involvement and peer review into the regulatory process at a level near that previously reserved for rulemaking. This is expected to improve the acceptance of recommendations in generic letters; however, it will also increase the time it now takes to issue a generic letter. The staff would follow this procedure as part of the shutdown risk program, if the generic letter route were adopted.

Regulatory Analysis

The findings of the NRC staff's regulatory analysis of potential improvements in safety during shutdown and low-power operation are presented in the enclosed draft regulatory analysis report. In conducting the regulatory analysis the staff performed quantitative, i.e, (cost/benefit), assessments of two specific alternatives for resolving shutdown issues. The alternatives include, (a) improved outage planning and control and improved technical specifications, and (b) instrumentation for pressurized water reactors. The staff also performed qualitative assessments for the above alternatives and for improvements in fire protection.

In conducting the cost/benefit portion of the analysis, the staff assumed that each alternative would be implemented through license amendment in response to a generic letter. However, given that the actions industry would need to take in response to rulemaking are the same as those assumed to be taken in response to a generic letter--technically and administratively--the costs

of implementation for industry would not be different; and, given the similarities between NRC activities for rulemaking and a generic letter approach, in particular, the fact that a full regulatory analysis has been prepared in support of a generic letter, the cost of implementation through rulemaking to the NRC would not be significantly different.[4] Consequently, the results of the cost/benefit analysis apply equally to rulemaking or a generic letter approach.

CONCLUSION:

The staff is considering new requirements for shutdown and low-power operations in the following areas: outage planning and control; technical specifications; fire protection; and instrumentation. Actions on the part of licensees could be required by amending regulations in 10 CFR Part 50 or through a voluntary license amendment in response to a generic letter. The staff has considered the pros and cons of rulemaking versus a generic letter approach, including the views of the Office of the General Counsel, and has concluded that given the importance of outage programs to plant safety, rulemaking is a more appropriate means from a policy and legal perspective to establish a generic requirement for an outage program that covers administrative controls, limiting conditions for operation, fire protection and use of instrumentation during shutdown and refueling modes. In this approach, the need for limiting conditions for operation to be incorporated into the plant technical specifications would be specified in the rule, and guidance for developing these technical specifications would be provided by a generic letter. The new staff positions regarding instrumentation for shutdown conditions and fire protection would be incorporated in a new regulation and associated regulatory guide to be used by licensees when implementing the new regulation.

The staff has prepared a schedule which calls for bringing a final rule to the Commission no earlier than February of 1995. This schedule allows for (1) an appropriate period for the CRGR and ACRS to complete their reviews of the staff's proposed rule, regulatory guide, revisions to the NRC inspection program and regulatory analysis, (2) a 90-day period for public comment, (3) a period for analysis of the public's comments and a period for preparation of a Commission paper. We anticipate that CRGR will begin its review in December of 1993. Further, due to the complex nature of the proposed actions, CRGR review may require more than one meeting. Thus, we expect to resolve the CRGR's and the ACRS's comments and issue the proposed rule and associated

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[4] This presumes that a significant amount of litigation in support of orders would not be necessary. If this were not the case, the cost of rulemaking could be considerably less.

documents for public comment in May of 1994. The staff has considered the safety implications of delaying regulatory action and believes they are not significant because (1) such action is not necessary for adequately protecting the public, (2) the licensees are implementing the industry's initiative to improve shutdown operations at all plants, and (3) the NRC has increased its inspection activities during outages through the use of Temporary Instruction 2515/113.

COORDINATION:

The Office of the General Counsel has no legal objection to the paper.

James M. Taylor
Executive Director
for Operations

Enclosure:
Draft Regulatory Analysis in accordance with 10 CFR 50.109

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ENCLOSURE

REGULATORY ANALYSIS IN ACCORDANCE WITH 10 CFR 50.109
REQUIREMENTS FOR SHUTDOWN AND LOW-POWER OPERATIONS
AT NUCLEAR POWER PLANTS

February 1993

DIVISION OF SYSTEMS SAFETY AND ANALYSIS
OFFICE OF NUCLEAR REACTOR REGULATION
U.S NUCLEAR REGULATORY COMMISSION
WASHINGTON DC 20555-0001

CONTENTS

EXECUTIVE SUMMARY

The findings of the NRC staff's formal regulatory analysis of potential improvements in safety during shutdown and low-power operation are presented here. The staff addressed such improvements previously in NUREG-1449, "Shutdown and Low-power Operation at Commercial Nuclear Power Plants in the United States," which was issued as a draft report for comment in February 1992. The results of the regulatory analysis have confirmed the staff's preliminary finding that public health and safety has been adequately protected while plants have been in shutdown conditions, but that substantial safety improvements are possible and warranted.

In the draft version of NUREG-1449 issued for comment in early 1992, the staff identified the following five areas in which improvements in shutdown operations appeared to be warranted:

(1) outage planning and control
(2) fire protection
(3) operations, training, procedures, and other contingency plans
(4) technical specifications
(5) instrumentation

In conducting the formal regulatory analysis, the staff performed qualitative as well as quantitative evaluations of the five items above as a combined comprehensive program for conducting shutdown activities at either PWRs or BWRs (referred to as Improvement A). The staff has assumed that such a program is governed by two main categories of controls, which includes (1) administrative controls for activities related to organization, management and procedures, and (2) limiting conditions for operation (LCO) for controlling the availability of equipment needed to mitigate an accident. In doing this the staff has viewed programmatic and procedural actions related to items 2, 3 and 5 listed above as administrative controls incorporated into the process of planning and controlling outages. The staff has assumed that imposition of such controls by the NRC could be done through either rulemaking or, an amendment to the license which included revisions to the administrative section of the technical specifications. The specific administrative controls are listed in Table 2.1.

For purposes of the regulatory analysis, Item 4 above, i.e technical specifications, has included only LCOs on equipment. These would normally be imposed via an amendment to the license. The specific LCOs treated in the regulatory analysis are listed in Table 2.2 and described in detail in Table 2.3.

For PWRs, the staff has also considered a specific hardware improvement in addition to the improved outage program discussed above. The hardware improvement enhances the capability for monitoring of reactor vessel water level during operation with a reduced inventory (referred to as Improvement B).

The staff's overall conclusion is that implementation of the improvements in in outage programs, including new technical specifications and the improvement in PWR instrumentation will provide substantial and cost-justified enhancements to safety. This judgment is based on a qualitative assessment, which is supported by a quantitative cost-benefit analysis. The qualitative elements of the assessment are as follows:

(1) The improvements reflect the NRC safety philosophy of defense-in-depth in that they address: (a) prevention of credible challenges to safety functions through improvements in outage planning and fire protection; (b) mitigation of challenges to redundant protection systems, through improved procedures, training, improved technical specifications and contingency plans.

(2) Accident sequences during shutdown which are as rapid and severe as those during power operation should be addressed with commensurate requirements. This is supported by the staff's engineering analysis of accidents during shutdown conditions documented in NUREG-1449.

(3) The improvements being proposed by the staff are aimed directly at problems which have been repeatedly observed in operating experience, e.g., loss of decay heat removal, loss of AC power, loss of RCS inventory, fires, personnel errors, poor procedures and poor planning, and lack of training.

(4) Using technical specifications to control the availability of safety related equipment is necessary because (a) operators are trained and accustomed to operating the facility within the clear limits set by technical specifications, and (b) technical specifications establish clear and enforceable regulatory requirements. Indeed, 10CFR 50.36 defines limiting conditions for operation (LCO) as "the lowest functional capability or performance levels of equipment required for safe operation of the facility." In addition, recent experience has shown that while industry guidelines for outage programs (NUMARC 91-06) recognize the need for an enhanced accident mitigation capability; the lack of specificity regarding controls for mitigative equipment can lead to less than prudent interpretations when the guidelines are put into practice. In two instances involving PWRs, the staff has observed that although the guidelines were followed in developing the outage plan, operation in a mid-loop condition with one of two diesel generators out-of-service was permitted under the plan.

Other qualitative reasons for proposing requirements are discussed in Section 5 of the regulatory analysis.

The quantitative analysis of the improvements includes (1) a relatively simple (point estimates), yet enlightening probabilistic risk assessment to estimate the change in core-damage frequency and radiological consequence when each of the improvements is implemented, (2) an assessment of the costs of implementing each of the improvements and (3) an assessment of the future cost savings associated with a reduction in the probability of core-damage due to the improvements. The PRA does not include an uncertainty analysis due to the

lack of statistical data for shutdown conditions. However, a sensitivity study has been performed to assess the effect of uncertain assumptions in the PRA on the overall results of the quantitative analysis. The sensitivity study is included as Appendix 3.

Risk Assessment

On the basis of its analysis of operating experience in NUREG-1449, including the accident sequence precursor analysis, the staff has identified the following as dominant event sequences during shutdown: loss of all AC power, loss of RCS inventory, and loss of reactor vessel level control in pressurized-water reactors (PWRs). The staff analyzed these sequences by means of event trees it developed specifically for the regulatory analysis. In doing these analyses, it was necessary to make a number assumptions and judgements regarding the impact the proposed improvements would have on the event sequences. This is because the improvements manifest themselves primarily through human actions during the accident sequences. Because of this the results of the analysis contain a considerable uncertainty. These analyses indicate reductions in estimated core-damage frequency that are considered to be substantial for PWRs and BWRs (i.e., equal to or greater than 1E-05). The findings follow:

PWRs: Improvements A and B result in a CDF reduction of 8.0E-05/r-y[1] and 5.7E-05/r-y, respectively.

BWRs: Improvement A results in a CDF reduction of 9.5E-06/r-y.

Containment capability and releases of radioactivity for accident sequences during shutdown are evaluated in Section 2 of Appendix 2. The staff concludes that an intact containment will effectively prevent early releases from shutdown accidents. Large, dry PWR containments should remain intact if closed before being challenged. Severe core-damage accidents in open containments or in containments that fail are expected to have offsite consequences similar to severe core-damage accidents initiating from power operation. Onsite consequences within a few hundred meters of open or failed containments may be more severe at shutdown than at power. A representative dose to the public for a severe core-damage accident without an effective containment was estimated to be 2E+04 person-Sv (2E+06 person-rem).

For PWRs, improved instrumentation and implementation of new technical specifications combined with new outage planning and control measures yield reductions in core-damage probability greater than 1E-05/r-y, and thus, they are considered to provide substantial additional protection.

The reduction in core-damage probability for boiling-water reactors (BWRs) just meets the staff's test of 1E-05/r-y for "substantial additional protection". However, the marginal reduction in core-damage probability is offset by the need to compensate for the additional risk associated with not being able to close the containment in BWR plants.

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[1]r-y = reactor-year

Impact/Value Analysis

The values (changes in public and occupational radiation exposure) and impacts (costs and savings) were assessed for the alternatives identified. The specific values and impacts that are analyzed are designated "attributes." These attributes include the benefits of avoiding accidents as well as direct consequences of implementing the recommendations of the generic letter (GL).

Estimated values and impacts are presented in Section 4 of this analysis. Values and impacts were combined to form impact/value ratios for the two improvements, and the results are reported in the table that follows.

REGULATORY ACTION	IMPACT/VALUE RATIO
	$/person-Sv [$/person-rem]
OUTAGE PLANNING AND TECHNICAL SPECIFICATIONS	
PWRs	5,200 [52]
BWRs	160,000 [1,600]
WATER LEVEL INSTRUMENTATION	
PWRs	(28,000) [(280)]

Two plant populations were considered: PWRs and BWRs. Estimates enclosed in parentheses signify negative impacts or cost savings (e.g., avoided offsite property damage). Only best estimates of the values and impacts were used (no upper or lower bounds were estimated).

Dominant value is avoided public health risk (V1) for both alternatives and both plant groups. Avoided occupational exposure associated with accident management and cleanup (V2) contributes a small amount. Routine occupational exposure due to implementation of the GL recommendations (V3) is almost negligible.

Dominant impacts are direct licensee cost to implement the improvements and changes in operating costs (I1) and avoided offsite property damage (I3). Avoided onsite cleanup and power replacement costs (I2) have a small contribution while the costs to the NRC (I4) are essentially negligible.

The estimated impact/value ratios indicate that improvements are clearly cost-effective when applied to the PWR population. However, for the BWRs the improvement marginally exceeds a cost-effectiveness standard of $100,000/person-Sv [$1000/person-rem]. However, the staff believes the lower cost effectiveness is offset by the need to compensate for the additional risk associated with not being able to close the containment in BWR plants. Consequently, on the basis of the results of the impact/value analysis, the staff recommends that Improvement A be implemented at all plants and Improvement B be implemented at PWRs.

1 STATEMENT OF THE PROBLEM AND OBJECTIVE

1.1 Background

1.1.1 History of the Problem

Over the past several years, the Nuclear Regulatory Commission (NRC) staff has become increasingly concerned about the safety of operations during shutdown. Loss of decay heat removal (DHR) during shutdown and refueling has been a continuing problem. In 1980, DHR was lost at the Davis-Besse plant when one residual heat removal (RHR) pump failed and the second pump was out of service. After reviewing the event and studying the requirements that existed then, the NRC issued Bulletin 80-42 and Generic Letter (GL) 80-43 calling for new technical specifications to ensure that one RHR system is operating and a second is available (i.e., operable) for most shutdown conditions. The Diablo Canyon event of April 10, 1987, highlighted the fact that midloop operation was a particularly sensitive condition. After reviewing the event, the staff issued GL 88-17, recommending that licensees address numerous generic deficiencies to improve the reliability of the DHR capability. More recently, the incident investigation team's report on the loss of AC power at the Vogtle plant (NUREG-1410) emphasized the need for risk management of shutdown operations. Furthermore, discussions with foreign regulatory organizations (i.e., French and Swedish authorities) about their evaluations regarding shutdown risk have reinforced previous NRC staff findings that the core-damage (CDF) for shutdown operation can be a fairly substantial fraction of the total CDF. Because of these concerns regarding operational safety during shutdown, the staff conducted a careful, detailed evaluation of safety during shutdown and low-power operations which is documented in NUREG-1449.

1.1.2 Current Status of the Problem

Currently, inspections which have been conducted during shutdown at a number of sites show that shutdown operations seem to be improving. Utilities are responding to both NRC and industry (NUMARC, INPO and EPRI) initiatives in the areas of outage planning and operations. Despite such improvements, significant operational events continue to occur during shutdown, most recently at Oconee (September 1991) and Prairie Island (February 1992).

1.1.3 Previous Regulatory Actions

NRC's issuance of generic communications, specifically bulletins and generic letters, gives insight into the events of interest and the evolution of requirements. The NRC issued eight generic letters related to shutdown and low-power operations:

GL 80-42, "Decay Heat Removal Capability"
GL 80-53, "Transmittal of Revised Technical Specifications for Decay Heat Removal Systems at PWRs"
GL 81-21, "Natural Circulation Cooldown"
GL 85-05, "Inadvertent Boron Dilution Events"
GL 86-09, "Technical Resolution of Generic Issues B-59, (n-1) Loop Operation in BWRs and PWRs"

GL 87-12, "Loss of Residual Heat Removal (RHR) While the Reactor Coolant System (RCS) Is Partially Filled"
GL 88-17, "Loss of Decay Heat Removal"
GL 90-06, "Resolution of Generic Issue 70, 'Power-Operated Relief Valve and Block Valve Reliability,' and 94, 'Additional Low-Temperature Overpressure Protection for Pressurized Water Reactors' [pursuant to 10 CFR 50.54(f)]"

These generic communications present a chronology of events and actions requested by the NRC to preclude or mitigate events that could affect the nuclear power plant during low-power and shutdown operations.

Generic Letter 88-17 is the most comprehensive and most widely applicable of the generic letters. It specifically addresses shutdown concerns and is the most recent generic letter to contain recommendations regarding low-power and shutdown operations. GL 88-17 made recommendations for PWR operation with reduced inventory covering areas of instrumentation, administrative controls, and operator procedures and training.

The effectiveness and completeness with which GL 88-17 has been implemented varies. All licensees operating PWRs have improved reduced inventory operation. Some licensees exceeded the GL 88-17 recommendations; whereas others responded minimally, or have not yet implemented the recommendations. However, GL 88-17 only discusses operation of PWRs during reduced inventory.

One important insight provided by the list of generic letters is the "issue-at-a-time" nature that regulation of shutdown operations has taken over the years. This was another major reason for undertaking the comprehensive study documented in NUREG-1449. In this regard, the set of requirements proposed by the staff to resolve shutdown issues is considered to be a comprehensive set that addresses shutdown issues in an integrated fashion.

1.2 Problem Statement

1.2.1 Definition of the Problem

The staff's comprehensive evaluation of shutdown and low-power operations, documented in NUREG-1449, included observations and inspections at a number of plants, analysis of operating experience, deterministic safety analysis, and insights from probabilistic risk assessments. From this evaluation, the staff has concluded that public health and safety has been adequately protected during the period that plants have been in shutdown conditions; but that substantial safety improvements are possible and warranted for the following reasons:

(1) Significant precursor events involving loss of DHR capability continue to occur despite NRC efforts to resolve the problem.

(2) There is a significant lack of controls, including regulatory controls, that in the past allowed plants to enter circumstances likely to challenge safety functions with minimal mitigation

equipment available and containment integrity not established.

1.2.2 Safety Importance

Only a very limited number of probabilistic risk assessment (PRA) studies covering shutdown conditions have been performed, and those studies contain considerable uncertainty. The uncertainty is due largely to the predominant role played by operators and other licensee staff in shutdown events and recovery from them. Human reliability is difficult to quantify, especially under unfamiliar conditions which are often not covered in training or procedures. The collection of PRA studies discussed in NUREG-1449 gives some insight into the likely range of shutdown risks for the spectrum of current plants. The mean core-damage probability (CDP) for shutdown events appears to be in the range of 6E-05 to 7E-06 per reactor-year (r-y). Although detailed uncertainty analysis is not available for most of the PRAs covering shutdown conditions, some insight can be gained by examining the uncertainty analysis in NUREG-1150 where the CDP uncertainty ranges (5th and 95th percentiles) are approximately one order of magnitude. From this limited information, the staff concludes that a reasonable estimate of the range of CDP is 1E-04 to 1E-06 per reactor-year. The public health risk appears to be dominated by core damage in combination with an open or partially open containment.

1.2.3 Industry Actions

The industry has addressed outage planning and control with programs that include workshops, Institute of Nuclear Power Operations (INPO) inspections, Electric Power Research Institute (EPRI) support, as well as enhanced training and procedures. One activity (a formal initiative proposed by the Nuclear Management and Resources Council (NUMARC)) has produced for the utilities a set of guidelines to use for self-assessment of shutdown operations (NUMARC 91-06). These guidelines serve as the basis for an industry-wide program that will be implemented at all plants by December 1992. This high-level guidance addresses many of the areas in outage planning needing improvement. Detailed guidance on developing an outage planning program is beyond the scope of the NUMARC effort. The NRC staff met with NUMARC representatives and the associated utility working group on several occasions to share technical insights and discuss program status. In addition, as part of this regulatory analysis, the staff evaluated NUMARC 91-06 against NUREG-1449 (its own proposed criteria). This evaluation is documented in Appendix 1. The staff concludes that NUMARC 91-06 represents a significant and constructive step, effects of which have already been realized by many utilities using the draft guidance in recent outages.

1.2.4 The Need for Regulatory Action

In NUREG-1449, the staff concluded that regulatory involvement probably needed to be increased, and identified regulatory actions to be considered for regulatory analysis consistent with the requirements of 10 CFR 50.109. Because these actions are not required for adequate protection, they have been evaluated against the Commission's Safety Goal Policy to determine whether or not they would result in a substantial increase in the overall protection of the public health and safety.

As noted above, it is estimated that the core-damage probability during shutdown and low-power operations is on the order of 1E-04 to 1E-06 per reactor-year. Further, it was concluded that many shutdown operations may take place with the containment partially open. Thus, a large release could occur with a probability in excess of the Commission's guidance. Therefore, cost-effective regulatory actions are appropriate to achieve an order-of-magnitude reduction in core-damage probability, and an improvement in the likelihood of containment isolation, when necessary. These goals will substantially increase the overall protection of public health and safety.

2 IMPROVEMENTS EVALUATED FOR SHUTDOWN AND LOW-POWER OPERATIONS

In the draft version of NUREG-1449 issued for comment in early 1992, the staff identified the following five areas in which improvements in shutdown operations appeared to be warranted:

(1) outage planning and control
(2) fire protection
(3) operations, training, procedures, and other contingency plans
(4) technical specifications
(5) instrumentation

In conducting the formal regulatory analysis, the staff performed qualitative as well as quantitative evaluations of the five items above as a combined comprehensive program for conducting shutdown activities at either PWRs or BWRs. The staff has assumed that such a program is governed by two main categories of controls, which includes (1) administrative controls for activities related to organization, management and procedures, and (2) limiting conditions for operation (LCO) for controlling the availability of equipment needed to mitigate an accident. In doing this the staff has viewed programmatic and procedural actions related to items 2, 3 and 5 listed above as administrative controls incorporated into the process of planning and controlling outages. The staff has assumed that imposition of such controls by the NRC could be done through either rulemaking or, an amendment to the license including revisions to the administrative section of the technical specifications. For purposes of the regulatory analysis, Item 4 above, i.e technical specifications, has included only LCOs on equipment. This would normally be imposed via an amendment to the license. For PWRs, the staff has also considered a specific hardware improvement in addition to the improved outage program discussed above. The hardware improvement enhances the capability for monitoring of reactor vessel water level during operation with a reduced inventory.

The improvements treated explicitly in the regulatory analysis are discussed below. Additional improvements evaluated but not selected for formal quantitative analysis are also briefly discussed.

The quantitative analysis of the improvements discussed below includes (1) a relatively simple (point estimates), yet enlightening, probabilistic risk assessment to estimate the change in core-damage probability and radiological consequence when each of the improvements are implemented, (2) an assessment of the costs of implementing each of the improvements and (3) an assessment of the future cost savings associated with a reduction in the probabilitiy of core-damage due to the improvements. Qualitative analysis has also been used to evaluate the improvements. Qualitative analysis is particularly important when considering regulatory action to address shutdown and low-power issues because comprehensive probabilistic risk assessments for these operating modes do not yet exist.

2.1 IMPROVEMENT A---Planning and Controlling Outages (PWR & BWR)

Improvement A assumes that licensees would improve their programs for planning and controlling outages by incorporating new and improved administrative controls and limiting conditions for operation. Licensees would be required, either by rule or technical specification, to develop and use a program for planning and controlling outages that would include those elements listed in Table 2.1. It is also assumed that the NRC would conduct a routine, region-based inspection to verify that licensees had taken the actions specified through administrative controls. In addition, it is assumed that licensees would adopt new technical specifications, summarized in Table 2.2 and described in detail in Table 2.3, through the license amendment process. The proposed improvements to standard technical specifications only affect operating modes in which there is fuel in the reactor vessel. The changes are aimed at improving the availability of systems designed to remove decay heat, add makeup water to the reactor vessel, and establish containment integrity in PWRs with or without offsite AC power available.

The staff considers the programmatic guidelines in NURMARC 91-06 to address those program elements listed in Table 2.1 with the notable exceptions being element 7 (Instrumentation) and element 9 (specific contingency plans for fire protection). Consequently, the staff believes that a licensee program that 1) fully implements the guidelines in NUMARC 91-06, and 2) incorporates the features regarding fire protection and instrumentation listed in Table 2.1 would be consistent with the staff's assumptions regarding the administrative controls portion of this improvement.

Table 2.1 Elements for an Outage Program

(1) clearly defined and documented safety principles for outage planning and control

(2) clearly defined organizational roles and responsibilities

(3) controlled procedure defining the outage planning process

(4) pre-planning for all outages

(5) strong technical input based on safety analysis, risk insights, and defense in depth

(6) independent safety review of the outage plan and subsequent modifications

(7) planning and controls which (a) maximize the availability of existing instrumentation used to monitor temperature, pressure and water level in the reactor vessel, and (b) provide accurate guidelines for operations when existing temperature indications may not accurately represent core conditions

(8) controlled information system to provide critical safety parameters and equipment status on a real-time basis during the outage

(9) contingency plans and bases, including those necessary to ensure that effective DHR during cold shutdown and refueling conditions can be maintained in the event of a fire in any plant area

(10) realistic consideration of staffing needs and personnel capabilities with emphasis on control room staff

(11) training

(12) feedback of shutdown experience into the planning process

Table 2.2
Limiting Conditions for Operation during Cold Shutdown and Refueling**

	Pressurized Water Reactors		Boiling Water Reactors	
SYSTEM	PWR Limiting Cond. for Operation Mode 5 Mode 6 Low Level	PWR Limiting Cond. for Operation Mode 6 High Level	BWR Limiting Cond. for Operation Mode 4 Mode 5 Low Level	BWR Limiting Cond. for Operation Mode 5 High Level
Residual Heat Removal	2 Trains OPERABLE*	1 Train OPERABLE*	2 Trains OPERABLE*	1 Train OPERABLE*
Emergency Core Cooling	2 Trains OPERABLE	Not Required*	2 Trains OPERABLE*	Not Required*
Offsite AC Power	1 Offsite Source OPERABLE*	1 Offsite Source OPERABLE*	1 Offsite Source OPERABLE*	1 Offsite Source OPERABLE*
Onsite AC Power	2 Onsite Sources OPERABLE	1 Onsite Source OPERABLE*	2 Onsite Sources OPERABLE	1 Onsite Source OPERABLE*
Primary Containment Integrity	Required When Decay Heat Rate is > [ ] and RCS Temperature is > [ ]	Not Required*	Not Required*	Not Required*
Service Water	2 Trains OPERABLE	1 Train OPERABLE	2 Trains OPERABLE	1 Train OPERABLE
Equipment Cooling Water	2 Trains OPERABLE	1 Train OPERABLE	2 Trains OPERABLE	1 Train OPERABLE

* Currently specified in Standard Technical Specifications

** The staff will consider alternative actions to compensate for relaxation in the number of systems or trains specified in the LCO when such relaxation is necessary for purposes of performing maintenance.

Table 2.3-a

CHANGES TO BWR TECHNICAL SPECIFICATIONS ASSUMED IN THE REGULATORY ANALYSIS

(1) The specification in the STS for AC power sources during shutdown (i.e., "AC Sources - Shutdown), has been modified and now requires redundant onsite emergency AC sources be operable during cold shutdown and refueling when the water level is less that [23] feet above the reactor pressure vessel flange. Redundancy is not required when the water level in the refueling cavity equals or exceeds [23] feet above the reactor pressure vessel flange because the passive cooling capability in the refueling cavity allows sufficient time to restore a DHR loop or establish and alternate method of cooling. This change ensures that the capability to remove decay heat will not be lost under conditions that include a loss of offsite power and a single failure of one onsite AC source

(2) New specifications have been added to the STS to require operability of the plant service water system (standby service water system for BWR/6) and ultimate heat sink during Modes 4 and 5.

Table 2.3-b

CHANGES TO PWR TECHNICAL SPECIFICATIONS ASSUMED IN THE REGULATORY ANALYSIS

(1) The Technical Specification for "RCS Loops - Mode 5, Loops Filled," and "RCS Loops - Mode 5, Loops Not Filled" have been combined into one specification for "RCS Loops - Mode 5." In addition, Action statements have been added requiring, (a) containment integrity be established if one required decay heat removal (DHR) loop becomes inoperable and cannot be returned to service in 8 hours; (b) an alternate method of DHR be established if both required DHR loops are inoperable; and (c) containment integrity be established if both required DHR loops become inoperable, and containment integrity is not already established per a separate specification on containment integrity discussed in Item 4 below.

The requirements to establish an alternative method of DHR and achieve containment integrity, when one or more DHR loop(s) becomes inoperable, are designed to ensure defense in depth when normal cooling systems become unavailable. In most cases, the emergency core cooling system will be available to serve as backup for core cooling and to act as a first line of defense when normal systems are unavailable.

(2) The technical specification for the emergency core cooling system during shutdown (i.e., "ECCS - Shutdown") has been modified to require redundant trains of high-pressure injection (HPI) during cold shutdown and refueling with water level in the refueling cavity less than 23 feet above the reactor pressure vessel flange. (Current STS require only one train.) The applicability for the STS on "ECCS - Operating" has been extended to Mode 4. Also, the applicability of the STS covering the refueling water storage tank has been extended to Mode 5 and Mode 6 with water level in the refueling cavity less than 23 feet above the reactor pressure vessel flange and flooding the cavity with water from the RWST is not in progress.

(3) Because of the change to the STS "ECCS - Shutdown," the STS for "Low Temperature Overpressure Protection" has been modified to require either a larger size vent to mitigate the effects of higher mass addition from a second HPI train, or specific controls to isolate HPI trains during shutdown and refueling (i.e., keep HPI discharge valves closed and tagged and keep pumps in pull-to-lock).

(4) Studies in NUREG-1449 show that shutdown risk is highest when decay heat is high and the RCS is in a reduced inventory condition. A new specification has been added to the STS to require containment integrity under these conditions. This specification requires containment integrity to be maintained during Mode 5, with natural circulation cooling not available, and Mode 6, with the water level in the refueling

cavity less than [23] feet above the reactor vessel flange. Containment integrity in these modes is not required after the core decay heat has been reduced below a plant specific value such that manual actions to close the containment can be accomplished prior to boiling in the RCS, assuming a loss of both the offsite electrical power system and unavailability of the onsite AC power system.

Some licensees may have available alternate emergency AC sources, as defined in 10 CFR 50.2, or portable power supplies which could be used to assist in manually closing containment. Licensees can base their estimates of the times to manually close containment assuming the availability of these power supplies provided that the availability of these power supplies are assured through their outage plan.

The staff believes that the LCO provides licensees with considerable flexibility through planning and good engineering, to minimize the need for containment integrity during normal activities while in Mode 5 or 6.

(5) New specifications have been added to the STS to require redundant systems for (a) component cooling water and (b) service water and operability of the ultimate heat sink during cold shutdown and refueling when the water level in the refueling cavity is less than [23] feet above the reactor pressure vessel flange. Redundancy is not required during refueling when the water level in the refueling cavity equals or exceeds [23] feet above the reactor pressure vessel flange because the passive cooling capability in the refueling cavity allows sufficient time to restore a DHR loop or establish an alternate method of cooling.

(6) The specification in the STS for AC power sources during shutdown (i.e., "AC Sources - Shutdown"), has been modified and now requires redundant onsite emergency AC sources be operable during cold shutdown and refueling when the water level in the refueling cavity is less than [23] feet above the reactor pressure vessel flange. Redundancy is not required when the water level in the refueling cavity equals or exceeds [23] feet above the reactor pressure vessel flange because the passive cooling capability in the refueling cavity allows sufficient time to restore a DHR loop or establish an alternate method of cooling. The specification also requires that if AC sources become inoperable and cannot be returned to service in 8 hours, the equipment supported by those sources must be declared inoperable. The proposed model technical specification does not recognize alternate sources of AC power that may be available during shutdown operations. However, the staff will consider plant specific technical specifications which factor in such sources on a case-by-case basis.

(7) Action statements have been added to the specification in the STS on "DHR and Coolant Circulation - Low Water Level" to require that, with one DHR loop inoperable, the water level in the refueling cavity be raised to

Table 2.3-b Continued

least [23] feet above the reactor vessel flange or that containment integrity be established if the loop cannot be returned to service in 8 hours. If both required DHR loops are inoperable, an alternate method of decay heat removal must be established. Containment integrity must be established before boiling occurs in the reactor coolant system if both required DHR loops become inoperable and containment integrity has not already been established.

The requirements to establish an alternate method of DHR and achieve containment integrity when one or more DHR loops becomes inoperable are designed to ensure defense in depth when normal cooling systems become unavailable. In most cases, the emergency core cooling system will be available to serve as backup for core cooling and to act as a first line of defense when normal systems are unavailable.

(8) Action statements have been added to the STS specification on "DHR and Coolant Circulation - High Water Level" to require that with no DHR loops operable or in operation, containment integrity should be established within 8 hours.

2.2 IMPROVEMENT B (Diverse Instrumentation for Monitoring Reactor Vessel Water Level (PWR Only)

For the second improvement, licensees of PWRs would be required to have an independent, diverse means of accurately monitoring reactor vessel water level during mid-loop operation (e.g., ultrasonic or local pressure differential measurements across the hot leg). This additional instrumentation should not be affected by pressure errors that could occur at one or more pressure sensors. Continuous indication in the control room and an alarm to alert operators to over-draining during an approach to a midloop condition would also be required.

2.3 Other Improvements Considered

The staff also considered, as an improvement, integration of the technical specifications with outage planning using a "risk-based" concept for shutdown operations. In this alternative, requirements on equipment necessary to ensure key safety functions would vary continuously during an outage, depending on level of decay heat, water level in the reactor vessel, water level in the refueling cavity, reactor coolant system (RCS) temperature, and the configuration of the RCS, (e.g., open or closed, nozzle dams installed, steamline plugs installed, and temporary seals in place). Other considerations in this concept include the allowable mix of operable and available equipment, and the reliance on safety-related equipment contrasted to reliable or temporary equipment. The staff believes that this approach to shutdown regulation has merit since its goal is to match the appropriate level of protection (using all available resources) against risk on a real-time basis throughout an outage. The approach would ideally allow maximum flexibility in performing maintenance while continuing to ensure the proper level of mitigation capability. However, this approach transcends many established concepts on which current technical specifications are based. It also requires a more sophisticated risk assessment capability than is now available. The staff believes that developing a novel approach to technical specifications for shutdown, in coordination with industry, would be a long-term effort. This improvement was not retained for detailed study because of perceived difficulties with implementation in the near term and difficulty in assessing the safety benefits quantitatively without an appropriate model.

In developing Improvement A, i.e, the portion related to improved technical specifications, the staff considered the need to revise General Design Criterion (GDC) 34 in Appendix A of 10 CFR Part 50 (residual heat removal system) which calls for redundancy in the design of the residual heat removal system. The need to change GDC 34 was considered because the proposed technical specifications allow, (1) operation in Mode 6 with a minimum of one train of RHR, one offsite AC power supply and one onsite AC power supply, when the refueling cavity is filled; and, (2) operation with a minimum of one offsite AC power source when in Mode 5 or 6. Such allowances appear to be in conflict with GDC 34 which states that:

> "A system to remove residual heat shall be provided. The system safety function shall be to transfer fission product decay heat and other

residual heat from the reactor core at a rate such that specified acceptable fuel design limits and the design conditions of the reactor coolant pressure boundary are not exceeded.

Suitable redundancy in components and features, and suitable interconnections, leak detection, and isolation capabilities shall be provided to assure that for onsite electric power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available) the system safety function can be accomplished, assuming a single failure."

However, when one considers the need to maintain redundant portions of systems, it becomes clear that the GDC alone are not a sufficient basis for regulation of equipment needed to achieve critical safety functions. Indeed, 10 CFR 50.36 states in part "(c) Technical specifications will include items in the following categories: ... (2) *Limiting conditions for operation.* Limiting conditions for operation are the lowest functional capability or performance levels of equipment required for safe operation of the facility." For the purpose of allowing maintenance of equipment, the staff interprets this to mean that it is not necessary that a limiting condition for operation include all of the equipment specified by the design criteria as long as safe operation is reasonably assured. The staff considers the GDC and the Technical Specifications to be complimentary requirements with the GDC establishing the design requirements and the Technical Specifications controlling operational issues such as availability and testing. With this in mind, the staff evaluated the risks associated with the allowances described above and judged them to be acceptable. These analyses are documented in Appendix 2. The analyses show that the inventory of water in a filled refueling cavity can provide an effective temporary heat sink which provides time for restoration of equipment. The analyses also show that redundancy of onsite AC power sources coupled with a minimum of one offsite (diverse) AC source, while in Mode 5 (PWRs) or Mode 4 (BWRs), is acceptable given the need to do maintenance on electrical systems.

3 EVALUATION OF THE REDUCTION IN RISK

3.1 Reduction in Core-damage Probability

On the basis of the analysis of operating experience in NUREG-1449, including the accident sequence precursor analysis, the staff identified the following as dominant event sequences during shutdown: loss of all AC power, loss of RCS inventory, and loss of reactor vessel level control in PWRs. These sequences have been modeled as discussed in Section 1 of Appendix 2. Core-damage probabilities for these sequences are point estimates built from best estimates of each step in the sequence. No uncertainty analysis was performed because of the lack of reliable statistical data for shutdown conditions. However, a sensitivity study has been performed to assess the effect of uncertain assumptions in the PRA on the overall results of the analysis. The sensitivity study is included as Appendix 3. The results of the sensitivity study show that despite sensitivity to changes in PRA assumptions, the conclusions regarding the proposed improvements remain valid when inputs are changed significantly, i.e the improvements provide substantial additional protection.

Table 3.1 summarizes the estimated core-damage probabilities calculated for the dominant sequences for each of the improvements discussed in Section 2.

Table 3.1 Estimated Core Damage Probabilities per Reactor-Year

Item	Base Case	Outage improvement and TS	Instrumentation
PWR, LOOP, < 23 feet	2.9E-5	9.6E-7	2.5E-5
PWR, LOSS OF LEVEL CONTROL	4.2E-5	1.4E-5	8.5E-6
PWR, LOSS OF INVENTORY	3.0E-5	4.9E-6	9.8E-6
PWR TOTAL	1.0E-4	2.0E-5	4.3E-5
PWR CHANGE	-	8.0E-5	5.7E-5
BWR, LOOP	6.3E-6	1.4E-7	N/A
BWR, LOSS OF INVENTORY	3.6E-6	2.2E-7	N/A
BWR TOTAL	9.9E-6	3.6E-7	N/A
BWR CHANGE	-	9.5E-6	N/A

These results indicate reductions in core-damage probability which are considered to be substantial (i.e., equal to or greater than 1E-05/r-y. They are as follows:

PWRs: Improvements A and B result in a CDF reduction of 8.0E-05/r-y and 5.7E-05/r-y, respectively.

BWRs: Improvement A results in a CDF reduction of 9.5E-06/r-y.

3.2 Containment Capability

Containment capability and releases of radioactivity for accident sequences during shutdown are evaluated in Section 2 of Appendix 2. The staff concludes that an intact containment will effectively prevent early releases from shutdown accidents. Large, dry PWR containments should remain intact if closed before being challenged. Severe core-damage accidents in open containments or in containments that fail are expected to have offsite consequences similar to severe core-damage accidents initiating from power operation. Onsite consequences within a few hundred meters of open or failed containments may be more severe at shutdown than at power. A representative dose to the public for a severe core-damage accident without an effective containment was estimated to be 2E+04 person-Sv (2E+06 person-rem).

3.3 Conclusion

For PWRs, improved instrumentation and implementation of new technical specifications combined with new outage planning and control measures yield reductions in core-damage probability greater than 1E-05/r-y. Thus, they are considered to provide substantial additional protection.

The reduction in core-damage probability for boiling-water reactors (BWRs) just meets the staff's test of 1E-05/r-y for "substantial additional protection". However, the marginal reduction in core-damage probability is offset by the need to compensate for the additional risk associated with not being able to close the containment in BWR plants.

4 CONSEQUENCES OF TAKING REGULATORY ACTIONS

This section of the regulatory analysis develops the values and impacts resulting from the various improvements discussed in Section 2, and combines them into appropriate impact/value ratios.

4.1 Attributes for Estimating Values and Impacts

The values (changes in public and occupational radiation exposure) and impacts (costs and savings) for each of the improvements were evaluated in this analysis. The specific values and impacts that are analyzed are designated "attributes." These attributes include the benefits of avoiding accidents as well as direct consequences of implementing the improvements. The attributes relevant to this analysis are shown in Table 4.1, where they are identified as arising from avoiding accidents or as direct consequences. The analysis performed is similar to that for the maintenance rule (Ref. 1) and follows the handbook for impact-value assessment (Ref. 2). The attributes considered in this impact/value analysis are discussed below.

4.1.1 Values

Two positive values arise from decreases in the frequency of consequences of accidents:

V1 = avoided public health risk

V2 = avoided occupational exposure associated with accident management and cleanup

In addition, there may be a positive (or negative) benefit associated with a decrease (or increase) in the routine occupational exposure to implement the improvements. Improvements in outage programs and activities can affect occupational exposures both positively and negatively. A third value used in this analysis is:

V3 = decrease (or increase) in routine occupational exposure due to the implementation of the improvements (positive or negative value).

4.1.2 Impacts

Three impacts to licensees and one to the NRC are defined:

I1 = direct cost to the licensee to implement the improvements and changes in operating cost (positive or negative impact)

I2 = avoided onsite cleanup and power replacement costs (negative impact)

I3 = avoided offsite property damage (negative impact)

Table 4.1 Attributes Used in the Impact-Value Assessment.

ATTRIBUTES: VALUES (PERSON-REM)	ATTRIBUTES: IMPACTS ($)	DESIGNATOR	AVOIDED ACCIDENT CONSEQUENCE	DIRECT CONSEQUENCE
Avoided dose to the public		V1	✓	
Avoided occupational exposure		V2	✓	
Routine occupational exposure		V3		✓
	Licensee implementation and operating cost/savings	I1		✓
	Avoided onsite cleanup and power replacement cost	I2	✓	
	Avoided offsite property damage	I3	✓	
	NRC cost	I4		✓

I4 = cost to the NRC covering training, inspection, review, and monitoring associated with the improvements (positive impact)

4.1.3 Calculation of Avoided Accident Consequences

Avoided accident consequences (V1, V2, I2, I3) were calculated using the estimated core-damage frequencies developed in Appendix 2, Section 1.4, and the equations reported in Table 4.2.

4.1.4 Impact-Value Ratio

Values and impacts were combined to form a impact/value ratio, S, in dollars per person-Sv [dollars/person-rem]:

$$S = \frac{Total\ Impact}{Total\ Value} = \frac{I1 + I2 + I3 + I4}{V1 + V2 + V3}$$

4.1.5 Plant Assumptions

Value/impact information that was developed considered the plant configurations at various sites. For example, some sites have three "identical" nuclear steam supply systems (NSSSs); while one site has three NSSSs supplied by three different vendors. Costs associated with developing procedures will differ between these sites since one site can use almost identical procedures for it's three NSSSs, but the other will have three different sets of procedures. Consequently, some information is developed on the basis of sites, some on the basis of number of NSSSs, and some consider the mix of NSSSs at the sites. The following data are used:

(1) 76 PWRs
(2) 38 BWRs
(3) 49 PWR sites
(4) 26 BWR sites

Sites with different NSSS designs are counted once for each design, for example, two sites are counted for ANO, one for the B&W unit, and one for the CE unit. Shared work, such as that performed by owners groups, is also included.

4.1.6 Analysis Assumptions

The impact/value information is developed for the following improvements which are described in Section 2:

Improvement A: outage planning and control; new technical specifications
Improvement B: improved water level instrumentation for PWRs

Table 4.2 Equations for Estimating Avoided Accident Consequences.

ATTRIBUTE DESIGNATOR	ATTRIBUTE DESCRIPTION	EQUATION
V1	Avoided dose to the public	$V1 = \sum_{i=1}^{N}$ {Annual core-damage frequency reduction for core damage state i; i = 1,N} x {Containment failure probability given core damage state i; i = 1,N} x {Public dose given release} x {Remaining plant life} x {Number of affected plants}
V2	Avoided occupational exposure	V2 = {Annual core-damage frequency reduction} x {Accidental occupational exposure given core-damage} x {Remaining plant life} x {Number of affected plants}
I2	Avoided onsite cleanup and power replacement cost	I2 = {Annual core-damage frequency reduction} x {Cleanup plus power replacement cost given core damage} x {Discount factor accounting for remaining plant life and 10 years for cleanup} x {Number of affected plants}
I3	Avoided offsite property damage	I3 = {Annual core-damage frequency reduction} x {Public property damage cost given core damage} x {Discount factor accounting for remaining plant life} x {Number of affected plants}

The mechanism of implementation is assumed to be a generic letter followed by licensee commitment and NRC follow-up to evaluate effectiveness.

4.2 Assessment of Values

4.2.1 Avoided Public Health Risk (V1)

Using the changes in core-damage frequency given in Table 3.1 and the assumed dose to the public from a shutdown accident of 2E+04 person-Sv (2E+06 person-rem) derived in Section 2.3 of Appendix 2, the avoided public health risks associated with the modifications are:

(1) PWRs

- Improvement A: (1.6 person-Sv/r-y)(76 PWR plants)(25 yrs/PWR plant) = 3,040 person-Sv (304,000 person-rem) avoided

- Improvement B: (1.1 person-Sv/r-y)(76 PWR plants)(25 yrs/PWR plant) = 2,090 person-Sv (209,000 person-rem) avoided

(2) BWRs

- Improvement A: (0.19 person-Sv/r-y)(38 BWR plants)(23 yrs/BWR plant) = 166 person-Sv (16,600 person-rem) avoided

4.2.2 Avoided Occupational Exposure (V2)

Estimation of avoided onsite consequences depends on core-damage frequency reductions, but not on assumptions about public dose. The occupational exposure consists of immediate and long-term components.

The onsite dose rate during a severe core-damage accident with a failed containment was stated as being in the range of 1E+02 to 1E+04 person-Sv (1E+04 to 1E+06 person-rem) per hour in Appendix 2, Section 2. The number of personnel on site during an outage typically ranges from the hundreds to a thousand and, as reported in NUREG-1410 (the Vogtle event), evacuation is not assured. The potential exists for an immediate high dose to onsite personnel. Despite this, the staff has not included this potential effect in its impact/value assessment because of the large uncertainty involving personnel movements.

The long-term component of avoided occupational exposure, V2, given a core-damage accident, was estimated using the equation reported in Table 4.2 in combination with a previously used calculation approach in which only internal contamination of buildings was considered. The following core-damage frequency (CDF) reductions (from Appendix 2, Section 1) apply:

PWRs: Improvements A and B result in a CDF reduction of 8.0E-05/r-y and 5.7E-05/r-y, respectively.

BWRs: Improvement A results in a CDF reduction of 9.5E-06/r-y.

Long-term occupational exposure occurs when cleanup and recovery take place beyond work immediately associated with the accident. The value used as an estimate for this exposure was based on a study of decommissioning a reference light-water reactor following a major loss-of-coolant accident in which the emergency core cooling system was delayed in starting (Ref. 3). All fuel cladding was assumed to rupture, causing significant fuel melting and core damage. It was also assumed that the containment building was extensively contaminated, and that the auxiliary building was contaminated, too. The estimated occupational radiation dose from cleanup and recovery was 200 person-Sv (20,000 person-rem). The postulated shutdown accident includes significant contamination of the auxiliary building and other buildings, as well as the surrounding plant area because containment is assumed to be open. For purposes of impact/value analysis, the staff assumed the 200 person-Sv (20,000 person-rem) would be doubled. On this basis, the avoided occupational exposures associated with the modifications are:

(1) PWRs

- Improvement A: (8.0E-05)(400)(25)(76) = 61 person-Sv avoided (6,100 person-rem avoided)
- Improvement B: (5.7E-05)(400)(25)(76) = 43 person-Sv avoided (4,300 person-rem avoided)

(2) BWRs

- Improvement A: (9.5E-06)(400)(23)(38) = 3.3 person-Sv avoided (330 person-rem avoided)

4.2.3 Routine Occupational Exposure (V3)

Section 3.2 of Appendix 2 covered installation of RCS water level instrumentation with a routine occupational exposure of 0.03 person-Sv (3 person-rem) during initial installation and 0.005 person-Sv (0.5 person-rem) per unit per outage thereafter. No allowance was taken for reduction via potential elimination of continuous monitoring of level at the Tygon tubing or its equivalent. Water level instrumentation only applies to PWRs.

(0.03 person-Sv/plant)(65 plants) + (0.005 person-Sv/plant and/outage)
(65 plants)(1 outage/yr)(25 yr) = 10.1 person-Sv (1040 person-rem)

where 65 PWR units are assumed to account for ultrasonic level instrumentation that is already installed.

4.3 Assessment of Impacts

4.3.1 Licensee Implementation and Operating Costs (I1)

Direct industry costs and savings are estimated and reported in this section. The staff separated industry costs into two subcategories: implementation (one-time costs) and (2) operating (continuing costs). Analyzed plant outage activity elements for industry implementation (II) and industry operating (IO) costs for the improvments are given in Table 4.3.

Table 4.3 Implementation and Operating Cost Items

OUTAGE ACTIVITY ELEMENT	II COSTS	IO COSTS
Generic letter response	A	
Prepare safety policy document	A	
Independent safety review		A
Development of bases	A	
Develop and/or modify procedures	A	
Contingency plans	A	
Prepare technical specifications	A	
Water level instrumentation	B	B

The nature of these costs (i.e., implementation, operating, or both) was also investigated. Their association to each of the improvements is indicated with an A or B in Table 4.3. Each outage activity element is described in Appendix 2, Section 3. No differentiation was assumed between PWRs and BWRs, unless otherwise stated. For analysis purposes, all licensees were assumed to incur costs of an "average" plant. All costs are given in 1993 dollars and are discounted at an annual rate of 10 percent as is required by the NRC (NUREG/CR-0058). Industry and NRC labor cost rates were developed using the February 1989 (Rev. 1) version of NUREG/CR-4627, updated to 1993 dollars by assuming an annual rate of inflation of 5 percent.

4.3.2 Industry Implementation Costs

The following industry costs were calculated:

(1) GL response: (40 staff-days/site)(8 hrs/day)(75 sites)($56/hr) = $1,300,000.

(2) Prepare safety policy document: (100 new pages/site)($2,000/page)(75 sites) = $15,000,000.

(3) Development of bases:

PWRs: (1 staff-year/site)(49 sites)(52 wks/yr)(40 hr/wk)($56/hr) = $5,700,000.

BWRs: (0.5 staff-year/site)(26 sites)(52 wks/yr)(40 hrs/wk)($56/hr) = $1,500,000.

Total (all plants): $7,200,000.

(4) Develop and/or modify procedures:

- PWR owners groups guidelines: (3 owners groups)(350 pages/owner group)($5000/page)= $5,250,000; $5,250,000/49 = $107,000/site.

- BWR owners groups guidelines: (200 pages)($5000/page) = $1,000,000;

$1,000,000/26 = $38,500/site.

- Plant specific procedures:

  PWRs: (350 pages/site)(49 sites)($2,000/page) = $34.3M.

  BWRs: (200 pages/site)(26 sites)($2,000/page) = $10.4M.

(5) Contingency plans: (26 staff-weeks/site)(75 sites)(40hr/wk) ($56/hr) = $4.4M.

(6) Prepare technical specifications: (30 new TS pages + 75 new bases pages)/site](75 sites)($2,000/page) = $15.8M.

(7) Provide water level instrumentation:

PWRs: (65 units)($190,000/unit) = $12.4M.

(8) Provide containment closure manifolds

PWRs: (76 PWRs)($500,000/PWR) = $38M.

4.3.3 Industry Operating Costs

Some industry costs are initial costs and others are incurred over the life of the plant. The latter are converted to a present value via:

$$\frac{(1+r)^t-1}{r(1+r)^t}$$

where: r = discount rate = 10%
t = remaining life = 25 for PWRs; 23 for BWRs

To obtain the present value for PWRs, one multiplies by:

$$\frac{(1.1)^{25}-1}{(0.1)(1.1)^{25}} = 9.08$$

and, for BWRs:

$$\frac{(1.1)^{23}-1}{(0.1)(1.1)^{23}} = 8.88$$

The following industry operating costs were compiled:

(1) Participate in NRC review audits: These audits are assumed to take place at the beginning of the effort. The cost is

(15 person-days/audit)(75 sites)(8 hr/day)($56/hr) = $500,000.

(2) Independent safety review:

Annual cost: (2 staff-months/plant)(4.3 wk/mo)(40 hr/wk)($56/hr) = $19,300/plant.

Present value: PWRs: ($19,300)(76)(9.08) = $13.3M
BWRs: ($19,300)(38)(8.88) = $6.5M
Total: $19.8M

(3) Water level instrumentation:

Annual cost: (65 units)($1,000/unit) = $65,000

Present value: ($65,000)(9.08) = $590,000

The staff believes that the proposed requirements will not lead to an increase in the duration of outages on an industry-wide basis; and therefore a zero cost has been assumed. This is based on information gathered in site visits and in discussions the staff has had with NUMARC, INPO and licensees. The reasons are as follows:

(1) The principal factors which determine the length of an outage are the scope of work to be accomplished, the completeness of preparations for the outage, including contingency plans, and the efficiency and effectiveness of the licensee's organization in conducting the outage. Poor planning is usually the reason for not completing the outage on schedule. Consequently, improvements in the process for planning and control of outages should also help eliminate delays in completing the outage on schedule and certainly not cause an increase in outage duration. Recent experience, reported in discussions with industry representatives, tends to support this conclusion. Statistics cited by industry representatives indicate that increased attention to outage planning and control appear to be leading to a reduction in schedule overruns from an average of 20 days to just a few days. In addition, one utility (i.e, Entergy Operations) recently reported that its most recent outage, which was planned using new industry guidelines for planning and conducting outages (NUMARC 91-06), was 2 days shorter than the previous outage, i.e, 52 days versus 54 days.

(2) Regulatory requirements, primarily technical specifications, have not traditionally been a principal factor in determining the length of an outage. The scope of technical specifications for shutdown conditions varies considerably throughout the industry. Some older plants with "custom" technical specifications have no requirements covering such things as residual heat removal and AC power during cold shutdown and refueling. Plants licensed more recently have standard technical specifications which are more comprehensive; and, as discussed in NUREG-1449, many plants have their own internal controls which go beyond current STS. While this wide variability of requirements exists, the staff has not observed a correlation between it and duration of the outage. However, it is true that some licensees may need to make adjustments in their outage plans and in their preparations for outages to accommodate the new technical specifications the staff is proposing.

4.3.4 Total Industry Implementation Cost (I1)

Sections 4.3.1 - 4.3.3 may be summarized as follows in $M:

Table 4.4 Total Industry Implementation Costs

PLANT	ITEM	A	B
PWRs	GL response	0.8	0.8
	Safety document	9.8	
	Bases development	5.7	
	Procedures	5.2	
	Procedures	34.3	
	Contingency plans	2.9	
	TS	10.3	
	Instrumentation		12.4
	NRC review	0.3	0.3
	Safety review	13.3	
	Instrumentation		0.6
	Contain. manifold	38.0	
	Total	120.6	14.1
BWRs	GL response	0.5	
	Safety document	5.2	
	Bases development	1.5	
	Procedures	1.0	
	Procedures	10.4	NA
	Contingency plans	1.5	
	TS	5.5	
	NRC review	0.2	
	Safety review	6.5	
	Total	32.3	

4.3.5 Avoided Onsite Cleanup and Power Replacement Costs (I2)

Avoided property damage costs (cleanup, repair, power replacement), I2, given a core-damage accident, were calculated using the equation reported in Table 4.2. Total cost estimates were calculated by adding the cost of replacement power to the cost of cleanup and repair. Replacement power costs were derived by assuming the average replacement power costs per day ($400K) and multiplying these figures by 365 to get the dollar costs per year. This calculation yielded an average yearly replacement power cost of $146M per plant (PWR or BWR).

Cost estimates for cleanup, repair and refurbishment were obtained from a study which estimated the cost of a major loss-of-coolant accident in which emergency core cooling was assumed to be delayed (Ref. 4). In that study, it was assumed that the cleanup activities would take 10 years to complete. Over the 10-year period, the cost of cleanup was estimated to be $373M per event; the cost of repair and refurbishment was estimated to be $106M per event. No distinction was made between values for BWRs and PWRs. As previously noted, the onsite consequences were limited to the containment and auxiliary buildings, whereas the shutdown accident would cause more widespread contamination onsite. Consequently, these values were doubled as an estimate of I2. Adding these costs, updating the figures to 1993 dollars, and doubling the value yielded a cost for cleanup and repair of $1,500M over the entire 10-year period.

Cleanup and repair costs were added to the power replacement cost to get total costs. These total costs were discounted at a 10-percent rate for each year after 1993, when the core-damage frequency reductions were assumed to begin. The total yearly cleanup and power replacement costs, given core damage, were then expressed in 1993 dollars. These yearly total costs were estimated to be $1,500M/10 + $146M = $296M per plant, as shown below:

(1) PWRs:

Improvement A: (8.0E-05/r-y)($296M)(9.08)(76 plants) = $16.3M
Improvement B: (5.7E-05/r-y)($296M)(9.08)(76 plants) = $11.6M

(2) BWRs:

Improvement A: (9.5E-06/r-y)($296M)(8.88)(38 plants) = $0.95M

4.3.6 Avoided Public Property Damage (I3)

Offsite property loss is one of the major impact categories for safety-related issues. In severe accidents, property damage off site can exceed damage on site. Public property damage costs, I3, were calculated using the equation reported in Table 4.2.

Scaled results for property damage costs, given a core damage, were obtained from NUREG/CR-2723 (Ref. 5). This study reported offsite property costs for accidents at 91 U.S. sites with licensed reactors or construction permits. These costs were based on results obtained using the computer code CRAC2. The

upper and lower bound estimates of the scaled damage costs were values from Indian Point Unit 2 and Maine Yankee, respectively. These values were updated to 1993 dollars using an annual inflation rate of 5 percent. A public property damage cost of $1600M per event was estimated.

These following offsite property damage costs were discounted at a 10-percent rate for each year after 1993, when the core-damage frequency reductions were assumed to begin:

(1) PWRs:

Improvement A: (8.0E-05)($1600M)(9.08)(76) = $88.3M
Improvement B: (5.7E-05)($1600M)(9.08)(76) = $62.9M

(2) BWRs:

Improvement A: (9.5E-06)($1600M)(8.88)(38) = $5.1M

4.3.7 NRC Costs (I4)

The following outage activity elements were identified in Section 3 of Appendix 2:

(1) Resident inspector time to verify compliance with generic letter:

(5 staff-day/site)(8 hr/day)($56/hr)(75 sites) = $168,000

(2) Review licensee response to the generic letter:

(5 staff-day/site)(8 hr/day)($56/hr)(75 sites) = $168,000

(3) Training resident inspectors:

(2 staff-day/site)(8 hr/day)($56/hr)(75 sites) = $67,200

(4) Training of regional staff:

(3 staff-day/region)(5 region)(3 days/staff)(8 hr/day)($56/hr) = $20,200

(5) Training of Headquarters Project Managers:

(4 staff-hour)(75 staff)($56/hr) = $16,800

(6) Preparing training material:

(10 staff-day)(8 hr/day)($56/hr) = $4,500

(7) Conducting training:

(20 staff-day)(8 hr/day)($56/hr) = $9,000

Total cost of these seven activities: $454,000

4.4 Impact/Value Assessment Summary and Conclusions

Estimated values and impacts are summarized in Tables 4.5 and 4.6, respectively. Values and impacts were combined to form impact/value ratios for each of the two regulatory actions; the results are reported in Table 4.7. Two plant populations were considered: PWRs, BWRs. Estimates inside parentheses signify negative values (e.g., increases in routine occupational exposure) and negative impacts or cost savings (e.g., avoided offsite property damage). Only best estimates of the values and impacts were used (no upper or lower bounds were estimated).

For both plant groups, the avoided public health risk (V1) is the dominant value. Avoided occupational exposure associated with accident management and cleanup (V2) contributes a small amount. Routine occupational exposure due to implementation of the GL recommendations (V3) is almost negligible.

Dominant impacts are direct licensee cost to implement the GL recommendations and changes in operating costs (I1) and avoided offsite property damage (I3). Avoided onsite cleanup and power replacement costs (I2) have a small contribution; the cost to the NRC (I4) is essentially negligible.

The estimated impact/value ratios indicate that the modifications are cost effective when applied to the PWR population. The impact/value resultant for the BWR population marginally exceeds the standard for cost effectiveness.

Impact of Uncertainties in the PRA on Value/Impact Ratios

A sensitivity study has been performed to assess the effect of uncertain assumptions in the PRA on the overall results of the analysis. The sensitivity study is included as Appendix 3. The results of the sensitivity study show that despite some sensitivity to changes in PRA assumptions, the original conclusions regarding the cost effectiveness of the proposed improvements remain valid when inputs are changed significantly.

4.5 References

(1) Saltos, N. T., et al, "Regulatory Analysis for Proposed Rule on Nuclear Plant Maintenance," Document prepared for NRC under FIN B2918 by Pacific Northwest Laboratory, March 8, 1991.

(2) Heaberlin, S. W., et al, "A Handbook for Value-Impact Assessment," NUREG/CR-3568, Pacific Northwest Laboratory, December, 1983.

(3) Murphy, E., and G. Holter, "Technology Safety and Costs of Decommissioning Reference Light Water Reactors Following Postulated Accidents," NUREG/CR-2601, Pacific Northwest Laboratory, 1982.

(4) Andrews, W. B., et al, "Guidelines for Nuclear Power Plant Safety Issue Prioritization Information Development, NUREG/CR-2800, Pacific Northwest Laboratory, 1983.

(5) Strip, D. R., "Estimates of the Financial Consequences of Nuclear Power

Reactor Accidents,: NUREG/CR-2723, Sandia National Laboratories, 1983.

Table 4.5. Summary of Industry-Wide Values for the Improvements (in person-rems) Over the Entire Life of the Affected Plants.

VALUE (person-Sv) [person-rem]		IMPROVEMENT "A"	IMPROVEMENT "B"
PWRs:			
	V1	3,040 [304,000]	2,090 [209,000]
	V2	61 [6,200]	43 [4,300]
	V3	0 [0]	(10) [(1,000)]
	Total	3,100 [310,000]	2,120 [212,000]
BWRs:			
	V1	166 [16,600]	
	V2	3 [300]	NA
	V3	0 [0]	
	Total	169 [16,900]	

Table 4.6. Summary of Industry-Wide Impacts for the Modifications (in $M) Over the Entire Remaining Life of the Affected Plants

IMPACT ($M)	IMPROVEMENT "A"	IMPROVEMENT "B"
PWRs:		
I1	120.6	14.1
I2	(16.3)	(11.6)
I3	(88.3)	(62.9)
I4	0.3	0.3
Total	16.3	(60.1)
BWRs:		
I1	32.3	NA
I2	(1.0)	
I3	(5.1)	
I4	0.1	
Total	26.3	

Table 4.7. Impact/Value Ratios Associated With the Improvements.

REGULATORY ACTION	IMPACT/VALUE RATIO $/person-Sv [$/person-rem]
OUTAGE PLANNING AND TECHNICAL SPECIFICATIONS	
PWRs	5,200 [52]
BWRs	160,000 [1,600]
WATER LEVEL INSTRUMENTATION	
PWRs	(28,000) [(280)]

5 DECISION RATIONALE

5.1 Safety Improvements

In this section of the regulatory analysis report, the staff presents its proposals (for implementation by licensees) and gives the rationale for its positions. These positions correspond to improvement A for PWRs and BWRs, and improvement B for PWRs discussed in previous sections of this report. The staff's rationale for these proposals is that they will provide substantial and cost-justified safety improvements. This judgment is based on a qualitative assessment which is supported by a quantitative cost-benefit analysis. The qualitative elements of the assessment are as follows:

(1) The improvements reflect the NRC safety philosophy of defense-in-depth in that they address: (a) prevention of credible challenges to safety functions through improvements in outage planning and fire protection; (b) mitigation of challenges to redundant protection systems, through improved procedures, training, improved technical specifications and contingency plans.

(2) Accident sequences during shutdown which are as rapid and severe as those during power operation should be addressed with commensurate requirements. This is supported by the staff's engineering analysis of accidents during shutdown conditions documented in NUREG-1449.

(3) The improvements being proposed by the staff are aimed directly at problems which have been repeatedly observed in operating experience, e.g., loss of decay heat removal, loss of AC power, loss of RCS inventory, fires, personnel errors, poor procedures and poor planning, and lack of training.

(4) Using technical specifications to control the availability of safety related equipment is necessary because (a) operators are trained and accustomed to operating the facility within the clear limits set by technical specifications, and (b) technical specifications establish clear and enforceable regulatory requirements. Indeed, 10CFR 50.36 defines limiting conditions for operation (LCO) as "the lowest functional capability or performance levels of equipment required for safe operation of the facility." In addition, recent experience has shown that while guidelines in NUMARC 91-06 recognize the need for an enhanced accident mitigation capability; the lack of specificity regarding controls for mitigative equipment can lead to less than prudent interpretations when the guidelines are put into practice. In two instances involving PWRs, the staff has observed that although the guidelines were followed in developing the outage plan, operation in a mid-loop condition with one of two diesel generators out-of-service was permitted under the plan.

Other qualitative reasons for proposing the requirements are discussed in each of the sections below.

5.1.1 Outage Planning and Control

STAFF POSITION

The technical findings in NUREG-1449 show that a more safety-oriented approach to planning and controlling outage activities is needed, and that such an approach will reduce risk during shutdown by reducing the incidence of precursor events and improving defense in depth. Such an approach should include 1) a comprehensive program for planning and controlling outage activities, and 2) limiting conditions for operation (LCO), controlled through the plant technical specifications, to ensure plant equipment needed for key safety functions are available. Using technical specifications to control the availability of safety related equipment is necessary because operators are trained and accustomed to operating the facility within the clear limits set by technical specifications. In addition, the technical specifications establish clear and enforceable regulatory guidelines. Indeed, 10CFR 50.36 defines limiting conditions for operation (LCO) as "the lowest functional capability or performance levels of equipment required for safe operation of the facility." whereas, administrative controls are defined as "provisions relating to organization and management, procedures, recordkeeping, review and audit, and reporting necessary to assure operation of the facility in a safe manner." In addition, recent experience has shown that while guidelines in NUMARC 91-06 recognize the need for an enhanced accident mitigation capability; the lack of specificity regarding controls for mitigative equipment can lead to less than prudent interpretations when the guidelines are put into practice. In two instances involving PWRs, the staff has observed that although the guidelines were followed in developing the outage plan, operation in a mid-loop condition with one of two diesel generators out-of-service was permitted under the plan.

Elements for an Outage Program

It is the staff's position that a complete program for planning and controlling outages in a safe manner would include those elements listed below:

Essential Elements for an Outage Program

(1) clearly defined and documented safety principles for outage planning and control

(2) clearly defined organizational roles and responsibilities

(3) controlled procedure defining the outage planning process

(4) pre-planning for all outages

(5) strong technical input based on safety analysis, risk insights, and defense in depth

(6) independent safety review of the outage plan and subsequent modifications

(7) planning and controls which (a) maximize the availability of existing instrumentation used to monitor temperature, pressure and water level in

the reactor vessel, and (b) provide accurate guidelines for operations when existing temperature indications may not accurately represent core conditions

(8) controlled information system to provide critical safety parameters and equipment status on a real-time basis during the outage

(9) contingency plans and bases, including those necessary to ensure that effective DHR during cold shutdown and refueling conditions can be maintained in the event of a fire in any plant area

(10) realistic consideration of staffing needs and personnel capabilities with emphasis on control room staff

(11) training

(12) feedback of shutdown experience into the planning process

Because the role of outage planning and control is central to shutdown safety, some regulatory controls to ensure adequacy and continued implementation at all plants are appropriate. Therefore, all licensees should develop and propose a technical specification to be included in the administrative controls section of the technical specifications that requires implementation and maintenance of a program for planning and control of outages that:

(1) includes the 12 elements listed above,

(2) is documented in a controlled procedure subject to inspection by the NRC and

(3) is subject to revision with the approval of an onsite safety review organization an

(4) includes the following actions to ensure that the capability for removing decay heat is not lost as a result of a fire while the plant is shut down:

(a) Conduct an assessment of the capability of plant equipment for ensuring that effective DHR during cold shutdown and refueling modes of operation can be maintained in the event of a fire in any plant area. For purposes of the assessment, the assumptions regarding the severity of fires may be based on realistic conditions in fire areas during cold shutdown or refueling with regard to (a) amount and location of combustible material, and (b) the existence of ignition sources or temporary electrical wiring.

(b) Should the assessment indicate the normal DHR function could be rendered inoperable by a fire, develop a DHR restoration contingency plan and document the plan for use by the plant staff in an emergency. Plant staff should be trained in the use of the contingency plan

(c) The results of the assessment, including the bases for contingency plans and any necessary plant modifications, should be documented and made available for inspection by the NRC.

Through its interactions with the Nuclear Resources and Management Council (NUMARC) and its pilot team inspections of shutdown operations, the staff has become aware that all utilities are currently assessing their outage programs against NURMARC's "Guidelines for Industry Actions to Assess Shutdown Management," NUMARC 91-06, dated December 1991. The staff considers the programatic guidelines in NURMARC 91-06 to address those program elements listed above with the notable exceptions being element 7 (Instrumentation) and element 9 (specific contingency plans for fire protection). Consequently, the staff believes that a licensee program that 1) fully implements the guidelines in NUMARC 91-06, and 2) incorporates the features regarding fire protection and instrumentation described listed above would also satisfy this administrative technical specification.

<u>Technical Specifications for Control of Safety Related Equipment</u>

Licensees should modify existing technical specifications and, if appropriate, should develop new technical specifications as described in Enclosure A of the proposed GL 93-XX using the model standard technical specifications (STS) provided in Attachments A-1 through A-5 of the proposed GL 93-XX. The model technical specifications are based on the new improved standard technical specifications documented in NUREG-1430, NUREG-1431, NUREG-1432, NUREG-1433, and NUREG-1434 (STS for Babcock & Wilcox plants, Westinghouse plants, Combustion and Engineering plants, General Electric BWR/4 plants, and General Electric BWR/6 plants, respectively), and reflect changes to improve the availability of systems designed to remove decay heat, add makeup water to the reactor vessel, and establish containment integrity, with or without offsite AC power available.

RATIONALE

Basing its position on the technical findings in NUREG-1449, the staff believes (1) that the role of outage planning and control is central to shutdown safety and (2) a more safety-oriented approach to planning and controlling an outage is needed. Such an approach will reduce risk during shutdown by reducing the incidence of precursor events and improving defense in depth. The findings of the impact/value analysis in Section 4 indicate that these reductions can be substantial and obtained in a cost-effective way.

Fire Protection during Outages

During shutdown and refueling outages, activities that take place in the plant may increase fire hazards in safety-related systems that are essential to the plant's capability to maintain core cooling. The plant technical specifications (TS) allow various safety systems to be taken out of service to facilitate system maintenance, inspection, and testing. In addition, during plant shutdown and refueling outages, major plant modifications are fabricated, installed, and tested. In support of these outage-related activities, increased transient combustibles (e.g., lubricating oils, cleaning solvents, paints, wood, plastics) and ignition sources (e.g., welding, cutting and grinding operations, and electrical hazards associated with temporary power) present additional fire risks to those plant systems maintaining shutdown cooling. The staff is concerned that a fire could damage the operable train or trains of DHR or other equipment that may be used for DHR. This fire damage could further complicate the plant's capability to remove decay heat.

In Appendix R to 10 CFR Part 50, Section III.G.1, the staff states: "Fire Protection features shall be provided for structures, systems and components important to safe shutdown. These features shall be capable of limiting fire damage so that:

"(a) One train of system necessary to achieve and maintain hot shutdown conditions from either the control room or emergency control station(s) is free from fire damage; and
"(b) Systems necessary to achieve and maintain cold shutdown from either the control room or emergency control station(s) can be repaired within 72 hours."

On this basis, it can be concluded that protection during full-power operations is the intent of the regulation. The regulation allows DHR functions to be damaged by fire. In addition, the regulation allows licensees to repair fire damage while the plant is being held in a safe hot-shutdown condition. Appendix R, Section III.G does not address the fire protection and separation concerns discussed in NUREG-1449 regarding those systems necessary to achieve and maintain DHR functions during shutdown operations.

For reasons discussed above, the likelihood of a fire is believed to be higher in the shutdown mode than at power. This, in combination with the potential lack of sufficient mitigative capability stemming from lack of requirements, results in the conclusion that the potential for core damage as the result of a fire is higher during shutdown than at power. Without performing an assessment of the effects a fire may have on the DHR function and those systems that may be used should DHR be lost, adequate decay heat removal is not assured. Thus, the staff concludes that such an assessment and associated contingency plans are needed to minimize risk to the public in the event of a fire during shutdown.

Technical Specifications

Technical Specifications (TS) ensure that important safety equipment needed to

mitigate an accident during shutdown is available to the operators and that the operators are always aware of what is available during during various operational conditions during shutdown. The staff and industry both recognize that current TS for some shutdown conditions are not an adequate minimum safety standard. Consequently, technical specifications should be changed to improve the availability of systems designed to remove decay heat, add makeup water to the reactor vessel, and establish containment integrity, with or without offsite AC power available. The changes proposed by the staff have been evaluated from a risk perspective and shown to yield significant reductions as discussed in previous sections of this regulatory analysis report.

5.1.2 Water Level Instrumentation for PWRs

STAFF POSITION

Licensees of PWRs should provide an additional means of accurately monitoring water level in the RCS during midloop operation. This additional instrumentation should not be affected by pressure errors that could occur at one or more pressure sensors. Normally, ultrasonic devices or other local measurements such as pressure differential across the hot leg will be necessary to meet this criterion. The installed instrumentation should include visual and audible indications in the control room to alert operators to an inappropriate condition. The instrumentation should be placed in operation before RCS inventory is reduced.

The proposed action regarding installation of new water level instrumentation, including an alarm, in a PWR is a cost-justified safety enhancement. This action stems from a desire to eliminate losses of the residual heat removal system due to air ingestion caused by operator error when lowering water level to achieve a mid-loop condition.

In adopting the staff's postion, licensees should make the appropriate facility modification, and update the safety analysis report. However, other approaches to resolving the problem of loss of DHR in a PWR during mid-loop operation would be considered by the staff as alternatives to installation of instrumentation for monitoring water level exclusively during midloop operation.

RATIONALE

The ability to maintain control of RCS level in PWRs during draindown and steady-state operation has been repeatedly demonstrated to be a problem. Numerous contributors to events have been identified, including poor procedures, poor training, poor planning, and poor instrumentation. The problem is most significant during mid-loop operation, where a small variation in level can cause loss of DHR. PRAs have consistently identified mid-loop operation as of higher risk than other operational states.

PWR licensees have added level instrumentation to cover shutdown operation in

response to GL 88-17, and level indications have generally improved in the last 3 years. However, events in PWRs continue to occur (Prairie Island 1992) in which existing methods for monitoring water level have failed to provide adequate indication of a level too low to support RHR pump operation.

The findings of the impact/value analysis in Section 4 indicate that addition of a diverse water level instument, including the necessary procedures and training for using it, can be done in a very cost-effective way.

APPENDIX 1

COMPARISON OF NUREG-1449 AND NUMARC 91-06

In Chapter 7 of NUREG-1449, the staff lists elements that are appropriate for conducting an effective outage program. These elements are compared with NUMARC 91-06 guidelines below. It is important to note that the NUMARC 91-06 guidelines constitute are intended to be used for assessing outage planning programs, not for developing a program. The NUREG-1449 item is quoted first (underlined); the NUMARC 91-06 assessment follows.

(1) Clearly defined and documented safety principles for outage planning and control

NUMARC 91-06 states that each utility should establish a safety philosophy, although it does not address documentation in detail. Licensees should evaluate outage practices, determine and document the basis for the assessment results, and use the results to improve outage planning and control.

Key safety functions are defined and guidance is given for maintaining these safety functions. Licensees are expected to optimize safety system availability, ensure the availability of systems that provide and support key safety functions, be aware that decay heat removal (DHR) and inventory control are key to shutdown safety, and establish schedules to reduce risk associated with loss of DHR.

The guidance given in NUMARC 91-06 is appropriate. However, the staff believes licensees should clearly define and document their safety principles for outage planning and control.

(2) Clearly defined organizational roles and responsibilities

NUMARC 91-06 identifies organization level involvement, coordination, and communication. The NUMARC guidelines are sufficient.

(3) Controlled procedure defining the outage planning process

NUMARC 91-06 does not address the need for a controlled, written procedure which defines and documents the way business will be done in the outage program. The staff believes having such a procedure is necessary to link work practices to the guidelines and ensure that all employees are trained and knowledgeable on how work is to be done.

(4) Pre-planning for all outages

NUMARC 91-06 does not specifically address the need for pre-planning

for all outages. In practice, all unforced outages are pre-planned and, at some facilities, plans for important outage work of a short-term nature are put into place ahead of time to be implemented if a forced outage should occur.

(5) Strong technical input based on safety analysis, risk insights, and defense in depth

The need for analysis and understanding of shutdown operations is stressed throughout NUMARC 91-06. NUMARC 91-06 states that a comprehensive understanding of the factors contributing to risk in the loss of DHR is essential to planning, implementation, and event mitigation. The need for ensuring defense in depth during outage operations is also emphasized.

NUMARC 91-06 directs licensees to consider the following areas when planning and implementing operations: level of decay heat, time to boiling, time to uncover the core, initial RCS inventory, RCS boundary configuration, natural circulation, steam generator heat transfer, criticality, and the refueling sequence.

The staff considers this guidance to be adequate.

(6) Independent safety review of the outage plan and subsequent modifications

NUMARC 91-06 directs licensees to conduct a safety review of the outage plan before final approval which (a) focuses on adequate defense in depth, (b) checks contingency plans and the adequacy of response procedures, and (c) ensures identification of actions that involve higher risk. In addition, licensees are to establish review and approval authority for implementation of changes to the plan and schedule, and should require that safety-significant schedule changes be reviewed using the same process as was used for the review of the original plan and schedule. NUMARC 91-06 indicates that for these reviews, personnel should be included who are knowledgeable about management expectations and who have not been directly involved in planning process.

The staff agrees with the NUMARC guidance.

(7) Controlled information system to provide critical safety parameters and equipment status on a real-time basis during the outage

NUMARC 91-06 provides adequate guidance in this area.

(8) Contingency plans and bases

NUMARC 91-06 gives substantial guidance for contingency planning. Contingency plans are to be developed in support of key safety functions for periods during activities that involve higher risk

when system availability drops below the level in the original plan. Contingency plans are also identified for operation in temporary configurations, such as use of a freeze seal, and also for such hazards as fire and flood.

The staff considers this guidance to be adequate

(9) Realistic consideration of staffing needs and personnel capabilities with emphasis on control room staff

Guidelines in NUMARC 91-06 pertaining to (a) establishment of overtime policy and (b) matching resources to activities address this item adequately.

(10) Training

Guidelines in NUMARC 91-06 for addressing shutdown operations and specific safety issues in the operator training program address this item adequately. Some examples of shutdown safety issues covered in NUMARC 91-06 are reduced inventory operation, response to loss of DHR, containment closure, contingency plans and use of temporary electric power configurations.

(11) Feedback of shutdown experience into the planning process

NUMARC 91-06 guidelines in this area are adequate. They instruct licensees to monitor practices and improvements, to use techniques that provide objectivity, to provide post-outage critiques, and to provide feedback regarding outages as well as including their own events and those related to industry experience.

APPENDIX 2

RISK ASSESSMENT AND COST ESTIMATES

1. CALCULATION OF CORE DAMAGE FREQUENCIES

1.1 Key Assumptions

1.1.1 Plant Configuration During an Outage

Plants pass through a number of operating states during outages. Contributors to risk vary with the operating state, and some states represent higher potential risk than do others. Different licensees operate with different configurations and different procedures within these states, and large variations are perceived in the potential risk due to such variations. Finally, the time spent in these states varies from licensee to licensee, as does the total time spent in various outages. For example, the staff is aware of a recent refueling outage that was planned for 20 days, although refueling outages usually range from a little under 40 days to a number of months as discussed in Section 3 of NUREG-1449 (Ref. 1). For risk evaluation purposes and to reasonably minimize the impact/value analyses, the staff has assumed a refueling outage schedule. For PWRs, it consists of the following:

Action or Condition	Days Spent
Cooldown and drain to midloop	2
Midloop operations	1
Operate with level below RV flange	7
Head removal, RV cavity flooding	1
RV cavity flooded operation	21
Post-flooded operation	18
Total	50

and for BWRs, it consists of:

Action or Condition	Days Spent
Cooldown to 200 °F (93 °C)	2
Remove drywell head	1
Remove RV head, dryer, install plugs	3
Remove separator, flood to 23 ft (7 m)	4
Flooded operations	21
Post-flooded operation	19
Total	50

1.1.2 Dominant Shutdown Event Sequences

Dominant event sequences have been identified during shutdown operation based upon the analysis of operating experience that is summarized in NUREG-1449. The events have been grouped as follows for impact/value analysis:

- PWRs: Loss of offsite power (LOOP), loss of RCS inventory, and loss of RCS level control

- BWRs: LOOP and loss of RCS inventory

1.1.3 Probabilities for Loss and Nonrecovery of Offsite Power (LOOP)

Chu (Ref. 2) compiled probabilities of LOOP and nonrecovery of offsite power for switchyards similar to the one at Surry. He assumed power operation data were representative of low power operation and that all nonpower operation data could be combined, and concluded that his results represented about 30 percent of the nuclear power plant switchyards. He reported that the probability of a loss of offsite power was:

- Power and low power operation: 0.11/reactor-yr (1.26E-05/hr)
- Shutdown operation: 0.25/reactor-yr (2.85E-05/hr)

where the plant is assumed in the stated condition for the identified time increment. The probability of nonrecovery is summarized in Figures 1 and 2, which provide estimated mean values with uncertainty bounds. The mean values were used for the impact/value analysis. This information has been assumed applicable to all plants for purposes of this analysis.

1.1.4 Failure and Recovery Rates for Emergency Diesel Generators (EDGs)

The staff reviewed typical EDG data and estimated the combined probability of starting, loading, and running to be 0.95. This included the following considerations:

- Shutdown operation includes off-normal power lineups.
- Support equipment may be influenced by the outage.

The case of two EDGs operable was treated by using the above information plus data from Table B-3 of NUREG-1032 (Ref. 3) to obtain the following:

- Basic failure to start = (0.05)(0.05) = 2.5E-3/demand
- Common cause failure to start = 5.7E-4/demand
- Common cause failure to run = 1E-4/hr

EDG repair times are given in NUREG/CR-2989, Figure 9.5.13 (Ref. 4). The staff assumed that information was applicable to shutdown operation, and used it to obtain the recovery times provided in Table 1.

Table 1. EDG Recovery Time

Time since failure, hrs	% repaired during time span	% recovered by end of time span
0-1	11.2	11.2
1-2	3.3	14.5
2-3	7.9	22.4
3-4	8.6	31.0
4-5	5.0	36.0
5-6	4.7	40.7
6-7	4.1	44.8
7-8	6.3	51.1
8-9	7.5	58.6
9-10	1.4	60.0
10-11	2.3	62.3
11-12	2.2	64.5
12-13	3.6	68.1
13-14	1.2	69.3
14-15	1.7	71.0
15-24	5.9	76.9
24-	21.4	98.3

1.1.5 Frequency of Loss of RCS Inventory and Level Control

Chu also compiled the data summarized in Table 2, where the staff added the last column (Type). Contributions to each type of failure shown in the table were summed to obtain the following initiating event frequencies for losing DHRS:

- Leak: 2.3E-05/hr + 1.8E-02/yr
- Level: 1.2E-05/hr + 1.23E-02/demand

The units on the above frequencies given on a per year and per demand basis are equivalent for this investigation since a single outage per reactor-year is assumed.

In a personal communication to Warren Lyon (NRC/NRR) on July 7, 1992, Robert Prato (NRC/AEOD) reported that for BWRs, the AEOD data base for 1987-1991 identifies four loss of inventory events in about 150 reactors-years. In another personal communication to Warren Lyon on the same date, Donnie Whitehead (Sandia National Laboratories) reported eight such sequences from his work on the Grand Gulf probabilistic risk analysis (PRA). In addition, the staff knows of several other events that do not appear in either data base. Thus, the staff concludes that more events occur than are reported, and has assumed an event rate of 1/10 per reactor-year.

Table 2. Shutdown and Low Power Operation Event Rate Information for PWRs

Item	Description	Events/hr	Type
RHR2	Low inv.: (a) overdrain (1.23E-2/demand)		Level
	(b) failure to maintain level	8.4E-6	Level
RHR3	DHRS LOCA: (a) leakage	1.1E-5	Leak
	(b) flow diversion	6.2E-6	Leak
	(c) open DHRS relief valve	5.4E-6	Leak
RHR4	Spur. SI, loss of heat exchanger flow	6.2E-6	Other
RHR5	Valve failure: (a) one train affected	1.8E-6	Other
	(b) two trains affected	6.2E-6	Other
RHR6	Pump failure: (a) not recoverable	7.1E-6	Other
	(b) recoverable	2.5E-5	Other
RHR8	Inability to operate DHRS (5.2E-3/demand)		Other
RHR9	DHRS voiding, gas binding	3.6E-6	Level
RHR10	Loss of CCW, SW to DHRS	1.7E-5	Other
RHR11	Events affecting both pumps	1.8E-6	Other
H	Flow diversion via DHRS (5E-3/yr)		Leak
	Flow diversion via CVCS (1E-3/yr)		Leak
	Flow diversion via drains (1E-3/yr)		Leak
J	Water loss via leak in DHRS (5E-3/yr)		Leak
	Water loss via leak in CVCS (3E-3/yr)		Leak
K	Maintenance caused RCS leak (2E-3/yr)		Leak
	Maintenance caused DHRS leak(1E-3/yr)		Leak

1.2 Analysis of PWR Accident Sequences

The staff developed and quantified 14 event trees to assess the effect of shutdown operations on probability of severe core damage in PWRs. These event trees are shown as Figures 3 through 16. The following comments apply:

- With the exception of the initiator, a "yes" response at a branch results in moving upward on the event trees. Branches that cease to grow indicate success, that is, no core damage.
- Two significant figures are carried in the trees and tabulated in results to minimize round-off error.
- Core uncovery and core damage are assumed to occur at the same time. The time difference between the two is typically less than an hour for the high decay heat rates that represent the major contributor to core damage.

1.2.1 Loss of Offsite Power in PWRs with the Refueling Cavity Filled

Figure 3 provides a basis for assessing changes for the case of the reactor vessel (RV) refueling cavity filled to a nominal 23-foot (7 m) depth. The bases and assumptions are as follows:

(a) LOOP. The outage includes 21 days with the refueling cavity filled. However, the period of greatest concern is approximately the first 5 days when decay heat is the highest and most of the irradiated fuel elements remain in the core. Using the expected LOOP rate of 0.25 events/reactor-year gives the likelihood of LOOP as:

$$(0.25)(5 \text{ days/yr})/(365 \text{ days/yr}) = 3.4\text{E-}3/\text{reactor-yr}$$

One outage per year assumed for discussing this event.

(b) EDG starts and loads. The probability of one EDG not starting and being loaded is 0.05, as discussed in Section 1.1.4.

(c) Power recovery before boiling. The time between loss of cooling and initiation of boiling is about 11 hours. The probability of not recovering offsite power in 11 hours is 0.038 (Figure 2) and the probability of not recovering the EDG is 0.38 (Table 1). The staff assumes that cooling established is synonymous with recovery of AC power and, consequently, the probability of not boiling is the probability of not recovering AC power: (0.038)(0.38) = 0.014.

(d) Nozzle dam intact. Although nozzle dams have been widely used at temperatures below roughly 120 °F (49 °C), they have not, to the staff's knowledge, been widely exposed to temperatures that exceed 200 °F(93 °C). They typically depend upon air pressure, and any replenishment of air that is needed may be unavailable during an extended LOOP. Nozzle dams could be exposed to roughly 15 psig

and 250 °F (121 °C) during a LOOP.[3] This branch represents an assumption to assess the effect of nozzle dam failure. If a failure occurs, it is assumed to occur 2 hours after boiling initiates since some time will be needed to heat the hot legs in the vicinity of the dams.

(e) <u>Power recovery before core damage</u>. With the nozzle dam intact, core uncovery occurs after several days. The staff assumed the probability of recovering AC power in that time to be effectively one. This produces a core-damage frequency of near zero for this branch.

Nozzle dam failure leads to core uncovery 18 hours after the LOOP, assuming catastrophic failure 5 hours after initiation of boiling. (A small leak is considered much more likely; a condition not addressed in this tree.) Table 1 shows the EDG recovery likelihood at 18 hours as about 0.74. However, credit was taken at branch (c) for EDG recovery with a likelihood of 0.62. Consequently, the effective probability at branch (e) is (1 - 0.74)/(1 - 0.62) = 0.68. Recovery of offsite power at 18 hours rather than at 11 hours yields a nonrecovery contribution of 0.02/0.038 = 0.5. The probability of not recovering AC power at branch e given that it was not recovered at branch (c) is thus (0.68)(0.5) = 0.34.

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[3]B&W nozzle dams have been described to the staff as having an inner and outer pneumatic seal, with annulus leak monitoring. A backup mechanical seal is designed to limit leak rate to ≤ 2 gpm (7.6 L/min) if both pneumatic seals fail. The dams are designed for 30 psid (207 kPa differential) at 225 °F (107 °C) and are considered by the vendor as seismically qualified, Class 1E equipment. They are only used in the cold legs and are unlikely to be exposed to an elevated temperature when the refueling cavity is flooded.

CE uses two dams in series, with the seal material required to withstand 250 °F (121 °C) according to vendor personnel. This nozzle dam has been used with the seals reversed for steam generator (SG) chemical decontamination in several plants. Temperatures of roughly 200 °F (93 °C) were withstood without problems. Again, pneumatic seals are used with an outside air supply.

<u>W</u> has two designs, one of its own and one by Busitech. The latter is designed for 20 psid (138 kPa differential) and is tested at 26 psid (179 Kpa differential). An EDPM rubber is used with an operating temperature of 40 to 270 °F (4 to 132 °C). Inflatable seals are used with two sources of air. Loss of both sources would result in a leakage of less than 3 gpm (11 L/min). (Leakage rate from tests is typically 3 drops/min.) Failure pressure for both designs is expected to be greater than 50 psig (345 kPa gauge). The <u>W</u> dam is rated at 58 psig (400 kPa gauge) and the Bisitech dam has a factor of four safety factor based upon ultimate strength of any part.

The core damage frequency due to LOOP is 8E-08/reactor-yr. Even if the nozzle dams were to fail every time they were exposed to boiling, the core damage frequency is only 8E-07/reactor yr.

This event tree also shows that a loss of DHR, regardless of cause, is of little concern due to the amount of time before boil-down could uncover the core. An event initiated by nozzle dam failure during operation at 23 feet (7 m) could lower the water level to roughly the top of the hot leg, but would not result in a loss of DHR. Other events involving loss of inventory are similar to those that occur with operation at less than 23 feet (7 m), but system response is slower because of the significantly larger water inventory. These events are addressed for the lower water inventory condition.

Because the estimated probability of core damage is sufficiently low for operation with the refueling cavity flooded, the staff did not further pursue cases for this operating condition.

1.2.2 Loss of Offsite Power in PWRs with Low Level in the Refueling Cavity

Figure 4 illustrates the estimated LOOP characteristics with less than 23 feet (7 m) of water in the refueling cavity. The event tree addresses the first 10 days of operation following shutdown for the assumed outage. There will be a similar period of operation following draining of the cavity when the decay heat generation rate is lower. There will also be non-refueling outages, some of which will involve shutdowns with an intact nuclear steam supply system (NSSS) where the SGs can remove decay heat; others will involve shutdowns for SG tube repairs and then the SGs will not be available to remove decay heat. Other outages may involve response to a failure in the RCS pressure boundary, such as a reactor coolant pump seal failure. A factor of 30 percent is added to the initiating event frequency to account for the total of such additional cases.

There is no differentiation between midloop and other RCS water level conditions in this event tree for the following reasons:

(1) When decay heat is high, time to boiling varies by only a few minutes with level in the RCS ranging between mid-pipe and a full RCS. The time variation is small enough that no significant differences in operator action or AC power recovery are anticipated before boiling initiates.

(2) Initiation of boiling with openings in the RCS pressure boundary will force water out of the loops until the level is in the vicinity of mid-pipe in the CE and W designs. Thus, boil-down time is independent of initial water level in these designs.[4]

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[4]This is not true of the B&W design. These PWRs are typically vented near the top of the hot leg and steam flow will not eject large quantities of water. They are not vented solely via the pressurizer.

(3) Initiation of boiling with a closed RCS will cause pressurization and forces water into the pressurizer until (a) a path is opened to the SGs, (b) DHRS safety valves open, or (c) pressurizer safety valves open. Pressurization will likely stop when a path is opened to the SGs if SGs are available for cooling. Lack of SGs will cause behavior similar to that discussed in item 2 (above) via relief out of safety valves.

The following comments apply to the tree branches:

(a) The probability of LOOP is (0.25)(1.3)(10)/365 = 8.90E-03/reactor-yr.

(b) There is no change between this and the previous event tree.

(c) Boiling is estimated to occur in 15 minutes and the probability of recovering offsite power in this time is 0.26. No credit is taken for recovery of the EDG due to the short time. Similarly, no allowance is made for gravity feed or for use of other water addition methods that do not require AC power to prevent boiling. Such steps often require operations outside the control room and are not well addressed in existing procedures.

(d) The RCS is assumed closed for the first 2 days and open for the remaining 8 days.

(e) SGs are assumed effective only if the RCS is closed and the SG secondary side is filled. A full secondary side is not assured in many of today's operations, although it often occurs due to the practice of placing SGs in wet layup. The staff has assumed SGs are available 3/4 of the time based upon observations of plant operations. Operator actions to vent steam are included in the 3/4 assumption.

SGs may be partially effective with openings in the RCS. This is an unanalyzed area and the potential contribution of SGs has been neglected.

Some licensees do not block all SGs based on the assumption that the unblocked SGs can be used for heat removal if DHR is lost. The staff assumed SGs are not available if nozzle dams are installed because SGs are not proven to be effective under such conditions.

(f) A large vent is one that results in no backpressure during boiling. Only the SG manways satisfy this requirement. Thus, large vents do not exist once nozzle dams have been installed in W and in CE plants.[5] Nozzle dam installation is assumed to be accomplished in the first 2 days of the 8 days being considered here.

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[5]Large vents often exist in B&W designs. A large opening is often provided near the top of the SG and nozzle dams are not used in the hot legs.

(g) The RCS closed condition without SGs will pressurize quickly. This pressurization is assumed to prevent gravity feed. Although accumulators could be used for injection, few licensees have considered accumulator capability during shutdown and no credit was given for such usage.

Gravity feed, with a large vent, is assumed effective 95 percent of the time. This low failure rate is assumed reasonable in the absence of good procedures because operators are aware of this makeup method as a means to recover level if DHR system problems occur. The staff bases this conclusion on numerous reviews of events and procedures and on interviews with operators. Note, however, that procedures often direct operators to control water level and that level indications may be high under these conditions. Hence, operators may have to violate plant procedures to add water. Conversely, core exit thermocouples will start to indicate superheat, a clear indication that water is needed.

Absence of a large vent will cause some pressurization. Although gravity feed may be less effective, it still appears reasonable, particularly if a pressurizer manway is removed. A 9/10 probability of success was assumed to take into account the lowered effectiveness, principally (1) due to a reduced time to core damage if backpressure reduces gravity feed effectiveness, and (2) due to the belief that operators are more likely to make mistakes in this configuration. NUREG-1410 (Ref. 5) provides additional discussion of this topic.[6]

(h) Core uncovery is estimated to occur in 2 hours if water cannot be added to the RCS. The probability of not recovering offsite power in 2 hours is 0.32. This branch is conditional on not recovering offsite power within 15 minutes at branch c. The nonrecovery probability at branch h is therefore 0.32/0.74 = 0.43. The probability that the EDG is not recovered in 2 hours is 0.86, and no recovery was assumed at 15 minutes. The total probability of not recovering AC power with respect to this branch is (0.86)(0.43) = 0.37.

Gravity drain is assumed to extend the time from 2 hours to 6 hours with a small vent. The probability of not having the EDG at 6 hrs is 0.59 and the likelihood of not having offsite power is 0.10. The probability of not having AC power at this branch is (0.10/0.74)(0.59) = 0.080.

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[6]A number of plants, principally those of CE design, cannot be gravity fed from the refueling water storage tank or its equivalent. Such plants, assuming they are represented generically according to this tree will have a core uncovery probability due to LOOP alone of:

$$(8.9E\text{-}03)(0.05)(0.74)[(0.8)(0.37) + (0.2)(0.25)(0.37)] = 1E\text{-}04/r\text{-}y$$

Figure 5 illustrates the estimated effect of implementing new technical

specifications and improvements in outage planning and control described in Section 2. The following comments apply to this tree:

(a) The outage improvement program should make offsite power more reliable and reduces the probability of LOOP. The improvements are assumed to reduce the probability of a LOOP to midway between the present shutdown loss rate of 0.25/r-y and the power operation value of 0.11/r-y; that is, (0.25 + 0.11)/2 = 0.18/r-y. Therefore, the event frequency is estimated to be:

$$(0.18)(10)(1.3)/365 = 6.41E-03/r-y$$

(b) Two EDGs are required by the new TS. As discussed in Section 1.1.4, the basic probability of failing to start given a demand is (0.05)(0.05) = 2.5E-03. The common-cause failure to start is 0.6E-03 and the failure to run given a successful start is (1E-04/hr)(10 hrs) = 1E-03, where a 10 hour run is assumed. The total probability of not having one EDG start and load is the total, 4.1E-03.

During shutdown operation, the operator is often required to manually reconfigure part of the electrical system and to load all or part of the loads following a LOOP. The probability of not doing this correctly is considered to be included in the 0.05 probability of failing to obtain a satisfactory start and load.

(c) The failure probability is (0.68 + 0.74)/2 = 0.71, consistent with branch (a).

(d) No change is anticipated in the fraction of time the RCS is open.

(e) Improvements are not assumed to change SG availability.

(f) The vent capability is, in part, dictated by the RCS design. Extended operation in midloop would allow use of a large vent for a longer time, but this is not considered reasonable because of the high probability of encountering problems in midloop. This branch is considered to be unaffected by the procedural improvements.

(g) The gravity feed failure probability has been assumed reduced by a factor of 2 based on the assumption of better planning, better procedures, better training, and better contingency planning.

(h) At 2 hours the probability of not recovering offsite power based on power operation is 0.28. The appropriate value for offsite power nonrecovery probability is (0.28 + 0.32)/2/0.71 = 0.42. The probability of one of two EDGs not being recovered is assumed to be $(0.86)^2 = 0.74$. The conditional probability of not recovering AC power at 2 hours given that it was not recovered at 15 minutes is (0.42)(0.74) = 0.31.

For 6 hours, the calculations are as follows:

- offsite power nonrecovery probability = (0.08 + 0.10)/2/0.71 = 0.127
- probability of not recovering one of two EDGs = $(0.593)^2$ = 0.35
- AC power nonrecovery probability = (0.127)(0.35) = 0.044

Improved level instrumentation will alter the LOOP event tree as illustrated in Figure 6. Level instrumentation, including visual and audible alarms, is assumed to only affect the probability of attempting gravity feed. A factor of 2 improvement in the failure probability for attempting gravity feed is assumed. All other event tree failure probabilities are unchanged from the values in Figure 4.

1.2.3 Loss of Level Control in PWRs

The ability to maintain control of RCS level during draindown and steady-state operation has been repeatedly demonstrated to be a problem. Numerous event contributors have been identified, including procedures, training, planning, and instrumentation. The problem has been of most significance during midloop operation, where a small variation in level can cause loss of DHR. PRAs have consistently identified midloop operation as of higher risk than other operational states. Consequently, the staff assessed maintenance of level control by addressing midloop operation as the condition that will capture much of the probability of core uncovery.

Time at midloop is variable. Some plants, such as Diablo Canyon, are not routinely taken into midloop during refueling outages, whereas other plants may be operated in midloop for days. In estimating the initiating event frequency, the staff assumed one day per year in midloop operation plus an additional 30 percent as was done in Section 1.2.2 to account for additional time at similar conditions.

Figure 7 illustrates the base case for level control. No allowance is given for recovery of DHR unless water is added to the system since the initiator is assumed to be insufficient water. Conversely, addition of water is assumed sufficient for preventing core uncovery. The following comments apply:

(a) Utilizing the initiating event frequency given in Section 1.1.5, the probability of a loss-of-level control event is (24 hr/yr)(1.2E-05/hr) +(1.23E-02/yr) = 0.013/yr. Increasing this by 30 percent to account for additional contributions to the loss rate during a one year period, one obtains (0.013)(1.3) = 0.017/r-y.

(b) Boiling will occur in roughly 15 minutes following an early loss of DHRS operation. Although this time is short, operators are sensitive to loss of DHR and it is addressed in procedures. The probability of failure to prevent boiling is taken as 1/10 for this branch.

(c) Most of the draindown operation and some of the steady-state midloop operation will occur with the RCS open. This is assumed to be the case 3/4 of the time.

(d) A large hot leg opening is assumed for 1/2 the time the RCS is open.

(e) SG availability is assumed to be 3/4, as previously discussed.

(f) The staff estimated a failure probability of 0.002 of taking the correct steps to add water, having the equipment available to accomplish this action, and restoring level and DHRS operation within about 1½ hours time. Since the branch b probability of this failure was 0.1, the probability associated with the top path of branch f becomes 0.02. Similar comments apply to the other parts of branch f.

The path without a large vent is judged less likely to succeed in the longer term in combination with gravity feed because of backpressure.

Figure 8 illustrates the effects judged to be obtained via improvements in outage planning and technical specifications. The following comments apply:

(a) A factor of 1½ improvement is judged reasonable for improved outage planning. Much of this was previously covered in GL 88-17 and should already be addressed, thus significantly reducing the problem that existed several years ago. Improved outage planning, continued follow-up on GL 88-17, and better procedures, particularly during draining, are considered to be the principal contributors to improvement.

(b) There is little time to respond and many aspects were previously addressed in GL 88-17. No improvement is assumed.

(c) No additional comments apply that have not been discussed above. The same applies to branches d and e. In the remainder of this document, such branches will not be identified in the text.

(f) Although much of this was previously addressed in GL 88-17, additional improvement is anticipated. Improvements in outage planning and control and new technical specifications are assumed to improve the failure probability for taking corrective steps to add water by a factor of 2.

The instrumentation improvement effects are illustrated in Figure 9. The following comments apply:

(a) Audible and visual alarms will identify low water level before a point at which DHRS operation is jeopardized. Past level indication problems are assumed eliminated by instruments that are not susceptible to those problems. DHRS instrumentation is additionally assumed to identify an approach to loss. A factor of 5 reduction is assumed reasonable.

1.2.4 Loss of Inventory in PWRs

Loss of inventory is treated similarly to loss of level control. Figure 10 addresses the base case, and the following comments apply:

(a) The initiating event frequency from Section 1.1.5 is (2.3E-05/hr)(1.3)(24 hr/yr) + (1.8E-02/yr)/2 = 0.0097/r-y. The value 1.3 is used only for the time in the condition, since the second term is an annual term. Half of the events given on a per year basis are assumed mitigated before DHRS operation is affected.

(b) If the leak remains undiscovered until the RHRS is lost, then only 10 to 15 minutes will elapse before boiling initiates. For practical purposes, all leaks will stop when they reach the bottom of the hot leg, and time to boiling and time to core uncovery following loss of the RHRS due to a loss of inventory will be roughly the same as for a loss of the RHRS.

(e) SGs can extend the time; but if inventory continues to be lost, the effectiveness of the SGs will also be lost. However, termination of the leak before core uncovery is sufficient to prevent core uncovery if the SGs are effectively cooling in the reflux mode. The same rationale applies to this case as used in the case of loss of the DHRS as a result of loss of level control.

(f) The same rationale apply as applied to the case of loss of the DHRS due to a loss of level control.

Figures 11 and 12 illustrate the effects of improvements in outage planning/TS and instrumentation, respectively. The rationales are essentially the same as previously discussed, and the assumed changes are reflected in the changes in the branch probabilities in moving from tree to tree. Note that branch (a) reflects a factor of three improvement for implementation of improved outage planning/TS and for new instrumentation.

1.3 BWR Event Trees

1.3.1 Loss of Offsite Power in BWRs

A 7-day base case is assumed preceding flooding the RV cavity since some of the time the RCS will be closed and steam-driven systems may be available to provide core cooling. This will often be true for nonrefueling outages.

The base case LOOP event tree is illustrated in Figure 13. Appropriate comments are as follows:

(a) 7 days results in a loss probability of 4.79E-03.

(c) Boiling is estimated at 2 hours from LOOP. The firewater failure probability is judged to be ¼ on the basis that work inside containment is far more difficult once boiling has initiated and little preparation was seen regarding use of firewater under the conditions that may exist.

(d) Uncovery by boiling is estimated as 15 hours after LOOP. Failure to recover offsite power is 0.02 and failure to recover the EDG is 0.29; (0.02)(0.29) = 0.0058.

(e) This branch addresses the potential problem of steam entering the plant during up to 13 hours of boiling and causing problems that prevent re-initiation of core cooling when AC power is restored. No data are available and, to the staff's knowledge, the problem has not been addressed. A failure probability of 1/10 is assumed.

One may also consider that firewater was used to prevent boiling, but such usage may impact recovery following restoration of AC power because water could wet or flood lower floors that contain equipment.

Figure 14 addresses BWR improvements. Additional branch comments are as follows:

(a) The same assumption of improvement of offsite power availability is made as was made for the PWRs.

(b) This reflects the requirement for two EDGs. The values are the same as for the comparable PWR case.

(c) Outage planning, procedures, and training are assumed to decrease the probability of firewater not being available from ½ to 1/10.

(d) The nonrecovery probability is $(0.02)(0.29)^2 = 1.7E-03$.

1.3.2 Loss of RCS inventory in BWRs

Loss of inventory events in BWRs are represented by Figures 15 and 16. Figure 15 represents the base case, with the following comments on selected branches:

(a) The 1/10 is an estimate as discussed in Section 1.1.5.

(b) Automatic isolation based upon low level should isolate many of the causes of a loss of inventory. Causes for failure to isolate include equipment failure, isolation feature inoperable, and loss paths that do not isolate automatically, such as use of freeze seals in drain paths or other operations via such paths. The 1/10 is an estimate of such effects.

(c) Operator actions may be involved in this branch, with a higher probability considered for the lower path than the upper. Values less than E-03 are not assumed if the equipment is not covered by TS.

(d) This branch is reached if operators have not been able to actuate the ECCS. The top path is based upon assuming the control rod drive (CRD) water path did not work with a probability of 1/10, followed by a firewater system with ⅓ failure probability, followed by a service water system with a ½ failure probability. Each value includes a contribution from operator error, and the contribution becomes larger with each step because it is assumed that if the operator fails at one step, then the probability of success at the next step is less. Thus, the top path failure probability is $(0.1)(0.33)(0.5) = 0.016$.

The bottom path is based upon the assumption that CRD flow is insufficient for core cooling given that the leak has not been isolated. A failure probability of ½ is assumed for both firewater and service water.

Figure 16 addresses the improvements with the following branch comments:

(a) A factor of 3 improvement was assumed in the probability of a loss of inventory because of better outage planning and implementation.

(b) A factor of 2 improvement was assumed because of better outage planning and implementation. The principal improvements result from elimination of paths that would not be isolated and from assurance that the automatic isolation feature would be operable.

(c) A factor of 2 improvement is assumed on the basis of requiring minimum cooling/makeup capability.

(d) A factor of 2 improvement was assumed.

1.4 Conclusions Regarding Event Frequencies

The core-damage probabilities obtained from the trees are summarized in Table 3. Note that the two significant figures are carried. This is done only for calculation purposes to prevent accumulation of round-off errors. This information was compiled to allow assessment of the effect of changes in shutdown operation, and these values are obtained by subtracting the probability of core damage with the change from the base case, which does not have the change. The important value is the difference.

Table 3. Estimated Core Damage Probabilities per Reactor-Year[1]

Item	Base Case	Outage improvement and TS	Instrumentation
PWR, LOOP, < 23 feet	2.9E-5	9.6E-7	2.5E-5
PWR, LOSS OF LEVEL CONTROL	4.2E-5	1.4E-5	8.5E-6
PWR, LOSS OF INVENTORY	3.0E-5	4.9E-6	9.8E-6
PWR TOTAL	1.0E-4	2.0E-5	4.3E-5
PWR CHANGE	-	8.0E-5	5.7E-5
BWR, LOOP	6.3E-6	1.4E-7	NA
BWR, LOSS OF INVENTORY	3.6E-6	2.2E-7	NA
BWR TOTAL	9.9E-6	3.6E-7	NA
BWR CHANGE	-	9.5E-6	NA

[1]Point estimates from a simplified PRA model

2 ESTIMATE OF RADIOLOGICAL CONSEQUENCES

2.1 Analysis of a Severe Accident During Shutdown at Surry

The Office of Research (RES) is conducting a program at Brookhaven National Laboratory (BNL) to develop probabilistic safety assessment methods for shutdown operation in PWRs. Preliminary calculations from this program have been considered for purposes of the impact/value analysis (Ref. 6). The following sequences of events were assumed at Surry for accidents initiated from an RCS partly drained condition:

Time in minutes for accident initiation			
	time after power operation of		
Item	1 day	3 days	10 days
Calculation start, water above core	0	0	0
Half of core uncovered	60		
Gap release and hydrogen production	100	140	230
Fuel melting	117	160	260
30% of core melted	141		
Core dryout	153		
60% of core melted	219		
Lower RV head failure	249	340	590

The RCS was assumed to be open to containment by way of the pressurizer, and calculations included both containment open and closed. The containment open calculation was based upon the premise that containment leaked at the equipment hatch at a rate sufficient to prevent pressurization. This will provide some holdup time in which settling and deposition can occur, but the decontamination factor is likely small.

In the closed containment case, the pressurization rate during boiling was 3 psi/hr (21 kPa/hr), followed by a constant pressure period until shortly after core dryout. A hydrogen burn occurred at 500 minutes which caused a containment pressure spike to 120 psig (830 kPa) (from a pressure of 22 psig (150 kPa)) with containment pressure returning to 25 psig (170 kPa) after the spike. Containment pressure increased at 0.4 psi/hr (3 kPa/hr) after the spike. Typical, large, dry containments are expected to withstand such transients and to provide relatively long-term protection.

The calculated population doses assuming a core-damage accident with an open or failed containment are summarized in Table 4. The ranges, in part, reflect an attempt to introduce uncertainty by changing the variables associated with calculation of each type of event, including such event variations as gap release only, arrested core melts, and core melts that progressed through the bottom of the reactor vessel. The 5 percent and 95 percent figures are

considered, at best, to be rough approximations. Note the correspondence between shutdown and full power with containment failure results, especially the mean/median and 95 percent values.

Table 4. Preliminary Dose Estimates from the Brookhaven PRA Program

Distance, dose at miles (km)	5%, mean/ median, or 95%	Dose, person-rem (Sievert) for accident initiating At shutdown	At power	Ratio of shutdown to that at power
50	5%	2.8E+05 (2.8E+03)	7.7E+04 (7.7E+02)	3.6
(80.5)	mean/med	8.3E+05 (8.3E+03)	7.4E+05 (7.4E+03)	1.1
	95%	1.7E+06 (1.7E+04)	3.1E+06 (3.1E+04)	0.55
1000	5%	1.0E+06 (1.0E+04)	2.6E+05 (2.6E+03)	3.8
(1609.3)	mean/med	4.0E+06 (4.0E+04)	3.0E+06 (3.0E+04)	1.3
	95%	1.0E+07 (1.0E+05)	1.7E+07 (1.7E+05)	0.59

The probability of terminating a core-damage accident once it has initiated is judged small, and the 5 percent and much of the mean/median table values are less meaningful. The 95 percent values are judged to be more representative of accidents that lead to the melting of a significant fraction of the core. As an approximation, the doses from power and from shutdown are the same.

Onsite dose rates for a large containment leak, which was called a "parking lot dose rate," was also calculated. The dose rates at 325 ft (100 m) from the containment that are considered appropriate for use in the impact/value study are:

Model	Dose rate, person-rem/hr (Sievert/hr)
Wilson/reg. guide 1.145	2.4E+05 (2.4E+03)
Ramsdell	8.0E+03 (8.0E+01)

Although a factor of 25 difference occurs due to the modeling, and large uncertainties are caused by such variables as weather and the influence of topography, the important observation is that these large dose rates represent a significant hazard to personnel.

2.2 Analysis of a Postulated Severe Accident During Shutdown at Grand Gulf

Sandia National Laboratories calculated similar information for accidents postulated to initiate during shutdown operation at Grand Gulf. Sandia assumed a loss of DHRS event with the assumption that the primary containment remained at atmospheric pressure. It reported the following (Ref. 6):

Time from accident initiation (hours)		
	Time after shutdown	
Item	4 days	15 days
Water level at top of active fuel	12.7	19.7
Gap release	18.3	28.3
RV failure	25.4	39.8

The calculations were performed for a plant operating state (POS) that starts when the RV head is loosened and ends when the RV cavity is filled with water (Sandia's POS 6). Sandia assumed the RV head was removed for analysis purposes.

The closed containment calculations resulted in an initial containment pressurization rate during boildown of 0.6 psi/hr (4.1 kPa/hr) (considerably less than the 3 psi/hr (21 kPa/hr) for Surry), followed by a decreasing pressure before significant core damage (in contrast to the steady pressure for Surry). The post-vessel failure rates were 0.4 psi/hr (2.8 kPa/hr) (identical to Surry) for no burning of hydrogen and 0.9 psi/hr (6.2 kPa/hr) with modeling of hydrogen burn.

Off-site dose consequences for selected core damage sequences of particular interest to the impact/value study are:

Item	Dose, Person-Rem (Sievert)	
	50 mile (80 km)	1000 mile (1600 km)
Direct leak from containment to environment	6.3E+05 (6.3E+03)	7.1E+06 (7.1E+04)
Containment rupture to environment	9.5E+05 (9.5E+03)	1.1E+07 (1.1E+05)
Containment open to aux bldg via the equipment hatch	6.6E+05 (6.6E+03)	7.5E+06 (7.5E+04)

The first and last cases are comparable. The first case accounted for some holdup time for settling and deposition in containment, and the last accounted for a similar mechanism in the auxiliary building. Ranges of consequences similar to those discussed for Surry are summarized in Table 5.

Table 5 Summary of Dose Information for Grand Gulf

5%, mean/ median, or 95%	Dose, for accident initiating at shutdown with containment open to aux. bldg. person-rem	(Sievert)	at shutdown with containment failure to environment person-rem	(Sievert)	at power person-rem	(Sievert)	Ratio shutdown (aux) to power
at 50 mi (80 km)							
5%*	1.4E+05	(1.4E+03)	2.6E+05	(2.6E+03)	3.2E+04	(3.2E+02)	4.4
mean/med	3.0E+05	(3.0E+03)	4.2E+05	(4.2E+03)	1.3E+05	(1.3E+03)	2.3
above calc	6.6E+05	(6.6E+03)	9.5E+05	(9.5E+03)			
95%*	5.3E+05	(5.3E+03)	8.0E+05	(8.0E+03)	3.1E+05	(3.1E+03)	1.7
at 1000 mi (1610 km)							
5%*	1.3E+06	(1.3E+04)	2.3E+06	(2.3E+04)	2.2E+05	(2.2E+03)	5.9
mean/med	3.0E+06	(3.0E+04)	5.0E+06	(5.0E+04)	1.4E+06	(1.4E+04)	2.1
above calc	7.1E+06	(7.1E+04)	1.1E+07	(1.1E+05)			
95%*	6.5E+06	(6.5E+04)	8.7E+06	(8.7E+04)	4.0E+06	(4.0E+04)	1.6

*These are listed as low or high by Sandia because the number of samples was considered inappropriate to assign a 5% or 95%.

The correlation between power and shutdown at the higher ranges is consistent with the Surry results. Also, note the correspondence of the calculated "point" events with the "95%" values; a substantiation of the judgment that the higher ranges were more representative of the more severe core-melt accidents. Again, as an approximation, the doses from power and from shutdown are the same.

"Parking lot" dose rate predictions were as follows:

Item	Dose rate per hour at 100 yd (91 m) person-rem	Sievert
Direct leak from containment to environment	2.E+05	2.E+03
Containment rupture to environment	5.E+05	5.E+03
Containment open to aux bldg via equip hatch	2.E+05	2.E+03

These results for "parking lot" dose rate, and the conclusions, are essentially the same as for Surry. Personnel in the "parking lot" area during or following a release would be at risk.

2.3 Dose Selections for Impact/Value Analysis

The conclusions that severe accident dose for power and shutdown are of the same magnitude have been reached before. For example, Chu (ref. 11) used this assumption to calculate consequences for a shutdown risk investigation involving Generic Issue 99. His results are summarized in Table 6, with information from the above shutdown investigations added for comparison.

The following information from Table 6 applies for essentially unmitigated releases with respect to the population within a 50-mile (80 km) radius:

- unmitigated Zion releases, power operation: 7E+06 - 2E+07 person-rem (7E+04 - 2E+05 Sievert)
- Surry, power: 3E+06 (3E+04 Sievert)
- Surry, shutdown: 2E+06 (2E+04 Sievert)
- Grand Gulf, shutdown, release to environ: 1E+06 (1E+04 Sievert)

If one compensates for the low population at Grand Gulf by extrapolating the Grand Gulf values to the Surry values, there results a dose of (1E+06)(319)/64 = 5E+06 person-rem (5E+04 Sievert). Adjusting the Zion values to account for its higher population and the fact that the most likely wind condition at Zion is over water, the effective unmitigated releases on a basis comparable to Surry are 3E+06 to 9E+06 person-rem (3E+04 to 9E+04 Sievert). On the basis of a rough approximation, considering Surry population density, the following results:

- Zion: 3E+06 - 9E+06 person-rem (3E+04 - 9E+04 Sievert)
- Surry: 2E+06 - 3E+06 person-rem (2E+04 - 3E+04 Sievert)
- Grand Gulf: 5E+06 person-rem (5E+04 Sievert)

These average to 4.4E+06 person-rem (4.4E+04 Sievert). This average value was then adjusted to account for a generic population density of 100 persons/mi^2, (39 persons/km^2) yielding 2E+06 person-rem (2E+04 Sievert). This value has been used as the expected generic plant dose that would result from a severe accident that initiated during shutdown operation without a closed containment.

2.4 Conclusions

Population dose from severe accidents that initiate from shutdown and from power operation may be treated as the same as an approximation for initial impact/value analyses. On average, a shutdown accident that is not mitigated by a closed containment is anticipated to cause a dose to the public of the order of 2E+06 person-rem (2E+04 Sievert). This value, combined with the previously determined core melt probabilities, yields the public risk information provided in Table 7.

Table 6. Dose Summary

Event	Plant	Person-rem at 50 mi	Sievert at 80 km	Person-rem at 500 mi	Sievert at 800 km
PWR2: large, unmitigated release 5 days after power operation; no core cooling, containment cooling, or spray	Zion Generic PWR	2.37E+07 4.38E+06	2.37E+05 4.38E+04	1.03E+08 5.6E+07	1.03E+06 5.6E+05
PWR4: LOCA, no core cooling or contain. spray, contain. not isolated, release 5 days after power operation	Zion	6.71E+06	6.71E+04	1.54E+07	1.54E+05
PWR5: PWR4 with containment spray	Zion	1.99E+06	1.99E+04	3.95E+06	3.95E+04
PWR2B: PWR2 with containment spray	Zion	1.25E+07	1.25E+05	3.25E+07	3.25E+05
PWR2/10	Zion	7.91E+06	7.91E+04	1.85E+07	1.85E+05
PWR2/100	Zion	1.23E+06	1.23E+04	2.43E+06	2.43E+04
PWR2, release 2 days after power oper.	Zion	2.46E+07	2.46E+05	1.04E+08	1.04E+06
Shutdown, 95%	Surry	1.7E+06	1.7E+04	1.0E+07*	1.0E+05*
Power, 95%	Surry	3.1E+06	3.1E+04	1.7E+07*	1.7E+05*
Shutdown, 95%	Grand Gulf	8.0E+05	8.0E+03	8.7E+06*	8.7E+04*
Power, 95%	Grand Gulf	3.1E+05	3.1E+03	4.0E+06*	4.0E+04*
Shutdown, containment rupture to environment	Grand Gulf	9.5E+05	9.5E+03	1.1E+07*	1.1E+05*

*At 1000 miles (1609 km); no data were provided for 500 miles (800 km).

Table 7. Public Risk Due To Core Damage

Item	Outage improvements and TS	Instrumentation
PWR CHANGE IN CORE MELT PROBABILITY, EVENTS/REACTOR-YEAR	8.0E-5	5.7E-5
PWR CHANGE IN EXPECTED DOSE PERSON-REM/REACTOR-YEAR (SIEVERT/REACTOR-YEAR)	160 (1.6)	110 (1.1)
BWR CHANGE IN CORE MELT PROBABILITY, EVENTS/REACTOR-YEAR	9.5E-6	NA
BWR CHANGE IN EXPECTED DOSE PERSON-REM/REACTOR YEAR (SIEVERT/REACTOR-YEAR)	19 (0.19)	NA

The dominant factor in a severe shutdown accident is whether or not the containment remains intact, since, for practical purposes, an intact containment will prevent a release. The large, dry PWR containments, if closed, are likely to prevent a release.

Shutdown accidents appear to be more likely to involve a ground-level release. In such cases, dose rates will be fatal within a few minutes at locations within a few hundred yards of the release location. This is important because several hundred to a thousand additional people are on-site for a typical refueling outage, and because a severe accident with an open containment will preclude many activities at the site immediately following the accident.

3 ESTIMATED COST

3.1 Generic Letter

The staff drafted an NRC generic letter (GL) as part of this value/impact analysis. Effort involved in preparing a response to the GL and staff activities involving follow-up include the following efforts:

- 5 days of resident inspector time per site
- 5 days of staff review time per licensee response
- 40 days of licensee time per site to prepare a response to the GL
- 15 days of licensee time per site to support audit inspections
- 2 days of training time per site for one resident inspector from each site
- 3 days of training time per regional person trained (assume 3 per region)
- 4 hours of training time for each headquarters project manager
- 10 days of staff time to prepare training material
- 20 days of staff time to conduct training

These estimates do not include licensee effort to implement the GL. These are addressed below.

3.2 Outage Planning and Control Improvements

Much of the effort represents a reorientation of outage planning and control and, as such, replaces or modifies work the licensees already perform. This is not counted as additional effort. Only additional effort is covered in Section 3.2.1 through 3.2.6.

3.2.1 Safety Document

This document is prepared by the licensee. The document defines safety policy and gives safety guidance. A few licensees already have such a document, some are preparing it, and some had no plans to prepare such a document when contacted in 1991.

NUMARC 91-06 (page 10) specifies a senior management policy that states the utility outage nuclear safety philosophy, outage schedules developed through interactions with involved organizations and disciplines, and other items. The staff requirement is to supplement the documentation of that work and to additionally prepare a suitable reference document for planning and conduct of outages. The staff requirements for safety, which are somewhat more detailed than specified in the NUMARC document, should also be addressed. An equivalent of 100 pages per site is assumed with the perspective that although more pages will be prepared, much of the effort can be coordinated as generic activities.

3.2.2 Independent Safety Review by Licensees

This is part of the quality control that some licensees have implemented and others are addressing. A key change for some licensees is the that the reviews are to be performed by personnel who are knowledgeable of the

requirements in the safety document and who have not been directly involved in the planning process. The review should cover the following items:

- outage planning, including work packages
- routine implementation
- changes to plans
- up-to-date status information
- feedback of experience

NUMARC 91-06 provides sufficient guidance for the independent reviews of outage plans. An additional 2 person-months per unit per outage is assumed for the increased coverage.

3.2.3 Development of Bases and Understanding

Numerous topics have been addressed in NUREG-1269 (Ref. 7), NUREG-1410 (Ref. 5), GL 88-17 (Ref. 8), NUREG-1449 (Ref. 1), many inspection reports, and other references. Some have been investigated, some are being investigated, work remains with others, and little has been accomplished with still others. Large variations exist among licensees and among owners groups. The two major areas to be addressed are:

- review plant analysis and data base
- develop bases supported by analysis and/or test

The staff assumes that licensees with similar plants will work together on this effort and that it can be accomplished with an expenditure of 1 person-year for PWRs and with 0.5 person-year for BWRs. Cost is estimated on a per-site basis.

3.2.4 Procedures

Many normal and abnormal operating procedures will be affected. The staff assumed 700 new pages would have to be prepared for each major type of PWR and that 400 pages would be necessary for the BWRs. Although much can be shared on a generic basis, much must be prepared on a plant-specific basis. The staff assumed half of the effort would be shared through such organizations as owners groups.

3.2.5 Contingency Planning

An initial effort of 0.5 person-year per site is assumed for setting up general outage guidance.

3.2.6 Other

Numerous other items, such as training and avoidance of perturbations during operation, are to be addressed within the scope of outage planning and implementation. These are not judged to entail additional effort, nor are they judged to impact negatively on the outages.

3.3 Technical Specifications

The following are assumed:

- 30 new TS pages per site
- 75 new TS "bases" pages per site

The containment closure TS for PWRs, and assessment of the impact of the closure requirements, are based upon the following:

(1) The need, as identified in Section 2.1 (above), to withstand a transient pressure spike.

(2) Studies in NUREG-1449 show that shutdown risk is highest when decay heat is high and the RCS is in a reduced inventory condition. The containment LCO requires containment integrity to be maintained during Mode 5, with natural circulation not available, and Mode 6, with the water level in the refueling cavity less than [23] feet above the reactor vessel flange. Containment integrity in these modes is not required after the core decay heat had been reduced below a plant specific value such that manual actions, assuming a loss of both the offsite electrical power system, and the unavailability of the onsite AC power system, to close the containment can be accomplished prior to boiling in the RCS. Some licensees may have available alternate emergency AC source, as defined in 10 CFR 50.2, or portable power supplies which could be used manually close containment. Licensees can base their estimates of the time to manually close containment assuming the availability of these power supplies provide that the availability of these power supplies are assured through their outage plan.

The staff believes that the concept for this LCO provides licensees with considerable flexibility, through planning and good engineering, to minimize the need for containment integrity during normal activities while in Mode 5 or 6. However, for the purpose of estimating impact, the staff has made the conservative assumption that the containment may need to be closed early in the outage when the decay heat rate is highest.

The staff has assumed that in the worst case licensees would deal with a restriction on containment access by designing, fabricating and installing new manifolds that bolt to existing, unused containment penetrations in order to provide services such as additional power, sludge lancing, and eddy current testing. As previously discussed, these must usually be capable of withstanding pressures up to the containment design pressure in order to provide the necessary protection. The staff has further assumed they can be installed without opening a "hole" in containment by using an unused containment penetration, and by only removing one blind flange on the penetration at a time. The staff has further assumed that if extra room is necessary for the installation that the following process can be used:

(1) One (of two) blind flanges are opened on an unused containment penetration and a closed "tank" is attached, thus providing a space into which cabling connections, etc. can be inserted from the other side of containment.

(2) The second blind flange is removed from the other side of containment and a manifold is attached.

(3) The "tank" is removed.

The staff estimates that the cost of such manifolds will be $500,000 per containment.

The TSs are not judged to increase outage time when considered in conjunction with better outage planning.

3.4 Instrumentation

The requirement is for an additional independent, accurate, reliable RV water level indication or its equivalent in the control room for both normal and accident conditions when the refueling cavity is not filled. The cost is estimated as:

- $180,000 and 0.03 person-Sv (3 person-rem) for initial installation of two ultrasonic monitors, one in a hot leg and one in a cold leg. This is based on a personal communication from Mark Patrick (Oconee) to Leonard Wiens (NRC) on April 28, 1992. Oconee has installed two ultrasonic monitors in each of three units at an average cost of $142,500 per unit and an average exposure of 0.023 person-Sv (2.3 person-rem) per unit. Oconee assumes exposure cost of $5000 per rem.

- $1000 per unit and 0.005 person-Sv (0.5 person rem) per unit per outage after initial installation. Oconee reports that for a normal outage, continuing cost is $600-$700 per installation per unit with an exposure of 0.005 person-Sv (0.5 person-rem) per unit.

4 REFERENCES

(1) "Shutdown and Low-Power Operation at Commercial Nuclear Power Plants in the United States," Draft Report for Comment, NUREG-1449, February 1992.

(2) Chu, T. L., et al, "PWR Low Power and Shutdown Accident Frequencies Program, Phase 1 - Coarse Screening Analysis," Draft Letter Report prepared by Brookhaven National Laboratory for the NRC under FIN L-1344, November 13, 1991.

(3) "Evaluation of Station Blackout Accidents at Nuclear Power Plants," NUREG-1032, June 1988.

(4) Battle, R. E., and D. J. Campbell, "Reliability of Emergency AC Power Systems at Nuclear Power Plants," NUREG/CR-2989, Oak Ridge National Laboratory, July 1983.

(5) "Loss of Vital AC Power and the Residual Heat Removal System During Mid-Loop Operations at Vogtle Unit 1 on March 20, 1990," NUREG-1410, June, 1990.

(6) Cunningham, Mark A., "Abridged Level 2 and 3 Low Power and Shutdown Risk Analyses," NRC Memorandum to Robert C. Jones, Chief, Reactor Systems Branch, June 12, 1992.

(7) "Loss of Residual Heat Removal System, Diablo Canyon, Unit 2, April 10, 1987," NUREG-1269, June, 1987.

(8) "Loss of Decay Heat Removal," GL 88-17, October 17, 1988.

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FIGURE 1

FIGURE 1 PROBABILITY OF RECOVERY OF OFFSITE POWER ~~DURING POWER OPERATION~~

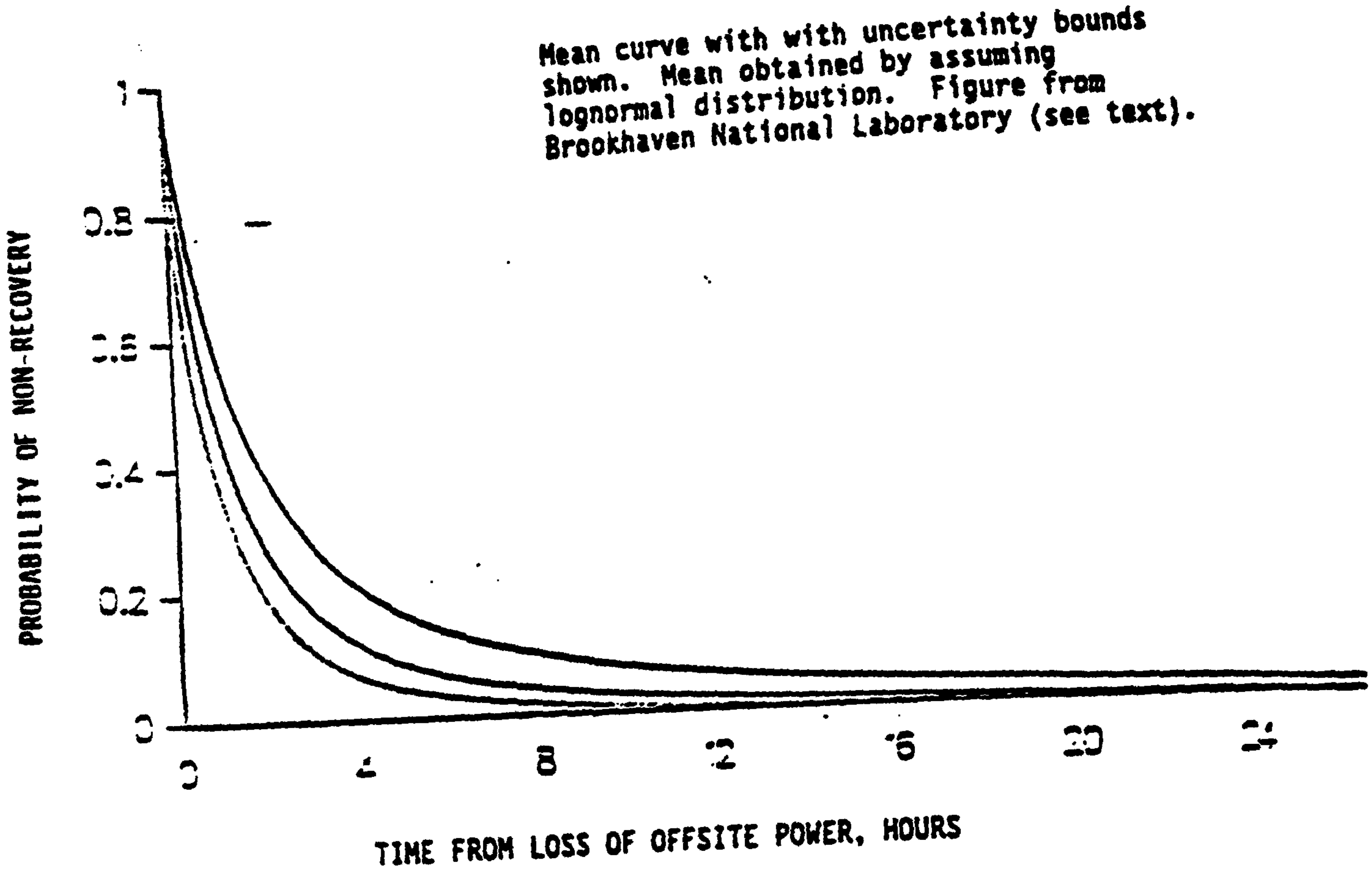


FIGURE 2

FIGURE 2 PROBABILITY OF RECOVERY OF OFFSITE POWER DURING NONPOWER OPERATION

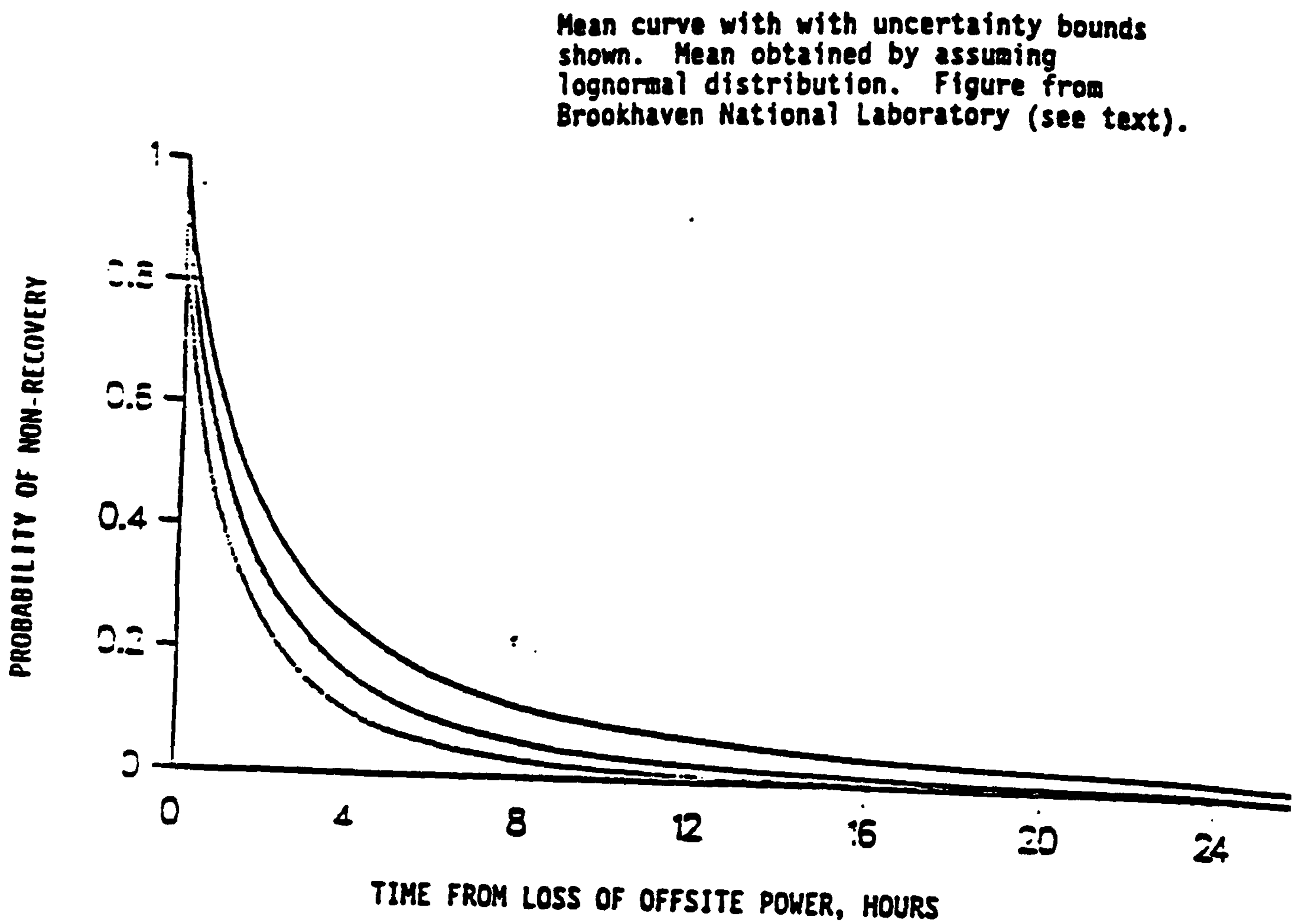
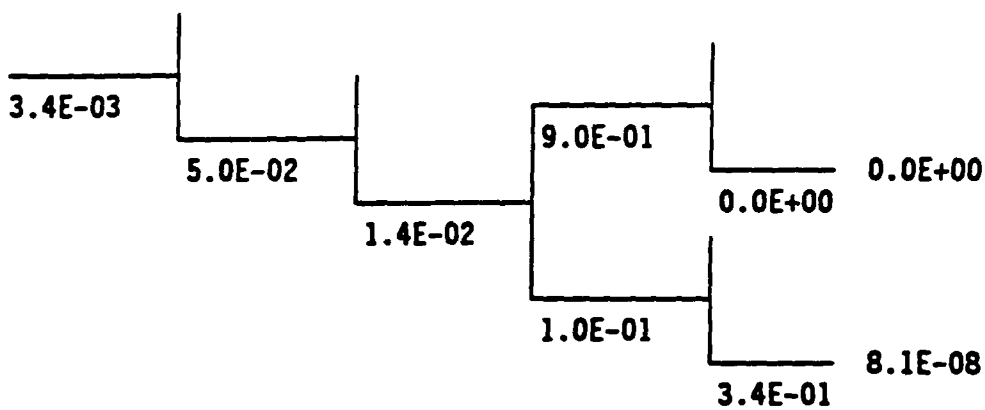


FIGURE 3: PWR LOOP EVENT TREE - CAVITY FLOODED

(a) LOOP	(b) EDG STARTS AND LOADS	(c) AC POWER BEFORE BOILING	(d) NOZZLE DAMS INTACT	(e) AC POWER BEFORE CORE DAMAGE	CDF



ENCLOSURE 2, Appendix 2

FIGURE 4: PWR LOOP EVENT TREE - CAVITY NOT FLOODED

(a) LOOP	(b) EDG STARTS AND LOADS	(c) AC POWER BEFORE BOILING	(d) RCS OPEN	(e) SGs CAN REMOVE HEAT	(f) LARGE VENT	(g) GRAVITY FEED	(h) AC POWER BEFORE CORE DAMAGE	CDF

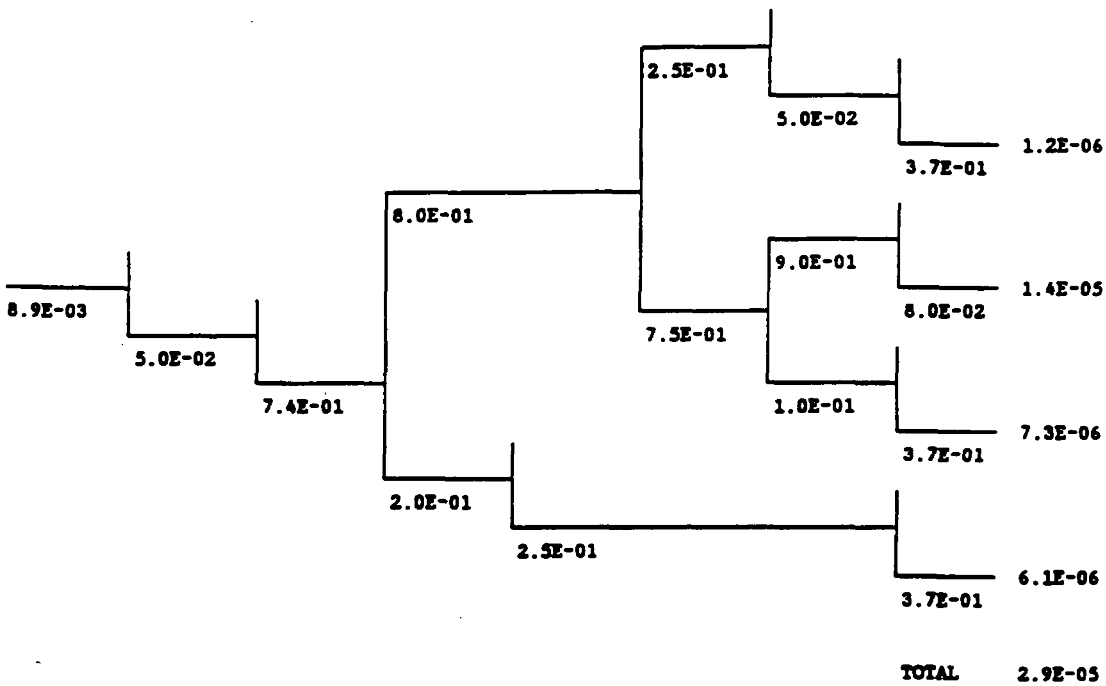


FIGURE 5: PWR LOOP EVENT TREE - CAVITY NOT FLOODED
OUTAGE PLANNING AND TS IMPROVEMENTS

(a) LOOP	(b) EDG STARTS AND LOADS	(c) AC POWER BEFORE BOILING	(d) RCS OPEN	(e) SGs CAN REMOVE HEAT	(f) LARGE VENT	(g) GRAVITY FEED	(h) AC POWER BEFORE CORE DAMAGE	CDF

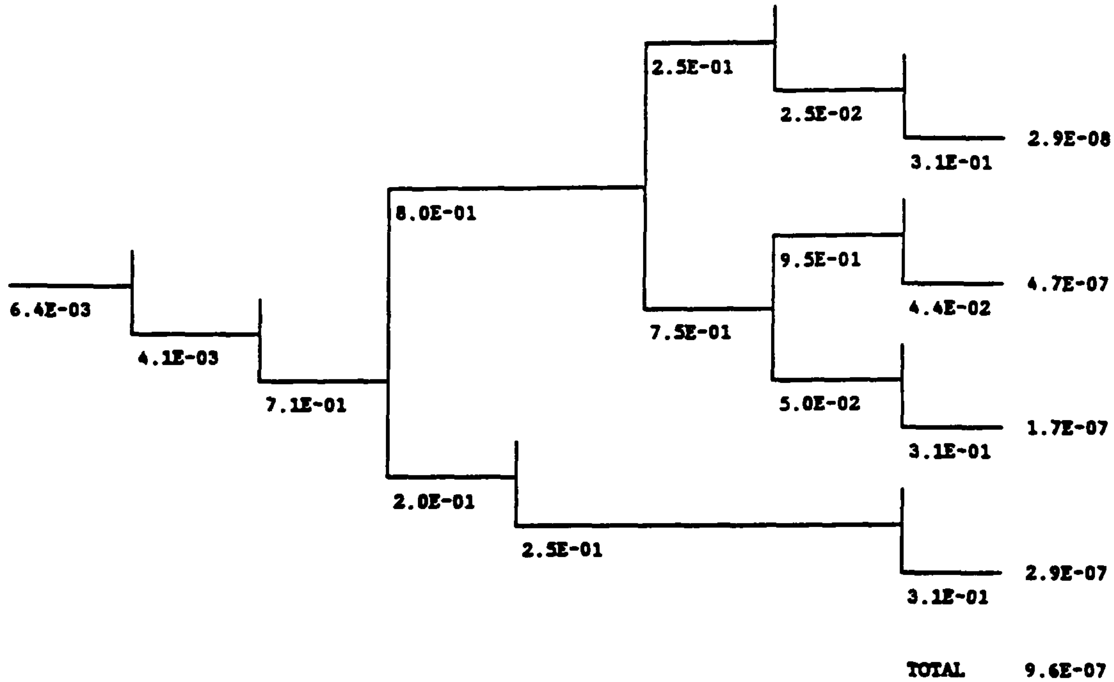


FIGURE 6: PWR LOOP EVENT TREE - CAVITY NOT FLOODED
INSTRUMENTATION IMPROVEMENTS

(a) LOOP	(b) EDG STARTS AND LOADS	(c) AC POWER BEFORE BOILING	(d) RCS OPEN	(e) SGs CAN REMOVE HEAT	(f) LARGE VENT	(g) GRAVITY FEED	(h) AC POWER BEFORE CORE DAMAGE	CDF

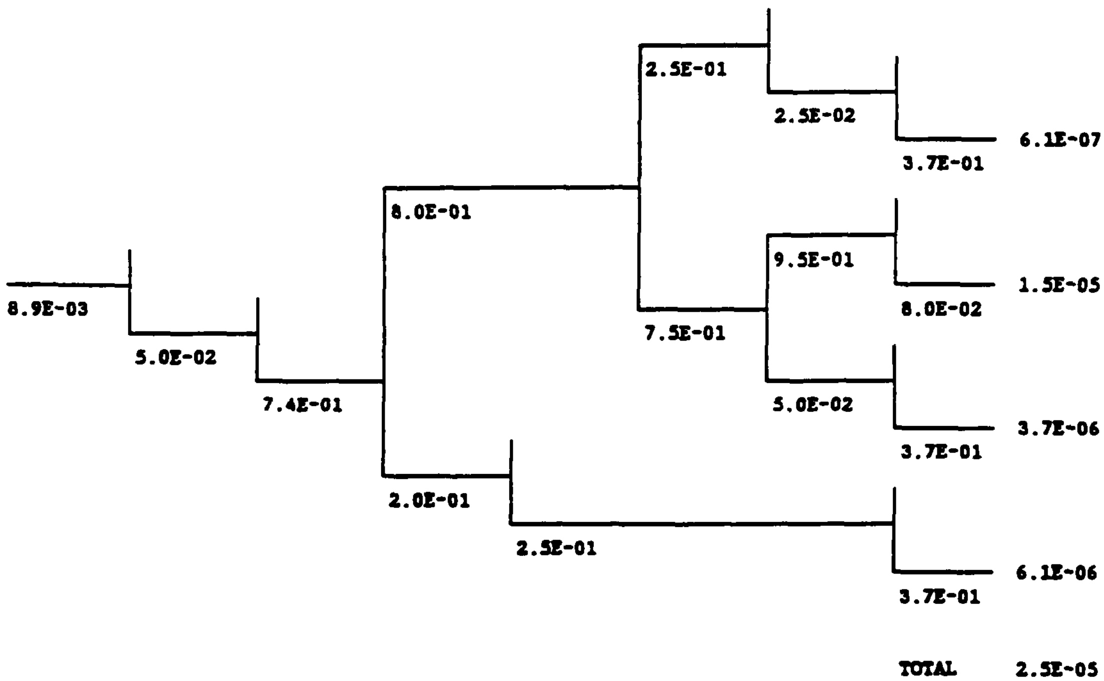


FIGURE 7: PWR LOSS OF LEVEL EVENT TREE - CAVITY NOT FLOODED

(a) LEVEL CONTROLLED	(b) BOILING PREVENTED	(c) RCS OPEN	(d) LARGE VENT	(e) SGs REMOVE HEAT	(f) WATER ADDITION	CDF

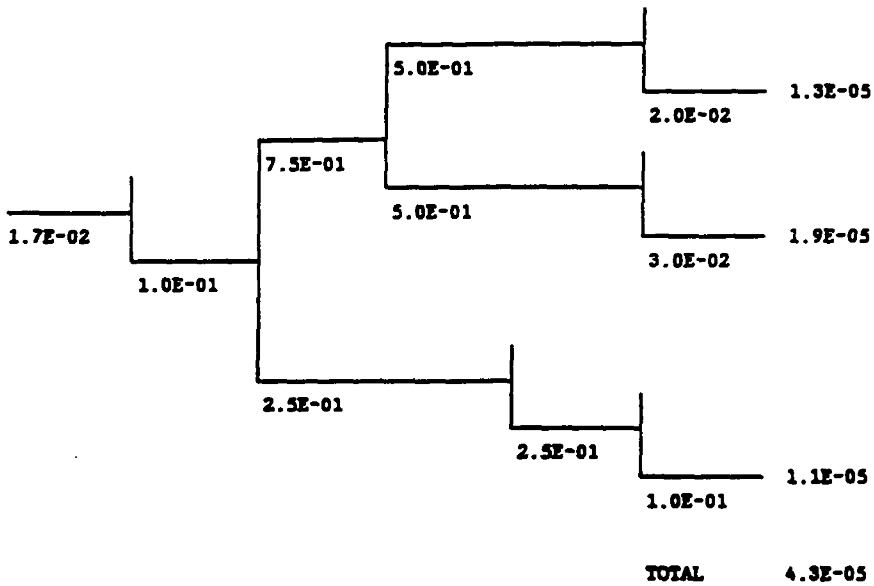


FIGURE 8: PWR LOSS OF LEVEL EVENT TREE - CAVITY NOT FLOODED
OUTAGE PLANNING AND TS IMPROVEMENTS

(a) LEVEL CONTROLLED	(b) BOILING PREVENTED	(c) RCS OPEN	(d) LARGE VENT	(e) SGs REMOVE HEAT	(f) WATER ADDITION	CDF

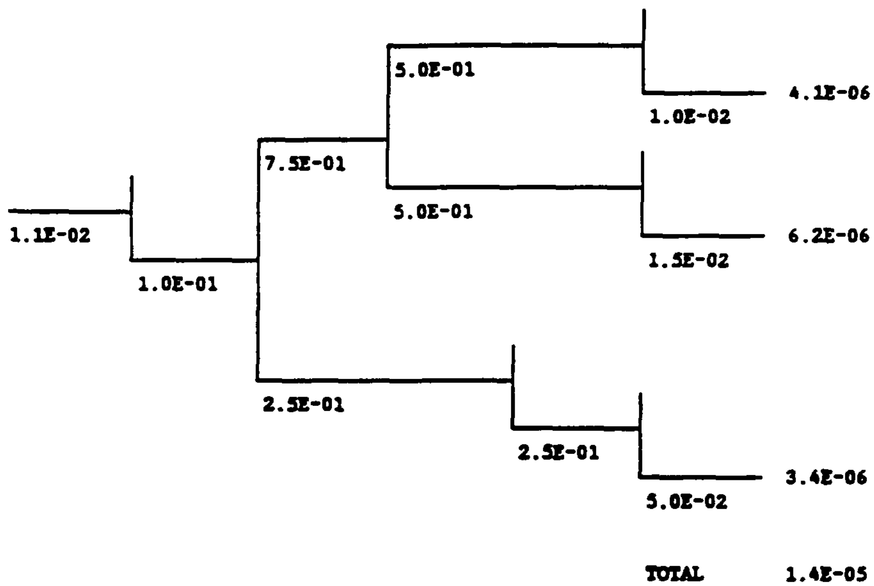


FIGURE 9: PWR LOSS OF LEVEL EVENT TREE - CAVITY NOT FLOODED
INSTRUMENTATION IMPROVEMENTS

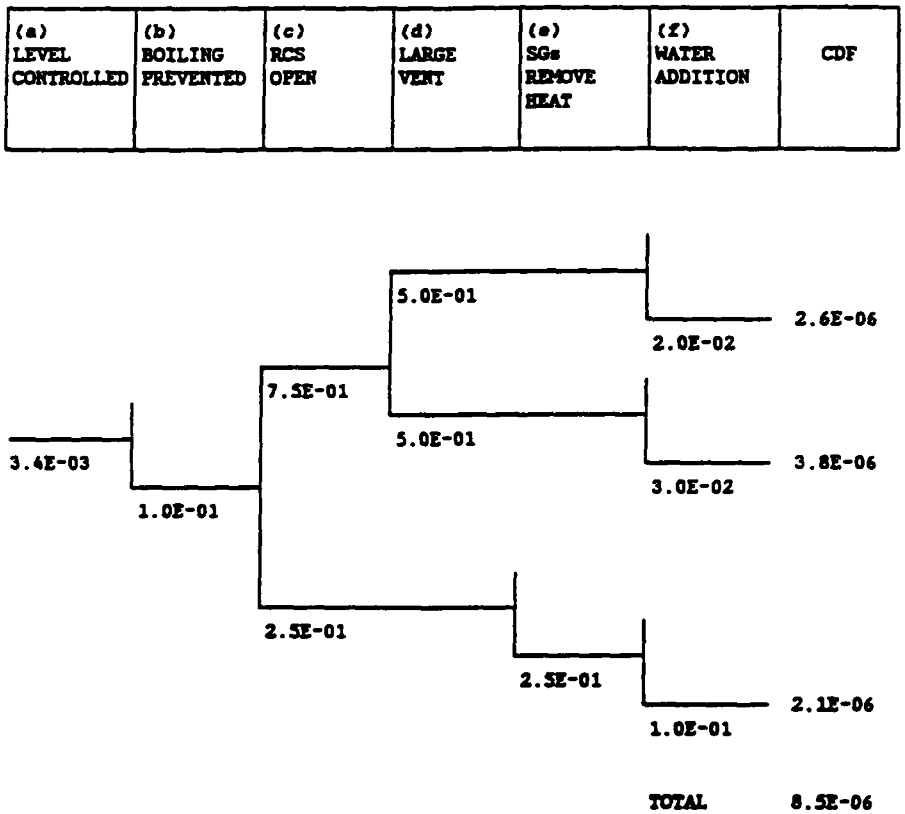


FIGURE 10: PWR LOSS OF INVENTORY EVENT TREE - CAVITY NOT FLOODED

(a) LEVEL CONTROLLED	(b) BOILING PREVENTED	(c) RCS OPEN	(d) LARGE VENT	(e) SGs REMOVE HEAT	(f) WATER ADDITION	CDF

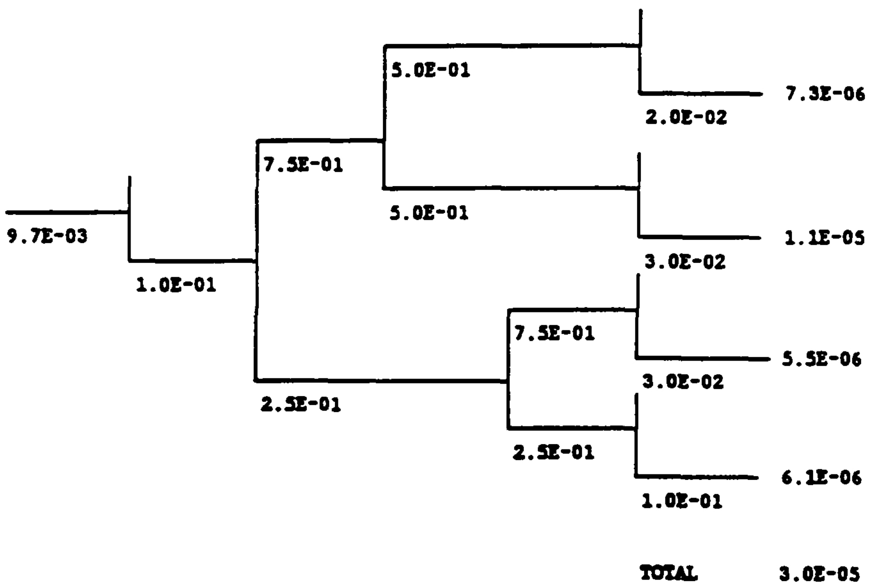


FIGURE 11: PWR LOSS OF INVENTORY EVENT TREE - CAVITY NOT FLOODED
OUTAGE PLANNING AND TS IMPROVEMENTS

(a) LEVEL CONTROLLED	(b) BOILING PREVENTED	(c) RCS OPEN	(d) LARGE VENT	(e) SGs REMOVE HEAT	(f) WATER ADDITION	CDF

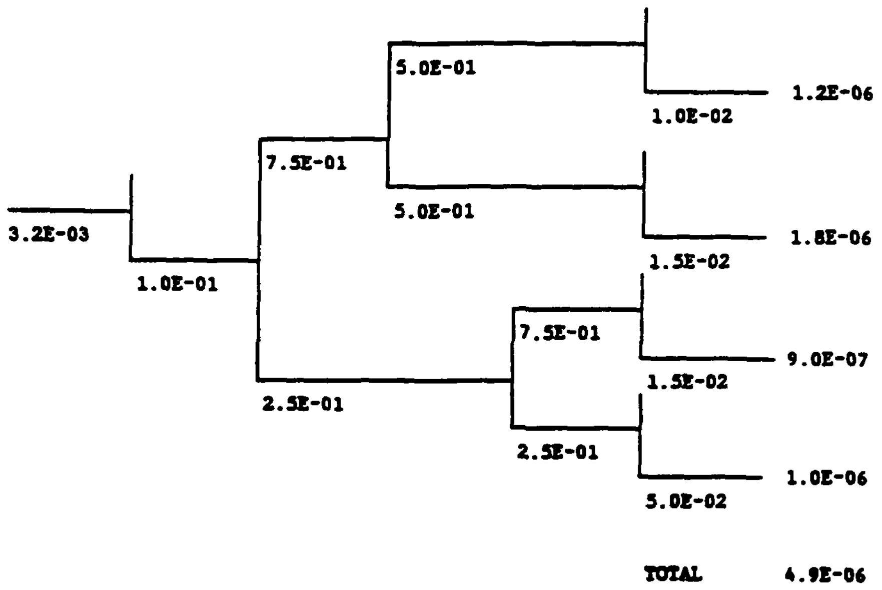
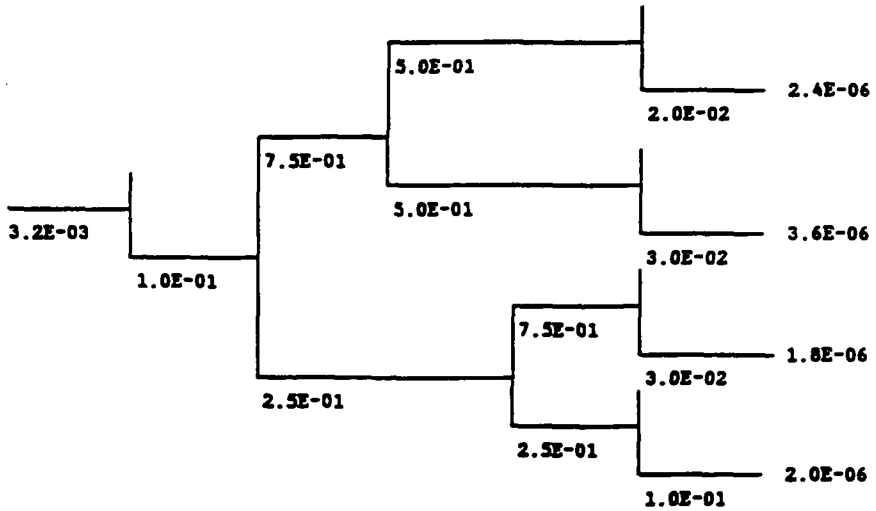


FIGURE 12: PWR LOSS OF INVENTORY EVENT TREE - CAVITY NOT FLOODED INSTRUMENTATION IMPROVEMENTS

(a) LEVEL CONTROLLED	(b) BOILING PREVENTED	(c) RCS OPEN	(d) LARGE VENT	(e) SGs REMOVE HEAT	(f) WATER ADDITION	CDF



TOTAL 9.8E-06

FIGURE 13: BWR LOOP EVENT TREE - CAVITY NOT FLOODED

(a) LOOP	(b) EDG STARTS AND LOADS	(c) FIRE WATER ADDITION	(d) AC POWER BEFORE CORE DAMAGE	(e) CORE COOLING RESTORED	CDF

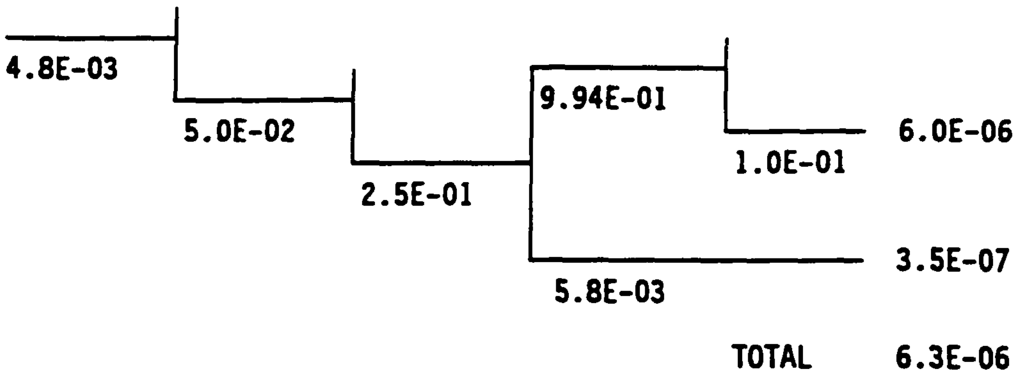


FIGURE 14: BWR LOOP EVENT TREE - CAVITY NOT FLOODED
OUTAGE PLANNING AND TS IMPROVEMENTS

(a) LOOP	(b) EDG STARTS AND LOADS	(c) FIRE WATER ADDITION	(d) AC POWER BEFORE CORE DAMAGE	(e) CORE COOLING RESTORED	CDF

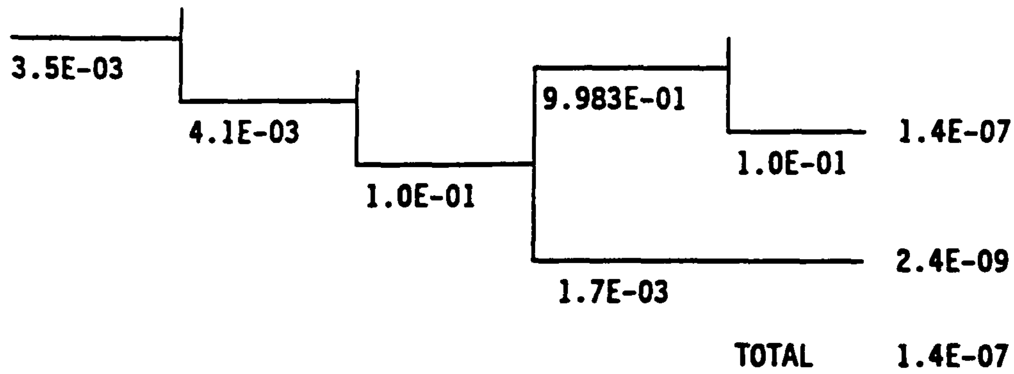
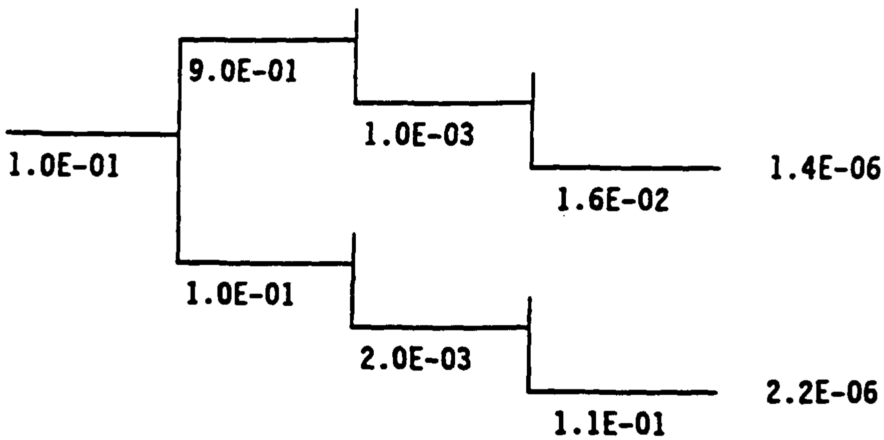


FIGURE 15: BWR LOSS OF RCS WATER

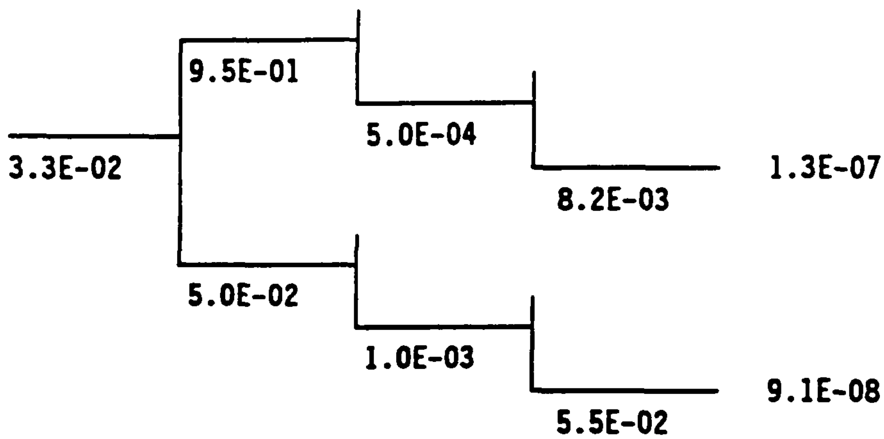
(a) LOSS OF WATER	(b) AUTO-ISOLATION	(c) EMERGENCY CORE COOLING ACTUATES	(d) ALTERNATE EQUIPMENT PROVIDES COOLING	CDF



TOTAL 3.6E-06

FIGURE 16: BWR LOSS OF RCS WATER
OUTAGE PLANNING AND TS IMPROVEMENTS

(a) LOSS OF WATER	(b) AUTO-ISOLATION	(c) EMERGENCY CORE COOLING ACTUATES	(d) ALTERNATE EQUIPMENT PROVIDES COOLING	CDF



TOTAL 2.2E-07

APPENDIX 3

SENSITIVITY STUDY OF INPUTS TO THE PROBABILISTIC RISK ASSESSMENT (PRA)

1.0 INTRODUCTION

In the regulatory analysis, implementation of the proposed modifications are evaluated on the basis of calculated impact/value ratios for each improvement. The determination of values (changes in public and occupational radiation exposure) and impacts (costs and savings) is based primarily on the calculated change in the core-damage frequency (CDF). A reduction in the core-damage frequency provides the primary benefit of avoided public health risk. In addition, cleanup costs, offsite damages, and power replacement costs are also avoided through a reduced CDF. In Appendix 2, the changes in CDF were determined for the three most important shutdown event sequences: the loss of AC power, the loss of RCS inventory, and the loss of reactor vessel water level control in pressurized-water reactors (PWRs) only. For many of these event sequences, it was necessary in some cases to make an "educated guess"[1] as to the degree of improvement stemming from the implementation of the proposed improvements. This resulted in the use of estimated reduction factors in deriving some of the initiating event frequencies and branch failure probabilities used in the sequences leading to core damage with improvements in place.

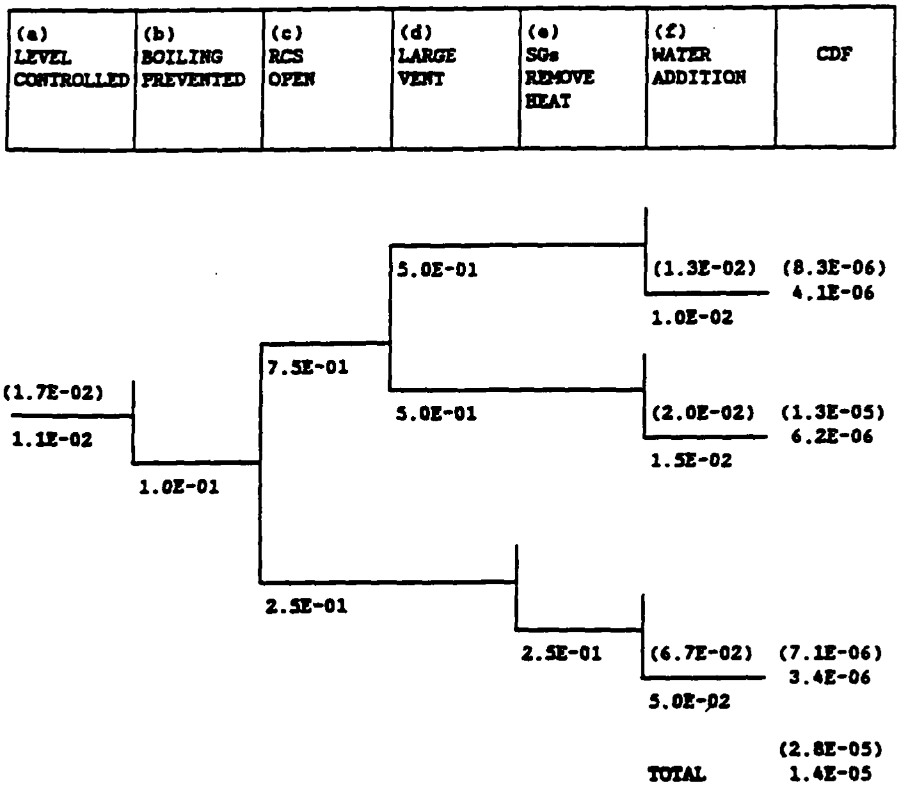
The following presents the results of a study of the sensitivity of the impact/value ratios presented in Section 4 of the regulatory analysis to the assumption in the PRA in Appendix 2.

2.0 DISCUSSION

For this study, the PRA assumptions with a high degree of uncertainty regarding improvement were first identified, and then the CDFs for each associated event tree were recalculated using either higher or lower estimates for the initiating event frequency and failure probabilities (for improved conditions) throughout to obtain upper or lower estimates for CDF, respectively. Using these revised CDF values as bounds, a range for the potential values for the impact/value ratios was then calculated. Figure A3-1 illustrates the approach as applied to the event tree for the loss of level control for a PWR with improvements made in the area of outage planning and control and technical specifications. At several of the branches, values in parenthesis indicate failure probabilities which were modified in the sensitivity analysis to obtain an upper estimate for CDF.

[1]Also commonly referred to as expert opinion

FIGURE A3-1: PWR LOSS OF LEVEL EVENT TREE - CAVITY NOT FLOODED
OUTAGE PLANNING AND TS IMPROVEMENTS



In the original analysis of the sequence in Figure A3-1, implementation of outage planning and TS improvements were reflected in a reduction in the inputs for two steps in the event sequence.

- The initiating event frequency for the occurrence of a loss of level control event is reduced by a factor of 1½. (Step a)

- The probability of failure to take corrective steps to add water is reduced by a factor of 2. (Step f)

In the sensitivity analysis for the sequence in Figure A3-1, the improvement factors for both of the above steps were either reduced or increased to reflect pessimistic or optimistic impacts of the improvements on CDF, respectively. For example, the upper estimate for CDF for this sequence was determined by assuming that there is no improvement in the initiating event probability over that which currently exists without improvements to outage planning and technical specifications. In addition, the reduction in the failure probability in step f was modified to reflect less improvement (factor of 1½) than that assumed in the original analysis (factor of 2). As a result, the overall CDF in this particular case doubled as a result of the modifications to the event tree step probabilities in the sensitivity study.

The procedure outlined in the above example was repeated for each selected event sequence to obtain an upper estimate for CDF with improvements in place. To obtain a lower estimate for CDF, event step probabilities and initiating event frequencies were systematically decreased to reflect an increased degree of improvement. In the example given above, this translated into decreasing the probability in step a by a factor of 2 rather than 1.5. Also, a factor of 3 improvement was applied in step f.

The assumptions in Appendix 2 evaluated in this study are identified in Tables A3-1 and A3-2 for all event sequences. The base assumptions are those used in the analysis within Appendix 2. The modified assumptions used in this sensitivity investigation are listed as well. In the loss of offsite power sequence for improvement B, all of the reductions in the event step probability made in the event tree analyses were judged to be sufficiently justified, and no variation was applied to these values. For this case, no estimate was made for an upper or lower value for CDF.

Table A3-1 Assumptions in Event Sequences - PWRs

Event Sequence[2]	Assumption in Appendix 2	Lower Value	Upper Value
Loss of Offsite Power$_A$	The frequency of LOOP is equal to the average between the current outage value and the current value for power operation.	The frequency of LOOP is equal to the value during power operation.	The frequency of LOOP is unchanged from the current estimate for the LOOP during shutdown.
Loss of Offsite Power$_B$	The gravity feed failure probability is reduced by a factor of 2.	N/A	N/A
Loss of Level$_A$	The initiating event frequency is reduced by a factor of 1½. The probability of failing to take corrective steps to add water decreases by a factor of 2.	Improvement factors of 1½ and 2 are increased to 2 and 3, respectively.	No improvement assumed for loss of level frequency. A 1½ factor of improvement is assumed for the water addition step.
Loss of Level$_B$	The probability of occurrence for a loss of level event decreases by a factor of 5.	Initiating event frequency decreases by a factor of 7.	Only a 3-fold improvement is assumed for the occurrence of a loss of level event.
Loss of Inventory$_A$	The probability of a loss of inventory event occurring decreases by a factor of 3. The probability of failing to take corrective steps to add water decreases by a factor of 2.	The loss of inventory event frequency shows a 4-fold improvement. Water addition failure probability is reduced by a factor of 3.	A 1½ factor of improvement is assumed for the initiating event frequency and the step to take corrective measures to add water.
Loss of Inventory$_B$	The probability of a loss of inventory event occurring decreases by a factor of 3.	The loss of inventory event frequency improves by a factor of 4.	The loss of inventory event frequency improves by a factor of 1½.

[2]Subscript refers to improvement A or B described in Section 2 of the regulatory analysis

Table A3-2 Assumptions in Event Sequences - BWRs

Event Sequence	Assumption in Appendix 2	Lower Value	Upper Value
Loss of Offsite Power	The initiating event frequency for the LOOP is equal to the average between the current outage value and that for power operation. Firewater unavailability decreases to 1/10.	The initiating event frequency for LOOP is equal to the value during power operation. Fire water unavailability decreases to 1/20.	The initiating event frequency is assumed equal to the current shutdown LOOP rate. Fire water unavailability is 1/5.
Loss of Inventory	Initiating event frequency is decreased by a factor of 3. Auto-isolation and alternate means of cooling improve by a factor of 2.	The initiating event frequency for a loss of inventory event decreases by a factor of 4. Factor of 3 improvements are assumed for auto-isolation, alternate cooling and ECCS initiation.	The initiating event frequency for a loss of inventory event occurring decreases only by a factor of 2. Improvement factors of 1.5 are assumed in all other steps.

3.0 RESULTS

With modified probabilities in the event trees, and using the same procedure as in Appendix 2, high and low estimates for CDFs were calculated. These results are given in Table A3-3 along with the base case CDF values determined in Appendix 2, i.e those reflecting no improvements.

Event step factors of improvement for both PWRs and BWRs were decreased by approximately 30 to 50 percent in calculating a upper estimate for "improved" CDF. As apparent from Table A3-3, the upper estimate CDF for each of the improvements degrades the change in CDF for PWRs by approximately 30 percent. However, total change in CDF for BWRs show a decline of less than 10 percent.

Increasing relevant factors of improvement yielded the low estimates for "improved" core-damage frequencies. The subsequent decrease in the failure probabilities throughout the event trees translated into an increase of less than 10 percent in all cases for the change in CDF.

The change in CDFs shown in Table A3-3 were used to evaluate the sensitivity of the impact/value ratios. These results are given in Table A3-4.

Table A3-3 Estimated Core-Damage Probabilities per Reactor-Year[3]

Item	Base Case	Outage Improvements and TS	Instrumentation
PWR, LOOP, < 23 feet	2.9E-5	1.5E-6 **9.6E-7** 5.2E-7	2.5E-5 **2.5E-5** 2.5E-5
PWR, LOSS OF LEVEL CONTROL	4.2E-5	2.8E-5 **1.4E-5** 7.1E-6	1.7E-5 **8.5E-6** 6.0E-6
PWR, LOSS OF INVENTORY	3.0E-5	1.3E-5 **4.9E-6** 2.5E-6	2.0E-5 **9.8E-6** 7.4E-6
PWR TOTAL	1.0E-4	4.3E-5 **2.0E-5** 1.7E-5	6.2E-5 **4.3E-5** 3.8E-5
PWR CHANGE	-	5.7E-5 **8.0E-5** 8.3E-5	3.8E-5 **5.7E-5** 6.2E-5
BWR, LOOP	6.3E-6	4.0E-7 **1.4E-7** 4.6E-8	N/A
BWR, LOSS OF INVENTORY	3.6E-6	6.9E-7 **2.2E-7** 6.2E-8	N/A
BWR TOTAL	9.9E-6	1.1E-6 **3.6E-7** 1.1E-7	N/A
BWR CHANGE	-	8.8E-6 **9.5E-6** 9.8E-6	N/A

[3]For cells showing three values: The top value represents the high estimate of CDF; The bold value in the center is the nominal value given in Appendix 2; The bottom value is the low estimate for CDF.

Table A3-4: Nominal, Upper and Lower Impact/Value Ratios Associated With the Two Plant Outage Improvements.

REGULATORY ACTION	IMPACT/VALUE RATIO $/person-Sv [$/person-rem]		
	Lower Change in CDF	Nominal	Higher Change in CDF
OUTAGE PLANNING AND TS			
PWRs	20800 [208]	5200 [52]	3700 [37]
BWRs	176000 [1760]	160000 [1600]	154000 [1540]
INSTRUMENTATION			
PWRs	(24700) [(247)]	(28000) [(280)]	(28500) [(285)]

The results in Table A3-4 indicate that the impact/value ratio for PWRs with outage planning/TS improvements increased by a factor of 4 when event tree step probabilities were increased to reflect a higher CDF with improvements. The relatively large increase in this value over the nominal value given in Appendix 2 is the result of a decrease in avoided dose to the public, a decrease in avoided occupational exposure and a decrease in the avoided future costs made possible by the improvements, with no change in industry implementation costs for these improvements. Despite the increase in the impact/value ratio, the overall value is still quite low compared to the criterion for cost effectiveness of $1000/person-rem avoided.

Improved water level instrumentation for PWRs and improvements to BWRs in outage planning/TS are not affected significantly by modifying the assumptions outlined in Tables A3-1 and A3-2.

4.0 CONCLUSIONS

The systematic increase of failure probabilities assumed in the analysis in Appendix 2 has a variable effect on the final impact/value ratios. Results for improvements for BWRs and new instrumentation for PWRs were found to be relatively insensitive to the changes made throughout this analysis. The reduction of approximately 40 % in the margin of improvement anticipated from these proposed modifications translated into only a small increase in the impact/value ratio. On the other hand, the impact/value ratio for PWRs with outage planning/TS improvements was found to be sensitive to the assumptions regarding potential benefits. From an optimistic standpoint, the impact/value ratio decreased by about 30 percent. However, when the

failure probabilities were increased the impact/value ratio increased by a factor of 4. Despite the noted degradation in the impact/value ratio for the changes considered in this study, the conclusions regarding the proposed improvements remain valid, i.e that they provide substantial additional protection and are cost effective.