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NUCLEAR REGULATORY COMMISSION

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

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Sheraton Motor Inn
Brooks Avenue
Rochester, New York
Thursday, March 18th, 1982

Meeting of the Advisory Committee on Reactor Safeguards was convened at 8:30 a.m.

PRESENT FOR THE ACRS:

W. M. Mathis, Chairman
David C. Fischer, Member
Raymond F. Fraley, Member
Chester P. Siess, Member
Harold Etherington, Member
Ivan Catton, Consultant
Dale Fitzsimmons, Consultant

PRESENT FOR NRC STAFF:

Allen Wang
Bill Russell
Jim Lyons

PRESENT FOR RG & E

Robert Mecredy
Arthur Morris
Bruce Snow
Lee Lang
Eric Volpenheim

I N D E X

P R O C E E D I N G S

CHAIRMAN MATHIS: The meeting will come to order. This is a meeting of the Advisory Committee on Reactor Safeguards Subcommittee on Reactor Operations, regarding the Ginna Nuclear Power Plant.

I am W. Mathis, Subcommittee Chairman. The other ACRS Members here today are, on my left Mr. Siess; Harold Etherington and NRC Consultants Dr. Catton and Mr. Fitzsimmons. Also with us today, except he's behind the screen, is Ray Fraley, Executive Director of the ACRS.

The purpose of the meeting is to discuss the January 25th incident, the Steam Generator Tube failure and Systematic Tube failure as it applies to the Ginna Station.

This meeting is being conducted in accordance with the provisions of the Systematic Evaluation Program, and David Fischer on my right is the designated Federal Employee for the meeting.

Rules for participation in today's meeting were announced as part of the Notice for this meeting previously published in the Federal Register on March 1st, 1982.

A transcript of the meeting is being

kept and it will be requested that each speaker first identify himself and speak with sufficient clarity and volume that he can be readily heard. We have received no request for oral statements from members of the public. We have received no written statements from members of the public. I think we'll proceed with the meeting and I'll call on Bob Mecredy of RG & E to start off. Bob?

MR. MECREDY: Good morning. I'm Bob Mecredy. I'm Manager of Nuclear Engineering for RG & E. I would like to introduce the agenda for this morning. We have prepared a presentation to address each of the issues suggested by your staff.

Bruce Snow, the Ginna Station Superintendent, will provide a brief description of the Ginna Station and summarize its operating history. This will provide a basis for some of the later discussion.

Although not related to the tube rupture incident we will move to the discussion of the NRC Systematic Evaluation Program of the Ginna Station.

George Wrobel, Senior Nuclear Engineer at RG & E will discuss the current status of the review. George is our Lead Engineer in this review.

I will follow George with a brief appraisal of the SEP Program to date.

We have provided time before the break for any additional questions you may have on the Systematic Evaluation Program for us or the NRC Staff. Following the break we will move to discussion of the January 25th Tube Rupture incident.

Art Morris, Assistant Training Coordinator at Ginna will discuss the sequence of events focusing on the key action taken and the rationale for those actions. He will also discuss the procedures that were used in responding to the incident.

Eric Volpenheim of the Westinghouse Nuclear Staff Department will discuss some of the general procedure-related questions you have suggested.

Lee Lang, Superintendent of Nuclear Production will conclude our presentation for this morning with a discussion of the Emergency Plan Implementation, including a review of the organizational structure in the facility.

Tomorrow we will be discussing the theme Generator Investigations To Date; Radiological consequences in the other areas you suggested in your agenda. Any question about the agenda of the organization at this time?

(No response)

CHAIRMAN MATHIS: Proceed.

MR. MECREDY: Okay. Mr. Snow.

MR. SNOW: Good morning. My name is Bruce Snow. My title is Superintendent at the Ginna Station. The purpose of my presentation is to provide you with a brief summary of the Ginna Station Systems performance and history.

The Ginna Station is a Westinghouse 1520 megawatt pressurized water reactor. It drives the Westinghouse 496 megawatt electrical turbine generator. The director coolant system is seen before you on a current overhead. The pressurizer contains about 800 cubic feet of volume. On the top there's two power-operated relief valves in line with two motor-driven block valves. Director coolant pumps are 6,000 horsepower motor-driven which circulate 90,000 gallons per minute of water each through the reactor. The steam generator is a Westinghouse Series 44 Steam Generator which has a full-load steam flow of V3 times 10 to the sixth pound per hour each.

The feedwater system is comprised of the main feedwater system which contains two motor-driven feed pumps, an auxiliary feedwater system comprised of two motor-driven feed pumps and one steam-driven feed pump. All three of which start automatically.

In addition to that we have a stand-by feedwater system which is comprised of two motor-driven pumps. They're manually started and receive their water supply from Lake Ontario. They're located in a separate building from the auxiliary feedwater system.

The core cooling system is comprised of the safety ejection pumps. There's three intermediate pressure pumps. There's two residual heat pumps of the low-pressure variety. The container vessel is approximately 130 feet in diameter and occupies a million cubic feet of volume and is carbon steel lined. The plant layout which is shown on the next overhead provides a brief overview of our entire plant site.

I guess I need to step up here to show some of these locations. In the main plant building the service building is situated along the west side where office staff is located. The turbine building is situated here (indicating) where our turbine generators are located. In the middle of the main plant building is the containment building. In there is situated the reactor vessel and steam generators and reactor cooling pumps. The auxiliary building is located on the southern side of the plant where our staff systems and reactor auxiliary systems are located.

Back on this southeast corner is where the stand-by auxiliary feed pump building is located, and the auxiliary feedwater system is located in the building in this area (indicating). So they are on completely opposite sides of the plant.

An addition has been put on the east side of the plant where our technical support center is located and our Full Flow Condensate Demineralizer building is located. I'll have slides later to show you on that.

The entrance into the plant is through the guard house, which has been added as a result of our security addition. And the screen house is located directly south of the Lakeshore where our service water pumps are located. Directly south of the plant is our Training Center, and it also serves as a survey team center in the implementation of our emergency plant.

Up north is the location of our

diesel generators. I would point out that we have a very low level radwaste storage building up to the east of the plant.

I want to share with you briefly Ginna Station's performance statistics. Megawatts generated has been over 33 million, lifetime capacity factor has been 69%, and availability has been 75%. You can see the history of the availability over the past ten or eleven years at Ginna Station.

Now, the Ginna Station history: The initial criticality was in 1969, the fall of that year. In July of 1970 was the commercial operation. Changes have been made to the plant over the past eleven years of operation, which I'll show you on some slides. They're summarized before you as Armor Stone Modifications, turbine building flood protection, pipe breaks outside containment, including jet shields, stand-by auxiliary feedwater systems and in-service inspection upgrade. In 1977 a full-flow condensate demineralizer system was added. In 1978 security modifications were added. And in 1980 TMI modifications including technical support center.

If I could have the slides now I'll show you some details of these modifications. In 1974 a big effort was needed to raise the level of the Armor Stone at the shoreline to protect the facility against potential high-lake levels and further shore erosion. Note the Armor Stone at the bottom of the slide.

Also, I would like you to please note the parking lot and fix that in your mind for a future slide.

Shortly after the Armor Stone addition NRC Regulatory Requirements dictated we provide for protection of vital equipment some possible circulating waterpipe breaks. After a reanalysis of our flooding protection we had to relocate doors that lead to vital equipment adjacent to the turbine building, door frames were raised and access rooms were provided.

The white structure to the left is a jet shield. Many of these were installed in 1975 following completion of studies which analyzed the effects of potential breaks in high-pressure piping. The jet shields were a means of protecting vital equipment from potential breaks of piping located nearby.

These additions were all outside of the containment vessel. Because the existing auxiliary feed pumps were located in the intermediate building, an area where high energy lines are located back up and redundant feedwater pumps in a separate remote location were installed.

A new stand-by auxiliary feedwater system, including two 200 gallon a minute pumps with a hundred feet of piping were installed in this new auxiliary addition.

Shown here is one of the new pumps. In addition we had to upgrade our inspection requirements to require non-destructive examination of all piping wells once every ten years and higher stress locations once every three and a third years.

As shown here we're also obligated to perform a hands-on inspection of every pipe, hangar and shock suppressor under routine schedule. This is being done on a hangar-installing a main steampiping containment near the steam generator.

As a result of the pipe-break studies we have installed a super wall to protect the control room from the effects of a large pipe break in the turbine building. Since this slide the wall is completed and complies with security and fire protection standards. To provide better chemistry control of the feedwater and extend steam generator life a completely new system was designed and installed in 1977. This project required a new building east of the turbine building which houses the huge demineralizers shown here and control panel to operate and regenerate demineralizers.

Existing space in the turbine building was used to install three large-capacity generator booster valves. And they're tied into the existing condensate and feedwater system.

Since 1977 most visible changes have been made to the security system. Here are the massive amounts of electrical cable required for the added system. To provide space for screening and entry of individuals to meet Federal Requirements a new guard house, shown to the right, was built in 1978. The old guard house pictured in the left background became the security training center.

In order to meet the Federal Laws a new receiving building was constructed so deliveries could be received at Ginna without requiring the trucks to come on the site within security areas. To provide the minimum light intensity to meet these safety regulations new high light standards were installed. As a side light to increase the manpower needed to maintain and operate Ginna Station changes such as doubling the size of the parking lot shown here had to be made.

In addition to the service building provided for added space. This addition contains office staff, expanded shop space and stockroom storage areas.

Here is the latest addition to Ginna Station, the Technical Support Center. This TSC was added as a result of the TMI accident and will be utilized by operations and emergency response personnel to assist and coordinate activities necessary during an event at Ginna Station.

In summary, the Ginna Plant has been operated and maintained over the past eleven years efficiently providing for the health and safety of the public.

CHAIRMAN MATHIS: Thank you, Bruce, any questions?

(No response)

CHAIRMAN MATHIS: We'll move onto the SCP Program.

MR. WROBEL: My name is George Wrobel, Senior Nuclear Engineer at RG & E, and I have been working on these Systematic Evaluation Programs for the past four years.

I'll try to summarize that in the next

45 minutes or so.

The Systematic Evaluation Program began as a review of the eleven nuclear plants, the oldest nuclear plant plus some of the older plants like Ginna that did not have full-term operation licenses.

The purpose of the review was to review the plants against the current regulatory requirements as expressed in the NRC Standard Review Plan.

The purpose would also form a documentation basis for the review in addition to review for physical modifications.

The final portion of the Standard Review Plan - - excuse me - - the final review would then be used as the basis for license conversion from a provisional operation license to full-term operating license.

The plan was begun in November of 1977 for Ginna Station with 137 topics. Forty-five of the topics during the course of the review were not - - were eliminated from the SEP Program because they're either not applicable directly to Ginna Station or because they were being reviewed generically. The 92 topics were reviewed during the course of the

SEP.

The present statis is that Ginna Station is going through the initial phases of what is called the"Integrated Assessment." As of this point we have reached agreement with the NRC in approximately 75 out of 92 topics reviewed. Agreement was shown on 58 of the 72 topics as being Ginna Station meeting the current regulatory requirement or the equivalent.

We have made notification to meet current criteria on one topic plus portions of others and we have a commitment at the present time to make modifications on 16 other topics, ten of which would be through administrative changes and six physical modifications we have committed to make.

As of this time the SEP Review has not shown any modifications would require immediate action. The Ginna Station met the original design criteria on all topics reviewed. We have made some modifications to date and we have committed to make modifications, but these are to serve to increase the safety margins rather than showing any defects.

We also have about 17 topics that are incomplete at this time and still require further review. We and the NRC have committed to complete this review and some of them we're still performing studies on and the NRC is still performing some studies, and we expect to complete the rest of the topics in the near future.

Although the purpose of the Systematic Evaluation Program was to look at all the modifications and try to perform the assessment of all topics together, we have made modifications were it was deemed convenient during the course of our shutdowns over the past few years. So far we have spent approximately two million dollars in physical modifications and we have also spent about three million dollars for analysis in engineering and administrative costs. We expect the total SEP Program to cost in excess of $20 million dollars by the time all modifications are completed.

There were two topics reviewed where it was deemed that rapid resolution was necessary. The seismic anchorage of electrical equipment was originally received through the SEP. The senior seismic review team toured all the SEP facilities and the review was incorporated into an I & E Bulletin 8011. The review at the Ginna Station showed that all of the electrical equipment was anchored. However, there was not sufficient documentation on all of the anchorage and some of the anchors were not accessible for testing. We had the option of testing the anchors, but since they weren't accessible we decided to install new anchors that would meet current criteria.

The second was a check valve test program where we have to assure that the low pressure systems that interface with the reactant coolant system that the check valves used would properly seat.

We had check valves in there and we hadn't had failure, but for added assurance we performed a test of the check valves to make sure they seat prior to going into operation.

In addition to those two we have also made additional physical modifications at the plant. These were done because it was convenient at the time rather than waiting, since we knew what the modifications would be and it would fit into our shutdown schedule we made modifications at that time.

The battery rooms were blocked off from the air-handling room. There was a service waterline in the air-handling room subject to postulated pipe cracks which could potentially flood out the battery room.

In order to assure there would be no

flooding of the batteries there was a door there and it is now a block wall. We have also seismically braced the battery racks. We have also done some modification on the containment isolation logic.

A large effort that we have embarked upon that was not directly part of the Systematic Evaluation Program is what's called the "Seismic Piping Upgrading Program." This program was initiated by RG & E to look at all of the piping systems to current criteria, evaluate the systems and then upgrade, if necessary in putting in new anchors and things like that. We have used that extensively in the course of the Systematic Evaluation Program, and would have probably had to do a goodly portion of it as part of the SEP anyway.

Since we initiated it and are able to generate floor response spectra, we did a seismic analysis of safety-related piping systems, pipe support to meet current criteria. We used that. The NRC has reviewed that program as part of the SEP and that's the reason why the seismic review of Ginna Station has gone very well. We have been able to integrate that program together with the SEP. That program is about a $20 million dollar program.

A large portion of the Systematic Evaluation Program was an analysis and review of systems. There was a large number of analyses performed for Ginna both by RG & E and by the Nuclear Regulatory Commission. Some of the examples of the analyses completed both by RG & E and NRC were a new mass and energy release to containment following a steamline break. The NRC did an analysis and RG & E performed an analysis to show the containment design pressure would not be exceeded in the event of a postulated steamline break. There were a large number of seismic analyses of seismic systems and components. Both the NRC and RG & E performed a containment liner integrity analysis to show the postulated steamline condition and post loca condition would not cause any damage to the containment liner under loading conditions.

MR. SIESS: What kind of damage was anticipated? Possible Buckling?

MR. WROBEL: Possible buckling, yes. None was shown to occur. We had done a design basis flooding event. Where we have done flooding analysis both at the lake and at the near-creek basin, to show that there would not be any flood levels that were not designed for Ginna.

We have also done a new atmospheric transport and diffusion characteristic study based on the new regulatory guide to show our original atmospheric CHI over Q's were acceptable. We have also done some electrical studies, a containment electrical penetration fault study and a short circuit and failure analysis study for Class IE and DC Systems.

The NRC has done a large number of studies both on their own and through consultants. Again, a seismic capability of structures was done by Lawrence Livermore, and shown that the Ginna structures could withstand postulated seismic force.

Additional electrical studies were done both on the reactor protection for isolation devices and the engineered safety features design. The ventilation system at Ginna Station was reviewed by the NRC Consultants. And there's a study that is still ongoing on wind and tornado loadings done by NRC and that RG & E is performing studies on proper wind and tornado loadings for the Ginna Station.

There is also a detailed comparison of codes that were used at the time Ginna was built and designed back in the mid and late-'60's to current codes and standards both from an equipment standpoint on AISC Section 3 versus B3101, things like that. And on the AISC codes of the mid-'60's, like 65 to 80. The comparison has been made but it is not yet completed.

Throughout the course of the Systematic Evaluation Program RG & E made a number of commitments to make additional modifications. The major ones are shown on the slide here. We have reviewed high energy line break, postulated high energy line break, inside containment, and have decided in certain areas some shielding or cable rerouting would be beneficial.

We may also put in a leak detection system. The topic is not yet complete but we have comitted to at least study it further and probably will put in some shielding and cable routing.

We also have a cable tray test program being done by R.F. Bloom in California. That particular test is not yet completed, although well along, and what we're doing is showing that the cable tray arrangmment and support we have can withstand the seismic force postulated. This is an SEP owner's group program being done by all ten plants. Ten of the eleven plants.

We have also committed to put in a bypass of thermal overload protection for certain motor-operated valves actuated automatically following a safety ejection signal.

We have committed to put in a second RWST level transmitter.

We have decided to upgrade the station battery testing to the new requirements.

We're putting in back-up protection for certain containment electrical penetration as a result of our fault study.

We'll be performing additional inspections of water control structures, such as the breakwall intake structure, and we'll also be making some modifications to safety-related cooldown procedures and long-term post loca cooling procedures.

We're also doing some additional DC monitoring both in the battery rooms and in the control room. There are a number of minor changes that didn't seem worthwhile presenting, many of which are technical specification changes we plan on incorporating at the end of the Integrated Assessment.

As a result of four and a half years of review we still have some items which have not been fully completed, and that either the NRC or RG & E is still studying. We expect to complete these within the next few months.

RG & E is still performing an analysis to try to determine what the proper wind and tornado loading conditions for the Ginna Station should be. The plant was designed for straight wind. The design basis for tornado loading was not credible at that time. We're looking to see whether we should upgrade to tornado protection and also what type of wind and snow loadings are appropriate. We have not completed that study yet. We meet the original design criteria that was found to be acceptable. We're also looking at the design basis flooding and groundwater level. The NRC studied that. We have submitted our results of the evaluation and are having them checked by our own consultant.

We have some very minor slopes on the Ginna site and we're performing a stability analysis on that.

The code changes for structures and equipment I mentioned earlier. We have got a list of differences between 1965 and 1980 codes. We're now evaluating them to see whether or not they're significant. The original analysis showed that we didn't expect them based on a sampling basis to be significant. However, we're going to continue to evaluate those.

Tornado and internally-generated missiles are factors not incorporated into the original - - well, tornado missiles were not incorporated into the original design of the plant. We're evaluating that to see whether or not tornado missiles are a credible item to design for. Internally-generated missiles the plant was designed for.

We're still looking and evaluating to see whether or not some additional shielding or restraints on valve operators would be appropriate. We have almost completed that review. So far with no modifications necessary.

We're also continuing our high energy line break analysis, inside containment, to determine whether or not jet shielding might be appropriate from high energy line breaks mostly for available protection.

We're still performing additional seismic analysis which is not completed. The analyses which have been completed to this point have been shown to be acceptable. A number of areas are still requiring further review.

We're evaluating the containment isolation system, the valve configuration at Ginna, to verify conformance with the general design criteria. We have identified some differences from the explicit requirements of the general design criteria. However, we're evaluating whether those are significant enough to warrant modification.

Again, like I mentioned earlier, we will be modifying the post loca sump switchover procedure. The extent of the modification may be just procedural modification or clarification. That procedure is not yet completed - - that particular study; and the operator action times that are current criteria.

The purpose of the Systematic Evaluation Program was to show that it was useful to look at a large number of topics as related to particular components and review of particular components rather than reviewing a particular item, for example, the service water pumps for seismic.

What we have done through the Systematic Evaluation Program is to review it against seismic and then if we find there is a potential beneficial modification, not to make it immediately since it is only an upgrading, but to look at other factors that could affect the service water pump.

For example, design basis flooding or tornado missile protection are all potential areas of upgrading for the particular service water pumps. Fire protection is another example. Rather than making one fix and then another fix for another area later we'll be upgrading the plant totally.

For example, the service water pumps we would upgrade them for all the necessary modifications at one time rather than doing one at a time. That way we would make the most efficient use of our analyses and our physical upgrade. Those are just two examples. There are other examples I could have picked out.

MR. SIESS: Since you're now in the Integrated Assessment stage could you tell me what you consider to be included in or implied by the term "Integrated"?

MR. WROBEL: It's pretty much what we talked about at the end. We'll have reviewed the plant against all of the standard review plan safety criteria applicable for a particular component, and any modifications that might result from that we would like to make one modification rather than two.

For example, I use the refueling water storage tank as an example where we could upgrade the refueling water storage tank to seismic criteria. However, tornado missiles - - it would not necessarily protect it against tornado missiles if we decide it's necessary. Therefore, we would rather make one modification that includes both seismic and tornado missiles.

MR. SIESS: Then you include in the integration only the various SEP items?

MR. WROBEL: No. We're also - - other items that have come about we have also tried to incorporate.

For example, the fire protection modifications do affect safety regulated equipment which was reviewed for SEP items. Therefore, we would try to incorporate the SEP resolution of a topic together with the fire protection requirements necessary.

MR. SIESS: What about the action plan items, are they also in that category? Or have you already done those?

MR. WROBEL: The TMI Action Plan items?

MR. SIESS: Yes.

MR. WROBEL: Where possible they're incorporated into the final package of modification. Some of them we were not able to base on schedule or constraints. We're told to put it in at a certain time. If possible, we try to integrate those into the SEP. I'm not sure we have been able to do that in every case.

MR. SIESS: There were a number of the original SEP items taken out of the list because they were action plan items, I believe.

MR. WROBEL: Correct.

MR. SIESS: Are those coming back in now as you do the integrated assessment?

MR.WROBEL: To the extent we can we're putting those in, also.

MR. SIESS: Are the revisions clear on those? As of now your SEP revisions seem to be reasonably clear. You and the staff have reached agreement on what you should have, and so forth? Is it truly integrated now up to the 137 items, or whatever it was originally?

MR. WROBEL: I would say most of them are. I think the SEP has helped us integrate all modifications resulting both from action plan items.

MR. SIESS: Okay.

MR. WROBEL: Different people are doing the review on that.

MR. SIESS: The other word was "assessment."

I got the impression in the SEP that after deficiencies were found, that is, deficiencies according to the present rules and regulations, standard review plan, et cetera, there still had to be an assessment to determine whether those indeed required back fitting. Not everything found to be different now would necessarily require back fitting. I have seen on one of the SEP plans a problematic risk assessment that says of these things aren't worth doing.

MR. WROBEL: True.

MR. SIESS: I don't recall your mentioning anything in that category.

MR. WROBEL: I should have mentioned that. RG & E did not do a problematic risk assessment, however, the NRC has contracted with Santia Laboratories to do a problematic risk assessment on the items that are yet unresolved where we have differences not on the entire program but only on those we have not committed to make modifications.

MR. SIESS: That is, there's some items where you and NRC have decided that they really ought to be done? Obvious advantages --

MR. WROBEL: Where we have made a commitment to make modifications we have decided they were prudent to make.

MR. SIESS: Are there any that you or NRC have decided are not worthy doing?

MR. WROBEL: Yes. Except I have to - - as of this moment the problematic risk assessment study for Ginna is not yet complete. Therefore, I have seen preliminary results which show that some areas would not - - are considered of low risk and that each, though we don't meet the explicit words of the particular regulatory guide, for example, we have either alternates or that it's just not of enough safety to consider back fitting; I tend to think those items would not go into the next phase of SEP whenever that starts.

MR. SIESS: What I've heard are suggestions that the only basis for deciding a back fit is not necessarily a PRA?

MR. WROBEL: No. I probably should have had that in here. No. There was a large number of evaluations that were done during the course of the review. Not necessarily the integrated assessment. And during the review what we tried to show was that we had systems that did not meet the explicit requirements of the standard review plan.

However, we had alternate systems acceptable to perform the same function. The NRC in some cases has decided, yes, the differences were significant, however, the alternatives we had were acceptable. Therefore, that item was closed.

MR. SIESS: So it's been possible to redesign without a PRC?

MR. WROBEL: Yes.

MR. SIESS: That's encouraging. Thank you.

CHAIRMAN MATHIS: To carry that on further, are there any other unresolved differences other than the PRA that might require back fitting?

MR. WROBEL: Yes. Do you want to put the open items on?

(Slide)

MR. WROBEL: One drawback to the problematic risk assessment, at least in the time frame we're talking about for our integrated assessment, is that it cannot address natural phenomenon. As you can see a goodly number of the items yet unresolved for Ginna involve low probability natural phenomenon.

Therefore, those items we have done studies for the NRC has done studies also. The results have not yet matched. And we're still debating whether or not, for example, to design Ginna for a design basis tornado or whether to use a more reasonable wind as a design basis for Ginna.

MR. SIESS: That would be a problematic

basis decision, wouldn't it? I don't know how you would get at a design tornado problematically.

MR. WROBEL: We're using studies of recurrent intervals to see whether it's of high enough probability to be used as a back fit. The NRC on those is using materialistic criteria. They have done some current studies also. We just haven't agreed.

MR. SIESS: By "materialistic" you mean maximum credibility?

MR. WROBEL: Right. Probably maximum precipitation.

MR. SIESS: It's not probably in there.

MR. WROBEL: Yes.

CHAIRMAN MATHIS: What about the last two items, they fall in that category?

MR. WROBEL: No. The last two items are being looked at from a problematic risk assessment standpoint. The containment isolation valves we have are redundant boundaries. For the most part the review is not complete. The redundant boundaries we have do not meet the explicit working of the general design criteria. We also have some systems considered "closed systems" that do not have the isolation valves that are required by the general design criteria. Those closed systems - - we may add a redundant isolation valve to those systems to upgrade the current criteria, even though not considered necessary in the version of the general design criteria Ginna was originally built to - - that was the pre-1970 criteria. Those post local sump switchover connection there is there's a Draft NC Standard, "NC-6" I believe is the number that required one minute per operator action.

We have stated that it does not take the operator one minute to throw each pump switch. Therefore, the timing criteria is the area of contention here.

For example, we say we can do a switchover in five minutes. If you do the one minute per action it turns out to be ten minutes.

MR. SIESS: The question is automatic switchover versus manual switchover?

MR. WROBEL: The duration of the manual switchover - -

MR. SIESS: I think the staff requires automatic switchover, don't they?

MR. WROBEL: Some current plans - -

MR. SIESS: That's the criteria you don't meet. And you're arguing you can do it manually, that

that's a timing question?

MR. WROBEL: That's a timing question.

MR. CATTON: Did any items turn up that weren't found beforehand by NRC?

MR. WROBEL: Were any new topics added to the SEP?

MR. CATTON: Did any items not called out by NRC on the SEP turn up?

MR. WROBEL: Considering the SEP essentially reviewed Ginna against the entire standard review plan, it would have been very difficult.

MR. CATTON: Okay.

MR.WROBEL: There were new issues that have arisen since the beginning of SEP. For example, TMI action items that we're not doing within SEP for the most part.

MR. CATTON: I wonder if you found anything before NRC did?

MR. WROBEL: Not that I can think of.

MR. MECREDY: There's no overhead switches.

MR. WROBEL: That's part of SEP. If I think of any I'll tell you later.

CHAIRMAN MATHIS: Okay.

MR. WROBEL: It's hard to recall four

and a half years worth explicitly.

CHAIRMAN MATHIS: Any other questions?

MR. FITZSIMMONS: Concerning your check valve test program, during the testing of the check valves were there occasions you ever found one that didn't work as required?

MR. WROBEL: We have only done it once. We have only implemented that during our last refueling outage and they worked then. There was instances at other plants where I guess the check valves did not work, which is why the NRC concern was raised. The last check valve testing program we did showed that the valves did seat properly.

MR. FITZSIMMONS: All right. Thank you.

MR. CATTON: How do you test the check valves?

MR. WROBEL: By pressurizing upstream of the check valves. And we have installed, I guess, in some cases, a pressure meter and in some cases a flow meter. We have explicit flow requirements on the check valves. I believe it's five gallons per minute is the next permissible o: 50% greater than the last time we did the test.

MR. CATTON: Were there two check valves?

MR. WROBEL: Yes.

MR. CATTON: And you put pressure across the upstream and pressure across the downstream?

MR. WROBEL: We have taps downstream, upstream of each check valve. Upstream. And we get one of them pressurized just by the fact the primary system is at pressure. The second one in between is evacuated and tested.

MR. CATTON: How do you avoid water hammer between the two check valves?

MR. WROBEL: I don't know the explicit method. I'm sure I could find it for you. We have a procedure for it. We haven't had any water hammers. Generally there's some small amount of leakage and, therefore, the piping between the check valves is designed for primary system pressure. So the small amount of leakage would tend to fill up that pipe.

MR. CATTON: I would like to see the procedure if you could get it for me later.

MR. WROBEL: Thank you.

CHAIRMAN MATHIS: I think we have got a couple other questions.

MR. SIESS: Before you leave the SEP, what I wanted to ask is essentially who is doing the integrated assessment, you or the staff or some combination thereof?

MR. WROBEL: I'll address that. The staff is doing the integrated assessment for the Ginna Plant. We have had a lot of input to the integrated assessment and we have a lot of dialogue back and forth. But the actual integrated assessment for Ginna is being done by the staff.

MR. SIESS: There was some discussion earlier among some of the staff in the plant, it came up in connection with the scheduling where the staff was going to do the integrated assessment and publish it and some of the utilities said they wanted a chance to review it. Is this being worked back and forth between you and the staff or are they going to come out with a new regulation that has a final conclusion in it and you're going to respond or what?

MR. WROBEL: The present schedule for the integrated assessment completion for Ginna is that the staff will have completed for ACRS Review by the end of May. That will be the first time that we will see that completed. We'll see drafts of it. I'm sure we'll be working with the staff on the generation of the integrated assessment then. They'll need our input on some of the open items. Our alternative resolution or completion of some of our studies, however, the draft integrated assessment for Ginna is scheduled to be completed by the staff very - - just like Palisades was already completed.

MR. SIESS: If it's completed, I haven't seen it. When the staff has completed the integrated assessment do you have a chance to respond to it?

MR. WROBEL: We'll be responding at the same time you're looking at it.

MR. SIESS: I have a question for the staff about instances where I think there's been an arrangement for the licensee to do the integrated assessment. Are you going to address that later? We'll save that for the staff.

MR. FRALEY: I have a couple of points of clarification. You did note you had modified the containment isolation logic somewhere around the line, can you tell us more about what that involves?

MR. WROBEL: Yes. In general, it had to do with two signals that could close containment isolation valves, the purge valves. Both the high radiation signal and safety injection signal. When the containment isolation signal was reset then neither automatic signal could again close the containment isolation valves.

So, for example, if we had a safety injection signal that closed it then we reset safety injection. If we later got a high radiation condition, that was also bypassed. But what we have done now is it would not bypass both signals. If safety injection were the thing that caused the containment isolation, we reset safety injection and that would not prevent high radiation from subsequently closing the valve.

MR. SIESS: Was that an original SEP item or action plan item?

MR. WROBEL: I think it was both. I think they kind of came together concurrently.

MR. RUSSELL: 1977 came before '79.

MR. WROBEL: We did them together.

MR. FRALEY: With respect to your electrical equipment anchors, you noted you did replace them, and did that involve all electrical equipment or just safety-related electrical equipment?

MR. WROBEL: It involved all safety-related equipment and non safety-related equipment whose failure could damage safety-related equipment.

MR. FRALEY: Okay. One other thing.

You analyzed your penetration for various faults. Apparently you installed back-up protection of some sort. What was the nature of that?

MR. WROBEL: Some type of over-current relays, I believe. I don't know the explicit - - the primary protection met current criteria. However, the back-up protection timing on the protective device was slowing that current criteria so, therefore, we're replacing the back-up protective devices. I don't know exactly how that's being done.

MR. FRALEY: Was that both for safety-related power cables or instrumentation or everything?

MR. WROBEL: Everything. It was a penetration protection rather than circuit protection. To prevent penetration from failing.

MR. FRALEY: At some time it might be interesting if we could hear more about your boiler water chemistry control. Maybe Mr. Snow could address that and what impact your full flow demineralizer had on your steam generator performance.

CHAIRMAN MATHIS: Can we get on that on the other topic?

MR. MECREDY: That's part of a prepared presentation for tomorrow.

CHAIRMAN MATHIS: We talk about the

action plan and the relationship, if you will, of the SEP Program to that. Where do you really stand today with regard to the action plan? Can you give me a summary on that?

MR. WROBEL: Would you rather do that, since I haven't been involved in all aspects of the action plan. I have been tied up in SEP and where they come together I have done that. Items not SEP items that were action plan items I haven't been involved in, so I would rather not answer that.

CHAIRMAN MATHIS: Maybe we can take this up later on. I would like to see where we stand on that particular topic.

MR. MECREDY: Okay.

CHAIRMAN MATHIS: Any other questions? We're running ahead of schedule.

MR. MECREDY: I have about five minutes on all SEP.

CHAIRMAN MATHIS: Fine.

MR. MECREDY: Let me give a brief appraisal of where we see SEP today and also I could elaborate on the integration of modifications with an example you have seen a slide of and you'll see out at the plant this afternoon.

On balance we feel the Systematic

Evaluation Plan is useful. It's providing a documentation base which will aid us in the future both in performing plant modifications and in responding to future safety concerns. It is also led to the development of information on a variety of ways we can shut the plant down.

For example, to cold shutdown, this includes reviews of alternative sources of water, alternative sources of power, and these have been integrated into portions of our operator training program.

We think that's been of benefit. Although none of the modifications we have been performing or have performed as a result of SEP have increased the electrical output of the plant, they will increase the safety margins. The program, as you recognize it, has developed somewhat more slowly than originally anticipated. This is not unexpected. It was a different program. It has the NRC staff more involved in performing analysis instead of their traditional role of review.

It also involved a comparison of plant design against older criteria versus current criteria. In some cases current criteria very explicitly. The turnover within the NRC staff as well as utility response to the accident at Three Mile Island also has resulted in delays in the completion of the program. In the past year or two significant progress has been made. To the point where we expect to conclude, as George mentioned, the SEP review by later this year. We have been deeply involved in the SEP. Despite the fact that the program was initially laid out as an NRC review program, even at that point we were heavily involved in working with the NRC staff providing information, performing analysis and reviews.

We have committed to a number of changes both administrative and equipment-wise and we expect that some, although not all the current open items, may result then in additional commitments on our part to change the plant.

We believe it is important to integrate the fixes, the modifications resulting from SEP with modifications resulting from other reviews.

We found in the past this has been valuable. For example, Bruce Snow showed you a slide of the control room wall. In that case we integrated three different - - very different requirements into one modification; fire protection, pipe break in the turbine wall and security requirements. We were able to install one modification to satisfy all three of those. Had we done those singly it's likely we would have installed one wall for the first in response to the first issue, remove that and install a second wall to respond to the first and second issue, remove that and installed a third wall to respond to the first, second and third issues.

By integrating these modifications we were able to perform one modification and probably provide a better modification design and more efficient from the standpoint of manpower on our part and the NRC's part, also.

Based on the current schedule the safety evaluation report for Ginna will not include a package of modifications responding to all the issues. We do expect to be in a position to commit to address issues and perform modifications, but because of the available time and the time which would be required to perform the conceptual designs for both SEP issues and some others, such as fire protection, we don't anticipate being able to integrate those at the time we'll be meeting with you again on the SEP results.

However, we would intend to perform

that integration and we would be providing information on that integration to the NRC staff.

I would be happy to answer any other questions you have at this time for us.

CHAIRMAN MATHIS: One other question. This last discussion leads to it.

During your SEP evaluation and assessment did you have any thought or any application to systems interaction as you went through the assessment?

MR. MECREDY: George, would you like to address that?

MR. WROBEL: We did some systems interaction study. I guess it was a concern raised by Westinghouse. And it had to do with failure of non-safety related systems and the affect on safety-related systems.

We did not do an entire systems interaction study per the unresolved - - I guess the action plan item - - not action plan but unresolved safety issues. I don't know the number. We did a partial one but not as part of the SEP. We have been looking at it at various times.

CHAIRMAN MATHIS: Do you intend to proceed with that or do you have any plans in that regard?

MR. WROBEL: I don't think we have any firm plans in that regard right now.

MR. SIESS: Somebody pointed out recently one of the best sources of information on systems interaction came from operation experience. You have got a lot of that.

Can you think of some instances during the 12 or 13 years of operations of, shall I say, unexpected systems interactions, water getting into air lines and lousing up a couple of things or common failures of systems that didn't go down the line when accidently they could have?

MR. WROBEL: We have a lot of examples at other units. I would have to think about it for awhile. I don't have any on top of my head.

MR. SIESS: Do you look for these things in the plant? I see now you have a shift technical advisor who is supposed to think about things like that. Some kind of a local review group.

MR. SNOW: We do now have a program of reviewing events in the plant and looking for ways of making things better and safer.

I'm not sure that's what your question is. The events are very minor and they're reviewed by our on-site safety committee as one board that reviews them.

Additionally, our Operational Assessment Group reviews them independent of our on-site safety board.

MR. SIESS: It's really a question of what they're looking for. We have got Carl Michaelson's group sitting up somewhere in the Washington area looking at these things. Operations is a source of information. We keep seeing these things, as somebody said, from other plants. But some of them must have happened here. There's things that show interaction that weren't exactly expected that didn't cause any problem, but if they had gone a little farther and interacted a different way they could have. It takes a little imagination to extrapolate. I guess it depends on what you call a "systems interaction." Everyone's got their own definition.

MR. MECREDY: At least one definition perhaps, is non-seismic equipment interacting with seismic equipment. And in our electrical anchorage program we did look at that.

Another area involved fire protection systems and the potential for their actuation causing flooding.

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MR. SIESS: Or non-safety systems interacting?

MR. MECREDY: Yes. Certainly in area where we have been performing plant modifications, for example, we have addressed the possibility of flooding some prolonged actuation of fire systems. Part of my problem is the variety of definitions people seem to have.

MR. SIESS: Some interaction comes from common cause. Those are a little easier. Those have been addressed for quite awhile.

MR. CATTON: Also, as you know, there's going to be new guidelines for operating procedures. Have you given any thought to how you're going to implement them or are you familiar with the new guidelines?

MR. MECREDY: There's a variety of guidelines in the emergency procedure area.

MR. CATTON: That's what I'm referring to.

MR. MECREDY: There are currently guidelines that have been developed by the Westinghouse owner's group. We have implemented some of those guidelines.

There are some additional guidelines

in preparation now under review by the NRC. We are working closely with the Westinghouse owner's group. Art Morris could address it in a little more detail. He's personally working as one of the representatives of the Westinghouse owner's group with INPO.

MR. SIESS: That's enough. One last comment from me, anyway.

In your presentation you indicated that the fixes for the SEP, including the analysis, would come to in excess of $20 million dollars.

MR. MECREDY: Yes.

MR. SIESS: There's another item on the seismic piping of $20 million, that wasn't included in that?

MR. MECREDY: Yes.

MR. SIESS: So maybe $40 million?

MR. MECREDY: For those two items.

MR. SIESS: If I look at a plant designed over 20 years ago it seems to me that it's come through pretty well. If you can bring it up to present day standards for that kind of money and, again, looking at the items that are actually there, I get a certain amount of comfort of what we were doing 20 years ago. I wasn't doing it but some people were.

I assume you have made other modifications during the years.

MR. MECREDY: Yes. We have made a large number.

MR. SIESS: To update to current processes.

MR. MECREDY: Yes.

MR. SIESS: Basically, I think for a 20-year old design - - I don't know how old the design is, the plant isn't 20, but they usually start designing them early.

I know the criteria back there. Is that your impression; that you came through pretty well? I'll ask the staff later.

MR. MECREDY: First of all, given some of the open items are still under review; so it's difficult to quantify where we'll end up on those. I think we're relatively pleased as to where we have come out. We have not been greatly surprised as to where the differences between the plant design and the current criteria have been.

Besides that the electrical design of the late '60's meets the current criteria, we have been pleased with that, certainly.

MR. SIESS: Some of that seismic design - -

and we're still changing seismic design for plants designed ten years ago, and I'm not sure we're through with it yet.

So that almost automatically would be separated out of it.

MR. FRALEY: In your examination of the electrical systems in the interaction, did you look at the interaction of non-electrical equipment in the same way; with, say, the electrical system or each other and if not, I guess why not?

You seem in some cases you have used a PRA to make such judgments and in other cases you have used deterministic judgment. Where or how do you decide to draw the line between your electrical systems and, say, mechanical and electrical systems?

MR. MECREDY: In terms of the interactions?

MR. FRALEY: Yes.

MR. MECREDY: I can't answer that.

MR. WROBEL: On some of the topics, the mechanical systems - - I'm not sure I completely understand the question, but the high energy break study or internal missile study we have had have explicitly included the effects of the electrical equipment and the actuation systems. If that's what you mean.

If you mean something else I don't know the answer.

MR. FRALEY: In those instances you have non-seismic situations, for example?

MR. WROBEL: We have looked at the effects of non-seismic equipment on - - non-seismic equipment on electrical equipment, definitely.

MR. FRALEY: If it failed during a seismic - -

MR. WROBEL: If it failed then it wouldn't destroy the table tray, for example. Yes, we've done that.

CHAIRMAN MATHIS: Any other questions here?

(No response)

CHAIRMAN MATHIS: I'll ask Mr. Russell of the staff if he has any comments?

MR. RUSSELL: My name is Bill Russell, Chief of the Systematic Evaluation Program Branch.

I would like to thank RG & E for appearing first. This is a unique experience for the ACRS to appear after the Utility. Normally it's the other way around. We did this for Palisades back in October. I would like to propose that we address the staff comments in two areas. Those which are specific to Ginna as far as the open items on the agenda.

I would like Allen Wang of the SEP Branch to address those. And we have a letter of revised issues which identifies all the open items on Ginna. It's the same handout we gave the ACRS back in October on Palisades. It identifies what the open items are, what the staff requirements are, but does not give you the answers as to what we propose to do about them yet.

That's the integrated assessment process. We expect to issue that report to you by the end of May.

The question came up earlier that you hadn't seen the Palisades Report yet. We still expect to get that out in time for the subcommittee meeting on the 15th of April.

It will not be out the 31st, but I expect it to be out within a few days of March 31st.

At this point I would like to turn the stand over to Allen to address the open items on Ginna and then I'll return to answer your questions on SEP in general and how we're doing an integrated assessment.

MR. WANG: My name is Allen Wang,

Integrated Assessment Project Manager for Ginna. The handout you received for this meeting is the meeting notice with a list of the differences from current license criteria to be reviewed during the current integrated assessment.

This is similar to the list presented to you for Palisades. This list was compiled last week in a meeting with RG & E in Rochester.

As you note, our list is longer than the Utility's and this is because the Utility has eliminated those topics for which they have made proposals to resolve issues or met some of our recommendations. The staff has not finalized these and kept them in the listing. We have scheduled a meeting for April 2nd between the NRC staff and GR & E to discuss the PRA study being done by Santia and to listen to licensees proposed for resolution of the open items.

We hope to reschedule to issue the integrated assessment for Ginna at the end of May, as Bill said.

I'm not sure if you want to go through any one of these issues or not, but you have the listing. Basically they're fairly close to what George presented earlier.

CHAIRMAN MATHIS: I don't think there's need to go into that detail.

MR. WANG: All right.

CHAIRMAN MATHIS: Any other questions?

(No response)

MR. RUSSELL: The staff had discussed with Rochester a couple areas in the plant we did feel would be appropriate for you to look at while you're up here to see how the issues integrated together, in particular, the screenwell house where the service water pumps are.

It's the tie to the ultimate heat sink for moving decay heat and it's an important area for you to look at while you're here. To see how the various fixes are together.

MR. SIESS: What areas?

MR. RUSSELL: The service water pumps, fire protection because of fire loading in the building, and with respect to wind and tornado loading, because the building was not originally designed for wind loads, susceptible to tornado missile and external flooding and pipe break which could supply the electrical controllers for the service pumps.

There's a number of issues that need to be addressed collectively in that area. That's an important area to view on your plant tour.

I guess at this point there's a couple of comments which were made earlier which I would like to identify. The purpose of the integrated assessment is to review those differences that exist in the plant from current licensing criteria and to make basically two decisions.

One is, is the difference significant enough to upgrade the facility and, if it is, why? And the other decision is, if the staff judgment is that it is not an important enough item to upgrade the facility, why?

We don't intend to approve explicit design changes to the facility through the integrated asssessment. Rather, we would like to identify those areas which need to be upgraded, provide the Utility an opportunity to come up with the most efficient design which addresses those concerns, and then to provide a schedule for actual implementation.

The schedule and the process will be looked at through the SEP evaluation. We don't expect to approve detailed design. We may be in the process of approving criteria similar to FSAR criteria. For example, in the wind and tornado loading area we expect to be able to approve the design parameters, the pressure drop and snow loading, et cetera, and to approve the analysis loading combination and method. But not to approve the explicit design, the detail design. There are also questions about how TMI issues - - unresolved safety issues and SEP topics integrated together.

You're aware we deleted from the SEP Program 24 of the 137 topics related to either the TMI action plan or the unresolved safety issues program which are ongoing in the NRC.

The integration occurrence from 0737 items is the item which is installed in the plant. To the extent it addresses an SEP topic we went back and either revised the topic evaluation to reflect that recent modification or in other cases considered it in the evaluation through the topic review.

The schedule for the TMI items was not delayed to permit coordination with other SEP topics. For the unresolved safety issue items there's ongoing rograms for those continuing. Once the criteria is established for the review of these items and the "generic issue" is resolved to the point where the staff has a position, Ginna Station will be required to meet that position as will other operating reactors. And the schedule will be established at that time.

So the coordination between TMI and USI is not as close as we once envisioned. TMI is in the forefront. We're taking credit for the TMI fixes to make sure we don't fix something twice to the extent we can.

However, where the implementation of a TMI item is not yet complete or in the case of fire protection, the appendix to our requirements, we're trying to the extent we can to coordinate those.

A good example exists on Ginna Station where they have a request pending to get to cold shutdown in 72 hours. That also relates to SEP issues with respect to component cooling water system reliability and the RHR system from the standpoint of flooding.

The fire protection here is a fire which would eliminate the RHR pumps. We feel those should be looked at together and we're doing that. So the pump they have of cool down using the steam generator in a water condition to get to cold shutdown is being looked at by SEP. We're coordinating them to the extent we can.

Where the schedule or constraint is such that an implemented fix is required in the plant by a certain date, that's going ahead. We're not delaying the TMI schedule to accommodate the SEP schedule.

MR. SIESS: In your assessment you first decide whether something needs to be done, do you also decide at that time how soon it needs to be done? You've mentioned "schedule" several times.

MR. RUSSELL: I wouldn't be able to address this specifically to Ginna. I can address it where we are on Palisades.

We have the early milestone. For instance, submission of design information to the staff where there have been scheduled proposals by the Utility which we found acceptable.

We look at the safety significance of the items and determine whether this is an item required immediately or whether it's an item which provides additional margin and something we would require to be installed in the plant for the balance of the life of the plant.

MR. SIESS: You don't really mean "immediately"?

MR. RUSSELL: There's some items we have required all plants to address.

MR. SIESS: Immediately is just to shut a plant down.

MR. RUSSELL: On an accelerated schedule as compared to another schedule. Some examples are, we have taken the electrical equipment anchorage done back in January of 1980 which subsequently became an I and E Bulletin addressed to all reactors.

MR. SIESS: I was thinking about the remaining - -

MR. RUSSELL: That's an issue we get asked each day. You asked the same question on Palisades. Why did I feel it was okay to continue working?

As each issue comes up and we forward each question to the Utility we have to ask that question ourselves; is this something we have to accelerate on? It's a judgmental decision. We don't explicitly write down for each issue why this one is okay to go for six months or a year or whatever the time frame is.

CHAIRMAN MATHIS: One other question. Do you attempt to work with the licensee and come up with a reasonable time schedule, shall I say?

MR. RUSSELL: Time schedules are usually reasonable to me. I don't know the Utility always agrees that they're reasonable. I might describe what the integrated assessment process is.

Because it's a joint process between the staff and the Utility, although the staff is the author of the document.

We have had a series of three days of meetings last week where we went over a preliminary version of the list of identified differences, the open items. We went back and we toured the facility to look at the items which had come up since we were here in November. And we had preliminary suggestions as to what the staff views were on each item as to its significance and which items it appeared to the staff we would accept the licensee's proposals on.

We're now in the process of writing up our positions on each item and expect to have that draft available at approximately the same time we get the Santia risk assessment. This is a risk assessment which evaluates two aspects. One aspect is the importance of the system to overall risk.

For instance, in auxiliary feedwater system you expect to be quite important. The DC batteries, et cetera. And we rank the system importance as high, medium or low. Then we look at the before and after case of the staff recommendation.

What exists in the plant now and what has the staff recommended and how much of an improvement in system availability is gained by implementing the staff recommendation. That is rated as high, medium or low. And then we judge whether the overall improvement is from a risk perspective high, medium or low, which is kind of a marrying of the system's importance and how much of an improvement do you get by the staff recommendation.

MR. SIESS: Who's doing the PRA on Ginna?

MR. RUSSELL: Santia Laboratories.

MR. SIESS: Who did Palisades?

MR. RUSSELL: Santia.

MR. SIESS: Are you going to use Santia for all?

MR. RUSSELL: We have contracted for the first two. We expect to be using them for all of them. The people involved also were involved on the Irap studies. On the Palisades case we used the yet unpublished Calver Cliffs(sic) PA Studies to obtain system importance. We are to an extent using it.

The first plan we have a full-blown PRA Study, per se, probably will be Millstone Unit 1. We'll have the benefit of a Plant's specific evaluation to make judgments and do the sensitivity of the staff recommended improvement to risk.

But PRA is only one factor we're using. We're also considering safety significance from a deterministic judgmental basis. We're evaluating in a hierarchy whether there are various ways of satisfying the NRC's concern.

Are there other systems which can perform the same functions? Procedural modifications or procedural changes made? You work your way down to hardware modification. Then you ask is there one hardware modification preferred over others?

To that extent we're considering cost clearly in some of the recommendations we're making. What's the cost benefit of one improvement versus another where they achieve the same goal?

MR. SIESS: You used the word "change" in one sentence and "improvement" in the next. What were the possible adverse changes?

MR. RUSSELL: The practicality of making a physical modification, for example, pipe whip constraint, inside containment. It's not physically possible to put in restraints in some areas because of radiation. So we're proposing other methods.

MR. SIESS: That wasn't what I meant by "adverse." A pipe whip restraint which may reduce risk due to pipe whip may increase the risk to something else.

MR. RUSSELL: The issue of the automatic realignment to recirculation is one where - - I'll express my personal view rather than the staff view.

I have seen instances where the automatic systems have failed and ECCS Systems realigned before they were supposed to. THe Arkansas event is one that immediately comes to mind. Where you have a total loss of the ECCS function as a result of this automatic system. In my mind it would be preferred to have a very reliable manual system with a very limited number of steps with adequate instructions to the operator to perform those steps with a sufficient time period so it could be reasonably accomplished. That's my personal view. And we're looking and in fact walked through at the plant the last time we were there at the detailed procedures and had the operator indicate all the steps he verified, all of the manipulations he performed to obtain a hands-on judgment of whether this was a reasonable procedure or not.

Our conclusions are not yet finalized. We think there are things to be done to improve that procedure. There's too many steps and too many verifications in too short a period of time.

That's an example of one where meeting the staff requirements today may not be the best thing to do. So we would like to judge that.

The challenge I have in the branch and the people working for me is to write down explicitly why we think some incorporation is necessary and why it is not. And subject that to review and specifically looking for your comments in those areas.

CHAIRMAN MATHIS: You'll get them. One other question. You mentioned the screenwell house is a specific item to pay attention to, do you have any other suggestions along that line?

MR. RUSSELL: I'm not sure whether they plan on taking you through the auxiliary building area. The last time I was in there we had to suit up in anti-contamination clothing. It's an area where there's a number of modifications structurally. There are modifications associated with the issue Mr. Fraley identified; the system's interaction. The non-safety grade tanks inside the building whose failure could result in flooding of safety-related equipment.

I expect there will be upgrading in that area and that is going to be one of the more significant areas of upgrading. It's also one that you can conceptually discuss from drawings without going into the area.

CHAIRMAN MATHIS: Anything else?

MR. RUSSELL: No.

CHAIRMAN MATHIS: Any other questions of Bill?

(No response)

CHAIRMAN MATHIS: We're just about on schedule. We'll take a ten-minute break then.

(Whereupon, at 10:30 o'clock, A.M. the hearing in the above-entitled matter recessed until 10:40 for a short recess)

CHAIRMAN MATHIS: The meeting will come to order. The next item on the agenda is the review of the steam generator tube rupture incident. I guess Mr. Morris, are you the first man on deck?

MR. MORRIS: Good morning. My name is Art Morris, I'm a Senior Reactor Operator at Ginna Station. I'm a member of the training department at the Ginna Station. I've been involved in the Westinghouse Owner's Group procedures subcommittee and I have been involved in the IMPO Utility Combine for procedures, emergency procedure guidelines.

But possibly more importantly for today, I was in the control room of Ginna Station on

January 25th, about ten minutes after the incident started and remained there until around 4:00 o'clock in the afternoon.

The areas I would like to address today are the background of the control room team, including a brief discussion of the communication and management that went on in the control room during the event.

The emergency procedures that were used, including their basis and a discussion of the tube rupture showing a brief sequence of major events.

The control room team consisted of one senior reactor operator and two reactor operators and one shift technical advisor. The senior reactor operator is the shift supervisor. This particular shift supervisor had 20 years of operational experience. Both nuclear and fossil. He was a licensed operator at Ginna Station for eight years, six of those years he was Senior Reactor Operator.

The Head Control Operator - - one of the reactor operators - - has 15 years of operational experience, both fossil and nuclear. He has held a reactor operator's license for four years. The control operator is a reactor operator and he has eleven years of operational experiences, including Navy and Ginna experience. He has been a licensed RO at the station for one year.

The Shift Technical Advisor has a Bachelor of Science Degree, does not have a reactor operator or senior reactor operator license. He's been involved in the industry for about three years and has been at Ginna Station for two of those years.

MR. CATTON: How long has he been out of school?

MR. MORRIS: How long has he been out of school? I don't know.

MR. SNOW: He's been out of school about three years.

MR. CATTON: Thank you.

MR. MORRIS: The control room management communications is something I want to touch on briefly and specific to the incident itself.

Both bottom up and top down communications functioned very well. The control room manager, the shift supervisor was in charge at all times. There was never any question in anyone's mind as to who it was that you went to for the bottom line decisions. He was the pivot point and made all other communications within the control room effective independent of the number of inputs there were.

The procedures are the procedures we're using today, emergency procedures are based on the Westinghouse Owner's Group Guidelines. They were adequate, they were used. And today we have added and changed in somewhat the procedures to fine-tune them from the lessons we learned during the incident.

Those changes and modifications have been fed back to the Westinghouse Owner's Group procedure subcommittee by myself in a presentation to them.

MR. CATTON: Do the procedures meet the new guidelines coming out?

MR. MORRIS: The procedures met the Revision I Guidelines, which the Revision III are the most recent ones are based on also. Have the same basis.

CHAIRMAN MATHIS: Just a point of clarification. The procedures you have reference to are the IMPO Guidelines?

MR. CATTON: The ones we heard about yesterday?

CHAIRMAN MATHIS: You're referring to the same?

MR. MORRIS: Yes. Those procedures, that

revision III are already on the street, per se, for the high head plants and they'll hit the street somewhere we hope in April or May for the low head plants.

CHAIRMAN MATHIS: Thank you.

MR. MORRIS: That's low head safety injection, for some clarification there. It has nothing to do with elevation. Okay.

The event itself: The event occurred -- your basil problems are you have a reactor trip and safety injection. Those things require some immediate actions that the operators have memorized. Those I always consider as being out of the way. They are over and done with. The rest of the event deals with the tube rupture incident specifically, stopping of -- identifying exactly that you have a steam generator tube rupture and then stopping the leakage from primary to secondary. So I have some overhead here and what I have done is divided this up into three phases, if you will.

Phase 1 is the tube rupture diagnostic. That is, how do I get from the fact I have some problems in the plant to the steam generator tube rupture procedure itself?

Phase 2 is leak stoppage or the

stopping of primary to secondary flow.

Phase 3 is to cool down to cold shutdown. If I could realign this thing now. Good thing I'm in training or I wouldn't know how to do all this stuff. Okay.

Phase 1, again, we'll call the "Tube Rupture Diagnostic." With the reactor coolant system pressure and pressurizer pressure and level decreasing rapidly, that combined with the fact there's no indications of loss of coolant in the containment vessel, that high radiator sump level and that the operator sees an increasing radiation level on the air ejector and/or blow down monitors, keys him in to the procedure for steam generator tube rupture.

We have other possible ways of identifying steam generator tube rupture specific to the FAR if you lose power to the detector you have steam generator level. The steam generator in the level in the faulted steam generator will continue to isolate after you either lose feedwater into it - -from the TMI lessons learned we have installed steam monitors on the steam line, which also aid the operator in knowing to go to the steam generator tube rupture procedure.

So, he's in the steam generator tube rupture procedure.

MR. CATTON: Which of these many things did he notice? Which is the first clue?

MR. MORRIS: The first clue generally is an air ejector radiation monitor alarm, because it's so sensitive to the primary to secondary leakage. In this particular case there were a number of others that he used, but those are the ones specific to getting him into the procedure. Those are the ones that are going to convince of him of what he has. He used many others as confirmation. We have incorporated some of those into the procedure because it appears those are going to happen every time.

MR. CATTON: What were they?

MR. MORRIS: Steam flow and feed flow mismatch in the steam generator along with some specific indications of how steam flow is behaving.

So we have learned some of those things and, again, those were fed back to the Westinghouse Owner's Group procedures subcommittee and they're looking at those kinds of things as well. Okay.

MR. FITZSIMMONS: So that when he grasped the first input, if you will, he immediately went to steam generator tube rupture as a probable situation?

MR. MORRIS: Those helped. And then as he moved along through the others and the ones that I showed before are the ones that really key him into it. He's not going to jump into the procedure because he wants to make sure he isn't missing it.

He goes into those decision-making stages. Collects a little information and more and more and finally says, yes, this is it. And the steam generator tube rupture event he knew he was in a steam generator tube rupture event when he had all that information.

MR. FITZSIMMONS: What was the elapsed time for that kind of assembly of information and decision-making process?

MR. MORRIS: Extremely fast. If you consider that in this part he had identified which steam generator it was and isolated it within 12 minutes, then he already knew before that that he was in a steam generator tube rupture event, period.

So it's quick. The point should be made that the flow rate from primary to secondary in our incident was largely making it more evident.

But it's pretty clear cut. The operators don't have much of a question in their mind with the diagnostics given where they should go. What procedure they should get help from. Okay.

MR. ETHERINGTON: To use pressure and level as a criterion, this would have to be before the reactor trip because after the trip the cool down would have a much bigger effect than the leakage?

MR. MORRIS: The instantaneous cool down, yes. But the pressure continues to go after that. But that has to be taken into account, yes. The fact it does cool down after reactor trip.

MR. ETHERINGTON: Do you have time to recognize this loss of pressure before the reactor trip?

MR. MORRIS: Yes. The alarms and indication.

MR. ETHERINGTON: Only an inch or two before reactor trip?

MR. MORRIS: An inch or two of level?

MR. ETHERINGTON: Yes.

MR. MORRIS: A little more than that, but not much pressure. You lose pressure quickly depending on the size of the break, again.

MR. CATTON: How do you establish the

steam flow of mismatch?

MR. MORRIS: Alarms. Okay. Phase 2, then, "Leak stoppage" has five basic steps all procedurally guided.

That is, to identify which steam generator is the faulted one; isolate that steam generator from steam and feed; cool down the reactor coolant system by 50 degrees using the non-faulted steam generator; depressurize the reactor coolant system to equalize the faulted steam generator. Right there, basically, leak flow is stopped. And then terminate safety injection pump operation since the safety injection pumps will repressurize reactor coolants system by themselves.

Now, the criteria for terminating safety injection pump operation. I have on the slide that it's a 200 pounds per square inch pressure increase following depressurization of the RCS and 20% pressurizer level.

Now, as you know between Steps D and E are depressurization steps. The power operator relief valve failed to close. Since that was our depressurization means. We depressurized for a period of time down to less of the faulted steam generator pressure. The blocked valve for that power operator relief valve was closed within a minute of knowing that it was - - that the power operator relief valve itself was stuck open and the majority of that time was valve stroke time. The valve stroke in 40 seconds.

MR. FITZSIMMONS: You knew it was stuck open on the basis of what?

MR. MORRIS: Simply that the operator tried to close it when pressures were equalized and we didn't get an immediate open-closed indication, which indicates it's on its way closed. We based it on that immediately and within a few seconds he went to close on the blocked valve.

We're all pretty sensitive to that today, needless to say. The A & B steps again identify and isolate the steam generator were completed within 12 minutes. Completed the depressurization C & D, down to the depressurization of the RCS within about 30 minutes. And the termination of safety injection pump operation was accomplished at the end of about an hour and ten minutes. Okay.

Are there any questions so far?

MR. SIESS: In Step D what pressure do you have to get down to?

MR. MORRIS: Really, whatever the

faulted steam generator pressure has remained at. Generally it will be around a thousand pounds.

MR. SIESS: Was it in this instance?

MR. MORRIS: In this instance, yes, it was around a thousand pounds.

The third phase of it would be the cool down to cold shutdown. Since the lead flow has stopped from primary to secondary you can basically line the plant up to the point where you can cool down by the normal means except you're only going to cool down on one steam generator for us.

So the next obvious step for us in the procedure is to start a reactor coolant pump. Start a reactor coolant pump in the non-faulted loop. Then return to normal reactor coolant system volume and pressure control. This involved putting in the CVCS System energizing pressurizer heaters. And continue the cool down to cold shutdown steaming the non-faulted steam generator only and eventually cooling down and putting the RHR system in service and depressurizing the reactor cooling system such that there will be no leak flow. Then we can do the things we're doing now; get in those steam generators and plug it up. Okay.

In conclusion, unless there's any

questions - - I could field any questions now if you have any?

(No response)

In conclusion, then, the incident at Ginna outcome is obvious to all of us now. I would like to say that the communication management network within the control room is responsible for that a good deal. Particularly the decisions that were placed on the operators because of the differences perhaps from the norm or the way that a tube rupture goes.

Specifically, the power operator to lead valve sticking open. That kind of decision-making process is difficult, especially in stressful times. And without the kind of organization that we saw in our control room it would become even more difficult.

Communications and management within the control room at our station was absolutely excellent. Thank you.

MR. CATTON: Having gone through this incident now would there be any instrumentation or information that would have been more helpful to you?

MR. MORRIS: I can name a number of

instruments that would be helpful and useful.

MR. CATTON: Could you do so?

MR. MORRIS: However, whether they're required or not - -

MR. CATTON: That wasn't the question.

MR. MORRIS: Is something I wouldn't say. It's apparent I think that a reactor vessel level indicator would be helpful if the operator could believe what the vessel indicator said, and only "if."

CHAIRMAN MATHIS: Where have we heard that before?

MR. CATTON: That's one piece of instrumentation. Are there others?

MR. MORRIS: No. The others are specific to my control room and many others already have the instrumentation that I would tell you. So there's nothing generic.

MR. CATTON: Maybe on our tour you could point some of these out.

MR. MORRIS: I could do that easily.

MR. CATTON: The second part is the procedures. Procedures being in a state of evolution at this time did you learn anything that would be helpful to others as far as procedures are concerned?

MR. MORRIS: Just the procedure format itself or the technical content of the procedure.

MR. CATTON: The technical content of the procedure, the direction given to the operator?

MR. MORRIS: The direction, overall method of handling the incident, I don't think we learned an awful lot about that. We learned a lot of the little things you always learn. Some of those are technically based just that they don't impact the flow of the procedure.

MR. CATTON: Some are more important?

MR. MORRIS: Certainly important to us and we have incorporated every one of them we have found and found to be something we feel is going to happen every time.

We also don't want to add something that is going to be a confusion factor because the next one doesn't look like this one. We haven't added those.

Again, I fed those back to the procedure subcommittee and they were interested. Because if you're an operator you're interested in the little things. You can handle the big picture stuff and the procedure and all the technical guidance for that, does all of that, but it's the little things that make a difference to the guy operating the switches. We want to make sure we have learned as much as we can from that.

MR. ETHERINGTON: I'm in two minds about your comment about the excellence of the performance of the operator. This is fine. Supposing he hadn't done quite so well? How much margin of error or - - how many mistakes might he have made and we got really into a serious problem?

MR. MORRIS: I don't think I can answer that. A number of mistakes would be hard to pin down.

MR. ETHERINGTON: I wish you just said he performed normally rather than excellent.

MR. MORRIS: I think I'm prejudice. That's why.

MR. FRALEY: If he had water level indication do you think he would have done anything differently or just felt better about what he was doing and done just about the same thing? For example, would he have turned off his high-pressure injection system earlier or later or shut his PORV earlier or later or what?

MR. MORRIS: That's hard to say whether or not - - it's another piece of information. That's what that level indicator would be. All of those pieces have to be analyzed before he's convinced he has all the bases covered he wants to cover in that part of the procedure.

MR. FRALEY: There's nothing obvious he would have done differently?

MR. MORRIS: It would have been another piece of information. Anything else would be second-guessing.

MR. FRALEY: In the systems being proposed, you're familiar with the two systems, I'm sure, do you think they wo d have been reliable during this transient - - the rate of the transient, the rate which they can respond?

Do you think they would have been useful or not or would you have discounted them?

MR. MORRIS: Not having dealt with those systems - - I know what the systems consist of but their response to a transient like this, I don't know. It would be unfair to speculate.

MR. CATTON: It's not often that we get to talk to someone in your position. There's really two concepts. One can talk about the level in the vessel or one can talk about the total primary inventory. You as an operator are responsible for running that system. Which would be more desirable or do you have any druthers?

MR. MORRIS: Systems inventory or - -

MR. CATTON: The vessel level? Or have you thought about it?

MR. MORRIS: I have thought about it. I would like to know both. I think that vessel level is the one that you want to know. You want to find that out. Particularly after you have drawn what you know is the steam void in the upper head, when we did that on our depressurization.

Very interested in that. You're finding ways in your own mind to find that out. You really want to know. So my answer is, both. Vessel level becomes to the operator's mind something he wants to find out somehow. And he'll take whatever action he can and use whatever instrumentation he has to do that.

MR. SIESS: In this instance the leak was a large one - -

MR. MORRIS: Yes.

MR. SIESS: Suppose it had been not so large, would the operator's response time have been correspondingly longer?

MR. MORRIS: No. The identification - - there's a break point there somewhere.

MR. SIESS: You would pick up the activity in the steam line and reactor as rapidly?

MR. MORRIS: Yes. The air rejector monitor is so sensitive that even a leak totally undetectable in pressure it picks it up right away.

MR. SIESS: Were you operating with any leakage at the time?

MR. MORRIS: None.

MR. SIESS: Would it have made a difference if you had a small leak or would the increment have still been large?

MR. MORRIS: As a matter of fact, it may have been the first diagnostic aid; to already have a leak there, maybe that's just what happened to me.

Now, I have got a decreased level and pressure.

MR. SNOW: In response to the question about the low level leakage, we have with our current systems detected leaks less than a tenth of a gallon per minute and the operators have detected those and we have responded accordingly with our procedures.

Additionally, I would like to ask you to discuss the upper head thermo-couples we have had the benefit of.

MR. MORRIS: We have had a program, a Westinghouse Program awhile back now - - I don't remember which year - - but when they were concerned about the flow in the upper head, bypass flow into the upper head and upper head coolant.

So three of the core exit thermo-couples were withdrawn back to the elevation of the reactor vessel flange.

We used those thermo-couples during this incident to try to make decisions on one, was there an upper head void and, two, how long was it if it was there? It was very useful.

MR. SIESS: Where are those normally?

MR. MORRIS: At the exits. Westinghouse withdrew them for us rather than being at the lower plant - -

MR. CATTON: You were able to use the thermo-couples to detect the void?

MR. MORRIS: Yes.

CHAIRMAN MATHIS: One other question. We have talked a lot about a safety parameter display system. I'm sure you're familiar with that.

Recognizing you probably don't have a detailed design in mind or something of that nature, but do you envision such an aid would have truly been helpful?

MR. MORRIS: I would have to give you a personal opinion on that.

CHAIRMAN MATHIS: That's all right.

MR. MORRIS: It depends on what's on it, where it's located and who ultimately uses it.

CHAIRMAN MATHIS: Do you have a recommendation as to your personal opinion again as to answer those questions?

MR. MORRIS: Yes.

CHAIRMAN MATHIS: That was easy.

MR. MORRIS: I would be glad to talk to you about it sometime.

MR. FRALEY: Were your upper head thermo-couples, we'll call them - - you have a saturation meter in your plant?

MR. MORRIS: Yes.

MR. FRALEY: Didn't they give you the same information?

MR. MORRIS: No. The saturation meter has feeds from it from the TH leg, RTD's, that's different elevations from where the upper head voiding was. So it didn't, no.

MR. FRALEY: And the thermo-couples

read high?

MR. MORRIS: The thermo-couples read at saturation for the pressure that was right then in the reactor coolant system and it was pretty apparent that was going on. Very useful piece of information. And we read that with some exit thermo-couples as well, matched those against saturation throughout.

We have a report which includes traces of those kinds of things. Very interesting and useful piece of information.

MR. FITZSIMMONS: In this particular instance what was the role of the shift technical advisor with your operators and your senior operator?

MR. MORRIS: The shift technical advisor did assess and did his function, but in addition to that he was the person who read, interpreted and kept track of where we were in the procedural guidance relative to the action on the control board. Very useful function.

Anytime someone would turn around to him and say where are we or what's next, did I forget anything, if he wasn't already reading it he could tell you precisely what it was. Very useful.

MR. FITZSIMMONS: He was monitoring as

well the steps and making sure the steps weren't taken out of order or things of this sort?

MR. MORRIS: Exactly.

MR. FITZSIMMONS: Was there any concern given in the watching of the safety injection and the duration of time given to the thermal shock question as to another generic problem; repressurization, things of this sort?

MR. MORRIS: No.

A VOICE: As a member of the public I would like to ask some questions. I won't be able to make the tour of the reactor safety equipment. I find Mr. Morris' answers to a person like myself here as representative of the Safe Energy Alliance Group, I feel Mr. Morris' answers aren't satisfactory answers to the questions I have and my organization has as to whether or not the reactor can be operated in a safe manner.

There were things that happened at the time and I don't feel they're being addressed by this committee in terms of why the errors were made and what could be done to avoid making those errors in the future.

CHAIRMAN MATHIS: If you care to write out your questions and give them to us tomorrow we'll take care of it. Theoretically if you don't have it written out or have warned us about it, we just don't permit it.

A VOICE: Perhaps I could give you the questions now and the committee could ask them.

CHAIRMAN MATHIS: In writing. If there's nothing more from Mr. Morris we'll proceed on then.

MR. VOLPENHEIM: My name is Eric Volpenheim. I would like to begin with a discussion of the consequences of the steam generator tube rupture event compounded by a stuck open valve on the secondary side.

I'll make a very brief discussion. And address not only the concerns but what we're doing about them on a generic basis.

As Art was pointing out the operator response to a design base tube rupture is to reduce the primary system pressure to the faulted steam generator pressure in order to terminate leakage from the primary to the secondary side.

For a design base event the integrity of the secondary system will assure that the secondary side is maintained at approximately a thousand pounds per square inch. Therefore, the RCS pressure can be reduced to that pressure and still maintain sub cooling which provides sufficient indication to the operator of adequate coolant inventory.

If we were then to assume that a secondary valve failed to open, in a stuck open position we're dealing with the safety code, since any other valve that fails to open can be isolated by using manual means. Then the pressure on the faulted steam generator will decrease. By "faulted" I'm referring to the steam generator which has the stuck open safety valve on it. This may or may not correspond to the ruptured steam generator. In either case there's different problems that have to be addressed.

In particular, if this valve were to stick open on the ruptured steam generator we have concern of continued leakage from the primary to the secondary side of the steam generator.

The sequence of the action the operator would take would be similar with the exception he cannot terminate the leak he can only reduce it. In order to reduce it he would have to get to cold shutdown, depressurize the system all the way and then balance charges and let down.

He also has an additional concern to

address and, that is, the one of a stuck open safety valve which results in an abnormal cool down event.

However, this is a relatively limited concern and can be addressed by limiting the amount of coolant introduced to that steam generator.

Let me address what the Westinghouse Group has done to address this issue.

MR. SIESS: What has been the experience in the industry with safety valves sticking open?

MR. VOLPENHEIM: There is a probability they will stick open. I don't have a number.

MR. SIESS: I just want statistics. We have got several hundred reactor years of operation.

MR. VOLPENHEIM: I'm not familiar with the frequency that they stick open.

MR. SIESS: Does anybody know? We had one incident at Dresden where some sort of lever on there jammed and I know there's some that have not closed completely. I'm talking about something sticking open with significant release of either steam or water.

MR. VOLPENHEIM: I'm not familiar with the frequency of that at all. This event has been identified to a probability risk assessment applied to the Westinghouse Owner's Group emergency response guideline program as a "incredible event." Unlikely but incredible. And one that warrants what we have referred to as optimum recovery guideline.

As far as what has been done to address this, in the emergency response guidelines for a design base tube rupture event we take precautionary measures which limit or minimize the potential for lifting of a steam generator safety valve.

That is, we would reduce our CS temperature following the trip using condenser steam if available or atmospheric relief valve if the condenser is not available to preclude lifting of the steam valve.

We recognize this is not going to be effective in all cases. So the Westinghouse Owner's Group have supported an effort to analyze a design basis tube rupture coincidental with stuck open safety valves as part of the Westinghouse emergency group response guideline.

We have analyzed the number of different variations of this event. That's where a safety valve were to stick open on a ruptured steam generator or non-ruptured. And the result has been we have developed an emergency response guideline for recovery to this event to cold shutdown.

This has been distributed to member Utilities applicable to high head plants as of November of 1981. We're currently in the process of identifying changes or modifications which would make these guidelines applicable to low head safety injection plants, as Art Morris pointed out.

The schedule for this is currently April 1st of this year for distribution. Based on the result of the meetings yesterday or Monday it may be pushed back to May. These guidelines have been reviewed [illegible] NRC staff, in particular the one which deals with the steam generator tube rupture with stuck open valves.

Comments received have been favorable and constructive. I'm not aware of any formal response or formal approval, although we expect that soon.

MR. CATTON: Any changes in the procedure as a result of this incident?

MR. VOLPENHEIN: I'll address those if you'd like. These basis analyses for this particular event indicate although the event would result in increased primary secondary carry-over and the potential for increased radiological increases, they would still be a small fraction of the ten CFR 100 limitations.

As far as the post-Ginna Station review items, we have looked and are continuing to look at items presented by Mr. Morris as well as internal items within Westinghouse which we feel may have an impact on the generic Westinghouse Owner's Group guidelines.

I can provide some description of the Westinghouse perspective on these. It's not yet been approved by the Westinghouse Owner's Group so we'll have to defer comment on their position to a later date.

We have looked at, in particular, reactor coolant trip and restart, the SI termination, voiding of the RCS, the long-term cool down procedures. We have also proposed a plan which will address the steam generator overfill issue.

The status of these efforts are for the reactor coolant pump trip issue. The Westinghouse position has not changed as a result of this. We still feel that the potential for misdiagnosis by any particular operating staff is sufficient to warrant reactor coolant pump trip.

The question of reactor coolant pump

restart has also not been changed. We feel there's good reason why the reactor coolant pump restart has been placed where it is in the tube rupture emergency response guideline.

Voiding of the RCS, in particular, the upper head region we see as principally a training problem. We don't see any safety concern with voiding the upper head, only operational concern.

That is, how does it affect instrumentation readings the operator might see and key his operator actions to? We are currently reviewing the current emergency response guideline package to identify areas where improved information or additional information is needed as to the consequences of RCS voidin instrumentation response.

The safety injection reinitiation criteria, we see no changes that are needed in those. We feel they are adequate. We feel they are consistent with the emergency response guideline program taken in its entirety. And we feel it's sufficient for the particular tube rupture events that have occurred.

The long-term cool down issues; we have identified a number of minor changes which provide additional clarity. In particular, as part of the emergency response guideline program we have identified alternate cool down methods for the ruptured steam generator.

Although the RG & E or Ginna personnel had not an opportunity to implement the versions or the low head version for those alternate cool down methods, they did follow the technical sequence or technical ideas in that recovery.

However, when we reviewed what we had provided as guidelines we found it was inadequate and would not have provided a sufficient indicator for them to actually do that. So in our revision and review process we're correcting or modifying these alternate cool down methods.

The clarity of the guidelines. There's specific instances which Art Morris pointed out or identified in his presentation to the Westinghouse Owner's group where the wording can be ambiguous. We have corrected that.

These modifications are all part of the Phase 2 of the emergency response guideline program.

The current schedule for the completed package is June 1st of this year. I would anticipate that would slip somewhat. The major impact that we can identify or the most useful information we can find from this event is that the education or the training that we provide with - - "we" as Westinghouse provide with the emergency response guideline, is not sufficient.

We recognize there is a need to improve these training seminars we provide by either providing more of them or restructuring them so that we could be more effective in communicating our ideas and concerns to the actual operating personnel and member Utilities.

Are there any questions?

MR. SIESS: Is there a simulator for a Westinghouse II loop plant?

MR. VOLPENHEIM: Not that I'm aware of.

MR. SNOW: There are no II loop simulators for our Westinghouse Plant. But ever since 1971 or 1972 we have been sending our operators for simulating training.

During the first five or six years we sent them once every two years to the simulator up at Zion(sic). Since TMI we have been sending them every year and we have sent them to Independence Point and Surrey, as well as Westinghouse Zion and

Westinghouse Pittsburgh.

MR. SIESS: Is a steam generator tube rupture one of the casualties they look at?

MR. SNOW: Yes.

MR. SIESS: It seems to me it might be different for a IV loop plant than a II loop plant, is that taken into account in any way in the training?

MR. MORRIS: You're right.

MR. SIESS: In one case you have got III.

MR. MORRIS: The volumes alone make it different. The base concept of how you handle it are not different. That's what you get out of it. You can't explain this is going to be this much faster or this much slower. That's difficult.

MR. SIESS: But you know there's a difference.

MR.MORRIS: Yes. You know what the differences are and you appreciate them. But there are several other simulator constraints that really ought to be addressed and are by Westinghouse. It's different to simulate a steam generator tube rupture and all of those things we know can happen today for a steam generator tube rupture on a simulator.

MR. CATTON: You can't simulate the tube --

MR. MORRIS: It's really hard. So you do the best you can. It's an excellent training tool and getting better all the time.

CHAIRMAN MATHIS: Thank you. The next speaker?

MR. LANG: My name is Lee Lang, I'm the Superintendent of Nuclear Production. I would like to start out with a brief description of our off-site and on-site radiological emergency organizations. I'll show you the ties with the State of New York, Wayne County and Monroe County. I'll also briefly describe some of the information that is given to those organizations.

The first slide shows our off-site organization which is run by the corporate recovery manager, which is the Vice-President of Electrical and Steam Production. He's responsible and manages the overall recovery operation of the Ginna Station facility.

Next on the far-left is the Advisory Support which provides advisory technical support to complement any on-site personnel.

Next would be the Nuclear Operation Support Manager, who coordinates the activity of the off-site operation to support the on-site organization.

The Engineering Support Manager coordinates the design and construction activity of the Utility in terms of vendors, triple S suppliers, any construction and any off-site vendors.

The Facilities & Personnel Manager provides the administrative logistics communications and the personnel support for the recovery operation.

The Public Affairs Manager basically is the official source of the RG & E statements to the media. He coordinates all of the media responses.

The Technical Advisor for the media basically supplies accurate technical data to the corporate spokesperson. The other main organization is obviously the site organization. Which reports to the downtown organization through the Nuclear Operations Manager. It's run by the Emergency Coordinator who has interface with the On-Site NRC personnel. He's in his organization Dose Assessment, Plant Assessment, which is basically Systems, Maintenance, things of that nature; communication and administration, security, and is also tied-in to our survey center where the off-site survey and on-site survey information comes from.

Some of the information that is relayed

to the State of New York, Wayne County and Monroe County would be things such as the safety injection system status, the residual heat removal status, the accumulators, containment spray systems, service water and the containment vessel fans and filters.

We would also let them know if the diesels were operable and running, containment radiation, the classification of the event; whether the release is contained as well as meteorlogical data such as wind speed, direction and the general weather conditions.

Those are relayed from the control room via our hot line system to the State of New York, Wayne and Monroe Counties, as well as the NRC through the NRC hotline.

CHAIRMAN MATHIS: One question. How is the mechanics of relating that kind of information - - who says what to whom?

MR. LANG: In our plant procedure we have three attachments as part of the procedure filled out by the operator and they have this type of data I spoke of and that status is relayed by one of the operators to those three people via our hotline.

CHAIRMAN MATHIS: He hands them a piece of paper for their communication?

MR. LANG: He tells them what the paper says. They have the same paper on the other end.

CHAIRMAN MATHIS: Okay.

MR. CATTON: When is this structure put into place during an incident?

MR. LANG: When is the structure - -

MR. CATTON: When do you put people into all the blocks?

MR. LANG: Okay.

MR. SNOW: I guess I could respond to that.

The emergency organization implementation commences at the station in the event we develop an unusual event, which would be the first one in our emergency procedures.

At that particular level of an emergency the shift supervisor is the emergency coordinator and based on his evaluation of the circumstances may or may not institute a total organization.

There is some unusual event classifications relatively minor. A fire that lasts longer than ten minutes we don't need to man the technical support center. In the event something of a greater magnitude, then the emergency organization will be implemented accordinly.

MR. CATTON: At 10:44 you had a slight emergency declared, was this structure in place at that time?

MR. SNOW: Yes. On the plant side.

MR. LANG: I'll cover that in my slide. How we did in our particular incident.

MR. CATTON: All right.

MR. LANG: Any other questions?

CHAIRMAN MATHIS: Go ahead.

MR. LANG: Here's a schematic or block diagram of our technical support center at the plant showing some of the key areas. And as part of your tour today I believe you're going to see the technical support center.

We have the plant assessment section where the maintenance personnel and operation personnel work together in assessing the accident.

The Dose Assessment area, area for the emergency coordinator was the overall manager of the incident. There's various other communications devices such as a telecopier, telephones, as well as conference rooms for conferences.

This diagram shows our emergency off-site facility which is in the main office of the RG & E Building downtown Rochester approximately 20 miles from the Ginna Station. This shows the Recovery Manager with his personnel, which are not really quite clear, but the Advisory Support, Facility Manager, Nuclear Support, are all in those proximity of the Recovery Manager.

Also we have areas for the State of New York Representatives, Wayne and Monroe Counties, DOE, NRC, FEMA and telephone and communication area manned by specific personnel for the hotline, radios, as well as special telephones.

Another particular area of interest is the press area, which is in the basement of the RG & E building. It's commonly in use but has specific areas set up for press conference rooms, information areas.

We have a rumor control section which is manned. And for the PIO's and the NIC, FEMA, Wayne and Monroe Counties as well as the State specific areas and communication devices for their purpose.

As far as the facilities and how they worked out, the control room, you're going to see later in the day. I think Mr. Morris told you how it functioned. We'll go over that.

The Technical Support Area, which you'll also see. We believe the layout was adequate. It was workable. It had the entire staff available for all its functions. The communications worked and were acceptable. Perhaps the only comment would be we might need a better way of documentation of everything that went on.

The EOF had approximately the same comment and some of the numbers of people downtown which were set up for the incident. We had 30 people in the EOF, including the Dose Assessment area. The security for the building and the various floors composed of 74 employees from 19 different departments for approximately 34 hours.

The Public Relations people had 64 people dealing with 164 different media people.

In the Engineering end, which is on another floor of the RG & E building, there were 25 people mobilized to assist the Plant through the Recovery Manager. Others included food, which had to be sent in for the plant personnel around the clock until the incident was in the recovery stage.

Diesel fuel, which is automatically shipped to the plant as soon as an incident is declared. And various other functions. But those were the most important ones.

Some of the communications which were set up to take care of any particular action or incident. Obviously there's the normal company telephone extensions which are available throughout the EOF throughout the RG & E Building as well as the technical support center and other areas of the plant.

We installed a Centrex telephone system, which is just a specific special system for any emergency, which has 60 direct lines to any outside telephone system at the main office.

The Ginna Station has what they call a "dimension 600 direct telephone line," which has three controls in the recovery center alone.

The Ginna Station has direct lines to the Dose Assessment area and to the Vice-President of Electrical and Steam Production Office.

The New York State Hotline ties Ginna Station Control Room, Ginna Station Technical Support Center, RG & E Main Office Recovery Center, RG & E Main Office Dose Assessment area, Wayne County, Lyons, New York, Wayne County Sheriff's Office Alternate Warning Point, Monroe County, Monroe County Fire Dispatcher Alternate Warning Point, Western District ODP, Batavia, New York, Lake District ODP, New York State Department of Health, New York State ODP Radiological and New York State Division of State Police Alternate Warning Point.

CHAIRMAN MATHIS: When that system is activated, do you automatically go onto all those outputs?

MR. LANG: It automatically rings them all. We have a protocol set-up for roll call and everyone is suppose to answer. There's a procedure that goes along if someone doesn't answer and who's supposed to call them back later if they don't answer at the roll call at the end, also. That also encompasses two different telephone companies; the Rochester system and the Bell system.

There's also an NRC Health Physics Network phone which ties Dose Assessment at the Plant and the Emergency Downtown Facility as well as the Dose Assessment area together.

There's the NRC Emergency Network System which ties the Recovery Center, the Control Room and the Survey Centers together.

We have radio communications which ties the Recovery Center, Dose Assessment, Control Room, TSC, Survey Centers and we're in radio contact with all the survey teams with all these various radio systems.

We have the plant computer and downtown computer tied together and that information is tied through with a terminal at the recovery center and the Dose Assessment as well as the Technical Support Center and the Control Room.

Also, we have many computer printers available throughout the entire RG & E system for information to be gathered from the plant through its computer and the downtown computer.

We also have a point-to-point back-up system for portable radios through the New York State Radio Frequencies. Where we can tie-in if nothing else works to notify the State of New York as well as the County.

I would like to now review the incident only in terms of the notifications that were made during the incident. Starting at 0928 when the incident occurred and almost immediate notification of the NRC through the hotline system in the control room. The Technical Support Center was started to be manned within five minutes. Notification was made to Vice-President of Electric and Steam Production almost once again at 0935, who is also the

Recovery Manager.

At 0947 notification was made to the State of New York, Wayne and Monroe Counties from the Control Room through the hotline.

At approximately 10:00 o'clock the Emergency Off-Site Facility began to be manned.

At 1125 it officially was manned - - was completely manned and took over its function from the Technical Support Center. Almost immediately at 11:30 the first press conference occurred.

Our basic conclusions: The TSC, EOF News Center Facilities worked well. We see no major changes in equipment or procedures that are necessary at this time.

There are some minor pieces of equipment which we'll probably purchase and other little minor procedures we'll obviously change for things that perhaps would work better just as the plant procedures.

But basically everything seemed to work very well. If there's any questions I'll be glad to answer them at this time.

MR. FRALEY: When did you first notice you were getting a steam bubble?

MR. LANG: I guess I'll turn that over to Art.

MR. MORRIS: The initial depressurization basically did that. Initial depressurization you can see on the trays that you basically drew one right then. Then the presumed growth of that void was the first time we saw any growth that caused pressurized level changes was when we depressurized the reactor coolant system to the faulted system generator pressure, and that's when the operator steam valve stayed open. It didn't close. That was the next time. That took place 30 minutes or so after the incident began.

MR. FRALEY: Was it because you noticed your pressurizer level acting up or was it because you noticed your thermo-couples performing unusually?

MR. MORRIS: Both. We were tracking upper head thermo-couple temperature right along. So saturation pressure for that temperature was known. As soon as we depressurized that pressure we felt - - and it was confirmed by the pressurizer level that indeed the upper head bubble was larger.

MR. SIESS: You were looking for a steam bubble?

MR. MORRIS: After we depressurized that far, yes.

MR. SIESS: You expected it?

MR. MORRIS: Yes.

MR. FRALEY: Again, your saturation meter told you you had a saturation condition but didn't tell you you had a steam bubble?

MR. MORRIS: It told us we were sub cool and indeed we were. The loops were sub cooled but the upper head had a steam void in it which did not interrupt circulation through the core at all.

CHAIRMAN MATHIS: Any other questions?

Before you leave, Mr. Lang, we had another series of questions here suggested. As a result of the TMI experience you have a different concept and different set-up on emergency facilities that apparently has worked well. And you feel that's adequate? You don't contemplate any additional changes of any magnitude?

MR. LANG: That's correct.

CHAIRMAN MATHIS: A question of the shift technical advisor always enters the scene; does anyone care to comment on that? I see Art's grinning over there.

MR. MORRIS: Relative to his usefulness or what?

CHAIRMAN MATHIS: I won't exactly put it that way. I'll make it a little easier on you. Did he make a contribution?

MR. MORRIS: Yes. Yes, indeed. Relative to his function in life, his defined function in life, he did that. And in addition he helped with the procedure area.

MR. LANG: His function was described correctly by Art. His degree had very little to do with it.

CHAIRMAN MATHIS: You have covered the additional plan instrumentation. And we already raised the question of the 60 parameter display system. Which we'll get into that later.

MR. FRALEY: In keeping NRC informed, the Emergency Center, do you do that or does the NRC Local Representative do that once he arrives? Is that your function or his?

MR.SNOW: You're talking about the hotline?

MR. FRALEY: Yes. To NRC.

MR. SNOW: I guess we work together on that. The shift has a shift communicator whose responsibility is for communication to the NRC and other outside agencies. We do do that and the phone was manned by one of our personnel periodically as well as our resident inspector periodically.

We work as a team depending on what types of information we were transferring between each other.

MR. FRALEY: Did you need to turn to the local NRC Representative - - what was his role, as an observer, primarily? Did you need to turn to him for decision-making?

MR. SNOW: Generally I would say in the control room he observed, commented and questioned and he was - - it was not an adversary type of relationship between the control room personnel and our NRC inspector.

Later on during the day as we were in our cool-down phase he became involved in our on-site review committee meetings where ideas were exchanged and suggestions were made, suggestions were asked for.

Again, I would say we worked together and it was not an adversarial relationship.

MR. SIESS: You said you had a shift communicator, was it?

MR. SNOW: Yes.

MR. SIESS: Was this one of the shift crew who had that responsibility in an incident?

MR. SNOW: Yes.

MR. SIESS: An extra man you don't need on the board?

MR. SNOW: Yes.

MR. SIESS: So you don't have to take somebody off the board to make telephone calls?

MR. SNOW: Exactly.

MR. FRALEY: Do you think the nuclear data link would have been helpful in keeping NRC informed?

MR. SNOW: My personal opinion is no.

MR. SIESS: Would it have relieved you of any communication needs?

MR. SNOW: My personal opinion is it would have generated more questions than we would have had time to answer.

MR. FRALEY: Did you need to get any decisions from NRC during the course of this accident or generally not?

MR. SNOW: Generally not. We were involved in discussions after the initial event interms of de-escalation of our emergency classification. I wouldn't say they were involved in the decision directly, but we did involve them in our discussion to reach our decision. There was no formal review or request for formal review from the

NRC response team.

MR. CATTON: Could we get a comment from somebody on NRC on how well things were handled?

MR. PETRONE: The Division Director is not here but he will be here tomorrow.

CHAIRMAN MATHIS: Thank you. Are there any other questions?

(No response)

CHAIRMAN MATHIS: It looks like we're running ahead of schedule. We can either adjourn for an hour or adjourn until 1:30. I don't wish to put you at any disadvantage. What is your pleasure?

MR. MECREDY: We'll be ready at the Ginna Station whenever you get there. We have concluded our presentation for this morning.

CHAIRMAN MATHIS: Let's reconvene at 1:15 for the tour. We'll reconvene in the lobby.

We're adjourned temporarily.

(Whereupon, at 12:15 o'clock, the hearing in the above-entitled matter adjourned)

NUCLEAR REGULATORY COMMISSION

This is to certify that the attached proceedings before the

Nuclear Regulatory Commission Advisory Committee on Reactor Safeguard

in the matter of:

Date of Proceeding: March 18th, 1982

Docket Number:

Place of Proceeding: Rochester, New York

were held as herein appears, and that this is the original transcript thereof for the file of the Commission.

RICHARD F. CONSOLA

Official Reporter (Typed)

Richard F. Consola

Official Reporter (Signature)

FROM: Peter R. Mitchell - Spokesperson, Roch. Safe Energy Alliance
121 Edgerton St.
Rochester, N. Y. 14607
442-2929

TO: ACRS

TOPIC: Testimony by Art Morris on the Ginna Accident and Operator Response.

Questions are being submitted to the Committee through agreement and consideration given by the Hearing Chairman and Mr. Ray Fraley, ACRS Executive Director.

1. Background. The question was asked as to whether the existance of a water level indicator would have led to the operators responding differently with the HPIS and the PORV. Mr. Morris indicated this would be just one more piece of information and it would be second guessing. Hindsight is very important and can lead to both improved equipment and responses. The Themis P. Spies preliminary evaluation indicated, among other things, that two discharges of radioactive steam to the atmosphere from the faulted (B) generator occured as a result of HPI initially being left on longer than necessary and then being restarted at 11.15 a. m.

Questions. Why was the initial use of HPI not terminated when the reactor repressurized to Westinghouse guideline standards?

Why was the HPI restarted at 11.15 a. m.?

In what manner did the 11.15 restart deviate from the Westinghouse guidelines?

Why wouldn't the existance of a water level indicator enable the operator to respond with greater precision in the use of HPI?

2. Background. The question was asked Mr. Morris as to whether the problem of reactor vessel thermal shock was considered during use of HPI. His answer was no. According to the Themis P. Spies preliminary report, the industry has indicated to the ACRS that operators would always terminate HPI before the primary system was unacceptably repressurized.

Questions. What repressurization perimeters did the Ginna operators use?

Has Westinghouse established guidelines regarding the thermal shock issue (both pressure and temperature)?

Did any of the reactor vessel cool at a rate in excess of that stipulated in the plant technical specifications.

If Westinghouse has not established guidelines regarding the thermal shock issue, are guidelines being contemplated, and,,if so, when will they be incorporated into the Ginna operating procedures?

3. Are there any contemplated changes in the design and operation of the PORV (due to the frequency with which they stick open)?

4. Were the emergency procedures in place at Ginna consistent with current Westinghouse Emergency Operator Guidelines for Steam Generator Tube rupture? If not, how were they different?

Are any changes contemplated by Westinghouse in their Guidelines and, if so, why?

Did the guidelines for response to a steam generator tube rupture contain instructions for actions to be taken ~~xxxxxxxxxx~~ when a steam bubble develops in the reactor vessel?

As a result of their experience with this accident, would the Ginna operators recom end any changes in the Westinghouse guidelines?

5. Is there any safety signifinance associated with stratification of the secondary coolant in the faulted (B) steam generator? Are any changes being recommended? If so, when will they be incorporated?

6. <u>Background</u>. The ACRS expressed a strong interest in learning more about reactor system interactions under accident conditions. The question was asked whether the Ginna operators had learned anything that would be helpful to others as far as procedures (both operator directions and technical based). Mr. Morris answered that little was learned from procedural directions on how to handle the accident, but technical based knowledge was gained and some changes have already been incorporated. He indicated this information has been provided the procedure subcommittee.

<u>Question</u>. What are the changes and/or suggested changes? How do I get a copy of this material?

7. <u>Background</u>. Mr. Morris indicated there were a number of instruments specific to the control room (besides a trustworthy water indicator guage) that would be helpful in dealing with future accidents. Since I was unable to accompany the ACRS on the tour, what instrumentation or modification of existing instruments would be helpful?

Questions for the ACRS.

In considering other coolant system failures and response scenarios, Theis P. Spies in his Preliminary Evaluation discusses two potential failures-- 1. tube leaks occuring in both steam generators simultaneously, and, 2. stuck open secondary side safety/ relief valve.

In failure 1., the Westinghouse guideline recommends using the steam generator experiencing the smallest leak to cool the reactor. Is it possible to prevent releases of radiation to the atmosphere using this procedure? Is a feed and bleed a more desirable approach? Will the guidelines be changed to incorporate a feed and bleed approach?

Since a failure of the sss/rv can lead to core uncovering unless a) the valve is closed or b) additional cooling water supplies were made available, what steps are being taken to protect against this type of mode failure?

What caused the drop of the A generator pressure (less than 150 psi) with corresponding loss-of-condenser vacuum? What significance did this condition have in the accident sequence? Is any remedial action recommended?

DISSEMINATION OF INFORMATION TO INDUSTRY AND GENERAL PUBLIC

1. RGE

   A. NOTEPAD - CHRONOLOGY

   B. WESTINGHOUSE OWNERS GROUP PRESENTATIONS

   C. REPORT TO NRC

2. NRC INQUIRY TEAM

3. INPO

4. WESTINGHOUSE REVIEW

5. EDISON ELECTRIC INSTITUTE (EEI)
   NUCLEAR OPERATION COMMITTEE

6. AIF +ANS PRESENTATION

RADIOLOGICAL ASSESSMENT

1. ORGANIZATION

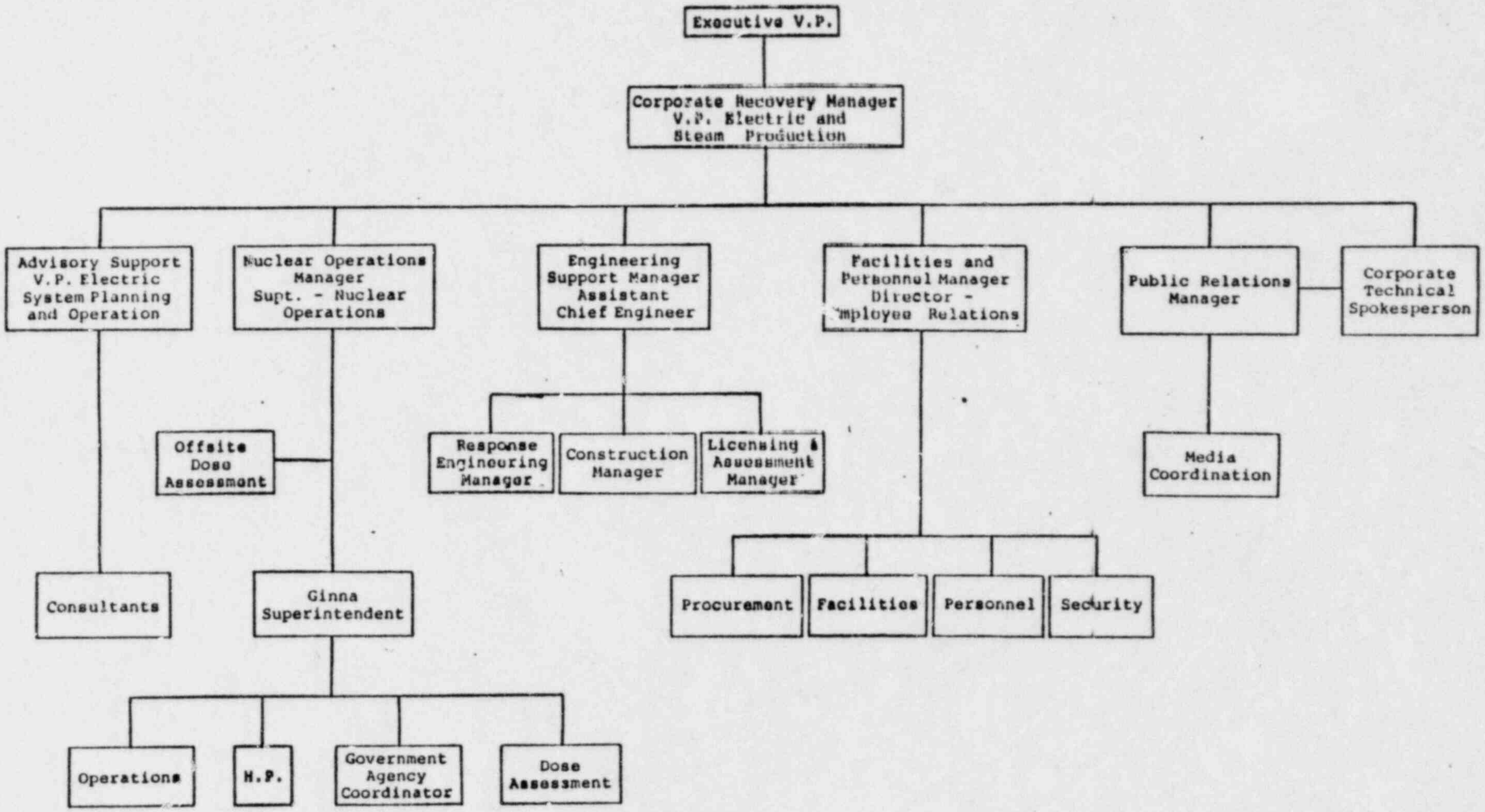
2. RELEASE ESTIMATES

3. SURVEY TEAMS

4. ENVIRONMENTAL MEASUREMENTS

5. DOSE ESTIMATES

RG&E
NUCLEAR EMERGENCY
OFFSITE RESPONSE PROCEDURE
4.0 STRUCTURE OF RECOVERY ORGANIZATION



GINNA EMERGENCY OFFSITE RESPONSE ORGANIZATION

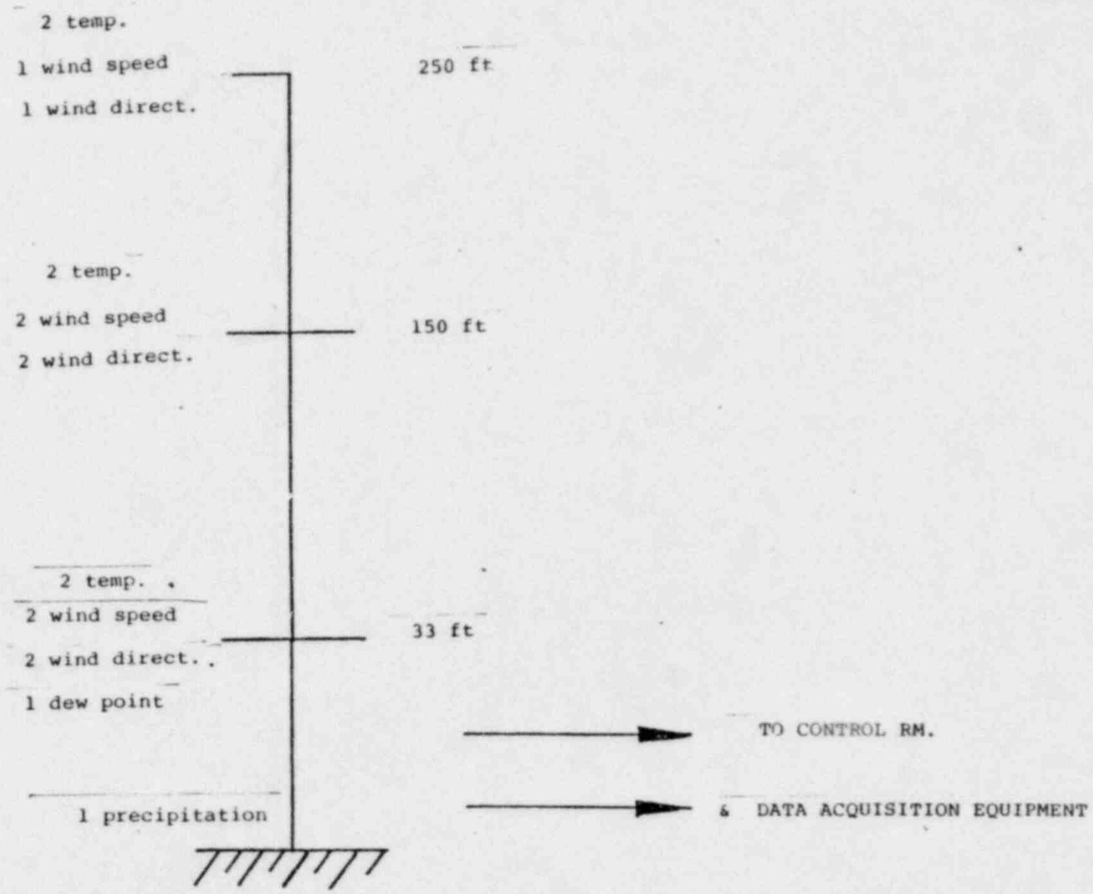
ESTIMATED NOBLE GAS RELEASES

	CURIES
AIR EJECTOR AND GLAND SEAL OFF-GAS	26
TURBINE DRIVEN AUXILIARY FEEDWATER PUMP EXHAUST	0.03
"B" STEAMLINE SAFETY VALVE LIFTINGS	4-16
TOTAL NOBLE GAS	30-42

ESTIMATES OF RADIOIODINE, PARTICULATES AND TRITIUM RELEASED FROM SAFETY VALVE LIFTS

	CURIES
TOTAL IODINE - 131 EQUIVALENT	0.16 - .63
TOTAL PARTICULATES	0.3 - 1.3
TRITIUM	5.9 - 24

GINNA PRIMARY WEATHER TOWER

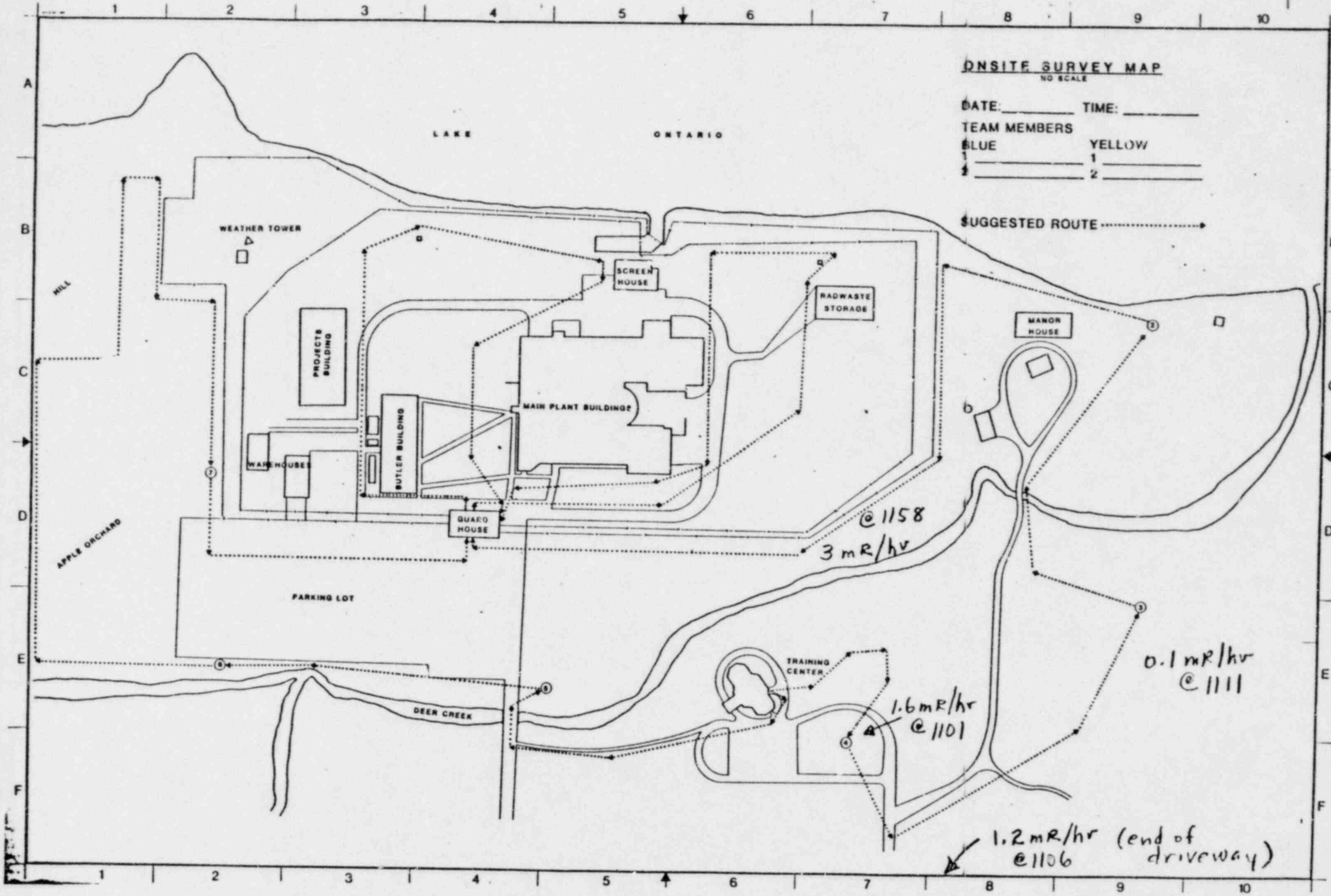


PRIMARY TOWER

EMERGENCY SURVEY TEAMS

2	ONSITE
3	OFFSITE
1	SPARE
2	OFFSITE (EOF)

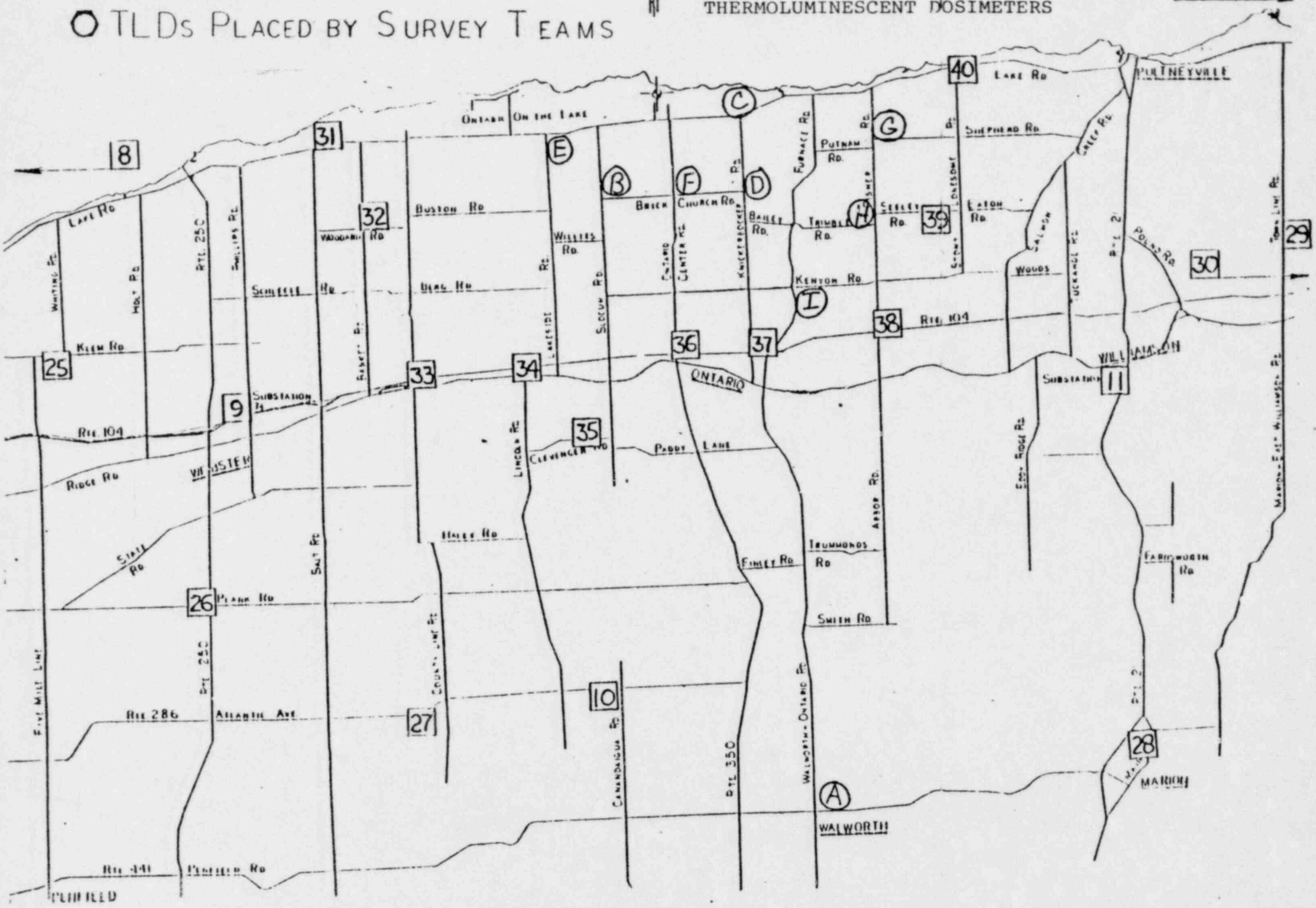
- GINNA TEAMS MANNED BY 1030, 1/25/82
- 7 COORDINATED ONSITE AND OFFSITE SURVEY CAMPAIGNS, 1/25/82 - 1/27/82


ONSITE SURVEY MAP
NO SCALE
DATE: TIME:
TEAM MEMBERS
BLUE
YELLOW
SUGGESTED ROUTE
LAKE ONTARIO
WEATHER TOWER
HILL
PROJECTS BUILDING
WAREHOUSES
BUTLER BUILDING
MAIN PLANT BUILDINGS
SCREEN HOUSE
RADWASTE STORAGE
MANOR HOUSE
GUARD HOUSE
PARKING LOT
APPLE ORCHARD
DEER CREEK
TRAINING CENTER
@1158
3 mR/hr
0.1 mR/hr
@1111
1.6mR/hr
@1101
1.2mR/hr (end of driveway)
@1106

LOCATIONS OF RG&E OFFSITE THERMOLUMINESCENT DOSIMETERS

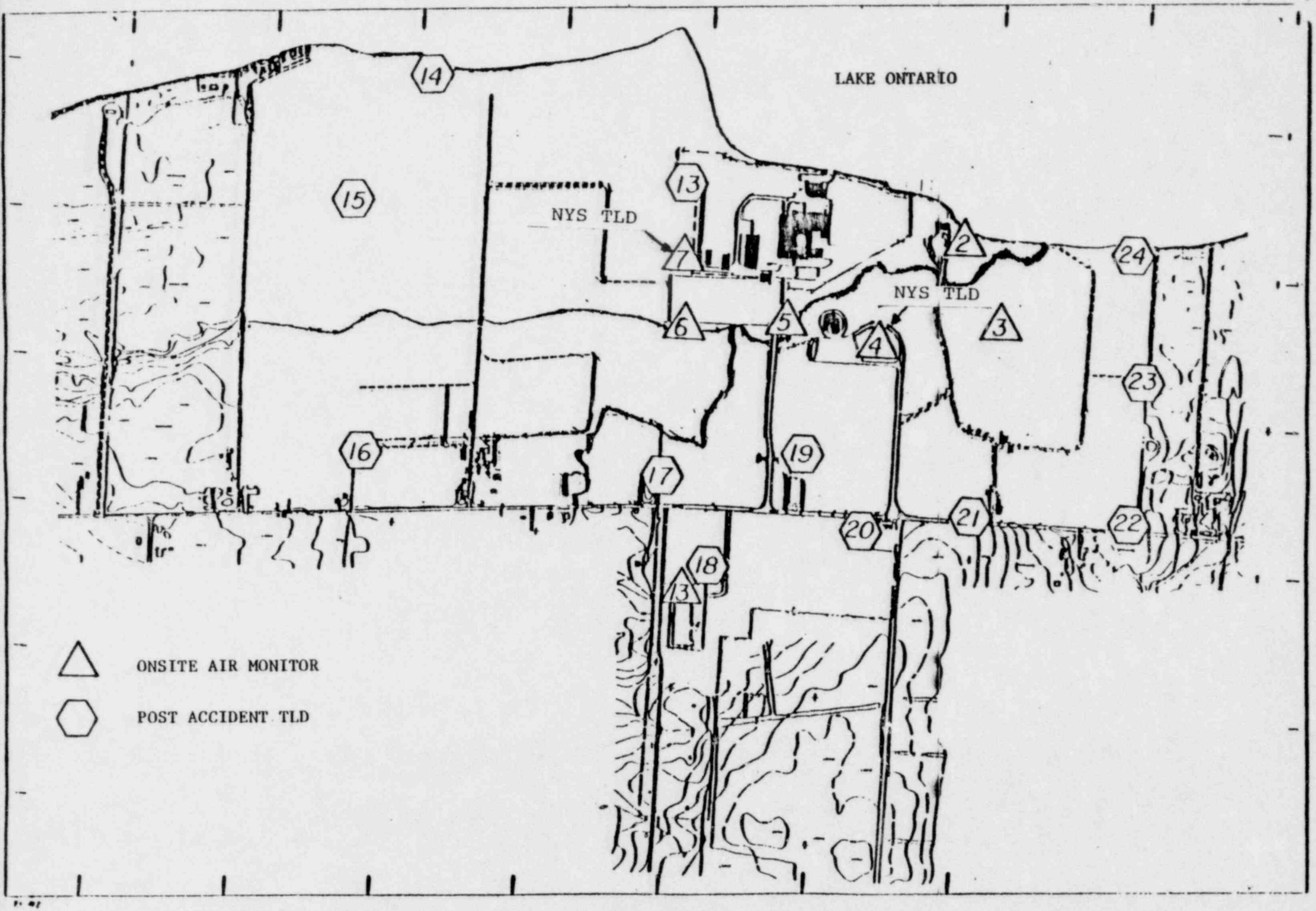
□ TLDs PERMANENTLY PLACED

○ TLDs PLACED BY SURVEY TEAMS



LOCATIONS OF RG&E ONSITE THERMOLUMINESCENT DOSIMETERS

INCLUDING LOCATIONS OF NEW YORK STATE TLDs



AIR SAMPLING

ONSITE:

AIR MONITOR #4 (1125-1510)	I-131	3.4×10^{-10}	$\mu Ci/cm^3$
	I-133	3.8×10^{-9}	

OFFSITE:

1 MILE ESE (1105-1115)	I-133	9.5×10^{-11}	$\mu Ci/cm^3$
3 MILES ESE (1233-1243)	I-133	9.3×10^{-11}	

SNOW SAMPLING

- ~ 100 SAMPLES ONSITE AND OFFSITE

- DETECTABLE CONCENTRATIONS

	μCi/gram
RADIOIODINES AND PARTICULATES	10^{-2} - 10^{-8}
TRITIUM	10^{-1} - 10^{-5}

WATER SAMPLING

ONTARIO WATER DISTRICT (1.1 MILE EAST)	-	NO ACTIVITY DETECTED

COMPOSITE SAMPLING 3 TIMES/WK

SUMMARY OF UPPER BOUND
OFFSITE DOSE ESTIMATES FROM
GINNA STEAM GENERATOR
TUBE RUPTURE EVENT 1/25/82

DOSE PATHWAY	MAXIMUM ESTIMATED OFFSITE DOSE (mrem)	
PLUME		
INHALATION	8	(thyroid)
	0.5	(whole body)
DIRECT EXPOSURE FROM NOBLE GAS PLUME	0.3	(whole body)
	0.2	(skin beta)
INGESTION		
DRINKING WATER	0.25	(whole body)
FISH	8	(whole body)

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

March 17, 1982

Docket No. 50-244
LS05-82-03-078

Mr. John E. Maier
Vice President
Electric and Steam Production
Rochester Gas & Electric Corp.
89 East Avenue
Rochester, New York 14649

Dear Mr. Maier:

SUBJECT: INTEGRATED ASSESSMENT MEETING AT NRC (BETHESDA)

Our letter dated March 9, 1982, subject "Integrated Assessment Meeting at Ginna," scheduled a meeting in Bethesda, Maryland, for April 2, 1982. The purpose of this meeting is to review your proposals on the identified differences. Enclosed is an updated listing of all topics with identified differences from licensing criteria (Enclosure 1) and a brief summary of the actual identified differences (Enclosure 2). This list was discussed and updated with your staff during the March 10 - 12, 1982, meeting in Rochester, New York.

Sincerely,

Dennis M. Crutchfield

Dennis M. Crutchfield, Chief
Operating Reactors Branch No. 5
Division of Licensing

Enclosures:
As stated

cc w/enclosures:
See next page

Ginna
Docket No. 50-244
Rev. 2/8/82

Mr. John E. Maier

cc
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Director, Bureau of Nuclear
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State of New York Energy Office
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Empire State Plaza
Albany, New York 12223

Rochester Public Library
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Rochester, New York 14604

Supervisor of the Town
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GINNA

TOPICS WHICH DO NOT MEET CURRENT CRITERIA OR EQUIVALENT

TOPIC NO.	TITLE
II-1.A	Exclusion Area Authority and Control
II-2.A	Severe Weather Phenomena
II-3.B	Flooding Potential and Protection Requirements
II-3.B.1	Capability of Operating Plant to Cope With Design Basis Flooding Conditions
II-3.C	Safety-related Water Supply [Ultimate Heat Sink (UHS)]
II-4.D	Stability of Slopes
III-1	Classification of Structures, Systems and Components
III-2	Wind and Tornado Loadings
III-3.A	Effects of High Water Level on Structures
III-3.C	Inservice Inspection of Water Control Structures
III-4.A	Tornado Missiles
III-4.C	Internally Generated Missiles
III-5.A	Effects of Pipe Break on Structures, Systems and Components Inside Containment
III-5.B	Pipe Break Outside Containment
III-6	Seismic Design Considerations
III-7.A	Inservice Inspection, Including Prestressed Concrete Containment with Either Grouted or Ungrouted Tendons
III-7.B	Design Codes, Design Criteria, and Loading Combinations
III-8.A	Loose Parts Monitoring and Core Barrel Vibration Program
V-5	Reactor Coolant Pressure Boundary (RCPB) Leakage, Detection
V-10.A	RHR Heat Exchanger Tube Failures

TOPIC NO.	TITLE
V-10.B	RHR Reliability
VI-4 (Systems) (Electrical)	Containment Isolation
VI-7.B	ESF Switchover from Injection to Recirculation Mode
VIII-3.B	DC Power System Bus Voltage Monitoring and Annunciation
IX-3	Station Service and Cooling Water Systems
IX-5	Ventilation Systems
IX-6	Fire Protection

GINNA

TOPIC NO.	TITLE
II-1.A	Exclusion Area Authority and Control

Difference Summary

The Exclusion Area Boundary (EAB) has been changed, as submitted by RG&E letter dated June 26, 1981. This change is potentially significant enough to warrant a change to the Ginna Technical Specifications to incorporate the new exclusion area boundary map.

TOPIC NO.	TITLE
II-2.A	Severe Weather Phenomena

Difference Summary

10 CFR 50 (GDC 2), requires that the plant be designed to withstand the effects of natural phenomena. The combined snow load for structural capability assessment at Ginna is 100 lb/ft^2. Various safety related buildings were not constructed to withstand such a load.

TOPIC NO.	TITLE
II-3.B	Flooding Potential and Protection Requirements

Difference Summary

10 CFR 50 (GDC 2), as implemented by Standard Review Plan (SRP) 2.4.10 and Regulatory Guide (RG) 1.59 prescribes that the plant have adequate flood protection. The water levels produced by a Probable Maximum Flood (PMF) on Deer Creek would cause water to pond 8' above grade on the north side.

TOPIC NO.	TITLE
II-3.B.1	Capability of Operating Plants to Cope With Design Basis Flooding Conditions

Difference Summary

10 CFR 50 (GDC 2), as implemented by SRP 2.4.10 prescribes that the plant have adequate flood protection. The plant has no existing plans or technical specifications (TS) that relate to flooding from external sources.

TOPIC NO. TITLE

II-3.C Safety-Related Water Supply [Ultimate Heat Sink (UHS)]

Difference Summary

10 CFR 50 (GDC 2), as implemented by SRP 2.4.10 prescribes that the plant have adequate flood protection. An occurence of the Probable Maximum Flood on Deer Creek would inundate both the service water and circulating water pumps.

TOPIC NO. TITLE

II-4.D Stability of Slopes

Difference Summary

10 CFR 50 (GDC 2), as implemented by SRP 2.5.5 prescribes that the plant be adequately protected against failure of natural or man-made slopes. The failure of the onsite slopes would affect safety-related structures.

TOPIC NO. TITLE

III-1 Quality Group Classification of Structures, Systems and Components

Difference Summary

10 CFR 50 (GDC 1), as implemented by Regulatory Guide 1.26, requires that structures, systems and components important to safety be designed, fabricated, erected and tested to quality standards commensurate with the importance of the safety functions to be performed.

The following are deviations from current requirements:

) Category C joints of vessels which would currently be classified by ASME Section III, 1977 as Class 2 or 3 but built to ASME Section III, 1965 as Class C do not satisfy current radiography requirements

) The regenerative heat exchanger and the excess letdown heat exchanger do not satisfy current radiography requirements because they are Class A vessels built to Class C requirements.

TOPIC NO. TITLE

III-2 Wind and Tornado Loading

Difference Summary

10 CFR 50 (GDC 2), as implemented by Standard Review Plan Sections 3.3.1 and 3.3.2 and Regulatory Guide 1.76 and 1.117 requires that the plant be designed to withstand the effects of natural phenomena. The existing design and construction of structures important to safety for wind and tornado loadings does not meet current licensing criteria of remaining within Standard Review Plan stress limits.

TOPIC NO. TITLE

III-3.A Effects of High Water on Structures.

Difference Summary

10 CFR 50 (GDC 2), as implemented by SRP 2.4.12 prescribes that the plant be designed for groundwater problems. Groundwater induced loads have not been considered for a groundwater elevation higher than elevation 250 ft. msl. It is not clear what groundwater elevation was used in the design of the diesel generator building. Also, seismic Category I structures, systems and equipment were not designed for flood due to Deer Creek.

TOPIC NO. TITLE

III-3.C Inservice Inspection of Water Control Structures

Difference Summary

10 CFR 50 (GDC 45), as implemented by Regulatory Guide 1.127 requires that the cooling water system shall be designed to permit appropriate periodic inspection of important components to ensure the integrity and capability of the system. The following are necessary for compliance with the intent of Regulatory Guide 1.127:

1) The inspection program now underway at Ginna should be formalized so that standard report forms are submitted by competent and qualified inspectors to be reviewed by qualified engineers.

2) The licensee should develop a checklist for discharge canal inspections, including their frequency.

3) The Deer Creek basin should be formally recognized as a water control structure and inspected accordingly on an annual basis and following severe rains which cause flooding.

   (a) The Inservice Inspection Program for Deer Creek should be supplemented by adding: clogging of culverts by debris, slump conditions, soil creep, and bed load movement.

   (b) The wooded area downstream of the Visitors Center should be cleaned out to initially establish adequate water conveyance during floods and a baseline for future inspection and maintenance.

4) The Licensee should compile a comprehensive file of engineering drawings for safety-related water control structures to establish immediate post-construction conditions.

5) The routine inspection frequency is acceptable, but special inspections also must be performed after extreme events such as floods and seiches which may jeopardize the integrity of water control structures. The formal inspection program to be initiated at the R. E. Ginna Plant should incorporate such special inspections.

6) The Licensee should develop a formal inspection program for water control structures that will result in the development of a comprehensive file of appropriate inspection reports.

7) The Licensee's monitoring program to be developed for the revetment must be approved by the NRC.

TOPIC NO.	TITLE
III-4.A	Tornado Missiles

Difference Summary

10 CFR 50 (GDC 2), as implemented by Regulatory Guide 1.117 prescribes structures, systems and components that should be designed to withstand the effects of a tornado, including tornado missiles, without loss of capability to perform their safety function.

The following safety-related structures, systems and components were found to not be protected from tornado missiles:

1) Component Cooling System

2) Refueling Water Storage Tank

3) Electrical Busses 14, 17 and 18

4) Service Water System

5) Diesel Generators and their Fuel Supply

6) Relay Room

7) Main Steam and Feedwater piping between isolation valves and the containment penetrations..

8) The Top Surface of the Spent Fuel Pool is open and, therefore, the internals are exposed

9) Boric Acid Tanks

TOPIC NO.	TITLE
III-4.C	Internally Generated Missiles

Difference Summary

10 CFR 50 (GDC 4), as implemented by SRP Section 3.5.1.1 and 3.5.1.2 prescribes that structures, systems and components important to safety be designed to withstand the effects of internally generated missiles inside or outside of containment.

The following are deviations or open items that have been identified:

1) An evaluation of the piping and components associated with the ECCS accumulators with respect to missile generation and protection has not been completed.

2) An evaluation of the effects of missile generation along the CVCS let-down line inside containment has not been completed.

3) An evaluation of the potential effects of an unrestrained valve operator associated with the steam generator blowdown system on safety related components and systems has not been completed.

4) The refueling water storage tank is inadequately protected from missiles.

TOPIC NO. TITLE

III-5.A Effects of Pipe Break on Structures, Systems and Components Inside Containment

Difference Summary

10 CFR 50 (GDC 4), as implemented by SRP 3.6.2 prescribes that structures, systems and components important to safety be designed against the dynamic and environmental effects of postulated pipe ruptures.

The following are deviations from review guidelines that have been identified:

1) The first open item was concerned with the general assumptions of this topic assessment was that a check valve in an incoming line would prevent primary system blowdown in the event of a pipe break upstream of the valve. This is true provided the check valve closes. Adequate assurance must be demonstrated that these normally open check valves will fulfill their assumed isolation function.

2) For the "A" accumulator line a mechanistic evaluation was performed. The stresses in this line were all below the criteria, so breaks were postulated at terminal ends and at the loop compartment where no adverse interactions would occur.

   The second point is located just on the reactor side of the (normally locked open) motor-operated valve. At this location no adverse pipe whip interactions will occur. If remedial measures to provide this protection can be shown to be impractical, fracture mechanics evaluations can be performed to establish that conditions that could lead to a double-ended rupture do not exist as discussed in the guidance provided in the Attachment to Enclosure 3. The effect of a break in the two inch accumulator level taps on nearby instrument circuits is still under review by the licensee.

3) For the pressurizer surge line, since some jets could affect safety-related equipment, analyses similar to those described in item 2 above should be provided.

4) For the letdown line, licensee evaluation of the effects on cables and cable trays is continuing. Adequate protection for instrumentation should be provided.

5) The situation for the steam generator blowdown lines is similar to item 7 for the instrumentation. With respect to the fan coolers, this size break is not limiting with respect to containment pressure/temperature reduction capability. The containment spray system would be available for containment cooling. As for item 4 above, final resolution will occur after the effects on the cable trays are evaluated.

6) Pipe breaks were not postulated in the primary loop on the basis of the work done under TAP A-2. We concur with this approach. However, the SEP branch intends to evaluate the effects on safety-related equipment of jet loads resulting from the crack sizes associated with these analyses.

TOPIC NO.	TITLE
III-5.B	Pipe Break Outside Containment

Difference Summary

10 CFR 50 (GDC 4), as implemented by SRP 3.6.1, 3.6.2, BTP MEB 3-1 and BTP ASB 3-1, requires in part that structures, systems and components important to safety be designed to accommodate the dynamic effects of postulated pipe ruptures.

The following are deviations from review guidelines that have been identified:

1) Because high and moderate energy line breaks in the screen house could damage the power supplies to all service water pumps, the licensee must provide protection for these power supplies in accordance with Standard Review Plan 3.6.1 consistent with the service water system modifications which must be performed in connection with other ongoing SEP reviews and the fire-protection review.

TOPIC NO.	TITLE
III-6	Seismic Design Consideration

Difference Summary

The requirements of 10 CFR 50 (GDC 2) and 10 CFR 100, Appendix A as implemented by Regulatory Guides 1.26, 1.29, 1.60, 1.61, 1.92, 1.122 and SRP 2.5, 3.7, 3.8, 3.9, 3.10 prescribe structures, systems and components that should be designed to withstand the effects of a postulated earthquake without loss of capacity to perform their safety function.

The evaluation results are summarized below:

1) The structures were found capable of withstanding the postulated seismic event except two sets of steel bracings located in auxiliary and turbine building for which modifications are required.

2) ESW Pump Operability is an open item.

3) RWS Tank and other safety related tanks are open items.

4) Control room electrical panel structural integrity is an open item.

5) The functional integrity of electrical equipment is being evaluated by testing through SEP Owners Group program.

6) Qualification of electrical cable trays is being evaluated by testing through SEP Owners Group program.

TOPIC NO.	TITLE
III-7.A	Inservice Inspection, Including Prestressed Concrete Containments with Either Grouted or Ungrouted Tendons

Difference Summary

Regulatory Guide 1.35, Revision 2 as interpreted in the Standard Technical Specifications requires that the licensee have an inspection program that will detect any structurally significant deterioration of Category I structures in order that the structures will be capable of performing their necessary functions. The following are deviations between the tendon surveillance program at Ginna based on current Technical Specifications and Regulatory Guide 1.35, Revision 2:

1) The acceptable lift-off requirement does not meet current criteria because the existing Technical Specification at Ginna require that the average of the 14 tendon stresses be greater than a value constant with time. Current criteria requires that each tendon fall within acceptance limits that vary with time.

2) Tendons which are found to be unacceptable are not handled as required in Section 7 of Regulatory Guide 1.35, Revision 2.

3) Regulatory Guide 1.35, Revision 2 requires inspections and mechanical tests be performed on one unstressed wire per tendon per inspection.

4) Ginna should include in its ~~inspection report~~ wire breakage and filler grease.

TOPIC NO.	TITLE
III-7.B	Design Codes, Design Criteria and Loading Combinations

Difference Summary

10 CFR 50 (GDC 1, 2 and 4), as interpreted by Standard Review Plan 3.8, required the plant to be designed and contructed to various design codes, criteria, loads and load combinations. The following are areas where differences exist between the plant design and current licensing criteria.

1) Code changes have been identified in the following structural elements: (See table next page from SEP Topic III-7.B issued 12/30/81.)

2) Load and Load Combinations

3) A thermal discontinuity exists in the liner plate at the point where the insulation stops. This will cause high thermal stresses in the liner during postulated LOCA temperatures and could result in the liner buckling and failing.

TOPIC NO.	TITLE
III-8.A	Loose Parts Monitoring and Core Barrel Vibration Program

Difference Summary

The requirements of 10 CFR 50 (GDC 13), as implemented by Regulatory Guide 1.133, Revision 1, and SRP Section 4.4 prescribe a loose parts monitoring program for the primary system of light-water-cooled reactors. Ginna does not have a loose parts monitoring program that meets the criteria of Regulatory Guide 1.133.

Structural Elements to be Examined	Code Change Affecting These Elements: New Code	Old Code
Members Designed to Operate in an Inelastic Regime	AISC 1980	AISC 1963
Spacing of lateral bracing	2.9	2.8
Short Brackets and Corbels having a shear span-to-depth ratio of unity or less	ACI 349-76 11.13	ACI 318-63 —
Shear Walls used as a primary load-carrying member	ACI 349-76 11.16	ACI 318-63 —
Precast Concrete Structural Elements, where shear is not a member of diagonal tension	ACI 349-76 11.15	ACI 318-63 —
Concrete Regions Subject to High Temperatures	ACI 349-76	ACI 318-63
Time-dependent and position-dependent temperature variations	Appendix A	—
Columns with Spliced Reinforcement subject to stress reversals; f_y in compression to 1/2 f_y in tension	ACI 349-76 7.10.3	ACI 318-63 805
Steel Embedments used to transmit load to concrete	ACI 349-76 Appendix B	ACI 318-63 —
Containment and Other Elements, transmitting In-plane shear	B&PV Code Section III, Div. 2, 1980 CC-3421.5	ACI 318-63 —
Region of shell carrying concentrated forces normal to the shell surface (see case study 13 for details)	B&PV Code, Section III, Div. 2, 1980 CC-3421.6	ACI 318-63 1707

Structural Elements to be Examined	Code Change Affecting These Elements New Code	Old Code
Beams	AISC 1980	AISC 1963
a. Composite Beams		
1. Shear connectors in composite beams	1.11.4	1.11.4
2. Composite beams or girders with formed steel deck	1.11.5	--*
b. Hybrid Girders		
Stress in flange	1.10.6	1.10.6
Compression Elements	AISC 1980	AISC 1963
With width-to-thickness ratio higher than specified in 1.9.1.2	1.9.1.2 and Appendix C	1.9.1
Tension Members	AISC 1980	AISC 1963
When load is transmitted by bolts or rivets	1.14.2.2	--
Connections	AISC 1980	AISC 1963
a. Beam ends with top flange coped, if subject to shear	1.5.1.2.2	--
b. Connections carrying moment or restrained member connection	1.15.5.2 1.15.5.3 1.15.5.4	--

*Double dash (--) indicates that no provisions were provided in the older code.

TOPIC NO. TITLE

V-5 Reactor Coolant Pressure Boundary Leakage Detection

Review Criteria

10 CFR 50 (GDC 2 and 30), as implemented by SRP 5.2.5 and Regulatory Guide 1.45 requires the measurement of leakage from the reactor coolant pressure boundary (RCPB) to the containment and interfacing systems and states design criteria for the systems employed for such.

For systems employed for measurement of leakage from the RCPB to the containment, Regulatory Guide 1.45 states that: 1) system should be an airborne particulate radioactivity monitor that is SSE qualified, 2) a minimum of two others should be present which are OBE qualified, and 3) all systems should have a sensitivity to detect leakage of 1 gpm within 1 hour. Those employed for measurement of intersystem leakage should include sensors for things such as radioactivity, flow, level, pressure, temperature, etc. and be OBE qualified. All the above systems should 1) have alarms and indicators in the main control room, 2) be readily testable and calibrated during normal operation, and have their availability in the technical specifications.

Difference Summary

The following summarizes the deviations from review guidelines that have been identified:

1) Although all of the recommended types of leakage detection systems for measurement of leakage from the reactor coolant pressure boundary to the containment have been incorporated in the facility, the systems do not meet all of the sensitivity, operability or surveillance criteria.

2) Information concerning the leakage detection systems for the detection of inter-system reactor coolant pressure boundary leakage is incomplete. Therefore, we cannot determine the extent to which Regulatory Guide 1.45 is met.

3) Standard Technical Specification 3.4.4.6 and the corresponding surveillance requirements concerning the operability of the reactor coolant pressure boundary to the containment leakage detection systems should be added to the R. E. Ginna Technical Specifications. Also, the current basis for Ginna Technical Specification 3.1.5.3 and FSAR should be revised to state that the sensitivities of the reactor coolant pressure boundary to containment leakage detection systems.

4) Information concerning the use of the primary coolant system inventory balance leak rate sensitivity and time required to achieve sensitivity is incomplete. Therefore, we cannot determine the contribution of this technique to the overall leak detection sensitivity.

TOPIC NO. TITLE

V-10.A RHR Heat Exchanger Tube Failures

Difference Summary

SRP 9.2.1 requires that the service water system include the capability for detection and control of radioactive leakage into and out of the system and prevent accidental releases to the environment. The Service Water System does not have a radiation detector.

TOPIC NO. TITLE

V-10 B RHR Reliability

Difference Summary

10 CFR 50 (GDC 19 and 34), as implemented by SRP 5.4.7, BTP RSB 5-1 and Regulatory Guide 1.139, require that the plant can be taken from normal operating conditions to cold shutdown using only safety-grade systems, assuming a single failure and utilizing either onsite or offsite power through the use of suitable procedures. The Ginna plant has safety-grade plant systems capable of safe shutdown under these conditions; however, the plant operating procedures rely upon other non-safety grade systems and do not specify how the cooldown would be accomplished by the operator in the event of failures in non-safety grade systems. Also, while we nave concluded that the OPS and RHR relief valves provide sufficient RHR system overpressure protection, however, the present technical specifications would allow operation of the RHR without enabling the OPS.

TOPIC NO. TITLE

VI-4 Containment Isolation Systems

Difference Summary

1) The isolation valving arrangements do not meet the requirements of 10 CFR 50 (GDC 55 or 56), as implemented by SRP 6.2.4 from the standpoint of valve location for penetrations 112, 120b, 121c, 121d, 123, 124b, 129, 140, 202, 203a, 203b, 205, 206a, 207a, 210, 304, 305a, 305c, and 332a.

2) The isolation valving arrangements do not meet the requirements of 10 CFR 50 (GDC 55 or 56), as implemented by SRP 6.2.4 from the standpoint of valve number for penetrations 100, 102, 105, 106, 108, 109, 110a, and 110b.

3) The isolation valving arrangements differ from the explicit requirements of 10 CFR 50 (GDC 55, 56 and 57), as implemented by SRP 6.2.4 from the standpoint of valve type by using a check valve outside containment for penetrations 105, 109, 121a, and 129.

For penetrations 121a and 129 the nitrogen pressure regulating valve is not an adequate isolation valve.

4) The isolation provided does not meet the requirements of 10 CFR 50 (GDC 55, 56 and 57), as implemented by SRP 6.2.4 from the standpoint of valve actuation for penetrations 112, 120b, 121c, 121d, 123, 201, 203, 205, 206a, 207a, 209, 305a, 308, 311, 312, 315, 316, 318, 320, 323, and 332a.

5) 10 CFR 50 (GDC 57), as implemented by SRP 6.2.4 was used to judge the acceptability of the isolation provisions for lines 301 and 303 (auxiliary steam heating to containment) since a closed system was identified inside containment. The licensee should verify that this portion of the system is of safety grade design to assure that the use of GDC 57 is appropriate.

6) The ESF reset pushbuttons are inadequately protected from accidental actuation.

TOPIC NO. TITLE

VI-7.B ESF Switchover From Injection to Recirculation Mode

Difference Summary

1) Item 19 of SRP Section 6.3 states that the complete sequence of ECCS operation from injection to long term core cooling (recirculation) should be examined to see that a minimum of manual action is required and that where manual action is needed a sufficient time (greater than 20 minutes is available for the operator to respond. The current Ginna procedures for switchover from injection to recirculation do not meet current NRC criteria for operator actions.

2) Branch Technical Positions ISCB 20 has not been satisfied because of the short time (11 minutes) that is available for the operator to detect and correct a failure to follow procedures and his reliance on a single alarm to alert him to such an error.

TOPIC NO. TITLE

VIII-3.B DC Power System Bus Voltage Monitoring and Annunciation

Difference Summary

10 CFR 50.55a (h) as implemented by SRP 8.3.2 and Regulatory Guide 1.47 requires that the dc power system be monitored to the extent that it is shown ready to perform its intended function. The Ginna control room has no indication of battery current, charger output current, charger output voltage, battery high discharge rate, bus under/over voltage, or battery or charger breaker/fuse status.

TOPIC NO. TITLE

IX-3 Station Service and Cooling Water Systems

Difference Summary

10 CFR 50 (GDC 44), as implemented by SRP 9.2.1 and SRP 9.2.2 requires a system to transfer heat from structures, systems and componets important to safety to an ultimate heat sink. The technical specifications allow the plant to be operated with only two out of four service pumps which, since two pumps are needed to handle post-accident heat loads, renders the system vulnerable to a single failure. There is no redundant level indication for the CCW Surge Tank. The failure of various non-seismic tanks could cause flooding of various safety related equipment in the auxiliary building.

TOPIC NO. TITLE

IX-5 Ventilation Systems

Difference Summary

10 CFR 50 (GDC 60), as implemented by Standard Review Plan 9.4.5 requires that the plant include a means to suitably control the release of radioactive materials in gaseous and liquid effluents. Current criteria requires that the capability exist to direct ventilation air from areas of low radioactivity to areas of progressively higher radioactivity. There are two scenarios which could possibly violate this requirement, both of which occur with the main exhaust fans shut-down when offsite power is not available and the plant is operating on emergency diesel power.

TOPIC NO. TITLE

IX-6 Fire Protection

Difference Summary

10 CFR 50 (GDC 3), as implemented by 10 CFR 50.48 and Appendix R requires that structures, systems and components important to safety shall be designed and located to minimize, consistent with other safety requirements, the probability and effect of fires. Ginna cannot reach cold shutdown within 72 hours, as required by Appendix R, in zone ABRH, since a fire there could cause the loss of both RHR pumps.

Ginna Nuclear Power Plant

ACRS Subcommittee Meeting

March 18, 1982

Introduction

Plant Description

Systematic Evaluation Program

Current Status and Schedule

Appraisal of SEP

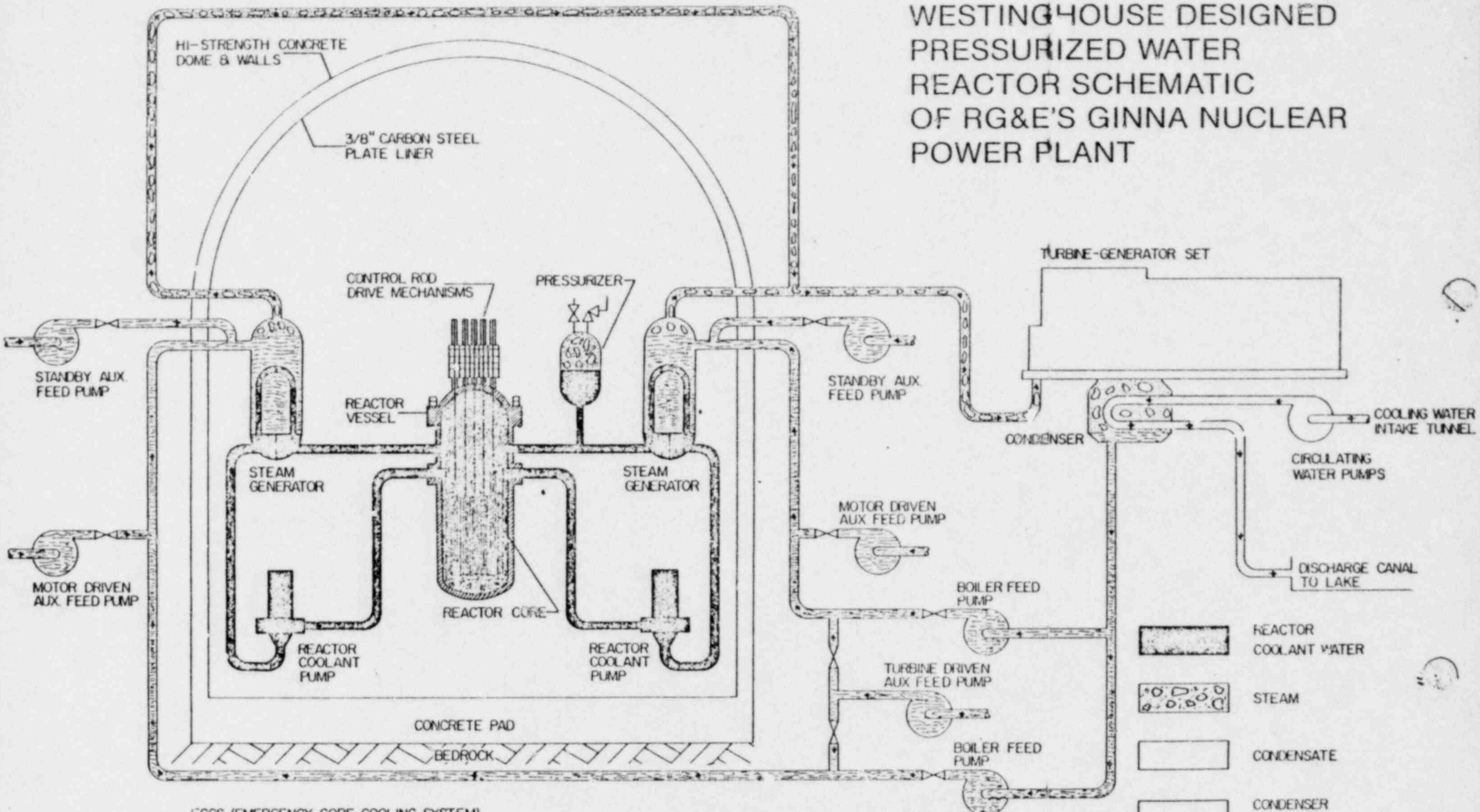
Break

Steam Generator Tube Rupture Incident

Sequence of Events

Emergency Organization Response

WESTINGHOUSE DESIGNED PRESSURIZED WATER REACTOR SCHEMATIC OF RG&E'S GINNA NUCLEAR POWER PLANT



ECCS (EMERGENCY CORE COOLING SYSTEM)

3 HIGH PRESSURE SAFETY INJECTION PUMPS
2 LOW PRESSURE SAFETY INJECTION PUMPS
2 PASSIVE TANKS FOR LOW PRESSURE INJECTION

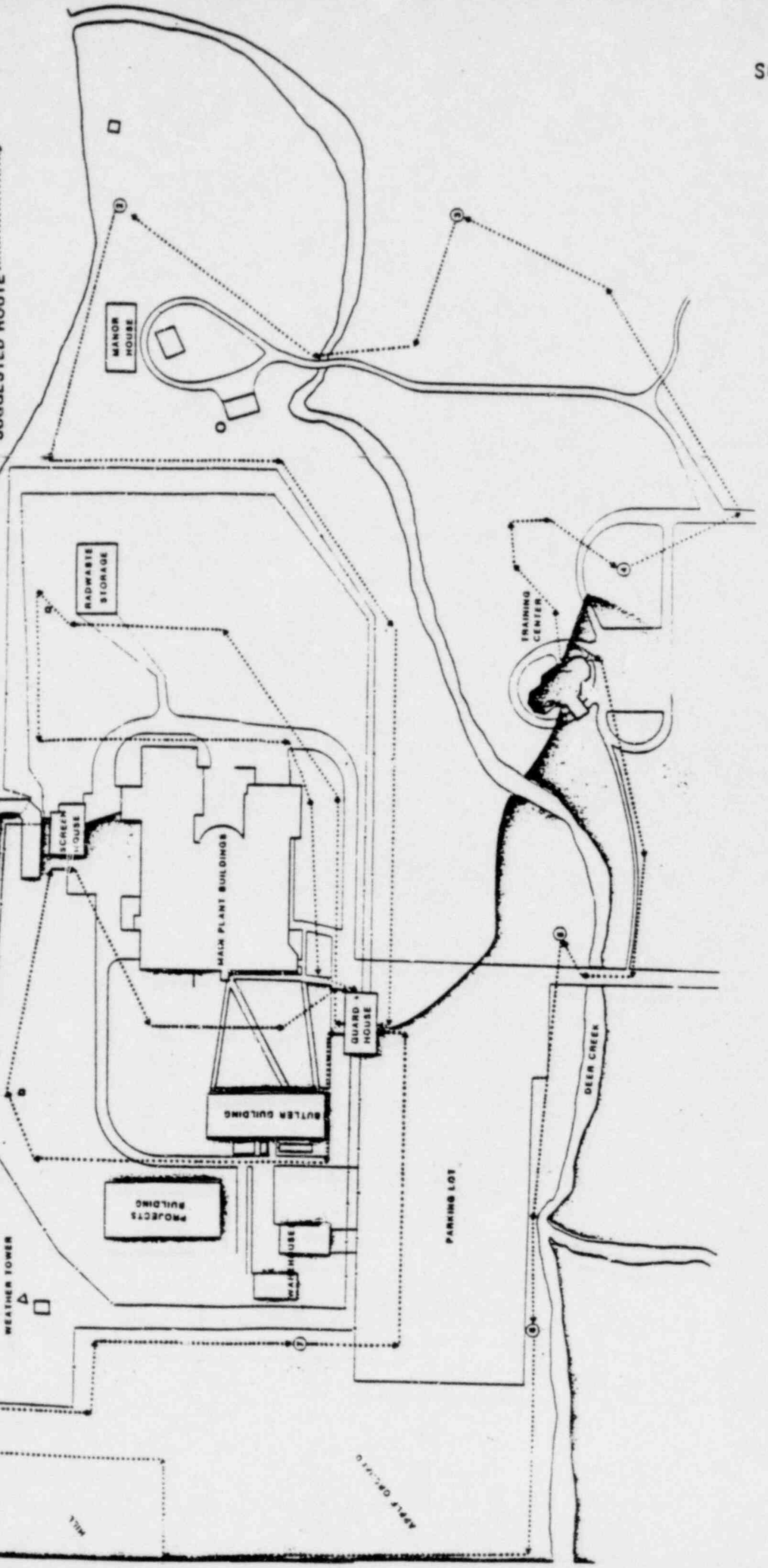
ONSITE SURVEY MAP
NO SCALE

DATE: ______ TIME: ______

TEAM MEMBERS

BLUE	YELLOW
1 ______	1 ______
2 ______	2 ______

SUGGESTED ROUTE ··········



RGE

HISTORY

GINNA STATION

PERFORMANCE STATISTICS (LIFE TO DATE)

MWE GENERATED:	33,853,048
CAPACITY FACTOR:	69%
AVAILABILITY:	75%

ANNUAL AVAILABILITY

	1976 - 58%
1981 - 82%	1975 - 77%
1980 - 76%	1974 - 62%
1979 - 73%	1973 - 95%
1978 - 81%	1972 - 69%
1977 - 86%	1971 - 76%
	1970 - 70%

RGE

HISTORY

GINNA STATION

1969	NOV.	INITIAL CRITICALITY
1970	JULY	COMMERCIAL OPERATION
1972		UPGRADE TO 1520 MW
1974		ARMOR STONE TURBINE BLDG FLOOD PROTECTION
1975		PIPE BREAKS OUTSIDE CONTAINMENT JET SHIELDS STANDBY AUXILIARY FEEDWATER SYSTEMS INSERVICE INSPECTION UPGRADE
1977		FULL FLOW CONDENSATE DEMINERALIZERS
1978		SECURITY
1980		TMI MODIFICATIONS INCLUDING TECHNICAL SUPPORT CENTER

SYSTEMATIC EVALUATION PROGRAM
R. E. GINNA

PURPOSE: REVIEW 11 NUCLEAR PLANTS (OLDEST PLANTS AND THOSE WITH POL'S) AGAINST SAFETY CONCERNS EXPRESSED IN THE NRC'S STANDARD REVIEW PLAN. COMPLETION OF SEP WILL FORM A DOCUMENTATION BASIS FOR SAFETY ASPECTS OF PLANT.

WILL PROVIDE BASIS FOR LICENSE CONVERSION TO FULL TERM OPERATING LICENSE.

STARTED: NOVEMBER 1977 WITH 137 TOPICS

- 45 TOPICS DELETED - NOT APPLICABLE OR BEING RESOLVED GENERICALLY
- 92 TOPICS REVIEWED DURING SEP

PRESENT STATUS: GINNA GOING THROUGH INITIAL PHASES OF INTEGRATED ASSESSMENT. AGREEMENT REACHED ON APPROXIMATELY 75 OUT OF 92 TOPICS, WHERE REVIEW SHOWED THAT:

1. GINNA PLANT MET CURRENT CRITERIA OR EQUIVALENT - 58

2. MODIFICATIONS MADE - 1 (PLUS PARTS OF OTHERS)

3. MODIFICATIONS COMMITTED TO

   ADMINISTRATIVE CHANGES - 10

   PHYSICAL CHANGES - 6

SEP REVIEW HAS NOT DISCLOSED ANY MODIFICATIONS REQUIRING IMMEDIATE ACTION. THE GINNA PLANT HAS MET THE ORIGINAL LICENSING BASIS FOR ALL TOPICS REVIEWED. MODIFICATION MADE TO DATE, OR COMMITTED TO, SERVE TO INCREASE SAFETY MARGINS.

INCOMPLETED TOPICS AT THIS TIME INVOLVE ISSUES ASSOCIATED WITH LOW PROBABILITY EVENTS, SUCH AS NATURAL PHENOMENA, OR ADDITIONAL BACKUP (E.G., MORE REDUNDANCY).

EXPERIENCE TO DATE

WHERE NECESSARY OR CONVENIENT, MODIFICATIONS AND ANALYSES COMPLETED DURING COURSE OF SYSTEMATIC EVALUATION PROGRAM. APPROXIMATELY 2 MILLION SPENT FOR PHYSICAL MODIFICATIONS, 3 MILLION FOR ANALYSES AND ENGINEERING.

EXPECT TOTAL SEP COSTS TO EXCEED $20 MILLION.

TOPICS REQUIRING RAPID RESOLUTION

1. SEISMIC ANCHORAGE OF ELECTRICAL EQUIPMENT - SEISMIC REVIEW OF SEP UTILITIES GENERATED IE BULLETIN 80-11

   - ALL EQUIPMENT WAS ANCHORED; BUT MANY ANCHORS NOT ACCESSIBLE FOR TEST. NEW ANCHORAGE INSTALLED TO ENSURE MARGIN.

2. CHECK VALVE TEST PROGRAM - NRC REVIEW OF SYSTEMS INTERFACING WITH RCS REQUIRED ADDITIONAL CHECK VALVE LEAKAGE TESTING (RESULTED IN TECHNICAL SPECIFICATION CHANGES TO ALL UTILITIES)

   - PREVIOUS ASSURANCE OF CHECK VALVE CLOSURE DID NOT INCLUDE SPECIFIC TESTING CRITERIA

OTHER PHYSICAL MODIFICATIONS COMPLETED

1. BLOCKED OFF BATTERY ROOMS FROM POTENTIAL FLOODING DUE TO SERVICE WATER LINE CRACK.

2. SEISMICALLY BRACED BATTERY RACKS.

3. MODIFIED CONTAINMENT ISOLATION LOGIC.

------------------- PIPING SEISMIC UPGRADE -------------------

ALTHOUGH NOT PART OF THE SEP, SINCE RG&E INITIATED PROGRAM INDEPENDENTLY, THE PIPING SEISMIC UPGRADE PROGRAM HAS RESULTED IN DEVELOPMENT OF FLOOR RESPONSE SPECTRA, SEISMIC ANALYSIS OF SAFETY-RELATED PIPING SYSTEMS, AND ADDITION OF PIPE SUPPORTS. RESULTS OF PROGRAM USED IN SEP.

COST OF SEISMIC PIPING UPGRADE PROGRAM APPROXIMATELY $20 MILLION.

MAJOR ANALYSES COMPLETED

RG&E

1. MASS AND ENERGY RELEASE TO CONTAINMENT FOLLOWING STEAM LINE BREAK - RESPONSE TO NRC ANALYSIS.
2. ~~SEISMIC ANALYSIS OF VARIOUS PIPING SYSTEMS AND COMPONENTS~~.
3. CONTAINMENT LINER INTEGRITY ANALYSIS - RESPONSE TO NRC ANALYSIS.
4. DESIGN BASIS FLOODING ANALYSIS.
5. ATMOSPHERIC TRANSPORT AND DIFFUSION CHARACTERISTICS.
6. CONTAINMENT ELECTRICAL PENETRATIONS FAULT STUDY.
7. SHORT CIRCUIT AND FAILURE ANALYSES OF CLASS IE DC SYSTEMS.

NRC

1. SEISMIC CAPABILITY OF STRUCTURES.
2. REACTOR PROTECTION SYSTEM ISOLATION DEVICES.
3. ENGINEERED SAFETY FEATURES DESIGN.
4. VENTILATION SYSTEMS.
5. WIND AND TORNADO LOADINGS.
6. CODE CHANGES FOR STRUCTURES AND COMPONENTS.

RG&E COMMITMENTS

1. EFFECTS OF PIPE BREAKS (SHIELDING, REROUTING, RESTRAINING, LEAK DETECTION).

2. SEISMIC ANALYSIS AND BRACING OF VARIOUS COMPONENTS - COMPLETE CABLE TRAY PROGRAM.

3. ~~BYPASS OF THERMAL OVERLOAD PROTECTION FOR CERTAIN MOVS~~ FOLLOWING SI.

4. PROVIDED SECOND RWST LEVEL TRANSMITTER.

5. MORE STRINGENT BATTERY TESTING.

6. INSTALL ADDITIONAL BACKUP PROTECTION FOR CERTAIN CONTAINMENT ELECTRICAL PENETRATIONS.

7. PERFORM ADDITIONAL INSPECTIONS OF WATER CONTROL STRUCTURES.

8. MODIFY SAFETY-RELATED COOLDOWN PROCEDURE AND LONG-TERM POST LOCA COOLING PROCEDURE.

9. ADDITIONAL DC SYSTEM MONITORING.

10. VARIOUS MINOR EQUIPMENT AND TECHNICAL SPECIFICATION CHANGES.

OPEN ITEMS

1. WIND AND TORNADO LOADINGS/COMBINATIONS.

2. DESIGN BASIS FLOODING AND GROUNDWATER LEVEL.

3. STABILITY OF SLOPES.

4. CODE CHANGES FOR STRUCTURES AND EQUIPMENT.

5. TORNADO AND INTERNALLY GENERATED MISSILES.

6. HIGH ENERGY LINE BREAKS.

7. SEISMIC ANALYSES/MODIFICATIONS.
   - OPERABILITY OF ELECTRICAL EQUIPMENT.

8. CONTAINMENT ISOLATION VALVES.

9. POST-LOCA SUMP SWITCHOVER.

EXAMPLES OF INTEGRATION

SEISMIC, TORNADO MISSILES, INTERNALLY GENERATED MISSILES, HIGH ENERGY LINE BREAKS, AND FLOODING AS RELATED TO RWST.

SEISMIC, SITE FLOODING, FIRE PROTECTION, AND TORNADO WINDS AND MISSILES AS AFFECTING THE SERVICE WATER PUMPS.

PHASE I - TUBE RUPTURE DIAGNOSTIC

RCS/PRESSURIZER PRESSURE AND LEVEL
DECREASING RAPIDLY

AND

AIR EJECTOR / S/G BLOWDOWN
RADIATION INCREASING

\- ADDITIONAL DIAGNOSTIC AIDS -

S/G LEVEL INCREASING AFTER FEED WATER ISOLATION

RADIATION FROM THE MAIN STEAM LINE MONITORS

PHASE II - LEAK STOPPAGE

A. IDENTIFY -

THE FAULTED S/G

B. ISOLATE

~~THE STEAM & FEEDWATER TO THE~~
FAULTED S/G

C. COOLDOWN

THE RCS BY 50°F USING THE
NON-FAULTED S/G

D. DEPRESSURIZE RCS = FAULTED S/G.

E. TERMINATE SIP OPERATION

CRITERIA: 200 PSI PRESSURE INCREASE
20% PRESSURIZER LEVEL

PHASE III - COOL DOWN TO CSD

A. START AN RCP

IN THE NON-FAULTED LOOP

B. RETURN TO NORMAL RCS VOLUME AND PRESSURE CONTROL

1) INITIATE LETDOWN

2) ENERGIZE PRESSURIZER HEATER

C. CONTINUE COOL DOWN TO CSD

USING THE NON-FAULTED S/G

1) CONTROL RCS PRESSURE EQUAL TO THE FAULTED S/G

2) PLACE RHR IN SERVICE.

I. <u>ORGANIZATION</u>

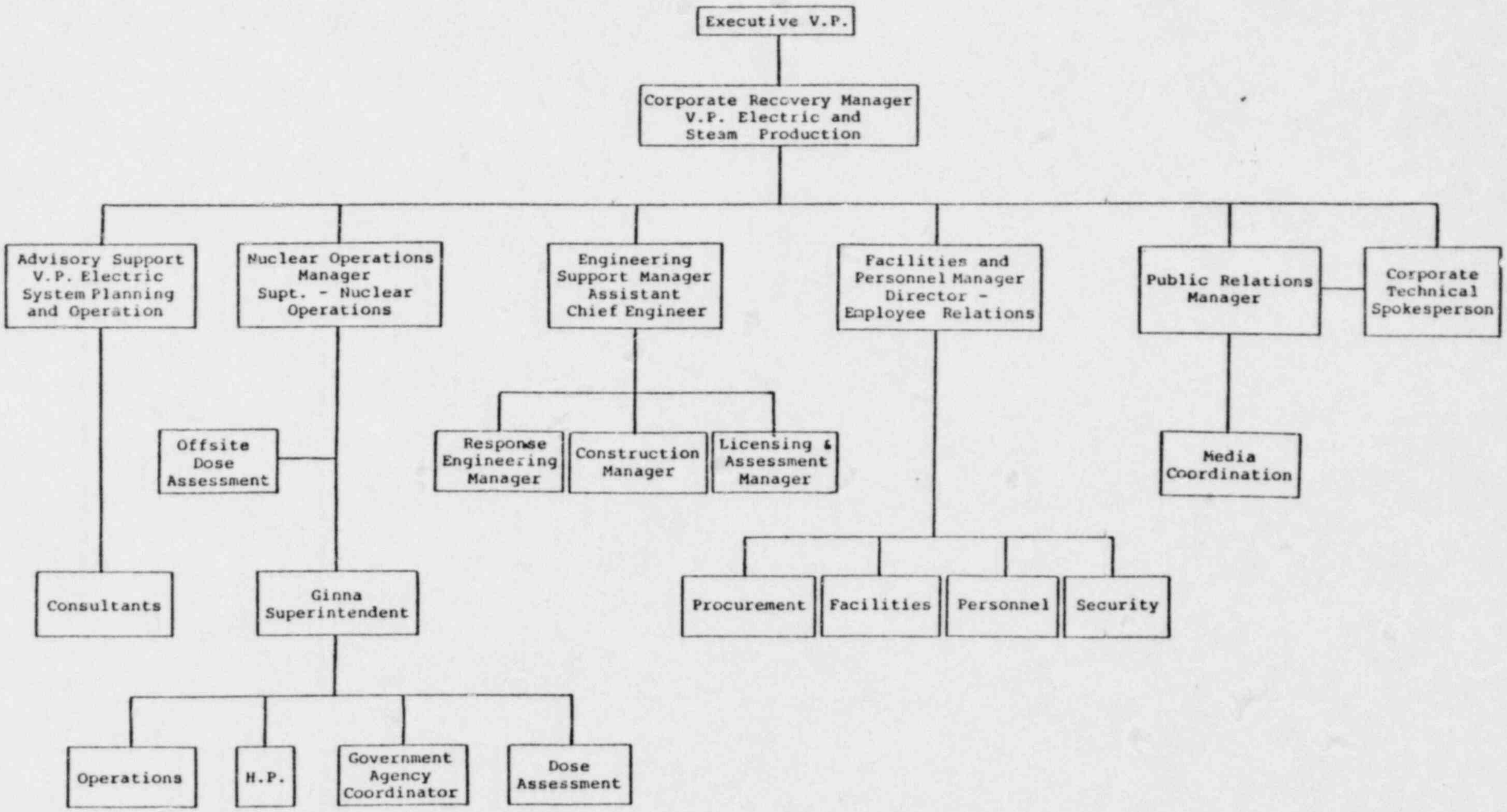
A - OFFSITE

1. DESCRIPTION OF FUNCTIONS
2. TIES WITH OTHER ORGANIZATIONS
    A. SONY
    B. WAYNE COUNTY
    C. MONROE COUNTY
3. INFORMATION AVAILABLE TO OTHERS
    A. EQUIPMENT STATUS
    B. NOTIFICATION - SITE AND GENERAL
        1. CLASS OF ACCIDENT
        2. METEOROLOGICAL DATA
        3. RELEASES
        4. RECOMMENDED PROTECTIVE ACTIONS

B - ON-SITE

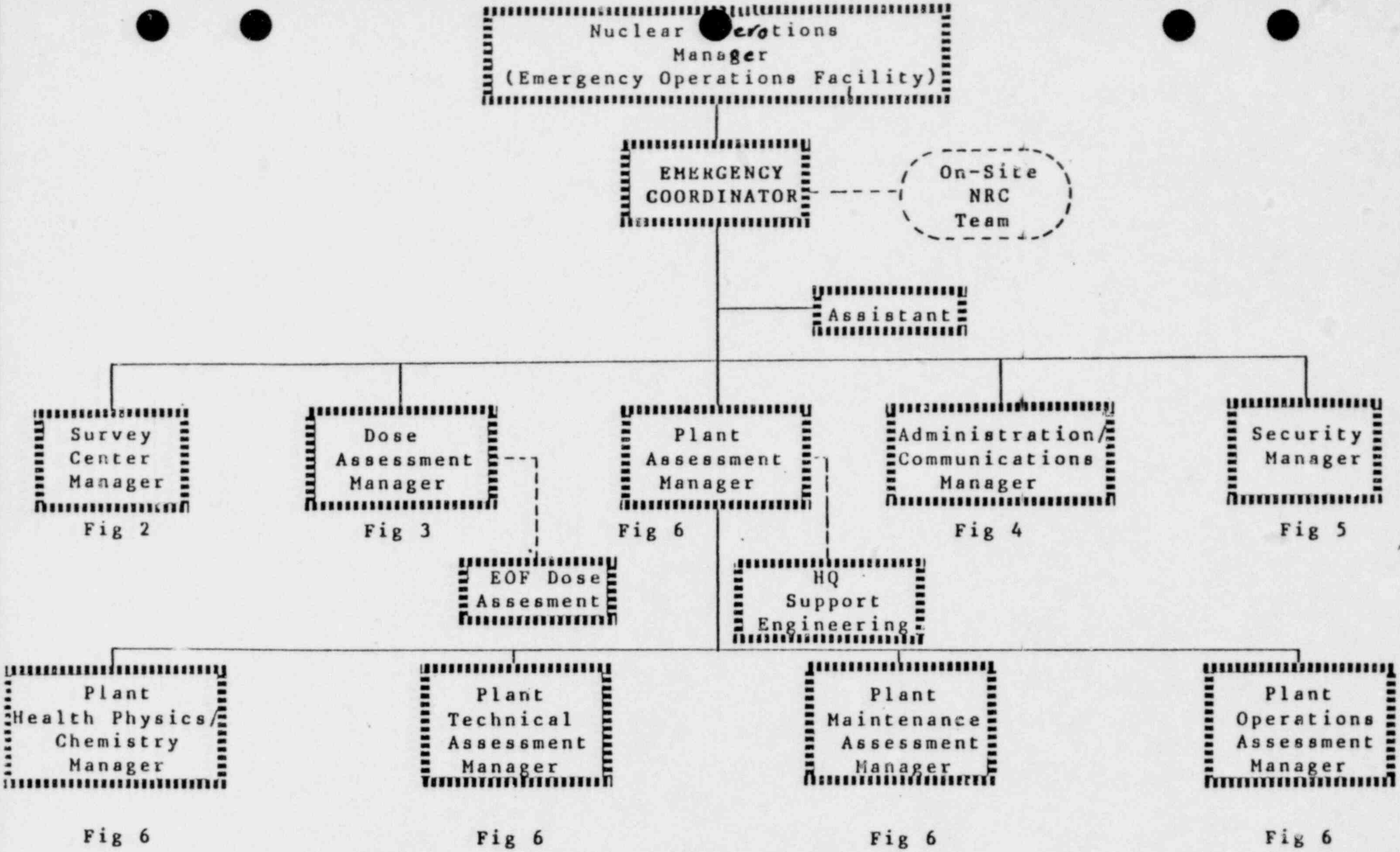
1. DESCRIPTION OF FUNCTIONS
2. TIES WITH OTHER ORGANIZATIONS
3. INFORMATION AVAILABLE TO OTHERS

RG&E
NUCLEAR EMERGENCY
OFFSITE RESPONSE PROCEDURE
4.0 STRUCTURE OF RECOVERY ORGANIZATION



GINNA EMERGENCY OFFSITE RESPONSE ORGANIZATION

(5)


Nuclear Operations Manager (Emergency Operations Facility)
EMERGENCY COORDINATOR
On-Site NRC Team
Assistant
Survey Center Manager
Fig 2
Dose Assessment Manager
Fig 3
Plant Assessment Manager
Fig 6
Administration/Communications Manager
Fig 4
Security Manager
Fig 5
EOF Dose Assesment
HQ Support Engineering
Plant Health Physics/Chemistry Manager
Fig 6
Plant Technical Assessment Manager
Fig 6
Plant Maintenance Assessment Manager
Fig 6
Plant Operations Assessment Manager
Fig 6

(6)

Figure 1

B - FACILITIES

1. CONTROL ROOM

2. TSC

   A. LAYOUT

      1. ADEQUATE.

      2. WORKABLE.

      3. ENTIRE STAFF AVAILABLE FOR ALL FUNCTIONS.

   B. COMMUNICATIONS

      1. ACCEPTABLE.

   C. OBSERVATIONS

      1. BETTER DOCUMENTATION NEEDED.

3. EOF

   A. MANNING

      1. 30 PEOPLE - INCLUDING DOSE ASSESSMENT

      2. SECURITY - 74 EMPLOYEES IN 19 DEPARTMENTS FOR 34 HOURS.

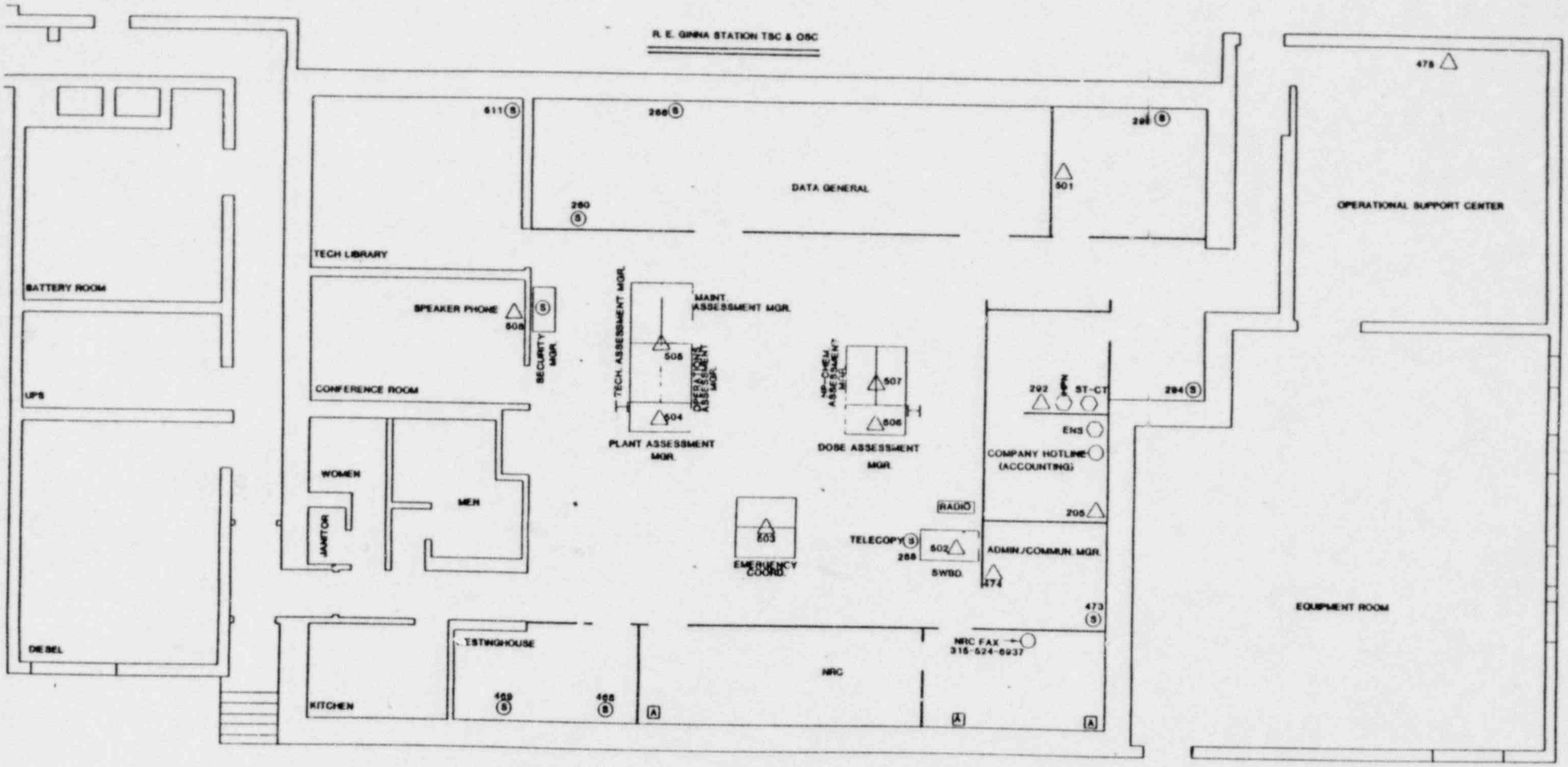
      3. PUBLIC RELATIONS - 64 PEOPLE DEALING WITH 164 DIFFERENT MEDIA PEOPLE

      4. ENGINEERING - 25 PEOPLE ASSISTING THE PLANT VIA THE RECOVERY MANAGER

      5. OTHERS - FOOD FOR OFFSITE AND ONSITE, DIESEL FUEL.

(4)

R. E. GINNA STATION TSC & OSC



(S) STRAIGHT LINE SET

(O) ENS, HPN, STATE-COUNTY

(△) ECTS 20 BUTTON

[A] STD. 6 BUTTON

△ ALL TSC ECTS'S HAVE:

PRIME EXTENSION 50X	DIRECT OUTSIDE LINES
280	716-546-7846
281	716-546-4016
599	315-524-4973
	315-524-4984

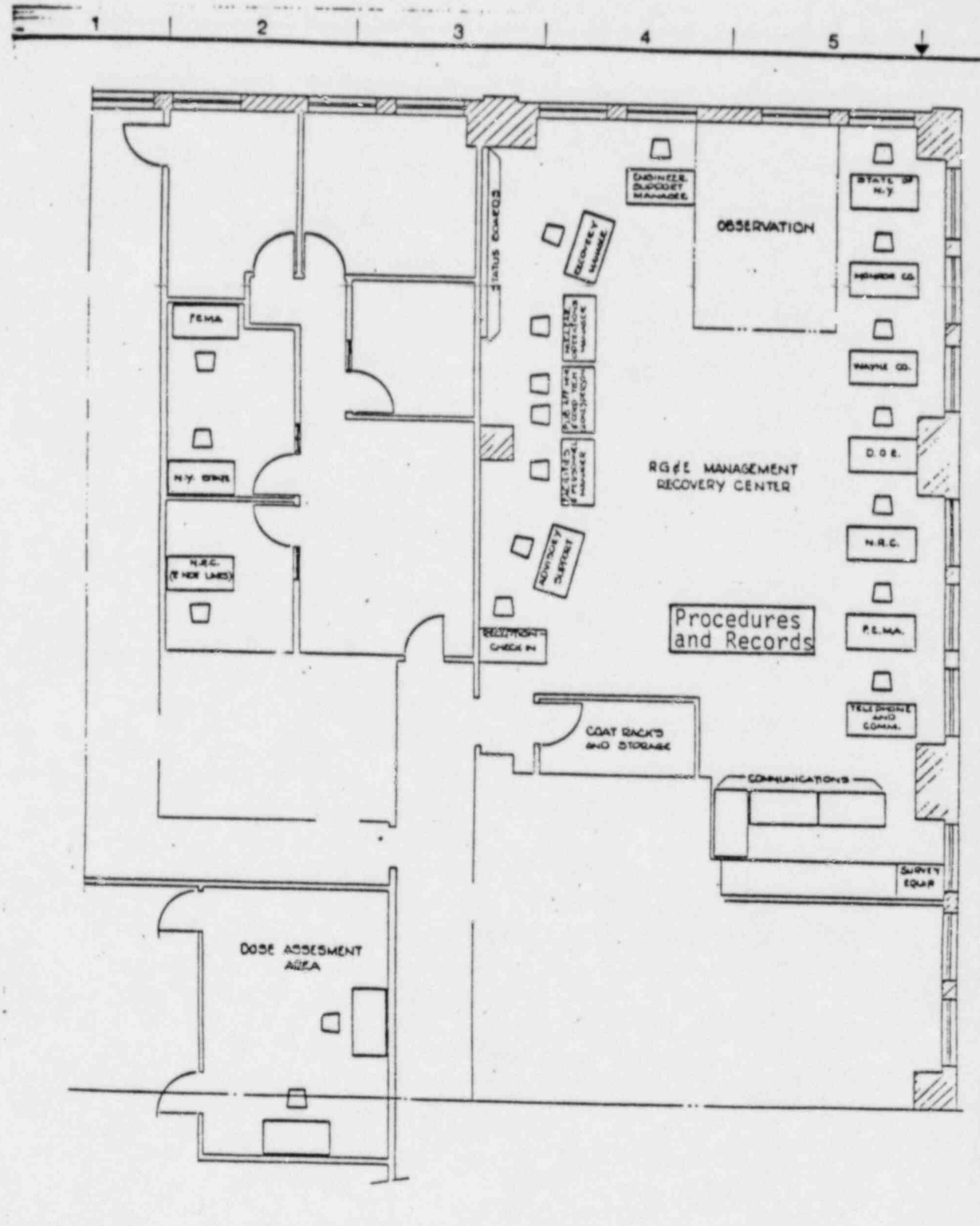
[A] 265

315-524-6935

315-524-6936

HPN #72

ENS


1
2
3
4
5
OBSERVATION
RG&E MANAGEMENT
RECOVERY CENTER
Procedures
and Records
COAT RACKS
AND STORAGE
COMMUNICATIONS
DOSE ASSESMENT
AREA
FEMA
N.Y. STATE
N.R.C.
STATE OF N.Y.
WAYNE CO.
D.O.E.
N.R.C.
F.E.MA.
TELEPHONE AND COMM.
ADVISORY SUPPORT
RECEPTION - CHECK IN

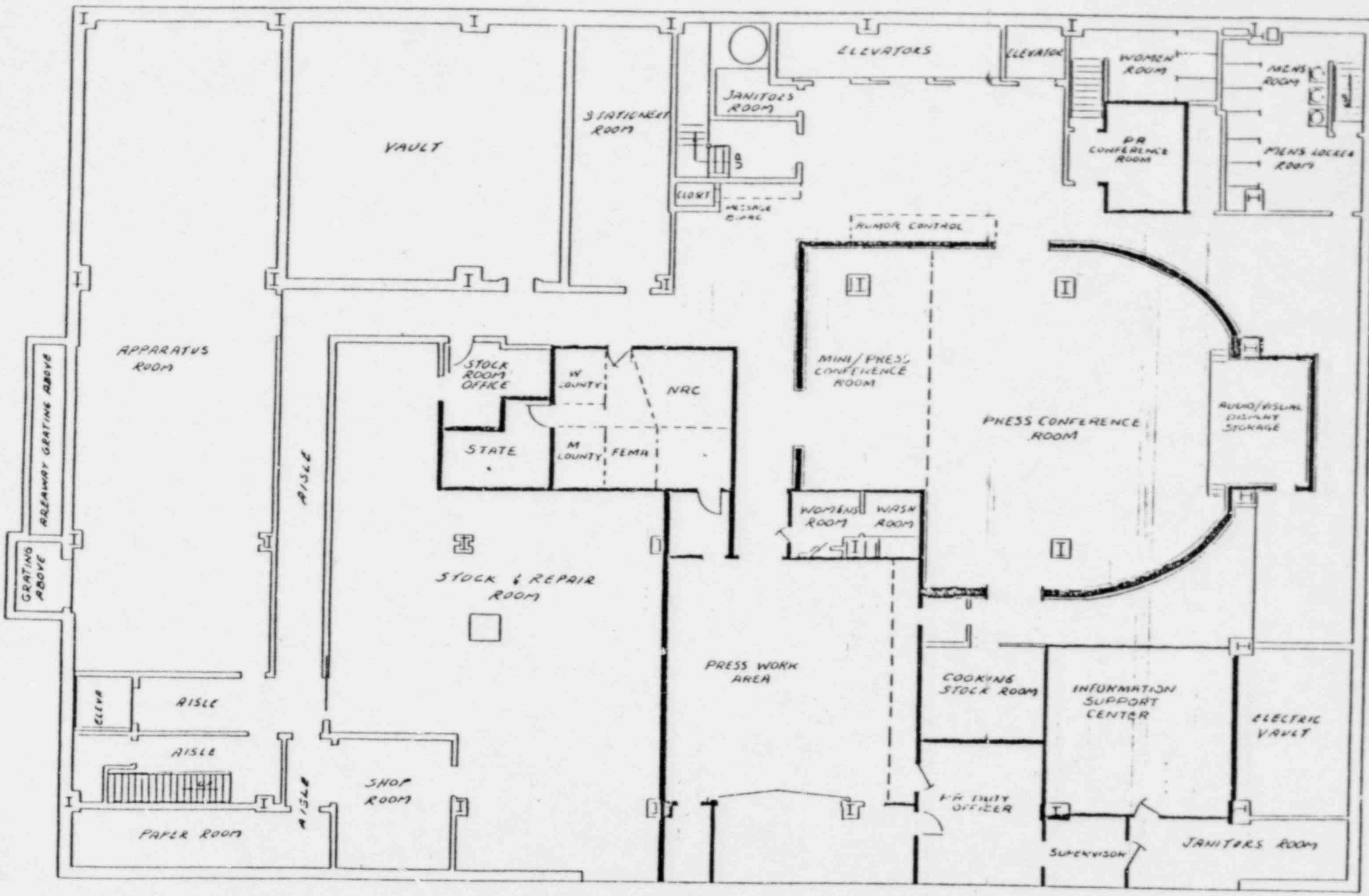


Exhibit 4

FIGURE 6-2

MAIN OFFICE - EMERGENCY
BASEMENT FLOOR PLAN

1) Normal Company telephone extensions. (Many available throughout the EOF)

2) Centrex telephone system. (60 direct lines to the outside telephone systems)

3) Ginna Station Dimension 600 direct telephone line. (3 in the Recovery Center)

4) Ginna Station - Payroll direct telephone line. (EOF Dose Assessment, TSC Dose Assessment, Payroll Department and V. P. - Electric and Steam Production office)

5) New York State telephone hotline. (1 - Ginna Station Control Room, 2 - Ginna Station Technical Support Center, 3 - RG&E Main Office Recovery Center, 4 - RG&E Main Office Dose Assessment area, 5 - Wayne County ODP, Lyons, N.Y., 6 - Wayne County Sheriff's Office alternate warning point, 7 - Monroe County OEP, Westfall Rd., 8 - Monroe County Fire Dispatcher alternate warning point, 9 - Western District ODP, Batavia, N.Y., 10 - Lake District ODP, Newark, N.Y., 11 - NYS Dept. of Health, 12 - NYS ODP Radiological (State EOC), 13 - NYS Division of State Police alternate warning point.)

6) NRC - HPN telephone line. (EOF Dose Assessment, EOF Recovery Center, Ginna TSC Dose Assessment)

7) NRC - ENS telephone line. (EOF Recovery Center, Control Room, Survey Center, TSC Dose Assessment)

8) Radios. (EOF Recovery Center, EOF Dose Assessment, Engineering, Control Room, TSC, Survey Center, Survey Teams)

9) Computer terminals (CRT). (EOF Recovery Center, EOF Dose Assessment, TSC, Control Room) Many more available, both at EOF and Ginna.

10) Computer printers. (Control Room, TSC, EOF Recovery Center) Many more available, both at EOF and Ginna.

11) Backup portable radio available for cross-state point to point notification, via Sheriffs and New York State Police radio frequencies.

INCIDENT

A. SEQUENCE OF EVENTS

0928	INCIDENT
	NRC NOTIFICATION
0933	STARTED MANNING TSC
0935	NOTIFIED V.P. ELECTRIC AND STEAM PRODUCTION
	(RECOVERY MANAGER)
0947	NOTIFICATION OF STATE
	WAYNE AND MONROE COUNTIES
1000	EOF STARTED TO BE MANNED
1125	EOF ACTIVATED
1130	FIRST PRESS CONFERENCE

B. CONCLUSIONS

1. TSC EOF NEWSCENTER FACILITIES WORKED WELL
2. NO MAJOR CHANGES IN EQUIPMENT OR PROCEDURES NECESSARY