BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of

Review of nuclear outage at
Florida Power Corporation's
Crystal River Unit 3

DOCKET NO. 970261-EI

PROCEEDINGS: STAFF WORKSHOP

DATE: Wednesday, March 26, 1997

TIME: Commenced at 9:30 a.m.
Concluded at 12:14 p.m.

PLACE: Betty Easley Conference Center
Room 148
4075 Esplanade Way
Tallahassee, Florida

REPORTED BY: JOY KELLY, CSR, RPR
Chief, Bureau of Reporting

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IN ATTENDANCE:

JAMES A. McGEE, Attorney, Florida Power Corporation.

PAUL McKEE, Manager of Operations Support, Florida Power Corporation.

ROY ANDERSON, Senior Vice-President, Florida Power Corporation.

PAT BEARD, Senior Vice-Presiden Nuclear Operations, Florida Power Corporation.

FRAN SULLIVAN, Manager Design and Engineering, Florida Power Corporation.

ROBERT ELIAS, FPSC Division of Legal Services

ROBERTA BASS, FPSC Division of Electric & Gas.

JIM BREMAN, FPSC Division of Electric & Gas.

CARL VINSON, FPSC Division of Research and Regulatory Review.

PROCEEDINGS

(Workshop convened at 9:35 a.m.)

MS. BASS: Good morning. If we could all take our seats, we'll get started.

MR. ELIAS: Notice issued by the Florida Public Service Commission on March 4th, 1997 advises that a workshop will be held in this docket, and that a review of the nuclear outage of Florida Power's Crystal River 3, at 9:30 a.m., Wednesday, March 26th, 1997, in Room 148, The Betty Easley Conference Center, located at 4075 Esplanade Way, Tallahassee, Florida.

MS. BASS: Good morning everyone and welcome to the workshop.

A couple of preliminary matters. There is a sign-in sheet at the very back of the room. If everyone would sign in, I'd appreciate it. There are also agendas for today's workshop next to the sign-in sheet.

Today's workshop is being reported by a court reporter, so when we get to the question and answer section, it will be helpful when questions are being answered that the individual answering the question state their name so that the court reporter will not be confused by several different people. I am not sure how many people will actually be responding to questions, but for the court reporter's benefit and our benefit later on when we're listening to the tapes or reading the transcript we'll know who answered the question.

It is Staff's intent today to use this workshop by focusing on the report that Florida Power Corporation filed with the Commission on March 19th of this year. Our questions will be directed to the Company in an effort to gather additional data and seek clarification of the information contained in the report.

It's our hope that all the responses to our questions, and questions from other interested parties here today, will give us a better understanding of the circumstances regarding the outage at Crystal River Unit 3 as outlined in the Company's report.

My name is Roberta Bass. I work in the Division of Electric and Gas. There are two other Staff members that will be asking questions today and I'd like to introduce them. Jim Breman works in the Division of Electric and Gas with me and Carl Vinson is in the Division of Research and Regulatory Review.

That's about all I have preliminarily. If the Company wishes to introduce now the people who will be making the presentation or you can do it as they get up and do the presentation. But at this time, unless there's any questions from anybody in the audience, we're ready to start with the presentation.

MR. McGEE: Thank you, Roberta. My name is Jim McGee. I'm an attorney with Florida Power Corporation.

I'd like to say that we appreciate the opportunity to participate in the workshop today and provide Staff with some information concerning the specific actions and circumstances that led to the shutdown of Crystal River 3 on September 2nd, 1996, as well as the reasons that Florida Power determined that it was necessary to keep the unit down for an extended outage.

Last week, on March 19th, we submitted a preliminary report on this issue. And today we'll give an overview of the key points that are covered in the report, and at the conclusion provide an opportunity for Staff to ask questions.

I think it would be appropriate right now to introduce the members of the presentation team.

First, we have Mr. Roy Anderson, who is our new senior vice president; been on the job for about two months. He's had 27 years in the nuclear power industry, most recently coming from Carolina Power and

Light, where he was responsible for their nuclear program.

Next I'd like to introduce Pat Beard on the end. Pat is our outgoing senior vice president for nuclear operations. Pat will be retiring at the end of the month. Saying that this will bring a grin to is face. Dr. Beard took over Florida Power's nuclear program in 1989 and during his tenure Crystal River 3 achieved the best operating performance in the plant's history.

Next we have Paul McKee, who is the manager of operations at Crystal River 3. Paul has been at Crystal River 3 since before the unit received its operating license, and he probably has the best institutional knowledge of anyone at Florida Power regarding the plant and its history.

We also have with us Mr. Fran Sullivan. Fran is the manager of design engineering. He's been at Florida Power for 15 years. Fran is responsible for all of the outage modifications that are taking place during the current outage. And with that, I'd like to turn the presentation over to Mr. Anderson.

MR. ANDERSON: Thank you. Again, my name is Roy Anderson.

The way I would like to start -- I'm getting training here.

The way I'd like to start, and I think it would be more helpful, is to have Paul McKee go through the chart showing the Crystal River nuclear plant and talk about the various components and their functions. And then I'll follow up with the discussion about the license and how those things tie together and then move on to the issues associated directly with this outage. I think that will lay the groundwork as all of us tend to drop back into our acronyms and jargons, so I think a little start from scratch with this diagram would be very helpful.

So, if I could ask Paul, would you come up and walk through the nuclear steam supply, the valves, the plant, the generation of electricity and the systems associated with hypothetical emergency situations.

MR. McKEE: Okay. What I'm going to try and do is just cover how we produce electricity using nuclear energy and why we're concerned about protecting the public and how we go about doing it.

Now, the basic concepts are going to be pretty simple, but when you go to apply those concepts that's when it gets more complicated.

For example, generating electricity is

pretty straightforward. You just move a magnet past a wire and the electrons in the wire will then move. That's the electrical current. But all of this equipment that you see up here is for one purpose, and that's for moving the magnet that's in the generator here. So everything else serves the purpose of causing that magnet to rotate.

We do that using nuclear fuel located in the core of the reactor. It's uranium. And the uranium is in the form of a ceramic called uranium dioxide in small pellets, and we'll talk about that in a minute. And the process is created by the fissioning of the uranium, the splitting apart of it. Why would you want to go to nuclear?

Well, when you think about a power plant, let's take a coal plant as an example. To make 800 megawatts it takes 300 tons of coal an hour and creates 30 tons of waste every hour. That's a lot of real estate to move around.

In a nuclear plant you can produce 800 megawatts by bringing in six truckloads of fuel once every two years; about 30 tons will last two years. But like anything else, there's no free lunch. The drawback is that at the end of that two years you've got 30 tons of highly radioactive waste that you have to handle.

By radioactive, I don't want you to be afraid of that word. What we're talking about is energy. And maybe a little illustration would help there in the way that energy can be converted and how you protect people from energy.

For example, suppose you had a donut this morning for breakfast. Your body is going to convert that into chemical energy. If your job is to change out one of those light bulbs up there, you come in, bring your ladder in, set it up; you convert chemical energy into potential energy as you climb up the ladder.

As you do your job, you control that potential energy using the chemical energy, and then come back down the ladder and you've safely done the job. But if you're at the top of the ladder and you slip and fall off, the potential energy is converted into kinetic energy. The gravity brings you towards the floor, and as your body gets at the floor level, the kinetic energy is then converted back and absorbed by your body and it does damage, such as cracking your skull and breaking your bones.

So energy when it is not controlled from that little donut that you had this morning now can do damage to you.

It's the same thing here. The energy that is in the core, in the form of electromagnetic radiation, can only do damage if it gets to your body. So the primary thing we're concerned with to protect the public is to keep radioactive material where it belongs. So we'll go through how we do that.

There's one other drawback when you use nuclear power, and that is that after the fission products, or after the fissioning occurs, the fission products that are left that are giving off that radiation are also giving off heat and the radiation can even be converted back into heat. So when you stop the fissioning process the heat doesn't go away. It's called decay heat. We can't make it go away any faster. It's going to decay on its own natural terms.

So we have to be able to remove that heat and keep it cool or it can cause the system to heat up and even reach the point where we could melt the fuel or do damage to the system, which would then result in the potential for radioactive material getting outside of our control.

Now, decay heat would normally be removed when we're shut down by a special system call the decay heat removal system. It takes water from around the core, brings it into the piping, through a pump, through a heat exchanger, cools it off, puts it back into the core and that flow of water removes the decay heat and keeps it down at temperatures below 100 degrees when we shut down.

But what we're interested in right now is how do we produce the power? So let's talk about that.

The first thing we start off with is the fuel. A fuel pellet is about the size of your little finger, and it's about the length from the tip of your finger to the first knuckle. We take the fuel pellets and stack them into tubes. Zirconium 4 alloy is the type of tubes we use. These tubes are 12 feet long.

So we just stack them one on top of the other inside the tubes and when we get the tubes full, we weld the ends of the tubes so it's sealed in there. We normally call the whole piece of it or the tube that is 12 feet long a fuel pin. And that material that is on the outside of the zirc-alloy we refer to as cladding. So when you hear us talk about cladding and the temperature of the cladding, that's what we're talking about, is this tube that the fuel pellets are stacked into.

Then we take 208 of those fuel pins and put them together in a cylinder, 8 inches by 8 inches and 12 feet long. We take 177 of the fuel assemblies, stack them in the reactor in the shape of a right circular cylinder. Now we have a coolable geometry because we want to be able to remove the decay heat as well as keep the radioactive material where we want it. And by putting it in that configuration it makes it easy to remove the decay heat. You don't have to have a lot of fancy pumps and heat exchangers and everything else. All you have to do is keep the fuel covered with water. If the water boils and you allow the steam to escape, it carries away the heat. So as long as you replace the water that boils off and keep the fuel covered, then you will protect the core and it can't heat up.

So you have to have a source of water, and a relief for the steam, a place for the steam to go. If you do that, you can remove the decay heat, keep it cool and prevent damage.

To produce power, though, we want to cause fissions to occur. We do that with control rods. The rods are merely special material that is inserted into the fuel assemblies and can moved in and out. It will absorb the neutrons. They absorb the neutrons better than the fuel does. It's like a sponge. It keeps the neutrons from reaching the fuel so fissioning can occur. So when we start up the plant, we will pull out the control rods. That will start the fissioning process. If we want to shut the plant down, gravity helps the rods go back in and that shuts it down. So we can control the power level of the plant.

So the next thing we want to do is remove the heat that we're now generating in there. So to do that we have a pump to pump water around it. There's actually four pumps, each one driven by a 10,000 horsepower motor. And there's 352,000 gallons a minute of water flowing through the core. So now we have a way to remove heat, but we want to keep it simple, we want to keep it compact, so we don't want that water to boil.

Water is unique in that as you raise the pressure, the temperature where it boils will also go up. So we raise the pressure to the point where we can get the water temperature to 600 degrees, but the water won't boil. We do this with a device called a pressurizer. That's why this is called a pressurized water reactor. We keep the water pressurized so that it won't boil and we can remove the heat by transferring fluid around it.

The pressurizer is nothing more than a tank that is connected directly to the system. In the tank are electric heaters that heat up the water, causes it to boil, creates a bubble. The steam bubble in the top pushes back on the water and makes the pressure. So when we get it up to 2150 pounds per square inch, we have got the system pressurized. The water at that pressure will boil at about 643 degrees. And so we can get 600 degrees coming out of the core and still have a margin of better than 40 degrees until we get to the boiling point.

We want to be able to control that pressure pretty precisely. So besides the heaters we have a sprayer that can spray water in there, condense the steam and reduce the pressure. If for some reason water surged in there, squeezed the bubble and caused the pressure to go up, we have a control valve that releases the pressure off; it goes into what is called a quench tank, or reactor coolant drain tank, which is merely a tank that has water in it with coolers to cool the water. The steam bubbles through there and is condensed back or quenched.

In case that's not big enough or in case the controls fail, there are two safety valves, two separate types, that also run back to that same tank. So if the pressure got too high, it could relieve the pressure and protect the piping system.

Now, taking the pressurized water as it passes through the core, it's only heated up about 50 degrees, but there's quite a bit of water flow so it carries a lot of power. Creates 2500 megawatts of power, thermal power, that passes through the core out through two 36-inch diameter pipes and over the top of the steam generator. The steam generator is just a heat exchanger that has a lot of tubes in it, 15,300 tubes. The water passes through the tubes. The heat is removed from it, the temperature drops about 50 degrees. So it's coming in about 600 degrees; going out about 550 degrees, right back through the pumps and just continues that cycle of removing the heat from the core and taking it through the steam generator.

And the steam generator, we want it to be as efficient as we can, so the water that we're putting into it is very close to the boiling point.

Now, there again, by using the combination of pressure versus temperatures we can control the temperature it boils at. So we maintain the pressure at around 900 pounds per square inch. That allows the water to boil at about 532 degrees. The water as it's coming in is very close to that, and as it goes down around the outside of the steam generator it picks up steam from the generated steam generator and is heated to the boiling point. So that when it comes in contact with the tubes at the bottom of the steam generator, the water is already at a boiling temperature, and it's boiling as it goes up around the tubes. As more and more steam is made, the steam is then heated until finally at the outlet we have superheated steam, close to 600 degrees and 900 pounds per square inch. This generates 6 million pounds of steam an hour, total, between the two steam generators; 300 million for each steam generator.

That amount of steam then flows through the steam pipes to the high pressure turbine where it causes the turbine to turn. It spins it up to 1800 revolutions a minute.

The steam then comes out of the high pressure turbine, goes to the moisture separator reheater where we heat it back up, again, for efficiency reasons, using some of steam directly coming from the steam generator. There are also mechanical separators in there that separate out any water particles or moisture drops so that the water won't come in contact with the low pressure turbine, which is also rotating at 1800 revolutions a minute, and do damage to it. So the dry steam goes into the turbine and we get every bit of energy out of it that we can.

It's not a perfect device, so some of the energy is still left in it. Steam comes out in what is called a condenser which is just another heat exchanger. You can think of like that radiator on your car, and instead of using air to cool, we use water from the Gulf. So the steam is around the outside of the tubes, the titanium tubes, seawater is being pumped through it and back out. So the seawater would pick up the heat and condense the water back into steam. That's why we call it a condenser. The only thing that happens to the seawater is it's heated up about 17 degrees.

If there were a leak in one of these tubes, the water leaks into the condenser, not out, so even with a damaged tube the only thing that is going out to the Gulf is the temperature.

The water that is then condensed is collected at the bottom of the condenser in an area called the hot well. It's pumped through a condensate pump because it's the water that just condensed back. We then clean it up with a demineralizer that removes any impurities that may have been picked up while it was passing through the piping and turbine system, and begin the process of heating the water back up by pulling steam off the turbine.

We heat the water up in stages. It goes through another heater here called a deaerator, where we remove any oxygen to make sure that we reduce any chance for corrosion in the piping and steam generator tubes. Put it through a feedwater booster pump. This is where we make the change. We now call it feedwater because we're in the process of feeding it back. It goes through the booster pump, through another heater, and the main feedwater pump into another heater, so that's six stages of heating. So it's almost up to boiling again. It goes in and starts the process all over again.

So that's basically how we generate power. But we want to make sure that we protect the public, that we keep the radioactive material where it belongs, and to do that we need to remove decay heat.

So we set up a whole series of hypothetical accidents. What kinds of things could happen to the plant and how could we handle it? It could be earthquakes; it could be hurricanes; it could be a steam line break; it could be a feedwater line break; it could be a loss of coolant accident, which means the reactor coolant, as the water is passing through the core, it leaks out. A whole series of accidents that we consider.

And the way we consider these accidents is saying there's a condition that's out there. For example, we want to have a good electrical supply, so we have off-site power. There are eight power lines that come into the substation and then two lines from the substation that go back into the plant that supply emergency power. Each one of those power supplies are backed up by a diesel. So there's two diesels capable of supplying all of the power that we need under any condition for safely shutting down the plant and keeping it cool. To be even safer, we want to make sure that we have batteries to back up the instruments and power going to the instruments and supply some of critical equipment, the valves, the pumps, things like that. So we have all of these levels of redundancy of the electrical power.

But suppose we set up a condition like we've lost off-site power. The next thing we'll set up is an accident. It could be a loss of coolant accident, it could be a feed line rupture or whatever the accident is. After we've set up the accident and a condition, then we say what single failure do we need to be protected for? Suppose it's a loss of a pump, or suppose it's a loss of battery, or suppose it's a loss of a valve, whatever it is you come with a single failure and you try it out. So you have all of these combinations of conditions, accidents and single failures that you have to design the plant to be able to withstand.

Let me explain how we go about doing that, just concentrating on one area as an example. We'll talk about the reactor coolant system, so this will fit in with other items that you'll be hearing today and we talk about having a leak in the reactor coolant system, a loss of coolant action, or LOCA. You'll hear that term used a lot.

So we start thinking about, hey, how can these things happen? What would be the biggest leak we could have? What would be the smallest leak? And the idea before Three Mile Island was that we would design for the biggest leak and the smallest leak and everything in between should be taken care of. We found out at Three Mile Island that was not quite true, but I'll get into that later.

The first one we'll talk about is the maximum hypothetical accident. This pipe, which is 36 inches in diameter, four inches thick, is one of the barriers that keeps radioactive material from getting out. Now, those barriers start with the fuel itself. It's a ceramic pellet, it melts at over 5,000 degrees, and it locks into it, the radioactive material, that is created as it fissions. Then the tubing itself, the cladding, is another barrier. Anything that could leak out of the fuel is contained within the cladding. Then the vessel and the piping itself, high quality, thick steel vessel, eight-inch thick vessel, four-inch thick piping with stainless steel cladding on the inside of it, carbon steel on the outside, that was inspected very carefully, built to high standards and is reinspected on a regular basis to make sure there is no erosion, corrosion or cracking in the piping or the reactor vessel. So there's no reason to expect it would crack. We don't know how it would crack, but we just assumed this pipe, 36-inch diameter pipe, breaks completely in half and moves aside so that both sides of the pipe are open and unrestricted and all of the water blows out.

So the final barrier is the containment building, which is a large steel tank; over 2 million cubic feet of just basically empty space that could contain all of this water flashing to steam, because as it leaks out, the pressure goes down, it's above the boiling point for water, so it's going to turn to steam.

This half-inch steel tank is backed up with three feet of concrete. And that's post-tensioned and re-enforced so it can support that tank and the pressure that could get into it. It's designed and routinely tested up to almost 50 pounds per square inch. If this accident happened and all the water flashed to steam, it would go up to above 40 pounds per square inch. But that pressure on the building is not something you want to keep there very long.

So the first protection equipment that we put in, we call this engineered safeguard equipment; equipment engineered to keep it safe, to protect the public, is a building spray.

The building spray picks up water from a large tank, over 450,000 gallons, pumps it into the building and sprays it down, cools off the steam and condenses it back to water. There are two of those pumps, two sets of piping, and two sets of rings up in the top of the containment dome that can spray the water down; completely independent of each other.

There are also coolers in the unit, inside the containment. These cooling units are cooled with outside water and they have fans, and they just blow the steam and air across the coolers and also help cool the unit down.

Now, as this blows off or as this breaks open and the water comes out, the pressure goes down. So the normal way we were keeping pressure up was through the pressurizer and through any additional makeup water that we add in there, it won't keep up with it. So we have a system called a high pressure injection system, HPI.

Now these are two pumps, piping, all independent, completely powered by separate power supply and backed up by diesel generators, that pump water from the same tank into the reactor vessel and replaces any water that leaks out. Now they start pumping as soon as the pressure drops below 1,500 pounds per square inch.

With this big a break the pressure is going to drop very rapidly. So, in addition, we have two tanks; they're called core flood tanks. They are half filled with water and the other half is filled with nitrogen gas at 600 pounds per square inch pressure. They have a little check valve in there, and as long as the pressure in the reactor coolant system is above 600 pounds, the water can't flow back in there, so that tank sits there half full of water with the pressure on it. And there are two tanks. When it drops below 600 pounds the valve automatically opens because of the pressure difference, the water flows into the core and supplies coolant.

As the water continues to leak out and the pressure continues to drop, then the low pressure injection pumps will start. When it gets below 200 pounds, about 185 pounds actually, they will start pumping water into the core to replace all of the water that's has leaked out and to keep the core cool.

While all of this is going on, all the water has been leaking out and we've been pumping the water out of the tank, so the tank is starting to get lower so we need to get some more water. Now, let's use the water in the reactor building because we've been spraying it down, it's been leaking out and we're pumping water in there, so the bottom of the reactor building is starting to fill up with water. And the reactor building sump is connected to piping. We can open valves and bring the water right back to the low pressure injection pump. And in the case of a big break like this, because the pressure rapidly drops down to whatever the pressure in the reactor building is, this pump can supply about 185 pounds per square inch pressure and keep it cool. That's how we handle the large breaks.

A small break would be like a one-inch instrument line. In these loops here are flow instruments which measure differential pressure and pressure instruments so we can keep track of the pressure and control it.

Suppose one of those broke off? The pressure wouldn't drop as fast; it would drop slow, and the high pressure injection could handle it. But if it went on long enough where the tank started to get empty, then we can take the water from the sump to the low pressure injection pump and connect the low pressure injection pump to the suction of the high pressure pump and still put the water in. That's called the piggyback operation, if you've ever heard that. That's what we're talking about, is using this pump that can suck the water out of the reactor building, put it to the suction of this pump, which can raise it to a high pressure and handle the small breaks.

One of the things we found out is you can get a certain size break that you can't cool by normal means or you can lose your cooling water, and you can't relieve the steam fast enough out that hole. So even though you have the capability of pumping the water in, the steam doesn't go away fast enough so you can't get enough water in to actually remove the heat. So you have to remove the heat through your normal means, which is steam generator.

But suppose you had one of those conditions, like the loss of off-site power, you've lost all of this pumping equipment over here. What we had initially was an auxiliary feedwater system that was used to cool the steam generator when we lost main feedwater. After Three Mile Island we learned about this other break in between the biggest and the smallest breaks that we had analyzed for where you needed to have this extra cooling, so we started upgrading this system.

This system consists of actually two separate piping systems and two separate pumps. One pump is electric-driven, and the other pump is turbine-driven.

The electric driven-pump, now that we're starting to think of it as safety-related pump needed for emergency use, we needed to get better electrical supply to that, so that was added on to the A diesel after Three Mile Island. So now we've added an electrical backup to it from the A diesel so if we lose off-site power, it can still run with that electrical power.

The steam-driven pump, steam turbine, gets its steam from the steam generator so it pumps water in and makes steam and can run itself. So it's okay.

We did need to upgrade the piping and the control systems and the valves that we used. And a system that was done, added to do that, was installed in 1985. It's called the emergency feed initiation and control system. You'll see the acronym EFIC. That's all it means, emergency feed, initiation and control. That system was added, and at the same time another tank was added to give us more water to be able to pump in, called an emergency feedwater tank.

We wanted to protect it from all types of accidents, so it has a large concrete re-enforced with steel building around it to protect it from missiles, tonadoes, hurricanes or anything else that might happen to it. The same way this tank has a concrete shield built right around, right up next to it, so it's not a separate building, but it is covered with concrete to protect it from the same kinds of things.

Other accidents that we're protected from are floods. That's what these steps represent. (Indicating) The plant is actually built up on a berm, 20 feet above normal ground level. These steps would break up any waves from any hurricane that was causing the flood, prevents it from washing away the berm. And as an additional protection, there's an 11-foot wall all the way around the plant with watertight doors in it that are closed whenever we enter a hurricane warning.

One of the accidents -- let's just walk through one of the accidents. Let's take the condition, loss of off-site power. Let's take the accident, a loss of coolant accident. And then we can start thinking about what are the different kinds of single failures that you can have.

And it really comes down that there are three single failures we are concerned about, and you'll hear more about this later.

One is what if you lost the A Battery. Why is that important? Well, you lose some of the controls that are applied to the A Emergency Feedwater and the A Diesel won't start, because the A Diesel needs battery power to start it.

What if you lost a B Battery? You don't lose a B Battery at the same time that you lose the A Battery; only one single failure. So you put everything back in service. You have the condition again, loss of off-site power, you have the accident of a small break, loss of coolant accident and we lose the B Battery. What does that do? That prevents the B Diesel from starting. It prevents some of the controls on the B side system that can pump water into it.

And another single failure would be, well, all the batteries are working at this time, but the turbine driven pump fails to start. Is that a problem? So you analyze it, because in some cases you have diesel and in some cases you don't. You have to analyze all the things and make sure you can cover all of these conditions. We will talk about that later.

But just kind of to wrap up, we produce electricity by fissioning, by removing the heat. The drawbacks to doing it with nuclear power, the fact that it's radioactive material that we have to protect the public from, so we keep it in its place, and the fact that decay heat has to be continuously removed even though the fissioning process is stopped, and there's a lot of equipment in there to make sure we can do that.

MR. ANDERSON: What I would like to do now, and I think it would help is go over the questions that I asked myself when I was coming here as a new employee, that I would want answers to, and it turns out they are the most frequently asked questions that I receive now that I'm here. So if I could, I'd like to go through those.

When I first came down to Florida Power, was asked to come down, the question in my mind is why is the unit shut down, because that dictates what I have to do to return the unit to service.

And in a very straightforward fashion the unit is shut down because we need to make modifications to our engineered safeguard systems to restore margin in the plant; and those modifications require an outage to perform, and an outage of relatively significant duration.

Now, if I can, I'd like to back up and talk a little bit about how the license is created, because I think I can explain why that is, because there's a series of questions that fall right off of this one.

The NRC, how they regulate, is they, in the code of federal regulations, set five design criteria for pressurized water plants, and they are relatively general. And the standard is if you are going to design a power reactor, you have to meet these five criteria.

The first is, is that the fuel clad will never exceed 2200 degrees Fahrenheit under any circumstances under any situation.

The second two involve the clad, also, and they have to do with ensuring that the cladding, which is zirconium, or zirc-alloy, an alloy, does not oxidize and does not react with the water to cause a zirconium hydrogen reaction because the concern is you could have an explosion.

The third that Paul mentioned -- or the fourth that Paul mentioned was that you'll maintain a coolable geometry. In other words, in earthquakes or rapid leaks where there may be disruption from hydraulic forces, the core will stay in position so the rods can be inserted and water can flow around the fuel to cool it.

And the fifth is, you have to demonstrate the ability over a long period of time -- a year is considered a long period of time here -- to cool the core.

That's it. How you do that, the NRC doesn't tell you how to do that, but that's in -- that's 10 CFR 50.46.B, whether it's a Westinghouse plant, a B&W designed plant, a Combustion Engineering designed plant, you all have to meet those five criteria. How you go about doing that is up to licensee, Florida Power, the reactor designer, B&W, or today it's

Framatome Technologies, an architect engineer that is designing the layout of all the equipment and selecting the particular pumps and equipment in our case it was Parsons Power, formerly Gilbert & Associates.

Interesting thing, too, about the design criteria is NRC didn't talk about this part of the plant, didn't talk about making electricity. NRC is concerned with the health and safety of the public and they are concerned about the protection of the reactor, and that's where their regulations focus. None of those five design criteria have you do anything to make electricity. It's almost a byproduct.

So with that fundamental design criteria, there are approved codes that are established, calculational methods that are established, limitations are established, equipment limitations from vendors are placed on it, and we run calculations to demonstrate that we can meet those five criteria, that this equipment installed in this configuration operated within these limits will meet those five criteria; and that comes down to a final safety analysis report.

NRC reviews that in detail; they concur.

That's the basis for the license. Now, the license is codified in the technical specification, so it's one step down; and what the technical specification does is it defines that your -- and I'll use the diesel generator, for example -- that we agree that the core will be protected, and we agree this equipment will operate provided you maintain the diesel generator at the limit that you said you would of 3500 kW level for no longer than 30 minutes.

Each piece of equipment associated with the safety systems has a defined limit, has a limit and a time; and that's the license. And from that license, from those specific things, we, the licensee, write procedures to operate the power plant to ensure we never exceed those values.

Now, the license, the technical specification also dictates what you should do under certain plant conditions if you do not meet those specifications. And I'll use the diesel generator again. Both diesel generators are required to be operational, to be able to operate within their limits while the reactor is running, while we're making power.

The technical specification says that if the diesel generator cannot operate within its limits or can't run at all, that you have a time limit, 72 hours, to resolve the problem or to shut the unit down. The technical specification is very specific about the condition you will place the plant.

So when we looked at emergency feedwater loading, this system that was not originally designed for this plant but added to the plant in concert with other motor operated valves that had been made safety related, and the diesel generator, we found that for a very short period of time the diesel generator exceeded 3500 kilowatts.

That means it didn't meet the technical specification. If it doesn't meet the technical specification, that means the unit -- that the issue either has to be resolved in 72 hours or the unit shut down until it is resolved.

Now, the other part is if the unit is already shut down, it's got to be resolved from -- before you start up. You're not allowed to go from a lower state to a higher state; in other words, operate for 72 hours and then shut it back down. That's not the purpose of the license.

That's the chain of events from a very broad based five things that the regulator requires in the code of federal regulations all the way through to the technical specification which directs the limits on the equipment and the time durations associated with it. That's why the unit is shut down.

Now, follow-on questions to this are always that I get is, is the plant safe. I mean, if you have to shut down and you don't meet this technical specification requirement, is the plant safe? The answer to that question is yes; unequivocally, yes. Because our analysis, when you go back -- I'll use the 2200 degrees Fahrenheit for the cladding temperature here in the reactor -- well, our analysis shows, this broad base of analysis shows that we don't approach 2200 degrees. The highest temperature our analysis shows it will get is 1859 degrees.

There's a fair difference between the temperature the core will reach and the actual limit. And if you call the diesel manufacturer and you say, "Will your diesel generator for several seconds operate at a higher level than 3500?" They will -- they'll say yes.

The challenge is that's not what the license says. The license says 3500 maximum, thirty minutes. Doesn't say 3700 for 30 seconds or two minutes; it says 3500. So we don't meet the license requirements.

Will the systems perform their function and keep the fuel below the 2200 degrees? Yes, they will. Does the system meet the license as codified in the technical specification? No, it doesn't.

And as a regulated entity, as a licensee, I much prefer a very specific license. You do this, this and this, and you can operate. If you can't do this, this and this, then you can't operate until you can. I like that situation. There's not a lot of qualitative discussion about what you should, could or might do; just meet it.

In our situation we couldn't, but the plant was safe. It just didn't meet those requirements, and they revolved around these two areas here, the diesel generator and emergency feedwater which, as Paul mentioned, was not safety related to start with and got added on and got transferred over to the diesel. So the next question that comes to mind, at least I've been asked a lot is, how did we get here?

I need to check, see if we are in sequence. (Referring to slides.)

And it goes back to TMI, and it was a watershed event for all nuclear plants. Paul said that nuclear plants were designed and the assumption was the analytical capabilities at the time were, back in the early '70's, if you designed for this double-ended shear of a 36-inch pipe and you designed for a rupture of a one-inch instrument line and you could show you could handle those two, then the assumption was, is that you could handle the continuum of accidents from the very large leak to the very small leak.

Three Mile Island proved that not to be the case. Our knowledge was evolving. The hole, or leak, that they had was about this big, I think, around that size. (Indicating) And, in fact, they had problems. There were other issues that came out of it.

But after that we went back and looked at the basis for the design, and the basis for the design in these systems were, as Paul mentioned. We looked at -- originally we had looked at a couple scenarios. One was a large leak with a loss of off-site power and one of the components not functioning, and then -- and the other was a very small leak with a loss of off-site power and some of the components not functioning, as well as other issues like earthquakes and tornadoes and hurricanes and airplanes crashing into containments and things like that.

But when we started to take the scenarios and get much more specific, in other words, a 36-inch pipe break, double-ended sheer, well, is it different if it breaks in the hot leg or the cold leg to which way the water is going to flow? Will it short circuit the core and go out the leak, or will it go around and go into the core where we want it?

It turns out it makes a difference, and we started to get very smart about that. Now, please appreciate these are very low probability events, but the license, the five design criteria, it doesn't talk about probability; it talks about meeting the criteria.

So we started going back -- and the industry has been doing this ever since, evolving and doing this and looking at different scenarios, different hypothetical, almost riddles -- and saying, can we resolve that?

Florida Power, my observation was their approach to dealing with this was to minimize the major mods that were performed; modifications that were performed. They -- we, I guess I should say -- we made a lot of control systems change.

We made the modifications here, but where others made major piping modifications and put in cavitating venturis and new motor operated valves, we tried to manage with what we had.

Many of our modifications, the EFIC that

Paul mentioned were control system modifications. In other words, if I went back to the original basis and looked at the calculations, could I refine my calculations to demonstrate that there was the capability there so that I wouldn't reach the 2200 degrees? Is there any way to use the major pieces of equipment which we had to not have to do those major modifications? And that, literally, is what we did.

While other plants were doing analytical work, some other plants were upgrading equipment and they were going through the design phase with trial and error. They were making modifications to the plants. They were -- one comes to mind in the case of Arkansas Nuclear 1. They had a great deal of difficulty with the cavitating venturis; had several starts at it before it worked for the first time, and we stuck to the control mods.

At the time, and talking to the folks that were there, when you looked at the problems these other folks were having with these major modifications, the control system modifications looked like a lot better approach than to start modifying the basis for the equipment.

We, also, as time -- and this has been an evolution. It literally goes on today. One of the questions we had here which was the 9-06 generic letter -- this is 96-06 generic letter on penetrations -- is fundamentally asking a question about penetrations in the plant and has a "what if" scenario -- if you will, another riddle -- and the question is can our system deal with this. It's the way you learn.

I'd almost liken it to that 737, a couple crashes they had. That plane has been flying for what, 20, 30 years, and now today there are modifications going on to the tail control systems because of two crashes?

It's the same thing here. You learn from these potential situations. And then we're required to demonstrate our systems can meet those five criteria, which usually sends us into some design work.

Our modeling skills have increased. The fundamental design work for this plant was done in the early '70s, maybe even the late '60s. Our ability to take that large pipe leak and peel it like an onion, making it ever smaller and ever smaller and ever smaller until we find a leak. And this is the situation we're dealing with right now is a leak that's 2.7 inches in diameter in a specific location in our system, somewhere in here, (indicating), that if it occurs and I have a loss of off-site power, and I have a loss of an A Battery or a B Battery or the failure to start of the steam driven pump, that I can't show that the diesel won't go above 3500, or I can't show that I won't go above the 1859 degrees on the fuel clad instead of 2200 and, therefore, I don't meet my requirements. And that's what we're dealing with.

My statisticians say that the probability is once in 11.6 billion years. That's twice the age of the earth, at least since -- when I read the National Geographic. But, again, probability is not the issue. License is codified; this is what you will meet and this is what -- and this is the situation we have. We got here because of our computer modeling.

As the diesels -- and we recognize the diesels, from my reading of the records, where the loading was getting tighter and tighter on them. We improved our instrumentation on the diesels, tried to get more sophisticated in the analysis of the diesels, and, in fact, when we did that, we found for a short period of time we were over.

In the spring of '96, we made an attempt to solve this problem. And these -- by the way, these modifications as we went along throughout time -- I mean, we have two NRC inspectors on site all the time. These don't go on in a vacuum. They go on with the fuel scrutiny of the Regulatory Commission; and at that time when we made these mods, everyone agreed. The best people working in the business agreed that these were all right.

In the spring we made one more attempt at a control mod, and what we found out in the fall subsequently, continuing to look at it, is that, in fact, we've reached the diesel generator loading criteria. The alternative would be to turn off a pump which would say -- which would reduce flow, reduce load, and also reduce the flow, and consequently we've had a -- we would go elevated in temperature.

So back to the technical specification. If the diesels can't do what they are supposed to do in the time frame you're required to do it at the limits that are specified, then you have 72 hours to resolve it or shut down. That's how we got here.

The question came in my mind when I came here, and I have been asked a lot, what is it going to take to return the unit to service?

Now, we codified this with the NRC in a confirmatory action letter, and I'll talk about it a little bit later. But, fundamentally, there are eight issues we've identified that we think we should resolve prior to returning the unit.

The two that are keeping the unit down are right here; the combination of the diesel generator and emergency feedwater. (Indicating) But because accident scenarios are not dealt with with just one system, they're not dealt with just the low pressure pump or the high pressure pump or the emergency feedwater pumps or the diesels or the building spray, they are dealt with in a combination; all of these working in concerts.

When you add margin to one, or use up margin in your analysis in one, you can affect the burden that the others have in resolving the accident scenario. So the reasonable thing, in my opinion, to do is to look at the remainder of these systems, and we did -- high pressure injection, emergency feed pump and some other modifications -- and do those in conjunction, while we're resolving this problem. Use the time wisely to restore margin in those other systems. So those eight issues have to be resolved.

The second thing that I agreed to, which I think is a reasonable thing, is are there any other issues out there? I don't want to bring the unit back, only to get, you know, the same set of information, get smarter and have another issue come up like this. So I want to look at the rest of the safety system, and we're going to do it in a graduated fashion.

First we'll look at those that have had the most modifications, those that are the most significant to mitigating accidents, and then we'll look at those very thoroughly, and then we'll look at specific attributes for others down the way.

And I think the third item is if we find something, we're going to resolve it. I expect to have that done by June. I mean, it's very important to get it done and get it behind us, because if anything comes out of it that's going to cause real work, I want to know it and get it done within the envelope of the work we're doing to return our system to tech spec requirements.

Finally, the third item is, is I want to make sure our engineering processes are the best that they can be, and I want to make sure my quality assurance processes are the best that they can be.

In a retroactive look -- this business is one where we always look retroactively. This thing was designed by people, and so when you learn something about it and you look back and you say how well did it perform, what did it do, the question is, what can I learn from it and what can I do differently to make tomorrow better than today, just like I hope today is better than yesterday. It's progress. It's the way we move along.

So I want to make sure for me that our engineering and our quality assurance processes, the ones outlined in the MCAP, do these reviews in absolutely thorough fashion.

I have been asked a lot, sometimes, well, okay, what would happen if you had found this issue in the spring of '96? No difference. Immediately go to tech spec. What happens if you found it a year ago? No difference. Go to tech spec. Like tech spec says, you meet the following criteria or you have 72 hours to resolve it, and if you don't, you can shut down while you resolve it. I mean, that stays right intact.

I'd like to do it the first time, because the NRC does their looks in a retroactive fashion and they get judged in a retroactive fashion, and the question is, is everybody was here, everybody looked at the analysis, and in retrospect, we found the problem with the diesel generator loading. What can I do so I don't cross that path again? Not in that specific situation, but in general. That's why that fourth bullet is there. (Indicating)

This is another one which is interesting. Does the SALP Report or the confirmatory action letter, the one I just discussed, or the watch list change anything? No.

This plant, if it had the highest SALP grades and we didn't meet the technical specification limit, would be shut down. This plant, if we met these limits -- and we had the criticisms, those retroactive criticisms that the government gives us when they look back over the last 18 months or 24 months, even though we had those, if this didn't exist, we'd be operating today.

The SALP Report, it's a systematic assessment of licensee performance. It is the NRC's cumulative look backwards in time at what went on and their evaluation of whether it -- what happened and why. And, it's up to us to figure out how to make it run perfectly. We get one either anywhere between 12 and 24 months in time frame.

The confirmatory action letter. The confirmatory action letter is part of the NRC's regulatory process by which they can issue enforcement discretion, and the mechanism works something like this: NRC has a -- has, by regulation, the right to issue civil penalties for violations of regulation. They vary in severity from 4 to 1, 1 being the most severe penalty that they will levy and 4 being the least. Usually level 3 and above bring a civil penalty along with it.

As the safety significance of the violation increases, or the repetitive nature increases or you don't take action, then so does the severity level.

We had violations, as a retroactive look at the engineering work that was done here, that said, you know, over the last several years, you could have or should have seen this. Remember, these were submitted to the NRC, and the people during that time didn't, but they look backwards and say, what can we learn from this. And, in fact, we were out of requirement with the license, the technical specification and, therefore, that is a significant problem.

We've met with them, we've talked with them, and we've said we understand the issue. I'm not sure that a civil penalty will -- it's not going to increase our attention to the problem. We don't like it. We're going to resolve it. This unit isn't running. That's not good. That's gives us -- you know, giving us a fine isn't going to change anything, and they agreed.

So in order to do that, what they had to do was, very frankly, we talked, and they said to me, "We understand, Mr. Anderson, that you will -- " does that go backwards (indicating) -- "you will resolve those issues and restore that margin. We understand that you will look at the rest of the systems. You said you'll do that -- the safety systems -- in this manner to make sure there are no other issues laying out there like this with our current understanding. You'll resolve them if you find them, and you'll take a look at the engineering process and learn something from the past so we don't repeat these things in the future." And I said, "Yes, I agree with that."

They sent me a letter confirming it, and I think you have a copy. At the end of it, it's pretty Draconian, because it says, "If this isn't exactly what you agreed to, you call us immediately to resolve it."

And the reason -- I can't speak for the reason exactly -- but I interpret those words when I saw them is -- because they were getting ready to act, to give us discretion, not provide civil penalties;

and, in fact, that's what was done. I didn't know that until I got the letter. But the significance of this letter -- go forward please again. (Referring to slides) One more. I don't know where I am in your slides. Go backwards. I'm lost now. Okay; C-A-L.

The significance of that to me was, I got agreement, you know. The NRC -- said, "Look, I'm going to do these things." And the NRC said, "Fine. If you do those things, it's okay with us; that's what we expect you to do." And then in the letter they sent to us, "and if you don't, we reserve the right to reinitiate those penalties that we have not implemented." I understand that.

The watch list. The watch list was created about ten years ago. Fundamentally what the NRC staff does it meets every six months, and in that watch list, in that meeting, they literally, if you will, put all the resources they have on the table and each senior executive talks about the plants, the power plants, the fuel facilities in their area and what is going on; and they decide where they are going to spend more resources and where they are going to spend less resources and those places where they will spend more resources are on the watch list.

Then there's a public meeting that is held, and that's when that's announced, but it doesn't change what we have to do to start up, but it does give us a lot of public scrutiny; and it's not a group of plants I particularly care to be associated with. But it, in fact, does not change what we have to do to start up.

Next line now. I got asked this question when I went-- how do you feel about the situation? I kind of had -- and that's what do you think? Well, I guess my feeling is this: That the modifications that we're going to be doing, the cavitating flow venturis and emergency feedwater, those have been done at ANO before, the design work has been done.

The analysis work has -- that we're doing on our steam driven feed pump, similar work was done by B&W for Davis-Besse. The diesel generator upgrade that we were doing was done at Baltimore Gas & Electric's Calvert Cliff plant, so we're going to use their work. Much of these things, the trial and error that these folks went through years ago, has been done.

So from my standpoint, I am a lot more comfortable with this position than I was at a previous plant where I had a never-before-seen problem and a never-before-engineered or designed solution that we had to implement because of an evolving issue.

So I don't -- there's a lot of work to do, but when I can take designs that others have used and engineer them to my plants, I'm a lot surer of the results and what we have to do to restore the margin. The regulators have also seen these, and we talked to the regulator about a cavitating venturi or a motor operated cross-connect. They've already seen those modifications or similar ones. They know the purpose of the modification. They know how it is fundamentally supposed to work, and so then the business says, "Okay, we'll wait and see how well you execute it." And that's a reasonable thing. I accept that. That's my responsibility.

So from that standpoint I'm very comfortable from this -- and it's entered -- we've always -- the whole time we have been talking about this side of the plant. This is the interest in the NRC. But in order for me to stay in business here, I have to worry about this side of the plant, too; and quite frankly, when I looked at the plant, you know, the last cycles have been very reliable. The plant had one of the best mills per kilowatt hour in the area, had a low capital embedded cost. I didn't think I was coming to anything but a runner.

I came down here and -- with objective of resolving these issues and I made a -- we're going to make a partnership with Framatome Technologies and we're going to use them as the design base agent, and we're going to solve these things similar to they have done at other places, and we're going to return this plant to service and run it. So I felt pretty good. Next slide.

You talk about how do you define excellence. I think excellence in power plant operations is safe, reliable, economic and environmentally sound operations, not one without the other, but all in balance. And what this outage is about is restoring the balance to this plant, and restoring the -- getting back inside the technical speculation and restoring the margin associated with these systems so that we get back in balance with safe, reliable, economic and environmentally sound.

With that, I would open it up for questions as to the report, the reasons why the outage has occurred or anything we can explain.

MS. BASS: Why don't we at this point take a break until about 11:00, give us a chance to stretch our legs, and then we'll start with the questions and answers.

(Brief recess.)

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MS. BASS: If everyone would take their seats we can get started, please.

I thought for a minute Jim McGee was going to answer all of the questions for us.

I guess my first question would be to ask the Company if you could very specifically go over the reason for the outage that occurred September 2nd, and perhaps show us on your chart where that occurred, and then go into the situation involving the diesel generators, which seems to be the reason for the extended outage.

MR. ANDERSON: I think Paul, you best talk about the leak, point it out to us on the chart.

MR. McKEE: The chart doesn't show it directly, but the system that caused the outage to begin with is used on the generator, Item 42 up there. It's the oil supply to the generator to lubricate the bearings. And beneath the generator is a large tank, and the oil, as it circulates, comes back into that tank and it uses a device called a deducter, which is just a pump that will pump the fluid by using pressure of existing fluids. You've probably seen a little device that you attach to your garden hose and can suck water out; it's the same type of thing.

That device was causing vibration in the pipe. And as the pipe continued to vibrate, some of the supports failed in there which allowed the pipe to vibrate more.

In addition, the pipe had what is called inclusions in it. It just means some sand or some leaky areas were in the pipe and those lined up in a certain way that that's where the break occurred from the vibration. It caused it to split in that certain fashion. It would have split anyway from the vibration, but the inclusions caused it to split there.

So when this pipe failed, then the pressure to the bearings, oil pressure started going down. So it's just like in your car, when the light comes on, tells you you have low oil pressure, we had to do something. So we shut the unit down, went in there, found the pipe, replaced it, took action to repair the supports and improve them, and had the unit ready to go back into service.

MS. BASS: Wasn't it this time that you did -- you reanalyzed your technical specifications or did the testing on the unit, or however you want to term it, that you determined then that the unit could not be brought back up because you did not meet the technical specs. Can you kind of tell me how all of that evolved?

MR. ANDERSON: Fran, can you answer that because you were in the thick of it.

MR. SULLIVAN: Yes. We were reanalyzing some questions that had come up as a result of the outage that Mr. Anderson was referring to from the spring of '96.

As a result of that analysis, in working with our NSSS vendor Framatome, and in answering questions from the Nuclear Regulatory Commission, that's when we began to understand the issue that has kept us shut down.

It's an extremely complicated issue. Not only diesel loading is involved but the design basis for emergency feedwater, mitigation strategies for small break LOCA mitigation. It takes several hours to explain. That's the way we understood it, yes.

MS. BASS: Are these tests that are normally done when you go into -- after a refueling outage, do you perform the same types of tests every time? I'm not being clear about what I'm asking.

MR. BEARD: Test on the emergency diesel generators?

MS. BASS: Yes. You said that these were things that were indicated during the refueling outage. And you tested again when you took the unit down because of the oil leak.

MR. SULLIVAN: It wasn't a test; it was an analysis.

MS. BASS: Was the analysis done during the refueling outage the same analysis that was subsequently done during the outage September 2nd?

MR. SULLIVAN: No, it was not.

MR. BEARD: Our understanding of these complex series of events by our engineering staff, headed by Fran Sullivan, it's just a continuum from, say, early spring '96, during the refueling outage where we made one modification. As Mr. Anderson said at that time we thought okay, this will resolve this thing once and for all. But it's so complex. We continued to study it, as Mr. Sullivan said, and then came to a further realization.

On October 4th he came to me with his team. We discussed these issues. And it was clear to us and to me -- me being in charge at the time -- that we would have to declare the diesel generator inoperable. Of course, we were on a shutdown, so it wasn't a matter of shutting the unit down but clearly we had to maintain the unit shutdown until we got to the bottom of this issue.

MS. BASS: Okay. Can you describe for me specifically what the problem is with the diesel generator now? The system that's affected by it.

MR. SULLIVAN: There's a couple of problems in the diesel generator. The one that Mr. Anderson referred to is our technical specifications have limits for our diesel. That limit is 3500 kW. We, as a result of some analysis that was done throughout the year, came to the conclusion that in a certain scenario, that we exceeded that limit for approximately two to three seconds. And that is the analysis that refers back to the law that Mr. Anderson is referring to where we exceeded it.

MR. ANDERSON: I think the other side, it's almost more a scenario of events. And I'll just play out the thought process.

Okay. We overload the diesel for two or three seconds. We don't meet the license. Let's turn those pumps off. Maybe we don't need them for this situation. Now, if you turn them off, plan to do that, what other types of problems exist that unloading or turning off those pumps cause? And it starts a series of issues.

And what -- the knowledge that was learned during this period of time was that "A" and the "B" was an overloaded initiating event. "B", you couldn't turn off the emergency feedwater pumps or associated equipment because you needed them for cooling. And then the question is how long do you need them for cooling down to reduce pressure -- that's what I say, there truly is interconnection, if I'm doing this correctly, between the diesel generator and the emergency feedwater system. That interaction between the two that set our system up, you could equally describe the problem as one of we have to keep power to the emergency feedwater system longer than the diesel will allow, which is a corollary, I guess, of the diesel is overloaded for a sort period of time. And both are equally true.

The safety systems are almost like a net. Their strength is in their combined working together -- which is whenever I sit down to go through this in detail and understand it, it's very maddening. One thing affects another, affects another, affects another, and then when we've done that, the question is to go back and relook at all of the scenarios we can consider; all of the breaks, all the break sizes, all of the pressure, all of the pressure sizes, all of the initiating conditions and make sure we haven't changed any of those other things.

And this plant had pushed -- it has worked around adding equipment to this plant for a long time and used up the margin. So that when you get down to trying to turn off the pump, it affects another situation and puts us out above the required margin and in another place. So you do something else.

And you're walking around this thing with Framatome, with the most experienced people we could find in the industry there's no alternative. In order to make this less complex, we need to restore the margins and take it from there.

MR. SULLIVAN: Yes, you described it correctly.

MS. BASS: Can you describe for me the specific scenario that causes that generator to exceed its margin? What exactly are all of the parts of it?

MR. SULLIVAN: Yes, ma'am.

The first thing we need to talk about is a loss of coolant accident. It's a certain size, certain small size break. There's a complete spectrum of breaks we may have. As we were talking about earlier you can have a big one-inch break up to a 36-inch break, and it's a circumcised break that is giving us an issue. So now you have the break. Then we need to have a loss of off-site power.

MS. BASS: So the first thing is you have the break.

MR. SULLIVAN: That is correct.

MS. BASS: Once that has occurred, then you have another condition?

MR. SULLIVAN: Yes. We're not done yet.

MS. BASS: Okay.

MR. SULLIVAN: Then we have a loss of off-site power. And what that means is that the power into the power plant is removed and the diesel generators are required to power the emergency safeguards equipment.

There's actually three scenarios, but the one that initially concerned us was we called it a loss of DC; DC is electrical. We have DC power in the power plant to provide electrical power for, say, its related equipment. We lose -- and we have two trains of DC electrical -- we lose one of the those trains. In other words, that DC power is not available; a fuse, a large failure like we have to suppose. That created the situation where we were concerned about overloading the diesel.

MR. BEARD: You have to assume all of this simultaneously. That's what makes this so complicated. That's why you have to have computers. Human beings could never -- so you assume that concurrently you have a loss of coolant accident of a certain size; you've lost off-site power, and you've lost all of your battery power on one side; single-active failure. All at the same time you plug that into the computer and sit back and say what happens? If any of the limits appear to -- and this is all calculations, hypothetical -- if the calculations don't come out right, and the numbers don't match your technical specification, then you have to do something about it. That's the way it works, as Mr. Anderson said.

And that's a scenario that -- out of the millions of -- there's like a thousand basic accident scenarios that we have analyzed and others. And on top of that you can assume any single actual failure anywhere in the plant, there are hundreds of components in the plant -- you put those combinations together and they are almost infinite.

And you can see why in the beginning without today's Pentium chip computers that it was impossible for the designers to figure out everything. They said, "Gee, it works great. A loss of coolant accident; that will probably be the worst case and we'll design the plant to cope with that."

The only way that we could have avoided doing what we're doing now, the plant has to be shut down, is for the original designers to realize that a small great load of 2.7 inch diameter would get us to this problem. And no one realized that until well after Three Mile Island.

MS. BASS: Okay.

MR. ANDERSON: This I found interesting when I first got into it. It's not just the leak of a certain size, it's literally a leak in a 14-inch piece of pipe between two valves, two isolation valves. That's the one we're dealing with. It's not a two-inch leak in the reactor coolant system or a two-inch leak in any other pipe; two valves 14 inches apart, that pipe has to leak at a certain size. And the A Battery, DC power doesn't exist and you have a loss of off-site power.

And what we became aware of was in that specific circumstance our system is going to have to function so fast, and we have to have certain equipment available, that we couldn't show the tech spec margins.

I always find it interesting, in retrospect knowing it, it's like the riddle you know the answer to. Once you know the answer, or once you've seen how to draw the line through the maze, I can always redraw the line, but the first time out it's a blind alley. And that's what we faced here.

MS. BASS: Okay. If I could ask one thing when you start to answer a question, if you will just say your last name for our court reporter. It makes it easier for her.

I'm getting ready to leave this. Does anybody have any questions specifically on that?

Okay. If you would -- do you have your preliminary reports, because most of my questions are going to come directly from that. And it's easier to refer to the page so we have it in context.

On Page 1 it states that -- three lines up from the bottom -- it talks about a statistical probability of occurring once in 11.6 billion years.

Is this the probability associated with the current situation, the emergency diesel generators, or what does this probability correspond to?

MR. ANDERSON: That probability was calculated to say a leak of this size in that piece of pipe, in conjunction with the loss of off-site power, in conjunction with a loss of the A Battery, B Battery or a failure to operate steam driven feed pump. The statisticians ran the numbers and said the probability is once in 11.6 billion years.

MS. BASS: Okay. The modifications that you talk about at the bottom of the page, have any of those modifications been completed?

MR. SULLIVAN: The modifications on the diesel generators to rate them, increase their power 150 kW have been completed and we're in the process of testing the second diesel now.

MS. BASS: Okay. Have you made any cost estimates of what all of these modifications are going to cost?

MR. ANDERSON: We're going through that right now. And what I told my boss -- it was the same question, too, pretty vehemently, is first we have to -- first we have to decide what we have to do. That's why that action with the NRC was so important. This is what we're going to do. The next step was this is how we're going to go about it hopefully using as many of the changes that other plants have done and learned from experience. Once we determined the how, then you cost it out in detail. And that's what we're doing. I've committed to do that in the next month to get that done.

But I wanted to -- again, I want to nail down what we're going to do, how we're going to go about doing it and then I'll staff it and schedule it. Detail schedule it and move forward.

MS. BASS: Okay. On Page 2, in the second full paragraph you talk about extensive changes that are NRC safety systems over the years. And you used approaches that satisfied NRC regulatory safety requirements.

Does the NRC have to specifically approve those engineering approaches that you used, or do you choose the approach to use and then later on they let you know that was wrong or right?

MR. ANDERSON: If we do an engineering -- first of all, the NRC has two resident inspectors who look at everything we do. If we make changes to the design basis and/or changes to the license in the engineering approaches, we submit that and they approve them at that time.

They also -- I don't like to say "ever" or "never" because those don't exist -- they do inspect close all of our work as possible at that time.

It's interesting, in the contemporary reports back in '87, '90 and '95 time frame, in their evaluation of the work, when you read those and read the ones that are done today, ICAP, the retrospective look, they are very critical. That's a time that -- Fran, can you answer that more specifically as to what they looked at?

MR. SULLIVAN: As far as --

MR. ANDERSON: Engineering submittals.

MR. SULLIVAN: Engineering submittals. We also have a law called 10 CFR 5059.

50.59 is an evaluation process by which we go through to determine that the modification that we're doing to the power plant conforms with the standards and the licensing basis as the NRC understands it. If we go through that screening process and we find no problems with that, then the modification goes in and we will submit to the NRC on a periodic basis the updates to our licensing basis, or what we call our final safety analysis report or FSAR.

MR. ANDERSON: What is the frequency of that? Is it every six months?

MR. BEARD: Every refuel.

MR. SULLIVAN: Yeah.

MR. BEARD: The NRC reviews all of the modifications. As I've said, and let me sort of summarize one of three ways.

Under 10 CFR 50.59 there are three questions that are asked. If the answer to any one of those is yes, then we submit the modification at that time for NRC review. And this generally involves unanalyzed situations.

Secondly, if -- because that is not the case, then they see all of the modifications as part of our periodic update to our final safety analysis report.

Then as Mr. Anderson said, the various on-site inspectors, inspectors from the region are always watching us. So there's three different opportunities for them to be involved and understand what we're doing.

MS. BASS: And the NRC issues a formal document that says "we agree with this" or "We approve this" or --

MR. BEARD: Only in the first instance. In other cases their approval is implicit; if they don't say anything then obviously they concur. But by regulation the owner is required to submit official correspondence in that first instance that I mentioned.

MS. BASS: And the last full paragraph on that page, you make a statement the approach worked until 1996, when the company and the NRC determined that some of the changes they implemented could not meet the requirements.

How was that determined? What did you or what did the NRC do to determine that you no longer fully met the rigid requirements or rigid margins of safety?

MR. SULLIVAN: Crystal River determined that. Florida Power determined that. We did it via an analysis.

Quite simply, we sat down and we went through all of the scenarios that we had talked about previously, and rigorously analyzed them with some of the best minds we could find. And that's when we made the determination we had this problem. And that was in the fall of last year.

MS. BASS: The analyses that you did, did they result in a document or a report or anything?

MR. BEARD: Licensee Event Reports. In the appendices to this report there are two Licensee Event Reports that discuss these issues.

MS. BASS: Okay. In that paragraph you also state that in consultation with the reactor designer you performed comprehensive reviews. Were there reports done? Is that review in the form of a report or a document?

MR. SULLIVAN: That is a document that we just presented to the NRC back last week, last Tuesday and we'll be happy to show that to you.

MS. BASS: Okay. And we'll probably ask for that.

MR. ANDERSON: What we're doing is -- in the analytical work is we'll make a series of presentations because, again, it's a relatively commplex issue and a complex solution for the NRC, so we want to bring them along. "This is how we're approaching the problem. This is what we plan to do." And then as packages are put together, we'll send them in. We have not sent those in yet.

That's in our time line -- coming in the last of them, they should be starting to go in I would guess around May or June time frame, and probably be done in the September time frame, to support the restart. But we'd like to make sure they come in as a package because any one submittal taken by itself doesn't answer all of the questions. As a matter of fact, can cause just more questions. So it's more important we keep them familiar, move them in. We're going to move them in in a sequence and all at once.

MS. BASS: Okay. At the bottom of the page you talk about no available, less extensive modifications. How was that determined?

MR. SULLIVAN: We determined that as part of the analysis, the rigorous analysis we went through with Framatome, our engineering staff and their engineering staff. We also have consulted other nuclear plants of our type. And, again, that was part of that rigorous analysis that we showed to the NRC last week.

MS. BASS: That's also part of this report or what was presented to the NRC?

MR. SULLIVAN: Yes.

MS. BASS: Who made the final decision -- this is on Page 3 -- the final decision that the only way to restore the safety margins was to make the significant equipment modifications?

MR. BEARD: My name is Beard and I made the decision.

MS. BASS: Okay. And the next section, making the modifications, could these modifications have been done on a piecemeal basis or did they need to be done all at one time?

MR. BEARD: Let me give my opinion, and then Fran and Roy.

My opinion is that they cannot be made on a piecemeal basis; particularly the ones, the emergency diesel generators, emergency feedwater; that's the issue that we're down to address. The others, as Mr. Anderson has said, we could have elected not to have done those now, although it's smart to do so since we have this opportunity to avoid potential future "what ifs" as we continue to analyze. And analysis will continue forever.

But when you try to do things piecemeal in a nuclear power plant you usually end up wishing you hadn't because there are so many, it's been said, interrelated actions that you have to look at the system as a whole. So the answer is no. In my opinion you have to do it the way we're doing it, and as others have done.

MS. BASS: You state that if the modifications had been made any sooner, another extensive outage would have resulted, too. How did you come to that conclusion?

MR. ANDERSON: That the work that we're doing requires that the unit be shut down. I've looked at what others have done.

As we went out culling the industry on how some of these issues have been resolved, taking pieces, all of this work requires the system to be out of service. Once out of the service, the unit goes into the tech spec, limited condition of operation and it requires a shut down.

The longest line up there, diesel generator and emergency feedwater line has to be done with the unit shut down. You can't be operating when you do that.

MS. BASS: So there are other nuclear units that have made these modifications?

MR. ANDERSON: Similar modifications, that's correct.

MR. BEARD: Similar but not all exactly the same. None of the B&W plants, using the B&W plants, are exactly the same. They are all somewhat different. But all of them have in the past taken actions to do things similar to this.

If you recall, the Three Mile Island operating unit, which is still operating, was down for some like seven years after the accident before they came back on line. On the Davis-Besse unit they had an event in '85, and they are down for some three years. Arkansas Nuclear, well, the same thing.

So other B&W plants have had very long and costly outages. Not just for these reasons but for others, but including these, and we've not had that.

So now we're taking our turn to address this.

MR. ANDERSON: About the only way to avoid this outage is if the original designers had done this work during construction and had known what we had known what we know today and dealt with these issues. Other than that, I can see no way to avoid not doing this work.

MS. BASS: Did the other units take care -- did the other utilities take their units down for an extended outage and do it all at one time, or did they do it on a piecemeal basis over an extended period of time?

MR. ANDERSON: Yes.

MS. BASS: Thank you.

MR. ANDERSON: It happened both ways.

But it's interesting to look at, for example, Arkansas Nuclear and their cavitating flow orifices, that they didn't function the first time in the way these orifices were anticipated to. They were back down again. There were multiple times these units went down to do this work. Some of them chose to do pieces of this work in different outages.

Our choice here is since we have a long time line, to do the work underneath the time line and put it behind us. So it's not work that could potentially affect outage time in the future.

MS. BASS: How does your time line compare to what other utilities have done that have done it on an one-time modification?

MR. ANDERSON: From what we've seen, talking to executives of utilities at that time, pretty favorably.

MR. BEARD: I'd like to again point out, it's something that it's very difficult to compare us exactly.

For example, and I've forgotten which B&W unit it is, our major issue here is we have an emergency feedwater pump, the "A" pump, that is motor driven; takes electrical current. Once that was made safety related after Three Mile Island to address small break LOCAs, we had to put it on a safety diesel, we put it on the "A" diesel; that's when this issue started. Again, something that was not foreseen by the original designers.

But there is a plant that does not have motor driven emergency feedwater pumps, they're both steam driven. So they don't have -- Davis-Besse. So they don't have that particular problem.

So you see what I'm saying? Our plant is somewhat unique so it's difficult to say exactly --

compare time lines with time lines.

MS. BASS: Do you have any idea when the emergency diesel generator first did not meet its technical specs? The analysis that you did when you determined that it did not meet technical specs, was that the first time that you were aware that it did not meet technical specs?

MR. SULLIVAN: Yes. And the reason I say that is because we did not shut down before.

MR. BEARD: The first time that I was aware.

MR. SULLIVAN: If we do not meet our technical specifications, as Mr. Anderson referred to, we need to comply with the limited condition for operation, which means we either correct the situation within a specified time frame, or we shut our unit down.

MR. ANDERSON: Had we found it a year ago we would be doing this. Had we found it in that, you know, sometime in the future -- whether it was in the spring or a year ago in the spring, this same type of level of effort would have had to have been required at that time.

MS. BASS: How often would you do an analysis or run the computer model to determine whether or not it was within its technical specs?

MR. SULLIVAN: The particular model, the diesel loading model that we're talking about, we run it approximately every two years. Just so you understand the complexity of this, this model has major, major databases that are associated with it. In hard copy form it's about 7,000 pages. It takes a long time to run.

We are presently working with a modeling company to get a faster model so we can run more often, but --

MR. ANDERSON: The real answer is when we make -- to be absolutely specific, if we make a change to the power plant that takes on or removes load or changes the timing of any of the loads associated with any of the diesel generators, we will remodel the diesel generator.

If in industry situation with the FERC, a generic letter from the NRC that says "Have you thought about this? How do you know this couldn't happen at your power plant?" And it affects any of the systems that are powered from the emergency diesel generator or support the emergency diesel generator, we will rerun that analyses. It's our obligation.

MS. BASS: Is that an NRC requirement that if you make a change that would affect the diesel generator, that you run that specific model?

MR. ANDERSON: I would say specifically does the NRC say you have to do this if you do this? No. What it says is you have to assure that you're maintaining the margins and that you have not changed any of the loads that are identified in the technical specification, any of the assumptions that we use when we made these things. So from an engineer's point of view the way I can do that is to redo it. To make a leap of faith and say I don't think so can get us into trouble.

MR. BEARD: They don't tell you how to do it, you just have to meet the rules. I want to go back to the calculation again and make a couple of points.

As Fran said, we only make it once every two years. And in fact we just completed our -- and are even now doing a full computer-based model; is that correct?

MR. SULLIVAN: That correct.

MR. BEARD: Which is very expensive; it's 7,000 pages.

At the interim, as Mr. Anderson said, as we do a modification that would add an additional load, there is someone in design engineering specifically tasked with keeping the checkbook up-to-date. So you do that. I mean just mainly, okay, we're at 3100, added 12 kW, so we're at 3112. That's fine. But that's not good enough because also over time we may change a motor somewhere, do something over here, or we may gain additional information from a manufacturer for motors that says, "Hey, the load factor on our motor is different than what we told you and it draws more amps."

At some point you have to then put all of that back into the computer. Or as pumps degrade with time, they are not as efficient pumping water. And they may draw more current. So from time to time you have to go over and rebaseline the whole thing.

MR. ANDERSON: There was a problem, and I don't recall the plant specifically, but it ended up in a generic letter causing people to look at their diesel generators.

And basically it looked at instrument and relay, little switches, from a initiating event would operate in the chain from the piece of equipment it operates. And apparently with all of the errors that 2% inaccuracies, 2%, 2%, 2%, 2% -- I'm using just a example, this one particular plant's function didn't initiate within its limit at the end. And so we had to go back and do instrument relays backups. I was not here. I was at another power plant but I remember doing it.

What we found was when you started stacking up all of the most adverse potential errors, plus or minus 2% -- plus or minus 2%, even though statistically the probability of everything being low or high are typically low. That's eating the margin on this diesel generator. Because when we look at all of the relays and all the starting times and all the things, took them at the worst condition, we were required by the letter to assume it was the worst case. And consequently had to lower, that reduced, if you will, the margin for the start time, which was the mission. The way it showed up is we shortened our start time. I'm using this as an example.

But that particular issue has caused heartache in other systems when that's the measure by which we are held accountable. Very, very conservative but different from the way this plant was designed.

The way it was designed is, I take a switch and initiate it. If you operate on time at the right place and perform according -- everything is assumed to be okay. We don't do that anymore. And that's enough weight over time to redo this analysis.

MR. SULLIVAN: Our process requires all of this by the way. So when you ask the question does the NRC requires it, actually it's Florida Power's process. Our procedures require us to do the calculation reruns and the assessments that Mr. Beard is referring to. We do both. We do the calculation on a periodic basis if we don't do a major modification; if we do a major modification we run a calculation. If we add a light bulb in the control room, we do an assessment which is cost-effective.

MS. BASS: What was the impetus then for you to do this calculation now? If the unit was done, came down in September, but it wasn't a result of a change to the emergency diesel generator system, why did you do the analysis then on that particular system?

MR. SULLIVAN: We were running one of those periodic analysis that I was talking about. The way I like to describe it is that we maintain a checkbook on those small little changes, and periodically, by our process, we have to update the checkbook, balance the checkbook. And that's what we were doing in the spring and summer of '96, is bringing our checkbook up-to-date, if you will. And that's what put us in this situation.

MS. BASS: If it unit hadn't been down when you ran this check list, then it would have been one of those technical specifications that you would have had to bring the unit down if you --

MR. BEARD: That's correct.

MR. ANDERSON: Limiting condition of operation, which would dictate an action, which in this case was to shut down.

MS. BASS: At the bottom of Page 3 you talk about you were beginning to develop and implement corrective action plans far in advance of your shutdown. How far in advance of this shutdown? When did you begin these plans?

MR. BEARD: We began dialogue with the Nuclear Regulatory Commission in March of 1995 with our first meeting where we embarked on what we now call Phase I of our Management Corrective Action Plan. And even though in that time frame we were operating with the highest capacity factors in the country and what have you, we were not pleased with some of the things that we had seen in our plant, again realizing in our business, both our internal organization INPO and NRC we continue to ascribe for ways to perform standards of excellence. But nevertheless, they were our standards.

So we embarked on a Management Corrective Action Plan, Phase I, in March of '95. We completed that in 1996, early '96, and in April of '96 we embarked on what is now we call Phase II of MCAP. And that's the one that we provided you. We presented that to NRC for the first time in August of '96.

MS. BASS: Okay. On Page 4 you state the NRC stated that Florida Power took appropriate action in keeping the plant shut down. Did they state that in a letter or a document or --

MR. BEARD: Yes. There are a couple of places where they have endorsed both our MCAP and our actions. I think Roy in the SALP Report, in the enforcement action on engineering issues, I think there's an acknowledgement of that. And there's one other place where we're given credit for that.

MS. BASS: Are those documents that you have provided in the appendix to this report?

MR. ANDERSON: I can't speak to all of them but I believe the SALP Report is in here.

MR. BEARD: I want to make sure. Let's take an minute and get that. (Pause)

In fact, I think when they replied to our letter -- well, the confirmatory action letter, Roy, also gives credit. (Pause)

MS. BASS: I'm now on Page 10. You're discussing the emergency feedwater system. About halfway down the page you make a statement that "Florida Power opted to meet the loss of off-site power contingency in the case of its emergency feedwater " etcetera, etcetera.

Did you study what other options were available to you? Or were there other options available to you than the one that you picked?

MR. BEARD: This is back post Three Mile Island when we were meeting the new reg 737 requirements, and Paul McKee, maybe you can -- you were the only one around in that time.

MR. McKEE: Could I get you to state the question again? I was looking at the SALP, trying to find that other question.

MS. BASS: I guess maybe it was the wording that kind of threw me off. It said that Florida Power opted to meet the loss of off-site power contingency, we would lead me to believe that there were other operations available.

MR. BEARD: This is when the emergency feed pumps, Paul, were safety related. You know, things like other diesel, putting in other emergency diesel generators.

MR. McKEE: Yes. At the time the other options -- the only option that appeared to be available to us was installing another diesel generator, which would require a major outage, a lot of money and a lot of electrical cabling, breakers everything else in the plant. That was the option. And this one, by adding it in and by working on the control systems appeared to be a much better solution and prevent a long shutdown and a new diesel generator, similar to the type of thing that was done at Turkey Point where they had to add new generators.

MR. BEARD: I think I remember hearing figures of $100 million in two years or something like that.

Another option that we pursued to the point that we think that we do not want to pursue that any further, is that we've had our operators take manual action in certain scenarios. And that's okay to a point, but you don't want to burden them too much. So we've used up, in our view, as far as we want to go with that. Again that's a cost-effective way. You don't have to put in any modifications. But, again, you have to balance the burden you're placing on them.

MS. BASS: Okay. On Page 11, first

paragraph on that page you state that this action was done in consultation with Babcock & Wilcox, the designer of the reactor, and with the knowledge of the NRC.

When you say "the knowledge of the NRC," does that also imply approval of the NRC, or is that something that the NRC would have to give you specific approval on?

MR. BEARD: That's the trip lock -- no, no, that's the ASV 204, 1987, Fran?

MR. SULLIVAN: I'd have to --

MR. BEARD: I think there's a safety evaluation report from the NRC on that.

MR. SULLIVAN: We'd have to go back and look specifically at your question.

MS. BASS: Okay. You'll probably hear that again, then.

Also at the bottom of the page, third line up it also talks about a modification done with the knowledge of the NRC. And my question would be the same on that: Did that require approval also by the NRC?

MR. SULLIVAN: That one I can talk about a little more specifically. There were many discussions between ourselves and the NRC on that particular modification, the one that was done in 1990, so yes, they are involved and it was direct.

MS. BASS: On the next page, Page 12, you talk about essentially the unit's operating capacity and that it's had a very favorable operating history.

Do you have the data available on that?

MR. BEARD: Yes. Yes, we do.

I don't think we've provided that but we have it. It's all of that material that we put together last week.

MS. BASS: And the last paragraph on the page, about mid-way down in that paragraph, you're talking about while the plant was shut down that Florida Power became concerned. What caused you to become concerned?

MR. ANDERSON: Paul? Fran?

MR. BEARD: We'll give Fran a chance.

MR. SULLIVAN: I'm trying to find the spot here.

MR. BEARD: Towards the bottom of Page 12. This is the beginning of the refuel when we became worried about the MPSH on the emergency feedwater.

MR. SULLIVAN: Specifically the concern was as analysis that we were doing to support a modification, another modification in the power plant.

And a question came up in that if we had that scenario we talked about earlier, a loss of coolant accident with a loss of off-site power with a failure of a DC train electric, that we may have a problem where both our emergency feedwater pumps would cavitate, and cavitate means they would become inoperable, and that was the concern we were talking about.

MS. BASS: What other modification was being made?

MR. SULLIVAN: I'd have to go back and look at that. I don't remember the one in particular.

MS. BASS: On Page 13 in the first full paragraph, about midway through the paragraph, you state that Florida Power believed that the "A" emergency generator could now handle the load. What was that belief based on?

MR. SULLIVAN: That belief was based on correspondence between ourselves and the diesel generator manufacturer.

MS. BASS: Did you do tests to confirm that the emergency feedwater pump without the assist of -- I mean that the "A" emergency diesel generator could now handle the load when you brought it back up to service in May?

MR. BEARD: Getting back to your testing question, after every refuel outage we do test the emergency diesel generators, their ability to pick up load as close as we can to postulated accident conditions, realizing that we can't fully simulate nor would you want to. And our testing was fully satisfactory.

For example, I recall that we -- I think we tested at 3159, even though the tech spec was 3100 in the diesel, we have correspondence saying that it can certainly handle that.

So we didn't run at 3700 because you can't put enough load on it, you know, under normal conditions. You can extrapolate. But, again, we had correspondence from the diesel manufacturer based on their analysis that our calculated worst-case load of 3500, or whatever it was, would be okay. So we feel confident starting up the unit.

MS. BASS: Okay. On Page 14 in the top part of the -- in that first paragraph, I guess the last two sentences, it talks about improved technical specifications, that Florida Power was required to keep the plant shut down until it could rectify this problem: Required by NRC or required by the technical specs or -- ?

MR. ANDERSON: The technical specification directs that the unit stay shut down.

MS. BASS: That's what you were responding to, those technical specifications.

MR. ANDERSON: That's correct.

MS. BASS: The next paragraph, I guess it's about of the second sentence, "Florida Power exhausted the range of options available to it." What were those options? Or did you do a study to determine what those operations were?

MR. BEARD: There were operations like -- Fran, you join on this -- but, again, you know, consider putting additional burden on operators. And we did talk about that. You know, for example, you could say, "Well, we'll just have the operators turn back on the electrical driven feed pump at the right time and then turn it off." But our belief was -- and, in fact, the Nuclear Regulatory Commission has recently taken a position on this, is that no, adding additional operating burden was not a reasonable option. And, Fran, you can talk about other options we considered. But I think we knew the answer by that time.

MR. SULLIVAN: That is correct. Other options we've looked at, there's only so many pieces of equipment that you could take off the ES and still perform the safety functions. We're looking at doing some very small modifications this outage.

The other options that we've evaluated, though, are replacing the diesels, putting in a third emergency feedwater pump that would not be driven by a motor but be driven by a diesel generator itself. All of these are expensive modifications that will take two years to design and implement.

MR. ANDERSON: There is something, just to talk a little bit about emergency accident responsive power plant.

During emergencies the objective of the system, when we talked about operator actions -- the objective of the systems is that they will function automatically and the operators will observe their functioning, and only step in and have to take action when the automatic system doesn't function.

So the idea of not having a system that can function and do its job automatically in requiring operator action, not as a backup but as a first line of defense, is not the preferred mode. And that's what Pat was referring to earlier when the NRC -- you know, their position is, is that the system should do its job and the operator should act as a second line of defense, not the first line, and that's why those options are -- they are not preferred.

MS. BASS: Okay. On Page 15, fifth line up from the bottom, it says "Florida Power intends to submit a request for the NRC to approve license amendments relating to these modifications." Do you have any idea how long it will take to get those approvals?

MR. ANDERSON: I believe it will take a minimum of 60 days; 30 days in the public document room and 30 days minimum time to review those. That's why it's so important on the schedule that as this work is being done, calculations are being made, that we continue a dialogue with the NRC so that this isn't a two shopping carts full of detailed calculations and analysis that we give them and would like back in 30 days. It will be a culmination of the work.

I think Ms. Reyes at a recent press conference, who is the regional administer of the NRC, was asked that question directly, is can the NRC respond to the amendments that we'll be submitting and updates? And his comment was that if we keep to the plan, that he believes the NRC can support in the time frame that we have outlined.

MS. BASS: I think that's all of the questions that I have. Does anybody -- Jim, do you have any questions?

MR. BREMAN: Yes, I have a few. You mentioned some plants that did some modifications. If you turn to the time line chart over there where you have Crystal River unit restart plan, can you point to a line and name those units? Like for example, the diesel generator emergency feedwater interaction. Is there an unit that you're using as a model to meet that requirement?

MR. ANDERSON: Yes, I can do that, but I'd like to say that what we're doing is taking pieces of what others have done, because since the designs are similar but not exact, it's not a direct lift. I can't take their engineering work, for example, and apply it directly.

The emergency feedwater, the cavitating venturis, Davis-Besse, Three Mile Island, Rancho Seco all did those modifications. I'd have to check about Oconee. I thought Oconee did them also. I'd have to check that.

The low pressure injection time line for there is a TMI modification. High pressure injection flow restricting orifices. Oconee, TMI ANO. It's embedded in their isolation of normal makeup line, TMI, ANO, Davis Bessie, the diesel generator upgrades were done as Baltimore Gas and Electric's Calver Cliff Plant; one on top there we're using that work. Fran, do you want to jump in here if I missed some?

MR. SULLIVAN: Sure. Additional modifications that show up in that emergency feedwater interaction time line we're working the ANO on which is Arkansas Nuclear Unit 1. Install RB penetration MAR. There's a generic letter, 9606 that's out on that. That's a countrywide issue that has just come out. And we're working with other utilities on that one as well. In fact, we've come up with a device that we're going to apply for a patent for that other utilities will be using with us.

We are conversing with our fellow B&W plants on all of these designs to take the information that we can get. For example, that HPI cavitating venturi modification that's up there, ANO has done that.

We have talked to them and gotten the benefit of their lessons learned so we can improve upon our designs. On the emergency feedwater cavitating modification, we were utilizing their structural designs to structurally support devices, and, in fact, have beefed them up. So there are a lot of lessons learned there that we are taking from the industry which are helping us in our ability to do the job in a faster manner.

MR. ANDERSON: The issues we talked about, two of the failures we had to deal with were the loss of DC power, the batteries from A and B site. We're using work that was done as Oconee, Arkansas Nuclear 1 and Belefont plant. Again, just wherever -- we are looking at other people's work and where in conjunction with the reactor designer we feel it's best applicable to us and provides the clearest cut solution and has been testeded and proven, we're moving forward with it. But as you can see it's no one specific plant, because we're not exactly the same.

MR. BREMAN: Is there anything on this chart that's an option that might be deferred until the next fueling outage?

MR. ANDERSON: Yes. The cavitating venturis could be deferred. We're geared up to look at these systems and looking heavily with them. The reason we chose to do that work now is because of the extended outage to deal with the emergency diesel generator emergency feedwater interaction, and felt that while we had Framatome Technologies under contract, while we were dealing with these issues, while we had the welders trained, the engineers focused on it, and the plant was available, it was the right thing to do.

Fran, are there any others --

MR. SULLIVAN: No. The rest of the modifications up there are required for our startup plan.

I'd like to add on that HPI venturi modification, it is optional. That does two major things for us. It adds margin into the power plant.

Mr. Anderson, when we started off, he was talking about design margin. So it's a definite benefit for us in that regard. The second thing it does is it reduces operator burden, which we were talking about earlier, and the operator having to take actions earlier in an event. And while that's not an analytical margin, it's a real world margin because the operator doesn't have to put his hands on the controls until later in the event. It gives him more time to analyze.

MR. ANDERSON: Having that margin, having that done, is a benefit because if future questions come up -- and remember or appreciate that all of these plants -- these systems operate in concert, when a scenario comes up, if one does -- maybe one never will -- it gives us the option to lean on that system a little harder.

MR. BREMAN: I have a final question. It has to do with my lack of understanding of how these LERs get numbered. There's LER, there's a two-digit number, three-digit number. What is that? How does that work?

MR. BEARD: Yeah. The first two numbers of the year, the calendar year, like LER 96-0012 would be the 12th LER we wrote in '96. Then as you write supplements to an LER, like providing additional information, for example, in a case I just mentioned like the first supplement would be No. 96-0012-1 that's supplement 1 to the 12th LER 1996.

MR. BREMAN: That's all for now. Thanks.

MR. ANDERSON: We have requirements that we have to submit them within a specified time frame regardless of whether the investigation is complete? And we have to submit periodic updates until it is completely resolved and closed out. So that's why you end up you might see Rev. 1, Rev. 2, Rev. 3 and all it is is an update of what it going on.

Those occur particularly when the solution involves a refueling and work we would do then. And if it occurred during a cycle, you're going to see updates until we do the work.

MR. VINSON: I have a few questions related to the planning or the anticipation of the problem with the emergency diesel generators coming up.

For example, on Page 10 and part of the excerpt that Roberta read to you earlier, talks about "Florida Power opted to meet the loss of off-site power contingency," etcetera. "This placed an additional electrical loading burden on the A emergency diesel generator and thus reduced its operating margins."

I'm getting the picture of reducing margins or an approaching problem with the emergency diesel generators. And I'm not understanding why this was not anticipated. Why was this not something that needed to be planned for?

MR. BEARD: You mean what we're doing now? Why wasn't that planned for? Because it was our understanding and feeling, and we were satisfied, as was the NRC back in these days, that considering the alternative, like what we're doing now, like hundred million dollars for a new diesel generator was not a cost-effective or necessary thing to do. And, again, we're trying to deal -- we have been trying to deal with the fact that the original designer didn't foresee what we're now having to cope with. So we were very confident that this was sufficient. And it's only been since that time, as we've talked here many times, as additional requirements have been laid on and we've had additional insight into this type of event with the use of computers, that we finally come to this point.

So at every point previous to this we were satisfied that we were going to be okay, that we had done what was sufficient and cost-effective.

MR. ANDERSON: I think that -- to build on that, at the time, with the issues that were presented, our diesel generators had the capability of dealing with the problems. And I think the right thing to do is to use that capability. If tomorrow or a year from now we may find some other question or have another requirement put on where other equipment will be made safety grade, we'll deal with it at that time and I think that's the right thing to do.

To have margin in the power plant, excess capacity, whatever, built in, and then when the new question comes up, not to relook at its use but to just add more in, is not -- I don't think that's the right way to deal with the situation.

And I appreciate your comment because all nuclear power plants to one degree -- not all, that's wrong.

The other power plants that I have been dealt with, diesel loading, as we became more restrictive with our instrument error loops, has always been a question. And in each case these are hypothetical situations. And I've always taken the position that we should at this point -- we should look very hard at the plant to see how we can make the existing equipment do its job as opposed to add equipment and time and money and shutdown time to solve the problem.

So I think the actions at that time with what people knew and were certainly approved by everyone else were satisfactory. I agree with you though in retrospect. Will that continue in the future? I hope not. And I don't know of anything that would cause it.

MR. SULLIVAN: I'd like to follow up for a minute.

The issue that we're talking about here is when we initially put the diesel -- emergency feedwater pump on the diesel. This is the 1980 time frame; this is post Three Mile Island.

As Mr. McKee and Mr. Anderson referred to earlier, the original plant design did not have the emergency feedwater pumps as safety related. If you go back into the design periods of the '60s and '70s, the best minds in the world felt that was satisfactory.

As a result of Three Mile Island, you're talking a great wealth of information came out to the industry. A lot of modifications were done to our power plants as a result of Three Mile Island. Our training programs have increased. Our quality programs have increased and our engineering staff has increased.

What we've done is they made a decision to put a emergency feedwater pump on the A diesel. We had margin obviiously, or we couldn't are done that to start with on the original construction.

That's kind of the history. Now, how we could have prethought that, there's no way we could have done that.

MR. VINSON: Did the NRC conduct an electrical distribution system functional inspection at Crystal River 3 in the last five years?

MR. BEARD: Not in the last five years. I think it was 1987, Paul or Fran, as I recall. It had been done berore I arrived.

MR. SULLIVAN: The call it the ED electrical distribution safety functional inspection, and we'd have to get the year for you. I forget. It has been done at Crystal River.

MR. BEARD: I think it was '87 or '88.

MR. VINSON: So what would have prevented that inspection from having detected these margin problems?

MR. ANDERSON: I think the question is not so much what would have prevented it, but for the accident scenarios, we, in the collective industry and the NRC, were rooking at at the time we met the requirements.

However, subsequent to that, looking at other accidents -- I mean, we hadn't looked at a whole 2.7 inches in a 14-inch piece of pipe until very recently. I mean gone back and looked at every place. So I can't speculate back then why, but I can tell you that those inspections, the function of them was to take the design basis of the electrical distribution system, the loads that were applied to that, and ensure that these systems could function to the postulated scenarios, to the scenarios that had been postulated at that time. And without reading the report in detail, I would say our system either did that or they identified things that we had to do something about.

MR. BEARD: That is correct. They did identify some other design issues which we have dealt with. We've upgraded the switch yard. We've added another off-site transformer. We've changed the timing relays that block load, the emergency diesel generators with more accurate timing devices. And we upgraded the capacity of the diesels in 1990 by adding bigger turbo chargers or coolers.

So they did find issues that we've dealt with. This issue was not seen by themselves or ourselves at that time for the reasons we have talked.

MS. BASS: That's all the questions that Staff has.

Does anybody else have any any questions they want to ask at this time? Is there any other party or interested person that wants to present any additional information at this time that was part of the notice of the workshop? No.

Well, that's all we have. Thank you very much for coming and making the presentation and answering our questions. Thank you. over the 1214 p.m.

(Thereupon, the workshop concluded at 12:14 p.m.)

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STATE OF FLORIDA)
:
COUNTY OF LEON)

CERTIFICATE OF REPORTER

I, JOY KELLY, CSR, RPR, Chief, Bureau of Reporting, Official Commission Reporter,

DO HEREBY CERTIFY that the Workshop in Docket No. 97026-EI was conducted by the Staff of the Florida Public Service Commission at the time and place herein stated; it is further

CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript, consisting of 102 pages, constitutes a true transcription of my notes of said proceedings.

DATED this 27th day of March, 1997.

Joy Kelly

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