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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

April 26, 2006

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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

MEETING OF THE SUBCOMMITTEE ON POWER UPRATES

BEAVER VALLEY POWER STATION EXTENDED POWER UPRATE

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WEDNESDAY,

APRIL 26, 2006

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The subcommittee meeting convened at the Nuclear Regulatory Commission, Two White Flint North, Room T-2B3, 11545 Rockville Pike, at 8:30 a.m., Richard B. Denning, Chair, presiding,

SUBCOMMITTEE MEMBERS PRESENT:

RICHARD B. DENNING, Chair

SANJOY BANERJEE ACRS, Consultant

THOMAS S. KRESS

OTTO L. MAYNARD

JOHN D. SIEBER

GRAHAM B. WALLIS

ACRS STAFF PRESENT:

RALPH CARUSO

FIRSTENERGY STAFF:

BOB BAIN	Stone & Webster
DON DURKOSH	FENOC
BILL ETZEL	FENOC
KEN FREDERICK	FENOC
DAVID GRABSKI	FENOC
JEFF HALL	Westinghouse
NORM HANLEY	Stone & Webster
GREG KAMMERDINER	FENOC
COLIN KELLER	FENOC
JAMES LASH	FENOC
MARK MANOLERAS	FENOC
PETE SENA	FENOC
GEORGE STORLIS	FENOC
MIKE TESTA	FENOC

NRR STAFF PRESENT:

TIMOTHY COLBURN
STEVEN LAUR
GREGORY MAKAR
ROBERT PETTIS
MARK RUBIN
THOMAS SCARBROUGH
ANGELO STUBBS

A-G-E-N-D-A

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

8:33 a.m.

CHAIRMAN DENNING: We are now back in session. And this is Wednesday, April the 26th. And we're going to start off discussing mechanical impacts and Mike Testa.

MR. TESTA: First I'd like to thank the Committee for the opportunity to speak here today. My name is Mike Testa, I'm the extended power uprate Project Manager for Beaver Valley.

A little background on myself. I have 23 years of experience at Beaver Valley Power Station. The last five year I've been the uprate Project Manager and I also was on the full potential project from the beginning.

Today I'll be discussing the mechanical impacts that the uprate has on Beaver Valley Power Station.

Next slide, John.

I'll be discussing the steam generators, balance of plant heat exchangers, vibration monitoring program for the secondary piping systems, cooling water systems and flow accelerated corrosion, of which we'll have our program owner come up and speak on that program.

Today if there's any questions, I have Jeff Hall from Westinghouse to assist me as well as Bob Bain from Stone & Webster.

For steam generator vibration, we looked at the first thing, we used a thermal-hydraulic code Athos that computes the thermal-hydraulic parameters the tubes so the tube bundle would be subjected to.

We looked at the vibration potential in the U-bend and tube bundle entrance region. Out of two vibration mechanisms that were considered, were fluid-elastic instability, vortex shedding and random turbulent excitation.

And we also looked at tube wear. And that's tube wear in the U-bed radio at the antivibration bar interface.

The tube bundles, just the difference between the units now. For Unit 1 we replaced the steam generators. We discussed that yesterday. Model 54. Just installed in fact a few weeks ago here. The model 54 was designed for uprate conditions so the stress report, the design report considered uprate.

For Unit 2 we have the Series 51 steam generator, of course, which now will see increased flow because the uprate.

We reviewed the --

MEMBER WALLIS: I presume the steam generators is plural and you installed three of them?

MR. TESTA: Yes.

MEMBER WALLIS: Not just one?

MR. TESTA: Yes, correct. That's correct. Yes. Three loop PWR 3 steam generators.

We looked at the flow induced vibration effects --

DR. BANERJEE: What's the difference between the two?

MR. TESTA: Between a model 54 and 51?

Jeff?

MR. HALL: Yes. This is Jeff Hall from Westinghouse.

The differences are really many. With respect to the tube material itself the 51M is a 600 mm tubing where the 54F is a 690 thermally treated tubing. So issues such as stress cracking are greatly reduced with the new model generator.

The support plates are stainless for the new model generator versus carbon steel support plates.

The antivibration bars are better

designed for the new unit.

DR. BANERJEE: What does that better design mean?

MR. HALL: The support conditions are more assured. Where for the 51M sometimes you could pick up gaps between AVBs and the tubes, with the newer design with the reduced gaps you have a reduced potential for wear at the AVB sites.

DR. BANERJEE: So are these just gaps or are there actually things holding the tubes in place?

MR. HALL: Well, you could think of it as a bar that's inserted between the tubes in the U-bend region. It's a flat bar. Essentially it provides a support location to prevent the tube from moving in the out of plane direction.

DR. BANERJEE: But they're not broach plates or anything like that?

MR. HALL: Well with respect to the support plates. The support plates are in fact broached.

DR. BANERJEE: Okay.

MR. HALL: Where the 51M is a circular drilled hole.

DR. BANERJEE: And the 54F?

MR. HALL: The 54F is a broached configuration.

MR. KAMMERDINER: Excuse me, Jeff. This is Greg Kammerdiner.

Back on the AVBs, the other difference with the 54Fs, there's an extra set of AVBs. 51s have two sets of AVBs, the 54s have three. So there's more support in the upper bundle because there is an extra set of AVBs in the 54.

DR. BANERJEE: And the number of tubes are the same?

MR. KAMMERDINER: There's approximately 400 tubes more in the 54?

MR. HALL: Yes.

DR. BANERJEE: Four hundred out of how many?

MR. KAMMERDINER: The 51Ms have 3,376. The 54s approximately 400 more.

DR. BANERJEE: Ten percent more?

MR. KAMMERDINER: Yes.

DR. BANERJEE: Thanks.

MR. KAMMERDINER: Fifty-four stands for 54,000 square feet of heat transfer area. The 51, is 51,000 square feet.

DR. BANERJEE: Thank you.

MEMBER WALLIS: So the AVBs limit the amplitude of the oscillation, but they also give the tubes something to rub against, to bang against?

MR. HALL: Yes.

MEMBER WALLIS: Well, they're good and bad at the same time in a way.

MR. HALL: Beg your pardon?

MEMBER WALLIS: They're both and bad?

MR. HALL: Well, yes. No, they're actually all good.

MEMBER WALLIS: Okay. But it says here tube wear at IBBs. There is some rubbing or something going on?

MR. HALL: Yes. And that's primarily a result of the fit up between the tube and the bar itself. If you have the ability to move back and forth, well the tube is going to move back and forth. But if you're holding it sufficiently so that you don't have relative motion, well then you don't get wear.

MEMBER SIEBER: The AVBs go in the U-bend area, not below?

MR. HALL: That's correct.

MEMBER SIEBER: The old ones sometimes they weren't long enough to catch all the tubes. So you would end up with a tube that's not supported.

MR. HALL: Yes. And actually in both cases, the 51 in particular, there are some tubes in the U-bend region that are unsupported.

MR. TESTA: And actually, that's a lead in for the next bullet where we looked at -- go back, John.

Yes for Unit 2 again for the series 51, unsupported U-bends were reviewed for increased fatigue. And because the analysis that was performed, there was six tubes that we had to take out of service. And we did that.

Okay. As far as the next slide here, I just wanted to touch on the steam dryer. Again, look at the comparison between the PWR and the BWR. Just a little description on the secondary steam dryers on the steam generators. Now the main difference is between the 51 and the 54 is that the 51s have a two tier arrangement for the secondary dryers. I have sketch behind this to show that, whereas the model 54 has a single tear arrangement.

It's better illustrated here. Again, with the 51 they have two tiers of secondary steam dryers. You can see the lines that are drawn. The steam comes up and enters into the side region of the secondary dryer and then flows up, comes up through and then has a natural progression up through the secondary dryers.

The flow velocity in that region is on the order of 3½ to 4 feet per second. And you can see the vicinity of the nozzle region there's no structural components within the vicinity of the nozzle.

CHAIRMAN DENNING: I realize that later you're going to talk a little bit about experience. But could you tell us at this point how much experience is there with the 51 at the conditions that you're now going to go to?

MR. HALL: With respect to these conditions there's an immense amount of experience. These steam dryers, this configuration is used in a multitude of steam generator models, not just the 51s. The D models, D2, D3, D4, D5 all have a very similar arrangement. 54F a very similar arrangements. The Fs all have a two tier arrangement.

The velocities coming out of that area are all pretty much of the same order of magnitude. I mean, a couple of feet per second one way or the other, but they're all essentially the same.

Totally different orders of magnitude than some of the boiling water reactor dryers.

MEMBER SIEBER: Well, the one thing you don't have is a 180 degree change of direction.

MR. HALL: And all the consequences of that with respect to the turbulence that you can get, yes. It's all pretty much it comes out of the steam dryers and it continues on right up to the steam nozzle.

MEMBER SIEBER: The velocities are pretty low. They're like --

DR. BANERJEE: Can you stay there. Can you go back to that slide?

MR. TESTA: That one?

DR. BANERJEE: No, no, no.

MEMBER WALLIS: The velocities?

DR. BANERJEE: Yes.

MEMBER WALLIS: The one with the velocities, 107.

DR. BANERJEE: The velocities.

MEMBER WALLIS: That's it.

DR. BANERJEE: That's it.

MEMBER WALLIS: There's no history of problems with these dryers, I understand?

MR. TESTA: That's correct. In fact here

from this slide here it was to compare, again the 51 to the BWR. You can see that they have low velocities up through the dryers at 3½ to 4 feet per second where the BWR was on the order of 100 feet per second. And there have been no operational issues reported in the 51s or the 54s.

We had a backup slide just to show the operating experience.

DR. BANERJEE: Can you, please?

MR. TESTA: Sure. Okay. So for example, you know, well Beaver Valley which is going to operate at 2910. The difference with the model 54 one tier secondary dryer in the Unit 2, with two tier you can see the comparison to the other plants that utilize the similar secondary steam dryer arrangement.

MR. HALL: Yes, but these are not the only plants to have this particular dryer arrangement, too. There's many more.

MEMBER SIEBER: As far as megawatt production, Beaver Valley and North Anna are about the same so the operating experience from North Anna at that power level, it's got a fair amount of time behind it.

MR. TESTA: That's correct.

MEMBER SIEBER: So they aren't really breaking any new ground here.

MR. TESTA: In fact, North Anna is on the list here where they're operating at 2905.

MEMBER SIEBER: Got them beat by five?

MR. TESTA: Yes. Okay. Okay, John. No, go forward.

Now if there's no other questions on the steam generator, we also looked at balance of plant heat exchangers. From the uprate looking at the heat balance and the flow parameters that the equipment would be subjected to. We looked at the feedwater heaters and the feedwater heaters will operate within the design capacity.

The moisture separator reheaters, we went back to the vendor. We had a specific analysis performed to show acceptability under the increased flows.

As we mentioned yesterday, one of the modifications that we're going to do is on the condenser. Now our Unit 1 condenser was retubed a while back. And at that time the condenser was staked. Prior to the power escalation we will be taking the condenser in order to limit the tube vibration.

Vibration monitoring. This is a monitoring program for the secondary side for the balance of plant piping. We're going to monitor the secondary systems pre and post-EPU. This is going to include baseline walkdowns on each of the plants which we've already done. We have documented walkdowns.

Areas of interest where there's level of vibration that causes us to pay particular attention as we escalate power, we've identified those locations.

All this is within the guidance of ASME OM Part 3 that prescribes the walkdowns or the acceptance criteria that could be used and the method of performing this program.

CHAIRMAN DENNING: Could you help me a little bit on a walkdown where you're looking for vibration, what does one do quantitatively there?

MR. TESTA: Okay. What we do there is, for example, we came up with a screening criteria. We're looking at the displacement I'd say on the order of an eighth of an inch. And we'll walk it down to see if there's any signs, any noticeable signs of vibration. And we basically have documented from the plant, basically going from say component to component, basically identifying if we have vibration levels that would exceed that limit.

CHAIRMAN DENNING: Visually?

MR. TESTA: Visually. That's correct.

I have Bob Bain from Stone & Webster. If you'd like to add?

MR. BAIN: Yes. This is Bob Bain from Stone & Webster.

We followed the basic guidance of OM3 as Mike says. The first test criterion we used was visual on displacement of an eighth of an inch, which is within the guidance provided in OM3. They allow for visual measurements using simple devices such as rulers, hand held type mechanical simple devices like pencils, literally. And an eighth of an inch peak to peak displacement is easily visual on a focused walkdown. And as Mike says, these walkdowns were basically focused.

Over the last three or four years, actually, we took a schematics and basically connected the dots from equipment. So from pump to valve, valve to vent or drain, vent or drain to branch lines. So it was a focused walkdown looking at the piping, the components as well as the support hardware.

And any observation, again eighth of an inch was a fairly stringent criteria. Easily visually noted. That would get it onto this list of interest, as Mike identified.

And we followed up that list of interest literally over the last three or four years for both units.

CHAIRMAN DENNING: Is there quantitative stuff that one can do? I mean, are there instruments that you can go and put it up against the machine? I mean, the equipment --

MR. TESTA: Yes, there are.

CHAIRMAN DENNING: -- and have a measure of not only the displacement but the frequency?

MR. TESTA: Yes. There's a portable device, hand held accelerometers. And, again, we conduct these walkdowns. We use the experienced engineers. And if there's any question about the acceptance of the level of vibration, then we will use accelerometers to record the displacement and the frequency.

MR. BAIN: Yes. This is Bob Bain again.

And this hand held equipment that Mike references actually gives you data in displacement or velocity or acceleration. And OM3 allows you to do more detailed evaluations if required using velocity or displacement data. So the hand held is a good device to give you the next level of detail quantitatively.

MR. TESTA: Okay. Just the last mention here, large equipment like the reactor coolant pump and the turbine have continuous monitoring available. So we'll be monitoring that as we escalate power.

Okay, John.

Now the next area we looked at is cooling systems. The bottom line here is that the systems remain capable of dissipating heat for normal shutdown and accident conditions.

WE looked at these following systems, the flows were adequate without modification:

The river water system. Beaver Valley 1 the equivalent system service water for Unit 2;

The component cooling water;

Residual heat removal, and;

The safety injection containment depressurization system which uses the recirc spray heat exchangers.

Next slide.

Spent fuel cooling. We looked at spent

fuel cooling. As part of the project or the overall initiative, which we started we said five to six years ago, we looked at spent fuel cooling. And there was an amendment that we put in where we looked at the offload time. At that time we performed the analysis to incorporate the uprate decay heat loads.

MEMBER KRESS: Do you have dry casks on the site?

MR. TESTA: Not at this point, no. Still use the fuel pool.

MEMBER WALLIS: I think I remember your burnup is the same as it was before essentially, is that right?

MR. TESTA: Yes, I believe so. Yes.

The last area to touch on here is the auxiliary feedwater system. The auxiliary feedwater is fed from the condensate storage tank. The condensate storage tank is sized for 9 hours of hot standby conditions. And with the uprate or the increased decay heat, we've revised the tech specs to require 130,000 gallons useable volume for each of the tanks for both Unit 1 and Unit 2.

The other thing with the aux feedwater system, there were two accidents: The feedline break and loss of normal feed that required us crediting two aux feed pumps.

CHAIRMAN DENNING: I didn't understand with regards to the tech spec limit and the 130,000 gallons. What do you do physically to assure that?

MR. TESTA: Basically we have the calculated tank volume and maintain a level on the tank.

CHAIRMAN DENNING: So it's a level on the tank that has to be assured now that it's slightly higher than it was previously?

MR. TESTA: Yes. Yes.

CHAIRMAN DENNING: Gotcha.

MR. DURKOSH: This is Don Durkosh from Beaver Valley Operations.

Basically we obtained curves that show based on indications available to us what the volume is. And on every shift we have minimum levels that we're required to verify on a shiftly basis. So that's how we maintain our minimum tech spec values.

MEMBER MAYNARD: You didn't make any modifications to the tank. You're just changing the level setpoint there.

MR. TESTA: That's correct. That's correct.

MR. CARUSO: Why would you not normally keep the tank full?

MEMBER SIEBER: It goes up and down. You have to have surge volume.

MR. TESTA: To answer that question we normally do. As part of the review of our L5 logs we typically, our levels are high. What we try to do is basically clear the alarms. We have a low alarm that indicates we're approaching a tech spec limit. And normally we have a high alarm very close to the overflow. So we try to maintain it within that range so we have no alarms in the control room.

MR. TESTA: Okay. Again, just to finish this out here, there are two accidents that required us to credit two pumps. This was already in place for Unit 2. And with the revised analysis Unit 1 will now require two pumps also for these two accidents. It's basically accounting for the increased decay heat plus the addition of the cavitating venturies, which puts a little more system resistance into the system.

CHAIRMAN DENNING: And that's two out of how many?

MR. TESTA: Two out of three.

CHAIRMAN DENNING: And it had been one

out of three?

MR. TESTA: It had been one out of three, just for Unit 1. Unit 2 was already crediting two pumps.

Okay. Well, this completes my part of the discussion. I have Dave Grabski here, which he's our flow accelerated corrosion program owner, and he'll talk about the program.

Thank you.

MR. GRABSKI: As Mike said, I'm Dave Grabski. I am the FAC program owner.

A little background. I'm a FirstEnergy employee. I worked at Beaver Valley and before that Shippingport Atomic Power Station for a combined 26 years.

I've been the FAC program owner since the early '90s.

Next slide.

The first bullet, the EPU effects evaluated using CHECWORKS. So we've taken the revised heat balance diagram parameters and using the CHECWORKS models determined analytically what we'd expect as far as our wear rates. With most uprates, we've seen an increase in velocity and temperature. And those two factors play differently with different systems. Some systems we've seen a decrease in our wear rates, and others we've seen a slight increase.

The feedwater and extraction steam systems, those systems had a decrease. Systems like the feedwater heater drains, condensate have increased. Again, because of the play of those different parameters: Velocity and temperature mainly.

In preparation for the uprate we've actually replaced two extraction steam Ts because of the increase in our SMR relief valve set point that has cut into our margin between our measured wall thickness and our required wall thickness. Extraction steam is one system at Beaver Valley that does wear due to the flow accelerated corrosion mechanism.

CHAIRMAN DENNING: So there wasn't a materials change, it was just a thickness change?

MR. GRABSKI: We have upgraded the material to a chrome-molly. Basically anytime we make piping replacements at Beaver Valley, we'll upgrade to a chrome-molly. Chrome-molly is much more resistent to this particular degradation mechanism.

Based on the engineering evaluation we're going to focus on a few more systems. Well, not more systems, but more components within those systems, on those systems that we expect an increase in velocity. Mainly our moisture -- or I should say the heat drain system from our 4th to 5th point heaters, we had a significant velocity there. So we're going to focus examinations in the next outage there to get a baseline where we're at. And in the future go back to these areas to see how they're doing.

And there's some components at Beaver Valley 1 and 2 in the 4th point heat drain line. It's showing you in the next to the last column there some of the wear rates we saw before the outage. Very low. And heater drains is a low wear system at Beaver Valley. But we do see some increases based on the uprate.

DR. BANERJEE: Do you have a diagram showing where these components are in the steam cycle?

MR. GRABSKI: I don't have --

DR. BANERJEE: I have no idea where the four point heat is or what -- I imagine that it's extraction --

MEMBER WALLIS: This is a preheater.

DR. BANERJEE: Preheater?

MR. GRABSKI: Yes. We have six --

MEMBER WALLIS: Well, these aren't safety concerns anyway. These are just embarrassments for you if you break a pipe, it might be dangerous for anyone who is around the pipe.

MR. GRABSKI: It could be a personnel issue.

MEMBER WALLIS: It's dangerous for your people, but it's not a nuclear --

MR. GRABSKI: That's correct. This is a non-safety related piping systems.

MR. STORLIS: My name is George Storlis. I'm a FENOC employee.

An in Operations I can get a little bit of perspective to what the feed heater string is. The feed heater string is compromised of six feed heaters in line with the condensate feed system to preheat the feed. The fourth point is fourth in line, the sixth point being the lowest energy or lowest pressure system and the first point being an extraction steam of highest pressure off of the turbine cycle. And the fourth point is in route to that.

And we're talking pressures, temperatures that compliment the feedwater heat up that approaches the 440 degrees or so when it ultimately is arriving at the steam generators. So it takes a portion of the energy from the turbine cycle and uses that to preheat the steam and the shelf tube arrangement.

And that's the basics of it. If there's any questions, please ask.

DR. BANERJEE: Is the steam wet at this point?

MR. STORLIS: Yes. Yes.

DR. BANERJEE: What's the quality?

MR. STORLIS: Without having the curves and the diagram in front of me, I can't speak to that, that specific quality.

MR. KAMMERDINER: Probably some in the 90s.

MEMBER WALLIS: Pretty high.

MR. TESTA: This is Mike Testa.

We have a heat balance diagram, maybe that would help.

DR. BANERJEE: Does it show quality at various points, extraction points?

MEMBER SIEBER: That chart would work.

DR. BANERJEE: I can't do it in my head.

MEMBER WALLIS: And the problem is the wetness, presumably.

DR. BANERJEE: Yes, the wetness.

MEMBER WALLIS: But it's a few percent. It's not a humongous amount or is it designed to extract in a way that it separates the wall, and it would be wetter, wouldn't it?

MR. GRABSKI: Actually the steam quality is fairly low.

MEMBER WALLIS: That's in the turbine. But when you extract, don't you sort of have something that's centrifugally separates or anything like that?

MR. GRABSKI: We have steam traps and orifices to pull off the moisture.

MEMBER WALLIS: It's an oxidate or whatever it is that comes out, ends up in some condensate -- where does it go?

MR. GRABSKI: It varies with the system that might be wearing. If you're feedwater's wearing, you're going to get it in the steam generators on secondary side. A lot of the heater drains go to a receiver tank.

MEMBER WALLIS: The crude appears in the

steam generator. Where does the stuff that's worn away from the pipe?

MR. GRABSKI: Again, depending on what system it's in. The heat drains, there's a heat drain receiver tank that it could filter out at. We do have -- do you have something?

MR. HANLEY: Yes. Norm Hanley from Stone & Webster.

All the secondary side condensate and extraction steam heater drains all recovered. Some of it cascades back to the condenser, some of it's pumped forward to the feed pump suction. So it is all recovered.

MEMBER WALLIS: Isn't a lot of it dissolved and then it appears somewhere else in an--

MEMBER SIEBER: Heater drain and steam generator.

MEMBER WALLIS: In these steam generator?

MEMBER SIEBER: Yes. There is a blow down line on the steam generator.

MR. HANLEY: Right. There's a blow down in the steam generator. They also sample the secondary side.

MEMBER MAYNARD: Well, do you have

condensate polishers? Do you run it through --

MEMBER SIEBER: Only on Unit 2.

MEMBER MAYNARD: Only on Unit 2.

CHAIRMAN DENNING: Can you comment on the accuracy of CHECWORKS? I mean, obviously, it's not the four significant figures that's in that table.

MR. GRABSKI: Basically the models will improve with the number of examinations you do on the system. It correlates with the data you have. So without any data, I would take it as just a ranking. And that's what we use it for, as a ranking. But actually in our extraction steam which we examine the heck out of, they actually correlate pretty well once you get enough data in there.

MEMBER MAYNARD: I take it you also use industry experience what's found at other places --

MR. GRABSKI: Oh, absolutely. Our examinations are the backbone. But certainly ops experience, trending of data at our plants and then that's all factored in.

DR. BANERJEE: Is there any increased erosion due to the wet steam, the velocities being somewhat higher or --

MR. GRABSKI: Yes. That's in the

CHECWORKS algorithm higher velocity results in a higher wear rate.

DR. BANERJEE: Due to erosion or is it some erosion/corrosion?

MEMBER WALLIS: I suspect it includes both erosion --

MR. GRABSKI: The FAC takes in the both. That's the mechanism.

DR. BANERJEE: But does it also depend-- does this depend on the wetness as well?

MR. GRABSKI: Absolutely. That's a factor in the algorithm.

DR. BANERJEE: You feed this stuff into CHECWORKS and out comes these numbers?

MR. GRABSKI: Yes.

DR. BANERJEE: Hopefully.

MR. GRABSKI: Hopefully, yes.

DR. BANERJEE: Yes. Who developed this thing?

MR. GRABSKI: EPRI developed CHECWORKS. And it's the industry --

DR. BANERJEE: Probably validated against data?

MR. GRABSKI: They call it an empirical study --

DR. BANERJEE: I see.

MR. GRABSKI: -- based on lab and actual events in the industry.

MEMBER KRESS: There's sort of a Bayesian update. You go in and inspect and you compare the inspection findings, and then you adjust CHECWORKS to better agree with your findings?

MEMBER WALLIS: Learns about your --

MEMBER SIEBER: Putting your own data --

MR. GRABSKI: Exactly. As I said, they call it a pass one without any data. Once you get enough data in there, it correlates itself. And you have a line correlation factor, it's called.

DR. BANERJEE: So the predicative capability is always in question of these types of things? It's only as good as your database?

MEMBER SIEBER: By the time you are ready to decommission the plant, it will be very --

DR. BANERJEE: Yes, it'll be excellent by them.

MEMBER KRESS: Or by the time you're ready for a license extension.

DR. BANERJEE: Extrapolation is always dangers in these sorts of things. There's no theory or model there, right?

MR. GRABSKI: Well though EPRI calls it a model and it certainly does take into consideration velocity, temperature --

MEMBER MAYNARD: And geometry, right?

MR. GRABSKI: And geometry. Exactly. But again, it's as good as the data you're putting into it at the point.

DR. BANERJEE: Let's imagine that we take this today with the data you've got and try to predict what will happen two years from now. Has it ever been tested in this mode to show whether it gives a reasonable prediction?

MR. GRABSKI: Yes, I think it has.

DR. BANERJEE: It does?

MR. GRABSKI: Yes, it does. It certainly. Yes. It'll give you --

MEMBER MAYNARD: Isn't the main purpose of it, though, to predict areas where you may have high wear rates and that you inspect those and that you put those in your trending program? And you're actually using more actual trend data than you are a prediction from the program as to when that line might break?

MR. GRABSKI: Exactly. It gives you the places to look first. The highest susceptible line.

And I think it does a very good job of that. But once you get into a qualitative or quantitative measure, that's when you need to get some data in there to verify what the model is telling you.

You may be right on the money, but again once you get more and more data in there, you correlate the model and then it becomes a very good predictive tool.

MEMBER MAYNARD: Yes. Most of the plants do a lot of measuring of a large number of areas where they measure and periodically do that so they can see what's trending.

MR. GRABSKI: Exactly.

MEMBER MAYNARD: It's not just using a computer program to --

MR. GRABSKI: No. Your data proves it, but it's a great start because it's going to tell you that this T is more susceptible than this T, elbow to elbow.

MEMBER MAYNARD: But again that's the way the nuclear safety issue other than if it could result in an unnecessary plant transient or it may be a personnel safety, but from a nuclear safety accident it's not.

MR. GRABSKI: That's true.

MEMBER SIEBER: And if you take a big fitting like an elbow or a T, a single measurement is inadequate. You have to basically put a grid on that fitting.

MR. GRABSKI: Right.

MEMBER SIEBER: Take a lot of measurements of different positions. Because the wear will be local to someplace where there is an eddy in the flow stream.

MR. GRABSKI: That's correct.

DR. BANERJEE: Have you seen any erosion in the high pressure stages?

MR. GRABSKI: Excuse me?

DR. BANERJEE: Did you see any erosion at all in the high pressure stages?

MEMBER SIEBER: Main feed?

DR. BANERJEE: Yes.

MR. GRABSKI: Some feedwater, we have very low wear rates there. In our main steam coming off the steam generators, we haven't seen any wear--

DR. BANERJEE: What about the turbine plates, any erosion there, high pressure plates?

MR. GRABSKI: I don't know. That's not my expertise on the turbine.

MEMBER SIEBER: But generally speaking--

DR. BANERJEE: You should have any.

MEMBER SIEBER: -- what erosion you see, you see at the very -- the exhaust end of the turbine. And if your moisture separators and everything are working properly, you don't see hardly anything at all.

DR. BANERJEE: Not in nuclear plants, but some fossil plants you do because of the oxide--

MEMBER SIEBER: Well, generally the fossil plants are better than the nukes because they operate at a higher temperature.

MR. GRABSKI: That's true.

DR. BANERJEE: Yes. But the oxide flakes come and hit the high pressure stages sometimes, depending on how you cycle the plant. But you don't see any so the higher velocity doesn't give you a problem?

MR. GRABSKI: Again, I'm not a turbine guy.

DR. BANERJEE: Right.

MEMBER WALLIS: It's not a nuclear problem. It's not a nuclear safety problem. Just expensive if you have to fix the turbine.

CHAIRMAN DENNING: I think we're completed them, yes?

MR. GRABSKI: Yes, unless you have any questions.

CHAIRMAN DENNING: I think we're good. Thank you.

MR. GRABSKI: Thanks.

CHAIRMAN DENNING: And I think NRR now is going to present in the same basic area.

MEMBER WALLIS: They're going to defend CHECWORKS, are they?

CHAIRMAN DENNING: You can go ahead.

MR. SCARBROUGH: Thank you.

Good morning. I'm Tom Scarbrough in the Division of Component Integrity of NRR. And with me today is the Branch Chief in Division Engineering, Kamal Manoly and Dr. John Wu.

We're going to talk about the engineering mechanics aspects of the review. In terms of the components evaluated, they included the reactor vessel, the internals, the nozzles, supports, control rod drive mechanisms, the steam generator, reactor coolant pumps, the pressurizer and the supports, nuclear steam supply system and balance of plant piping systems and supports and safety related pumps and valves. Motor operated valves, air operated valves and safety relief valves.

The scope of the review included the impact of the EPU conditions due to changes in system pressure, temperature and flow rate.

The review of the licensee's evaluations of EPU conditions including the analytical methodology, loads, flow-induced vibration, calculated stressed and cumulative fatigue usage factors, acceptance criteria, ASME codes and addenda, functionality impact of EPU on Generic Letter 89-10 for motor operated valves and Generic Letter 95-07 for pressure locking and thermal binding of power operated valves.

The license's EPU evaluation does incorporate an improved leak before break criterion that allows elimination of postulated primary loop pipe breaks in the original design basis analysis. And after elimination of the primary coolant loop breaks by the application of the leak before break criterion, the existing design bases analysis for NSSS piping and components are bounded for the EPU evaluation considering postulated smaller branch line pipe breaks.

The specific areas where the Staff requested additional information included the main steamline and feedwater line flow-induced vibration due to increased flow rate, quantitative analysis and results for the Beaver Valley Unit 1 replacement steam generator, calculation of cumulative usage factors for the vessel flange closure stubs, considering 10,400 cycles as opposed to the 18,300 cycles of the design bases.

With respect to flow-induced vibration in particular, the main steamline and feedwater piping are instrumented at critical locations to monitor vibration levels at current rate of power and during power ascension up to full authorized EPU power level. The vibration monitoring and the collective data will be evaluated according to ASME Standard and Guide 2003 Part 3.

The flow-induced vibration effect on the steam separators and the steam generators is expected to increase somewhat for EPU conditions. Based on the licensee's response to the request for additional information to the request for additional information, the potential for flow-induced vibration of the steam separator is minimized due to its high stiffness resulting in a high natural frequency combined with a low velocity. And we heard about it, it's about 4 feet per second or so of passing flow. And past inspection performed for steam generator, moisture separators on operating PWR, pressurized water reactor plants have found no indications due to flow-induced vibration fatigue.

The flow-induced vibration on the U-bend tubing and the steam generators is within allowable limits. In other words, the fluid-elastic instability ratio was maintained less than the limit of 1.0. And peak stresses are less than the material endurance limit.

There were some pump and valve modifications to accommodate the EPU operations. These are relatively minor considering the 7 percent EPU power uprate. The charging and safety injection pumps have been modified to improve their high head performance and flow rate.

The tolerance settings for the main steam and safety valves and reactor coolant pressurizer safety valves have been adjusted.

New trim was installed in the feedwater regulating valves in Beaver Valley Unit 1 and those valves were replaced at Beaver Valley Unit 2.

Fast acting main feedwater isolation valves were installed in Beaver Valley Unit 1 similar to those in Unit 2.

And based on the Staff's review our conclusion is that the calculated stresses and accumulate usage factors in the NSSS and balance of plant piping and components are bounded by the original design basis analysis with the application of the leak before break technology, such that the postulated primary loop pipe breaks are eliminated.

The potential for flow-induced vibration is not increased for steam separators and the steam generator tubes at EPU conditions.

The main steamline and feedwater line piping is monitoring to remain within the allowable limits in accordance with ASME OM3 code guidance.

The NRC Staff reviewed the licensee's assessments related to functional performance of safety related valves and pumps at Beaver Valley for EPI conditions and based on that review the licensee has adequately addressed the EPU effects on safety related pumps and valves. And as a result, the Staff concludes that the licensee has demonstrated that the safety related valves and pumps will continue to meet their NRC regulatory requirements during EPU operation at Beaver Valley.

So we'd be happy to answer any questions you might have.

CHAIRMAN DENNING: I think this is pretty clean. Any questions? Okay. Thank you.

MR. SCARBROUGH: Thank you.

MEMBER WALLIS: Are we gaining time here?

CHAIRMAN DENNING: Oh, yes, we're gaining time.

We're going to go ahead with the next presentation.

An NRC presentation. By Gregory Makar.

MR. MAKER: Good morning. I'm Greg Makar. I am in the Division of Component Integrity. And my branch works on issues of steam generator integrity and other chemical engineering topics. And this morning the Staff reviews in five areas: Low accelerate corrosion, steam generator tube integrity, the steam generator blowdown system, chemical and volume control system and finally coatings.

Our review of flow accelerated corrosion begins with determining of the licensee has evaluated the changes due to the extended power uprate on the parameters like temperature, velocity, moisture content that are the keys in controlling flow accelerated corrosion rates. They did this and based on the known effects of this parameters, you see as Mr. Grabski explained, cases where the corrosion rates would be expected to increase and some where it would be expected to decrease.

MEMBER WALLIS: The boron content has no effect on any of this?

MR. MAKER: Excuse me, boron --

MEMBER WALLIS: Boron doesn't seem to be a parameter that comes into this at all?

MR. MAKER: No.

MEMBER WALLIS: This is simply because it's ignored or because it's proven to have no effect?

MR. MAKER: Well, if it changed the pH, say, then if the pH decreased because of it. But as I understand it, the pH does not decrease significantly enough to change the corrosion rate in this case.

So to satisfy that they were scoping things in properly, there's also the question of scoping things out because you want to keep your resources focused where they're needed. And there are criteria. And all of these cases we're going primarily by the EPRI guidelines on flow accelerate corrosion programs. That scoping out components based on things like temperature below 200 degree Fahrenheit, the chromium content being 1 and a quarter percent or higher. And this they're doing according to the EPRI guidelines.

DR. BANERJEE: Does NRC have any programs which independently check EPRI sort of guidelines and things?

MR. MAKER: No. No, computer models or programs.

DR. BANERJEE: Even the research programs or whatever?

MR. MAKER: No.

DR. BANERJEE: How do you know that -- do you audit it in some way other than just take their data or what?

MR. MAKER: The way that we evaluate this is by -- the NRC in the past was involved in developing a response flow accelerate corrosion and understanding the parameters that are the key influences on it. And I think at that time we did have research programs to determine those. I think we were in the lead at that time and helped lead industry toward a resolution and a development of the computer based programs. And followed and participated in research efforts to understand all the parameters and their influence.

DR. BANERJEE: So when did that effort terminate within RES or wherever in NRC it was?

MR. MAKER: I'm sorry. I don't know the answer to that.

DR. BANERJEE: Was it a long time ago or recently?

MR. MAKER: Well, several -- I don't know. And currently we sent -- for example, we send people to training to understand how CHECWORKS is used.

DR. BANERJEE: That's an EPRI training?

MR. MAKER: Yes. But the effect of these parameters on low accelerated corrosion is fairly well understood now. And I think the most value on making sure the licensees are following these programs and using -- skipping ahead a little bit. But the computer models for plants are one factor. But really the key is actually inspecting systems at repeatable locations and developing data so that you can then trend and determine corrosion rates. That allows you to make decisions about future inspections and replacement repairs. And also it improves the quality, the predictive ability of the model.

DR. BANERJEE: Does this apply mainly to components that can be inspected then or there components which inspection is difficult?

MR. MAKER: Yes. It should apply to all. There are cases where it's difficult to inspect components. And in that case what the licensees may do is go to a secondary inspection or a testing technique such a radiography, which isn't as good as ultrasonic testing. Or they may have another similar system behaves, is nearby, say, same type environment which behaves in the same way. And they'll use that --

DR. BANERJEE: So you're talking mainly of the secondary side rather than the primary side?

MR. MAKER: Yes. Yes.

DR. BANERJEE: None of this concerns the primary side then? Okay.

MEMBER WALLIS: Because of the materials that are used there, is that it, really?

MR. MAKER: Well, yes. Once you get to 1 and a quarter.

MEMBER SIEBER: Single phase flow.

MR. MAKER: Yes. And you need moisture fort his to occur.

MEMBER WALLIS: Moisture isn't

necessary. You've got this in the feedwater line.

MR. MAKER: Sorry. Yes.

MEMBER WALLIS: I mean --

MR. MAKER: And there's also a temperature --

MEMBER WALLIS: Okay. I guess --

MR. MAKER: Well, some things like velocity, as you increase velocity you would expect corrosion rate to increase. There are other effects like temperature where there's a peak around 300 degrees fahrenheit and then beyond that then it start decreasing.

MEMBER WALLIS: Well, CHECWORKS is well established, and it's updated from time-to-time. So throughout industry, isn't it? This is why the NRC has stopped --

DR. BANERJEE: Also I suppose from a safety point of view this is not incredibly significant.

MEMBER WALLIS: Right.

MEMBER SIEBER: Not safety related.

MEMBER MAYNARD: The NRC does perform periodic inspections at the site on the flow accelerated corrosion program.

MEMBER SIEBER: Sure.

MEMBER MAYNARD: So it's not something that's just left out.

MR. MAKER: Plant audits, yes.

MEMBER MAYNARD: Yes.

MR. MAKER: So following on that idea, the importance of the inspection, this is really their -- a key to their program is ultrasonic measurements at repeatable locations to develop corrosion trends. And therefore, the combination of the required thickness of the components, the measured thickness and the corrosion rates are the key to future inspections and replacement repair decisions. And the CHECWORKS computer program is one tool in managing this program.

Next slide, please.

So they are updating the models. I've done that for the EPU. It does predict some increases in corrosion rates in some cases, decreases in others.

In cases where there's a large increase, it happened to be a system with a very low corrosion rate to start with. And that was an example Mr. Grabski showed.

So considering all these things, we concluded that their program will continue to manage the flow accelerated corrosion effectively after the extended power uprate.

Next please.

Address steam generator tube inservice inspection. Our guidance here is some -- we have standard review plans on materials and also for inspection we're focused mainly on the NEI 97-06, which also refers to the more detailed EPRI steam generator program guidelines. And as you've heard, the steam generators in Unit 1 were replaced.

There are two key materials upgrades; the thermally treated Alloy 690 tubes and also the stainless steal tube support plates, which these two things have a big effect on types of degradation that are observed and the rates of degradation, initiation and propagation. There are also some additional design factors like the shape of the holes in the tube support plates, the type of the antivibration bar design. And all of these are major improvements in steam generators.

Now the temperature, and the temperature is one of the key parameters in causing degradation. That will remain within the range seen at other plants that have 690 tubes.

There is a possibility, as you

discussed, in tube vibration and wear. And there's been an evaluation that the likelihood for wear is low. But for our purposes we're looking at the fact that if there is wear, that is captured in the tube integrity program. That the inspections will see that they're required to evaluate that and monitor that in their operational assessments and their--

MEMBER MAYNARD: Has Beaver Valley either made their tech spec changes or committed to make the tech spec changes for the Generic Letter 06-01?

MR. MAKER: They have an application in house now that being evaluated.

MR. KAMMERDINER: If I could add something. This is Greg Kammerdiner from FirstEnergy.

We have submitted the license amendment request to adopt TSTF449 for both units.

MR. MAKER: So we're concluded for Unit 1 that their program will continue to manage degradation at uprate conditions.

Next please.

For Unit 2 they have the original steam generators with the milled annealed Alloy 600 tubing and both carbon steel and Alloy 600 tube support structures. The existing degradation mechanisms include several forms or several modes of stress corrosion cracking and also some small amount of antivibration bar where the cracking initiation and growth rates could increase based on the small temperature increase and also increases in flow and potentially sludge accumulation at EPU conditions. However, these changes are relatively small and still will remain within the experience we have at other operating plants. And we don't see this as a -- it will not degrade in anyway their ability to monitor, to detect and monitor degradation at uprate conditions.

And we also note that these steam generators have a couple of design features, improvements over a lot of the Alloy 600 plants, such as the heat treatment to stress relieve small radius U-bends and also shop pinning in the portion of the tube within the tube sheet. And these are things which are shown to retard the initiation of stress corrosion cracking.

The AVB wear rates for Unit 2 are measurable but low. But as with Unit 1, again, there are inspections performed to measure this and evaluate it.

We don't expect with these small changes and conditions any new forms of degradation to emerge as a result of the uprate. But, again, we're satisfied that their program will find them and will continue to be consistent with the guidelines at uprate conditions.

MEMBER SIEBER: I think one of the big factors is the chemistry control of feedwater. And Beaver 2 should do much better than Beaver 1 because it has a polisher, it has 1 years less life even though the capacity factor is better. And generally there's been good careful control of the chemistry. So I would expect to see lower rates of degradation than Unit 1 experienced through its lifetime.

MR. MAKER: Thank you. Yes. The importance of water in chemistry is really important.

MEMBER SIEBER: That's the key factor in my opinion

MR. MAKER: Next, please.

The steam generator blowdown system helps steam generator tube integrity by controlling the quality of the secondary coolant. The blowdown flow rates are not expected to increase as a result of the uprate because they're determined by some parameters that are not going to be effected. There is a repositioning of flow control valves due to decreased pressure. This will reduce the maximum achievable flow rate, but not be require. It will not reduce it below what's required.

So we conclude that this will not have an effect on the ability to remove impurities from the blowdown. And we also note here this is a system with potential for flow accelerated corrosion and it is in their FAC program.

Next please.

Chemical and volume control system. Several functions related to the water inventory and quality for the reactor coolant.

The heat exchange temperatures, heat exchangers are one of the key components. There are some slight changes in temperature increases and decreases, but they stay well within the -- well below the design values. And the heat exchanger pressures are not changing as a result of EPU.

Boration requirements continue to be met. And letdown flow rates, charging rates and nitrogen-16 delay times are not being affected significantly by this.

So, again, according to our Standard

Review Plan we concluded that this will be acceptable at EPU conditions.

Finally on coatings. Unit 1 coatings were specified according to the ANSI standard. We're evaluating compared to -- we have a Reg. Guide 1.54, there are ANSI standards that are called out in that. And we have a Standard Review Plan 6.1.2 on coatings.

Unit 1 coatings were specified according to ANSI N101.2. When Unit 2 coatings were specified, we now have the Reg. Guide which also referred to 101.2 as well as the newer ANSI standard on the quality of coatings.

And the licensee provided us with their uprate environmental parameters compared to the qualification test values for normal and design bases accidents showing that their bounded by those qualification values. And so we expect no effect on the adhesion or the degradation of those.

CHAIRMAN DENNING: I mean if there were any issues here in the painting areas, I don't think they're EPU issues. But I'm just curious, did you talk to management of these units about what the status is of their paints, whether there is observable flaking occurring in areas and potential problems there?

MR. MAKER: I didn't as part of the EPU. And I talked to our GSI-191 team members who are evaluating their coatings. Well, the debris issue which includes coatings. But they were not able to tell me the status of coatings yet.

CHAIRMAN DENNING: Okay.

MEMBER WALLIS: Well, it says coating failures are identified by inspection. I'd be curious to know have there been coating failures.

MR. MANOLERAS: Yes. This is Mark Manoleras, Beaver Valley, FENOC.

I own the coatings program and the coating engineer works for me. Our containment coatings actually have been in very good shape. If we identify a deficiency, it's put in our corrective action system. It's evaluated by that coating system engineer and then it is repaired.

We've had outside people come in and take a look at our coatings in response to the GSI-191 to make sure that what we believe is what the outside experts also believe. And we've gotten very good feedback on that, on our coatings, our containment coatings.

MEMBER WALLIS: Have you actually had to

replace some coatings?

MR. MANOLERAS: We've had to make very minor repairs to some coatings in containment.

MEMBER SIEBER: Those are typically scrapes --

MR. MANOLERAS: That's correct.

MEMBER SIEBER: -- as opposed to force or lack of -- somebody runs a cart into the wall, you can scrape.

MR. MANOLERAS: That's correct.

MEMBER SIEBER: And you have to repair that.

MEMBER WALLIS: So it's that kind of thing rather blistering or --

MEMBER WALLIS: Right.

MR. MANOLERAS: That is correct.

MR. MAKER: Okay. That concludes my presentation unless you have any further questions on these five topics.

CHAIRMAN DENNING: I think we don't. And I think Mr. Stubbs could now continue with the next presentation.

MR. MAKER: Thank you.

MR. STUBBS: Good morning. My name is Angelo Stubbs and I'll be discussing the review of the balance-of-plant systems.

Next slide.

Okay. In conducting our review we utilized Review Standard RS-001, which is a Review Standard for extended power uprates. And in general our review scope covered the balance-of-plant mechanical systems contained in Matrix 5 of the standard.

Scope of the BOP systems included over 20 systems, 6 major areas of review, the first of which internal hazards for which reviews were performed for the EPU impact on flood protection, equipment of floor drains, the circulating water system, missile protection, the turbine generator and pipe failures.

The second area, fission product control included reviews on the fission product controlling systems in the structure, the main condenser evacuation system and the turbine gland seal system.

For the next area, component cooling and decay heat removal we reviewed the spent fuel pool cooling and clean up system, service water system, react water cooling system, ultimate heat sink and auxiliary feedwater system.

Next slide.

The next area of review balance-of-plant included review of the main steam, main condenser, turbine bypass and consondate and feedwater system.

And the final two areas was the waste management system, which included gaseous liquid and solid radwaste and then the emergency diesel fuel oil storage and light loads were also reviewed.

In addition to our review of the systems I just mentioned, the staff also reviewed test considerations for certain BOP systems.

Next slide.

The Staff focused under review of auxiliary systems for which increased heat loads associated with the uprated plant might pose an increased challenge to the systems. The systems included the spent fuel pool coolings, the service water and ultimate heat sinks, auxiliary feedwater system and condensate and feedwater system.

In regards to the spent fuel pool cooling system, the Staff determined that the licensing bases evaluation, that is the current licensing bases evaluation which was performed at the power level of 2918 megawatts will be bounding for the EPU plant. But service water system and increasing the heat loads was not to have a significant increase in fact on the system. And they stable within the design temperatures of the system.

The Ohio River is the alternate heat sink for both of these plants and this capacity far exceeds the shutdown cooling and accident heat load requirements for the Beaver Valley units. And power uprate doesn't effect the temperature in that water for this.

The auxiliary heat water system is a system which required increased flow as a result of EPU at both units. In addition, Unit 1 has undergone a modification to add limiting flow venturies. And I'll discuss the EPU impact on these systems a little later when I address modifications that effected the BOP review.

And the condensate and feedwater system, there was minor modifications of the regulating valves. But the licensee evaluation showed that the condensate pumps had sufficient margin to operate at the EPU power and that sufficient flow could be provided to the system.

In addition to that the parameters of flow, pressure, temperature parameters will be monitored during the startup so that will help verify the performance also.

Next slide.

The modification. The modifications made to the balance-of-plant. These are I'd like to talk a little bit about. Take a few minutes to talk about.

The first was modifications to the high pressure turbine and the second is a modification to auxiliary feedwater system at Beaver Valley 1.

Next slide.

Okay. But in the case of the high pressure turbine in both units, the high pressure turbine is being replaced with an all reaction turbine. The Unit 1 modification has already been completed. They have calculated the maximum overspeed to be 118, which is below the acceptance criteria of 120.

The Unit 2 modification has not been completed yet and will be completed prior to operation at EPU. But at this time they have done the calculations for overspeed the licensee has committed to perform the appropriate overspeed analysis to ensure overspeed protection that's acceptable. Also as part of their operating surveillance tests verifies that the proper operation of the turbine overspeed trip protection system and that -- and they do this by demonstrating that the turbine works at or below the 111 percent at that.

MR. TESTA: Excuse me. This is Mike Testa.

I just wanted to clarify one thing for Unit 2. Now the way we're going to -- we're going to do a staged power increase. The existing turbine has additional capacity to it, around 5 percent. So we're going to elect to increase the power somewhat the existing turbine. But prior to going to the full extended uprate, we will replace the turbine with the reaction turbine.

MR. STUBBS: Okay. The auxiliary feedwater system, for this system in Unit 1 they're adding cavitating venturies. They're installing that as a modification to Unit 1.

At EPU the auxiliary feedwater pumps, which are now being credited for the feedwater line break and the loss of normal feedwater events, which is something that the current plant doesn't do.

Unit 2 licensing bases already credits these to AFW pumps. So this isn't a change to Unit 2. It's only a change to Unit 1. We did look at that. And the total required flow for the auxiliary feedwater system will be able to be met by any of the two pumps available out of the three that services that system. And there will be sufficient capacity for it to perform this intended function.

And the technical specifications, as I just mentioned, requires three alternate auxiliary feed pumps to be operable. And so this allows us to have a single failure and still require it to -- for the two events, the loss of normal feedwater and heat feedwater line break.

Next slide.

Okay. In summary, Staff finds that the proposed EPU to be acceptable with respect to the balance-of-plant areas based on:

The evaluations that was performed that we reviewed;

The commitments made by the licensee, and;

The tests that they will be performing.

So, is there any questions.

CHAIRMAN DENNING: Are there any questions? No.

Thank you very much.

MR. STUBBS: Okay. Thank you.

CHAIRMAN DENNING: Now what we'll do is we'll take a 15 minute break so we can prepare ourselves for the risk assessment presentations. And we'll be back by the clock on the wall at 10:00.

(Whereupon, at 9:49 a.m. off the record until 10:04 a.m.)

CHAIRMAN DENNING: We'll now come back into session. And our first presentation will be on risk analysis and its impact.

MR. KELLER: Good morning. My name is Colin Keller. I'm a supervisor of the PRA Group at Beaver Valley.

With me here today also is Bill Etzel to help answer any questions that the Subcommittee may have.

A little bit about myself. I've been in nuclear power for 24 years now at Beaver Valley, starting at the Shippingport Atomic Power Station and working through other engineering assignments through Unit 2 startup, equipment qualification and the last ten years I've been involved in PRA.

I'm here today to discuss the Beaver Valley EPU PRA models, one for each unit.

Next side.

And I'd like to talk about the elements

of the Beaver Valley model that were reviewed as part for this uprate. And also to talk about the resulting changes in core damage from these reviews.

Next slide.

The first element we reviewed was our initiating events. We found that from the extended power uprate there were no new initiators identified and also there were no significant increases in our initiating event frequencies as a result of the power uprate.

We also did a review of our success criteria. We used the MAAP code to perform these analyses to establish our success criteria. Also included setpoint changes in there due to containment conversion and new pump curves that were put in.

We found that new accident sequences were identified as a result of the power uprate.

We went on to review our component and system reliability. Comprehensive reviews of the equipment were performed. We found that systems will operate within their allowable limits. There was on the PRA failure rates or results. We will continue to use our existing monitoring programs to account for any additional system wear using

Maintenance Rule MSPI, flow accelerate corrosion.

We expect that our future model updates will capture any initiating event or equipment failure rate changes.

We also performed reviews of our operator response times for our human reliability analysis. The MAAP analysis was used to determine operator action times that are available. Higher decay heat did reduce times for some of these operator actions.

The most important impacts were:

For operators to start aux feedwater given a solid state system protection has failed and no SI signal present;

Operator initiates a bleed and feed, and;

And there was a reduction in time to recover from a loss of shutdown cooling due to reduced inventory.

This is a listing of Unit 1's five most important operator actions. You see there was a reduction in time for two of those actions from the pre-EPU to the post-EPU. And as a result of that, there was also an increase in their human error probability for both of those actions.

The following table --

CHAIRMAN DENNING: No. Let's stick a little bit with this. You were done with this table, let's spend a little bit more time on the table.

MR. KELLER: Certainly.

CHAIRMAN DENNING: So the first item and the last time are the only ones where you have a significant change in your human error rates, is that right?

MR. KELLER: Yes. And as you can see, those are also the ones that saw a reduction in operator action time.

CHAIRMAN DENNING: Now this initiating feed and bleed, there's really a major time, difference in time, isn't there? Between 78 minutes and 29 minutes, is that right?

MR. KELLER: That's correct.

MR. ETZEL: This is Bill Etzel from FENOC.

Yes. In the pre-EPU case that was done with a hand calculation and it was based on steam generator dryout. For post-EPU feed and bleed was based on a 13 percent wide range level in the steam generators.

CHAIRMAN DENNING: So the big difference is really a matter of --

MR. ETZEL: Yes, in setpoint levels.

CHAIRMAN DENNING: Okay. Now I'd like to spend just a little bit of time on each of these, if you would. And give us some -- and that doesn't necessarily have to be a lot. But let's start with the first one here.

The first is starting the auxiliary feedwater system when you have no safety injection. And it does look like the 43 minutes certainly seems a substantial period of time to be available for that. You say the confirmation as it was simulator observation. So tabletop and simulator observations. So you've run through this in the simulator at post-EPU conditions?

MR. KELLER: That's correct. And George Storlis is here. He will speak to that.

MR. STORLIS: Yes, I'll speak. My name is George Storlis. I'm with FENOC.

And operationally we train extensively in the simulator environment. Both Unit 1 and Unit 2 have separate simulators, have a lot of exposure to simulator time.

One of the key elements of any failure

of solid state is manual backup by the operator and the supervisors that stand behind the team as part of the simulation. And 43 minutes is an extensive period of time, as you pointed out, for diagnosing a failure and then ultimately responding to that failure with manual actions. So I'm quite confident that we can make that 43 minutes.

CHAIRMAN DENNING: Okay.

MR. STORLIS: Probably in the realm of 2 minutes or less.

CHAIRMAN DENNING: Although you did have a big change in the human error -- I mean a big change in the human error probability. But I won't get into the details of that. I don't care.

Now let's look at, the second one obviously that's not an issue is the 24 hours.

The next is this portable diesel driven fans to cool the emergency switchgear rooms.

MR. STORLIS: Switchgear ventilation affords a rather large heat sink in that area. The portable ventilation is established to enhance existing cooling. And in the absence of cooling you have a period of time to set up and establish that flow.

MEMBER MAYNARD: Is the equipment pre-staged?

MR. STORLIS: The equipment is available and staged in a brigade area. And it's available.

CHAIRMAN DENNING: What about this, this fourth one? Can you describe that one to me? The reactor coolant pump trip, what's happening here.

MR. ETZEL: This is Bill Etzel from FENOC again.

Yes. That's just a simple reactor coolant pump trip on CCW, which is our component cooling water. And component cooling water supports thermal barrier cooling along with motor and cooling to the motors of the pumps, the reactor cooling pumps. So therefore we assumed that you have five minutes to trip the pumps with that, otherwise you would get an increased RCP seal LOCA due to high vibration.

MR. STORLIS: Again, this is an area where operator training is repeated over and over and over again to identify the absence of cooling water flows to the coolant pumps and the need for the five minute window to shut the pumps off to preserve the pump's condition.

MEMBER SIEBER: It seems to me you actually had an event like that at one time. Is that correct? Where you lost seal coolant?

MR. STORLIS: We did have an event where in loss of an emergency bus did transcend itself into a loss of thermal barrier cooling. And the pump was managed immediate to that and seal injection was reapplied in the pump.

MEMBER SIEBER: You actually didn't trip the pump, you reestablished the flow?

MR. STORLIS: Seal injection, that is correct.

MEMBER MAYNARD: This is I think a pretty common requirement or guideline for all the Westinghouse --

MR. STORLIS: That is a true statement, sir.

MEMBER MAYNARD: -- seals.

CHAIRMAN DENNING: Let's go to the next table them.

MR. KELLER: Okay. The next table is similar and is a listing of the operator actions for the Unit 2.

CHAIRMAN DENNING: Okay. Let's see, are there any here that are particularly -- okay. Well, let's start at the bottom one, the -- let's see. This is manual trip after the solid state protection system fails to automatically actuate reactor trip. So this is --

MR. KELLER: Directly from the bench port.

MR. STORLIS: Again, this is George Storlis.

The operator identifying conditions as displayed on what we call our first op panel. It enables early diagnoses of the need for trip along with a validation with the existing instrumentation. And the operator's license responsibility and legal responsibility to bring that reactor off line on manual action.

CHAIRMAN DENNING: Okay. Let's see --

MEMBER KRESS: Did you use a human error model to get these probabilities?

MR. KELLER: Yes. We were using the HRA Calculator?

MEMBER KRESS: HRA Calculator. That's the EPRI --

MR. KELLER: That is correct.

MR. ETZEL: We just switched to the HRA Calculator.

Bill Etzel, FENOC.

When we did this analysis we used the

SLIM methodology, success likelihood index methodology.

CHAIRMAN DENNING: Let's see --

MEMBER KRESS: And the confirmation with the simulators tabletop was just to show that you did it within that.

MR. KELLER: Ensure that we would be capable of performing those actions with the times that we don't have.

CHAIRMAN DENNING: Now why do you say tabletop there and simulator? Isn't this something that you would have verified with the simulator, validated with the simulator.

MR. ETZEL: This is Bill Etzel from FENOC again.

Yes. We were going through an update on our PRA model at Unit 1. And like Colin said, we were using the HRA Calculator. So we waned to -- since we were changing methodologies, we wanted to validated all our human actions. So we had simulator runs for the Unit 1 PRA model update. Similarly, when we go through the Unit 2 update sometime later this year, we will also do some simulator benchmarks.

MEMBER MAYNARD: But many of these are

things that you're doing as part of normal ops training anyway, aren't you?

MR. STORLIS: That is correct, sir.

MEMBER MAYNARD: This last one in particular, that's one of the first things you do when you have an issue is to check it and there's more than one person doing that, too.

MR. STORLIS: And that is absolutely correct. We're practiced on these in the simulator environment repeatedly.

MR. SENA: Again, this is Pete Sena. The indications available to the operators at Unit 1 to take the actions such as manually tripping the reactor in the event of a first out indication for the need for a trip is virtually identical at Unit 2. So the actions are the same, the training is the same and the indications are the same. So you can translate the simulation walkthrough that we've done at Unit 1 into Unit 2 through the tabletop method and be confident that the times are identical.

CHAIRMAN DENNING: Yes. It is interesting, though, that you seem to have some significant differences between the two units as to what the risk important operator actions are, or am I misinterpreting the similarities here? Is that true?

MR. KELLER: There are some differences between the units, yes.

MEMBER WALLIS: These are all errors of omission where the operator fails to do something?

MR. KELLER: That's the probability that we've failed to accomplish that action.

MEMBER WALLIS: Do you somehow put in potential errors of commission by misdiagnosing something and doing the wrong thing? Does that appear in your PRA at all.

MR. ETZEL: This is Bill Etzel from FENOC.

Mostly they are failures of omission in that he does not perform this action as opposed to doing the wrong action and making things worse.

MEMBER WALLIS: Are there some items of commission that would be affected in some way by the power uprate in that there will be a little more going on or more likelihood to make a mistake or something like that? I don't know you assess that, but conceivably in could be a context which is more likely to produce an error.

MR. ETZEL: Yes. This is Bill Etzel again.

That's a possibility and hopefully through the simulator training and just normal time in the control room will help prevent that.

MEMBER WALLIS: Fix that up during simulated training. You observe and see if as a result of the EPU there's more tendency to make some mistake, and then you correct that in some way? Is that the way you find it? You do it by training in the simulator?

MR. ETZEL: Yes.

MR. STORLIS: And this is George Storlis.

With regards to the structure of the OP, operating procedures, the team concept in the control environment, the identification of a potential error being made is identified and corrected before the committing of the act. So from an operating perspective the confidence in the team, the confidence in the training, the confidence in the practice of simulation and EOP network provide a high level of assuredness of proper actions.

MEMBER MAYNARD: The EOPs are also fairly good that even if a mistake is made or there's multiple things going on, getting you back, prioritizing and taking care of the issues.

MR. STORLIS: That's correct. The response not obtained columns and so forth that structure a pathway to success is very high.

CHAIRMAN DENNING: And I think if you identified in your simulator training a place where people were making errors of commission, then you'd correct something rather than putting it as a probability failure in a PRA.

MR. KELLER: That's correct.

CHAIRMAN DENNING: So it's hard to identify them, Once you do, then presumably you'll fix them.

MR. KELLER: Yes. You want to reenforce the training so we would make sure that we'd meet these times.

MR. STORLIS: Either in robust barriers and the like to assure that if there is a likely error condition that it's remedied either by physical barrier or other means.

CHAIRMAN DENNING: Okay. Proceed.

MR. KELLER: Okay. Thank you.

Next slide.

In regards to the operator response times, we did do a validation of the operator times to complete these actions through combinations of tabletops, discussions of simulator training or observations. And the operator actions with small amounts of time available can be performed within the time that is available.

MEMBER WALLIS: "Can" is a big --

MR. KELLER: I'm sorry?

MEMBER WALLIS: "Can" is a big word. I mean can with probability of zero or one? You think it can be performed with high probability or something.

CHAIRMAN DENNING: Well, he has exactly the probabilities on this table.

MEMBER WALLIS: He does, I know. But --

CHAIRMAN DENNING: These are three significant figures.

MEMBER WALLIS: I know. So it's really it will be performed or likely to be performed.

MR. KELLER: Likely to be performed. That's probably yes.

MEMBER WALLIS: Right. There's some things I can do, but without much probability.

CHAIRMAN DENNING: Likely would be a very PRA term.

MR. KELLER: I understand. Likely to be performed.

Next slide.

We also did a review for shutdown risk conditions. We found the EPU has no unique or significant impacts to the shutdown risk. There'll be no changes to shutdown operations to our safe shutdown risk assessments.

Next slide.

Summary for Unit 1 is shown here for the total core damages from pre-EPU to post-EPU and with a breakdown of internals, externals and fire and also it shows the differences for the total LERF. And the changes in risk are well within the guidance provided by Reg. Guide 1.174.

MEMBER MAYNARD: One new piece of equipment that you put in was the main feed isolation valves, How was that treated? Did that end up with positive credit, negative credit relative to the PRA. Because a new piece of equipment --

MR. KELLER: Yes. You do have some additional failure probabilities with that and also with the cavitating venturies. There is a probability that they could plug. But overall for the sequences, and Bill correct me, where main feedwater was involved there was not a huge impact from those additional failure rates.

MR. ETZEL: That is correct.

MEMBER MAYNARD: On the main feed isolation valves are you using an existing design that's been out there proven or is this --

MR. ETZEL: This is Bill Etzel from FENOC.

We have these similar valves installed at Unit 2, so we use their failure rates and apply them to Unit 1.

CHAIRMAN DENNING: Now let me ask an embarrassing question.

MR. KELLER: Yes, sir.

CHAIRMAN DENNING: Maybe an embarrassing question. And that is, you know, we recognize that there are changes in risks that aren't quantified by the way we treat CDF and LERF, particularly as far as radionuclide inventory is concerned. I mean, the risk is going to increase with no changes in CDF and LEFT, you're going to see there is a true increase in risk of at least a percent associated with --

MEMBER KRESS: Sixteen percent.

CHAIRMAN DENNING: -- this.

MEMBER KRESS: Two plants.

CHAIRMAN DENNING: Two plants. Well, I'm

not sure that that's still eight percent per, Tom. But in any event, we have had other applicants who have said okay, we want to make sure that the risk is not increased, and so we look to see what aspects of our PRA indicate things that we could fix that would actually reduce the risk or maintain the risk.

And I realize, of course, you changed the generator on Unit 1 and there's been probably a decreased risk associated with that. But as far as just looking at the major contributors to risk and recognizing the potential benefit that's associated here that certainly is worth doing, but did you look to see are there things that at this particular time we might change so that indeed we're not increasing the risk?

MR. KELLER: Yes. We have looked and we actually have some recommendations based on that. We've looked at things like potentially going out and adding additional methods for RCP seal injection. There was a recommendation also to, I believe it was restructure an EOP to gain some benefit towards large early release frequency.

And, Bill, there were two other modifications for each unit we were also looking at?

MR. ETZEL: This is Bill Etzel from

FENOC.

Yes. We also looked at increasing seismic ruggedness. We have at Unit 1 block walls on our emergency batteries. So we're looking at increasing seismic readiness of those block walls.

Also putting some fire barriers around our HVAC fans in the cable vault and spreading area.

CHAIRMAN DENNING: And has management agreed to any of these upgrades or made a commitment to these at this time?

MR. KELLER: At this time our plans to take those to our plant health committee at site and to get them evaluated and go forward from there. See if they'd --

CHAIRMAN DENNING: What's the committee you said?

MR. KELLER: Called the plant health committee.

CHAIRMAN DENNING: Plant health committee?

MR. MANOLERAS: Yes. This is Mark Manoleras from FENOC.

Our plant health committee is comprised of basically the management team at the site. Each project is presented to the plant health committee and it's weighed on its benefit and risks to the station and then will be implemented in course; ranked and implemented in course.

CHAIRMAN DENNING: Yes.

MR. ETZEL: And this is Bill Etzel from FENOC.

We did present the alternate RCPC seal injection system to the plant health committee already.

CHAIRMAN DENNING: And has a decision been made on that at this point or is that --

MR. ETZEL: Yes. We have had positive feedback on it.

CHAIRMAN DENNING: Yes.

MR. KELLER: A decision was made whether to go and install it at this time.

MR. ETZEL: Yes. The decision was made was that we were going to take a look at options to actually implement those options and then estimates will be performed on those options. We will go to our next committee, which is our technical oversight committee, which takes a look at the technical robustness of the options and how those will be implemented.

So it's well along in the process to be

targeted.

CHAIRMAN DENNING: What are the criteria that the committee uses to decide whether they would undertake a safety improvement that effectively isn't providing economic benefit?

MR. ETZEL: Yes. We actually have a very detailed rating system. We went out and benchmarked the industry and took a look at basically industry best practice. And actually one of the significant contributors to identify a project selection would be an increase or decrease in risk. We actually have a very large portion of our process will actually look at the change in CDF. So it's actually a big contributor to selecting a project to be implemented.

CHAIRMAN DENNING: You know, that still didn't help me very much. I mean, I'm talking about some things here where there's no economic benefit to the plant, or at least the economic benefit isn't obvious of some of these safety related improvements that could reduce risk. And so the question is under what conditions would the plant management say, well, it really -- I'm willing to invest some money here to reduce the risk even though I'm not going to see an economic payback and there's no regulatory requirements.

MR. ETZEL: Yes. I'm sorry if I didn't answer that clearly. A reduction in that risk is one of the key contributors to ranking a project. It is probably one of the top three contributors to ranking a project.

CHAIRMAN DENNING: Thank you.

MEMBER KRESS: As a bit of a follow on to this question, does your PRA system have the capability to do a level 3 analysis?

MR. ETZEL: This is Bill Etzel again.

Currently we do not. We just have level 1 and level 2.

MEMBER WALLIS: With a follow up question again. I understand that management looks at decreasing risk as a criterion for endorsing a project. Presumably there's something on the other side of the balance which is the cost of implementing this. And I just wonder how much your management is willing to pay? Do they have some sort of a figure that says we're willing to pay so much for so much decrease in risk? Is there some kind of an economic that's understood in the plant or is it not? You don't have to give me the figures, but it seems to me in the end its cost benefit that's got to rule in the decision.

MR. SENA: This is Pete Sena.

When we go through the plant health committee there's a detailed ranking form, as Mark was speaking towards, as far as how we score a particular project. Some of the other criteria may be, for example, does the modification result in in improvement in radiation dose to folks doing work on the station. Other criteria would be, you know, a change in personal safety, a change in equipment reliability. So there are many factors.

Those factors are then accumulated and tabulated. And that is then weighed against all the other modifications that are proposed.

Now, out of a year we will go through and we will pick, perhaps, our top 12 or 15 projects to go implement to look a year ahead. But, again, we do have limited financial means, as every other utility does. So we have a specific set budget. But the ranking criteria does not apply to the initial cost estimate. It would then be categorized against all the other mods. And we have X number of dollars and how many mods do we want to do with that X number of dollars.

MEMBER WALLIS: And so you have to spend

your budget?

MR. SENA: We would spend our budget, correct.

MEMBER WALLIS: So there is no trade-off? It's just a question of which ones do you spend it on, is that it? That was an interesting economic viewpoint.

MR. SENA: Well, again --

MR. MANOLERAS: Well --

MR. SENA: Go ahead.

MR. MANOLERAS: This is Mark.

Again, we want to weigh all the factors for the selection of this modification. We may want to increase equipment reliability in an area, we may want to increase personal safety. So we do weigh all those facets when we select the modification packages.

MEMBER KRESS: Just out of curiosity, how far away is Pittsburgh from Beaver Valley's plant?

MR. MANOLERAS: It's approximately 30 miles.

MEMBER KRESS: Thirty miles?

MR. MANOLERAS: That's correct.

CHAIRMAN DENNING: Proceed.

MR. KELLER: Thank you.

The next slide is a similar summary for Unit 2 showing the same changes. And, again, the changes in risk for both CDF and LERF are below the thresholds for Reg. Guide 1.174.

MEMBER WALLIS: Reg. Guide 1.174 also gives you no incentive decreased risk.

MR. SENA: And, Dr. Wallis, if I may just go back to how we look at various projects we may do. One example to speak towards, for example, is we installed N16 monitors at Unit 2. We had them previously installed at Unit 1. But, again, this was a benefit to the station. Not a production benefit, but a safety benefit so that operators would have a key prompt indication of a potential tube leak. So, again, that is an excellent example of a mod that met our criteria to move forward with.

MEMBER WALLIS: Thank you.

CHAIRMAN DENNING: Yes?

MR. KELLER: Okay. And summary, all the PRA model elements were reviewed for impact and found that the increase in risk due to the EPU for both Unit 1 and Unit 2 does meet the acceptance criteria. There were small changes in operator times that were available for some actions, and additional equipment that was installed had a small impact on overall risk.

CHAIRMAN DENNING: Let me just state for the record, I mean I think it's fine for you to compare with Reg. Guide 1.174, but its applicability to power uprates is somewhat questionable. And I think that the way the risk analysis was used in the review is really in a slightly different way than applies 1.174 to a change in the licensing.

MR. KELLER: Since it's not a risk informed application?

CHAIRMAN DENNING: Right.

MR. KELLER: Okay. I understand.

CHAIRMAN DENNING: Well, not to say that it isn't interesting to look at.

MEMBER SIEBER: It's not a risk informed application. It's nice to have risk information.

CHAIRMAN DENNING: Right.

MEMBER SIEBER: And, for example, the PRAs the state of the art today, does not evaluate and assign risk numbers to how much margin that you're reducing.

CHAIRMAN DENNING: Right.

MEMBER SIEBER: And to me that's a significant thing, but we are not going to easily get to the point to do that. It's a tremendous amount of work. And that's probably off in the future in number of years.

MR. KELLER: That's all I have.

MEMBER WALLIS: Do you have some perspective on what's the effect of these power uprate on risk? I mean, this is a measure of safety and this is what we're here for, so we get some idea what are the consequences of an EPU. And I think that's useful. But it's not as if 1.174 is the rule that you're going to use.

MR. KELLER: Oh, agreed. But it is a measuring stick, yes.

MEMBER WALLIS: Yes.

MR. KELLER: Any other questions?

CHAIRMAN DENNING: Okay. I see no other questions. I think we're ready to move on to the staff.

MR. KELLER: Thank you.

CHAIRMAN DENNING: Thank you.

We're on the Staff's presentation on risk assessment.

MEMBER SIEBER: Risk evaluation.

MR. LAUR: Well, good morning. I'm glad to see it's still morning.

My name is Steve Laur. I'm in the NRR Division of Risk Assessment, Senior Reliability & Risk Analyst. I'm here today to discuss the Staff review of the Beaver Valley EPU risk assessment.

Next slide.

I'll give you the conclusion slide first and if that's all you want to hear, we can make this even shorter.

The licensee assessed the potential risk impacts of the extended power uprate. Our review concluded and agreed with the licensee that special circumstances do not exist that would rebut the presumption of adequate protection. So therefore, we have approved going forward with this proposed power uprate.

Next slide.

Just a reminder, I think you just mentioned this right before I got up here, but they are not risk-informed as defined in Reg. Guide 1.174. However, there is an applicable review standard 001 that basically describes the purpose for the risk information that the licensee provides.

First of all, to determine whether the risk is acceptable. But as I mentioned before, to determine special circumstances exist that would rebut the presumption of adequate protection afforded by compliance with regulations. And this is discussed in the Standard Review Plan, Chapter 19.

This has been said a few times yesterday and today, but I want to reiterate this. This is an 8 percent power uprate. The Staff has approved uprates on PWRs up to 17 percent and on BWRs up to 20 percent. And so far from the risk assessment and from other reviews we have yet to determine special circumstances.

Next slide.

One thing that's important in looking at a risk assessment using a PRA is what is the quality or pedigree of the PRA? Beaver Valley has two separate PRAs because the units were sufficiently different. These are full power seismic fire and internal events including internal flooding PRAs. And they calculate the risk matrix, core damage frequency and larger release frequency.

For other risks including other external events and shutdown risk, the licensee used qualitative risk assessment.

CHAIRMAN DENNING: Unfortunately, George Apostolakis isn't here to say what's a qualitative risk assessment --

MR. LAUR: Yes. I noted that. I appreciate that.

CHAIRMAN DENNING: That's okay.

MR. LAUR: PRA quality, these are uprates of the agency's IPE models, and in the case of the fire and seismic, IPEEE models that were submitted under Generic Letter 88-20.

They had an owners review on the internal events portion in accordance with the industry peer review guidelines in 2002 and they've incorporated the resolutions from those comments.

The seismic fire PRA models, we don't have an equivalent industry peer review process or standards. However, they were reviewed by the consultants that did the work. I take that back. They were reviewed by consultants when the IPEEEs were performed. And the NRC in the staff evaluation report found them acceptable for meeting the Generic Letter 88-20 purpose.

And so the conclusion that I made from all this is that the PRA is of sufficient scope, quality and level of detail to support this application.

We also conducted a very focused onsite

audit of the licensee's PRA last October. There were several purposes. One was to understand the risk of the EPU taken by itself. A second purpose was to check the quality of the PRA and the risk assessment that was done using the PRA and to understand and clarify some of the RAI responses in an onsite manner as opposed to multiple back and forth on the docket.

Let me go to the key findings. The key findings was that the licensee up to that point had not assessed the risk of EPU by itself. There were model enhancements and methodology changes and then modifications to the plant that were unrelated to EPU that were included in the post-EPU model which made the delta risk assessment not apples-to-apples comparison.

Also, as a result of the audit we identified the need to explain some apparently anomalous MAAP results.

Coming out of the audit the licensee actually identified a MAAP error and reperformed and resubmitted quite a bit of the HRA timing analysis. They also submitted a risk assessment that was more of an apples-to-apples comparison pre-EPU to post-EPU.

DR. BANERJEE: Which were the MAAP results that had to be explained? What type of results, do you remember?

MR. LAUR: There was a reactor coolant pump seal LOCA calculation for station blackout. Correct me if I'm wrong, I know it was station blackout. I think it was RCP seal LOCA that in most of the cases from pre-EPU to post-EPU timing decreased as you would expect. In one case it actually increased. And so we questioned that. And then on the audit we pulled the thread a little more, the licensee ended up getting Fauske & Associates involved in explaining how the MAAP code works, et cetera. And it turned out the actual timing increase was due to another change, it had to do with the accumulator setpoints. And therefore, it could be explained in terms of the thermal-hydraulics, which was not my expertise, but it could be explained in the fact that more accumulator water went in during the transient.

However, in the course of researching that they discovered a modeling error in the MAAP model that required redoing.

DR. BANERJEE: Do you recall what the error was?

MR. LAUR: They had the pressurizer surge line going into the top of the loop instead of in the middle of the loop.

MR. ETZEL: This is Bill Etzel from FENOC.

Yes. on the pressurizer surge line the MAAP code we had a loop sealed model where in reality we do not have one.

DR. BANERJEE: But why didn't it show up in the pre-EPU calculation and the post-EPU. I mean, the error would have been made in both, right?

MR. LAUR: Right. The error was a preexisting error to my understanding.

DR. BANERJEE: So why did it give this anomalous result?

MR. LAUR: I can't answer that. But I know in my review when we're looking at a table of timing changes due to EPU and you see all of them going in the expected duration, a little bit shorter, and one of them going longer, it causes you to question.

But as to why that wasn't caught earlier, I don't know.

MEMBER WALLIS: But the two aren't quite so connected. Maybe the result of this lead to a review of MAAP which showed up this error; I'm not sure the two things are connect.

MR. KELLER: Yes. This is Colin Keller.

That's correct, Dr. Wallis. The two were not related. The error was found in part of the review that we did to the NRC's --

MEMBER WALLIS: You were lead to look further at MAAP and then you found something -- okay.

MR. KELLER: Yes.

MR. LAUR: Right. I didn't mean to imply that this error was causing the anomalous result.

DR. BANERJEE: So why was there an anomalous result? Then we're back to --

MR. LAUR: Well, when I say "anomalous," it's apparently anomalous --

MEMBER WALLIS: But not really?

MR. LAUR: -- but the reason for the time getting longer in this one or two scenarios, I don't remember how many there were, had to do with changing accumulator pressure setpoints and level setpoints that resulted a change in addition to or actually opposite to the change caused by power increase. So that in this particular scenario instead of the timing getting shorter, this additional water from the accumulators actually caused it to be longer.

DR. BANERJEE: So it was a legitimate-- now you accept that as a legitimate finding?

MR. LAUR: Yes. Yes.

DR. BANERJEE: But at the end of it it allowed you to -- well, not allowed it actually initiated this review of MAAP which found an error. But that error had nothing to do with this?

MR. LAUR: That is correct. And the real point I was trying to make here is that they did review the MAAP analyses and resubmit them on the docket.

The other result out of the --

DR. BANERJEE: Was there any independent check of MAAP or audit of MAAP or was this what was done?

MR. LAUR: I don't know. The audit we did was not looking at MAAP. We're looking at very focused on the licensee's configuration control process for MAAP and for risk calculations and on specific areas that we had asked in RAIs that we didn't understand. And this was one of them. But I think there were two MAAP areas, and the one they were able to resolve right away and this one took a little longer.

DR. BANERJEE: What was the other area?

MR. LAUR: I'd have to look it up. I don't recall offhand.

DR. BANERJEE: Okay.

MR. LAUR: The other result, though, we did compare the licensee's procedure for configuration the PRA to the ASME PRA standard Section 5 and concluded it was a good process. They had virtually all the elements met for practicing the configuration control by procedure.

The licensee already covered the fact that the way we tend to assess the risk is to look at the various elements that make up a PRA and say what could be impacted. And I've got these combined in a couple of slides here. But this one talks about initiating events and equipment reliability.

The EPU does not result in any new initiating events. Even in the cases where an initiating event is modeled as a fault tree model of some operating system that fails during its mission time, the equipment reliability is not expected to change either. So therefore, those initiating events would not be impacted.

And for the same reason the systems that are mitigating the accidents are not expected to change because they're still operating within their same design limits.

Next slide.

Accident sequence and success criteria. The general accident progression, accident sequence progression did not change. In other words, the event tree models are the same. Now timing may be different at EPU conditions, but you don't expect to have to ask different questions in the event tree as a result of an 8 percent power uprate. And the licensee concluded that you don't, and I concur.

The success criteria for the most part stays the same. And I just want to talk about a couple of places where it didn't.

Station blackout is impacted slightly. If you have a station blackout and never recover offsite power, you're going to have core damage somewhat earlier. That translates int the time that the operator has to recover offsite power, which translates into a higher operator action failure probability and therefore core damage frequency. The licensee did include that in their post-EPU model.

The ATWS success criteria was impacted.

Addition of the cavitating venturies on Unit 1 means you can no longer mitigate a full ATWS event because you can't get full flow out of three AFW pumps. However, the PRA success criteria didn't change. And the reasons for that is that the licensee had conservatively not credited full flow in the pre-EPU model. And therefore, the success criteria is the same. The licensee reported no change in risk.

I pointed out in my safety evaluation that that's not correct. There is a change in risk. The change in risk would be if you had taken the conservatism out of the initial, the pre-EPU, and you'd actually get a delta. But I also know to looking at the information they submitted that ATWS is less than 1 percent on both units. Therefore, the max that could be would be a 1 percent. It would not change my conclusions.

CHAIRMAN DENNING: That really is interesting, though, in terms of just looking at delta risks where, as you quite properly pointed out, that making the conservative assumptions made it look like there was no change in risk whereas in reality there was a slight increase in risk.

MR. LAUR: That's correct.

CHAIRMAN DENNING: But I agree, it's a

negligible consideration.

MR. LAUR: The design bases loss of feedwater transient was picked up by one of the other branches and brought to my attention resulted in a request for additional information on how the PRA success criteria was impacted. It turned out it was not. And the licensee submitted realistic LOFTRAN and realistic MAAP calculations to show that in a realistic analysis that the success criteria pre and post-EPU does not change.

CHAIRMAN DENNING: Now, is this the success criterion that relates to two out of three aux feedwater pumps?

MR. LAUR: Right. The PRA from a realistic standpoint pre and post-EPU you only need one AFW pump for secondary side decay heat removal. Now in Unit 2 you need two steam generators because you have small atmospheric dump valves but as far as the AFW portion, which is what has been effected by the cavitating venturies, the realistic analysis shows that it does not change.

And then the final bullet here is actually the subject of a whole other slide, which is containment accident pressure credit for ECCS NPSH positive suction head.

Next slide.

This has a potential of impacting success criteria, so that's why I put it under here. I don't know how much you want me to go over this. I thought it was pretty well covered by the Licensee and by Rich Lobel yesterday.

CHAIRMAN DENNING: Yes, I think it was. So if you just want to kind of bottom line, feel free.

MR. LAUR: The bottom line is if you remember the two graphs that were respective of calculations before and after, there's a difference of about 30 seconds to one minute when they cross zero, in which I concluded there was an incalculable risk impact, delta risk impact, from crediting the containment accident pressure.

MEMBER WALLIS: Does all this go into the PRA then? I mean you have an actual evaluation of the change in the PRA as a result of crediting this containment accident pressure?

MR. LAUR: No.

MEMBER WALLIS: You don't?

MR. LAUR: Not to my knowledge. If you look at the absolute value of a contribution to risk, in other words not the change but what it would be, and the licensee indicated that a large LOCA and failure of containment isolation for example would be 1E minus 8. I don't have their model, but what I did look at was a failure on demand. If you use a bounding value for a failure on demand of a containment isolation valve, a typical common cause failure in a bounding LOCA of frequency of ten to the minus four, you're down to ten to the minus seven right there. So you're talking about a very low --

MEMBER WALLIS: No, granting there's containment overpressure is not really something that's necessary in order to bring the risk down. It's necessary in order to meet some other requirement.

MR. LAUR: That is correct.

MR. RUBIN: Dr. Wallis, that's correct. If I could just interject momentarily.

This is Mark Rubin, Branch Chief 1.

The reason this was looked at is because of the issues related to the VY power uprate and some of the concerns on granting NPSH over pressure and the fact that the Reg. Guide -- I'm sure Mr. Lobel talked about that previously. Because the Reg. Guide is under revision, a senior NRR management asked that we reflect on the potential risk impact to see if any existed on the power uprates and that in the future it be sort of looked at quickly, if all that's required, to validate little to no risk impact. And that's why this was looked at specifically.

But the conclusion, you're absolutely correct, has no real impact in this case.

MR. LAUR: And the point was already made yesterday, but we're not granting containment overpressure. That's the existing licensing basis.

MEMBER WALLIS: There's really no change. It's been granted before and there's almost no change in the requirements, so nothing has really happened here?

MR. LAUR: Exactly. That's what we concluded.

Human reliability. I guess in keeping with every other EPU that I've heard about, this is the major impact on risk, on calculated risk. EPU has a tendency to reduce times for operators to act. The change in the HRA due to EPU is not assessed directly by the licensee. What was done instead was a sensitivity study. And the reason for that was their pre-EPU timing was, as I mentioned, based on often grossly conservative hand calculations for the time. Their post-EPU they've upgraded to use MAAP on both units.

Secondly, the method they used cannot translate small changes in timing into realistic human error probabilities.

MEMBER WALLIS: But that's just what they do, isn't it? Isn't that what they do?

MR. LAUR: That's what they do. But that's--

MEMBER WALLIS: You're saying they can't do it meaningfully?

MR. RUBIN: This is Mark Rubin again.

Yes, I think that's what we're saying. Some of the HRA methodologies, especially the earlier ones we'll grant, as Dr. Apostolakis has shown us on many occasions. The small change is in timing. The model will calculate a difference in human performance or success rate, but it's really not a meaningful -- you have no confidence really in those small changes shown.

MEMBER WALLIS: What else are you going to do? If you're asked to calculate the CDF effect, you have to use some sort of HRA?

MR. RUBIN: Yes.

MR. LAUR: Yes.

MR. RUBIN: Certainly.

MEMBER WALLIS: And you're simply saying that this isn't a very good method. I think it's a little extreme to say it's not meaningful. It's maybe the best method available.

MR. RUBIN: What is meaningful -- well, certainly it does give a quantitative result. But what is meaningful is that the techniques allow us to identify the more important actions, look at the timing changes for those and see if they're significant and let us focus in risk case.

All we wanted to point out here is that we're in the areas of uncertainty, almost in the area of noise in the small calculational differences. But we do use the technology to help us focus in on the important human response actions and look at the timing changes on those.

MEMBER WALLIS: I think you ought not to use the word "meaningful" though. That might mean the wrong thing to some people. And you're just saying that there are uncertainties and these are very small changes anyway, and all that sort of thing. But you're still doing the best you can or the licensee is doing the best he can.

MR. LAUR: That's a good comment. When I say the "methodology," as I mentioned I used the success likelihood index method, but I'm not integrating that methodology. If you have a time reliability correlation, which I think is an artifact in some ways, but as Mark said you change time, you're going to get a change. And this method has a method on the performance there's a time. If you look at the SPAR-H model, they have discreet time steps ranging from not enough time to adequate time, to excess time. And the point I'll make on the next slide goes to more with symptom based procedures, it's almost a function of can you get to that step in the procedure and then do you have an error of omission when you get to that step.

So looking at the third major bullet, the way I assessed the risk was looking at the post-EPU core damage frequency and large early release frequency recognizing that the change in those is based on natural plant changes and on a sensitivity analysis for the HRA. Okay.

And I did ask the licensee in an RAI to validate important operator actions with short time frames. You know, demonstrate they can be done. In other words, they are not precluded. I understand you "can" meaning one to zero. What I'm saying is you haven't changed the time to where something that was maybe marginal but you could do it became precluded. And they did that and nothing fell into that category of being precluded.

So my conclusions focused on, like I said, that the actual CDF and LERF and whether or not special circumstances arose.

Next slide.

The licensee showed you a top five operator actions and they gave me whole pages of them, but if you look through them and sort them by importance, I tried to summarize them in two major categories. What shows up are depressurizing the RCS and feed and bleed cooling at both units and then some manual actions to, in the case of Unit 1 start auxiliary river water pumps and align them and Unit 2 solid state protection system failure so you have to start aux feedwater pump.

The licensee, as I said, validated these and all the other ones that could be performed. But just looking at the feed and bleed actions briefly. These are proceduralized, they're routinely practiced, they're performed in the control room with one minor exception. They take a relatively short time from two to ten minutes to actually perform the tasks. And they occur in response to symptom based procedures, not just the EOPs but also the functional restoration procedures.

So the last subbullet under there is what I was trying to say. It's really more of a function of how much time you have until you get to that step in the procedure as opposed to a slight decrease in the amount of time available.

And the other two actions up there are control room actions that are simple actions.

So we concluded that there was a minimal impact on EPU risk on the HRA.

DR. BANERJEE: What about switching to hot leg injection?

MR. LAUR: I don't recall that operator action, and I'd have to defer to the utility. That might be a good one for the utility to comment on.

MR. ETZEL: This is Bill Etzel from FENOC.

We currently do not model hot leg injection.

DR. BANERJEE: But you switch, right, to hot leg injection in the log term cooling scenario, right?

MR. ETZEL: Yes.

MR. DURKOSH: This is Don Durkosh. I'll be addressing that in the next presentation.

DR. BANERJEE: Okay.

MR. LAUR: Okay. External events, we've got seismic fires and other, which include high winds. There's nothing about EPU that would increase any of the initiating event frequencies or types of initiating events from these.

The quantitative assessment, since their PRA handles seismic and fires, demonstrated that a very small impact on the risk from those. And that comes from the fact that their seismic and fire PRA models are integrated with their PRA model. So human reliability increases and plant modification increases translate and propagate through those models.

And for other external events, the successive screening methodology that was used for their IPEEE remains valid and we conclude that would be a minimal impact on risk as well.

Next slide.

I don't have as many as the licensee had, but this shows you the post-EPU core damage frequency and large release frequency using their

HRA methodology with a MAAP realistic timing and that is what I used to conclude that there was no special circumstances. These are very small changes.

The increases include the modifications and the sensitivity analysis. These small. They meet the Reg. Guide 1.174 guidelines for being small, but it's not what I based my conclusion on for adequate protection.

Next slide.

The licensee did a qualitative assessment of shutdown risk using the questions in the Standard Review Plan, Chapter 19. And we agree that the shutdown initiating events aren't impacted. Times to boil times for operator actions are slightly decreased, but minimal impact on risk.

Finally, in conclusion the licensee assessed the potential risk from EPU. We concluded the EPU does not create special circumstances that would rebut the presumption of adequate protection and therefore we found this acceptable.

CHAIRMAN DENNING: Are there any questions?

Thank you. Good job.

MR. LAUR: Thank you.

CHAIRMAN DENNING: Okay. Now we're just going to continue on and we'll get into operations and testing starting off with human factors, I guess.

MR. DURKOSH: Okay. My name is Don Durkosh. I am a senior reactor operator currently licensed at Unit 2 and control room supervisor.

I also have with me George Storlis. George brings over 30 years of operating experience at Shippingport, Beaver Valley Unit 1 and Beaver Valley Unit 2.

A little bit about myself. I have 25 years of experience in the commercial nuclear power industry. I started my career with Westinghouse working in the engineering design analysis services area. I was the Westinghouse site manager at Beaver Valley and was in the unique position of kicking off this project and working with Mike Testa from a management perspective.

And I am licensed at Unit 2 and looking forward to raising power toward the end of this year at Unit 2.

The four areas that I plan to cover are human factors, training, our test plan and overview of our test plan and touch upon large transient testing.

From an overview perspective, the human factors impact of the EPU is minimal. There's a total of eight meter changeouts from a control room perspective. Six of them are related to the fact that we're replacing our accumulator pressure indicators with a digital indicator. And we also are replacing our containment narrow range pressure indicators as part of the containment conversion project. All eight of these meters have been replaced out at Unit 1 and on the Unit 1 simulator and in the process of being changed out at Unit 2.

Coming into the EPU project we were at an advantage in that in late 2002 and early 2003 Beaver Valley Operations staff undertook a major review of our emergency operating procedures. And e have substantially streamlines our EOPs and made them consistent with the Westinghouse ERGs. And, in fact, that's a project that I also worked.

So we had a very solid foundation for coming into the final portion of the EPU project having very streamlined procedures.

In the big picture here, the procedure changes that are coming out of the EPU project are rather minimally. They're primarily: Revise operating parameters, changes in limits and revise setpoints.

One area where the EOPs were directly impacted was the addition of an attachment that will require that the control room initiate a purge following a steam generator tube rupture. However, I do want to point out that that existing attachment already exists for purging the control room for a steamline break scenario. So in a big sense, it's a very minimal impact.

DR. BANERJEE: What are those two little things there? What was that interesting stuff.

MR. DURKOSH: Go back, but don't click on it.

What they are, they are backup slides. What I wanted to do, what I have here are examples of some of the normal operating parameters and some of the EOP setpoint changes. But I looked ahead at the NRC presentation and they have much more than I have, so I don't see any value going there, if that's okay with you.

CHAIRMAN DENNING: Thank you.

MEMBER WALLIS: What we could do is check that you and the NRC have the same presentation or there's no inconsistency.

MR. DURKOSH: All right. Click on it.

CHAIRMAN DENNING: Don't click it. Don't click.

MEMBER WALLIS: We'll trust you on that one.

MR. DURKOSH: All right.

Okay. I was at the Ginna presentation so I heard your feedback, what you really wanted to focus on; those areas that were potentially impacted. So, obviously, our action time, operator action time is a key issue so I wanted to address that.

Obviously with increased decay heat the available time to perform some actions are reduced. However, I do want to point out that the basic operator actions that we have to do remain unchanged. We are not implementing any new modifications that require new operator action times. And that's unlike Ginna where they did actually implement some modifications.

In most cases our action times have either remained the same or actually been extended to improve the overall process. And I do have a couple of slides where the case is actually reduced, and I'll talk about those.

During the course of this review we also identify procedure enhancements and we have incorporated those. Most notably, we did a complete review of our fire related procedures for Unit 1 and we did a major upgrade as part of the EPU project.

And action times are being revalidated. We've already talked about some using the simulator, using walkdowns, using tabletop discussions and field timing of operator actions in the field.

I do want to take a point. Colin had mentioned operator action time relative to the PRA. And for the scenarios that I saw, most of those are beyond design bases. So it gets you pretty deep into the emergency procedures and the contingency procedures. For instance, initiating bleed and feed. There's a loss of heat sink scenario which requires us to lose all of our aux feedwater pumps, not be able to use our main feedwater pumps, our startup feed pumps, our condensate pumps. So we're basically sitting as the steam generators are slowly drying out and getting ready to wait to initiate bleed and feed. So it's a pretty extreme scenario.

Okay. The next slide.

Okay. We talked about ECCS switchover to hot leg recirc. Ken had talked about and this question just came up.

At Unit 1 the existing time is 8 hours and when we go to uprate, that time will get reduced to 6½ hours.

At Unit 2 the current time is 7 hours and that will get reduced to 6 hours.

And in addition, at Unit 2 our design bases has us switch from straight cold leg recirc to hot leg recirc and back to cold leg recirc on a periodic frequency. That time rate now is 11½ hours and that'll be reduced to 9½ hours.

I think the question came up as to what the burden or impact is. Through our simulations generally within an hour or two of a large break LOCA scenario we are back into the emergency mainstream procedure called E1. And basically we are doing our preparations looking down the road and doing our preparations.

As was mentioned, approximately one hour before we will start taking steps to make sure we have AC power to the valves in questions. If we have any jumpers that require, we have those jumpers in position. And we're briefing on what actions have to occur.

And the time frame for actually

initiating switchover, at least I looked at the Unit 1 validation efforts on the simulator to initiate hot leg recirc. Coming into the procedure we're talking a matter of minutes. So those hot leg recirc procedures are relatively streamline. You're able to get in and get out very quickly.

DR. BANERJEE: I guess the impact would be if one was wrong in determining where the switchover time should be? If it was, say, three hours instead of 6½ h ours, there's no direct measure you have here. But it's not related to the uprate, it's in general this issue of not having a direct measure for the boron?

MR. DURKOSH: I agree. It's not directly impacted by the project.

DR. BANERJEE: Yes. The amount of time difference is not significant. All right.

MR. DURKOSH: Two areas that I would like to talk about is the tube rupture and isolating aux feedwater flow and the post trip fire scenario where if we did lose aux feedwater, we would want to restore it.

Relative to the tube rupture, one of the key operator actions is to isolate aux feedwater flow. I do want to point out that all of the EPU analyses that were performed were actually based on crew simulation data collected in 2002. So we had a solid footing for the analyses going forward.

And then as part of the EPU project in late last year we ran on the simulator with the new procedures that are being proposed, we had the Unit 1 crew go through and then we validated the fact that what we had done before we were able to meet.

For Unit 2 this EOP changes are in the final stages of being identified. There were tabletops that were performed and we are planning to do simulator validation later this year.

Next slide.

Relative to the fire scenarios, key action would be if you lost aux feedwater you'd need to reestablish it. I wanted to give you a positive message here. Relative to the Beaver Valley Unit 1 the EPU project established all of the critical operator action times. The entire set of fire related procedures were revised, streamlined and the walkdowns have been completed. So that validation effort is complete.

Relative to Unit 2, about 3 years ago our fire related procedures were updated. And it turns out that because that occurred in the midst of this EPU project, the aux feedwater critical times have already been incorporated in the procedures. So there's basically minimal work to do on Unit 2. Possible that any of the lessons learned from the Unit 1 procedures may get back to Unit 2. But we're not anticipating any major changes to our procedures; they're already there. And they've already included the operator action times that are appropriate for EPU.

The next slide.

Okay. Moving on to operator training. Basically we use classroom training of our design change packages. We'll go over our tech spec and licensing requirement manual changes. We'll go over any physical changes, procedure and setpoint changes. And then also we'll do simulator focus areas where if there is a change warning, a demonstration or hands-on training, we would do that. And for instance, the Unit 1 crews had a chance on the simulator to operate the new steam generator level control program following steam generator replacement. So the crews have time to basically get accustomed to the new control setpoint.

And then we always will continue our

transient response and EOP execution training.

And for startup and shutdown, we also use just-in-time training to get the crews focused in prebrief so that those activities go smoothly.

As we discussed over the last day and a half many of the modifications have been incorporated. So crew training has been going on here for the last couple of years as modifications have been made. And they'll continue up to our EPU uprate.

We do have plant specific simulators that we use, separate ones for Unit 1 and Unit 2. And the changes that we're talking about are primarily model and initial conditions. So there's no issue about going from current plant to EPU plant other than a matter of a couple of minutes to switch over the model. I know that question was raised at Ginna. So we do not have any issues being able to switch back and forth.

Moving on test plan. This is an overview of our test plan. Primarily consists of post modifications tests which, as I mentioned, many of them have already been performed and we'll continue doing them as the mods are made.

Our low power physics testing program

remains the same. There's no change there. What we are doing is we are collecting baseline data and then using that baseline data to support our power ascension testing. And in the power ascension testing we're planning on small increments. I have a couple of slides to show you of what our current plan is.

But basically we'll use the baseline data to make data projections. We'll collect data at steady state conditions and then we'll review that day and if we have any anomalies, we'll evaluate that and identify through our corrective action program what our next step would be.

So what I wanted to do here is here's kind of a profile of Unit 1 power ascension profile. As we discussed, we just completed our 1R17 refueling outage which involved replacing the steam generators. We have started up and we are operating at a 100 percent power currently. And during the startup process we did collect baseline data at roughly 90 percent and 95 percent. So we now have the data that we can use to predict where we expect to be. Following receipt of the safety evaluation report, we plan to uprate approximately a nominal 3 percent power uprate and we'll be using the baseline data to predict where the parameters should be so that we have a method to compare.

And we expect to operate the rest of the cycle at approximately 2770 megawatt thermal.

And then coming out of the new refueling outage, we expect to return to that power level and make two small moves approximately 2.5 percent each time collecting data, evaluating the data making sure that we're comfortable and then moving up to the ultimate power level of 2900 megawatts.

I have a similar slide for Unit 2. We are currently in cycle 12 with a 2R12 refueling outage plan for the fall. Our plans here is to come out of the outage, collect our baseline data at roughly 95 percent. Come up to our current license power of 2689, which is 100 percent power and then initiate shortly thereafter a nominal increase of 3 percent up to 2770. And our plan is to operate for the rest of basically the full cycle at 3 percent uprate. And then at the following refueling outage would be the next opportunity to go ahead and incorporate the high pressure upgrade at Unit 2 and basically come out of the outage at the referenced power level and again make two small moves up to the ultimate 2900 megawatt for core license power.

DR. BANERJEE: When do you have it all with robust fuel or whatever this new RFA? I don't remember.

MR. DURKOSH: I didn't understand the question.

DR. BANERJEE: When is the core completely peopled with this robust fuel?

MR. DURKOSH: We're there already.

DR. BANERJEE: Both units?

MR. DURKOSH: That's correct. As part of our extensive planning process for this phased implementation we started five or six years ago when we began to transition to RFA fuel. So both units today as we speak are 100 percent RFA fuel.

DR. BANERJEE: Okay. Thanks.

MR. DURKOSH: The next topic, I'd like to move on, is the topic of transient testing. So what should be considered when you evaluate the need for transient testing?

One thing that is very important is to evaluate the modifications and also to evaluate the NSSS control changes. And then based on that in your test plan ensure that you have adequate coverage for testing.

So there was a detailed evaluation that

was performed as part of the license amendment and follow up RAIs. As we indicated, each of the modifications will be fully tested. And as I've already mentioned, many of the modifications have already been incorporated and we're gaining operating experience with those modifications.

In addition, design engineering did an extensive owners review of the NSSS control supporting analyses. These are the operational transients to make sure that we would not have a reactor trip during selected design bases events.

And I think the key point that came out of that is there are no controller functional or logic changes. I know Vermont Yankee had somewhat of a fundamental logic change and transient testing may have been appropriate in that case.

We have no new control schemes. And our changes are primarily limited to setpoint changes that have been optimized for EPU conditions.

The conclusion from our earlier work is the aggregate impact does not adversely affect plant dynamic response.

Next slide.

Now Beaver Valley Unit 1 given the replacement steam generators, it was important that we did monitor control systems during startup. And I believe Pete mentioned yesterday that the feedback from the operators was very positive. So our control system operated as expected and in addition we did perform, and this was an area where we thought transient testing was important, we change our valve trims out, we did change our control operating setpoints and we had new steam generators. So there was a transient test performed, and actually it was completed over the last weekend. Basically we imputed a step change and we were monitoring the controller response.

If you can go to the backup slide. I had this data provided to me over the weekend. But basically this is the new control point, a nominal 65 percent. They imputed a signal that drove the controller down 5 percent and we had minimal overshoot. And then they initiated a similar transient up with minimal overshoot. So overall the control system worked just as planned. We easily met all the acceptance criteria. And this all happened within the last few days over the weekend. So very positive feedback on the test. The test and the control modeling worked just as expected.

As mentioned, large transient testing is normally a test that involves reactor trip at some high power. At Beaver Valley any turbine trip greater than 49 percent will result in a reactor trip. As I mentioned, there are no functional changes in the NSSS controls and the supporting reactor trip functions. So we do not believe large transient testing is necessary.

In addition, the simulation code, which was LOFTRAN, that we use supported the original plant. LOFTRAN has been around a long time. So my message here is the computer code and the model basically supported the original plant design and basically all Westinghouse plant designs. The startup testing confirmed that the plant matches the model, that computer code and model supports our current operational analyses, we have used it to benchmark our simulators, we use it in our non-LOCA analysis and we use it to optimize the EPU conditions. So no further benchmark testing was deemed necessary.

And again, my conclusion is based on the technical changes there's no large transient testing that will be necessary.

Slide.

So my overall conclusions in the

operations and testing area, the key take aways are:

Our procedure changes primarily involve operating parameters, limits and setpoint changes;

The power ascension process will ensure a controlled, closely monitored, very conservative approach to our new licensed power level;

And the modification in the NSSS control changes do not alter the basic design function of those systems, nor introduce a first-of-a-kind type change that will warrant large transient testing.

CHAIRMAN DENNING: How is the auxiliary feedwater flow test did following the changes that have occurred with the venturies?

MR. DURKOSH: Actually, those venturies were replaced I think in the previous outage. But generally what we do is we have an aux feedwater flow test, an operations surveillance test. And there were predictions on what the flow requirements are. And then we have tested the system.

CHAIRMAN DENNING: Yes. And actually test it and add water to the steam generator within those tests?

MR. DURKOSH: Yes. We normally will do that in the last stages of plant startup.

MR. HANLEY: Yes. This is Norm Hanley

from Stone & Webster.

And, again, when we implemented the modifications to add the venturies, we did use the OSTs to monitor the flow to the -- we also did a very detailed calibration with the venturie itself with the vendor. We did extensive tests to make sure the calibration and the predicted flows would match. We did an OST test where we did pump water to the generator and verify those conditions. And we also did an OST on the pump to verify the pump curve was matching what we used in the analysis.

MEMBER MAYNARD: And you do this test coming out of each outage, don't you?

MR. DURKOSH: That is correct.

MEMBER MAYNARD: I mean as far as the flow test, the calibration?

MR. HANLEY: That's correct.

MR. DURKOSH: That's correct.

Any additional questions? All right. Thank you very much.

CHAIRMAN DENNING: Okay. We will go ahead and continue to hear from the Staff.

You may proceed.

MS. MARTIN: Good morning. I'm Kamishan Martin. I'm a human factors engineer in branch of

Operator Licensing.

For our evaluation we reviews procedures, training in human factors, interface --

CHAIRMAN DENNING: I think you're going to have to speak louder. And is that mike working for sure.

The room's been all changed around and so we're having some trouble with the mikes. And you really have to get right up to this mike, too, I know from experience here.

MS. MARTIN: Okay. Can you hear me?

CHAIRMAN DENNING: Okay.

MS. MARTIN: The areas we reviewed include the training and human factors interfaces between the operator and the control room and in the plant related to performance.

These are the regulatory guidelines that I use in the evaluation.

The main areas that we use that we evaluated include the EOPs and the AOPs, the operator actions that are sensitive to the power uprate, the control room alarms, the SPDS and the training program and simulator.

As the licensee stated, the changes were slight modifications for parameter thresholds and the elimination to references to the BIT tech spec. This was eliminated because it's no longer credited as a source of boron -- borated water. Sorry.

There was one new operator action that was introduced due to the EPU and that includes the control room purge. And the one change was a change to another purge of the control room dealing with the steam generator tube rupture. I'm sorry. That's a new action.

The time reductions, some of the time reductions for operator actions were due to decay heat, but as the licensee stated, most of them stayed the same. There were only a couple that were reduced due to the EPU.

In Unit 1 all of the action times were validated through the simulator and through the walkthrough in the plant.

For Unit 2 the in plant operator action times were validated, but because the procedures aren't finalized at this time they only did a tabletop review. But the licensee has committed to validating the times on the simulator once the procedures are finalized. We determined this to be acceptable because of their commitment to validated operator action times on the simulator.

This is just a table with the operator action times that were most sensitive to the EPU.

In Unit 1, as I stated, all of them were validated. But in Unit 2 there was in particular that didn't have a margin between the time available and the time it would take the operator to actually perform this. But it hasn't been validated at this time because the procedures aren't finalized.

CHAIRMAN DENNING: Now let me see if I understand. Whose evaluation of action performance time was this, the 9.7 minutes for example in this first action? That's the plant says it can be done in 9.7 minutes or somehow you guys did it?

MS. MARTIN: No, the plant said that it could be done.

CHAIRMAN DENNING: Yes.

MS. MARTIN: And they performed a validation of this because it's in Unit 1 that it could be finished in 9.7 minutes.

MR. DURKOSH: Okay. This is Don Durkosh from Beaver Valley.

The Unit 1 operator action times were validated last fall on the simulator.

CHAIRMAN DENNING: Now, why don't you stay there just a second. And that is this action performance time versus time available, I mean obviously there's extremely small margin between 9.7 minutes and 10 minutes. Is that just a conservative value as to we're 99 percent confident that it can be done within 9.7 minutes or what's the difference between the 9.7 minutes and the 10 minutes there? Can you respond to that?

MR. DURKOSH: Sure. As was discussed in the non-LOCAs presentation from yesterday, the 10 minutes was the assumed operator action time for basically terminating an inadvertent SI basically precluding additional safety injection flow into the pressurizer. And they made an assumption of 10 minutes that operator action could be accomplished. And we confirmed that we were able to do it within 10 minutes.

MEMBER WALLIS: How much time is available?

CHAIRMAN DENNING: Ten minutes. And the 10 minutes is the rough criterion that you have of you have to do it within 10 minutes, right?

MR. DURKOSH: That is correct. And where it says "Time Available/Times used in the analysis," that's the specified time, that's the target time that we're aiming at reaching.

MEMBER WALLIS: I'm assuming the time available is longer than 10 minutes.

CHAIRMAN DENNING: Well, let me put a hypothesis down and then you can tell me why I'm wrong. Suppose this action in performance time if that was the mean time that it took staff to do this, then the probability of successfully doing it within this time would be about 50 percent. And I'm sure you're not telling me that. What is that 9.7 minutes telling me? That's not the mean time to perform it. What is it?

MR. SENA: This is Pete Sena again.

Dr. Denning, if I can back up slightly. If you recall during the non-LOCA transients for the inadvertent SI, the way we went through that transient was for the design bases assumptions we bias steam generator or correct in pressurizer level an additional 7 percent high from the norm and you put in these various conservatisms.

When we go through the design bases transient, the design folks that 10 minute window to get it done. So the operating crews go through the EOPs E zero, ES1.1 for inadvertent SI and all simulator crews went through the scenario and were able to perform that action within the 10 minute time period.

CHAIRMAN DENNING: So are you saying the conservatism is within the 10 minutes?

MR. SENA: Yes. That's correct. But again when we went through the analysis the way we qualified the acceptability of the analysis was through the qualifications of the downstream piping and the PORVs and not relying on the operator action time. That's how we precluded the event from going from a condition II event to a condition III event.

MEMBER WALLIS: Well, what does the 9.7 minutes mean?

MR. SENA: Well, that is the actual time that the operating crews completed the performance in.

CHAIRMAN DENNING: All of them or --

MEMBER SIEBER: The slowest one or the average?

CHAIRMAN DENNING: -- the slowest one? Yes.

MR. SENA: I cannot recall. I believe that might have been the maximum time, but let me get back to you. Let me phone call.

MEMBER WALLIS: The average, it isn't very good.

CHAIRMAN DENNING: Right. Other than the fact there's conservatism in 10 minutes, but then we don't have a real good feeling as to how much conservatisms.

MR. CARUSO: And let's ask once again if the operators don't get it done until 11 minutes, what does that mean?

MR. FREDERICK: This is Ken Frederick.

In a realistic sense it probably means that they will be closer to overfill. In the safety analysis world that means that we'll cycle the safety valve a couple of more times.

MR. DURKOSH: So Ken gave you the analysis impact. From a simulator perspective and all the training that we have received, I cannot recall ever challenging an overfill condition on this kind of transient. We have streamlined our procedures. We can get to SI termination very quickly within 10 minutes. And normally when we would stop the simulator at that point, we're nowhere close to being overwhelmed.

MEMBER MAYNARD: I think the importance of this is whether it ends up being classified as a condition II or condition III event. In reality if they don't get it done at all, you're still covered but your safety analysis just goes into a different wonder. But it's whether this is considered a condition II or condition III event.

CHAIRMAN DENNING: In this particular case.

MEMBER MAYNARD: Right.

MEMBER WALLIS: Does this chart come from a FENOC submittal? Is this something that you put together.

MS. MARTIN: I'm sorry, what was the question?

MEMBER WALLIS: Is this chart taken from the FENOC submittal or is it taken from--

MS. MARTIN: I put this chart together from information that was in a chart that they submitted that had more --

MEMBER WALLIS: I was wondering why we hadn't seen something like this before.

MEMBER MAYNARD: I thought this was discussed a little bit yesterday.

MEMBER WALLIS: Yes, I think it was. But we seem to be seeing it a different way now than we did yesterday.

CHAIRMAN DENNING: Yes.

MEMBER WALLIS: Now it doesn't look so

good.

MEMBER MAYNARD: Well, again, I think we had a similar discussion yesterday, though, in that what happens if the operator doesn't get the action done.

MEMBER WALLIS: Yes.

MEMBER MAYNARD: And you're still covered with your small break LOCA or whatever other analysis is covered. It's whether or not this ends up being a condition II or condition III event. And that's what was discussed with one of the NRC presenters --

CHAIRMAN DENNING: Well, that certainly is true in that first one. I'm not sure that that's true for everyone of these.

MR. DURKOSH: Well, I can address the other ones if you'd like.

CHAIRMAN DENNING: Well, why don't you go ahead and do that?

MR. DURKOSH: Okay. Sure.

So in the case of Unit 2, as I mentioned, an isolating aux feedwater on a tube rupture is a key operator action. Previously the previous analyses used 9.1 minutes. Based on the extensive simulator crew evaluations from, I think

2002, they came up with 5.5 minutes as being a very representative time to perform that action. And that was prior to our streamlining of our EOPs.

And the action performance time was tabletopped at 5 minute.

I do have some data available to me from Unit 1 which I believe it was of the order of less than 5 minutes for Unit 1 on the actual simulator.

MEMBER WALLIS: So the now column here is the time used before, pre EPU, is it?

MR. DURKOSH: That's correct. It's in the current.

MEMBER WALLIS: Okay. So the word "EPU" should disappear from the title.

CHAIRMAN DENNING: Yes. And "isolate" is that just an implication as far as offsite doses from the steam generator tube rupture or does it have more dire implications?

MR. FREDERICK: This is Ken Frederick.

Yes. Each individual action in the tube rupture procedure and the analysis associated with that is trying to minimize overfill of the generator. So for these particular cases --

CHAIRMAN DENNING: Overfill.

MR. FREDERICK: -- the goal is not to

fill up the steam generator.

CHAIRMAN DENNING: Okay.

MEMBER MAYNARD: Okay. Some of this also is to keep you from wasting water to the ruptured steam generator there?

MR. FREDERICK: Right.

MR. CARUSO: And what are the consequences of overfilling the generator?

MR. FREDERICK: If you overfill the generator, then you lose iodine partitioning, which makes the offsite doses go up.

CHAIRMAN DENNING: Okay. I think we're content with this figure.

MEMBER WALLIS: I suppose we are. And just a little bit mystified.

CHAIRMAN DENNING: Yes.

MEMBER WALLIS: If we're just comparing columns and you say you need 2 minutes and you got 2 minutes, that doesn't really help me much.

CHAIRMAN DENNING: Now, I don't think any of these are identified as important human actions from a risk assessment. Is that a true statement? Do we still have risk people here? Are they --

MEMBER WALLIS: I think we do.

MR. LAUR: This is Steve Laur again, NRR Division of Risk Assessment.

I don't know what the relationship between the design bases accident and the PRA is. But certainly cool down -- the action to cool down is one of the risk important operator actions.

I would point out that this a design bases discussion looking at the inputs from Chapter 15 and not a risk assessment.

CHAIRMAN DENNING: Yes.

MR. LAUR: And as I understand it, what the human factors are doing is verifying or validating that basically a go/no go criteria that you can meet the time whereas in the PRA risk assessment they use realistic timing and realistic scenarios and calculated the frequency of core damage sequences. So really it's not a comparable set of information.

CHAIRMAN DENNING: Yes. It does, however, give us a feeling as to what significance of margin in the design bases. But I think you're absolutely right, that that's probably the context that we ought to be interpreting this in rather than risk.

And I'm ready to move on to the next

viewgraph.

MS. MARTIN: These are the times that the licensee provided, the data that will be changed due to the EPU setpoints. This is a representation of the data that will change.

In the control room there will be no new displays except for as the licensee mentioned earlier, the SI accumulator should be upgraded to a digital display.

And all of the setpoints and displays will be normalized so that 100 percent remains a 100 percent and the actions don't change due to the renormalization.

For the SPDS, these are just the representation of the changes that will come. Nothing major. And this describes the change process that will be implementing the changes that we'll have.

For the simulator, as they mentioned previously, both the simulators have been benchmarked with engineering models. And they will be using the systematic approach training to train the operators for the --

CHAIRMAN DENNING: Thank you.

MS. MARTIN: This is just more general

information on the simulator changes and how they will cover the training for the simulator changes.

Our conclusion is that the licensee addressed the effects of the EPU on human factors and they have taken the appropriate actions to assure that the EPU does not adversely affect the operator actions. And we find these proposed changes to be acceptable because of their commitment to validation on Unit 2 and because of the issues that they've addressed.

CHAIRMAN DENNING: Very good. And I think we see no other questions.

Thank you very much.

And we'll move on to what is the last technical presentation, I think.

MR. PETTIS: Good morning. My name is Bob Pettis. I'm with the Division of Engineering. I'm filling in for Greg Galletti who was the technical reviewer for the Beaver Valley EPU. At present he's currently at Vermont Yankee and the license renewal inspection. So I'll do the best I can with what was the basis of his review.

As you're aware, the power ascension and testing program is covered under the SRP 14.2.1 and which we've had many discussions over the last several months.

The EPU test program should include sufficient testing to demonstrate that the SSCs will perform satisfactorily at the request power level. The Staff guidance considers the original power ascension test program that was done under the Reg. Guide 1.68 process and the EPU related plant modification, which most of the modifications fall into the area of plant systems branch which they probably have already provided their evaluation to you folks earlier today.

Staff guidance acknowledges that licensees may proposal alternative approaches to testing without adequate justification. We've centered around the large transient testing issue, but it's basically any departure from the original test program is reviewed as part of the technical justification for allowing those exceptions.

The Staff basis for requiring performance of testing including the large transient testing fell into the Reg. Guide 1.68 document which was basically established to ensure that there was a suitable test program at the original plant licensing phase that covered both the steady state and anticipated transients.

The objectives of Reg. Guide 1.68 were to familiarize operators with training, confirmation of design and installation of equipment, benchmark of analyses and codes and also to confirm the adequacy of EOPs.

One of the main objectives with 1.68 was also to provide necessary assurance that the facility could ge operated in accordance with the design requirements and validate any analytical models.

Under the Reg. Guide 168 there were a series of tests that were recommended back in the appendix. And two of those tests that were in the original 1.68 guidance were the so called large transient tests which are under discussion for the new plants today. And both of those tests that were required at original plant construction, again to validate analytical models in performance of a brand new plant.

Beaver Valley is planning on performing additional startup tests which were originally not part of the initial startup test program to maintain consistency with that of Unit 2. And I believe from what I could look at the SE, it had to do with the fact of the vintages of Unit 1 versus Unit 2 in order to have both plants be somewhat the same, the additional tests were included to make that happen.

Some of those examples included the secondary system vibration frequency and amplitude test, system expansion and restraint test, turbine plant system tests.

Beaver Valley will perform a series of post mod tests for plant design changes associated with the power uprate. A few of those are listed here. Replacement of main instrumentation, modification of HB turbine.

With respect to the transient testing issue, Beaver Valley like most others that have come before the agency, have elected not to perform the two large transient tests which are the MSIV closure and the generator load reject. Some of the accepted justification for not performing these tests for some of the previous plants were that the licensee's test program will monitor the important parameters during the power ascension test phase. And most of that occurs within 2½ to 5 percent increments where the licensee monitors the power ascension.

Tech surveillance and post mods will confirm the performance and capability of the modified components through tech spec testing, through normal QA and Appendix B type testing.

Operating history is a big factor that quite a few applications take credit for, which is listed in the SRP. And they've cited North Anna, Summer and Harris as similar plants that have undergone the uprates.

CHAIRMAN DENNING: Normally we tend to challenge the Staff in this particular area. But in all honesty, I don't think that there's any real serious concerns about large transient testing in this particular uprate.

MR. PETTIS: Okay.

MEMBER SIEBER: Percentage of power increase is really pretty small.

MR. PETTIS: I believe this 108 percent on Beaver Valley.

MEMBER SIEBER: Yes.

MR. PETTIS: But just to maybe reenforce that--

CHAIRMAN DENNING: And also looking at the lack of major modifications in --

MR. PETTIS: Yes. I was just going to mention that the technical staff in the balance-of-plant section identified that the balance-of-plant modifications don't warrant the need for the transient testing.

So based upon that part of the Staff's review, the Staff concludes that the EPU is satisfactory.

CHAIRMAN DENNING: Are there any questions? Thank you very much.

MR. PETTIS: Okay. Thank you.

CHAIRMAN DENNING: Well you never thought you were going to get away that easy, did you?

MR. PETTIS: No.

CHAIRMAN DENNING: Okay. Well, I don't hear anybody saying we ought to go to lunch. Let's finish out.

MEMBER SIEBER: If you want me to.

CHAIRMAN DENNING: Yes. Okay. So, first we'll hear from FENOC management and their wrapup.

MR. LASH: Again, I'm Jim Lash, Site Vice President. And I will be brief. I know I'm us and lunch.

The past two days I think our team as well as the NRC the presentations have concluded that the reviews have been detailed and there have been no safety issues identified and the Beaver

Valley approach is a conservative approach both from an analysis as well as a power escalation that we plan to employ at the station. And I assure you that the implementation of the power uprate will be performed safety and reliability using our plant modification process, our operator training program, our plant procedure modification processes and our adherence to the operating conditions.

That completes our presentation unless there are questions from myself.

CHAIRMAN DENNING: I don't see any questions. I would like to thank you and your staff for a very good presentation.

And as far as the full Committee meeting, we'll give you some more guidance as to what our expectations there. We have two hours there.

There was a little bit of duplication between some of the regulatory Staff's presentations and some of your presentation. I think that our guidance will be largely that we're going to focus more on your presentations in a few areas, and some of them are obvious.

MR. LASH: Sure.

CHAIRMAN DENNING: We're going to want

to certainly focus on the results of the accident analyses. But some other areas that aren't necessarily problems, but which ones has to look at like potential for vibrations and stuff like that. I think your story today was quite good on that. We'll have to abbreviate those.

And we'll give you some more guidance as to what the presentations.

MR. LASH: I appreciate that. I was going to ask you for that guidance. And I appreciate that.

CHAIRMAN DENNING: Yes. I think that rather than attempting to really lay it out at this meeting, Ralph will send you a message that kind of indicates how much time to figure on.

MR. LASH: Okay. Good.

CHAIRMAN DENNING: And in which areas.

MR. LASH: Very good.

CHAIRMAN DENNING: But there's nothing missing that I see, you know, that we're going to have to have additional things. It's really a matter of compressing and perhaps eliminating in some areas. And from the Staff's side, I think it's going to be an elimination in a lot of areas of some of the reviews that were of value to us to make sure that we saw that they had been comprehensive in their reviews and to see what their considerations were, but as far as the full Committee is concerned I think would be unnecessarily duplicative.

MR. LASH: Okay. Thank you.

CHAIRMAN DENNING: Okay?

MR. LASH: I do have another question, though.

CHAIRMAN DENNING: Yes.

MR. LASH: And that is just to confirm I think we've been checking all along. I don't believe we owe the Subcommittee anything?

CHAIRMAN DENNING: Let me just see if Ralph agrees.

MR. CARUSO: That's correct.

CHAIRMAN DENNING: Although it looked at some points like there might be, everything has been provided that we had asked for.

MR. LASH: Okay.

MEMBER SIEBER: Well, if Ralph has some of this typical --

MR. CARUSO: I'll be getting a copy of the WRP-2M. I'll send you off that today or tomorrow.

MR. LASH: Okay. Good.

CHAIRMAN DENNING: Okay?

DR. BANERJEE: And ATWS, I guess, but you have that.

MR. CARUSO: And I'll give you a copy of BACCHUS, too.

CHAIRMAN DENNING: Yes. Yes.

MR. LASH: Very good. I would like to thank the Subcommittee for allowing us to make this presentation of our power uprate proposal.

I'd also in your presence like to thank my team, which includes the subcontractors from Westinghouse and Stone & Webster for supporting us. The folks worked very hard. Their preparations were very thorough and I think that bore itself out in their presentations. So I thank the team as well.

That's it.

CHAIRMAN DENNING: Thank you.

MR. LASH: Thank you.

CHAIRMAN DENNING: And wrapping up for the Staff?

MR. COLBURN: I don't have any slides, so I can do that from here.

My name is Tim Colburn again.

And I'd just like to thank the Subcommittee also for allowing the Staff to make its presentation.

We reviewed the licensee's submittal against all of the areas in the Review Standard RS-001. We had a challenging review. There were numerous requests for additional information we provided to the licensee, but they stepped up and provided information every time we asked them questions that resolved all of our issues.

The Staff believes that the licensee has done a very good job in resolving the open items that we have along the review path and also in ultimately demonstrating that they can adequately and safely implement the power uprate of 8 percent for Beaver Valley Units 1 and 2.

And, again, look forward to whatever guidance the Committee would like to provide us on preparing for the full Committee.

CHAIRMAN DENNING: Very good. Thank you.

Any questions or comments from the Subcommittee?

Anything else we want to discuss before we --

MEMBER WALLIS: Well I think we should establish that we don't have any sort of outstanding questions or anything.

CHAIRMAN DENNING: Absolutely. Jack, do you want to start off?

MEMBER SIEBER: I would indicate that I worked at Beaver Valley for many years. So I don't have a bias one way or another.

When I read the application and through the SER, I found the application pretty easy to read, it was straightforward, easy to follow, legible, made sense. On the other hand, that was your second shot at it, I think.

In the SER it indicates a lot of requests for additional information that tell me that maybe the first application wasn't real complete.

On the other hand, all of that has been remedied and I think the document is in good shape. And I think the modifications that you intend to make on the plant are reasonable. The EPU level that you chose is reasonable because you still remain sort of in the middle of the pack as far experience is concerned. There are a number of plants like yours that operate basically with the same parameters. So you're not blazing ground in that area.

I was impressed with the presentations. I think that they demonstrated a good knowledge of analytical methods that were used and what they meant. And I congratulate your staff for that.

We had a discussion with some of your folks at the Ginna EPU and I noted that you've been sending people out to see what goes on in these meetings as a way to prepare for this meeting. And, obviously, you learned a lot because this meeting in my opinion went very well. The questions that we asked and that were important were answered well and with the analytical backup and operating experience backup. And I think those factors are important.

As far as issues are concerned, I don't see any issues that arise from this application. And I agree with the Staff's conclusions. And when we get an opportunity to vote on Rich's letter which he'll write, hopefully --

CHAIRMAN DENNING: I'd better. They don't pay me otherwise.

MEMBER SIEBER: -- I personally feel in the affirmative at this time with regard to granting the uprate.

So that would be my conclusion.

CHAIRMAN DENNING: Thank you.

Sanjoy, do you want to comment?

DR. BANERJEE: I think that the approach taken is quite conservative and lies within the bound of what has been done before. So I have no particular concerns.

I think I'd like to follow up a little bit more on the fate of the boron, which I will do when I look at the BACCHUS report. And a little bit more on the refluxing mod. But other than that, I have no major points. But the applicant doesn't really have to supply any more information at this time.

CHAIRMAN DENNING: Let me interject that with regards to the boron, I think there is more work that has to be done here. But not within the context of this EPU. And I have some recommendations that I will to the Staff about how I think that ought to be done there.

DR. BANERJEE: Far more generic issues which --

CHAIRMAN DENNING: Yes.

DR. BANERJEE: -- should not necessarily be a burden on the applicant.

CHAIRMAN DENNING: Yes.

MEMBER SIEBER: Yes, I agree with that.

CHAIRMAN DENNING: Graham?

MEMBER WALLIS: Well, I'm glad Jack made the speech, now I don't have to make it. I'm pretty satisfied with what I've heard.

I think in front of the full Committee you just have to present the key things and what are the main effects of the EPU as they effect the criteria for reactor safety; how do you meet those criteria. That's really the main issue.

Try to avoid a long discussion on PRA because, you know, the changes are so very small they don't effect the ultimate decision.

CHAIRMAN DENNING: Okay.

MEMBER WALLIS: I think there are some of these questions like the boron thing that we keep coming up with need to be resolved better at some time. But that's not something we should hang on this particular licensee.

Thank you.

CHAIRMAN DENNING: Tom?

MEMBER KRESS: I think it's all been said.

CHAIRMAN DENNING: Otto?

MEMBER MAYNARD: I think it's all been said, too.

CHAIRMAN DENNING: I think it's all been said, too.

We're adjourned.

(Whereupon, at 12:01 p.m. the meeting was adjourned.)

CERTIFICATE

This is to certify that the attached proceedings before the United States Nuclear Regulatory Commission in the matter of:

Name of Proceeding: POWER UPRATES (BEAVER VALLEY)

Docket Number: n/a

Location: Rockville, MD

were held as herein appears, and that this is the original transcript thereof for the file of the United States Nuclear Regulatory Commission taken by me and, thereafter reduced to typewriting by me or under the direction of the court reporting company, and that the transcript is a true and accurate record of the foregoing proceedings.

Lindsey Barnes

LINDSEY BARNES
Official Reporter
Neal R. Gross & Co., Inc.

ACRS Subcommittee on Power Uprates

NRC Staff Review of Extended Power Uprate Application
For
Beaver Valley Power Station, Unit Nos. 1 and 2

April 25-26, 2006

Introduction

Timothy G. Colburn
Senior Project Manager
Divsion of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Topics for April 25

- Background for Application (Staff)
- Introduction and Overview of the Application (Licensee)
- Plant Changes (Licensee)
- Fuel and Core Design (Licensee)
- Safety Analyses (Licensee)
  - Methodology
  - Non-LOCA Events
  - LBLOCA
- Safety Analyses-Non-LOCA&LBLOCA (Staff)

Topics for April 25

- **Safety Analyses (Licensee)**
  - SBLOCA
  - Long Term Cooling/Boron Precipitation
  - Containment Overpressure Credit
  - Dose Analysis
- **Safety Analyses (Staff)**
  - SBLOCA
  - Long Term Cooling/Boron Precipitation
- **Containment Analyses (Staff)**
- **Dose Analysis and AST (Staff)**

Topics for April 25

- Materials & RV Integrity (Licensee)
- RV and Boundary Materials (Staff)

Topics for April 26

- **Mechanical Plant (BOP) (Licensee)**
  - Cooling Sustems
  - Vibration Monitoring
- **Flow Accelerated Corrosion (Licensee)**
- **Mechanical Systems (Staff)**
  - Vibration, Corrosion/Erosion
  - Pumps and Valves
  - BOP
- **Risk Evaluation (Licensee)**

Topics for April 26

- Risk Evaluation (Staff)
- Operations and Testing (Licensee)
  - **Human Factors**
  - Training
  - Test Plan
- Human Factor Review (Staff)
- Power Ascension (Staff)
- Conclusions (Licensee and Staff)

Introduction

- Pre-application Submittals
  - Steam Generator (SG) Allowable Value Setpoints
  - Containment Conversion
  - BELOCA
  - SG Replacement (BVPS-1 only)
  - Relaxed Axial Offset Control
- Application with supplements
  - October 4, 2004 application with numerous supplements
  - Licensing Report
- Schedule and implementation

Beaver Valley Units 1 and 2
Extended Power Uprating

Non-LOCA Analysis

Samuel Miranda

NRC Staff Reviewer
PWR Systems Branch

Fuel/Nuclear/TH

- No Change to the Fuel Design
  - Both BVPS Units currently using RFA/RFA-2 with ZIRLO cladding
  - RFA/RFA-2 consistent with other applications
- No Change to the Nuclear Design
  - No Change to the Codes and Methodologies
- Thermal Hydraulics
  - NO DNBR transition penalty
  - VIPRE-01 replaces THINC IV
  - RTDP & STDP

Beaver Valley Units 1 and 2
Non-LOCA Analyses

1. Acceptance Criteria

2. Margins

3. Interpretations of Results - 3 examples:

   Steam System Piping Failures
   Spurious Actuation of ECCS
   Spurious Opening of a Pressurizer Relief Valve

Acceptance Criteria

ANSI-N18.2-1973	Standard Criteria	Analysis Criteria
Condition II anticipated transients, or anticipated operational occurrences (AOOs) [freq > 0.1/yr]	Event is mitigated by no more than a reactor trip; and plant can return to operation after corrective action	
	Event cannot develop into a more serious event	☐ Pressurizer does not fill ☐ Qualify PORVs and/or PSRVs for water relief
	Event does not breach any fission product barrier	☐ CHF is not exceeded ☐ RCPB P ≤ 110% of design P ☐ MSS P ≤ 110% of design P

ANSI-N18.2-1973	Standard Criteria	Analysis Criteria
<u>Condition III</u> infrequent incidents [0.01/yr ≤ freq ≤ 0.1/yr]	Small fraction of fuel rods may fail. 10 CFR 20 ≤ releases ≤ public restrictions outside Exclusion Area Boundary	☐ Meet Condition II criteria ☐ Show that only a small fraction of fuel rods fail; which meets release criterion
<u>Condition IV</u> limiting faults [freq < 0.01/yr]	Releases < 10 CFR 100 guidelines	☐ Meet Condition II criteria ☐ Fuel rod failures & dose
	Event does not cause loss of functions needed to cope with the fault (e.g., RCS and containment)	☐ 10 CFR 50.46 ☐ No hot leg saturation (a Westinghouse criterion)
ATWS	Not applicable (see WASH-1270) 10 CFR 50.62 requires DSS and AMSAC	Best estimate analyses show: RCS P ≤ ASME Level C stress limit (3200 psig)

Margins

Margin in the Safety Analysis Limits (SALs)

- **CHF**

DNBR ≡CHF/HF

Example (WRB-2M):

DNBR Correlation Limit 95/95 value, including empirical uncertainties	1.14
DNBR Design Limit (DL) Correlation limit + operational uncertainties	1.22
DNBR SAL DL + DNBR margin	1.55
DNBR Margin (1- DL/SAL), %	21.2

- **RCPB**

RCS Level C stress limit (psia) Best Estimate (e.g., ATWS)	3215
RCS P SAL (psia) Conservative (110% design P)	2749
RCS P margin (%)	17

Margin in the Safety Analyses

- **Acceptance Criteria**

  - Some events are judged according to more stringent acceptance criteria (e.g. steam line break)

  - There is margin between some analysis acceptance criteria and the standard acceptance criteria (e.g., hot leg saturation; pressurizer no-fill; fraction of failed fuel rods)

- **Initial Conditions and Parameter Values**

  - For each event analysis, uncertainties are applied to initial conditions in the conservative direction, for that event (e.g., power, RCS temperatures, SG tube plugging, pressurizer and SG water levels, protection system setpoints, and core reactivity feedback).

  - Margin is added to key parameter values (e.g., rod drop time, safety injection flow, decay heat generation, and scram worth)

  - Margin is added to system response times (e.g., signal processing delays, pump startup and valve opening times, and isolation valve stroke times

  - Wider-than-expected range of core-related parameter values (e.g., MTC and Doppler feedback) is assumed, to minimize the need to re-analyze events affected by core reloads

- **Analysis Methods**
  - Conservative critical flow calculations
  - No water entrainment for steam line break, to produce a high cooldown rate
  - Derivative method to underestimate DNBR, based on core limit curves (used by LOFTRAN and RETRAN)

- **Transient Assumptions**
  - Worst single active failure in the protection system
  - Scram worth based on the most reactive rod stuck outside the core
  - No credit for operation of control grade systems (e.g., pressurizer PORVs, heaters, or spray) unless they would aggravate the transient
  - No credit for some trips (e.g., reactor trip on turbine trip), nor for rods falling into the core when offsite power is lost

Conclusion

There is margin in the safety analysis limits (SALs), and in the safety analysis results.

Application example: CHF criterion

- Min calculated DNBR > DNBR SAL
  Analysis is acceptable since the SAL is met

- Min calculated DNBR = DNBR SAL
  Analysis is acceptable due to the margin inherent in both the analysis and the SAL

- Min calculated DNBR < DNBR SAL
  Analysis is not acceptable since it is not demonstrated that adequate margin exists between analysis result and SAL

Interpretation of Results - 3 examples:

Loss of External Load

A Condition II event that challenges RCPB pressure limit

Rod Withdrawal at Power

A Condition II event that tests the ability of the RPS to prevent DNB

Spurious Actuation of ECCS

A Condition II event that could develop into a Condition III event (SBLOCA)

Table 5.3.6-1A BVPS-1 Time Sequence of Events – Loss of External Electrical Load and/or Turbine Trip		
Case	**Event**	**Time (Sec)**
With pressurizer pressure control (minimum reactivity feedback-DNB Case)	Loss of Electrical Load/Turbine Trip	0.0
	Overtemperature ΔT Reactor Trip Setpoint reached	12.3
	Rods begin to drop	14.3
	Minimum DNBR occurs	15.6
Without pressurizer pressure control (minimum reactivity feedback-Pressure Case)	Loss of Electrical Load/Turbine Trip	0.0
	High Pressurizer Pressure Reactor Trip Setpoint reached	5.5
	Rods begin to drop	7.5
	Peak pressurizer pressure occurs	8.2

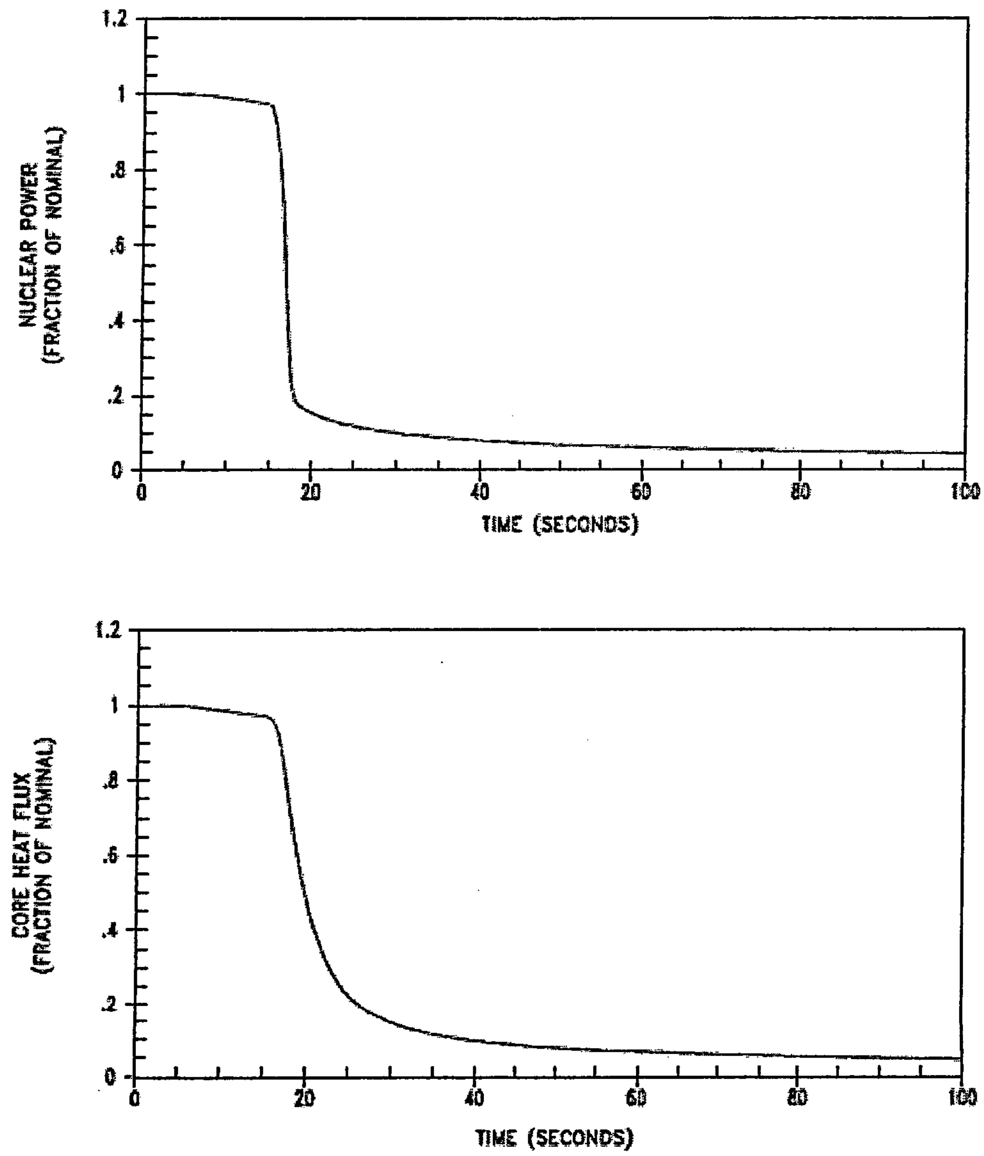


Figure 5.3.6-1A
BVPS-1 Loss of Load / Turbine Trip with Pressure Control
Nuclear Power and Core Heat Flux versus Time

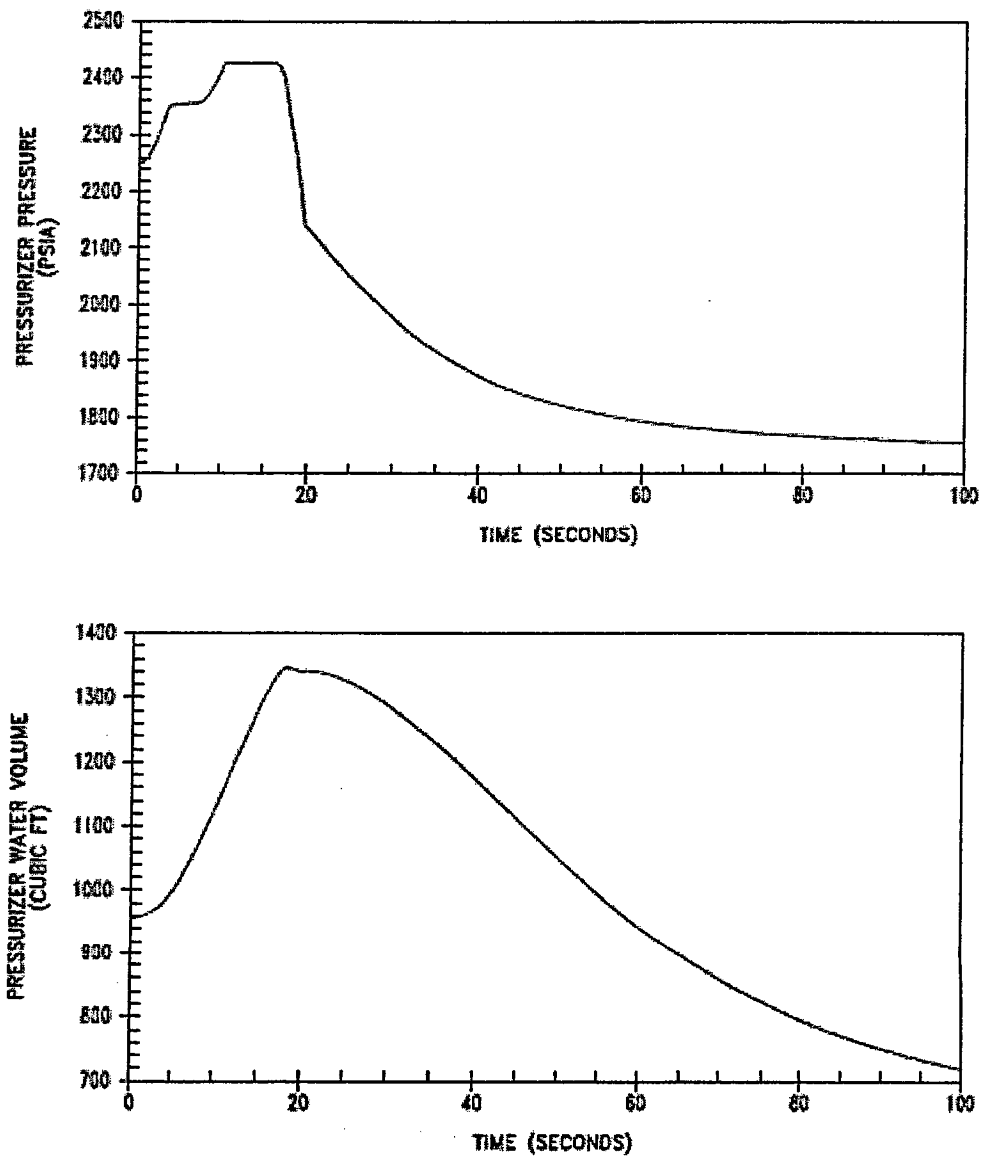


Figure 5.3.6-2A
BVPS-1 Loss of Load / Turbine Trip with Pressure Control
Pressurizer Pressure and Water Volume versus Time

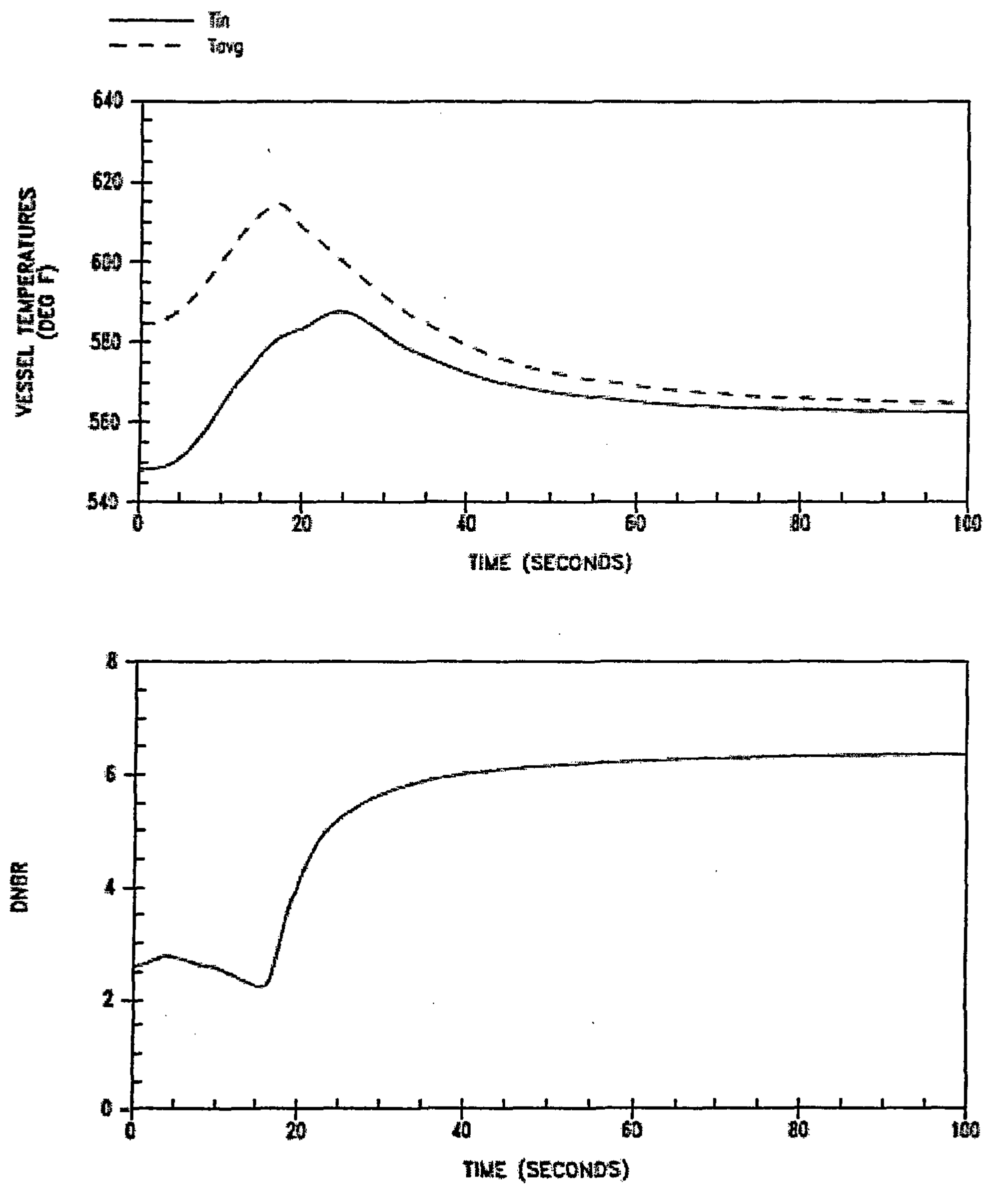


Figure 5.3.6-4A
BVPS-1 Loss of Load / Turbine Trip with Pressure Control
RCS Coolant Temperatures and DNBR versus Time

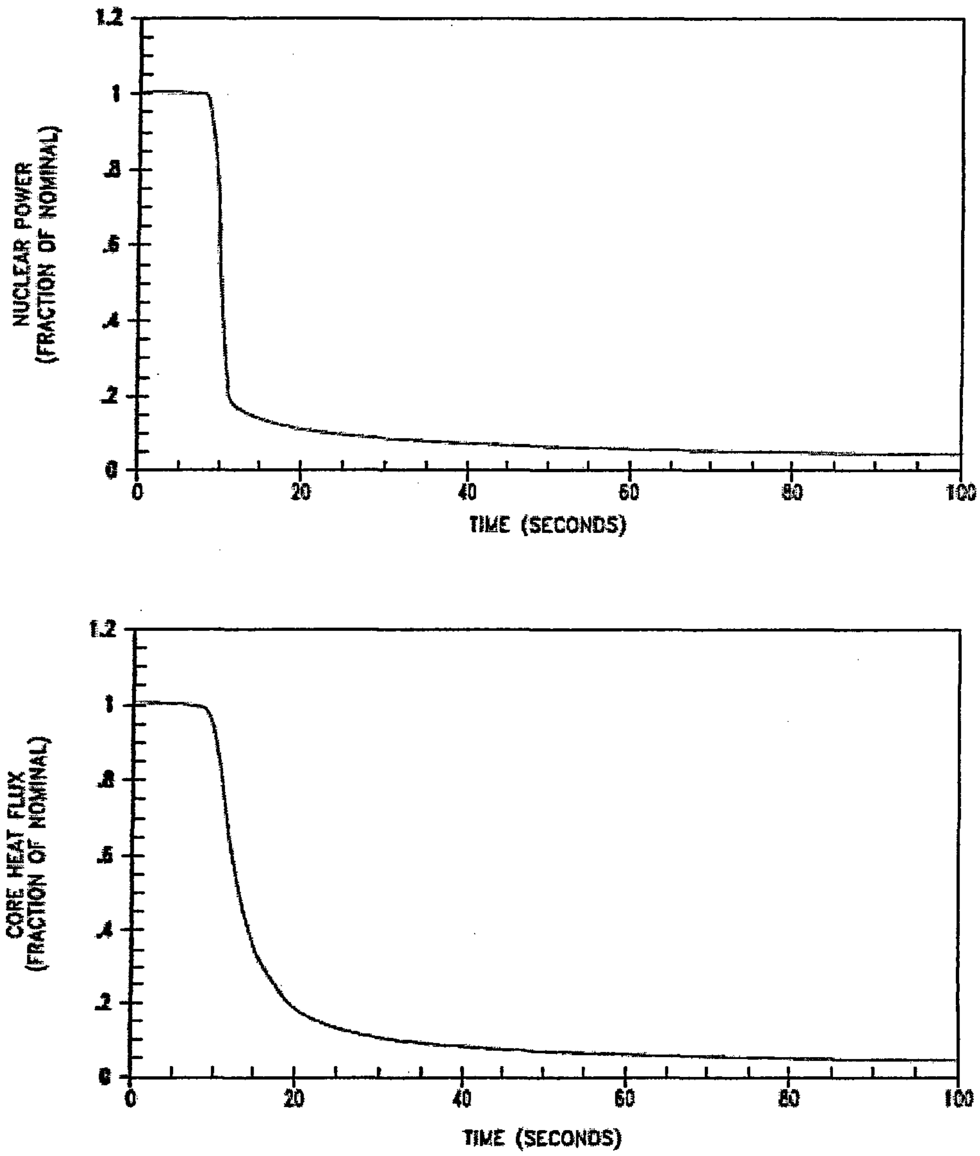


Figure 5.3.6-5A
BVPS-1 Loss of Load / Turbine Trip without Pressure Control
Nuclear Power and Core Heat Flux versus Time

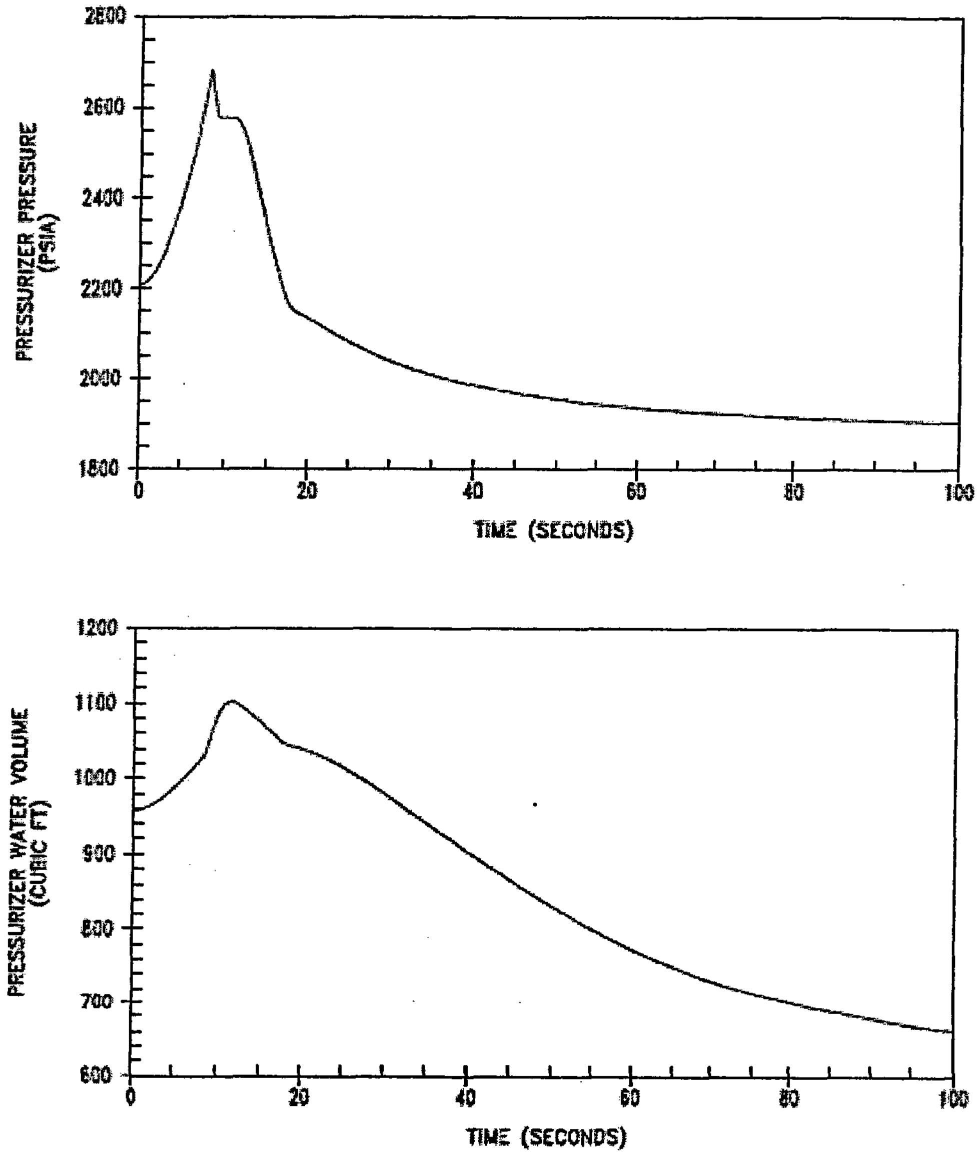


Figure 5.3.6-6A
BVPS-1 Loss of Load / Turbine Trip without Pressure Control
Pressurizer Pressure and Water Volume versus Time

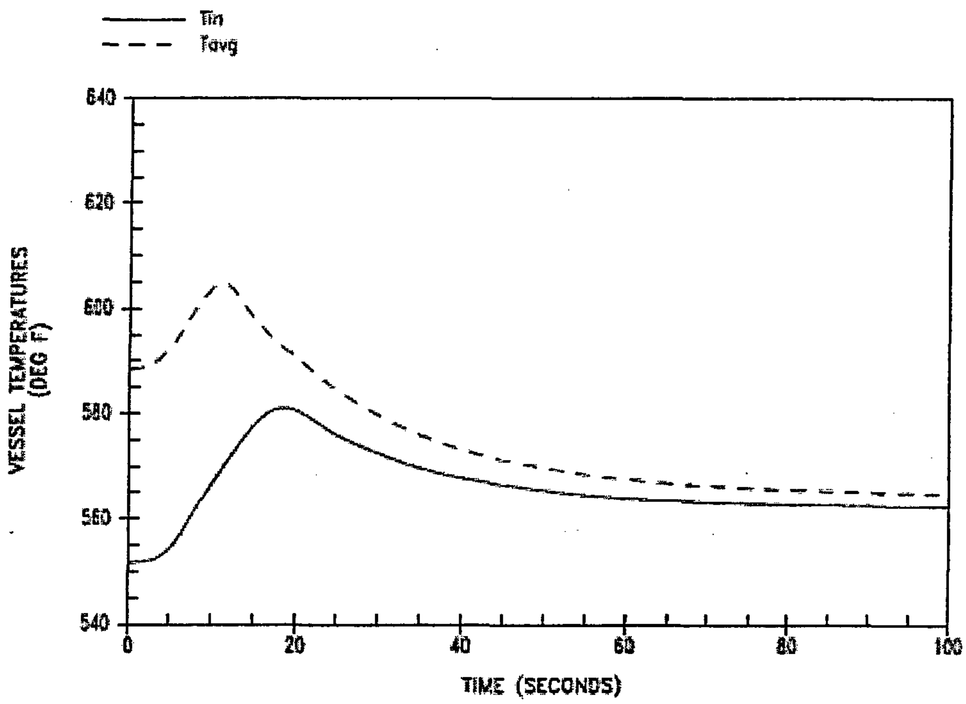
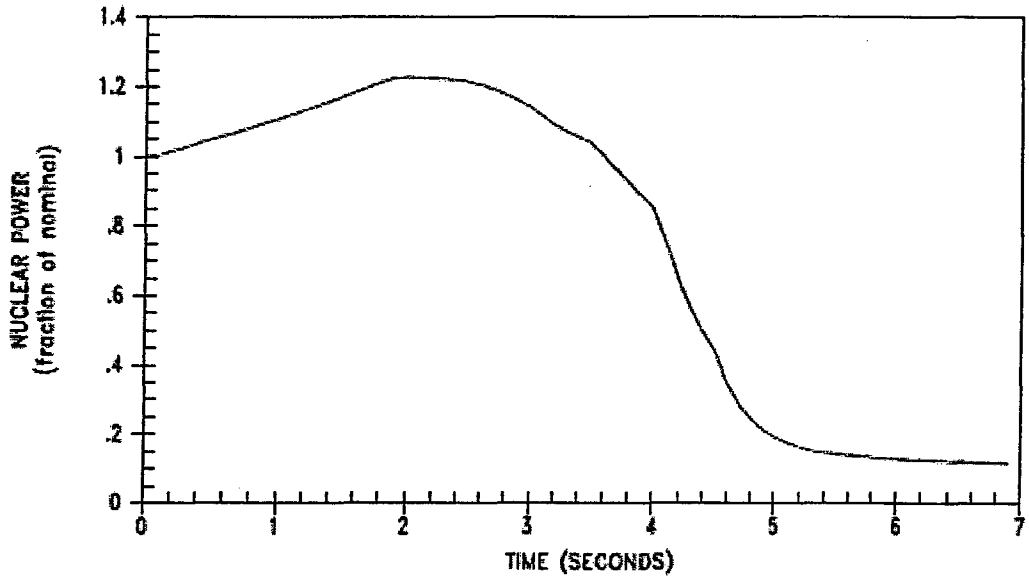


Figure 5.3.6-8A
BVPS-1 Loss of Load / Turbine Trip without Pressure Control
RCS Coolant Temperatures versus Time

Table 5.3.3-1A BVPS-1 Time Sequence of Events – Uncontrolled RCCA Bank Withdrawal at Power		
Case	**Event**	**Time (sec)**
100% Power, Minimum Feedback, Rapid RCCA Withdrawal (80 pcm/sec)	Initiation of Uncontrolled RCCA Withdrawal	0.0
	Power Range High Neutron Flux – High Setpoint Reached	1.4
	Rods Begin to Fall	1.9
	Minimum DNBR Occurs	2.9
100% Power, Minimum Feedback, Slow RCCA Withdrawal (0.4 pcm/sec)	Initiation of Uncontrolled RCCA Withdrawal	0.0
	Overtemperature Delta-T Trip Point Reached	104.1
	Rods Begin to Fall	106.1
	Minimum DNBR Occurs	107.1



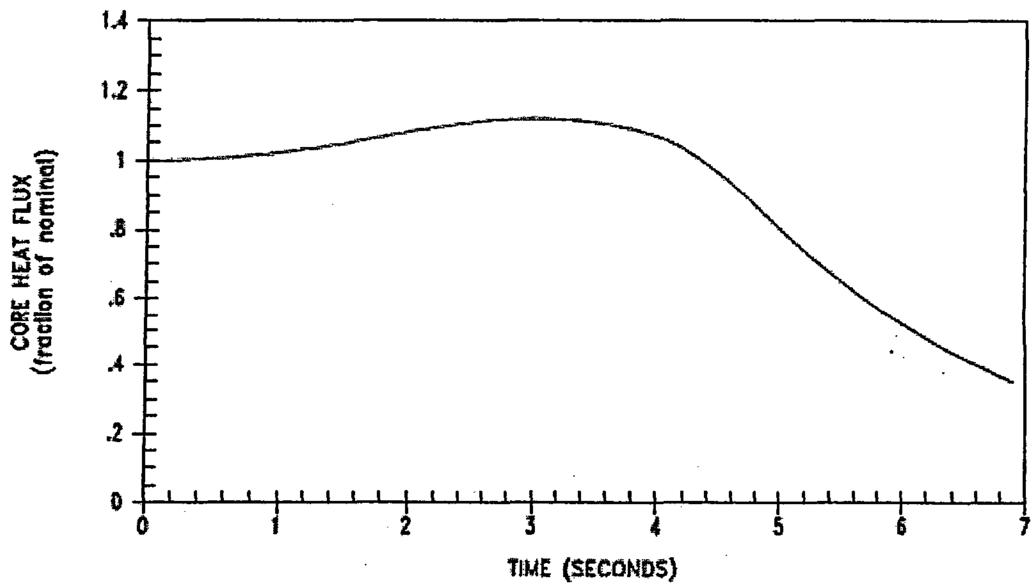


Figure 5.3.3-1A
BVPS-1 Rod Withdrawal at Power
Minimum Reactivity Feedback – 100% Power - 80 pcm/sec
Nuclear Power and Core Heat Flux versus Time

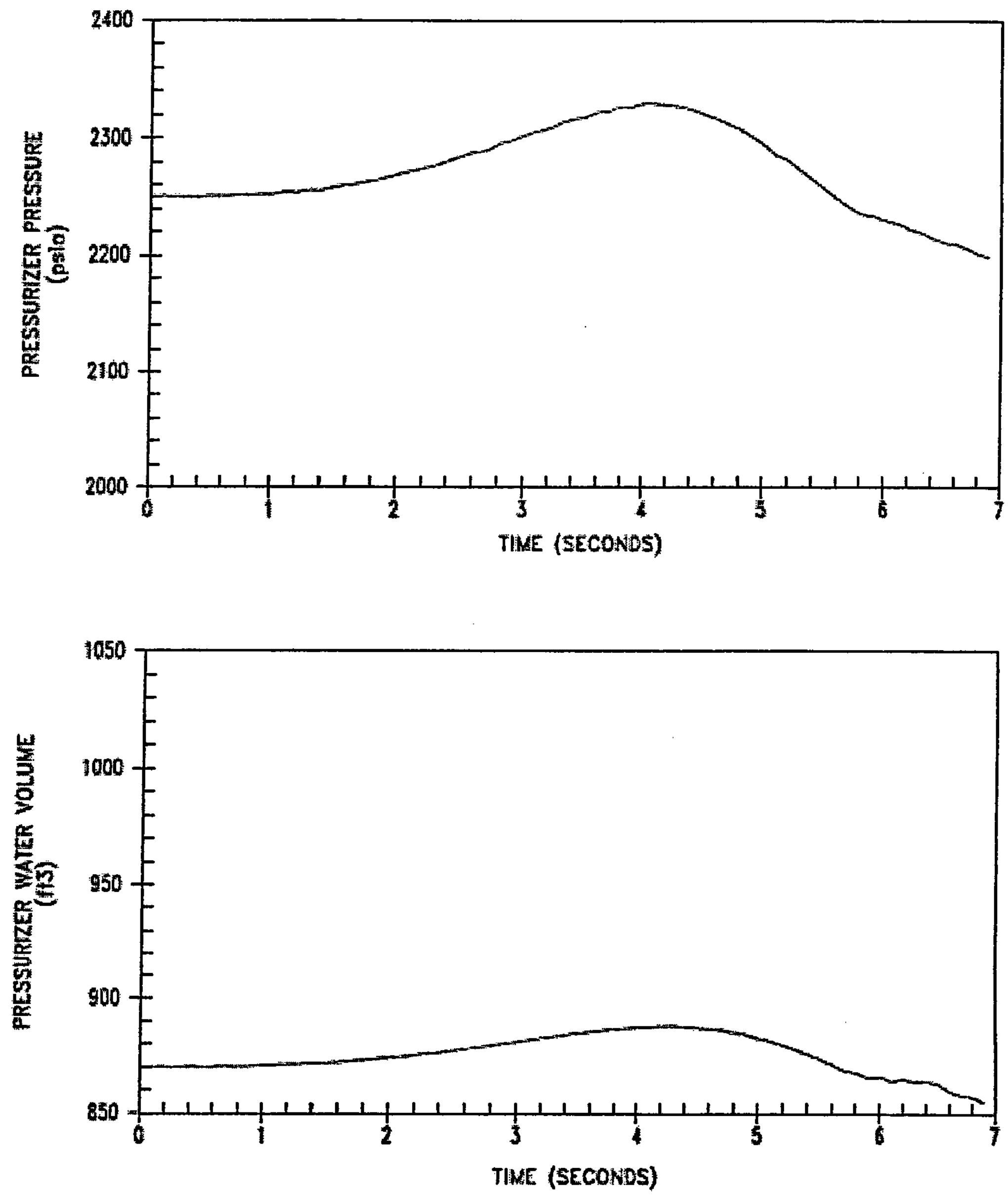


Figure 5.3.3-2A
BVPS-1 Rod Withdrawal at Power
Minimum Reactivity Feedback – 100% Power - 80 pcm/sec
Pressurizer Pressure and Water Volume versus Time

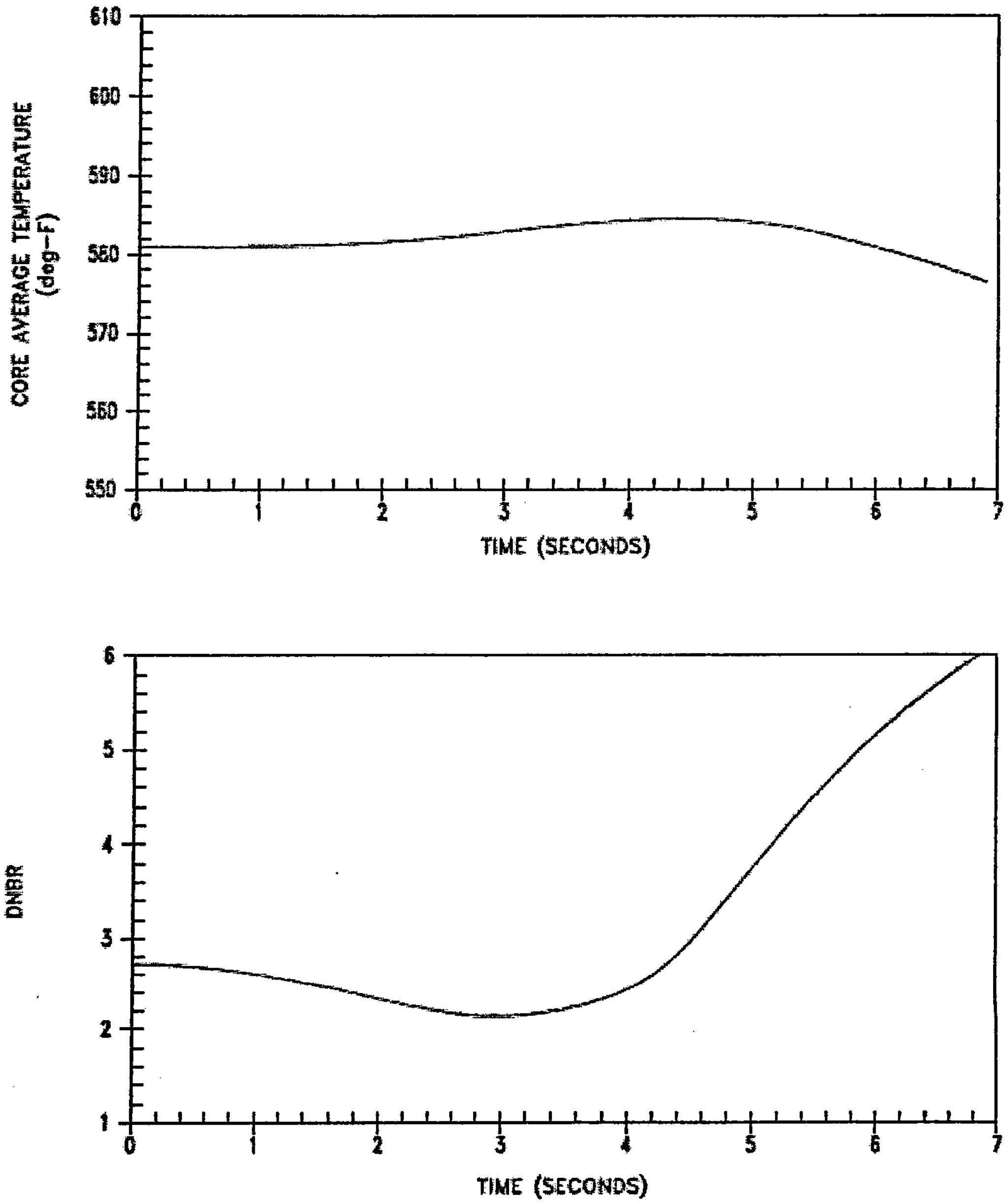


Figure 5.3.3-3A
BVPS-1 Rod Withdrawal at Power
Minimum Reactivity Feedback – 100% Power - 80 pcm/sec
Core Average Temperature and DNBR versus Time

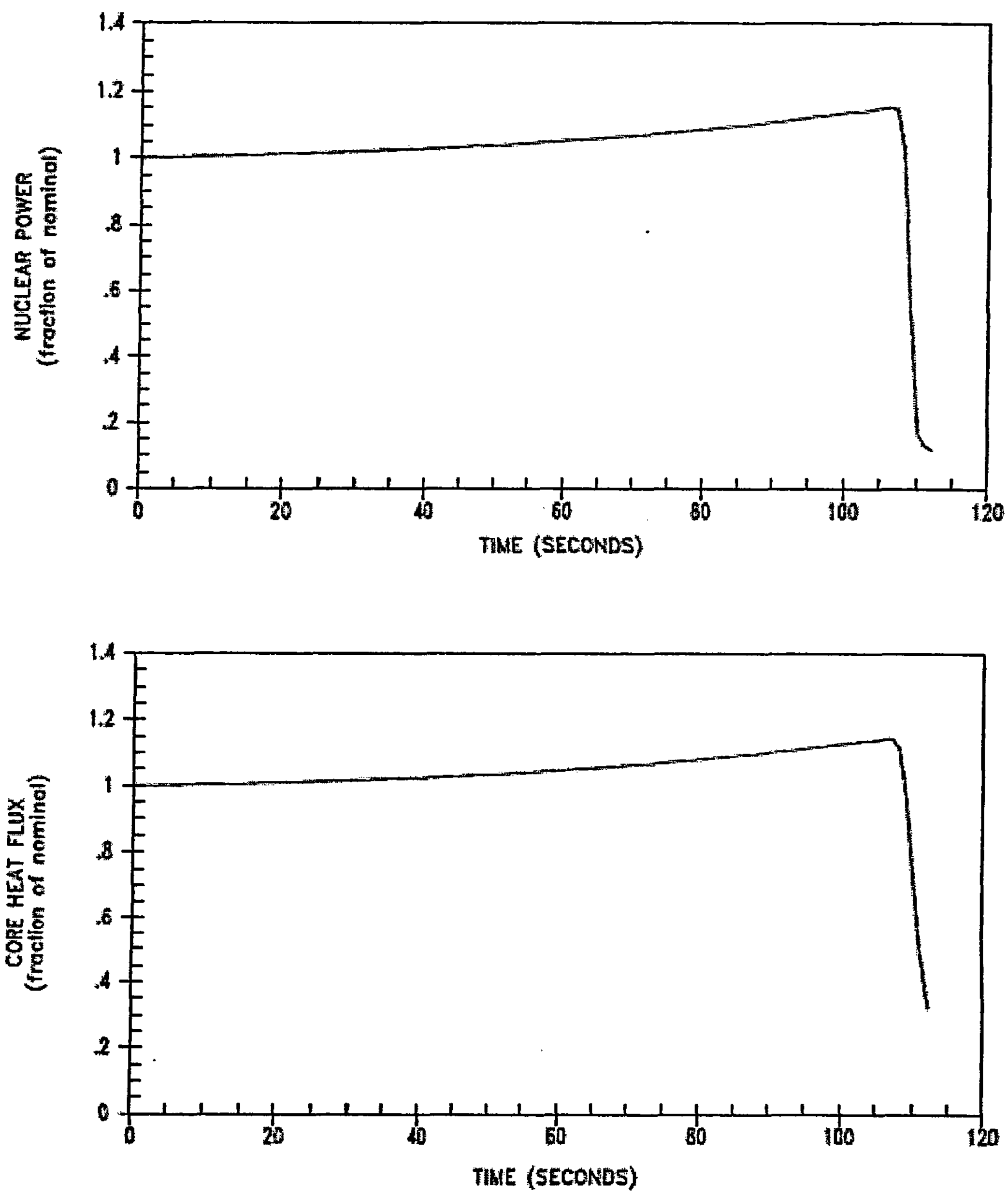


Figure 5.3.3-4A
BVPS-1 Rod Withdrawal at Power
Minimum Reactivity Feedback – 100% Power - 0.4 pcm/sec
Nuclear Power and Core Heat Flux versus Time

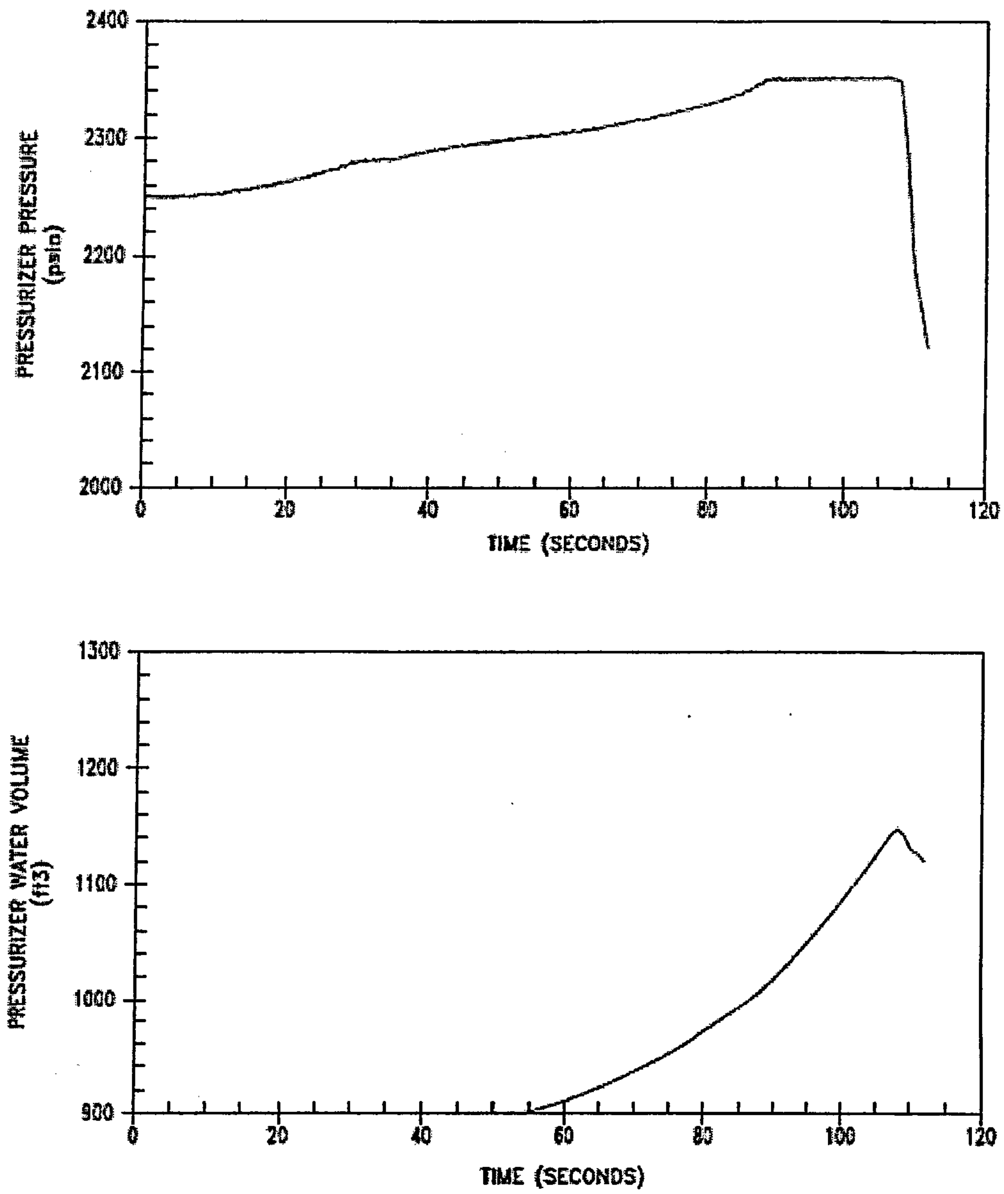


Figure 5.3.3-5A
BVPS-1 Rod Withdrawal at Power
Minimum Reactivity Feedback – 100% Power - 0.4 pcm/sec
Pressurizer Pressure and Water Volume versus Time

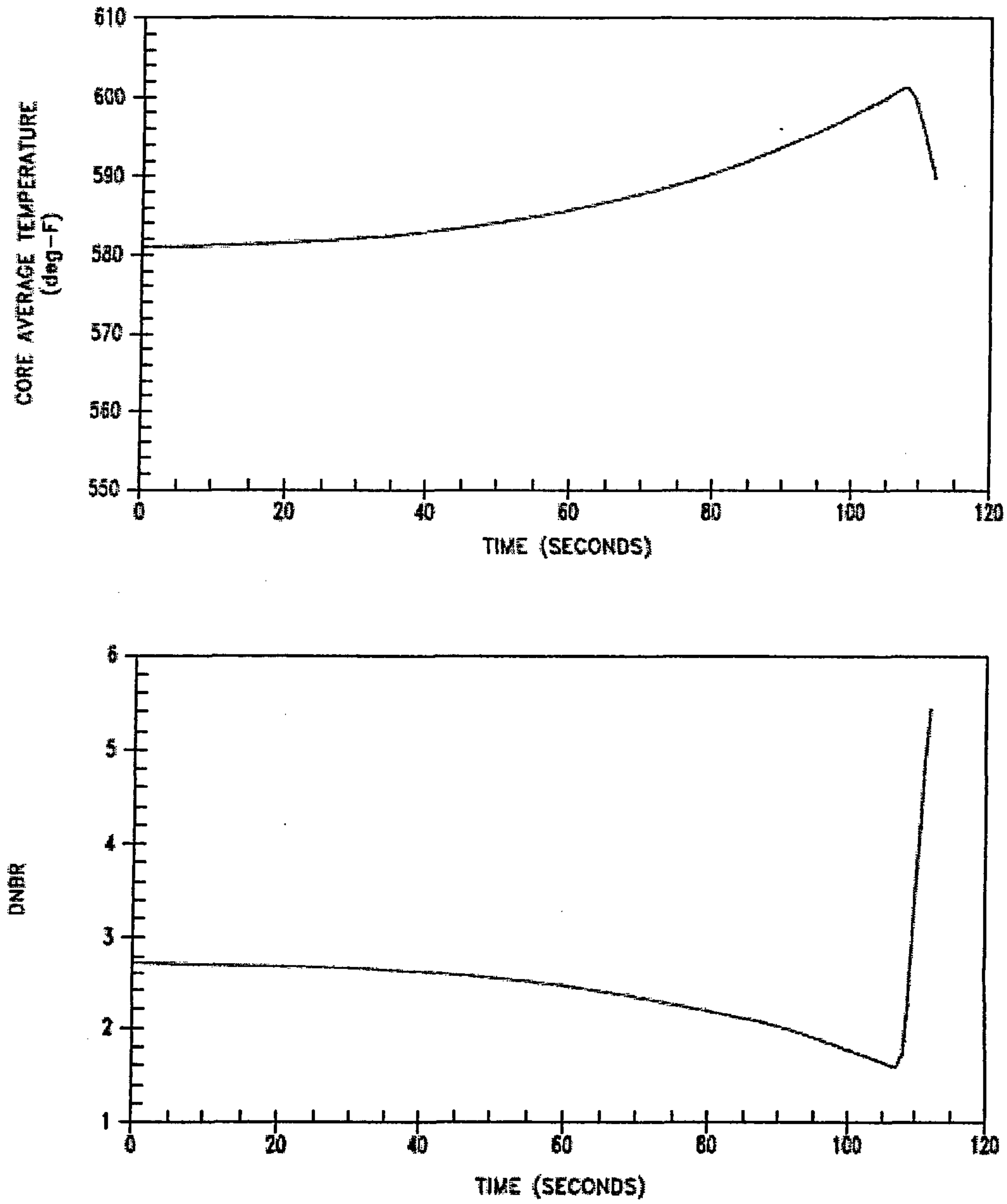


Figure 5.3.3-6A
BVPS-1 Rod Withdrawal at Power
Minimum Reactivity Feedback – 100% Power - 0.4 pcm/sec
Core Average Temperature and DNBR versus Time

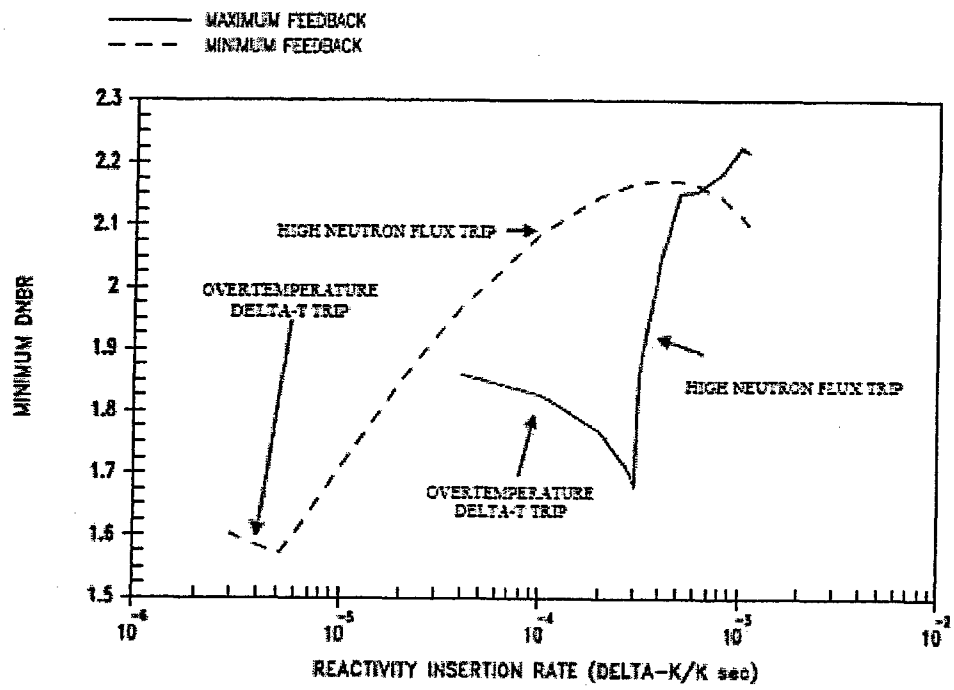


Figure 5.3.3-7A
BVPS-1 Rod Withdrawal at Power
100% Power
Minimum DNBR versus Reactivity Insertion Rate

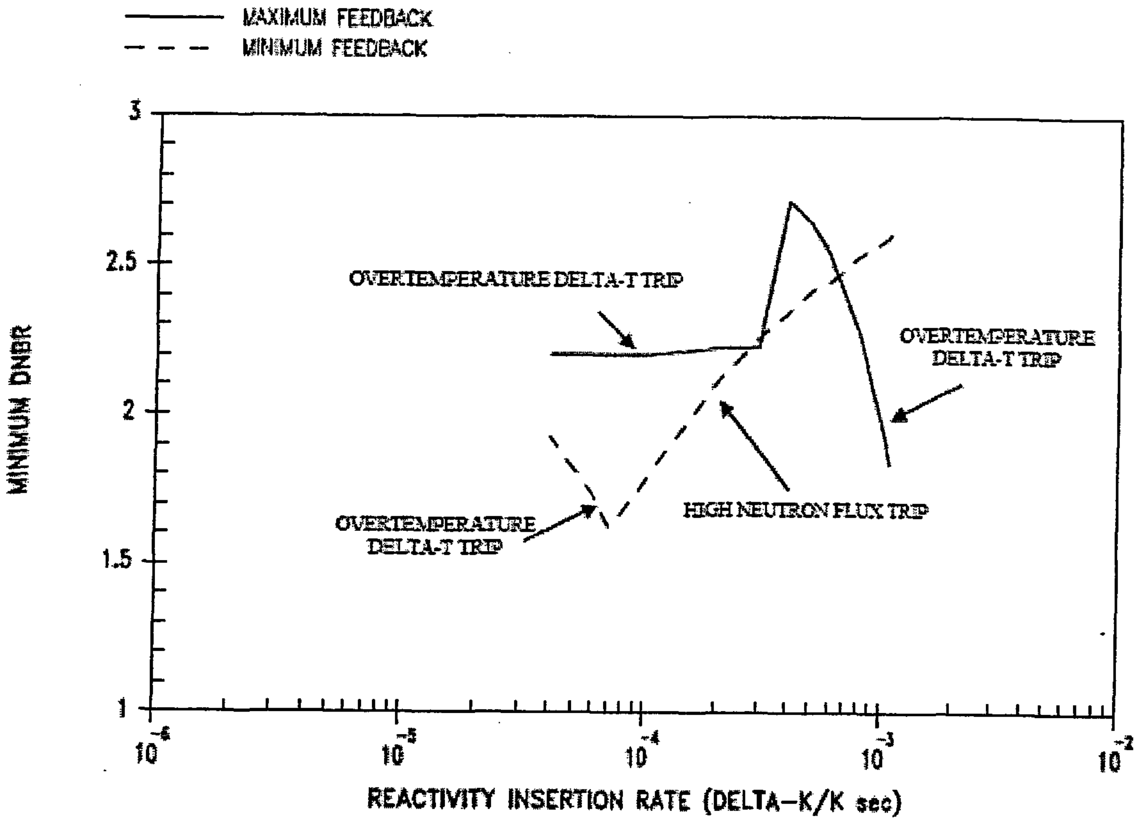


Figure 5.3.3-8A
BVPS-1 Rod Withdrawal at Power
60% Power
Minimum DNBR versus Reactivity Insertion Rate

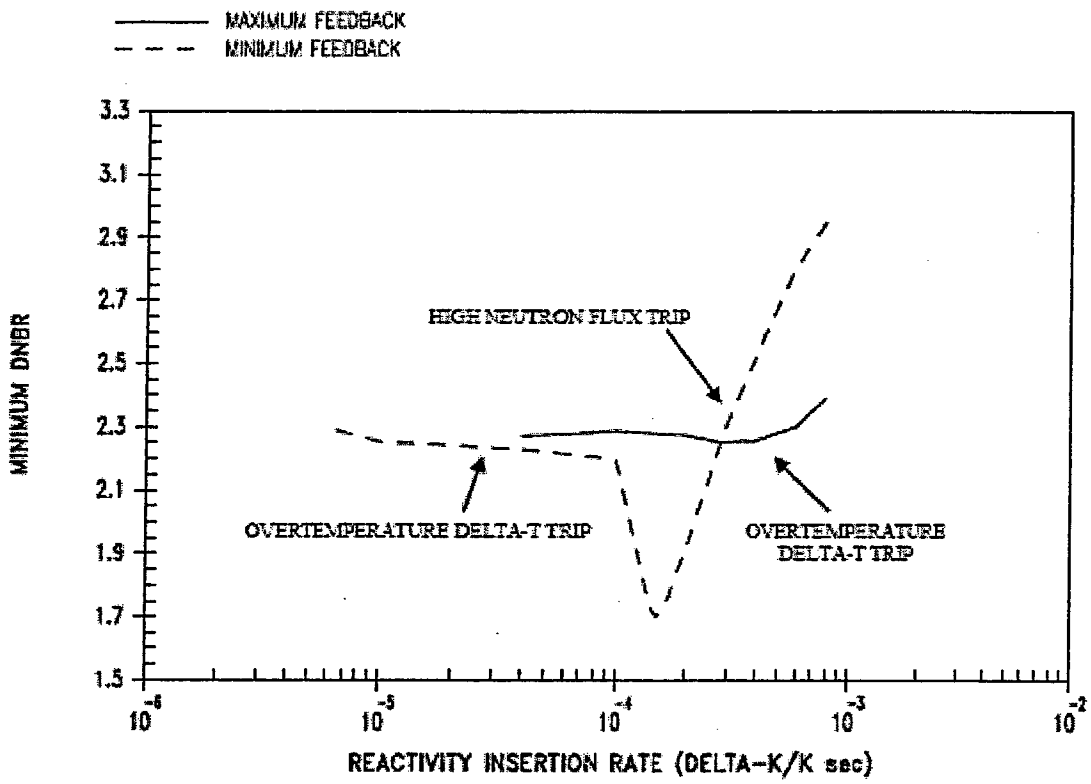


Figure 5.3.3-9A
BVPS-1 Rod Withdrawal at Power
10% Power
Minimum DNBR versus Reactivity Insertion Rate

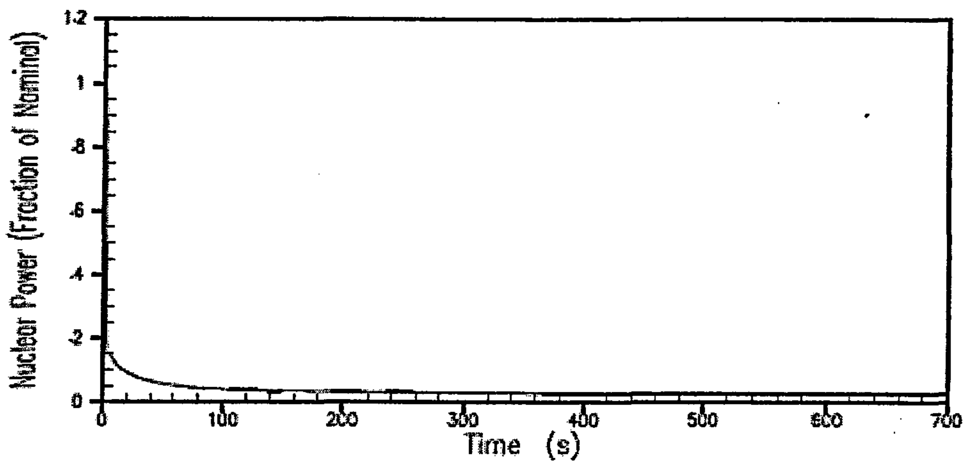


Figure V.1-1
BVPS-1 Spurious SI with Pressurizer Heaters On – Nuclear Power vs. Time

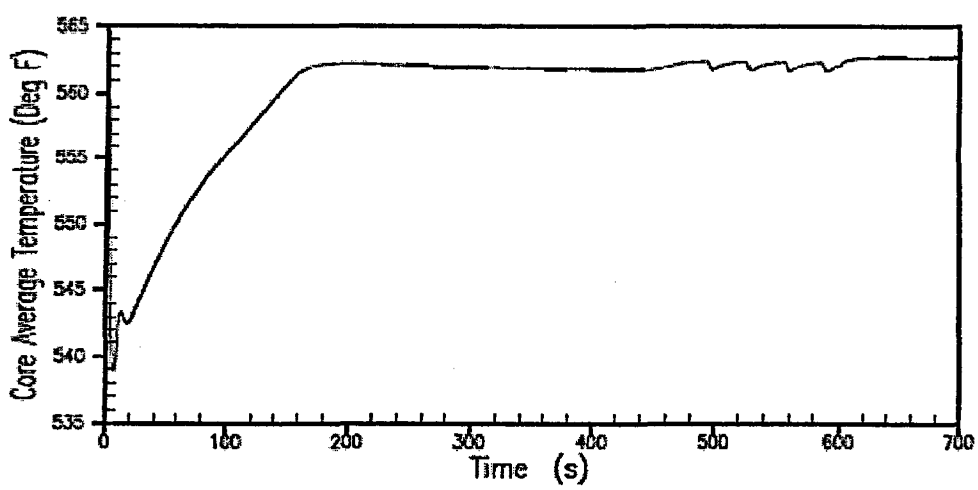


Figure V.1-2
BVPS-1 Spurious SI with Pressurizer Heaters On –
Core Average Coolant Temperature vs. Time

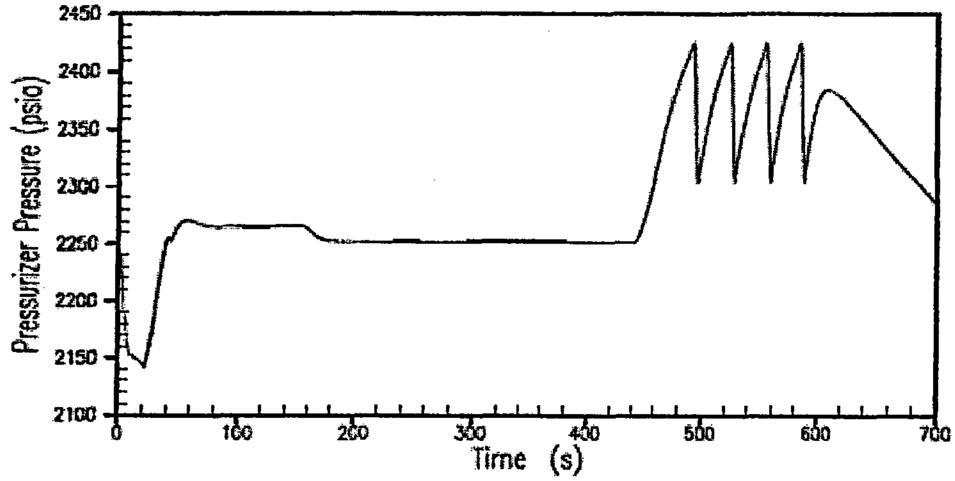


Figure V.1-3
BVPS-1 Spurious SI with Pressurizer Heaters On – Pressurizer Pressure vs. Time

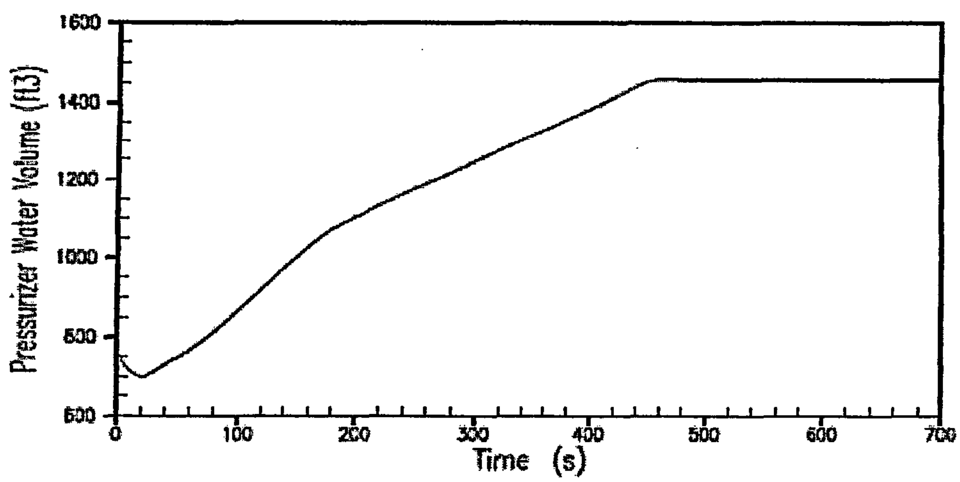


Figure V.1-4
BVPS-1 Spurious SI with Pressurizer Heaters On – Pressurizer Water Volume vs. Time

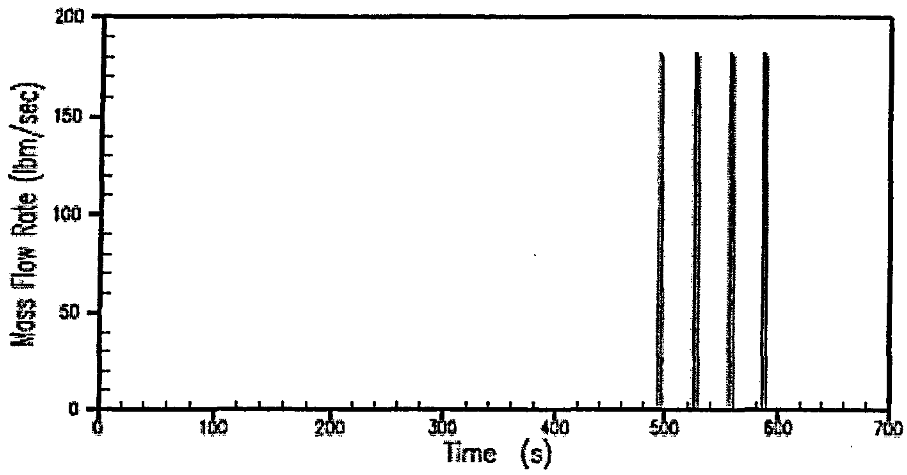


Figure V.1-5
BVPS-1 Spurious SI with Pressurizer Heaters On –
Pressurizer Safety Valve Water Relief vs. Time

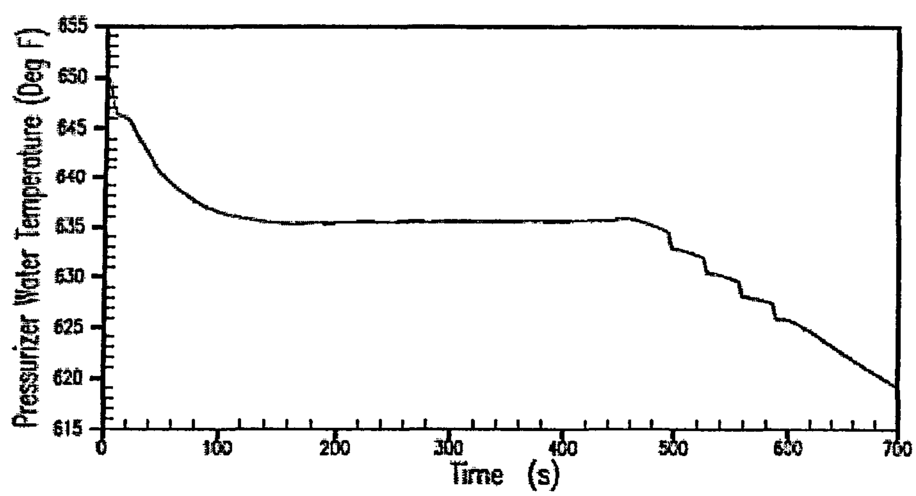


Figure V.1-6
BVPS-1 Spurious SI with Pressurizer Heaters On –
Pressurizer Water Temperature vs. Time

BEAVER VALLEY STATION

EXTENDED POWER UPRATE

SMALL BREAK LOCA

AND

POST-LOCA LONG TERM COOLING

L.: W. WARD

ACRS COMMITTEE MEETING ON POWER UPRATES
ROCKVILLE, MD

APRIL 27, 2006

BEAVER VALLEY EPU

SBLOCA AND POST-LOCA LONG TERM COOLING

AGENDA

- o INTRODUCTION
  - BEAVER VALLEY ECCS
  - APPROACH TO CONTROL PRECIPITATION
- o LARGE BREAK LOCA
  - POST-LOCA LONG TERM COOLING (BORIC ACID PRECIPITATION)
- o SMALL BREAK LOCA
  - SHORT TERM BEHAVIOR (PCT & CLAD OXIDATION)
  - POST-LOCA LONG TERM COOLING (BORIC ACID PRECIPITATION)
- o CONCLUSIONS

INTRODUCTION

o BEAVER VALLEY ECCS

- THREE LOOPS, 2917.4 MWT

- 625 PSIA ACCUMULATORS

- SWITCH TO SIMULTANEOUS INJECTION (HPSI)

- COLD LEG BREAK IS LIMITING FOR BORIC ACID PRECIPITATION

CONTROL OF BORIC ACID

- o LARGE BREAKS

  - RE-ALIGN HPSI TO SIMULTANEOUS HOT AND COLD SIDE INJECTION

- o SMALL BREAKS

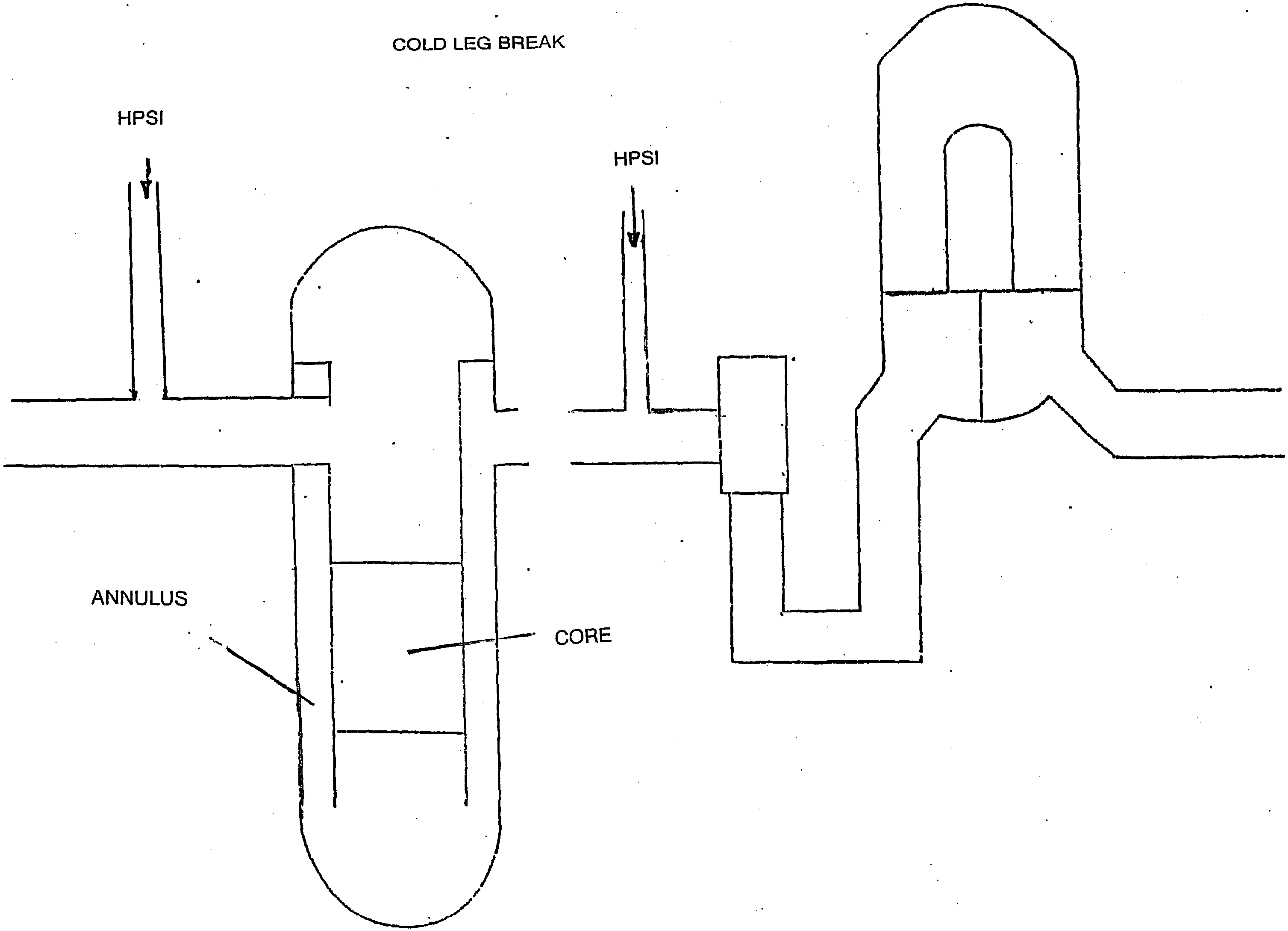
  - COOLDOWN RCS TO LOW PRESSURE CUT-IN (~ 140 PSIA)

  OR

  - REFILL RCS WITH ECC (RE-ESTABLISH SINGLE PHASE NAT. CIRC.)

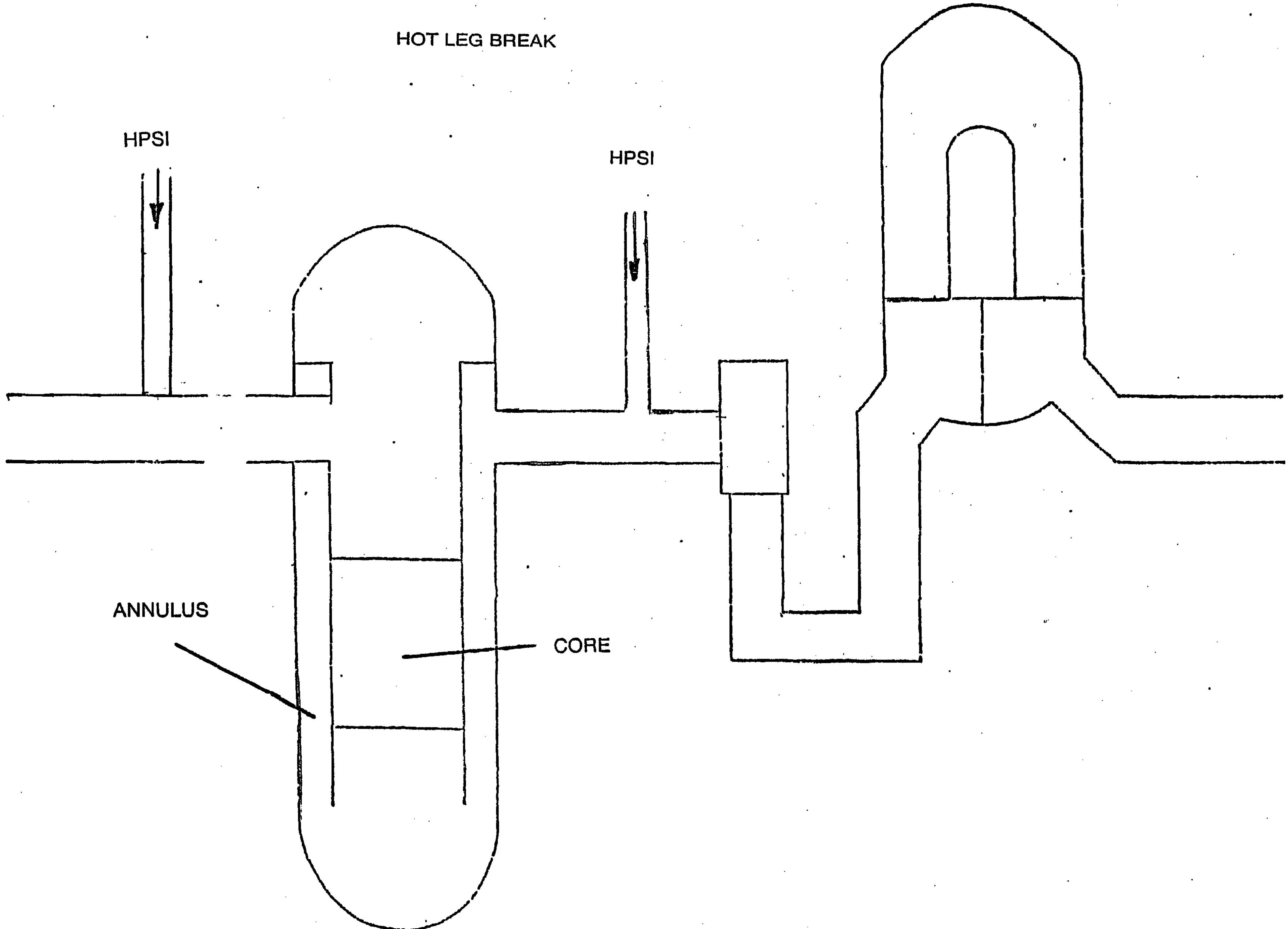
SIMULTANEOUS INJECTION

COLD LEG BREAK



SIMULTANEOUS INJECTION

HOT LEG BREAK



LBLOCA POST-LOCA LONG TERM COOLING

- o MODEL ASSUMPTIONS

  - MIXING VOLUME 1/2 LP, CORE, AND UPPER PL. BELOW HOT LEG BE

  - 1971 ANS STANDARD DECAY HEAT CURVE PLUS 20%

  - PRECIPITATION LIMIT IS 29.27%

  - MIXING VOLUME CALCULATED AS FUNCTION OF TIME

  - RWST & SIT CONCENTRATIONS OF 2600 PPM

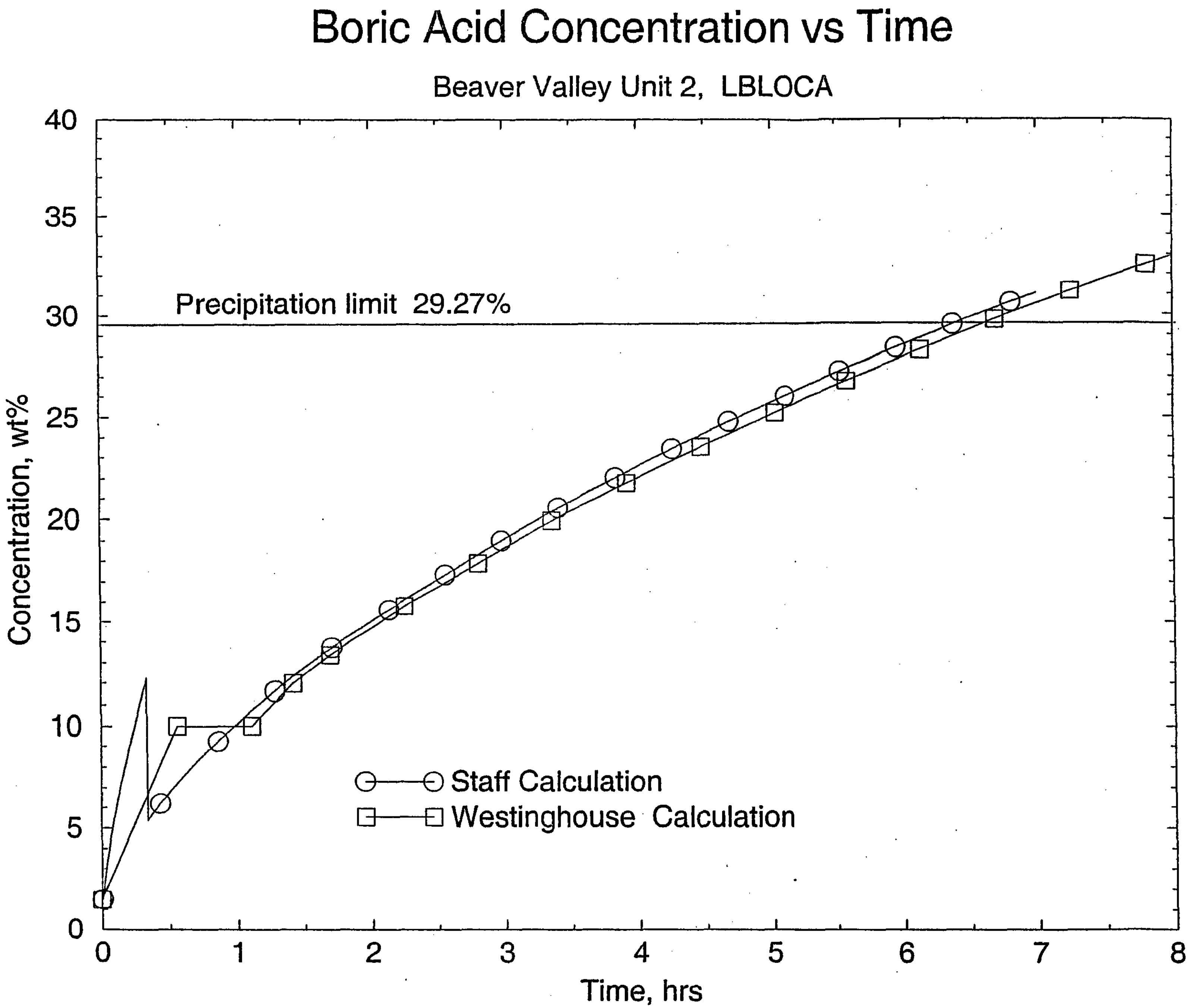
- o COLD LEG BREAK LIMITING FOR PRECIPITATION

- o INITIATE SIMULTANEOUS INJECTION BEORE PRECIPITATION OCCURS

  - STAFF CALCULATION CONFIRMS LICENSEE 6.5 HR TIME TO REACH 29.27% LIMIT

  - VERIFIES 6.0 HR TIME TO SWITCH TO SIMULTANEOUS INJECTION

  - TIMING IS CALCULATED ON CONSERVATIVE BASIS



Boric Acid Concentration vs Time
Beaver Valley Unit 2, LBLOCA
Precipitation limit 29.27%
Staff Calculation
Westinghouse Calculation
Concentration, wt%
Time, hrs
0
5
10
15
20
25
30
35
40
0
1
2
3
4
5
6
7
8

SMALL BREAK LOCA SHORT TERM BEHAVIOR

- o INVESTIGATED ONLY INTEGER BREAK SIZES
  - ONE, TWO, THREE, FOUR, FIVE, & SIX INCH DIA BREAKS(
  - 0.0055, 0.0218, 0.049, 0.0893, 0.136 FT^2 CLB's

    SPECTRUM TOO COARSE TO IDENTIFY WORST BREAK

    BREAKS BETWEEN TWO & THREE ARE MORE LIMITING

    LICENSEE EVALUATED ADDITIONAL BREAKS

    WORST BREAK 2.75 INCH

    1917 °F PCT (VS 1759 °F FOR TWO INCH DIA)

- o LICENSEE MODEL ASSUMED ALL LOOP SEALS CLEAR FOR ALL SBLOCA'S

- o MODIFICATIONS AS A RESULTS OF INTEGER BREAK SIZE RE-ANALYSIS AND USING STAFF APPROVED NOTRUMP SBLOCA MODEL

    - INCREASED SIT COVER PRESSURE FROM 595 TO 625 PSIA

    - MODIFIED HPSI PUMPS TO PROVIDE ~ 5% ADDITIONAL FLOW (EPU)

- o IMPROVES MARGINS FOR ECCS ANALYSES

o STAFF ANALYSIS

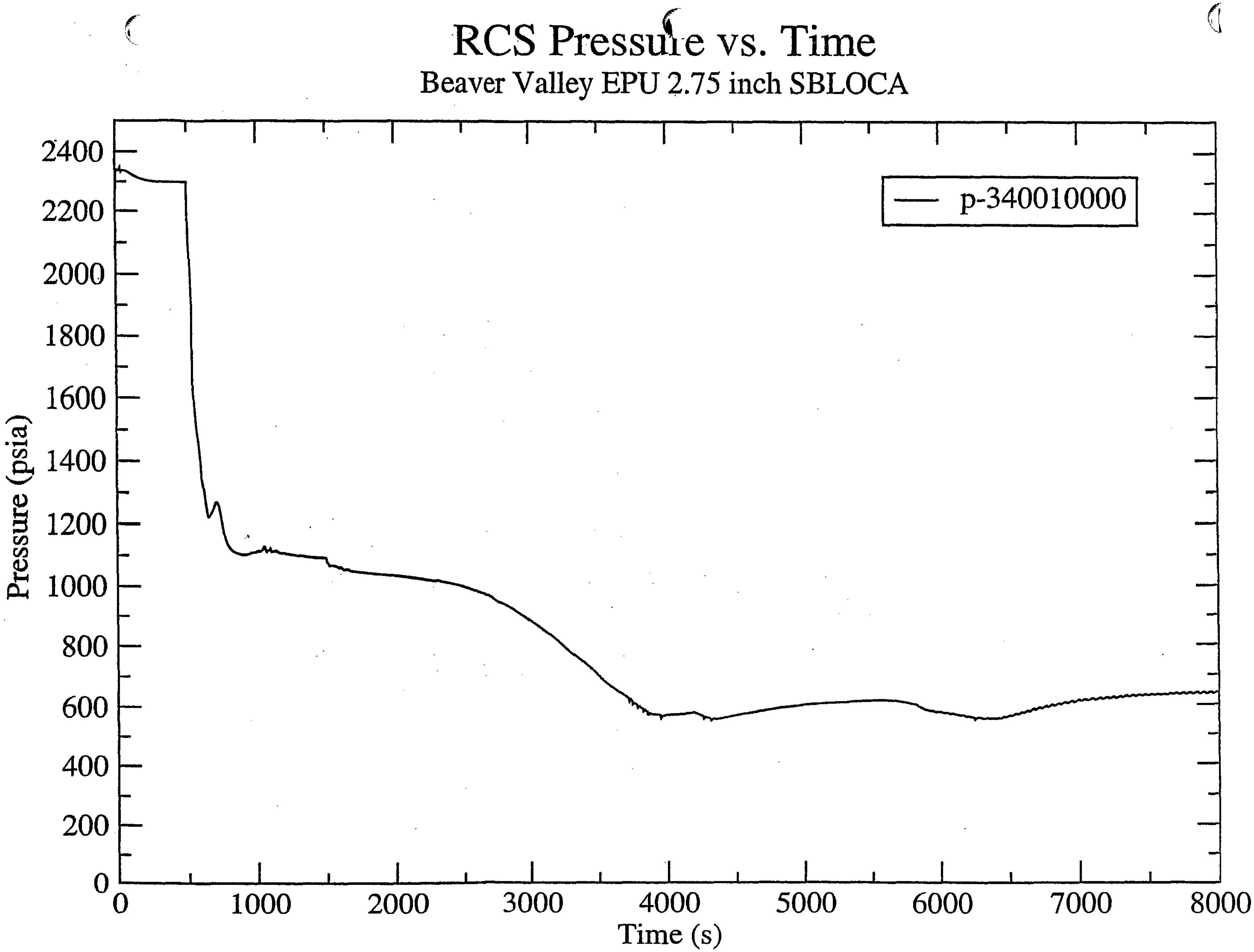
- CONFIRMED LICENSEE PCT OF 1917 °F VS 1907 °F STAFF CALCULATION

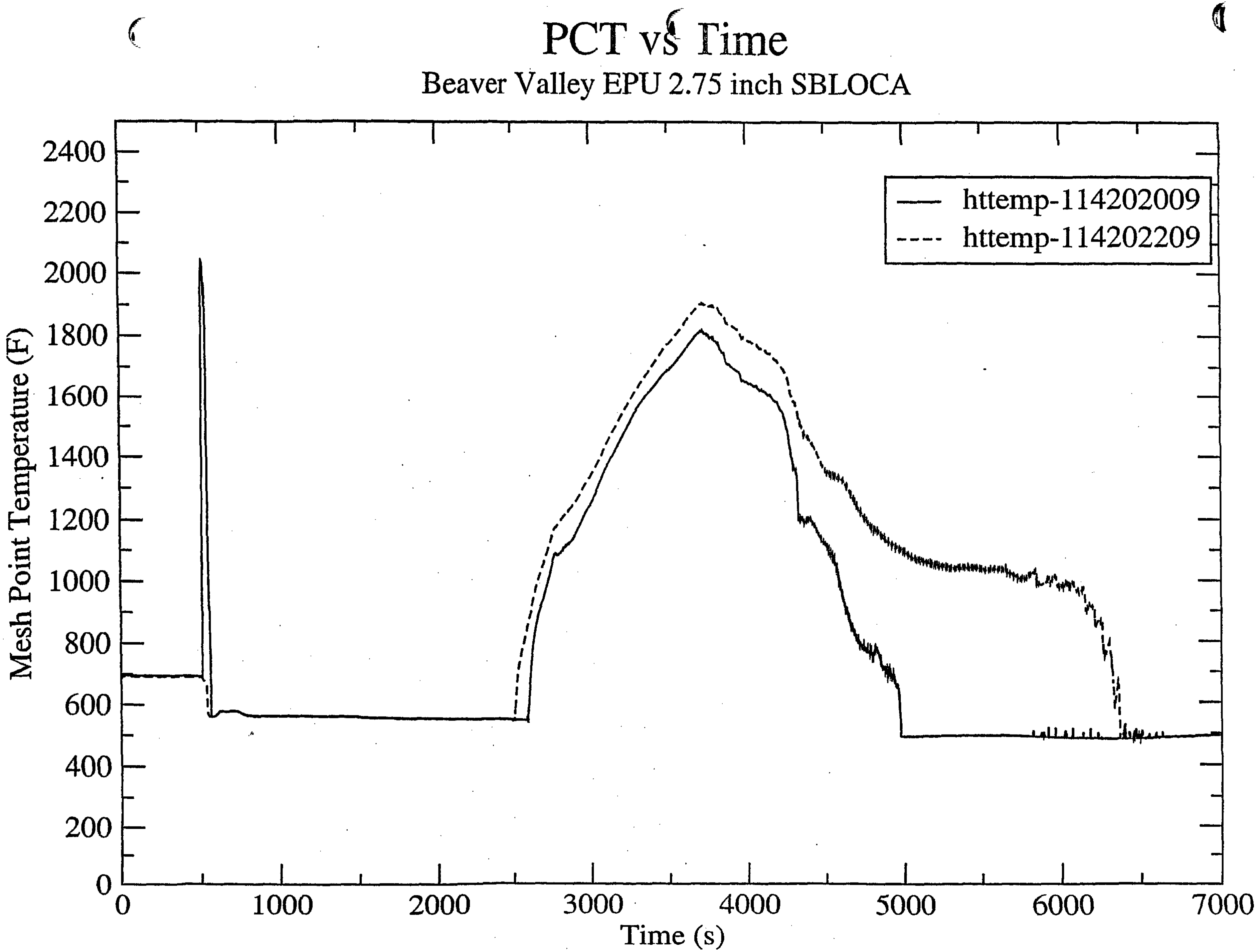
  RELAP5/MOD3 (24 AXIAL CELLS IN CORE PLUS HOT BUNDLE MODEL)

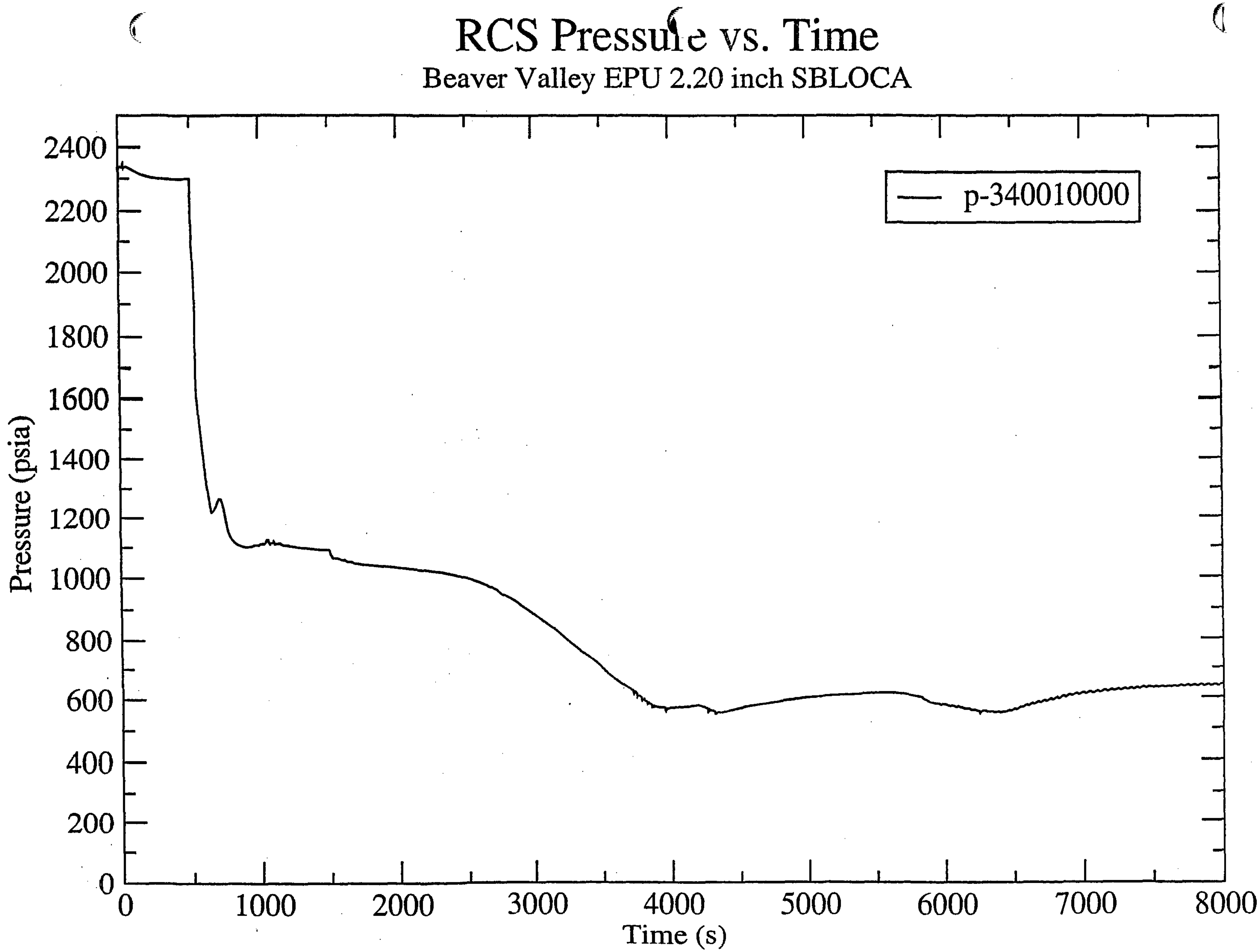
  2917.4 MWT

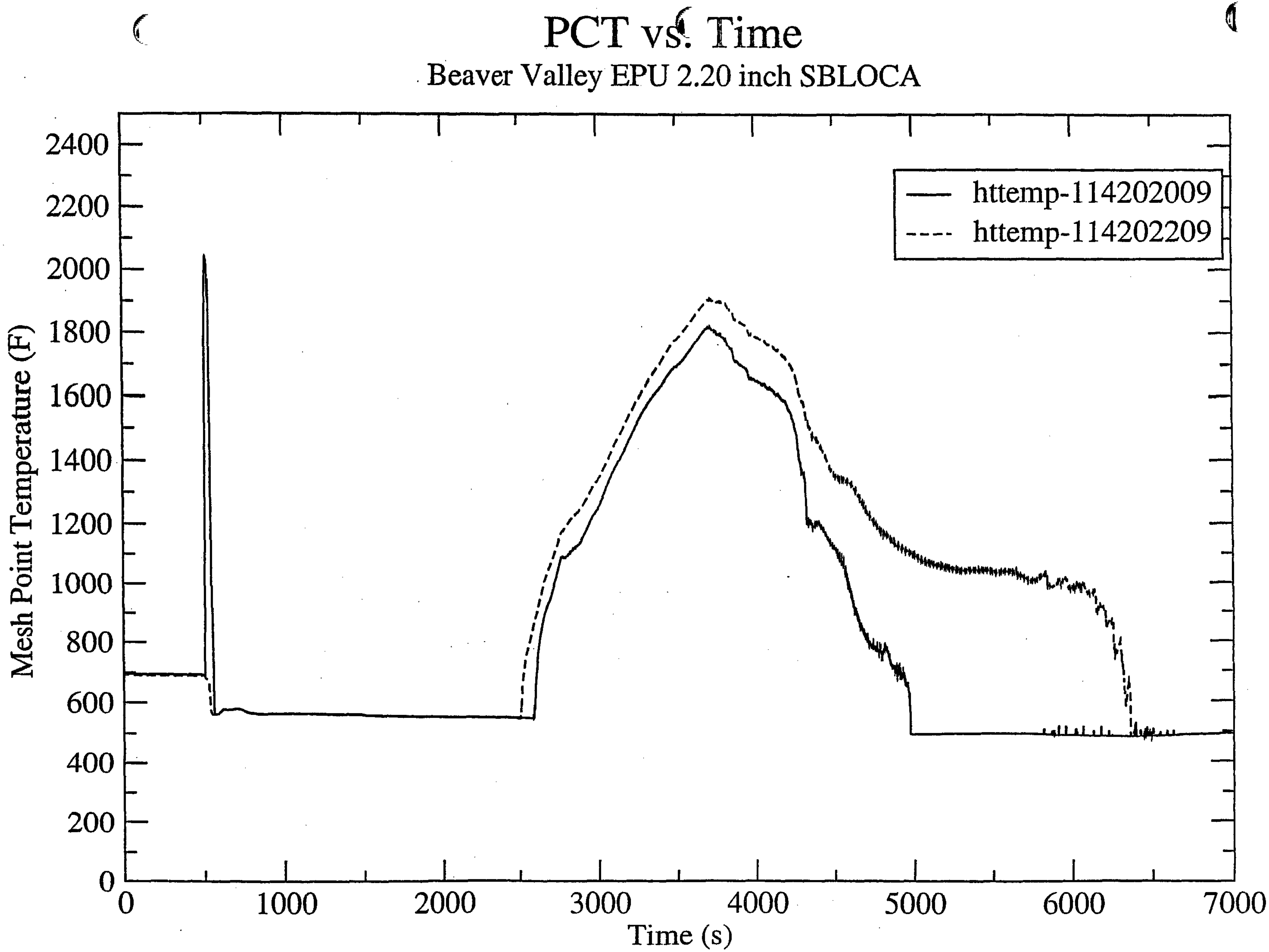
  14.0 KW/FT

STAFF CALCULATIONS ALSO CONFIRMED BREAKS ON TOP OF COLD LEG AND SEVERED ECC LINE ARE LESS LIMITING


RCS Pressure vs. Time
Beaver Valley EPU 2.75 inch SBLOCA
p-340010000
Pressure (psia)
Time (s)
0
200
400
600
800
1000
1200
1400
1600
1800
2000
2200
2400
0
1000
2000
3000
4000
5000
6000
7000
8000


PCT vs Time
Beaver Valley EPU 2.75 inch SBLOCA
httemp-114202009
httemp-114202209
Mesh Point Temperature (F)
Time (s)
0
200
400
600
800
1000
1200
1400
1600
1800
2000
2200
2400
1000
2000
3000
4000
5000
6000
7000


RCS Pressure vs. Time
Beaver Valley EPU 2.20 inch SBLOCA
p-340010000
Pressure (psia)
Time (s)
0
200
400
600
800
1000
1200
1400
1600
1800
2000
2200
2400
0
1000
2000
3000
4000
5000
6000
7000
8000


PCT vs. Time
Beaver Valley EPU 2.20 inch SBLOCA
Mesh Point Temperature (F)
Time (s)
httemp-114202009
httemp-114202209
0
200
400
600
800
1000
1200
1400
1600
1800
2000
2200
2400
0
1000
2000
3000
4000
5000
6000
7000

SBLOCA SHORT TERM BEHAVIOR (CON'T)

- o STAFF CALCULATION OF SMALL BREAKS ALSO SHOWED FIRST PEAK

  - EARLY CHF CONDITION

  - FIRST PEAK IS ~2000 °F WITH STAFF MODEL

  - PCT REMAINS WITHIN 10CFR50.46

- o STAFF WILL FOLLOW UP WITH GENERIC INVESTIGATION OF SBLOCA ANALYSIS MODELS/ASSUMPTIONS AND POTENTIAL FOR EARLY CHF

SMALL BREAK LOCA (LONG TERM COOLING)

- CONTROL OF BORIC ACID BUILD-UP

  - BOILING FOR EXTENDED PERIODS

  - PRESSURE REMAINS HIGH AND PRECLUDES CORE FLUSH

    RCS PRESSURE NEEDS TO BE REDUCED LOW ENOUGH TO FLUSH CORE

    OR

    DEMONSTRATE REFILL OF RCS

  - STAFF AUDIT CALCULATIONS SHOW RCS REFILLS

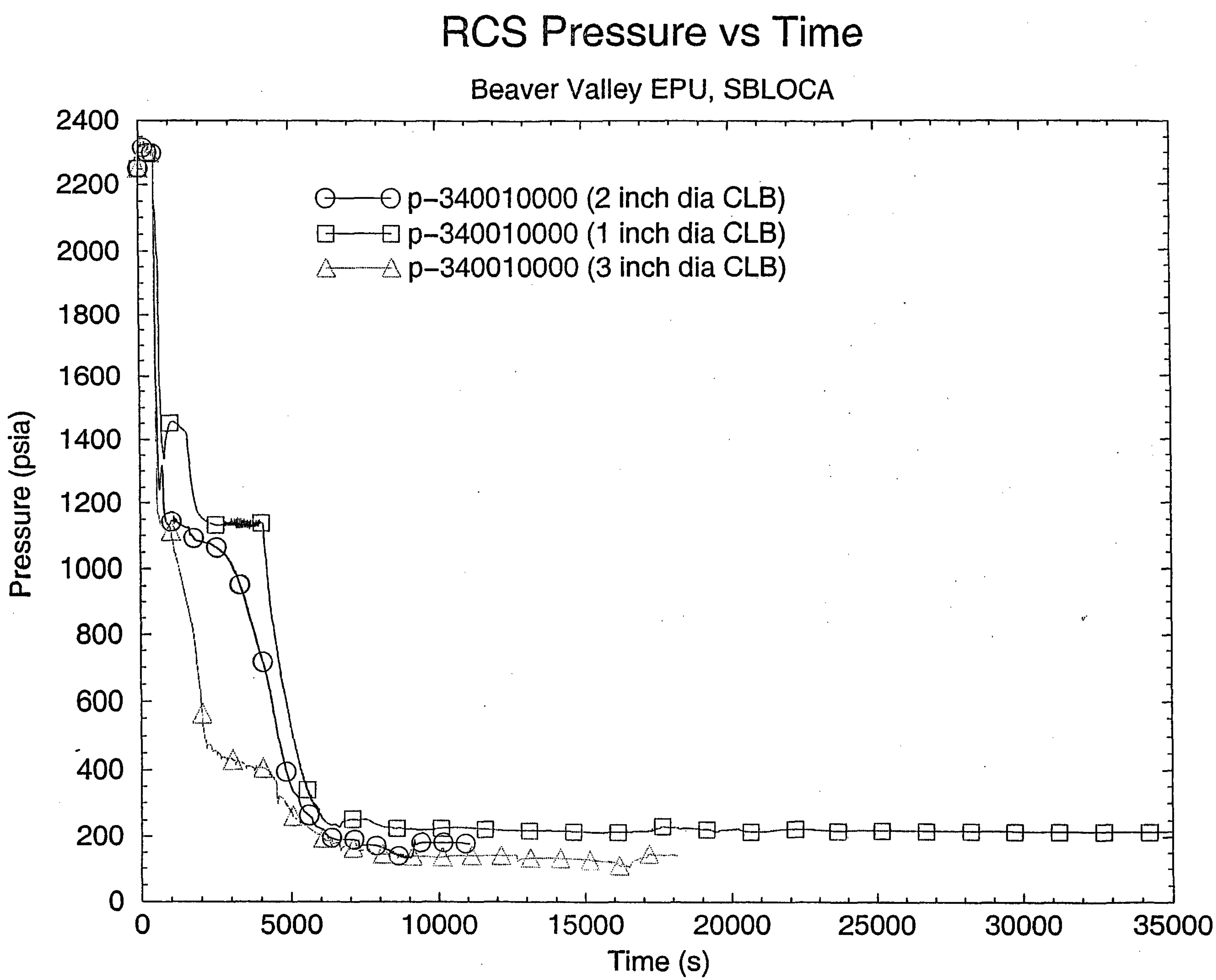
    1.8 HRS   1 INCH DIA CLB

    2.5 HRS   2 INCH DIA CLB

    4.7 HRS   3 INCH DIA CLB

  - RCS PRESSURE BELOW 100 PSIA FOR 4 INCH DIA CLB

    FLUSHES CORE



RCS Pressure vs Time
Beaver Valley EPU, SBLOCA
p-340010000 (2 inch dia CLB)
p-340010000 (1 inch dia CLB)
p-340010000 (3 inch dia CLB)
Pressure (psia)
Time (s)
2400
2200
2000
1800
1600
1400
1200
1000
800
600
400
200
0
0
5000
10000
15000
20000
25000
30000
35000

SMALL BREAK LOCA POST-LOCA LONG TERM COOLING (CON'T)

- EOP MODIFICATIONS

  COOLDOWN BEGINS NO LATER THAN ONE HR

  CAUTIONS TO OPERATORS TO PRECLUDE INADVERTENT DEPRESSURIZATION FOLLOWING LONG BOILING PERIODS

  EOP GUIDANCE ON EQUIPMENT AND TIMING FOR COOLDOWN

CONCLUSIONS

- o INTEGER BREAK SPECTRUM DOES NOT IDENTIFY WORST SMALL BREAK
- o EMPLOYED UNAPPROVED NOTRUMP SBLOCA MODEL
- o LICENSEE INCREASE SIT PRESSURE AND HPSI FLOW CAPACITY
- o STAFF RELAP5/MOD3 ANALYSIS CONFIRMED WORST SMALL BREAK

  SBLOCA WITHIN 10CFR50.46 LIMITS

- o STAFF CALCULATIONS

  CONFIRMED TIMING FOR BORIC ACID PRECIPITATION

  BOILING CAN LAST MANY HRS FOR SBLOCA
  (EQUIPMENT AND TIMING VERY IMPORTANT)

  IDENTIFIED NEED FOR EOP MODS

- o STAFF FINDS EPU SBLOCA SHORT TERM ANALYSES AND SBLOCA/LBLOCA LONG TERM COOLING ANALYSES MEET 10 CFR50.46 ACCEPTANCE CRITERIA

ACRS Subcommittee on Power Uprates

BEAVER VALLEY EPU CONTAINMENT REVIEW

Richard Lobel

Senior Reactor Systems Engineer

Office of Nuclear Reactor Regulation

April 25, 2006

CONTAINMENT CONVERSION

- February 6, 2006, NRC letter to FENOC approved the conversion of the Beaver Valley Unit 1 and Unit 2 containments from sub-atmospheric to atmospheric
- As part of this proposal, the licensee included consideration of EPU and Unit 1 steam generator replacement
- A new analysis method, MAAP-DBA is introduced

Millstone Unit 3

- The Millstone Unit 3 containment was originally designed and operated as a subatmospheric containment.

- Millstone Unit 3 containment converted to an atmospheric containment in 1991.

Beaver Valley Containment Normal Operating Conditions

- Subatmospheric Containment Pressure: Defined by a technical specification curve to between 8.9 psia (Unit 1) or 9.0 psia (Unit 2) and 10.5 psia
- Atmospheric Containment Pressure: Between 12.8 psia and 14.2 psia
- Atmospheric Containment Temperature: 70 F ≤ T ≥ 105 F

Subatmospheric Containment Design Bases

- Peak Pressure ≤ 45 psig
- *Containment shall be depressurized in one hour*
- *Once depressurized, containment remains subatmospheric*
- Containment liner temperature ≤ 280 F
- Subcompartments maintain structural integrity
- Minimum containment pressure ≥ 8 psia
- Unit 1 credits containment accident pressure for ECCS pump NPSH. Unit 2 does not.

Atmospheric Containment Design Bases

- Peak Pressure ≤ 45 psig
- *Containment pressure < 50% of peak within 24 hours*
- Containment liner temperature ≤ 280 F
- Subcompartments maintain structural integrity
- Minimum containment pressure ≥ 8 psia
- Unit 1 credits containment accident pressure for ECCS pump NPSH. Unit 2 does not.

LARGE BREAK LOCA

- For time < 1 hour: mass and energy release to containment calculated with NRC-approved Westinghouse methods
- For time > 1 hour: mass release calculated with same NRC-approved Westinghouse methods. Energy calculated with MAAP-DBA. (Staff performed audit calculations with RELAP to assess this approach. Good agreement. See Appendices to Staff SER.)
- Containment parameters calculated with MAAP-DBA
- Conservative inputs and assumptions

LOCA Results

Unit 1:
Power = 100% (EPU)
Break: Double Ended Hot Leg (DEHL)
Peak Containment Pressure = 43.3 psig
Corresponding containment atmosphere temperature:
267.8

Unit 2:
Power = 100% (EPU)
Break: Double Ended Hot Leg (DEHL)
Peak Containment Pressure = 44.9 psig
Corresponding containment atmosphere temperature:
270.1

Main Steam Line Break Accident

- Mass and Energy (M&E) release calculated with NRC-approved Westinghouse methods (WCAP 8822P-A
- Replacement SGs have flow restriction in steam generator nozzle (limits the break area)
- Cavitating venturis limit AFW flow to faulted SG for both units
- Spectrum of break sizes and power levels
- Both steam generator designs for Unit 1 considered
- Conservative assumptions

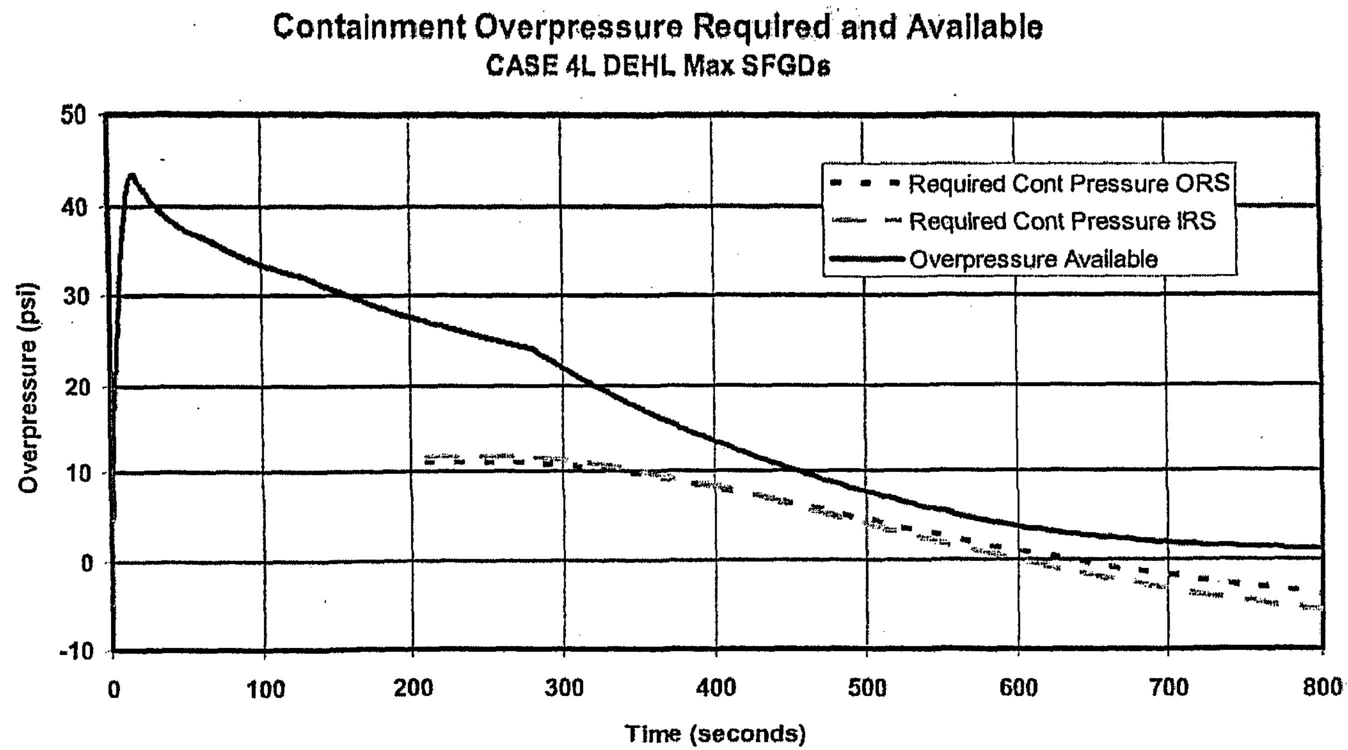
Peak Containment Liner Temperature

- LOCA produces higher containment pressures
- MSLB produces higher containment atmosphere temperatures
- For conservatism, heat transfer coefficient multiplied by 4 (consistent with SRP)
  - Unit 1: 254.1 F
  - Unit 2: 247.7 F
- Acceptance criterion 280 F

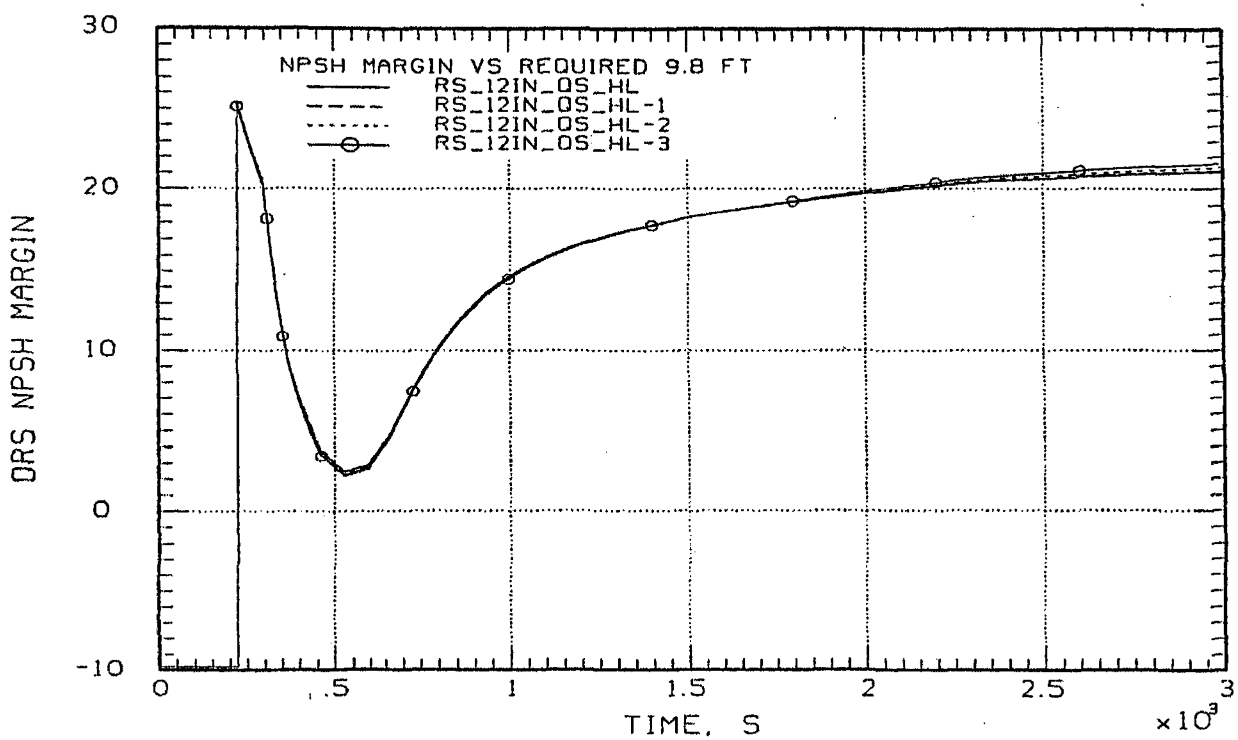
Sump Temperature and Net Positive Suction Head (NPSH)

- SRP 6.2.2 states that credit for containment accident pressure in determining available NPSH is acceptable for subatmospheric containments
- The Beaver Valley Unit 1 recirculation spray pumps satisfy this guidance at current power and at EPU
- Recirculation spray pumps start shortly after accident initiation when sump level is low and sump temperature is high
- Beaver Valley Unit 2 recirculation spray and ECCS pumps do not credit containment accident pressure for NPSH
- More realistic analysis assumptions do not eliminate crediting containment accident pressure

Sump Temperature and Net Positive Suction Head (NPSH)



Sump Temperature and Net Positive Suction Head (NPSH)



Sump Temperature and Net Positive Suction Head (NPSH)

- Pump testing with a pump hydraulically similar in design to Beaver Valley inside recirculation spray pump concluded that pumps will operate in stable condition without cavitation damage.

Sump Temperature and Net Positive Suction Head (NPSH)

- Staff accepted credit for containment accident pressure for available NPSH based on:

  Limited time needed

  (< 400 sec for limiting case)

  (< 20 minutes for non-limiting case)

  Containment pressure will be less than atmospheric pressure during operation

  Pump test data which demonstrates no damage to Beaver Valley pumps in cavitation

  No impact on EOPs

MAAP-DBA

- As part of containment conversion, licensee proposes to use the MAAP-DBA computer code for:

  containment analyses

  (LBLOCA, SBLOCA, MSLB)

  LBLOCA long term energy release

  SBLOCA mass and energy release

MAAP-DBA

MAAP-DBA is used to calculate the following containment conditions:

<u>Single Node</u>:

peak containment pressure
peak containment atmosphere temperature
maximum liner temperature

<u>Multiple Nodes</u>:

Sump water temperature and level

MAAP-DBA VALIDATION

- MAAP-DBA compared well with other computer code calculations and with separate effects data and integral tests results.
- Both single node and multiple node models used in validation
- Validation discussed in:

  November 24, 2003 licensee letter

  June 2, 2004 submittal Section 9.0

  NRC Staff February 6, 2006, SER

Conclusion

- February 6, 2006 NRC letter to licensee found containment conversion at EPU conditions acceptable
- February 6, 2006 NRC letter to licensee approved MAAP-DBA for Beaver Valley atmospheric containment calculations for applications listed previously

Source Terms and Radiological Consequences Analyses

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Source Terms for Input into Radwaste Management Systems Analysis

- RS-001 Matrix 9, EPU SE Section 2.9.1
- Radiological source term in reactor coolant system analyzed for EPU conditions
- Source term continues to meet requirements of 10 CFR Part 20, 10 CFR Part 50, Appendix I, and GDC-60

DBA Radiological Consequences Analyses

- RS-001 Matrix 9, EPU SE Section 2.9.2
- Implementation of Alternative Source Term (AST) using RG 1.183 guidance
- FHA
  - Increase in fuel inventory
- MSLB & SGTR (Unit 2 only)
  - Change in mass release
- Other DBAs previously approved

DBA Radiological Consequences Analyses (continued)

- Analyses based on proposed EPU conditions
  - Power Level 2,918 MWt (100.6% of 2,900 MWt)
  - Amendments No 243 & 122 issued September 24, 2001 approved 1.4% Measurement Uncertainty Recapture Uprate
- NRC staff performed an on-site audit of the radiological analyses supporting both the SGR and EPU LARs

Other DBAs

Prior AST selective implementations per
10 CFR 50.67 performed for EPU conditions

- LOCA & CREA
  - Amendments No 257 & 139 issued September 10, 2003
- LRA, LACP, SLB (Both Units) MSLB & SGTR (Unit 1 only)
  - Amendment No 273 BVPS-1 Steam Generator Replacement issued February 9, 2006

Control Room Assumptions

- CR Emergency Ventilation System (CREVS) credited for MSLB
  - 600 cfm filtered intake (pressurization mode)
  - 30 cfm unfiltered inleakage
  - Tracer gas test supports inleakage assumptions

- Post release CR purge credit via CR Emergency Air Cooling System (CREACS) for MSLB, SGTR and for Unit 1 FHA
  - No CREACS purge credit for Unit 2 FHA

DBA Radiological Consequences Analyses Conclusions

- Licensee has adequately accounted for the effects of the proposed EPU
- All DBAs meet 10 CFR 50.67 and SRP 15.0.1 dose acceptance criteria both offsite and in the control room
- The staff finds the proposed EPU acceptable with respect to the radiological consequences of DBAs

Reactor Vessel, Reactor Internal And Core Support Materials

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Impact on PWSCC of Alloy 600 Materials

- The staff evaluated the EPU safety analysis report to assess its impact on the crack growth rates for cracks in Inconel materials that initiated by primary water stress corrosion cracking (PWSCC). These materials include Alloy 600 base metal materials and Alloy 82 or 182 (Alloy 82/182) filler metal materials.
- The piping at BVPS Unit 1 (BVPS-1) does not include any Alloy 600 base metal or Alloy 82/182 filler metal materials.
- The BVPS- 1 reactor vessel closure head (RVCH) does include Alloy 600 nozzles and Alloy 82/182 filler metal materials. FENOC is replacing the BVPS-1 RVCH during the current refueling outage. Inspections of the RVCH will follow the criteria for replacement RVCHs in the First Revised Order EA-03-009.

PWSCC of Alloy 600 (Continued)

- The Alloy 600 and Alloy 82/182 materials in the BVPS Unit 2 (BVPS-2) piping are managed by FENOC's Alloy 600 management program. This management program proposes augmented volumetric inspections of these piping components based on the susceptibility ranking for the materials.
- The Alloy 600 nozzles and Alloy 82/182 partial penetration welds in the BVPS-2 RVCH are categorized as components that are highly susceptible to PWSCC. FENOC performs augmented inservice inspections (AISI) of these components in accordance with the AISI criteria in the First Revised Order EA-03-009 for "high susceptible" RVCHs.

Impact of EPU on RV and RV Internal Integrity

- Impacts on Reactor vessel (RV) integrity include:
  - Surveillance capsule programs
  - RTpts value calculations for the pressurized thermal shock assessments
  - RTndt value calculations used in establishing pressure-temperature (P-T) limits for the reactor coolant pressure boundary
  - Upper shelf energy calculations for demonstrating acceptable margins against ductile tearing of the RV materials
- Impacts on the structural integrity of the RV internals and core support materials

Impact on RV Surveillance Capsule Program

- After considering the effects of the EPU, the licensee is required to pull a total of five capsules from BVPS-1 and four capsules from BVPS-2.

- The licensee has removed, tested, and reported the test results for four capsule from BVSP-1 and three capsules in accordance with 10 CFR Part 50, Appendix H and ASTM E185-82.

- Minor EPU-based adjustmenets of the proposed withdrawal times for fifth mandatory capsule at BVPS-1 and fourth mandatory capsule at BVPS-2 were determined to be in compliance with ASTM E185-82 and acceptable. These capsules will be removed at a time when the capsule fluences are between one to two times the peak EOL fluences for the RVs, which is inaccordance with E185-82.

Impact on PTS Assessments

- Calculation of RTpts values is required by 10 CFR 50.61. The rule establishes screening criteria of 270 °F for RV beltline axial weld and base-metal materials (i.e, plate or forging materials) and 300 °F for RV circumferential weld materials.
- Results for BVPS-1: Limited by lower shell plate B6903-1 (Plate Heat No. C6317-1):
  - Licensee EPU-based RTpts value: 256.6 °F at EOL
  - NRC EPU-based RTpts value: 259.5 °F at EOL
- Results for BVPS-1: Limited by intermediate shell plate B9004-1 (Plate Heat No. C0544-1).
  - Licensee EPU-updated RTpts value: 149.0 °F at EOL
  - NRC EPU-based RTpts value of 148.6 °F at EOL.
- Thus, the RVs will remain in compliance with 10 CFR 50.61 for the EPU.

Impact on Pressure-Temperature Limits

- Two related license amendments permitted FENOC to remove the BVPS-1/2 pressure-temperature (P-T) limits from the Technical Specification (TS) limiting conditions of operation and to make any necessary changes to them in accordance with the methodology in an NRC-approved pressure-temperature limits report (PTLR).
- The license amendments were granted on October 8, 2002, and again on July 15, 2003.
- For BVPS-1/2, any changes to the P-T limits and submittal of the corresponding PTLR to the NRC (for information) is administratively governed under the requirements TS 6.9.6.
- Any necessary EPU-based changes to the P-T limits for BVPS-1/2 will be handled in accordance with TS 6.9.6 and the licensee's PTLR process.

Impact on the Upper Shelf Energy Assessment

- Calculations of upper shelf energy (USE) values are required by 10 CFR Part 50, Appendix G. The rule establishes that USE values must be greater than or equal to 75 ft-lb for RV materials in the unirradiated condition and greater than 50 ft-lb thoughtout the licensed life of the plant .
- Results for BVPS-1: Limited by lower shell plate B6903-1 (Plate Heat No. C6317-1):
  - Licensee EPU-updated USE value: 56 ft-lb at EOL.
  - NRC EPU-updated USE value: 53.8 ft-lb at EOL.
- Results for BVPS-2: Limited by lower shell plate B9005-2 (Plate Heat No. C1408-1).
  - Licensee EPU-based USE value: 60 ft-lb at EOL
  - NRC EPU-based USE value of 59.4 ft-lb at EOL
- Thus, thus, the limiting RV beltline plate materials for BVPS-1 and BVPS-2 willl remain above 50 ft-lb and in compliance with 10 CFR Part 50, Appendix G under EPU-based conditions.

Reactor Internal and Core Support Materials

- The licensee is following the ASME Section XI inservice inspection (ISI) requirements.
- In addition, the licensee made commitments to participate in the industry's research program and will develop an inspection program for the RV internals that is based on the recommendations of the industry initiatives.
- These commitments are consistent with Table Matrix-1 of Review Standard RS-001, Revision 0.

Conclusions

- The staff has concluded that the EPU will not significantly impact the safety margins for the following structural integrity assessments:
  - RV surveillance program
  - P-T limits for the reactor vessel
  - USE assessments for the RV
  - PTS assessment for the RV beltline materials
  - Structural integrity assessment of the RV internals
  - PWSCC of Alloy 600 and Alloy 82/182 components

BEAVER VALLEY POWER STATION

EXTENDED POWER UPRATE

SER SECTION 2.2

ENGINEERING MECHANICS BRANCH
(EEMB)

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Cheng-Ih (John) Wu
Thomas Scarbrough

- **Components Evaluated**
  - Reactor Vessel, Internals, Nozzles, Supports
  - Control Rod Drive Mechanisms
  - Steam Generator, Reactor Coolant Pump, Pressurizer and Supports
  - NSSS and BOP Piping Systems and Supports
  - Safety Related Valves (MOVs, AOVs, and SRVs)

- ## Scope of Review
  - Impact of EPU conditions due to changes in system pressure, temperature and flow rate.
  - Analytical methodology, loads, flow-induced vibration, calculated stresses and cumulative fatigue usage factors, acceptance criteria, ASME codes and addenda.
  - Functionality of valves and impact of EPU on GLs 89-10 and 96-05 for MOVs, and GL 95-07 for pressure locking and thermal binding.
  - EPU evaluation incorporating approved LBB for elimination of postulated primary loop pipe breaks.
  - Specific areas where staff requested additional information include MS and FW flow-induced vibration, analysis and results for BVPS Unit 1 main loop piping with SG, and CUF for vessel flange closure stubs.

Flow Induced Vibration

- MS and FW piping instrumented at critical locations and collected data are evaluated to ASME OM3.
- FIV on steam separator Increases at EPU. FIV on steam separators Is minimized due to its high stiffness and the low velocity of the passing flow.
- FIV on the U-bend tubing is within allowable limits (i.e., fluid-elastic instability ratio less than the limit of 1.0 and peak stresses less than material endurance limit)

- **Pump and Valve Modifications**

  - Charging/safety injection pumps modified to improve high head performance and flow rate.

  - Tolerance settings for Main Steam Safety Valves and Reactor Coolant Pressurizer Safety Valves adjusted.

  - New trim installed in the feedwater regulating valves (FRVs) in BVPS Unit 1 and FRVs replaced in BVPS Unit 2.

  - Fast-acting main feedwater isolation valves installed in BVPS Unit 1 similar to those in BVPS Unit 2.

- Conclusion
  - Stresses and CUFs in NSSS and BOP piping and components bounded by the original design basis analysis with the application of LBB.
  - The potential for flow-induced vibration not increased for the steam separators and the steam generator tubes for the EPU conditions.
  - MS and FW piping monitored to remain within allowable limits in ASME OM3 Code.
  - Safety-related valves and pumps will continue to meet NRC regulatory requirements during EPU operation at Beaver Valley.

Steam Generator Tube Integrity and Chemical Engineering Topics

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Flow Accelerated Corrosion (FAC)

- The program scoping criteria are consistent with industry guidelines (temperature, moisture content, component alloy content, amount of usage).
- EPU conditions change the temperature, flow velocity, and moisture content for some components.
- These changes are expected to increase the corrosion rates of some components and decrease the corrosion rates in others.

Flow Accelerated Corrosion (FAC)

- CHECWORKS computer models are being updated prior to implementing the EPU.
- The updated models are used in determining future inspection and repair/replacement plans.
- At EPU conditions the FAC program remains consistent with industry guidelines.

Steam Generator Tube Inservice Inspection

- Unit 1 has replacement steam generators with thermally treated Alloy 690 tubes and stainless steel tube support components (2006).
- Operating temperature will remain within the range found at other plants with Alloy 690 steam generator tubes.
- For Unit 1, the inspection program will continue to manage degradation effectively at EPU conditions.

Steam Generator Tube Inservice Inspection

- Unit 2 has original steam generators with mill annealed Alloy 600 tubes and both carbon steel and Alloy 600 tube support components.
- Increases in temperature, feedwater flow rate, and sludge accumulation could increase degradation rates.
- EPU conditions are not expected to introduce new forms of degradation.
- For Unit 2, the inspection program will continue to manage degradation effectively at EPU conditions.

Steam Generator Blowdown System (SGBS)

- Blowdown flow rates will not be affected by the change to EPU conditions, although blowdown flow-control valves may have to be repositioned.
- The ability of the SGBS to remove impurities from the secondary coolant will not be reduced at EPU conditions.
- Corrosion rates of SGBS components will continue to be monitored under the Flow Accelerated Corrosion Program.

Chemical and Volume Control System

- EPU operating conditions for heat exchangers are bounded by design values.
- Boration requirements at EPU conditions remain within system capabilities.
- Letdown flow rates, charging flow rates, and N-16 delay times will not be significantly affected by the EPU.

Protective Coatings (Paints) Organic Materials

- Original coating application was in accordance with ANSI N101.2 for both Unit 1 and Unit 2.
- Normal operating and design basis accident conditions in containment are bounded by coating system qualification tests for both Unit 1 and Unit 2 (temperature, pressure, radiation dose, chemical concentration)
- Coating failures are identified by inspection and evaluated by the Corrective Action Program.

Balance-Of-Plant (BOP) Systems

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Scope of Review for BOP Systems

- Review per RS-001, Matrix 5
  - Internal Hazards
  - Fission Product Control
  - Component Cooling and Decay Heat Removal

Scope of Review for BOP Systems

- Review per RS-001, Matrix 5 (continued)
    - Balance-of-Plant Systems
    - Waste Management Systems
    - Emergency Diesel Fuel Oil Storage & Light Loads
- BOP Testing Considerations

Scope of Review for BOP Systems

- Spent Fuel Pool Cooling
- Service Water System/Ultimate Heat Sink
- Auxiliary Feedwater System
- Condensate and Feedwater System

Modifications to BOP Mechnical Systems

- Replacement of High Pressure (HP) all-reaction turbines

- Addition of auxiliary feedwater flow limiting venturies for BVPS-1.

High Pressure Turbine Modification

- In both units the high pressure turbine is being replaced by an all reaction turbine.
- Unit 1 - modification completed - maximum overspeed calculated to be 118% which is below the acceptance criteria of 120%.
- Unit 2 - modification will be completed prior to operation at EPU and the licensee has comitted to perform appropiate turbine overspeed analysis to ensure overspeed protection is acceptable.

Auxiliary Feedwater System Modifications

- Cavitating veturies were installed in Auxiliary Feedwater System of BVPS-1.
- At EPU the number auxiliary FW pumps credited for the FWLB and LONFW events for BVPS-1 is now two.
- Unit 2 licensing basis already credits two AFW pumps for theses FW events and is not changed by EPU.
- Total required AFW flow for FWLB and LONF events for operation of uprated BVPS-1 will be well within the capacity of any two AFW pumps.
- Technical Specifications requires 3 AFW pumps be operable.

BOP Systems - Summary

- The staff finds the proposed EPU to be acceptable with respect to BOP area, based on:
  - the evaluation that was performed
  - the commitments that were made, and
  - testing that will be completed

Beaver Valley Power Station EPU
NRC Staff Review of Risk Evaluation

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Overview

- Licensee assessed potential risk impacts of the proposed EPU
- The proposed EPU does not create "special circumstances" that rebut the presumption of adequate protection afforded by the licensee meeting current regulations
- Risks of BVPS EPU implementation were adequately assessed by the licensee and are acceptable

EPU Risk Evaluations

- EPU submittals are not risk-informed
- Per RS-001, Rev. 0, "Review Standard for Extended Power Uprates," Matrix 13, "Risk Evaluation," licensees perform risk evaluations to:
  - Demonstrate that risks are acceptable, and
  - Determine if "special circumstances" exist (as defined in SRP 19, Appendix D)
- BVPS EPU is for an 8% increase

Scope of the Risk Evaluation

- Full-power PRA model
  - Internal events, including internal flooding
  - Seismic
  - Internal Fires
  - CDF and LERF
- Qualitative approach for other risk
  - High winds, external floods, other external events – screening per NUREG-1407
  - Shutdown risk – questions in SRP Chapter 19

PRA Quality

- Owners Group Peer Review July, 2002
  - 5 A level and 19 B level Facts & Observations (F&Os)
  - Resolution of F&Os incorporated into PRA model
- SDP Phase 2 model benchmarked 09/24/03 (both units)
- Seismic and fire PRA models
  - Reviewed internally by utility personnel and by IPEEE contractors
  - NRC SER found the results to be reasonable and capable of identifying the most likely severe accidents and vulnerabilities
  - Seismic and fire PRA models are integrated with the internal events PRA models
- <u>NRC staff finds PRA used in support of the EPU is of sufficient quality, scope, and level of detail to analyze the risks stemming from the EPU</u>

PRA Quality (cont'd)

- Onsite audit by NRR 10/18-19/2005
- Purposes of Audit:
  - Understand risk impact of EPU taken by itself
  - Check quality of PRA and risk assessment
  - Understand/clarify selected RAI responses
- Key Findings
  - Need to estimate risk from EPU alone, without model enhancements or unrelated changes
  - Need to explain several MAAP results
- Results
  - Good PRA configuration control process
  - Licensee corrected one MAAP model error and updated results
  - Licensee submitted risk assessment representing just EPU risk

EPU Impact on Initiating Events and Equipment Reliability

- EPU does not result in new initiating events and is not expected to increase the frequency of any initiating event
  - Equipment operating ranges and limits are maintained
  - Plant modifications will be implemented where necessary
- EPU will not adversely effect system functions important to risk
  - Plant modifications made to maintain or improve the performance of certain equipment
  - Plant systems and equipment will continue to be operated within design constraints
  - Component failure rates and equipment unavailability will not significantly change with the implementation of the EPU

EPU Impact on Accident Sequences & Success Criteria

- General accident progression in PRA not impacted by EPU
- For the most part, success criteria remains the same
- Station Blackout (SBO) impacted slightly -shorter time to core damage impacts time to recovery offsite power
- ATWS success criteria impacted
  - Cavitating venturis in AFW precludes ability to deliver full flow from all 3 AFW pumps to the steam generators
  - BVPS PRA models conservatively do not credit full AFW flow, so no calculated increase in ATWS risk from this source
  - Actual increase in ATWS risk would be very small, since ATWS accounts for less than 1% of total CDF for each unit
- Design basis loss of feedwater transient success criteria impacted, but best estimate criteria unchanged by EPU
- Negligible impact on containment accident pressure credit for ECCS NPSH (next slide)

Containment Accident Pressure for ECCS NPSH

- For Unit 1, pre-EPU licensing basis allows consideration of containment accident pressure in calculation of NPSH
- Unit 2 does not credit containment accident pressure due to physical design differences
- Only the Unit 1inside and outside recirculation spray pumps credit containment accident pressure
- Insignificant change in risk resulting from EPU
  - Accident pressure required for short duration (10-20 minutes)
  - Vendor tested a pump hydraulically identical to BVPS recirculation spray pumps and demonstrated the pumps are capable of stable operation at conditions where NPSH is reduced below the standard requirement
  - The difference in duration pre-EPU compared to post-EPU case is on the order of a minute (based on a representative calculation)

EPU Impact on Human Reliability

- EPU reduces time available for the operators to act, which may increase human error probability
- Change in HRA due to EPU not assessed directly (licensee performed sensitivity analysis) because:
  - Pre-EPU timing based mostly on hand calculations; post-EPU used MAAP analyses
  - HRA method cannot translate small changes in time available into meaningful changes in human error probability
- EPU risk due to operator action timing assessed by:
  - Quantifying post-EPU CDF and LERF using HRA timing from MAAP
  - Validating that important operator actions with short time available are not precluded at EPU timing
- NRC staff conclusion focused on post-EPU CDF and LERF and on whether adequate protection of public health and safety will be maintained

EPU Impact on Human Reliability (cont'd)

- Important operator actions with short time available
  - Depressurize the RCS
  - Implement feed and bleed cooling
  - Manually start auxiliary river water pumps (unit 1)
  - Manually start AFW on failed SSPS (unit 2)
- Licensee validated that these can be performed in the EPU time available and used MAAP to determine timing
- Depressurization and feed & bleed actions
  - Proceduralized, routinely practiced on the simulator, performed in control room (model includes local actions for depressurization in some scenarios)
  - Take a relatively short time to perform (2 -10 minutes)
  - Occur in response to symptom based procedures (EOPs and FRPs)
  - A reduction in time available would not be expected to have a significant impact on human error probability unless the time became so short the operator did not reach the procedure step
- The manual actions to start pumps are simple actions performed from the control room

EPU Impact on External Events Risk

- Fire
  - EPU not expected to result in new internal fire initiators, increase fire initiating event frequency, or result in new internal fire core damage or LERF scenarios
  - EPU has very small impact fire risk
- Seismic
  - EPU not expected to result in changes in SSCs' response to a seismic initiator or result in new seismic core damage or LERF scenarios
  - EPU has very small impact seismic risk
- Other External Events
  - EPU implementation will not affect the high winds, floods, and other external events analysis
  - The IPEEE evaluation remains applicable at EPU conditions

EPU Impact on at-Power Risk

Estimated Risk: EPU Implementation*		
(Per reactor year)	Unit 1	Unit 2
CDF post EPU	2E-5	3E-5
CDF Increase**	3E-7	4E-7
LERF post EPU	5E-7	1E-6
LERF Increase**	6E-8	5E-8

* Total - Internal events, fire and seismic
** HRA sensitivity + other EPU changes

EPU Impact on Shutdown Risk

- Shutdown initiating events are not impacted by EPU
- Impact of increased decay heat is not significant
  - Small decrease in the time available for operator actions
  - Adequate defense-in-depth minimizes impact of decreased response time
- Licensee will continue to control shutdown risk using plant procedure
  - Requires monitoring of the plant defense-in-depth features available during these operating modes
  - Provides guidance for evaluating the adequacy of protective measures, and specifies actions to be taken to ensure that there are adequate protective measures in place.
  - Requires development of a Pre-Outage Shutdown Safety Review of key shutdown safety functions.

Conclusion

- Licensee assessed potential risk impacts of the proposed EPU
- The proposed EPU does not create “special circumstances” that rebut the presumption of adequate protection afforded by the licensee meeting current regulations
- Risks of BVPS EPU implementation were adequately assessed by the licensee and are acceptable

Human Performance

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Human Factors Engineering Evaluation

- Areas of Review
  - Programs, procedures, training, and human system interface design features that are related to operator performance
- Purpose
  - Assure that the proposed Extended Power Uprate (EPU) does not adversely affect operator performance

Regulatory Criteria

- RS-001, "Review Standard for Extended Power Uprates Draft Review Standard for Power Uprates," Matrix 11
- 10 CFR 50.120
- 10 CFR Part 55
- Generic Letter 82-33
- Standard Review Plan Chapter 18.0, "Human Factors Engineering"

RS-001, Matrix 11, Standard Questions Related to Affects of EPU

- Emergency and Abnormal Operating Procedures
- Operator Actions Sensitive to Power Uprate
- Control Room Alarms, Controls, Displays
- The Safety Parameter Display System (SPDS)
- Operator Training Program and Control Room Simulator

Emergency and Abnormal Operating Procedures

- Changes include slight modifications for parameter thresholds and graphs which depend on power and decay heat levels and changes in setpoints
- Elimination or revision of procedures to reflect the elimination of technical specification requirements associated with boron injection tank (BIT)

Operator Actions Sensitive to Power Uprate

- EOP operator actions used in analysis
  - New operator action: control room purge after SGTR
  - Change to operator actions: Control Room purge after MSLB is now for 30 minutes at 16,200 cfm instead of within 8 hours of termination of environmental release
- Several operator action times affected in both units
  - Time reductions for some operator actions due to increased decay heat

Operator Actions Sensitive to Power Uprate

- Decreased Operator Actions Times:
  - Unit-1
    - Times validated for revised EOPs & confirmed on simulator and by step by step walk-through in plant
  - Unit-2
    - Revisions to EOPs not completed at this time
    - Licensee committed to validating operator action times obtained through talk-through process as part of procedural change process
- Staff determined acceptable based on Unit-1 validations and provided licensee validates performance in Unit-2 simulator prior to power uprate

Operator Actions Sensitive to Power Uprate

Summary of Restrictive Operator Action Times

Operator Action	Time Available/ Times used in EPU analysis	Action Performance Time	Time Used in current EPU analysis
Unit 1			
terminate high head safety injection flow to RCS	within 10 Minutes of the start of the event	9.7 minutes	No time for this action used in the current analysis
Unit 2			
isolate auxiliary feedwater flow to the ruptured SG	within 5.5 minutes after reactor trip	5.0 minutes	within 9.1 minutes after reactor trip
initiate cooldown from the intact SGs via the main steam system after MSIV closure	within 2.0 minutes after the MSIV is closed for inside the main control room	2.0 minutes	No time for this action used in the current analysis
	within 7.0 minutes after the MSIV is closed for outside the main control room	6.0 minutes	within 9.0 minutes after the MSIV is closed for outside the control room

Control Room Alarms, Controls, Displays

- Licensee provided a summary of limits, setpoints, and alarms affected including
  - Rx Trip setpoints -overprotection
  - Pressurizer Water Level Program
  - Accumulator water lever and pressure setpoints
  - Primary Plant Demineralized Water Tank (unit 1 only)
  - Replacement SG revisions to associated water level setpoints, alarms, EOPs, and the SMAGs (unit 1 only)
  - Steam Dump; Turbine 1st stage pressure alarm
  - RWST setpoints

Control Room Alarms, Controls, Displays

- No controls, displays, or alarms will be upgraded from analog to digital except the SI accumulator pressure indication display which will be upgraded for improved accuracy
- Re-normalized
  - Interfaces for control room controls, displays, & alarms will be such that 100% indications of rated thermal power (RTP) will remain at 100% RTP
  - No changes in operator actions for normalized protection, control, displays, and alarms

Safety Parameter Display System (SPDS)

- Instrument spans & setpoints changing in both units
- Replacement steam generators Unit-1 impact SPDS
  - Increased narrow range steam generator water level instrument span.
  - Display system will be re-calibrated such that the process limits match the existing patterns
- Plant Engineering Change Process (ECP) will be followed to make changes to SPDS
  - Includes operations, training, and the simulator groups when determining impacts on the changes and determining if additional training is necessary

Operator Training Program and Control Room Simulator

- ECP requires training department to perform an evaluation per the Systematic Approach to Training for all affected plant modifications, procedural changes, and operator action times

- Both units' simulators will be bench-marked with the best estimate engineering models for the 10 ANSI/ANS-3.5 Appendix B transients
  - Simulators will initially compared to the predicted values at 100% steady state; this will be followed by a final comparison to actual plant values at 100% power

Operator Training Program and Control Room Simulator

- Training will cover plant modifications, procedure changes, & changes to parameters, setpoints, scales, system
- Training & simulator changes will be completed prior to EPU implementation

Conclusions

- The licensee has:
  - Addressed the effects of the proposed EPU on available time for operator actions
  - Taken or has committed to take appropriate actions to assure that the EPU does not adversely affect operator performance
- The licensee will continue to meet applicable NRC requirements related to human performance
- The NRC finds the licensee's proposed EPU acceptable with respect to human factors

Beaver Valley Power Ascension and Test Program

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Beaver Valley EPU Test Program

- Standard Review Plan (SRP) 14.2.1, "Generic Guidelines for Extended Power Uprate Testing Programs," provides guidance for testing programs based on Regulatory Guide (RG) 1.68 and plant specific initial test program.
- EPU test program should include testing sufficient to demonstrate structures, systems, and components (SSCs) will perform satisfactorily at the requested power level.
- Staff guidance considers original power ascension test program and EPU related plant modifications.
- Staff guidance acknowledges that licensees may propose alternative approaches to testing with adequate justification.

Beaver Valley EPU Test Program

- Staff basis for requiring performance of LTT should consider Regulatory Guide 1.68 testing "Objectives"
  - Operator training and familiarization,
  - Confirmation of design and installation of equipment,
  - Bench marking of analyses codes and models, and
  - Confirmation of the adequacy of emergency and operating procedures.

Beaver Valley EPU Test Program

- Beaver Valley will perform additional start-up tests for Unit 1 which were not originally part of the initial start-up test program.
  - Maintain consistency with Unit 2 (these tests were initially applicable),
  - Examples include: secondary system vibration frequency and amplitude tests, secondary system expansion and restraint tests, primary sampling system tests, and Turbine plant system tests.
- Beaver Valley will perform a series of post modification tests for plant design changes associated with the power uprate:
  - Replacement of plant instrumentation and controls (e.g., Prz. Level control, Main steam, main feedwater control systems)
  - Modification to HP Turbine, Charging pump internals

Beaver Valley EPU Test Program

- Beaver Valley application does not require the performance of LTT (e.g., MSIV closure, T-G load rejection)
- Accepted justifications for not performing LTT for previous power uprate applications were applicable to the Beaver Valley EPU application.
  - The licensee's test program will monitor important plant parameters during EPU power ascension.
  - TS surveillance and post-mod testing will confirm the performance capability of the modified components.
  - Operating history and experience at other similar 3-loop LWRs at similar power levels (North Anna, Summer, Harris).
  - LTT is not needed for Code analyses bench marking.

Beaver Valley EPU Test Program

Conclusion

- SRP 14.2.1 allows for justification for not performing EPU power ascension tests.
- Fifteen domestic LWRs have implemented staff approved EPUs (up to 120% OLTP) without performance of LTT.
- Beaver Valley will implement a thorough test plan consistent with the initial test program and plant modifications based on the uprated conditions.
- The staff concludes that the proposed test program provides adequate assurance that the plant will operate in accordance with the design criteria and that SSCs affected by the proposed EPU will perform satisfactorily in service.

LBLOCA

CONSERVATISMS IN OXIDATION CALCULATION

- REFLOOD TIME PERIOD EXTENDED
- CONSERVATIVE W COBRA/TRAC TRANSIENT IS CHOSEN
- CONSERVATIVE ROD POWER CENSUS
- CONSERVATIVE ESTIMATES OF OXIDATION FRACTIONS

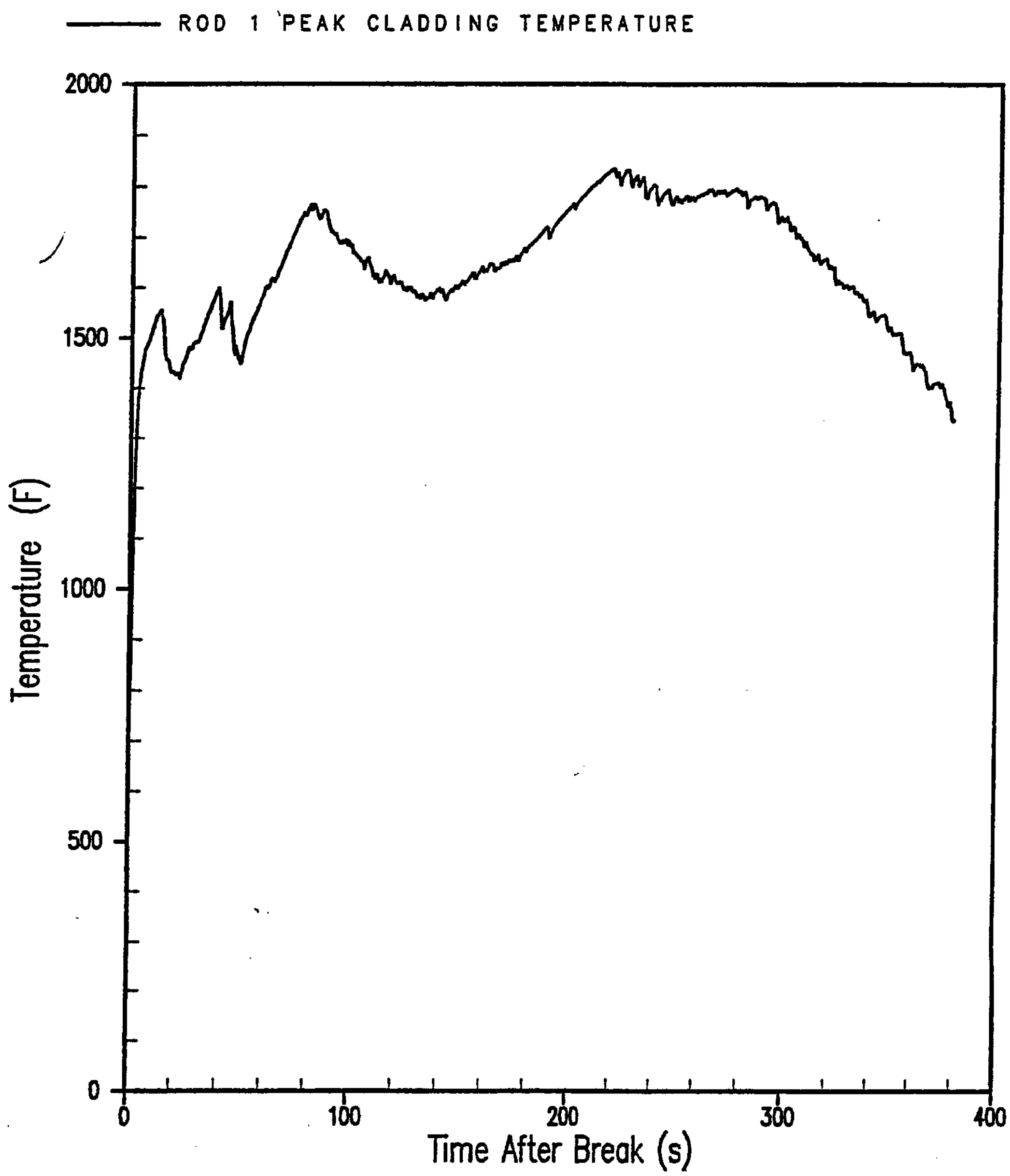


Figure 8.4-2 Peak Cladding Temperature for Reference Split Transient

CONTROL OF BORIC ACID

- o LARGE BREAKS

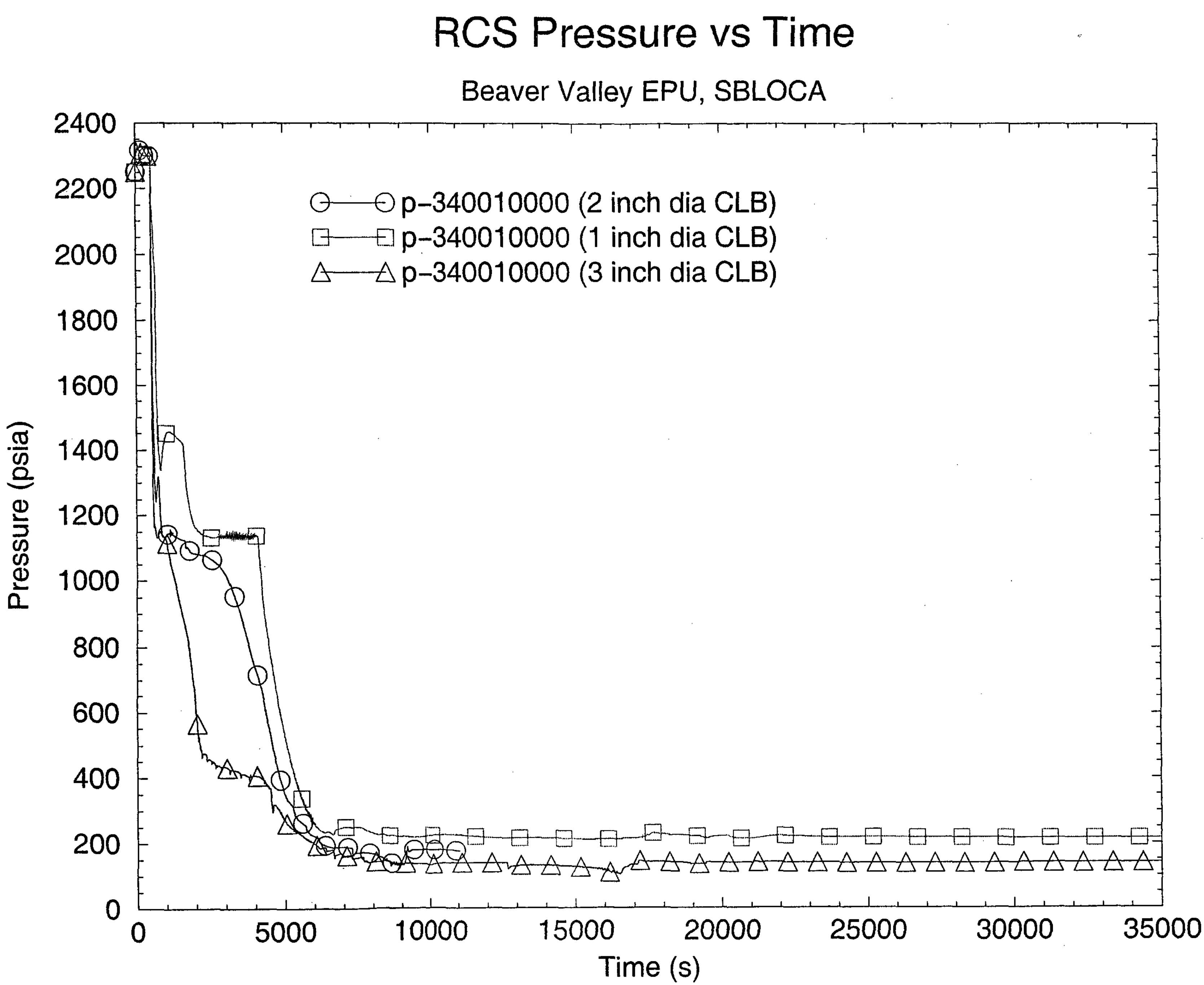
  - RE-ALIGN HPSI TO SIMULTANEOUS HOT AND COLD SIDE INJECTION

- o SMALL BREAKS

  - COOLDOWN RCS TO LOW PRESSURE FOR CORE FLUSH BY HPSI

  OR

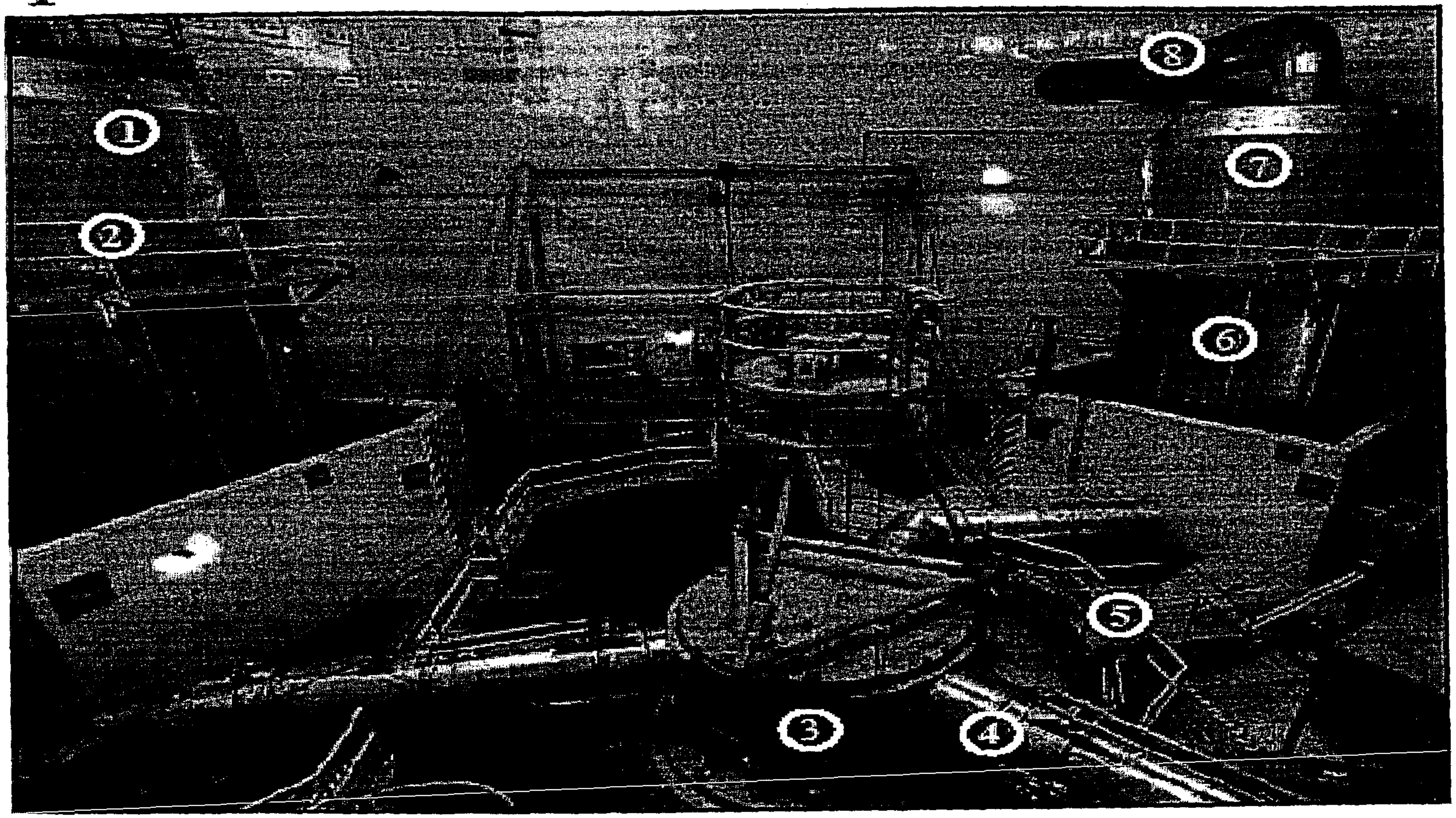
  - REFILL RCS WITH ECC (RE-ESTABLISH SINGLE PHASE NAT. CIRC.)



RCS Pressure vs Time
Beaver Valley EPU, SBLOCA
p−340010000 (2 inch dia CLB)
p−340010000 (1 inch dia CLB)
p−340010000 (3 inch dia CLB)
Pressure (psia)
Time (s)
0
200
400
600
800
1000
1200
1400
1600
1800
2000
2200
2400
0
5000
10000
15000
20000
25000
30000
35000

WHAT'S NEW *inside BV Unit 1 Containment*

Take a look below at the improvements made inside Unit 1 Containment during Beaver Valley's 1R17 outage.



1) Three brand new 368-ton steam generators were installed. Shown here is the top portion of Steam Generator 'B.'
2) New catwalks on the steam generators will eliminate the need to build scaffolding, saving time and dose.
3) A new, simplified Reactor Vessel Head will save 12 polar crane lifts per outage in the future.
4) A new configuration for the Control Rod Drive Mechanism ventilation was installed.
5) The Cable Bridge will allow easier access to the head and will simplify the process of disconnecting the Control Rod Drive Mechanisms and Rod Position Indicators in future refueling outages.
6) New mirror insulation was installed on all three Steam Generators and the Reactor Vessel Head. The insulation will help keep heat inside the steam generators and debris out of the containment sump.
7) Steam Generator 'A.' Steam Generator 'C' is not shown.
8) Close to 1.4 miles of welds on the Reactor Coolant System, Main Steam System, Feedwater Lines and instrument tubing were completed.

EPU Technical Specification Changes:

- Increasing the Maximum Power Level specified in each unit's license
- Revising the value of Rated Thermal Power (RTP) and adding definition to LRM
- Revising fuel assembly specific Departure from Nucleate Boiling Ratios (DNBR) and correlations
- Raising the maximum temperature of the refueling water storage tank
- Raising the positive tolerance setting for the pressurizer safety valves
- Revising the primary plant demineralized water storage tank volume requirement
- Adding WCAP-14565, VIPRE, and WCAP 15025, WRB-2M, to the list of approved NRC methodologies in Technical Specification 6.9.5

EPU Technical Specification Changes (Cont.):

- Deleting the Power Range, Neutron Flux High Negative Rate trip
- Increasing the operating band for accumulator water volume and nitrogen pressure (Unit 2 only)
- Revising the Steam Generator Technical Specification tube sleeve reference and TIG welded Steam Generator sleeve repair limit (Unit 2 only)
- Revising the specific activity of the primary and secondary coolant systems (Unit 1 only)
- Revising the required charging pump discharge pressure for reactor coolant pump seal injection flow (Unit 2 only)
- Raising the positive tolerance setting for the main steam safety valves (all but the lowest MSSV)
- Changing the allowable power limits associated with inoperable main steam safety valves

Nominal Operating Parameters (BVPS-1)

	EPU Condition	Pre-EPU Condition	Change
Core Power (MWt)	2900	2689	+7.9%
Taverage (F)	577.9	576.2	+1.7F
Tcold (F)	544.6	545.1	-0.5F
Delta T (F)	66.6	62.2	+4.4F
Thot (F)	611.2	607.3	+3.9F
Coolant Mass Flow (total lb/hr)	1.11E+08	1.11E+08	0%
Pressurizer Pressure (psia)	2250	2250	0 psi
SG Power (total MWt)	2910	2697	+7.9%
FW In (F)	440	434.3	+5.7F
Stm Out (psia)	805	825	-20 psi
Stm Mass Flow (total lb/hr)	1.27E+07	1.17E+07	+8.5%

Nominal Operating Parameters (BVPS-2)

	EPU Condition	Pre-EPU Condition	Change
Core Power (MWt)	2900	2689	+7.9%
Taverage (F)	574.2	576.2	-2F
Tcold (F)	538.9	543.4	-4.5F
Delta T (F)	70.6	65.6	+5F
Thot (F)	609.5	609	+0.5F
Coolant Mass Flow (total lb/hr)	1.05E+08	1.05E+08	0%
Pressurizer Pressure (psia)	2250	2250	0 psi
SG Power (total MWt)	2910	2697	+7.9%
FW In (F)	437	434	+3F
Stm Out (psia)	774	821	-47 psi
Stm Mass Flow (total lb/hr)	1.27E+07	1.17E+07	+8.5%

BVPS-1 OTΔT and OPΔT Equations

OTΔT Equation

$$\Delta T\cdot\left[\frac{1}{\left(1+\tau_4\cdot S\right)}\right]\leq \Delta T_o\cdot\left[K_1-K_2\cdot\left[\frac{\left(1+\tau_1\cdot S\right)}{\left(1+\tau_2\cdot S\right)}\right]\cdot\left[T\cdot\left[\frac{1}{\left(1+\tau_5\cdot S\right)}\right]-T^1\right]+K_3\cdot\left(P-P^1\right)-f\cdot(\Delta I)\right]$$

OPΔT Equation

$$\Delta T\cdot\left(\frac{1}{1+\tau 4\cdot S}\right)\leq \Delta T_o\left[K_4-K_5\cdot\left(\frac{\tau_3\cdot S}{1+\tau_3\cdot S}\right)\cdot\left(\frac{1}{1+\tau_5\cdot S}\right)\cdot T-K_6\cdot\left[T\cdot\left(\frac{1}{1+\tau_5\cdot S}\right)-T^{11}\right]\right]$$

- For BVPS-1, the K1, primary term used in the Overtemperature ΔT function to limit reactor power is reduced from 1.259 to 1.242, a reduction of 1.7% RTP given steady state conditions.

- For BVPS-2, the K1, primary term used in the Overtemperature ΔT function to limit reactor power is reduced from 1.311 to 1.239, a reduction of 7.2% RTP given steady state conditions.

- For Unit 1, the K4, primary term used in the Overpower ΔT function to limit reactor power is reduced from 1.0916 to 1.085, a reduction of 0.6% RTP given steady state conditions.

- For Unit 2, the K4, primary term used in the Overpower ΔT function to limit reactor power is maintained at 1.094

- The reduction in steady-state operating margin as a result of the "tuning" of this reactor trip function does not introduce possibility of spurious runback or plant trips due to the incorporation of lag modules that effectively filter out small input signal variations.

Pressurizer Level Control	22%= 547°F 54% @ full power Linear ramp Full power Tavg @ 576.2°F	22%= 547°F Variable @ full power Linear ramp Full power Tavg @ 566.2-580°F	No control changes No change of reference level at no-load temp. Tavg @ 566.2°F , 44% Tavg @ 576.2°F, 55-56% Tavg @ 580°F, 60% Revised level program will be implemented in 1R17 & 2R12
Steam Dump Control, Load Rejection Controller, Deadband	2°F	3°F	Changed to support maintaining P9 setpoint at EPU conditions
Steam Dump Control, Reactor Trip Controller, Trip Open Setpoints	First Bank 11.1°F Second Bank 20.0°F	First Bank 15.6°F / 9.1°F Second Bank 33.0°F/19.2°F	Changed to support maintaining P9 setpoint at EPU conditions Setpoints vary on full power Tavg. EPU values based on Tavg of 580.0°F/566.2°F
Steam Dump Control, Load Rejection Controller, Trip Open Setpoints	First Bank 9.5°F Second Bank 16.7°F Third Bank 25.7°F Fourth Bank 33°F	First Bank 8.8°F / 5.8°F Second Bank 15.3°F/9.0°F Third Bank 23.4°F/13.0°F Fourth Bank 30.0°F/16.2°F	Changed to support maintaining P9 setpoint at EPU conditions Setpoints vary on full power Tavg. EPU values based on Tavg of 580.0°F/566.2°F
Steam Dump Control, Reactor Trip Controller, Trip Open Setpoints	First Bank 11.1°F Second Bank 20.0°F	First Bank 15.6°F / 9.1°F Second Bank 33.0°F/19.2°F	Changed to support maintaining P9 setpoint at EPU conditions Setpoints vary on full power Tavg. EPU values based on Tavg of 580.0°F/566.2°F
Steam Dump Control, C-7B Setpoint	50%	35%	Changed to support maintaining P9 setpoint at EPU conditions
SG Level Control (Nominal setpoint)	44% NR Level	44% NR Level (BVPS-2) 65% NR Level (BVPS-1)	Nominal Level changing due to RSG (BVPS-1 only). Will be implemented in 1R17

BELOCA Methodology

The approved methodology uses a number of inputs that are set to bounding (conservative) conditions. Examples of these parameters include:

- Operating history (decay heat)
- Moderator temperature coefficient
- Hot assembly burnup
- S/G tube plugging level
- Pressurizer location (intact loop)
- Accumulator boron concentration
- Break location (cold leg)
- Offsite power (on - RCPs running)
- Safety injection flow (minimum)
- Safety injection delay (maximum)
- Containment pressure (conservative)
- Single failure (1 train ECCS)

BELOCA Methodology *(Cont.)*

- Other inputs are treated statistically as follows
- Nominal values used to establish a limiting reference transient
- Sensitivities are developed based on specified operating range
- 95/95 PCT is established using monte-carlo sampling over desired operating range
- Uncertainties are grouped into three categories:
  - Model parameter bias and uncertainty
  - Power distribution bias and uncertainty
  - Initial condition bias and uncertainty
- Uncertainties are added to the reference transient PCT to develop a distribution of PCTs

$$PCT_i = PCT_{REF} + \Delta PCT_{I,MOD} + \Delta PCT_{i,PD} + \Delta PCT_{i,IC} + \text{Superposition Correction}$$

BELOCA Methodology

The approved methodology uses a number of inputs that are set to bounding (conservative) conditions. Examples of these parameters include:

- Operating history (decay heat)
- Moderator temperature coefficient
- Hot assembly burnup
- S/G tube plugging level
- Pressurizer location (intact loop)
- Accumulator boron concentration
- Break location (cold leg)
- Offsite power (on - RCPs running)
- Safety injection flow (minimum)
- Safety injection delay (maximum)
- Containment pressure (conservative)
- Single failure (1 train ECCS)

BELOCA Methodology *(Cont.)*

- Other inputs are treated statistically as follows
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- 95/95 PCT is established using monte-carlo sampling over desired operating range
- Uncertainties are grouped into three categories:
  - Model parameter bias and uncertainty
  - Power distribution bias and uncertainty
  - Initial condition bias and uncertainty
- Uncertainties are added to the reference transient PCT to establish 95th percentile PCT

$$PCT_{95} = PCT_{REF} + \Delta PCT_{MOD} + \Delta PCT_{PD} + \Delta PCT_{IC} + \text{Superposition Correction}$$

DNB Events

RTDP Applicable? → No → Use STDP with W-3 and WRB-1

↓ Yes

Use WRB-2M where applicable

Not applicable for:

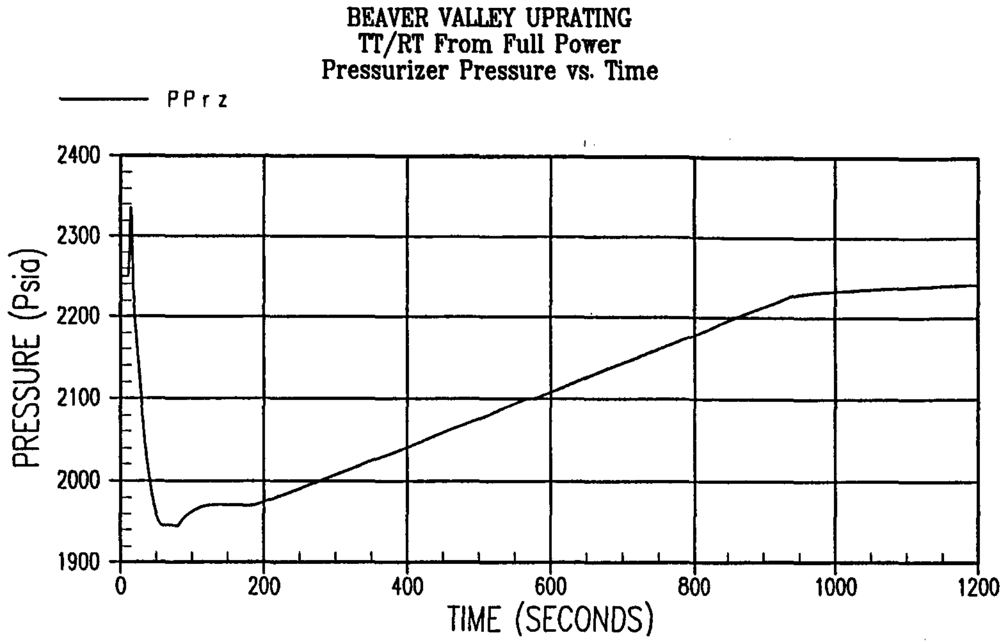
1) Events at 0% power

2) DNBR analysis below first mixing vane grid

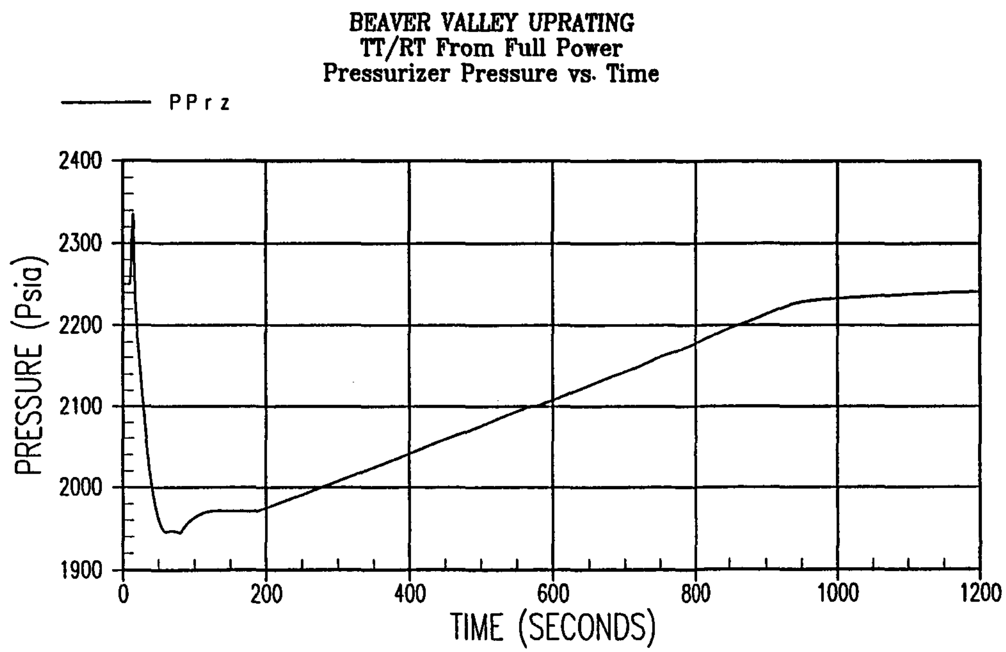
   (W-3 used for this analysis)

3) For analysis where fluid conditions are outside the approved quality or pressure range for WRB-2m

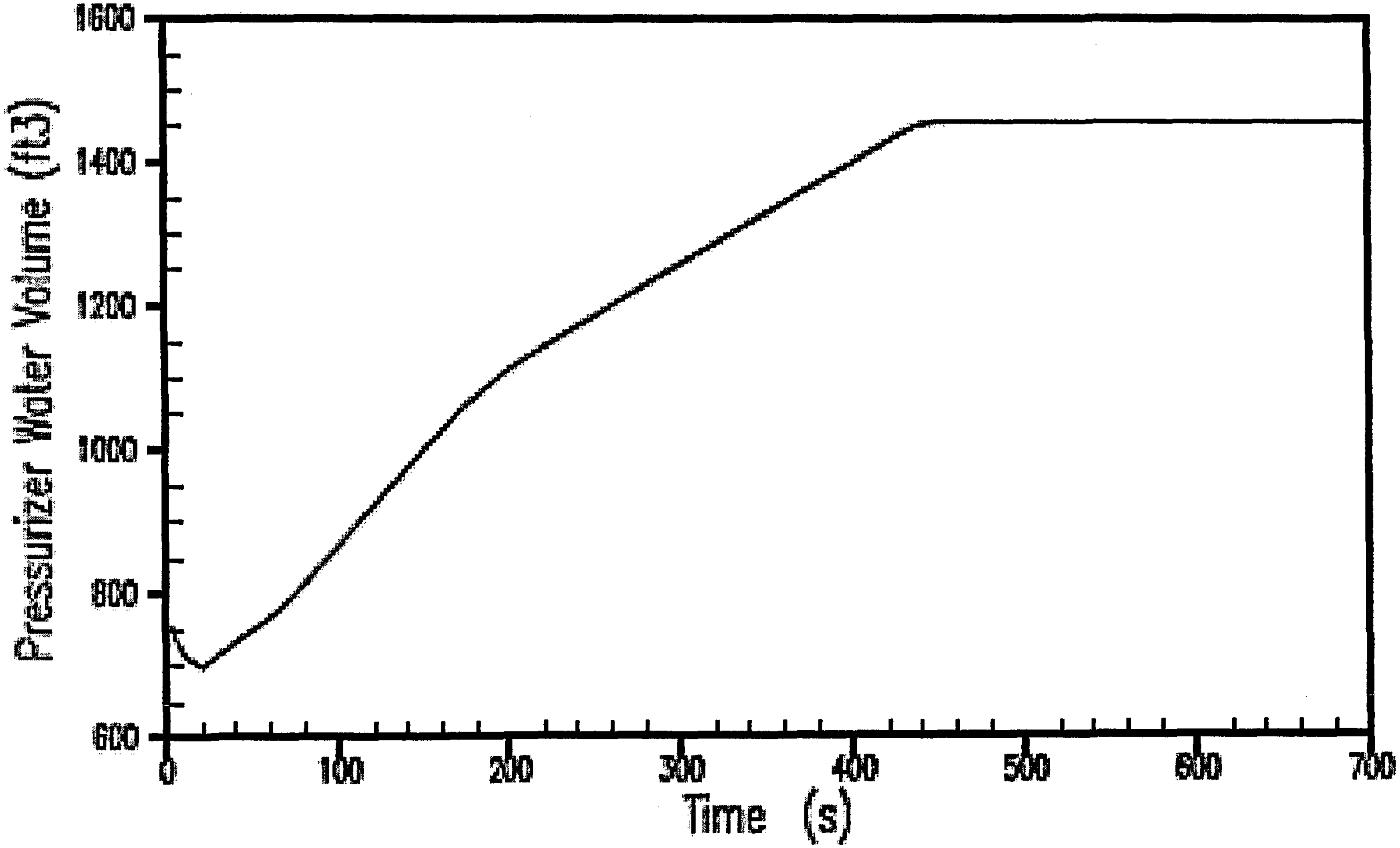
   (W-3 or WRB-1 used for outside approved range)


BEAVER VALLEY UPRATING
TT/RT From Full Power
Pressurizer Pressure vs. Time
PPrz
PRESSURE (Psia)
TIME (SECONDS)

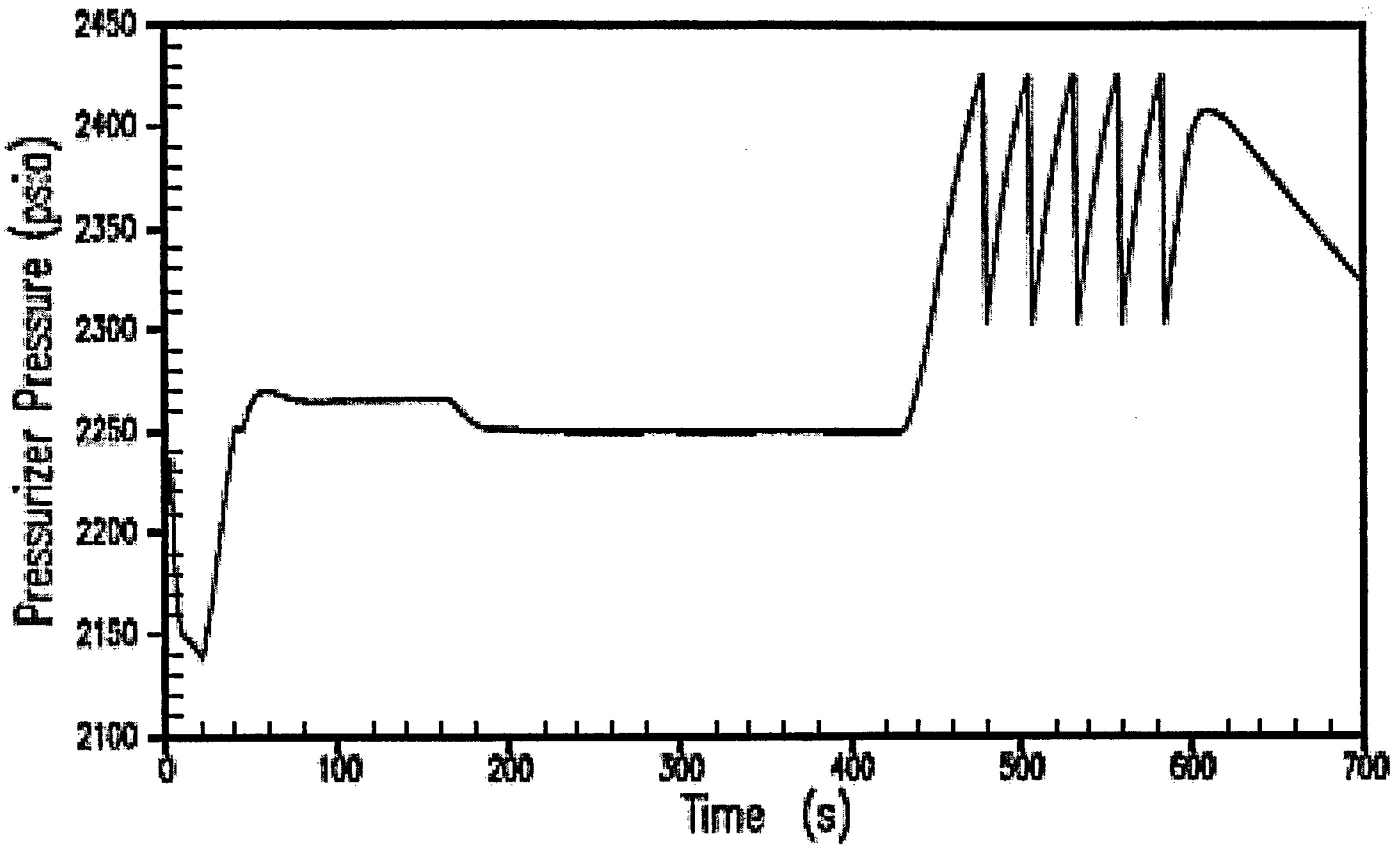
EPU


BEAVER VALLEY UPRATING
TT/RT From Full Power
Pressurizer Pressure vs. Time
PPrz
PRESSURE (Psia)
TIME (SECONDS)

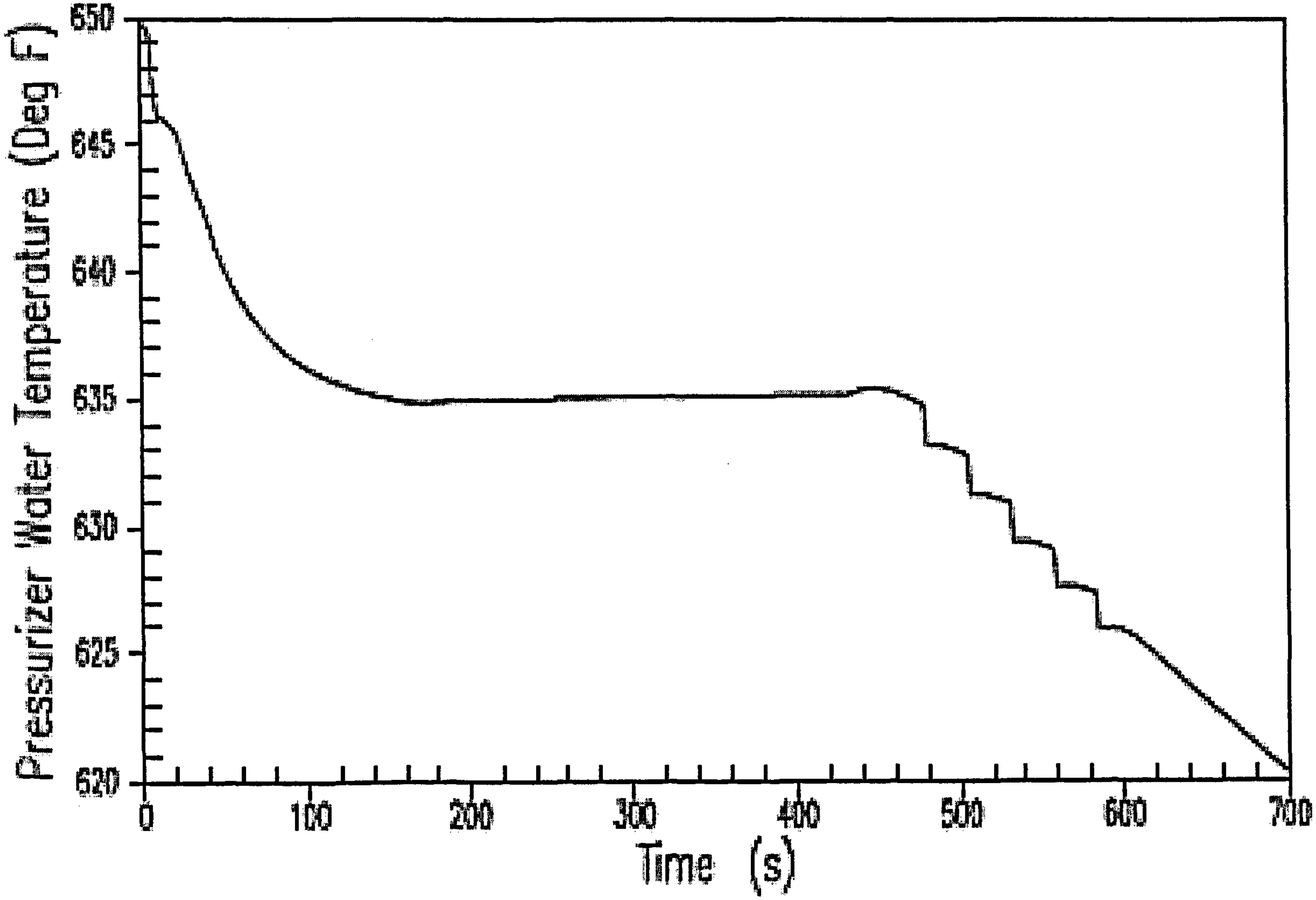
Pre-EPU



BVPS-2 Spurious SI with Pressurizer Heaters On – Pressurizer Water Volume vs. Time



BVPS-2 Spurious SI with Pressurizer Heaters On – Pressurizer Pressure vs. Time



BVPS-2 Spurious SI with Pressurizer Heaters On –Pressurizer Water Temperature vs. Time

BELOCA Methodology

The approved methodology uses a number of inputs that are set to bounding (conservative) conditions. Examples of these parameters include:

- Operating history (decay heat)
- Moderator temperature coefficient
- Hot assembly burnup
- S/G tube plugging level
- Pressurizer location (intact loop)
- Accumulator boron concentration
- Break location (cold leg)
- Offsite power (on - RCPs running)
- Safety injection flow (minimum)
- Safety injection delay (maximum)
- Containment pressure (conservative)
- Single failure (1 train ECCS)

BELOCA Methodology *(Cont.)*

- Other inputs are treated statistically as follows
- Nominal values used to establish a reference transient
- Sensitivities are developed based on specified operating range
- 95/95 PCT is established using monte-carlo sampling over desired operating range
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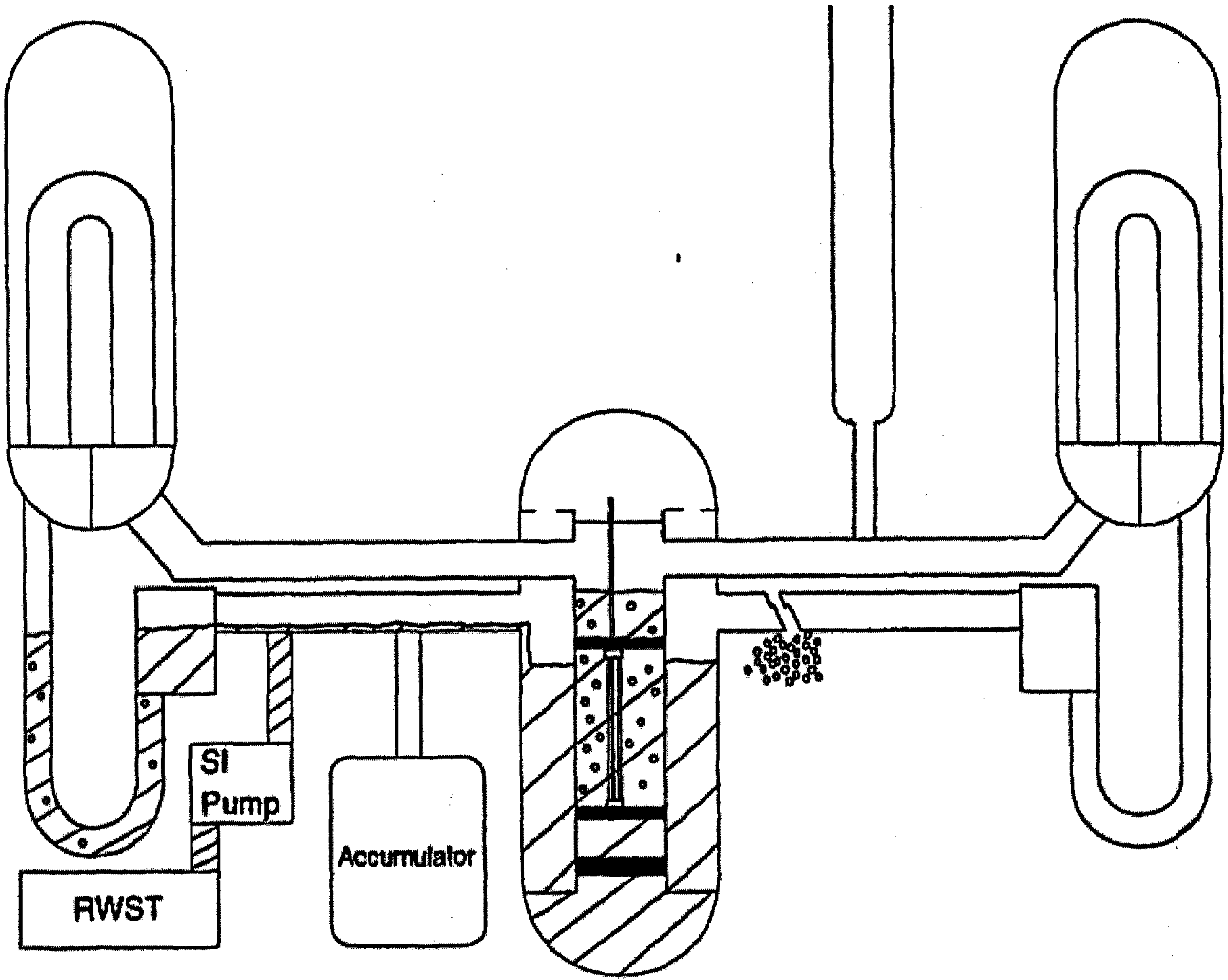
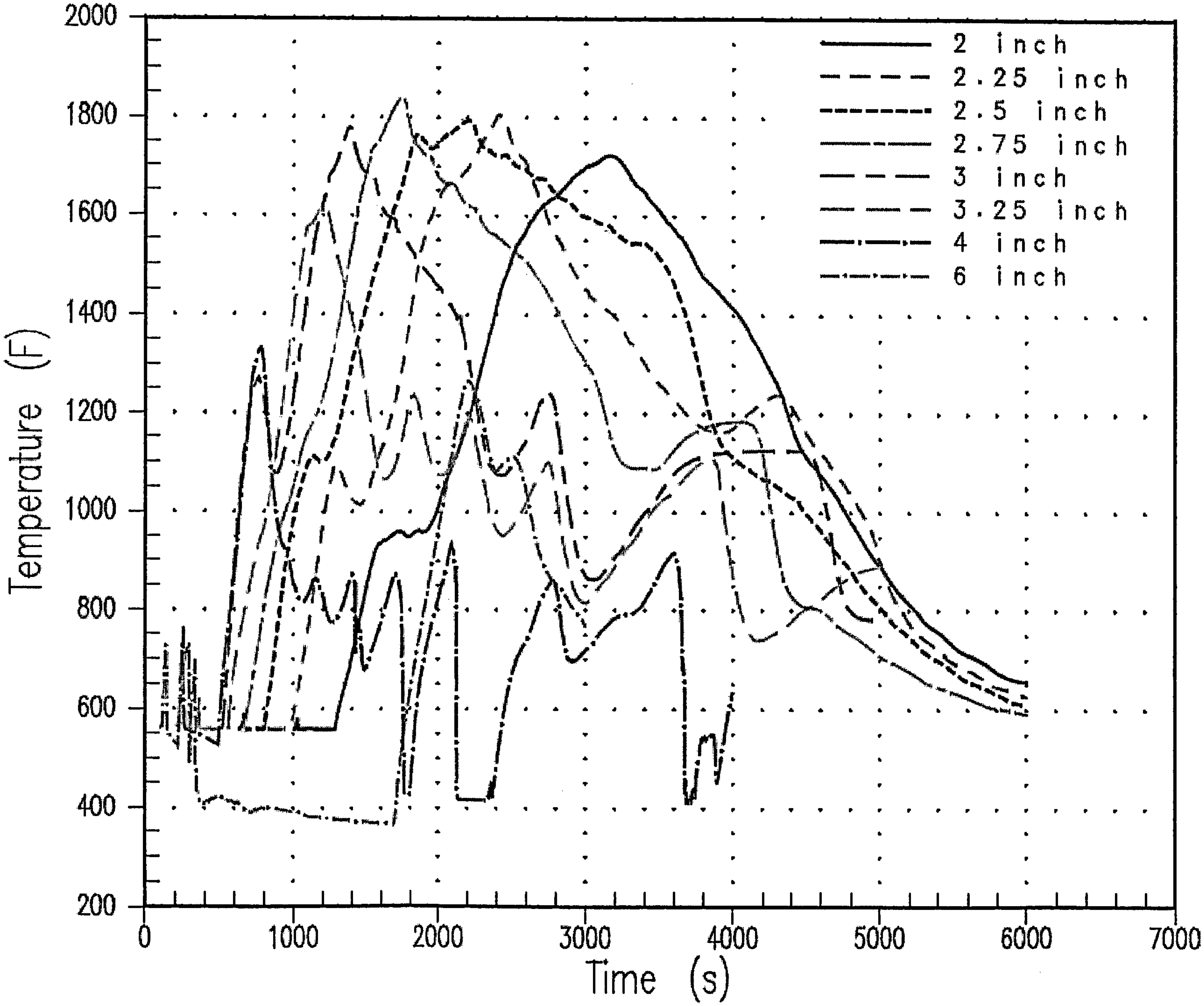
  - Power distribution bias and uncertainty
  - Initial condition bias and uncertainty
- Uncertainties are added to the reference transient PCT to establish 95th percentile PCT

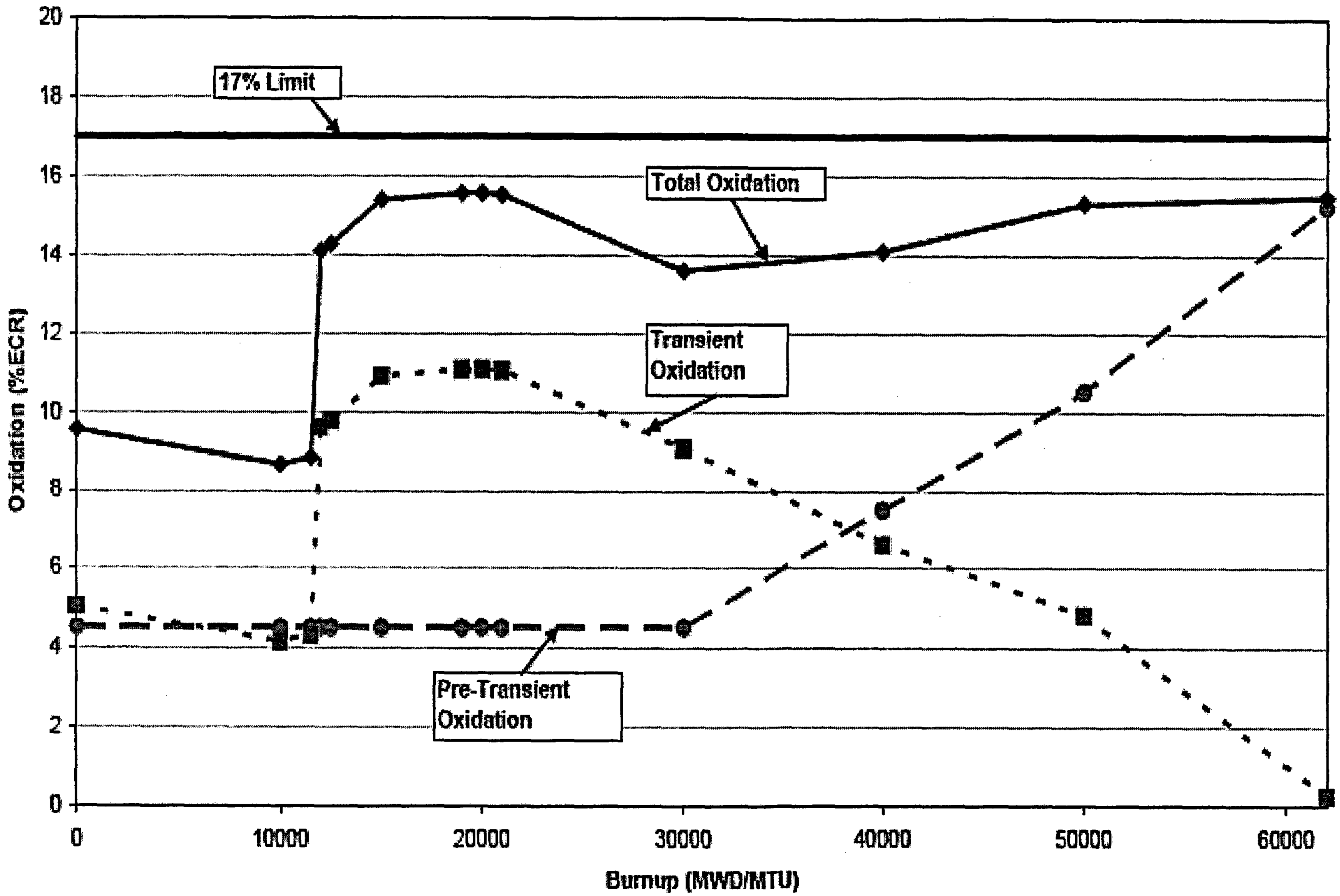
$$PCT_{95} = PCT_{REF} + \Delta PCT_{MOD} + \Delta PCT_{PD} + \Delta PCT_{IC} + \text{Superposition Correction}$$

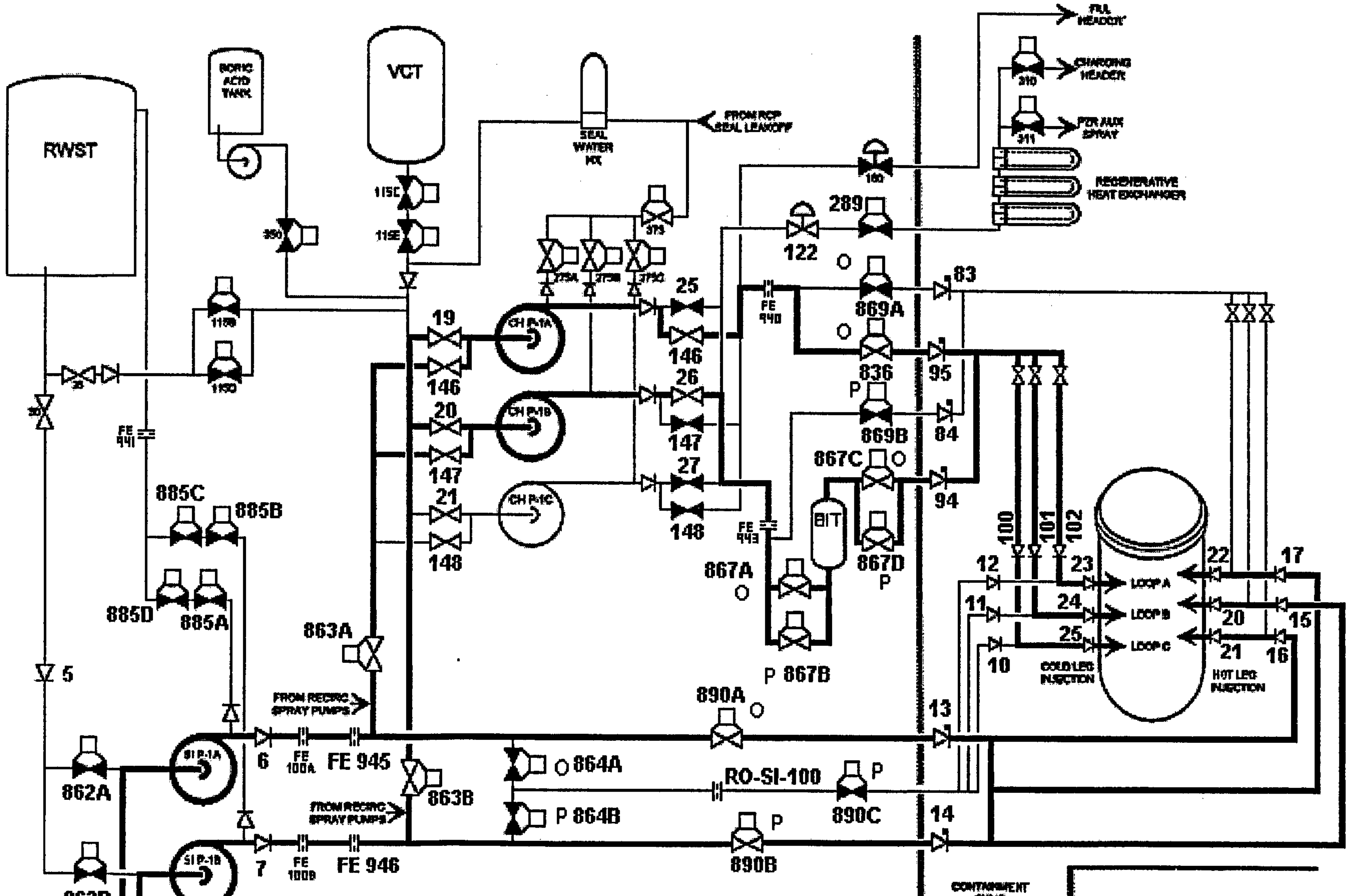

SI
Pump
Accumulator
RWST



2000
1800
1600
1400
1200
1000
800
600
400
200
Temperature (F)
0
1000
2000
3000
4000
5000
6000
7000
Time (s)
2 inch
2.25 inch
2.5 inch
2.75 inch
3 inch
3.25 inch
4 inch
6 inch

Pre-Transient, Transient and Total Oxidation vs. Burnup for Sample SBLOCA Evaluation

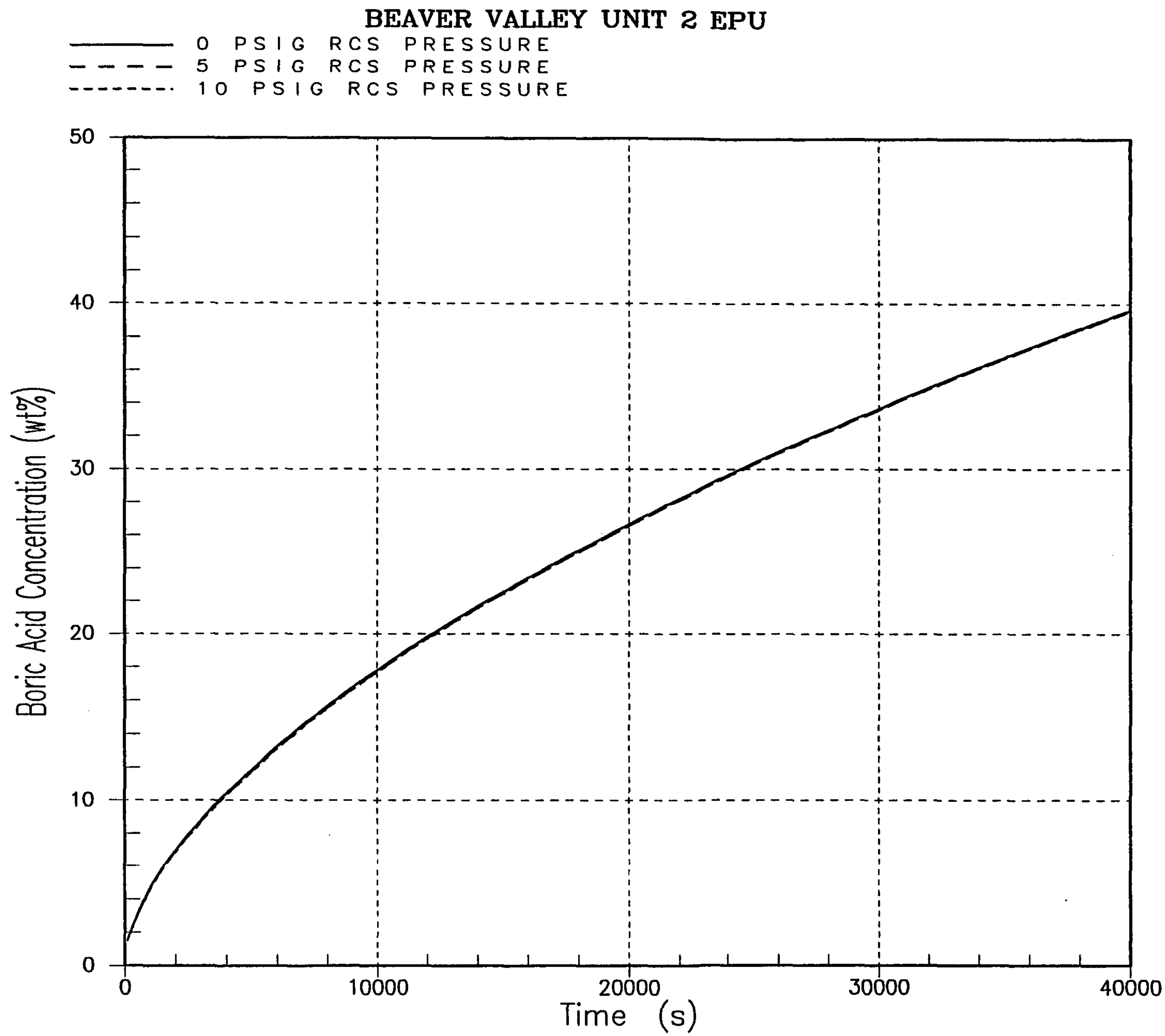


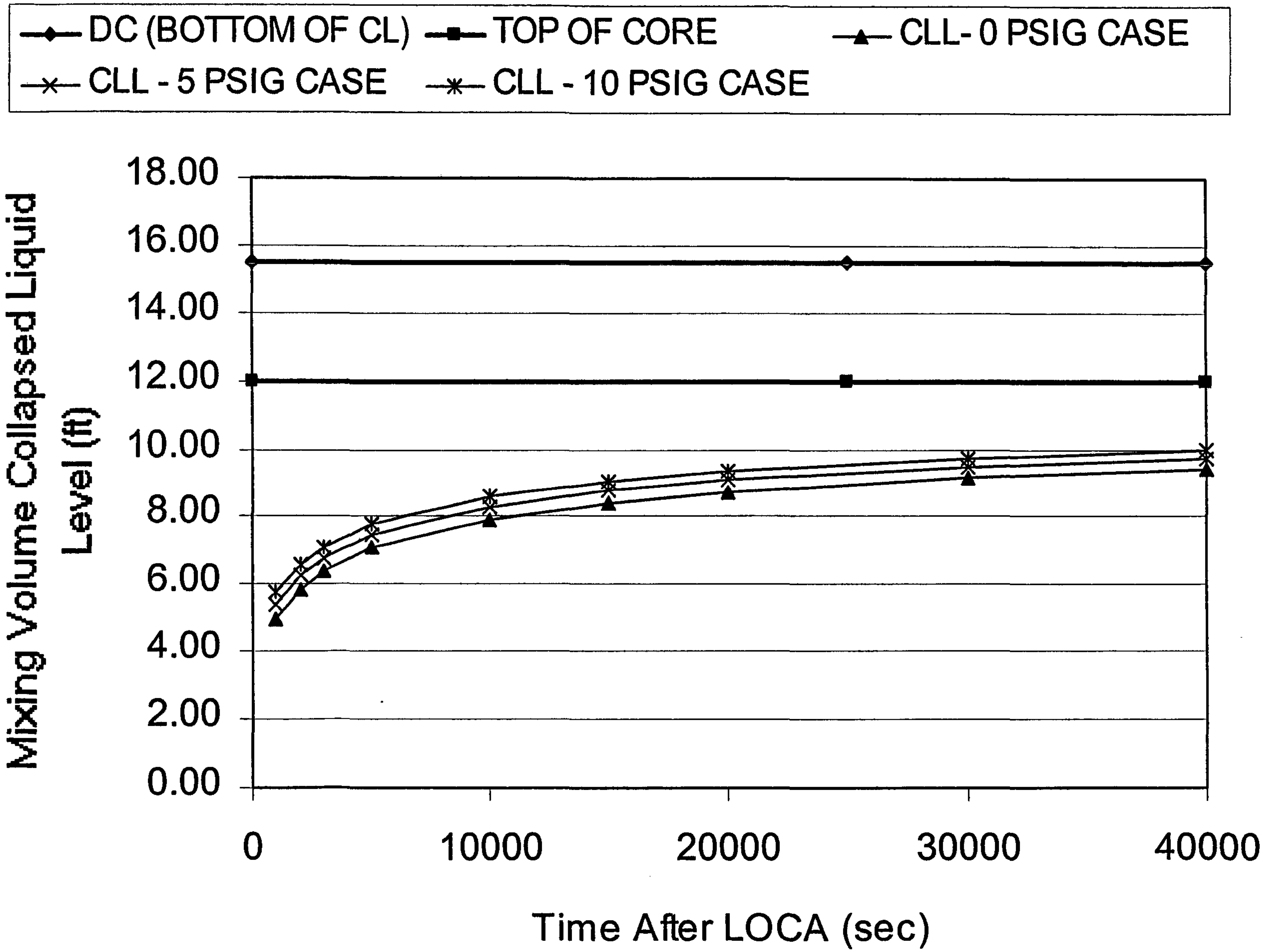


UNIT 1

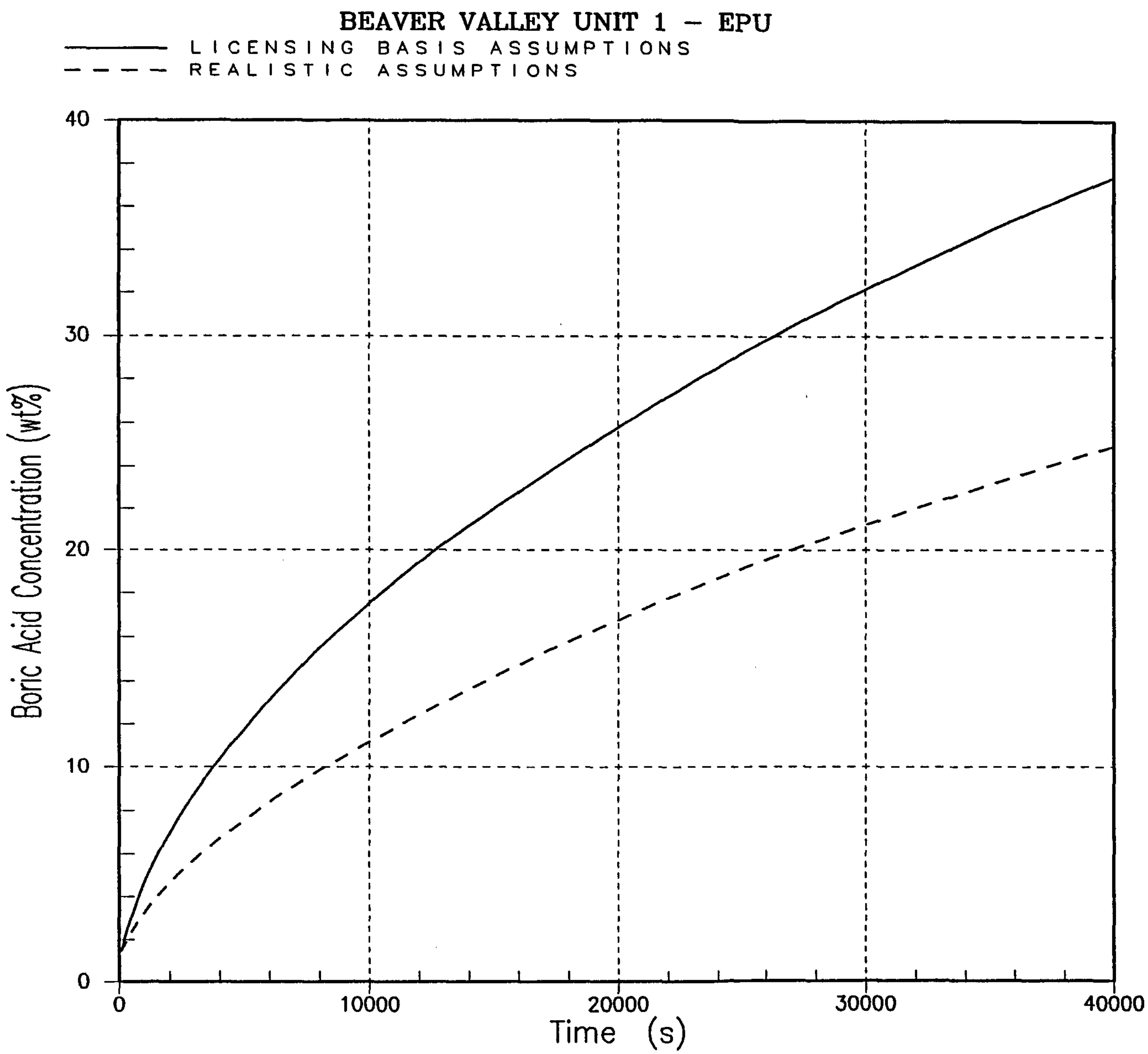
SAFETY INJECTION SYSTEM
SIMULTANEOUS HOT & COLD LEG
RECIRCULATION

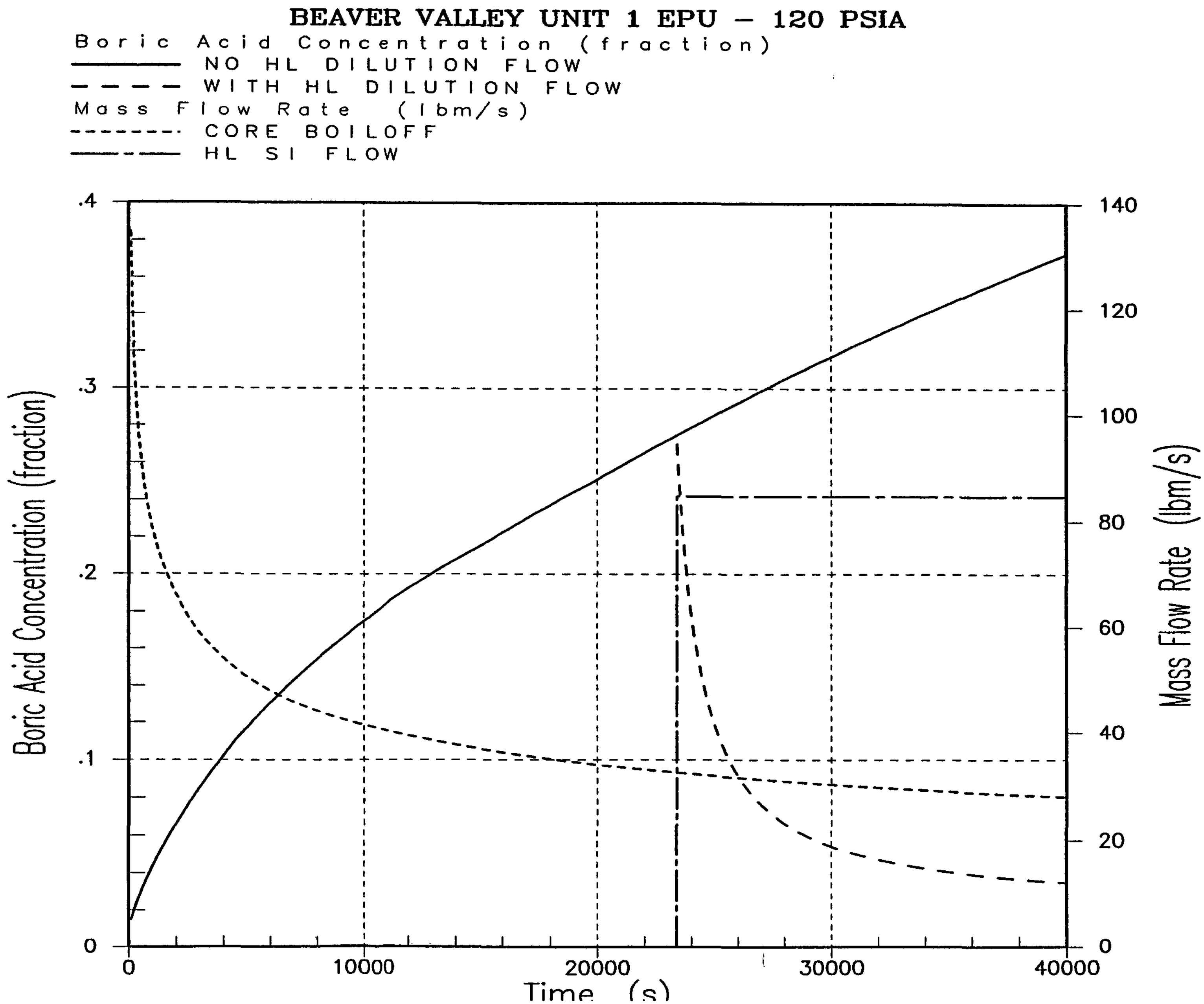
LHSI HOT LEG RECIRCULATION


BEAVER VALLEY UNIT 2 EPU
0 PSIG RCS PRESSURE
5 PSIG RCS PRESSURE
10 PSIG RCS PRESSURE
Boric Acid Concentration (wt%)
Time (s)
0
10
20
30
40
50
0
10000
20000
30000
40000

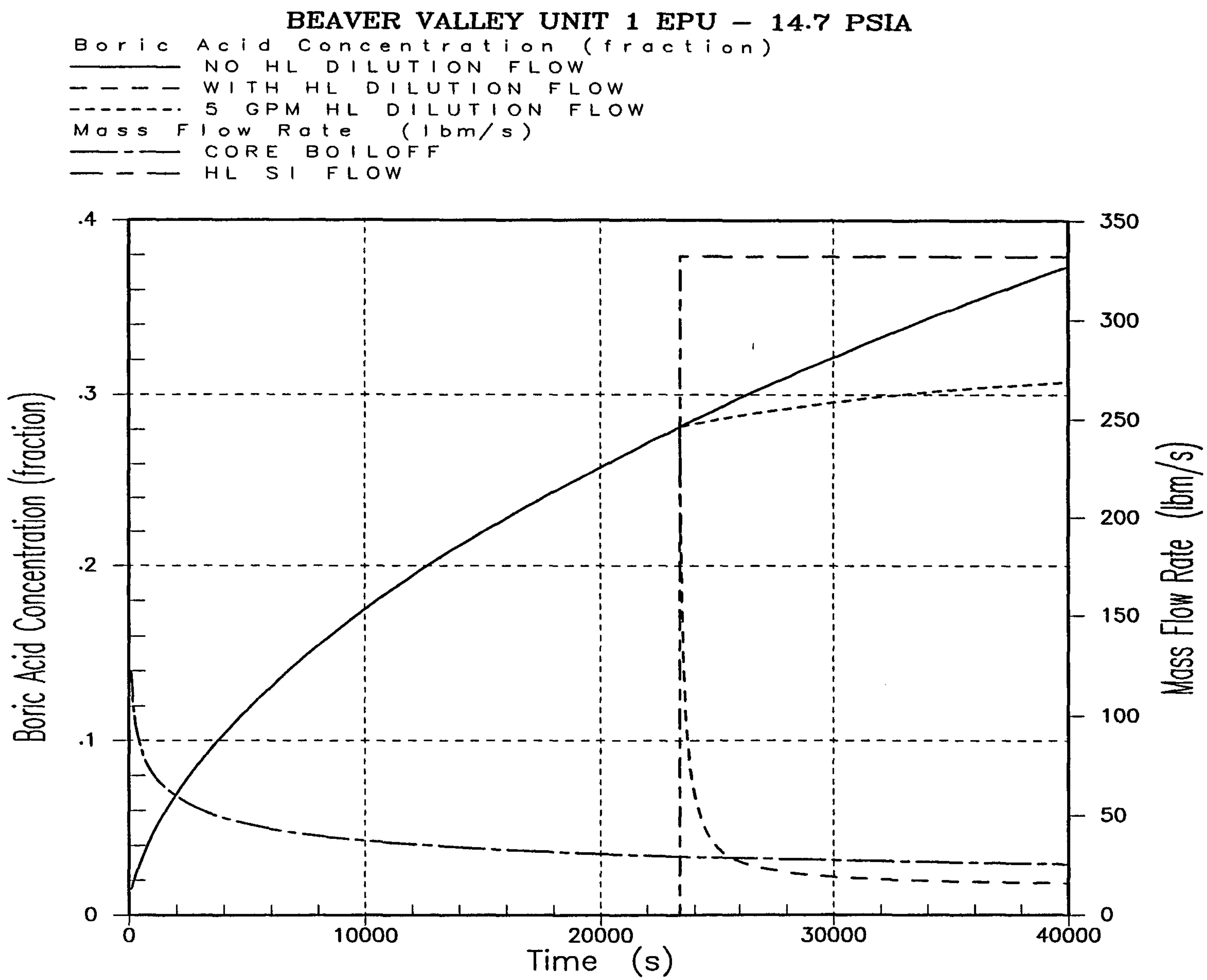


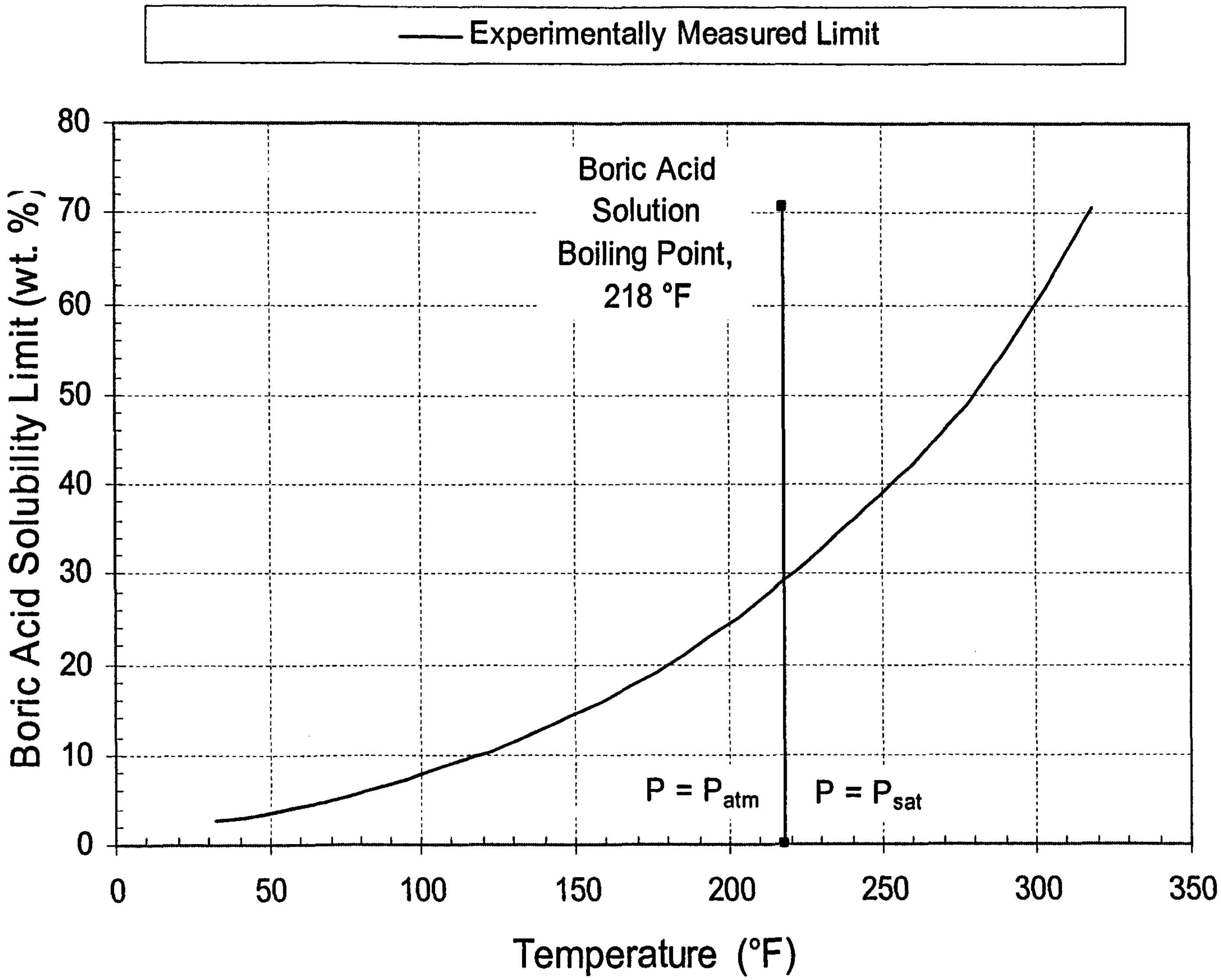
DC (BOTTOM OF CL)
TOP OF CORE
CLL- 0 PSIG CASE
CLL - 5 PSIG CASE
CLL - 10 PSIG CASE
Mixing Volume Collapsed Liquid Level (ft)
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
0
10000
20000
30000
40000
Time After LOCA (sec)


BEAVER VALLEY UNIT 1 – EPU
LICENSING BASIS ASSUMPTIONS
REALISTIC ASSUMPTIONS
Boric Acid Concentration (wt%)
0
10
20
30
40
0
10000
20000
30000
40000
Time (s)



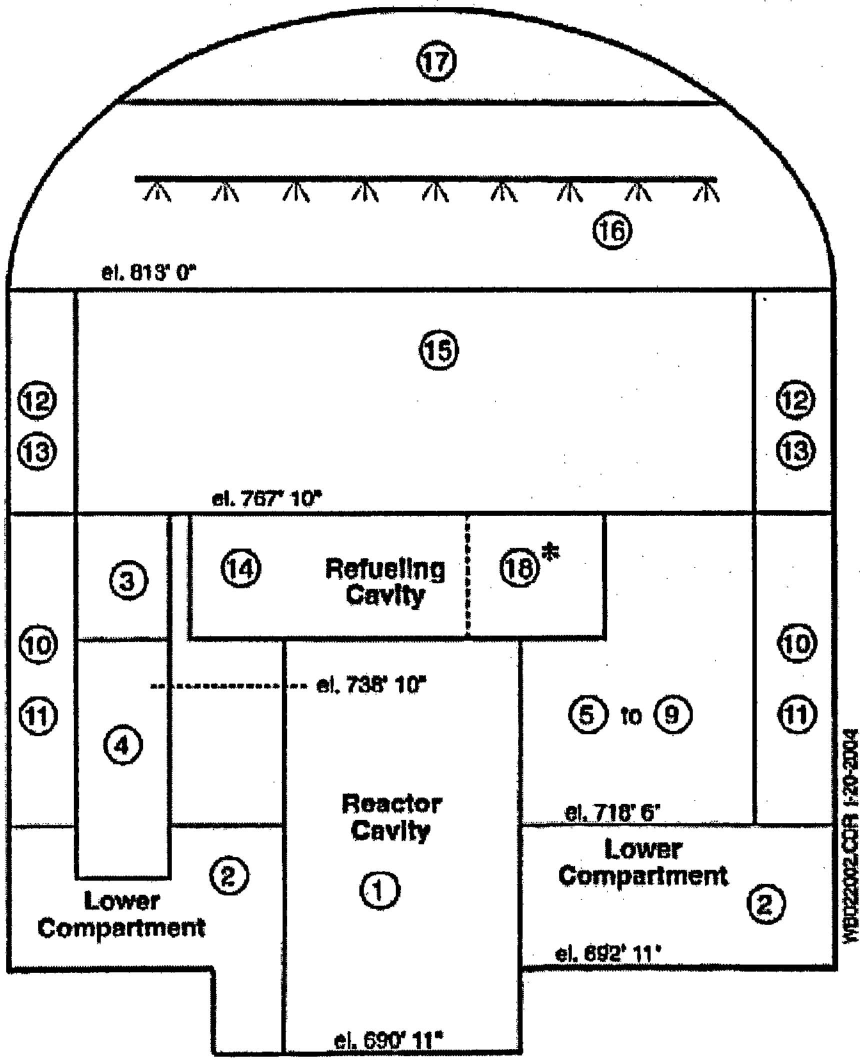
BEAVER VALLEY UNIT 1 EPU – 120 PSIA
Boric Acid Concentration (fraction)
NO HL DILUTION FLOW
WITH HL DILUTION FLOW
Mass Flow Rate (lbm/s)
CORE BOILOFF
HL SI FLOW
Boric Acid Concentration (fraction)
Mass Flow Rate (lbm/s)
Time (s)
0
.1
.2
.3
.4
0
20
40
60
80
100
120
140
0
10000
20000
30000
40000


BEAVER VALLEY UNIT 1 EPU – 14.7 PSIA
Boric Acid Concentration (fraction)
NO HL DILUTION FLOW
WITH HL DILUTION FLOW
5 GPM HL DILUTION FLOW
Mass Flow Rate (lbm/s)
CORE BOILOFF
HL SI FLOW
Boric Acid Concentration (fraction)
Mass Flow Rate (lbm/s)
Time (s)
0
.1
.2
.3
.4
0
50
100
150
200
250
300
350
0
10000
20000
30000
40000

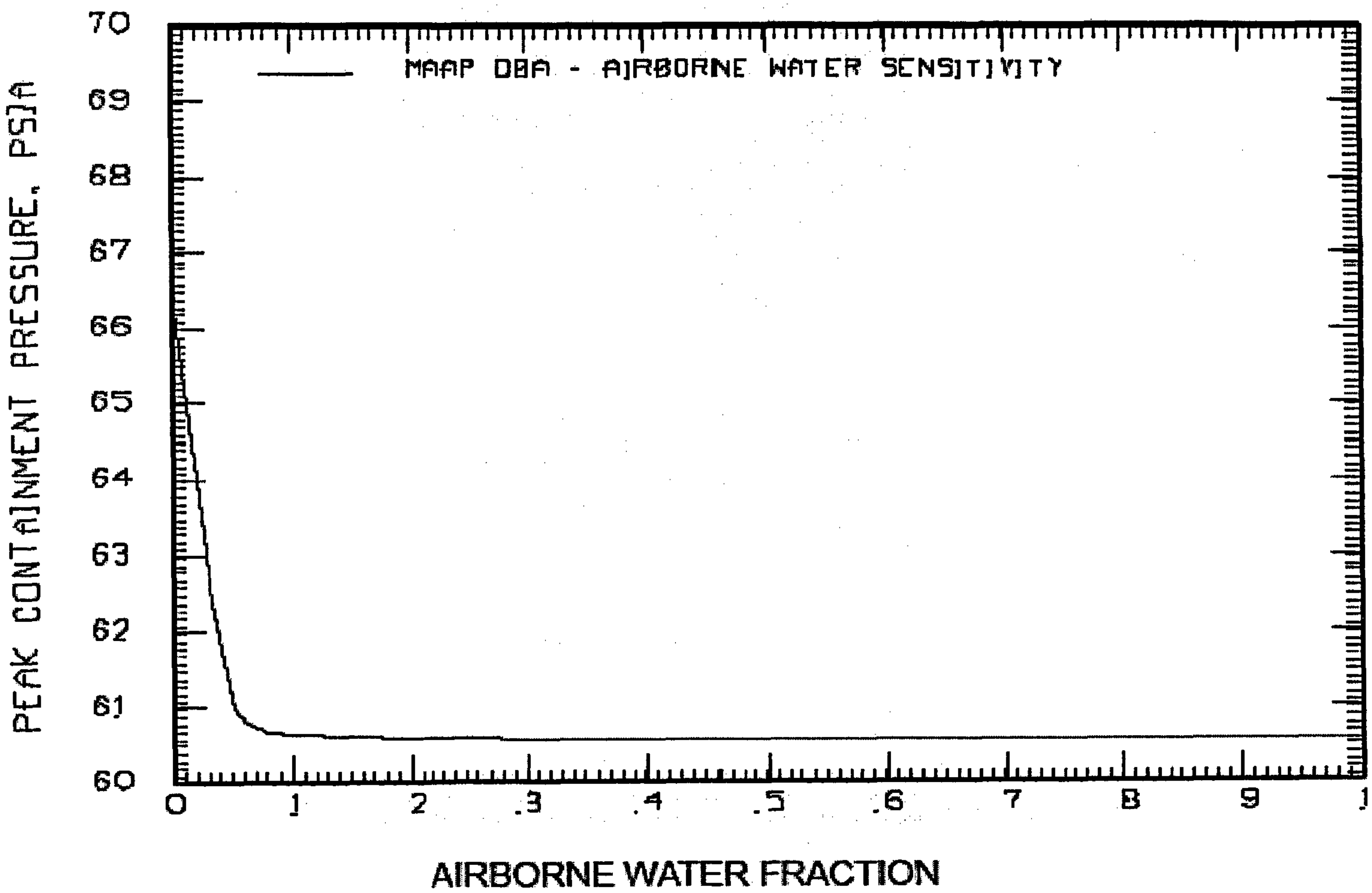


Boric Acid Solubility Limit vs. Temperature [Cohen, 1969]

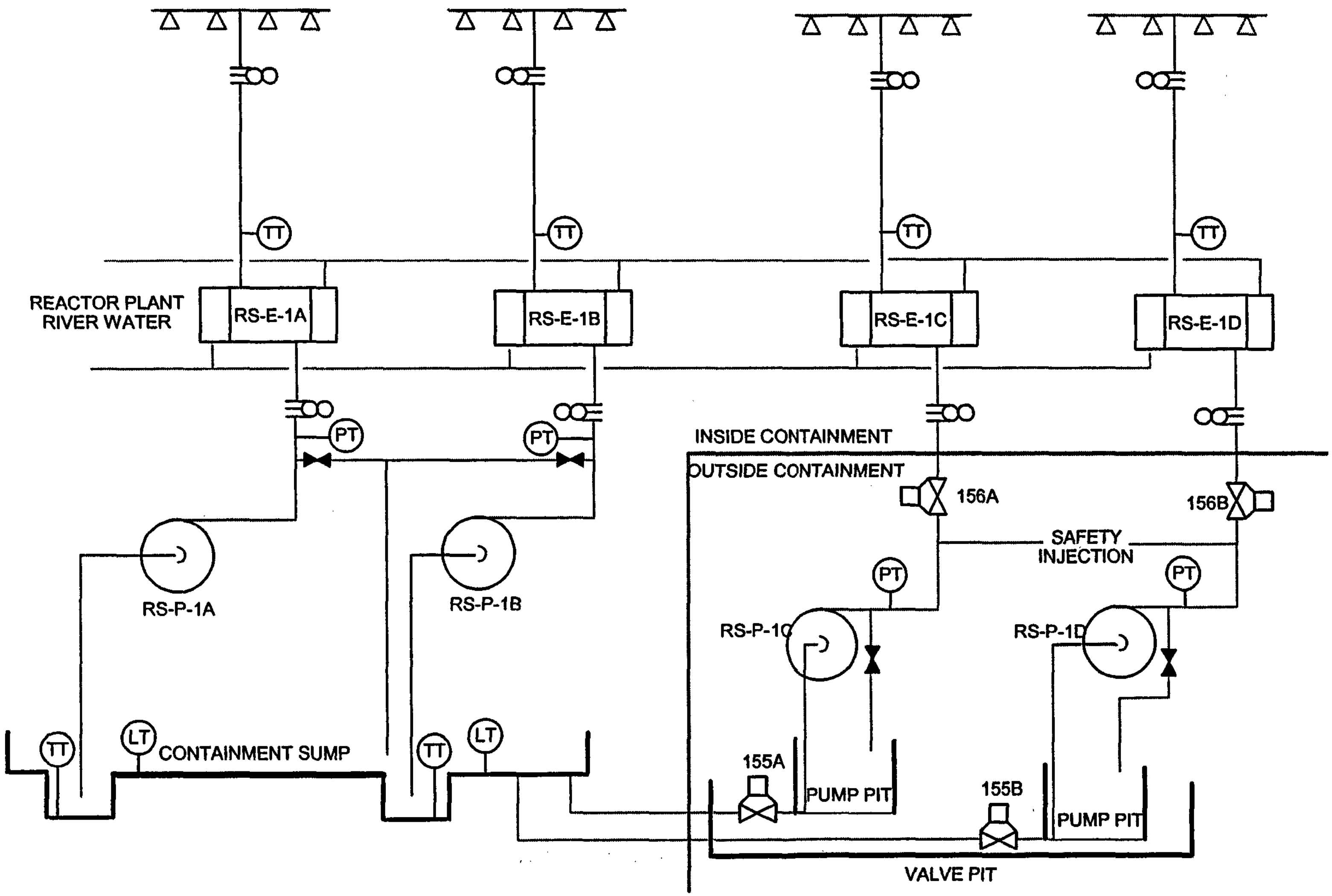
BVPS Multi-Node Containment Model



Sensitivity of Containment Pressure to LOCA Airborne Water Fraction



RECIRCULATION SPRAY SYSTEM



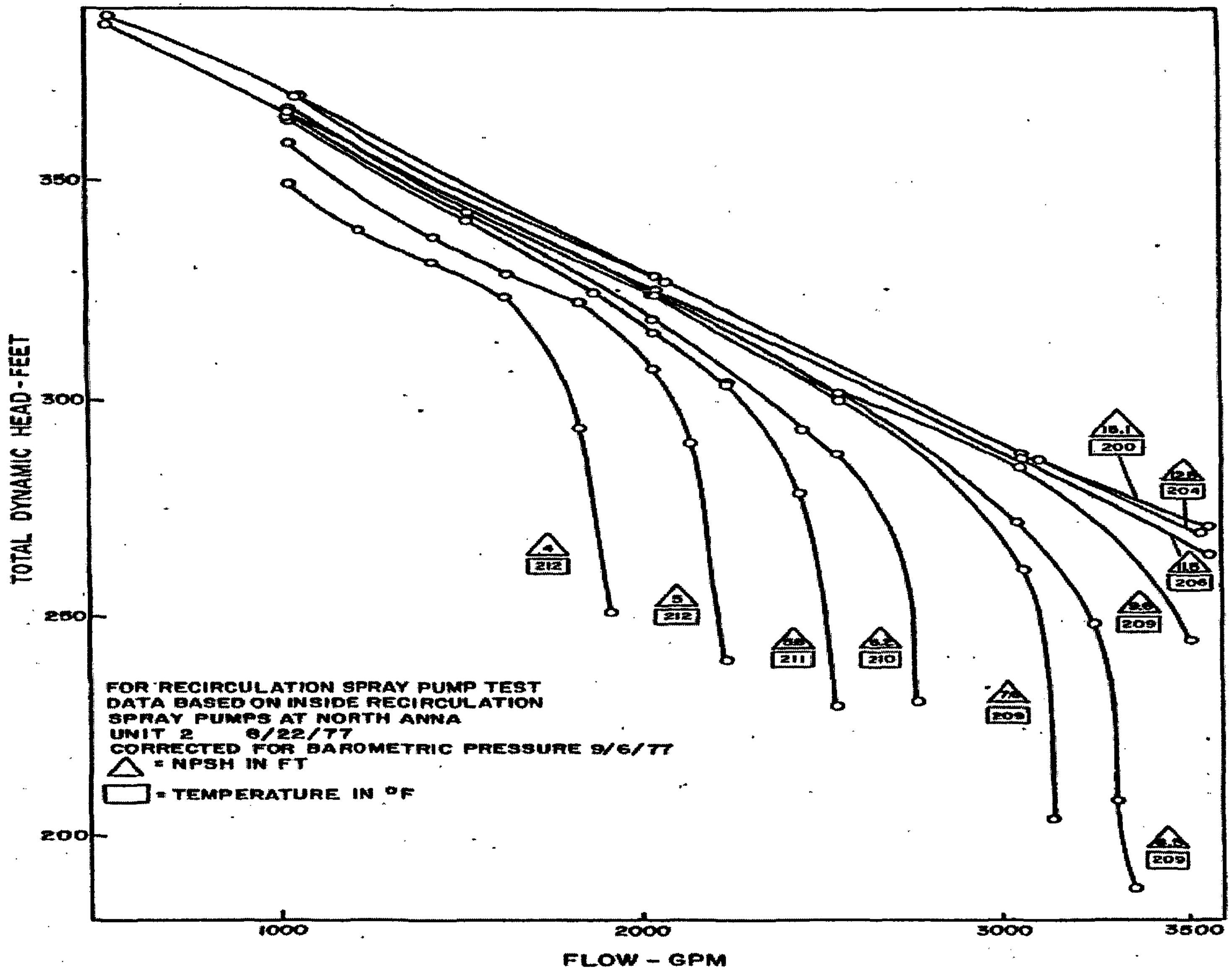
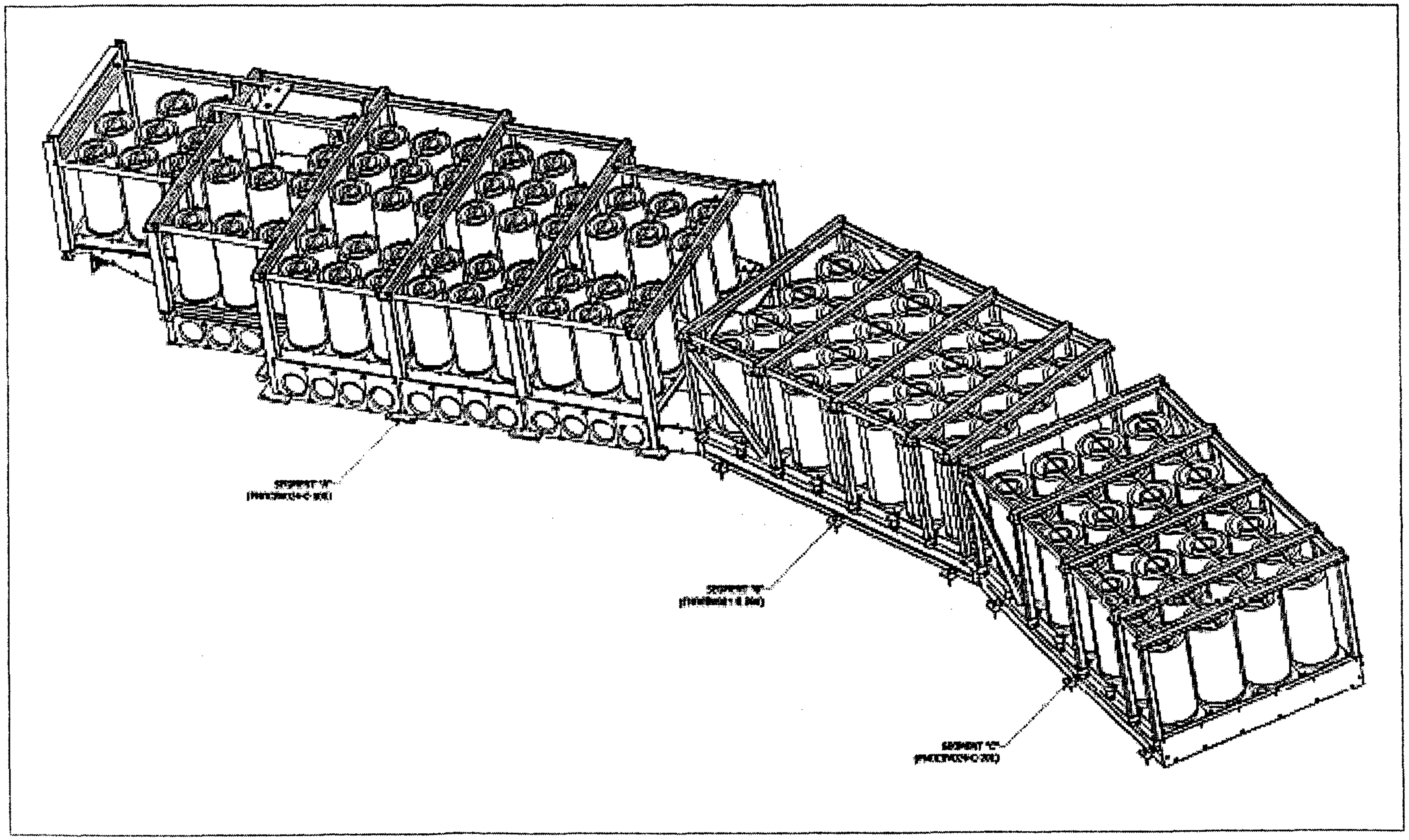


FIGURE 2.3-1
TOTAL DYNAMIC HEAD vs FLOW RATE FOR
RS PUMP TEST, NORTH ANNA 8/22/77
BEAVER VALLEY UNIT 1
DUQUESNE LIGHT CO.

Containment Sump Upgrades

- **Walkdowns of Unit 1 & Unit 2 Containments completed during refueling outages**
- **Re-analysis using NEI methodology ongoing**
- **Plant-specific debris head loss prototype testing in progress**
- **Plan to replace existing sump screens (about 120 sq. ft.) with much larger (more than 3,000 sq. ft.) strainers during next outages**
  - Unit 2, fall 2006
  - Unit 1, spring 2007
- **Planned sump screen upgrades will provide increased physical safety margin**

Containment Sump Upgrades



BV-2 Steam Plugging Summary

Mechanism	# tubes plugged
ODSCC	225
PWSCC – Support Plate PWSCC - U-Bend	2 21
TSP – Volumetric	30
AVB Wear	4
FIV – Pre-Uprate / Uprate	4 / 6
Free Span	88
Admin. (other)	59

SG Stress Corrosion Cracking Unit 2

- Upper bound T-hot of 611°F is within range of currently operating Model 51 (original) SGs
- Shotpeening of hot leg tube/tubesheet region and Row 1 and 2 U-bend heat treatment prior to operation has effectively limited PWSCC development
  - 2 tubes to date with reported PWSCC at top of tubesheet expansion transition
  - No incidence of U-bend PWSCC

SG Stress Corrosion Cracking Unit 2

- Another plant with Model D4 SGs (A-600 MA tubing, full depth roll expansion) performed shotpeening and U-bend heat treatment prior to operation
  - No incidence of Row 1, 2 U-bend PWSCC
  - Limited (<10) number of tubes with PWSCC at expansion transition
  - T-hot = 620°F
  - 13.2 EFPY at last inspection

SG Stress Corrosion Cracking Unit 2

- T-hot increase to 611°F from 608°F should increase ODSCC growth rates by about 7%, initiation rate by 9%
- BVPS Unit 2 ODSCC growth rates are low; number of affected tubes per outage is low for SGs of similar accumulated EFPY and tubing material.
  - Circumferential ODSCC PDA (Percent Degraded Area) growth of 10% at 95% probability
  - Growth rate should be <11% at 611°F
  - Circumferential SCC structural limit is approximately 73%

SG Stress Corrosion Cracking Unit 2

- Number of affected tubes with ODSCC at top of tubesheet is small
- Peak ODSCC +Pt coil amplitude of about 0.5V (all data) is well below in situ screening leakage threshold of 1V for axial ODSCC, 1.25V for circumferential ODSCC
- From 2R04 through 2R11;
  - 70 tubes with axial ODSCC
  - 116 tubes with circumferential ODSCC

SG Stress Corrosion Cracking Unit 2

- Extremely low incidence of axial ODSCC at tube support plate intersections
- From 2R08 though 2R11: 10 tubes confirmed with axial ODSCC at TSP intersections and plugged
- If GL 95-05 were implemented, none of these would have required plugging (<2V signal amplitude)
- TSP ODSCC average voltage growth rate <0.1V per cycle

SG Stress Corrosion Cracking Unit 2

- Row 3 to 10 Oblique PWSCC (first observed at Diablo Canyon in 2003)
- 100% Row 3 through 10 U-bends inspected with +Pt coil at 2R10; no degradation detected
- 20% sampling Row 3 through 10 at 2R11; no degradation detected
- Mechanism is highly stress dependent resulting in limited flawed arc lengths, typically <60 degrees arc
- T-hot of 611°F judged to have minimal impact based on observed history to date

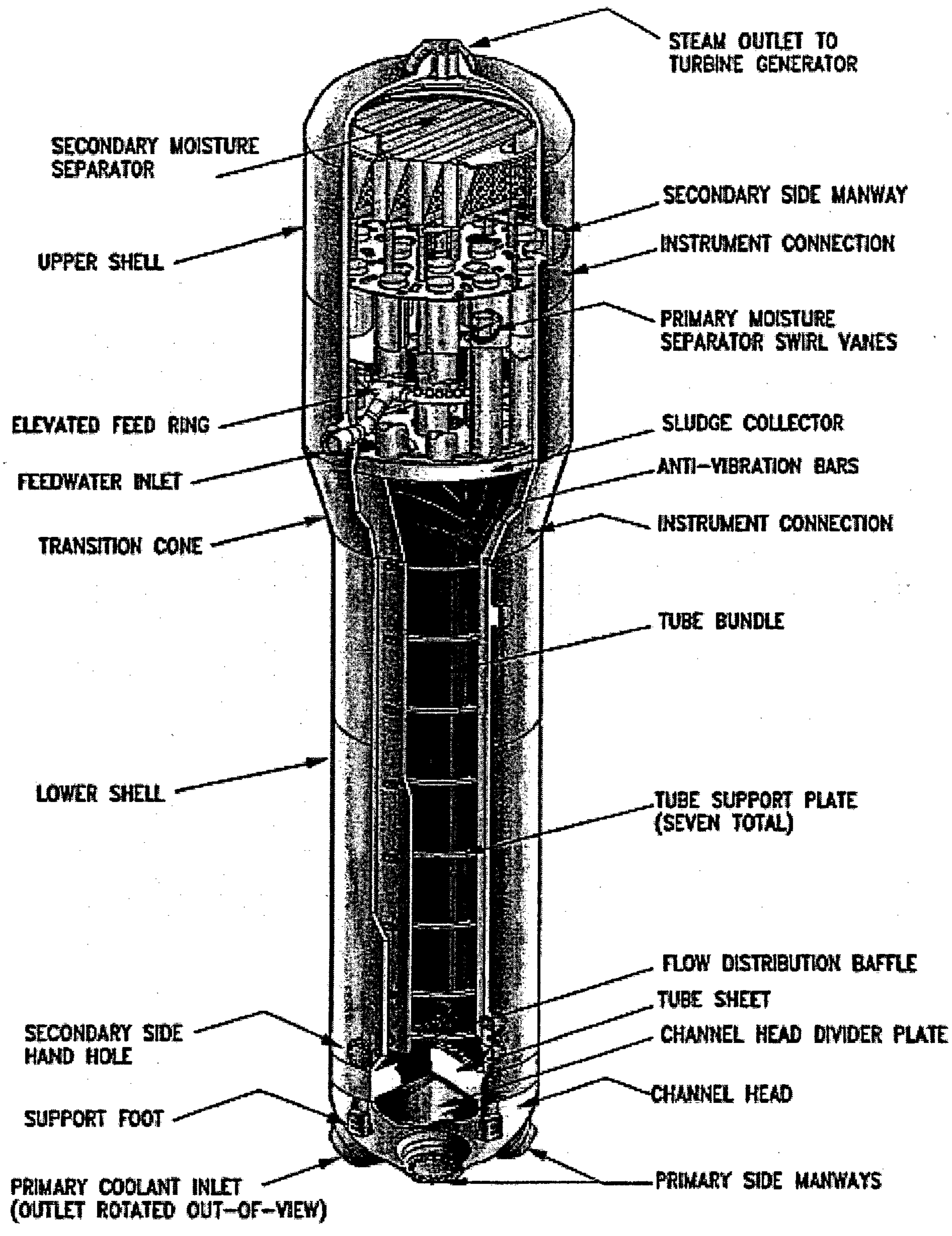


Figure 4.7-1
BVPS-1 Replacement Steam Generator

S/G Comparison

Plant	NSSS Power Level (MWt)	# of Loops	# of Steam Separators	S/G Model
BVPS-1 BVPS-2	2910 * 2910 *	3 3	1-tier 2-tier	54F 51M
Farley 1&2	2785	3	1-tier	54F
ASCO 1&2	2952	3	2-tier	D3
North Anna 1&2	2905	3	2-tier	54F -lower 51-upper
Shearon Harris	2912	3	1-tier	Delta 75
Vandellos 2	2954	3	2-tier	F
V.C. Summer	2912	3	1-tier	Delta 75

* Proposed

RHR / CCW System Heat Loads

Case	# of trains	Final RCS temp.	BV-1 (time)	BV-2 (time)
Normal cooldown	2	140 F	34 hrs.	51 hrs.
Single train cooldown	1	200 F	NA	57.9 hrs.
UFSAR App. 5A (natural circulation)	Aux. FW / SG PORVs to cut-in 2 RHR trains	200 F	NA	43 hrs.
Appendix R cooldown	See note	200 F	< 127 hrs.	< 72 hrs.

Note: 2 trains credited for BVPS-2. RHR not credited for BVPS-1.

Auxiliary Feedwater

Condition	Flow	BV1 pre-EPU	BV1 post - EPU	BV2 pre-EPU	BV2 post-EPU
Feed Line Break (FLB)	# pumps	1 /3	2/3	2/3	2/ 3
	Flow (gpm)	300	250 / 400	250 / 400	250 / 400
Loss Normal Feed (LONF)	# pumps	1/3	2/3	2/3	2/3
	Flow (gpm)	350	489	300	489

Mechanical Impacts – Flow Accelerated Corrosion

System	Description	Component ID	Component Geometry	Pipe Class	CHECWORKS Current Wear-Rate 100% Power (mils/year)	CHECWORKS Wear-Rate 110% (EPU) Power (mils/year)
		Significant Velocity Change				
BVPS-1: Heater Drain	4th Point Heater Drain Line	1-W4D-01-13T (Br) 1-W4D-01-14E 1-W4D-01-14EP 1-W4D-01-13TP 1-W4D-01-16N	Tee Elbow Pipe Pipe Nozzle	151	1.489 1.620 1.094 0.876 0.820	2.050 1.820 1.216 1.154 1.055
BVPS-2: Heater Drain	4th Point Heater Drain Line	2HDL-008-08-1R(S/E) 2HDL-006-58-1P 2HDL-008-11-1R(L/E) 2HDP-008-08-5N 2HDP-008-11-5N	Reducer Pipe Reducer Nozzle Nozzle	601	2.079 1.646 1.435 0.899 0.899	2.412 1.918 1.683 1.103 1.103

Probabilistic Risk Assessment

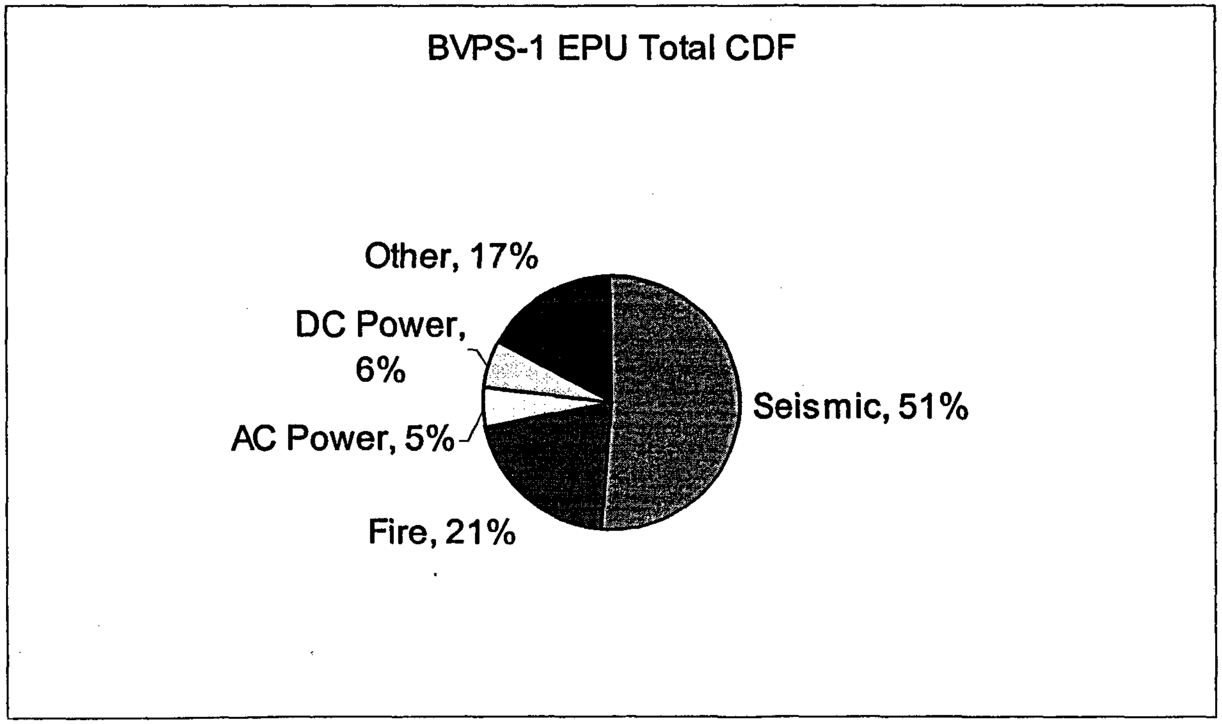
BVPS-1 Post-EPU Operator Actions with Short Time Available			
Description	**Total Time Available**	**Cue Time**	**Action Time**
Operator depressurizes the RCS via ASDVs	2.68 hours	30 minutes	9 minutes
Operator depressurizes the RCS via ASDVs given HHSI failed and AC Orange failed	72 minutes	20 minutes	9 minutes
Operators initiate bleed and feed operation	42 minutes	10.4 minutes	4 minutes
Same as OPROB1 except the operators fail to restore MFW and the dedicated AFW.	29 minutes	8.5 minutes	7 minutes
Operator manually starts and aligns auxiliary river water pumps.	13 minutes	2 minutes	3 minutes
Operator manually stops the EDG and aligns the diesel-driven fire pump.	1 hour	2 minutes	15 minutes

Probabilistic Risk Assessment

BVPS-2 Post-EPU Operator Actions with Short Time Available			
Description	Total Time Available	Cue Time	Action Time
Operator depressurizes the RCS via ASDVs (small LOCA and HHSI has failed).	72 minutes	20 minutes	2 minutes
Operator depressurizes the RCS via ASDVs, given HHSI failure and loss of emergency AC Orange.	72 minutes	20 minutes	9 minutes
Operators initiate bleed and feed operation	64 minutes	28.3 minutes	4 minutes
Same as OPROB1 except that the actions take place after the operators fail to restore MFW and the dedicated AFW.	35 minutes	18.4 minutes	7 minutes
Operator manually stops the EDG and racks the spare service water (SWS) pump onto the bus.	1 hour	2 minutes	13 minutes
Operator aligns the diesel-driven fire pump with offsite power available.	1 hour	2 minutes	15 minutes

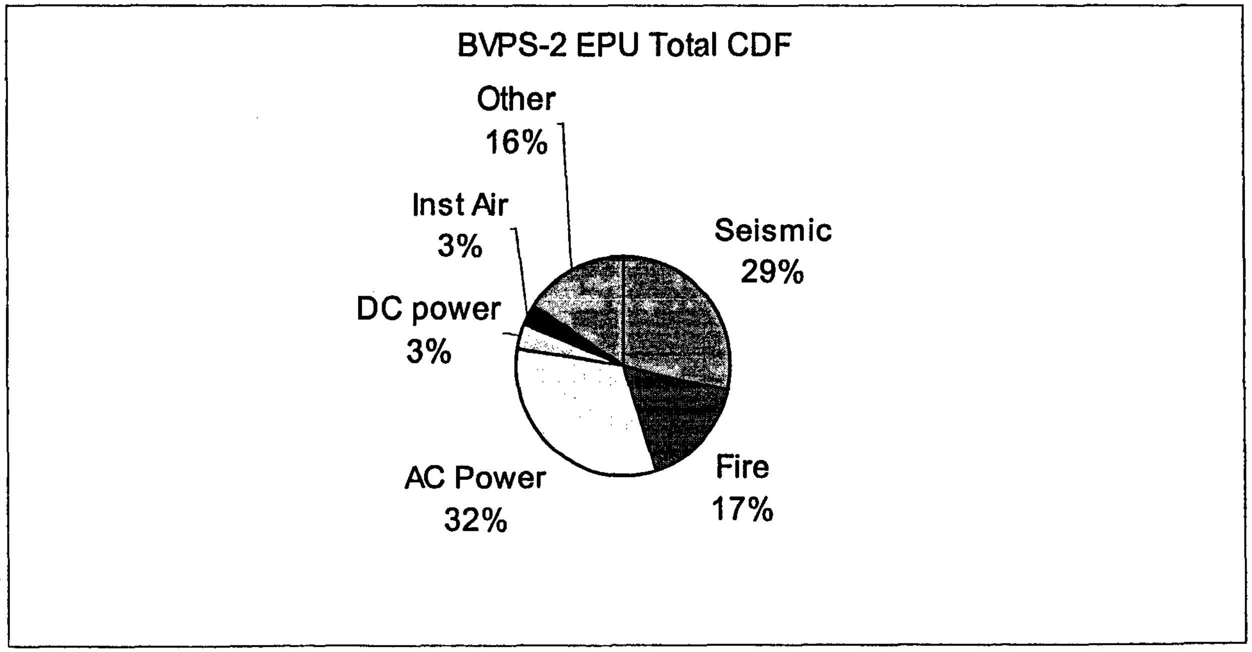
Probabilistic Risk Assessment

- **EPU Sequence Contribution to CDF (BVPS-1)**
  - **Contributors are consistent with Pre-EPU model**



Probabilistic Risk Assessment

- **EPU Sequence Contribution to CDF (BVPS-2)**
  - **Contributors are consistent with Pre-EPU model**



Examples Of Normal Operating Procedure Parameter Changes

- Control Room Logs including:
  - Containment pressure & temperature
  - Accumulator level & pressure
  - RWST temperature
  - S/G steam pressure
  - Pressurizer level
- Operator Tour Logs (BOP parameters)

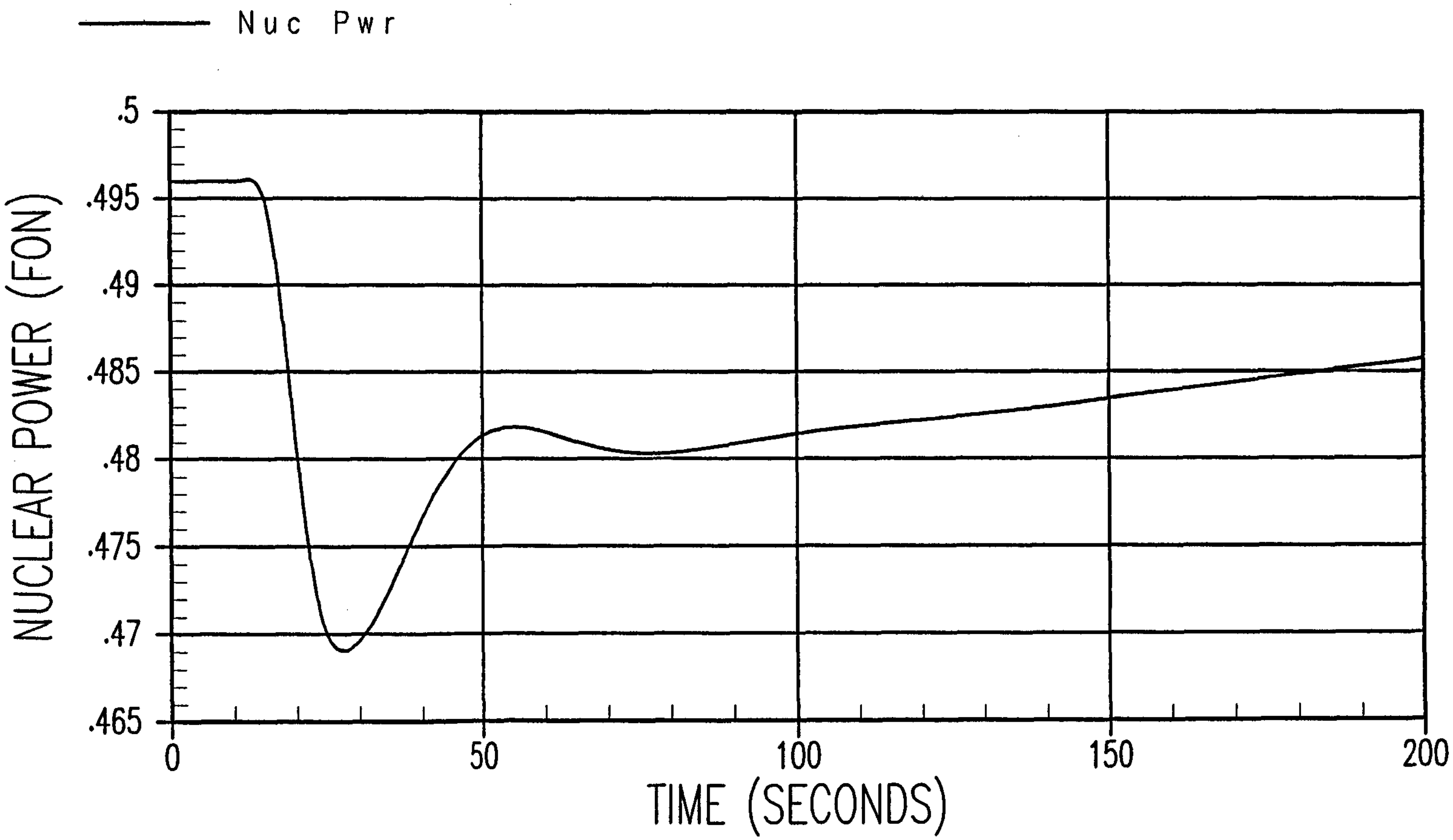
Examples of EOP Setpoint Changes

- Minimum AFW flow
- S/G Levels (BVPS-1 RSGs)
- Minimum SI flows (core boil-off)
- ECCS Switchover to Hot Leg Recirculation
- RWST Switchover (sump recirculation)
- Containment Actuation (Hi, Hi-2, Hi-3)
- RCS temperature & S/G pressure to preclude accumulator N2 injection

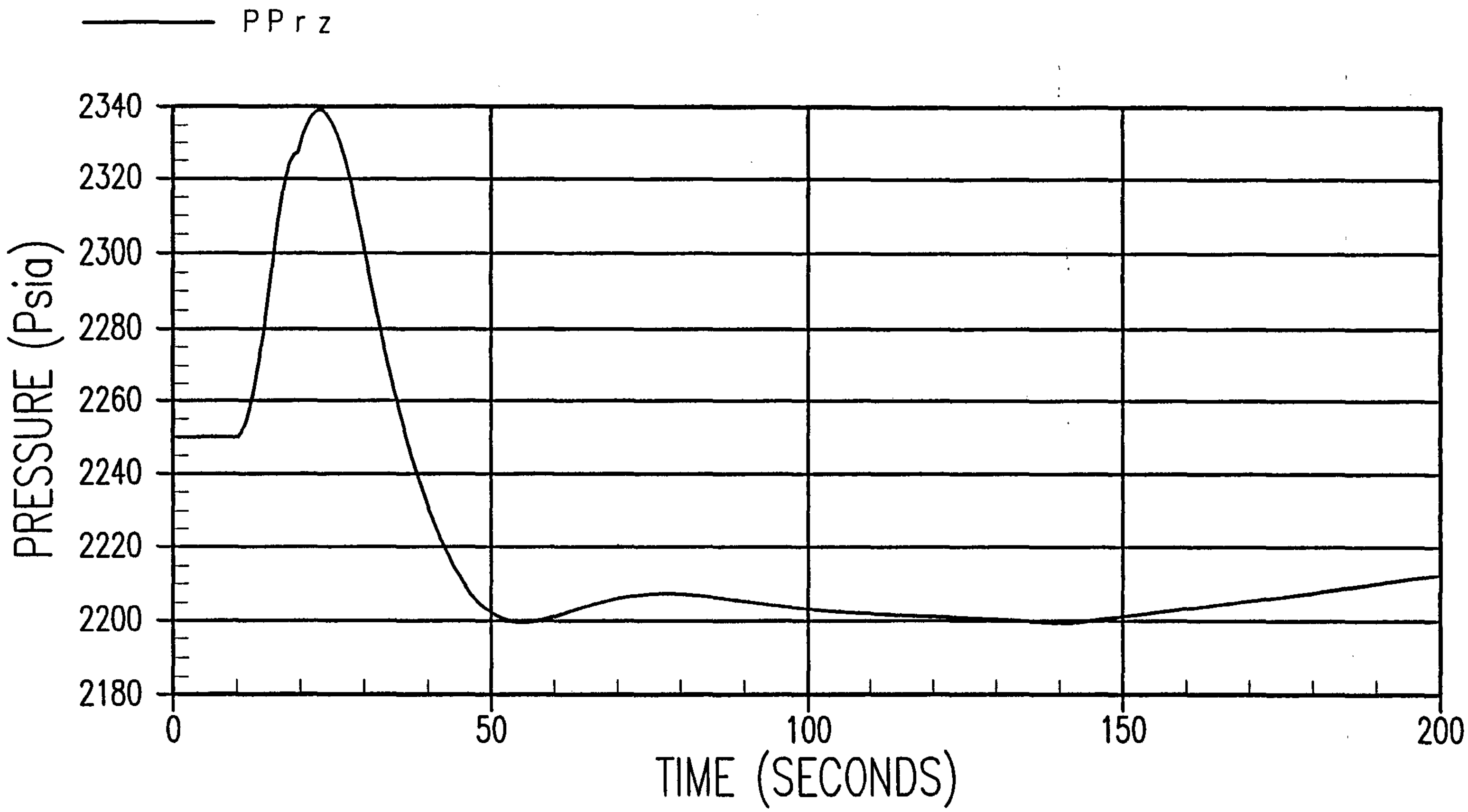
Reduced SGTR Action Times (min)

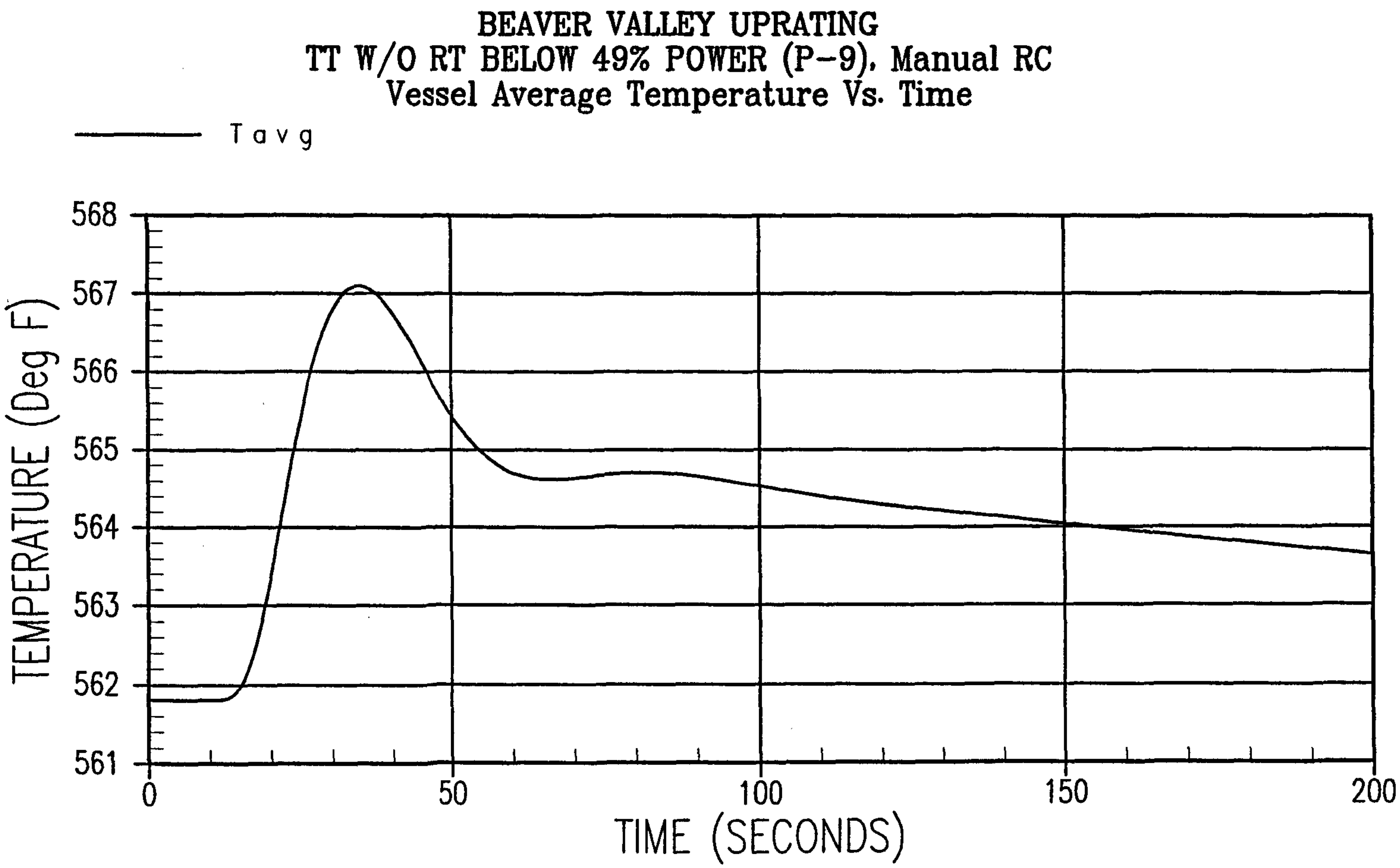
Action (following RX trip)	BV-1 Current	BV-1 EPU	BV-2 Current	BV-2 EPU
Isolate AFW flow	N/A	6.8	9.1	5.5
- Re-Validation		4.1 (sim)		5 (tt)
Isolated MSIV and initiate cool down	N/A	19.1	N/A	17
- Re-Validation		11.7(sim)		12 (tt)

BEAVER VALLEY UPRATING
TT W/O RT BELOW 49% POWER (P-9), Manual RC
Nuclear Power Vs. Time



BEAVER VALLEY UPRATING
TT W/O RT BELOW 49% POWER (P-9), Manual RC
Pressurizer Pressure vs. Time




BEAVER VALLEY UPRATING
TT W/O RT BELOW 49% POWER (P-9), Manual RC
Vessel Average Temperature Vs. Time
Tavg
568
567
566
565
564
563
562
561
TEMPERATURE (Deg F)
0
50
100
150
200
TIME (SECONDS)

Plant Hardware Modifications

Plant Modification	Post Modification Test	Further Tested by Turbine Trip
Replace Main transformer cooling (BVPS-2)	Performance test, In-service check	No
Replace Cooling Tower Fill (BVPS-2)	Performance test, In-service check	No
Replace heater drain level control valves/trim	Leak check, In-service check	No
Replace charging pump rotating impellors	Leak check, Performance test	No
Modify turbine plant cooling water system (remove orifice) (BVPS-2)	Leak check, In-service check	No
Replace isophase duct cooling system flow transmitters (BVPS-1)	Channel calibration, Leak check	No
Replace various BOP transmitters	Channel calibration, Leak check	No

Plant Hardware Modifications (cont)

Plant Modification	Post Modification Test	Further Tested by Turbine Trip
Add reactor cavity drains	As left check	No
Eliminate QS cutback feature (BVPS-1)	Leak check, Functional check	No
Replace S/G NR level transmitters (BVPS-1)	Channel calibration, Leak check, In-service check	No
Replace main steam and feedwater flow transmitters	Channel calibration, Leak check, In-service check	No (not used in RX trip logic)
Replace HP Turbine	Leak check, Overspeed test, Performance test, In-service check	No (isolated on RX trip)
Replace HP Turbine 1st stage pressure transmitters	Channel Calibration, Leak check, In-service check	No (not used in RX trip steam dump logic)

Plant Hardware Modifications (cont)

Plant Modification	Post Modification Test	Further Tested by Turbine Trip
Replace main generator rotor & stator rewind (BVPS-1)	Hypot test, Leak check, Torsional check, Flow test, In-service check	No
Staking of condenser tubes (BVPS-2)	Periodic tube-side inspections, In-service chemistry check	No
Change-out of main feedwater valve/trim	Stroke test, Leak check, In-service check	No (no change in partial feedwater isolation logic)
Addition of fast-acting feedwater valves (BVPS-1)	Functional check, Stroke test, Leak check, Response time test, SSPS slave relay testing	No

Plant Hardware Modifications (cont)

Plant Modification	Post Modification Test	Further Tested by Turbine Trip
RSGs (BVPS-1)	Leak check, Moisture carryover test, Performance test	No
Addition of auxiliary feedwater flow restrictors (BVPS-1)	Leak check, Flow test	No (reduces excess cooling post-trip previously requiring operator action)
Replace accumulator pressure indicators	Channel calibration, In-service check	No
Replace containment NR pressure transmitters & indicators	Channel calibration, Leak check, In-service check	No
Addition of dynamic compensation hardware for OTDT & OPDT reactor trip functions (BVPS-1) (match BVPS-2 design)	Channel calibration	No (Pressurizer Pressure Hi RX trip would actuate)

Setpoint /Scaling Changes

Plant Modification	Post Modification Test	Further Tested by TT
Change/add OTDT & OPDT RX trip constants & time constants	Channel calibration, In-service check	No (Trip function remains along with several diverse trips)
Reduce S/G Low-Low Level RX trip & AFW actuation setpoint (BVPS-1)	Channel calibration	No
Raise S/G Hi Level FWI actuation setpoint (BVPS-1)	Channel calibration	No
Rescale pressurizer reference level (due to full-power Tavg change)	Channel calibration, In-service check	No (No change to no-load temp. & associated przr. reference level)
Rescale containment NR pressure transmitters (BVPS-1)	Channel calibration, In-service check	No

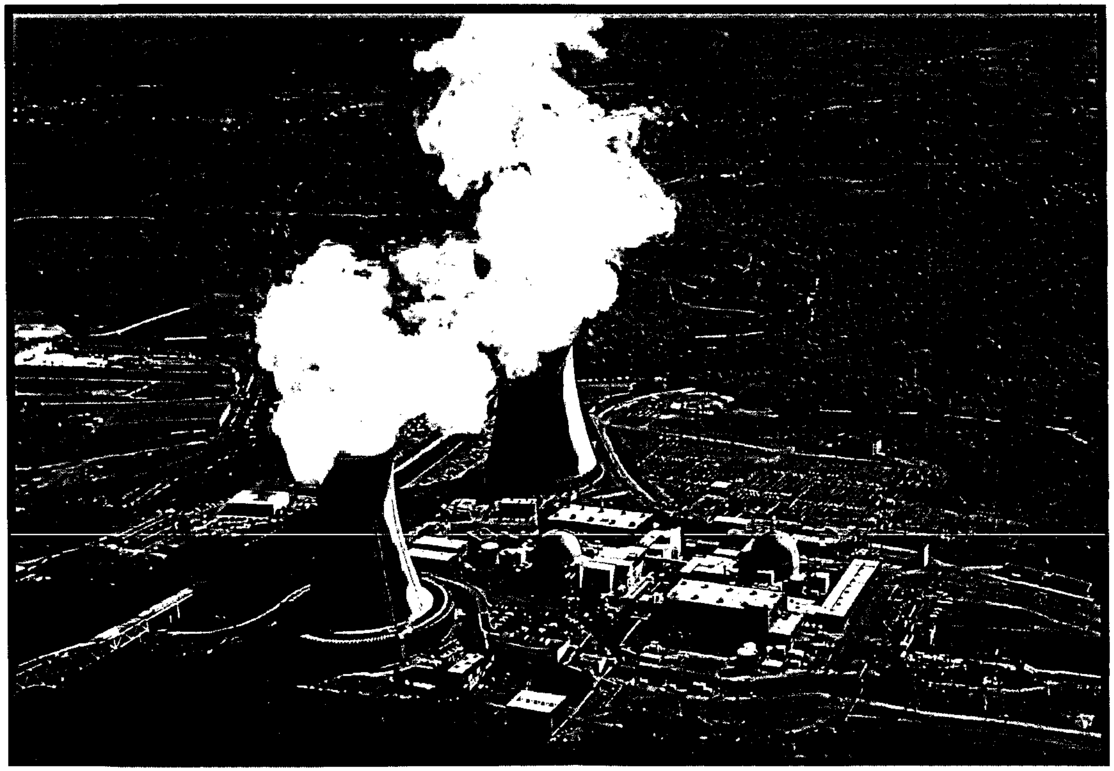
Setpoint /Scaling Changes (cont)

Plant Modification	Post Modification Test	Further Tested by TT
Revise S/G NR level control setpoint & associated alarm setpoints (BVPS-1)	Channel calibration, In-service check, Level control test	No
Revise steam dump (reactor trip controller) trip open setpoints	Channel calibration	No (No change to No-Load Temperature & associated przr. reference level)
Revise steam dump (load rejection controller) trip open & deadband setpoints	Channel calibration	No (Not in-service on turbine trip)
Revise steam dump C-7B setpoint (Large Load Rejection / 4 bank operation)	Channel calibration	No (Not in-service on turbine trip)

Setpoint /Scaling Changes (cont)

Plant Modification	Post Modification Test	Further Tested by TT
Revise Demineralizer Water Storage Tank control & alarm setpoints (BVPS-2)	Channel calibration, In-service check	No
Revise BOP instrument scaling	Channel calibration	No
Revise MSR relief valve setpoint	Bench test, Leak check, In-service check	No (isolated on turbine trip)
Revise RWST level switchover setpoint & RWST Hi temperature alarm setpoint	Channel calibration, In-service check	No
Rescale accumulator pressure & level and revise alarm setpoints	Channel calibration	No
Revise containment pressure ESFAS actuation setpoints (Hi, Hi-2, Hi-3)	Channel calibration	No

BEAVER VALLEY POWER STATION
Extended Power Uprate



ACRS Thermal Hydraulic Subcommittee

April 25-26, 2006

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FirstEnergy Nuclear Operating Company

Introduction

Jim Lash

Site Vice President

Agenda

• Introduction	• Jim Lash
• Overview	• Pete Sena
• Plant Changes	• Mark Manoleras
• Rx Fuel & Core Design	• A.R. Burger
• Safety Analysis	• Ken Frederick
• Materials & RV Integrity	• Dennis Weakland
• Mechanical Plant (BOP)	• Mike Testa
• Risk Evaluation	• Colin Keller
• Operations & Testing	• Don Durkosh
• Conclusion	• Jim Lash

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Introduction - Agenda

- Beaver Valley History
- EPU Timeline
- Beaver Valley Peer Units
- Oversight

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Beaver Valley History

- Beaver Valley Power Station Units 1 and 2
- Westinghouse NSSS 3 loop Pressurized Water Reactor (PWR)
- BV-1 Commercial Operation - 1976
- BV-2 Commercial Operation - 1987
- 2652 MWt original licensed Rated Thermal Power (RTP)
- 2689 MWt Appendix K Margin Recovery - 2001
- 2900 MWt Extended Power Uprate (EPU) - pending

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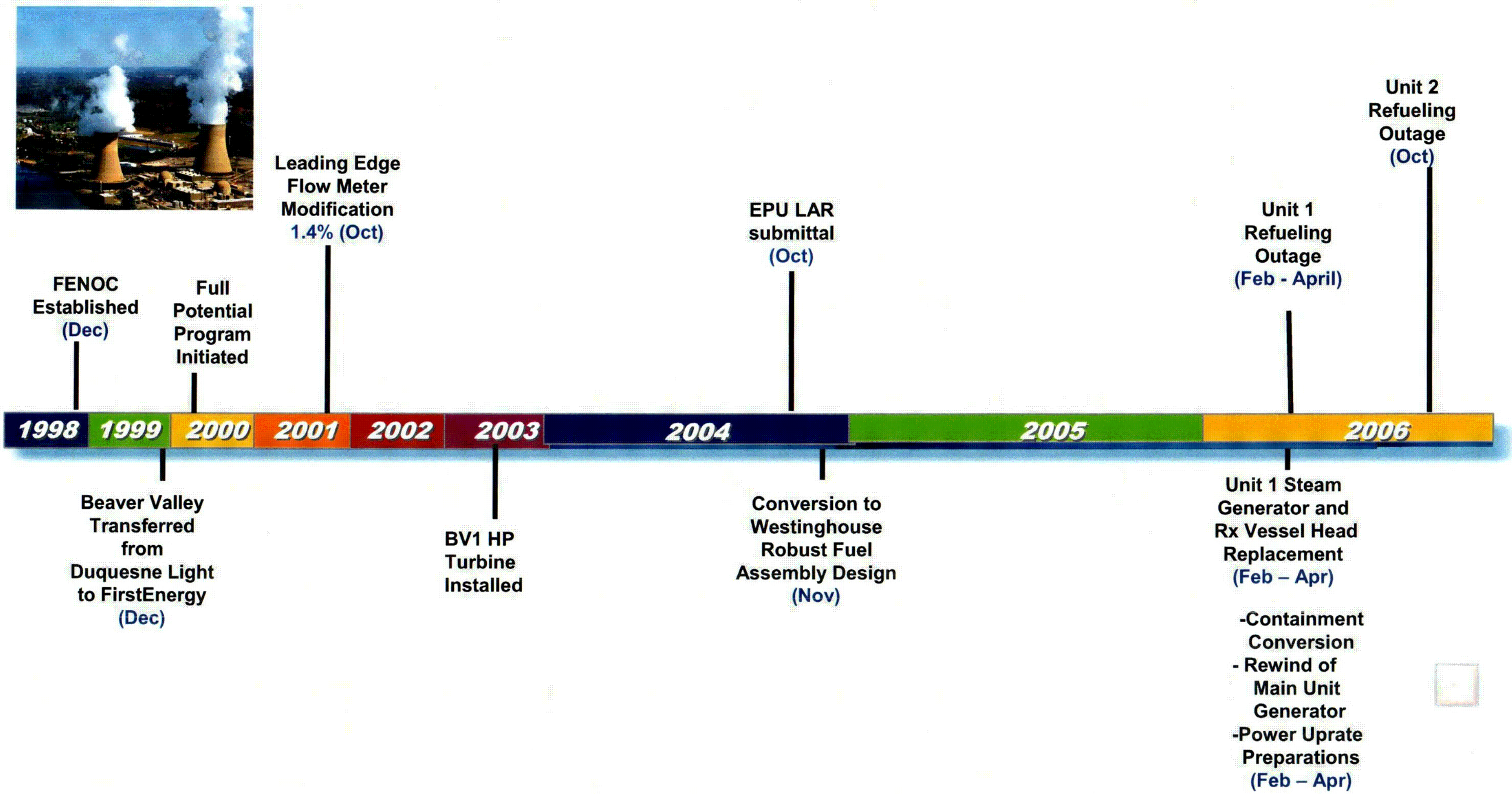
BVPS Progress Timeline – Leading up to EPU



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Beaver Valley Peer Units - Power Uprates

Plant	Uprated NSSS Power Level (MWt)
Beaver Valley Units 1 & 2	**2910**
North Anna Units 1 & 2	**2905**
V. C. Summer	**2912**
Shearon Harris	**2912**
Vandellos	**2954**
ASCO Units 1 & 2	**2952**

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Oversight

- FENOC senior management involvement
- Oversight of the engineering and licensing process
  - Engineering Assessment Board
  - On-site Safety Review Committee
  - Nuclear Oversight (QA)
  - Corporate Nuclear Review Board
  - Independent Assessments

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Overview

Pete Sena
Director, Site Engineering

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Overview - Agenda

- Preparations for Uprate
- General Criteria
- Project Team
- Technical Reviews

Preparations for Uprate

To Position BVPS Units for EPU:

Supporting Submittals Completed:

- **New Fuel Storage Rack Enrichment Limit Increase**
- **Positive Moderator Temperature Coefficient**
- **Accumulator and RWST Increased Boron Concentration**
- **Selective implementation of AST**
- **Minimum Decay Time Before Fuel Movement**
- **Relaxed Axial Offset Control (RAOC)**

Replacement Steam Generators (RSG) BVPS-1

Containment Conversion

Large Break Best Estimate Loss-of-Coolant Accident (BELOCA) Methodology

Extended Power Uprate (EPU) - Pending

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General Criteria

- Key Elements
  - Extended Power Uprate (EPU)
    - Containment Qualified in Containment Conversion submittal
    - LOCA analysis performed using BELOCA methodology
  - Containment Conversion
    - Analyses conservatively performed at EPU conditions
  - BELOCA
    - License methodology for BVPS
    - Results included containment conversion

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General Criteria

- Consistent approach with other power uprates
- Followed current licensing basis unless specifically identified
- Used BVPS analytical methodologies unless specifically identified
- No new industry (unlicensed) methodologies

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Project Team

- FENOC / BVPS
  - Overall project management
  - Review and approval of inputs
  - Proper interfacing of Information
  - Procedure / Training / Simulator updates
- Westinghouse
- Stone and Webster
- Siemens Westinghouse
- Other vendors

Technical Reviews

- Rigorous owners acceptance reviews of vendor outputs
  - Acceptance reviews proceduralized
  - Challenge meetings
  - Engineering reviews to verify correct implementation
- Supported NRC Staff Audit reviews in the areas of
  - Probabilistic Risk Assessment
  - Safety Analysis
  - Radiological Assessment

Plant Changes

Mark Manoleras
(Manager, Design Engineering)

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Plant Changes - Agenda

- Plant Modifications
- Electrical System Summary
- Use of Operating Experience

Plant Modifications

- Replacement of charging/safety injection pump rotating assemblies
- Conversion from a sub-atmospheric to an atmospheric containment design
  - Installation of fast acting feedwater isolation valves (Unit 1)
  - Installation of auxiliary feedwater cavitating venturies (Unit 1)
  - Addition of reactor cavity drainage port
  - Elimination of Quench Spray Cutback (Unit 1)
- Replacement of Steam Generators (Unit 1)

Plant Modifications

- Replace high pressure turbine with all-reaction design
- Install stakes in main condenser (Unit 2)
- Modify cooling tower fill (Unit 2)
- Raise set-pressure of moisture separator reheater relief valves

Plant Modifications

- Increase Cv of main feedwater control valves
- Replace Turbine Generator (T/G) rotor and rewind stator (Unit 1)
- Modify heater drain control valves
- Instrument replacements for higher flow range

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Electrical System Summary

- Initial electrical design is robust
- BV-2 Main Transformer cooling upgraded
- Iso-phase bus duct – material condition upgrade
- Operating limits on grid voltage and reactive load established to protect post-trip voltage on busses
- Grid can accommodate a Beaver Valley trip from EPU condition
- 4 hour station blackout coping capability is unaffected

Industry OE

- Vibration issues
- Turbine rubs
- Turbine control – valves wide open
- Isophase bus duct air flow and cooling
- Transformer cooling
- Power measurement

Rx Fuel and Core Design

A. R. Burger
(Supervisor, Core Design & Physics Support)

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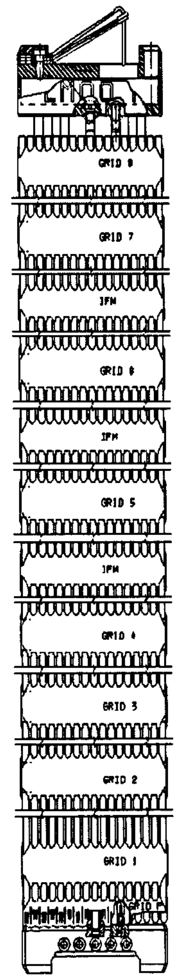
Fuel Design

- Robust Fuel Assembly (RFA)
  - 17 X 17 assembly
  - 2.6% enriched blankets (6 inches)
  - 0.374" OD ZIRLO™ Clad
  - 463 kgU
- Integral Fuel Burnable Absorber (IFBA)
- Intermediate Flow Mixing (IFM) Grids
- 6 cycles of operating history



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Fuel Design

- IFMs provide increased DNB margin and utilize WRB-2M correlation
- RFA design provides increased resistance to grid-to-rod fretting fuel failures
- Increased guide tube thickness provides margin for Incomplete Rod Insertion (IRI)

Core Design

- Conceptual core design models for up-rated conditions
- Equilibrium cycle burnups increase from 18,800 MWD/MTU to 20,200 MWD/MTU
- Increased average Linear Heat Rate (LHR) - 5.28 to 5.69 kw/ft with EPU
- Peaking factors remain at 2.4 for Fq and 1.62 for FNΔH
- increase in feed batch size from 60 to 64 fuel assemblies to accommodate uprate
- Continued use of low-leakage loading pattern

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Core Design

- No change in maximum enrichment
- No appreciable change in flux profile
- No transition core penalty - both units operating with RFA fuel design
- Relaxed Axial Offset Control (RAOC) provides increased operating flexibility compared to Constant Axial Offset Control (CAOC)

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Safety Analysis

Ken Frederick
(Nuclear Safety Analyst)

Safety Analysis Objectives

- Demonstrate compliance with regulatory limits and acceptance criteria

- To show that BVPS will operate with adequate safety margins at EPU conditions

Safety Analysis - Agenda

- BVPS EPU Design Parameters
- Safety/Control Setpoint Changes
- Safety Analysis Methodologies
- Non-LOCA Events
- LBLOCA
- SBLOCA
- Post LOCA Long Term Cooling / Boron Precipitation
- Containment/NPSH/Overpressure
- Dose Analysis

BVPS Power Uprate – Design Parameters

EPU Licensing Report	Rx Mass Flow E6 Lb/hr	Vessel Outlet Temp F	Vessel Outlet H Btu/lb	Vessel Inlet Temp F	Vessel Inlet H Btu/lb	Core Power Btu/hr	Power Ratio EPU / Current
Current Operation	99.5	610.8	628.97	541.60	536.83	9.168E09	NA
EPU Low Tavg (566.2 F)	101.1	603.9	618.84	528.50	520.98	9.894E09	1.08
EPU High Tavg (580.0 F)	99.3	617.0	638.35	543.10	538.67	9.898E09	1.08

Safety Setpoint

- OPΔT
  - Reduced trip setpoint
  - Added filters to optimize operating margin
- OTΔT
  - Reduced trip setpoint
  - Added filters to optimize operating margin
- Other protection system changes
  - Low-Low S/G Level (BVPS-1)
  - Negative flux rate trip elimination
  - Containment pressure setpoints raised (CC)
  - RWST Level Low-Low (SI Recirc) setpoint lowered (CC)

Control System Setpoint Changes

- Pressurizer Level @ full power
- Steam dump system control setpoints
- Steam Generator level (BVPS-1)

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Safety Analysis Methods

Method	EPU	Current
Large Break LOCA	BELOCA/WCOBRA-TRAC	BASH (App K)
Small Break LOCA	NOTRUMP	NOTRUMP
Non-LOCA	LOFTRAN VIPRE	LOFTRAN THINC
Control System Transients	LOFTRAN	LOFTRAN
Containment	MAAP-DBA	MAAP-DBA (LOCTIC pre-CC)
Dose Assessment	AST/ARCON 96	TID/RAMSDELL

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Non-LOCA Events

- Decrease in Heat Removal by Secondary System
  - Loss Of Electrical Load and/or Turbine Trip
  - Loss of Normal Feedwater
  - Loss of Offsite Power to the Station Auxiliaries
  - Major Rupture of a Main Feedwater Pipe
- Increase in Heat Removal by Secondary System
  - Excessive Load Increase Incident
  - Excessive Heat Removal Due to Feedwater System Malfunctions
  - Steam System Piping Failure at Full Power
  - Major Rupture of a Main Steam Pipe (HZP)

Non-LOCA Events

- Reactivity and Power Distribution Anomalies
  - Uncontrolled RCCA Bank Withdrawal from a Subcritical Condition
  - Uncontrolled RCCA Bank Withdrawal at Power
  - RCCA Misalignment
  - Uncontrolled Boron Dilution
  - Rupture of a Control Rod Drive Mechanism Housing- RCCA Ejection
- Decrease in Reactor Coolant System Flowrate
  - Complete Loss of Forced Reactor Coolant Flow
  - Partial Loss of Forced Reactor Coolant Flow
  - Single Reactor Coolant Pump Locked Rotor

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Non-LOCA Events

- Decrease in Reactor Coolant Inventory
  - Accidental Depressurization of the Reactor Coolant System
- Increase in Reactor Coolant Inventory
  - Spurious Operation of the Safety Injection System at Power

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Non-LOCA Acceptance Criteria

- Most Non-LOCA events are categorized as ANS Condition II for which the acceptance criteria are:
  - The critical heat flux is not exceeded (the calculated minimum DNBR does not go below the limit value at any time during the transient)
  - Peak heat generation rate remains within acceptable limits to prevent fuel centerline melt
  - Pressure in the RCS and main steam systems should be maintained below 110% of the design pressures
  - The event should not generate a more serious plant condition without other faults occurring independently

Non-LOCA DNBR Analysis

- DNBR is calculated using approved correlations
  - WRB-1,WRB-2M,W-3 used as applicable based on fuel type and RCS conditions
- Revised Thermal Design Procedure (RTDP) is used for most analyses
  - Combines uncertainties on RCS power, flow, temperature, and pressure into DNBR penalties by statistical methodology
- DNBR margin is retained in limits
  - For BVPS, 21.2% margin is retained between safety analysis limits and design limits for events using WRB-2M
  - Retained margin allows for greater core design flexibility during reload process

Non-LOCA DNBR Margin

DNBR		Corresponding Limit
1.55		Safety Analysis Limit
	Retained Margin	
1.22		Design Limit
	RTDP Uncertainties	
1.14		Correlation Limit (TS)
	Correlation Uncertainty	
1.0		Critical Heat Flux

WRB-2M DNBR LIMITS

Non-LOCA DNBR Results

DNBR Limited Events				
Event	DNBR Correlation	DNBR Limit	BVPS-1 DNBR	BVPS-2 DNBR
RCCA Bank Withdrawal from Subcritical	W-3,WRB-1	1.65, 1.45	1.83, 2.12	1.83, 2.12
RCCA Bank Withdrawal at Power	WRB-2M	1.55	1.57	1.58
RCCA Misalignment	WRB-2M	1.55	(1)	(1)
Loss of Load	WRB-2M	1.55	2.23	1.83
Feedwater System Malfunctions a. Feedwater Flow Increase b. Feedwater Enthalpy Decrease	 WRB-2M WRB-2M	 1.55 1.55	 1.75 1.67	 1.96 1.66
RCS Depressurization	WRB-2M	1.55	1.62	1.64
Main Steam Pipe Rupture (HFP)(2)	WRB-2M	1.55	2.56	2.56
Main Steam Pipe Rupture (HZP)(2)	W-3	1.61	2.41	1.83
Partial Loss of Flow	WRB-2M	1.55	2.25	2.25
Complete Loss of Flow	WRB-2M	1.55	1.64	1.64

(1) No DNBR Results-Analysis uses peaking factor limits for evaluation
(2) Condition IV event evaluated with Condition II limits

Service Level Stress Limits

D

3215 psia — **Service Level C Stress Limits** Limit Applied to ATWS

3122 psia — Initial hydrotest pressure

C

2997 psia — **120% of design pressure** Limit Applied to Locked Rotor

(Service level B stress limits)

2748.5 psia — **110% of design pressure** Overpressure Protection Limit Applied to Condition II events

B

2500 psia — **Design pressure** (2485 psig)

2250 psia **A** — Normal operating pressure

Non-LOCA Pressure Results

Limiting Overpressure Events						
Event	**Primary Pressure Limit (Psia)**	**BVPS-1 Peak Primary Pressure (Psia)**	**BVPS-2 Peak Primary Pressure (Psia)**	**Secondary Pressure Limit (Psia)**	**BVPS-1 Peak Secondary Pressure (Psia)**	**BVPS-2 Peak Secondary Pressure (Psia)**
Loss of Load	2748.5	2747	2746	1208.5	1192	1191
Feedwater System Malfunctions	2748.5	2357	2353	1208.5	1124	1141
Partial Loss of RCS Flow	2748.5	2374	2361	1208.5	989	995
Complete Loss of RCS Flow	2748.5	2504	2503	1208.5	993	1003
Locked Rotor	2997	2797	2825	-	-	-
ATWS	3215	3060	2900	-	-	-

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Non-LOCA Other Results

Pressurizer Filling Events			
Event	Pressurizer Water Volume Limit (ft^3)	BVPS-1 Peak Pressurizer Water Volume (ft^3)	BVPS-2 Peak Pressurizer Water Volume (ft^3)
Loss of Normal Feedwater	1458	1384	1193
Loss of AC	1458	1224	1194
Spurious Safety Injection	1458	Pressurizer Fills	Pressurizer Fills
Margin to Hot Leg Saturation Event			
Event	Margin to Hot Leg Boiling Limit (°F)	BVPS-1 Margin to Hot Leg Boiling (°F)	BVPS-2 Margin to Hot Leg Boiling (°F)
Feedline Break	0 (No boiling)	14.4	36
Maximum Fuel Stored Energy Event			
Event	Max Fuel Stored Energy Limit (Btu/Lbm)	BVPS-1 Max Fuel Stored Energy (Btu/ Lbm)	BVPS-1 Max Fuel Stored Energy (Btu/ Lbm)
RCCA Ejection	360	326.8	326.8

Non-LOCA Loss of Load Transient

- This event produces the highest primary and secondary pressures of the Condition II events
- Results from either a loss of electrical load without direct turbine trip or a turbine trip
- Protection for this event provided by:
  - Hi Pressurizer pressure trip
  - High Pressurizer water level trip (not credited)
  - Overtemperature ΔT trip
  - Low-low S/G trip if feedwater is lost
  - Reactor trip on turbine trip (not credited)

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Non-LOCA Loss of Load Transient

- Two cases are performed:
  - DNBR with pressure control
  - Pressure case with no pressure control
- Conservatisms in analysis
  - Inputs biased for worst results
    - Pressurizer pressure and level
    - RCS power, flow, and temperatures
    - Reactivity feedback
    - Manual rod control
  - No credit for condenser steam dumps or atmospheric relief valves
  - No credit for Pressurizer spray or PORVs for pressure case
  - Maximum setpoint tolerance for Pressurizer safety valves
  - Main feedwater lost at time of turbine trip
  - Safety valve performance model includes opening delays for loop seal purge, valve opening time, and setpoint shifts

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Non-LOCA Loss of Load Transient

Without pressurizer pressure control (minimum reactivity feedback-Pressure Case)	Loss of Electrical Load/Turbine Trip	0.0
	High Pressurizer Pressure Reactor Trip Setpoint reached	5.5
	Rods begin to drop	7.5
	Peak pressurizer pressure occurs	8.2

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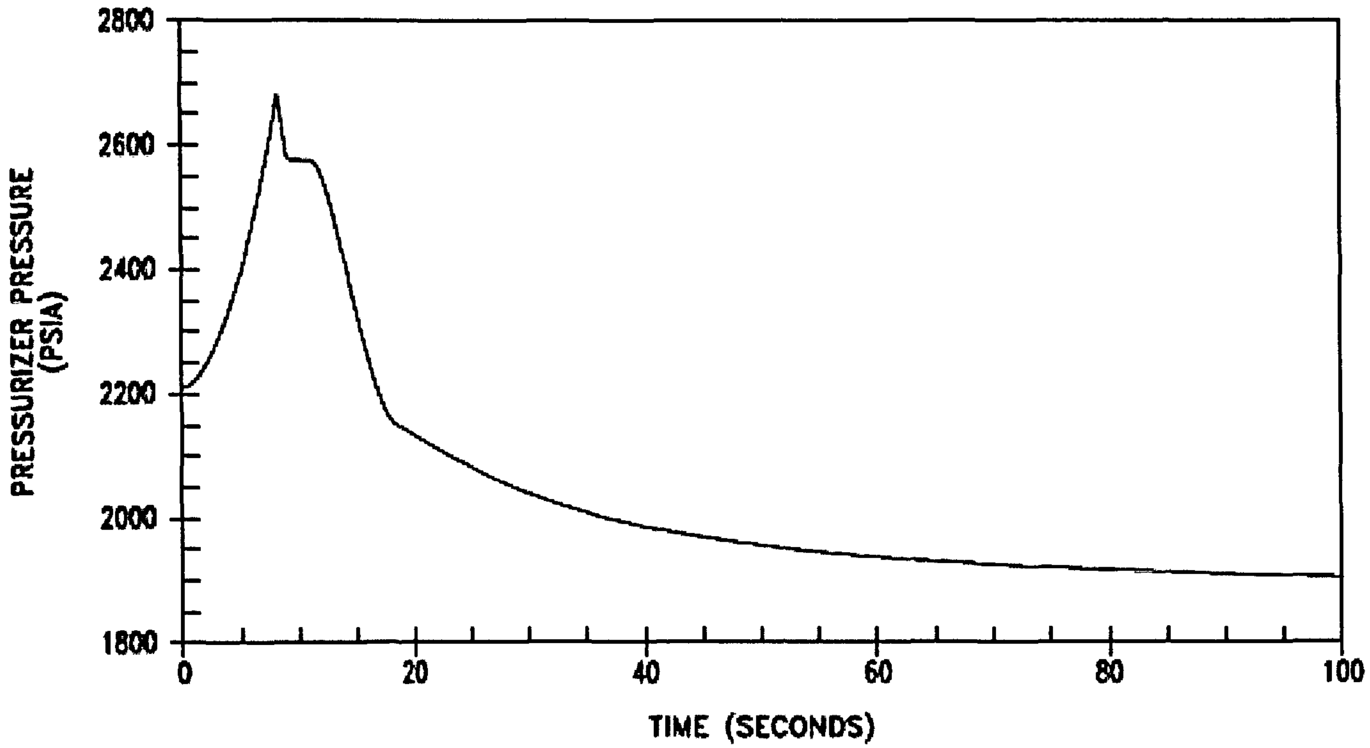
Non-LOCA Loss of Load Transient



BVPS-1 Loss of Load / Turbine Trip without Pressure Control
Pressurizer Pressure versus Time

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Non-LOCA Loss of Load Transient

Comparison of Peak RCS Pressure following Loss of Load Event		
	BVPS-1	BVPS-2
Pre-EPU Peak RCS Pressure psia	2732.7	2747.5
EPU Peak RCS Pressure psia	2747.3	2746.2

- A realistic analysis which credits all control systems show a peak pressure of 2340 psia and no safety valves lift

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Non-LOCA Rod Withdrawal at Power

- This event produces the most limiting results for DNBR
- Event initiated by malfunction of rod control or operator error
- Reactor protection provided by:
  - Power range high flux trip
  - Overtemperature ΔT trip
  - Overpower ΔT trip
  - High Pressurizer pressure trip
  - High Pressurizer water level trip
  - Positive neutron flux rate trip
- Rod withdrawal blocks also present but not credited

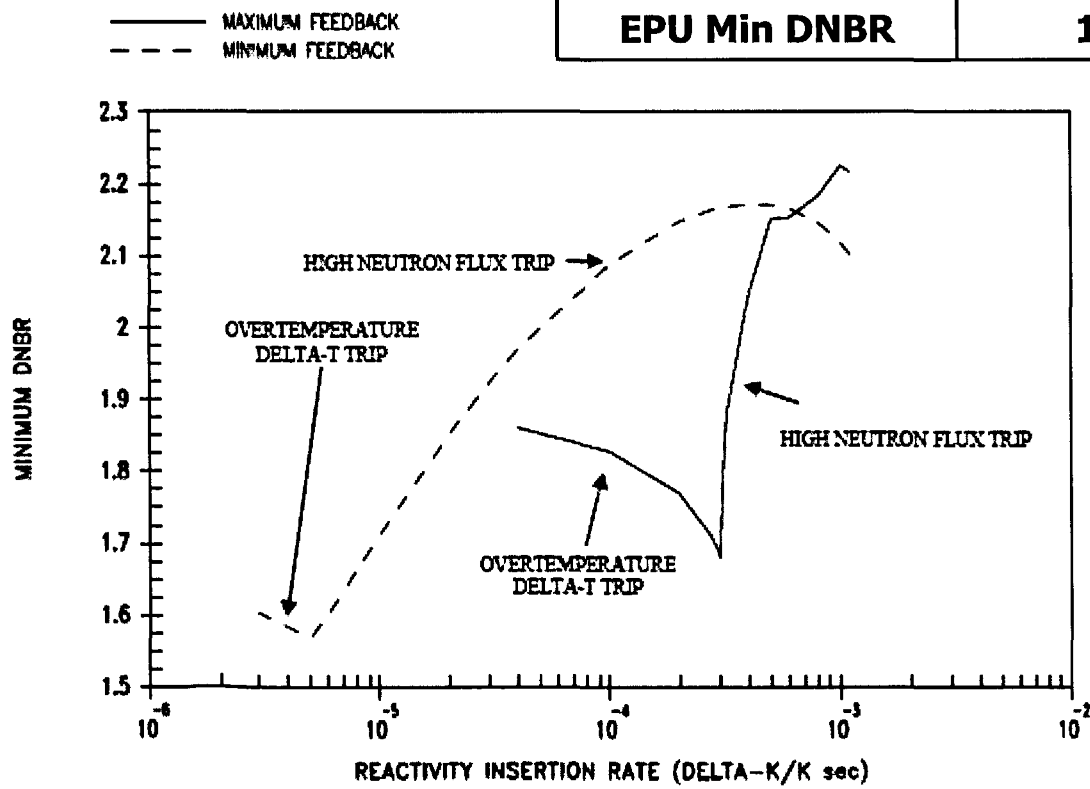
Non-LOCA Rod Withdrawal at Power

- Many cases are analyzed over a range of reactivity insertion rates and initial power levels of 10%, 60% and 100%
- Conservatisms included in the analysis:
  - Initial condition uncertainties on reactor power, temperature, flow and pressure
  - Conservative values of reactivity feedback
  - Maximum adverse uncertainties is assumed on all trip setpoints
  - Highest worth RCCA stuck out of core
  - Maximum positive reactivity insertion rate assumed is greater than BVPS design
  - Auto rod withdrawal has been eliminated

Non-LOCA Rod Withdrawal at Power

- Results demonstrate protection is adequate over range of reactivity rates assumed

Comparison of Minimum DNBR following Rod Withdrawal at Power	
Pre-EPU Min DNBR	**1.57**
EPU Min DNBR	**1.57**



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Non-LOCA Spurious Safety Injection

- Spurious Safety Injection is a Condition II event
- Event is initiated by a malfunction or error which initiates a safety injection signal
- SI signal generates a reactor trip and turbine trip
- DNBR is not challenged due to addition of cold water
- Primary concern is pressurizer overfill and water discharge through safety valves

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Non-LOCA Spurious Safety Injection

- Conservatisms included in analysis:
  - Maximum core power plus uncertainty
  - Initial pressure, temperature and flow conditions with uncertainties biased for worst results
  - Maximum initial pressurizer level plus uncertainties
  - Performed with and without pressurizer heaters
  - Two HHSI pumps start at maximum flow with uncertainties
  - PORVs not credited for PSV operability case
  - Colder water entering pressurizer is assumed to instantly mix with hot water volume (minimizes PZR temperature)
- Event mitigation provided by operator actions to either open PORV or shutdown HHSI pumps

Non-LOCA Spurious Safety Injection

- Pressurizer predicted to overfill prior to operator action at ten minutes
- Analysis used to generate water discharge parameters (# cycles, temperature, flow) for PORVs and Safety Valves
- PSV evaluation used WCAP 11677 methodology based on EPRI safety valve test results
- PORVs have qualified low pressure close signal
- Discharge piping analyzed to show design limits are met with a water discharge.

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Non-LOCA Spurious Safety Injection

- Analyses conclude that PSVs can pass water without damage
- PORVs also capable of discharging water without damage
- PORVs have qualified signal to close; do not need to rely on block valve closure
- Spurious SI event will not propagate to Condition III event

Non-LOCA Conclusions

- DNBR limits contain margin between safety analysis limits design limits to allow for core design flexibility
- Conservatism in peak pressure limits and analysis inputs allow for maintaining margins in operating limits
- All acceptance criteria for Condition II,III,IV Non-LOCA events are met at EPU conditions

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Safety Analysis – Large Break LOCA

- EPU analysis performed using Westinghouse 1996 BELOCA methodology using WCOBRA/TRAC
- PCT margin gained from methodology change, increase in containment operating pressure, and minimum accumulator pressure partially offsets increase in power from EPU
- Results indicate acceptance limits met with margin

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Large Break LOCA - Results

Parameter	Current (App K)	EPU (BELOCA)	Limit
Unit 1 Peak Clad Temperature	1996 °F	2021 °F	<2200 °F
Unit 2 Peak Clad Temperature	1908 °F	1976 °F	<2200 °F
Unit 1 Maximum Transient Local Cladding Oxidation	10.2 %	8.77 %	<17 %
Unit 2 Maximum Transient Local Cladding Oxidation	8.9 %	6.7 %	<17 %
Unit 1 Maximum Hydrogen Generation	0.91 %	0.98 %	<1%
Unit 2 Maximum Hydrogen Generation	0.58 %	0.91 %	<1%

Safety Analysis -SBLOCA

- Analysis performed utilizing NRC approved Evaluation Model (EM) with NOTRUMP
- PCT margin gained through plant modifications:
  - Increase in Safety Injection flows
    - New higher runout capacity HHSI pumps
    - Improved instrumentation => lower uncertainties
  - Increase in minimum SI Accumulator pressure

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SBLOCA – NRC Questions

- Coarseness of break spectrum
  - (Integer break sizes, e.g. 2",3",4")
- Loop seal clearing assumptions
  - NOTRUMP licensed for loop seal clearing on broken loop only
- Cladding oxidation should include pre-transient oxidation
- Operator actions to cool down and depressurize for smaller breaks need to be performed to refill reactor vessel in a timely manner

SBLOCA – NRC Questions

- BVPS analyses were re-run to address NRC issues
  - Break sizes were investigated at 0.25" increments
  - Allowance for loop seal clearing on intact loops was removed
  - Burnup studies for cladding oxidation were performed and shown to meet limit with pre-transient oxidation included
- Revised analyses incorporate increased accumulator pressure for improved results
- Simulator studies confirm EOP ES-1.2 cooldown and depressurization commenced within 30 minutes
- Revised analyses demonstrate acceptable results with adequate margin

Small Break LOCA - Results

Parameter	Current	EPU	Limit
Unit 1 Peak Clad Temperature	**1902 °F**	**1895°F**	**<2200 °F**
Unit 2 Peak Clad Temperature	**1902 °F**	**1917 °F**	**<2200 °F**
Unit 1 Maximum Transient Local Cladding Oxidation	**14.47 %**	**11.07 %**	**<17 %**
Unit 2 Maximum Transient Local Cladding Oxidation	**14.47 %**	**13.42 %**	**<17 %**
Unit 1 Maximum Hydrogen Generation	**0.72 %**	**0.64 %**	**<1%**
Unit 2 Maximum Hydrogen Generation	**0.72 %**	**0.77 %**	**<1%**

Post-LOCA Long Term Cooling

- Analyses performed to demonstrate:
  - Boron concentration in core can be maintained below precipitation limits (switchover time)
  - Safety injection flows in all alignments (cold leg and simultaneous hot and cold leg injection) are adequate to flush the core and remove decay heat

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Post-LOCA Long Term Cooling

- The NRC identified four items to be addressed for post-LOCA long term cooling boric acid analyses
  - Core voiding must be considered by reducing the mixing volume accordingly
  - Time-based Mixing Volume / System Effects must be considered
  - BA Solubility limit must be justified, particularly if sump additives or over-atmospheric pressure is credited
  - Appendix K decay heat must be used
- BVPS long term cooling calculations were re-done to address these items

Long Term Cooling -Analysis

- Core voiding must be considered by reducing the mixing volume accordingly
  - Core voiding was calculated used modified Yeh Correlation
  - Voiding calculations were benchmarked against Large Break and Small Break ECCS code calculations (WCOBRA/TRAC and NOTRUMP)

- Time-based Mixing Volume / System Effects must be considered
  - Time-based liquid volume was calculated using core voiding predictions
  - Liquid volume was benchmarked against Large Break and Small Break ECCS code calculations
  - Loop pressure drop effect was evaluated using large break ECCS code calculations

- BA Solubility limit must be justified, particularly if sump additives or over-atmospheric pressure is credited
  - The beneficial effect of sump additives on boric acid solubility was developed but not credited (Precipitation limit increases to from 29% to ~48% with NaOH additive)
  - Atmospheric pressure solubility limit was used in all calculations

- NRC considers Appendix K decay heat a requirement
  - Appendix K decay heat was used in all calculations.

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Long Term Cooling -Analysis

- Additional issue identified in Draft SER
- For SBLOCA scenarios which do not refill, capability to cool down and depressurize in <6 hours needs to be demonstrated
- Preliminary analyses indicate sufficient heat removal capacity is available to meet required times
- Discussions with staff indicate acceptable resolution of issue – FENOC will follow up with NRC to close the issue

Long Term Cooling Summary

- Post LOCA long term core cooling has been adequately addressed
- Results show the following for switchover time to hot leg injection:
  - BVPS-1 - 6.5 hours
  - BVPS-2 - 6 hours
- Emergency Operating Procedures require preparations be made to align to hot leg at:
  - BVPS-1 - 5.5 hours
  - BVPS-2 - 5 hours

Containment Analysis

- Amendments have been approved to convert BVPS-1 and BVPS-2 to an atmospheric containment design (Containment Conversion)
- Containment Conversion analysis accounts for EPU conditions which primarily impacts:
  - LOCA M&E Releases
  - MSLB M&E Releases
- LBLOCA and MSLB M&E release calculations use previously approved Westinghouse methodologies

Containment Analysis

- Containment integrity analyses utilize MAAP-DBA
  - New methodology recently approved by NRC for BVPS Containment Conversion Program
  - Similar to other approved codes (GOTHIC, COCO, etc)
  - Uses traditional heat transfer correlations (Tagami, Uchida)
  - Multiple node model used to capture water holdup for NPSH
- SBLOCA M&E releases use MAAP-DBA

Containment Analysis

- Containment will operate at slightly sub-atmospheric conditions
  - Prior to containment conversion 9 psia to 10.5 psia (air partial pressure)
  - Following containment conversion 12.8 psia to 14.2 psia

- Analysis credits plant modifications
  - Replacement Steam Generators (BVPS-1)
  - New feedwater isolation valves (BVPS-1)
  - AFW cavitating venturis (BVPS-1)
  - Reactor cavity drainage port
  - QS cutback elimination (BVPS-1)
  - Lowered RWST level setpoint for transfer to SI recirculation

Containment Analysis

- Containment Analysis acceptance criteria:
  - Containment Peak Pressure (LOCA and MSLB) < 45 psig design pressure
  - Containment pressure reduction of 50% of peak in 24 hours
  - NPSH for pumps which recirculate from sump exceeds required NPSH [Recirculation Spray (RS) and Low Head Safety Injection (LHSI)]
  - Minimum sump inventory is sufficient during pump start

Containment Analysis - Results

- Peak Containment Pressures within Design (45 psig) for all accidents

	EPU Peak Pressure Results psig	Pre-EPU Peak Pressure Results psig
BVPS-1 LOCA	43.3	40.0
BVPS-1 MSLB	42.6	44.2
BVPS-2 LOCA	44.9	44.7
BVPS-2 MSLB	39.3	41.0

Containment Analysis - Results

- Containment Pressure reduced to <1/2 Pa within 24 hours
- All NPSH requirements satisfied
- All equipment required to operate remains qualified for environmental conditions
- Piping and structures qualified for sump and atmosphere temperature profiles
- Minimum sump inventory sufficient for pump operation

Containment Overpressure

- Containment Overpressure (COP) is required for BV-1 to support NPSH for Recirculation Spray pumps
  - COP credit is part of existing licensing basis for BVPS-1
  - COP continues to be credited for Containment Conversion / EPU
  - BVPS-2 does not need to credit COP due to differences in physical layout (pumps at ~13 feet lower elevation)

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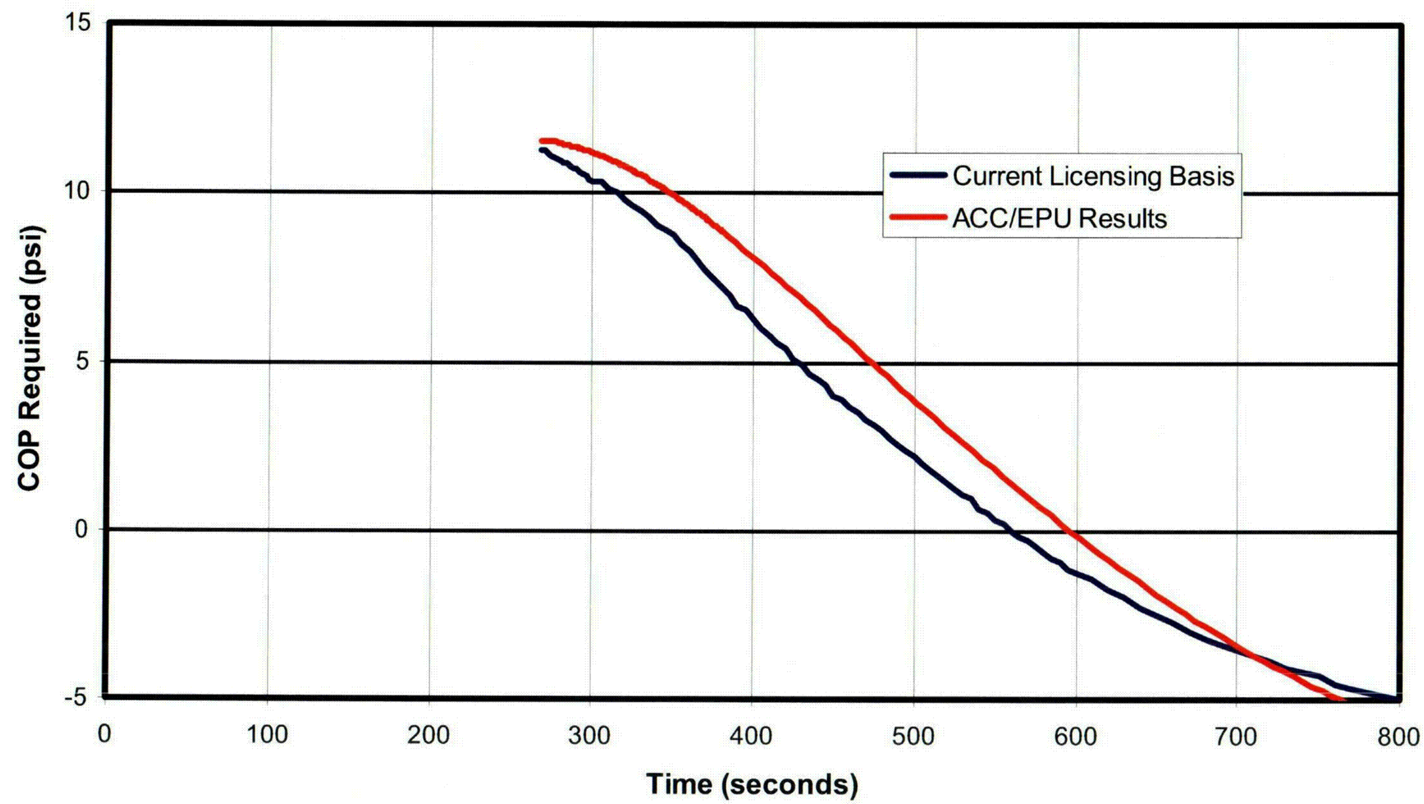
Containment Overpressure

- BVPS-1 Recirculation Spray System (RSS)
  - consists of four pumps and spray rings
  - automatically start within five minutes of a spray initiation signal (CIB)
  - draws water from the containment sump
- Due to early start time
  - sump level is relatively low
  - sump temperature high
  - NPSH availability is limited
- NPSH available decreases following pump start due to rapid depressurization of containment relative to sump temperature

COP Required for Inside RS Pump



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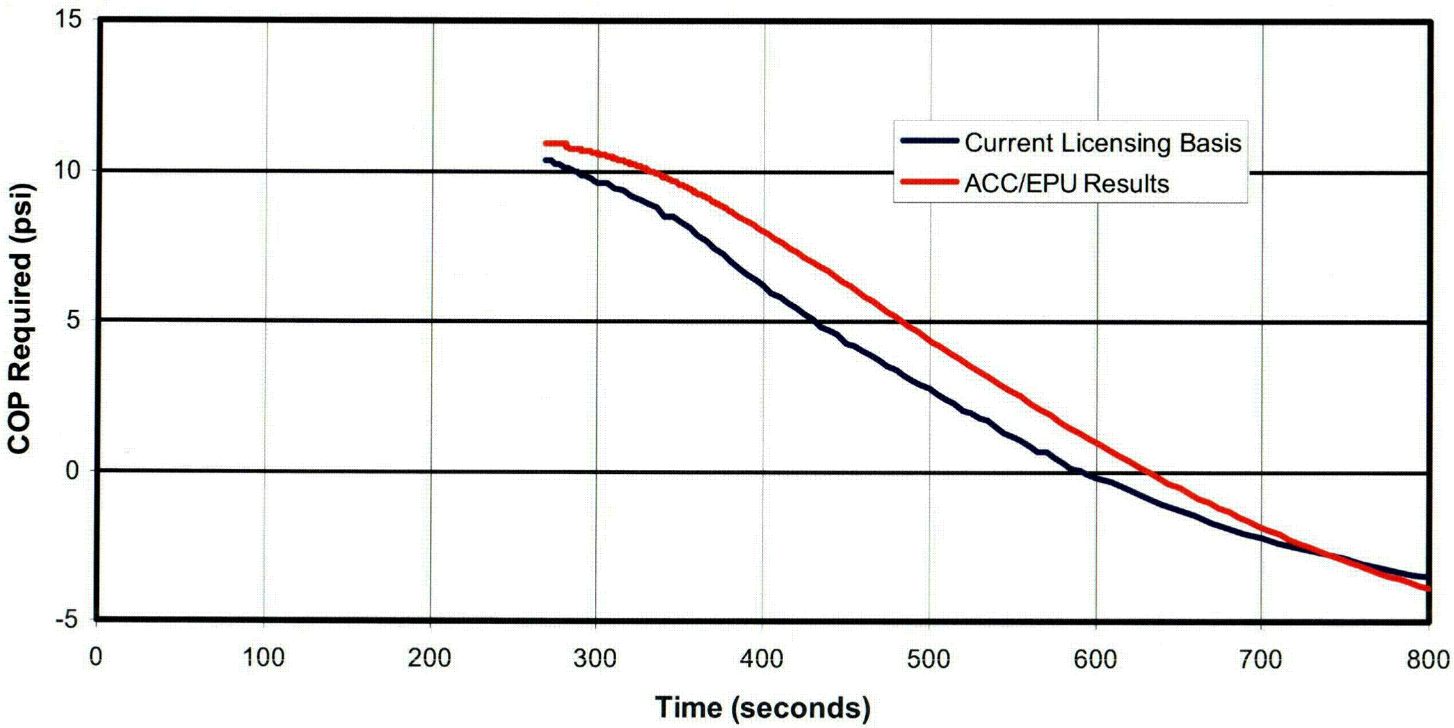
C02

COP Required for Outside RS Pump



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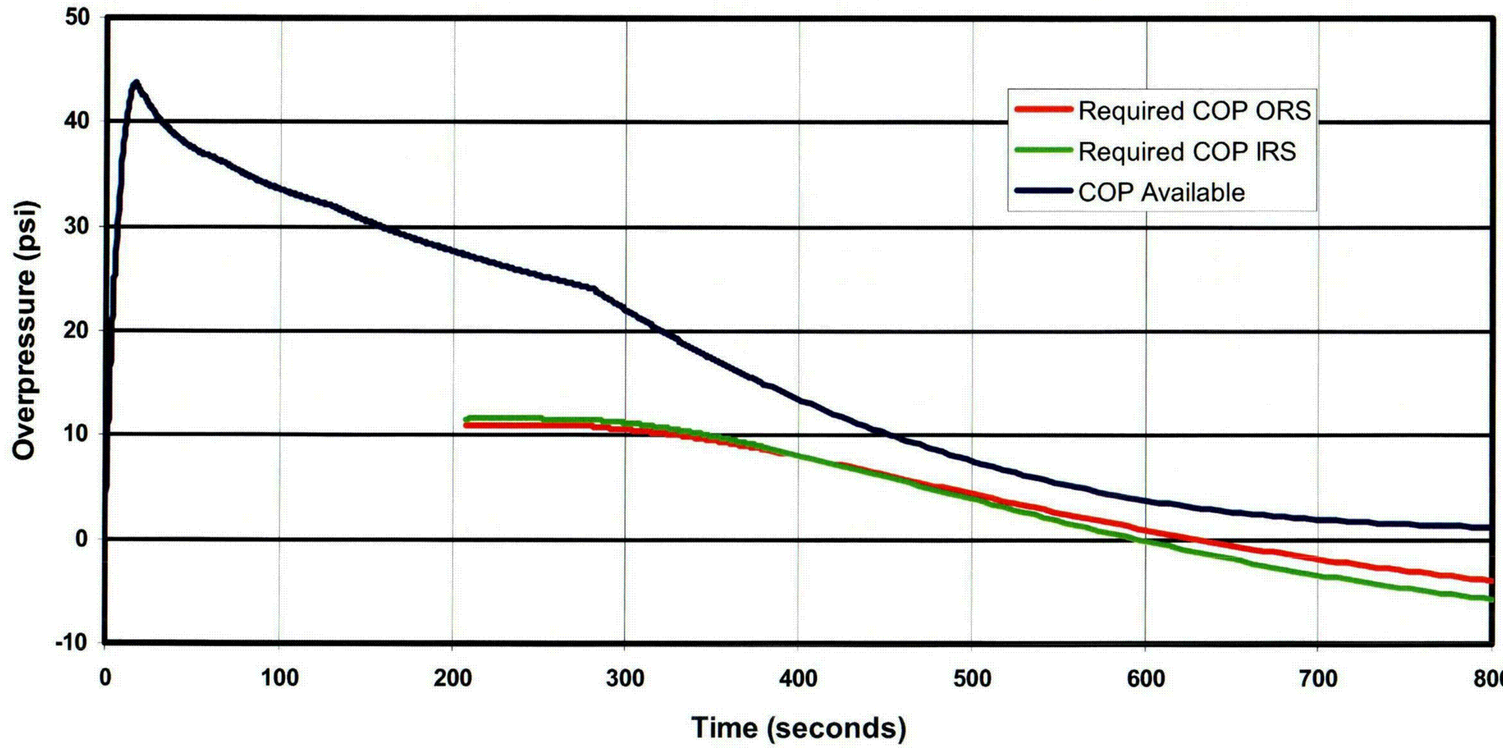
C03

Required and Available Overpressure



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C04

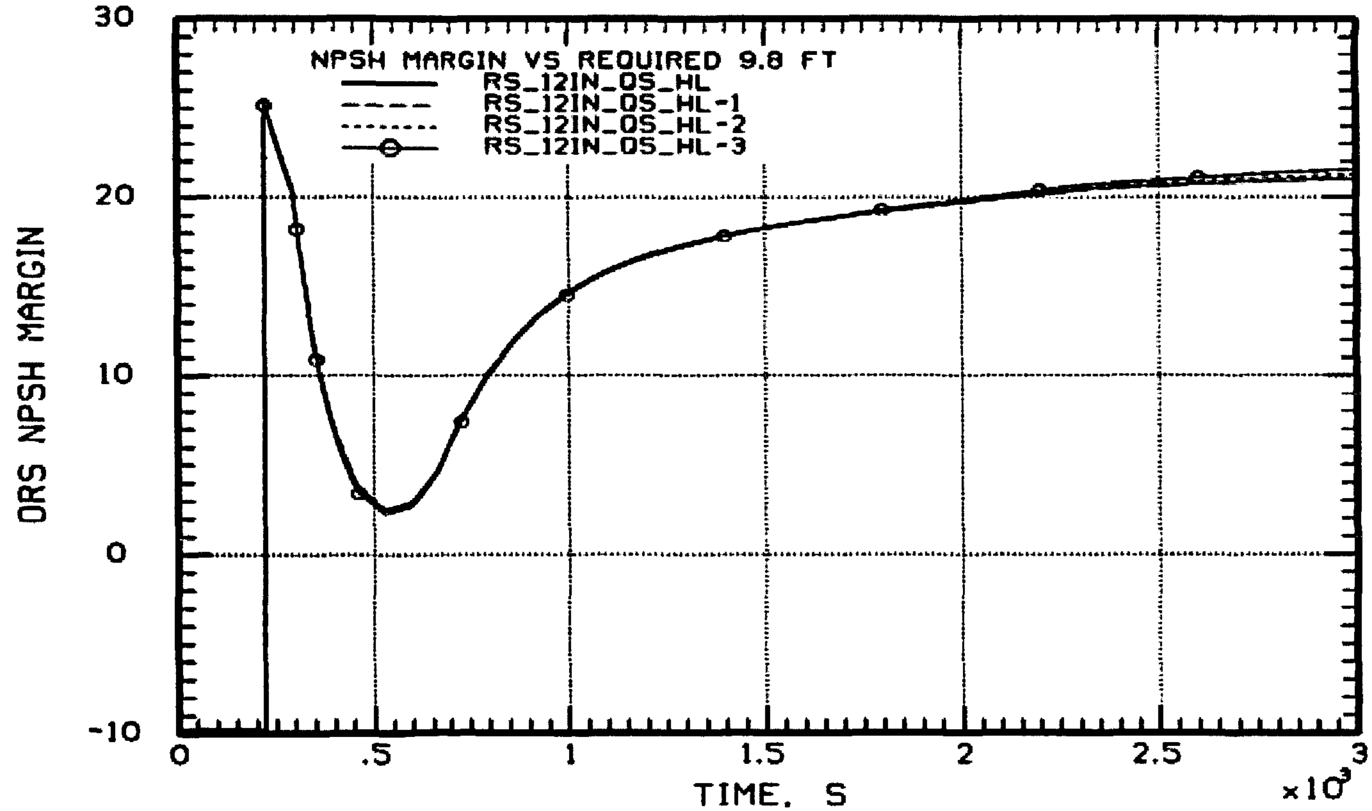
Containment Overpressure

- The previous curves are based on the limiting NPSH case and do not represent the bounding case in terms of COP time requirements
- Minimum heat removal cases are less limiting for NPSH margin but require COP for a longer period
- For all cases, COP is required for less than 20 minutes
- Based on testing completed on the model of RS pumps used at BVPS-1, the pumps are capable of operating at NPSH conditions below the standard definition of required NPSH (3% reduction in TDH) for a period of time exceeding the time of required COP

Containment Overpressure

- There is a low probability of losing containment isolation coincident with a LOCA (~1.0 E-8)
- The largest normally open piping penetrations which communicate directly with containment atmosphere are 2" diameter
- Loss of containment integrity is readily identifiable due to slightly sub-atmospheric operation
- Analyses have shown that failures of piping or isolation for lines which communicate directly with containment environment would not significantly effect NPSH
- The following plot shows the effect on the NPSH margin for containment openings of 1",2",3" diameter

Containment Overpressure



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Containment Overpressure

- No operator actions are required or credited to maintain required COP
- Operators are trained to observe pump performance for signs of cavitation
- Modifications to eliminate need for COP are considered impractical or ineffective
  - Lowering of RS Pumps
  - Injecting additional cool water into RS pump suction
  - Restricting pump flow to lower required NPSH

Containment Overpressure - Summary

- COP required for BVPS-1 RS pumps
- COP is part of current licensing basis for BVPS-1
- COP required for less than 20 minutes following pump start
- Type of RS pumps used at BVPS-1 have been successfully tested for operation below required NPSH
- The risk of losing COP is very low
- Modifications to eliminate need for COP are not practical

Safety Analysis – Dose Assessment

- Application of Alternative Source Term (AST) consistent with RG 1.183
- Updated X/Qs with more recent meteorological data
- ARCON 96 methodology used for on-site X/Q values
- Control room tracer gas test completed and results incorporated into dose analyses
- BV-2 continues to use Alternate Repair Criteria, Accident Induced Leakage for MSLB
- Calculated doses for EPU are within requirements of 10CFR50.67 for off-site and control room

Dose Assessment Results

Accident	EAB Dose (rem)	LPZ Dose (rem)	Offsite Limit	CR Dose (5 rem limit)
LOCA	14	2.5	25	2.0
CREA	3.1	1.5	6.3	1.3
MSLB (PIS)BV-1	0.08	0.01	25	0.5
MSLB (CIS) BV-1	0.11	0.04	2.5	0.66
MSLB (PIS)BV-2	0.4	0.1	25	0.2
MSLB (CIS) BV-2	2.5*	0.7	2.5	0.6
SGTR (PIS)	2.27	0.14	25	1.95
SGTR (CIS)	0.93	0.06	2.5	0.67
LRA	2.0	0.33	2.5	2.2
LACP	**	**	2.5	**
FHA	2.43	0.12	6.3	2.36
SLB	0.23	0.012	2.5	0.7

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* Alternate Repair Criteria **bounded by LRA

Safety Analysis Conclusions

- All applicable acceptance criteria are met at EPU conditions

- Beneficial plant modifications have been made to maintain safety margins at EPU conditions

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Materials & Rx Vessel

Dennis Weakland
(Fleet Materials)

Materials and Rx Vessel

- Reactor Coolant Pressure Boundary
  - Materials of Construction
  - Integrity Programs
- Alloy 600 Management
- Reactor Vessel Integrity
  - Pressurized Thermal Shock
  - Upper Shelf Energy

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RCS Materials

- Rx Vessel, SG and Pressurizer are carbon steel with Stainless Steel Clad
  - Penetrations
    - Stainless Steel
    - Alloy 600
- RCS Primary Loop Piping - Cast SS
- Balance of RCS Piping – SS
- Piping to vessel and component welds
  - Stainless Steel
  - Alloy 600 (82/182)

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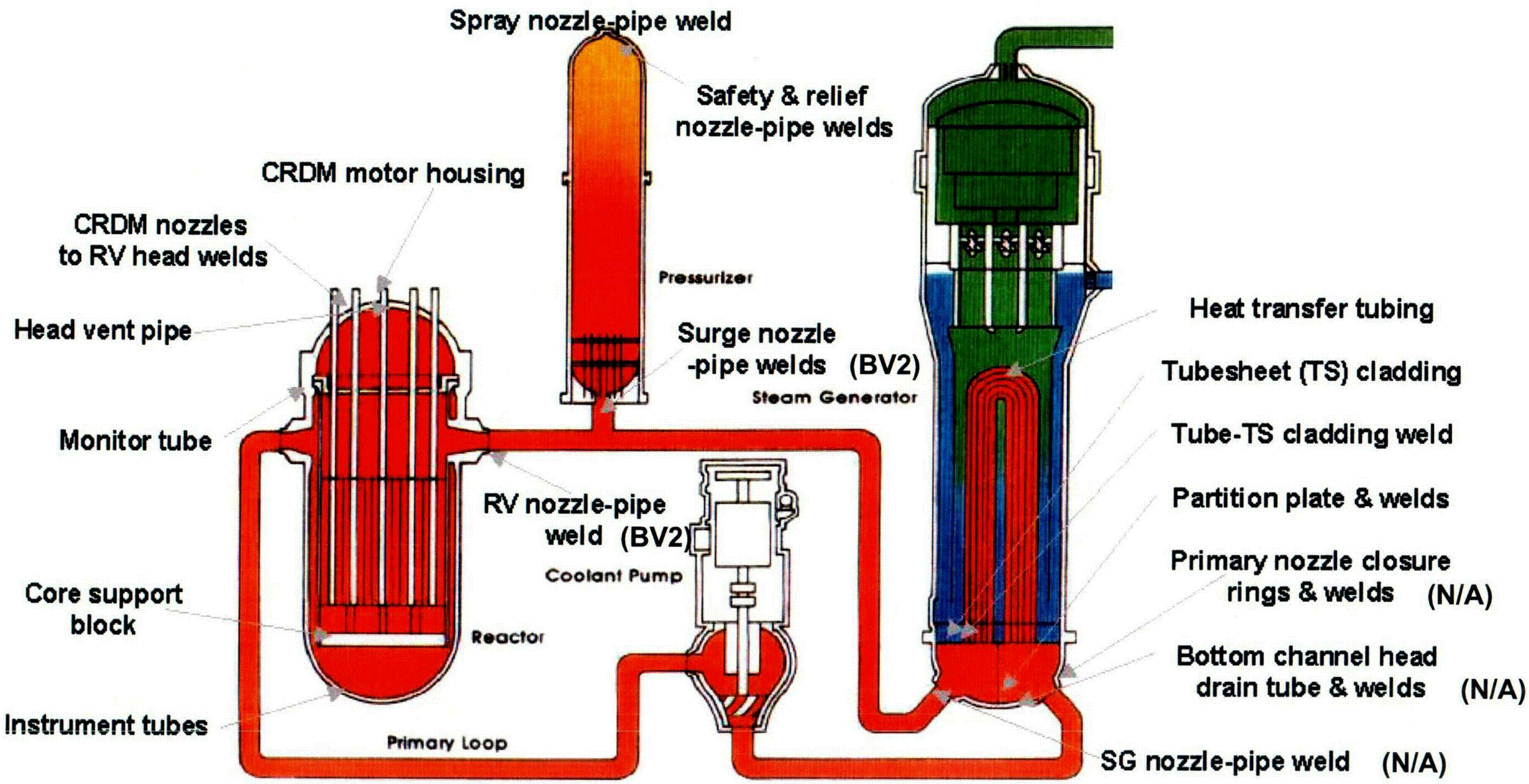
RCS Materials

Material Integrity Programs

- *Steam Generator Integrity Program*
- *Alloy 600 Program*
- *Boric Acid Program*
- *Reactor Vessel Integrity Program*
- *Materials Degradation Management Program*

These programs address specific RCS Integrity Issues and supplement the other Operations and Systems based Integrity programs

RCS Materials – Alloy 600 Program



NOTE: SG components are managed under the Steam Generator Management Program

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C05

BV-2 Head Inspection

- 2R10 (Fall 2003) Visual and Volumetric Inspection
  - Bare Metal Visual CDRMs and Head
    - No Degradation
  - Volumetric of CDRM penetrations
    - No Degradation
  - Eddy Current Exam of Vent line and weld
    - No Degradation
- 2R11 (Spring 2005) Visual Inspection
  - Bare Metal Visual CDRMs and Head
    - No Degradation

RCS Materials – Alloy 600 Program

Mitigation and Strategy

- BV Unit 1
  - RV Head and Steam Generators
    - Replaced (1R17, Spring 2006)
  - Pressurizer Nozzles
    - Weld Overlay (1R18, Fall 2007)
  - Remaining Alloy 600 will be limited
    - BMNs
    - RV Internals

RCS Materials – Alloy 600 Program

Mitigation and Strategy

- Beaver Valley Unit 2
  - Pressurizer Nozzles including Surge
    - Weld Overlay (2R12, Fall 2006)
  - Main Loop to Vessel Welds
    - Mitigation approach under review
  - Remaining Alloy 600
    - BMNs
    - RV Internals
    - SG Tubing and Internal Components
    - RV CRDM

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RCS Materials - Rx Vessel Integrity

- Reactor Vessel Materials Assessment Summary:
  - Fluence impact due to:
    - Uprate
    - Improved Capacity Factor
  - Surveillance schedule – No change BV 1 or BV 2
  - Upper Shelf Energy (USE) – > 50 ft-lbs for BV 1 and BV 2
  - PTS screening criteria (RTndt) - <270°F for BV 1 and BV 2
    - Both BV 1 and BV 2 are Plate Limited Plants
  - Applicability of heatup / cool down curves (Appendix G)
    - BV 1 Applicability adjusted for increase in fluence
    - BV 2 Analysis of record already addressed increase in fluence
    - Both will be revised through the PTLR Process
  - Operating pressure / temperature limits relative to ERG – No Changes for BV 1 or BV 2

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RCS Materials – RV EFPY

- Fluence – EFPY Relationship in EPULAR
  - *BV 1*
    - *WCAP 15571 Capsule Y – 28 EFPY*
      - *Fluence - 3.54 E19 n/cm²*
      - *RT_{PTS} – 259 °F*
      - *Assumed 1.4% Uprate, did not address 8% Uprate*
    - *EPULR Table 4.1.2-1A – 27.44 EFPY*
      - *Fluence - 3.54 E19 n/cm²*
      - *RT_{PTS} – 259 °F*
      - *Assumed 1.4% Uprate from WCAP, 8% Uprate in June 2003*
  - *BV 2*
    - *WCAP 15575 Capsule Y – 32 EFPY*
      - *Fluence - 3.85 E19 n/cm²*
      - *RT_{PTS} – 149 °F*
      - *Assumed 1.4% in 2001, 8% Uprate in June 2003*

RCS Materials – RV EFPY

- Fluence – Current EFPY Projections
  - *BV 1*
    - *Current Projection – 30.5 EFPY*
      - *Fluence - 3.54 E19 n/cm²*
      - *RT_{PTS} – 259 °F*
      - *Assumed 1.4% 2001 (WCAP 15571), 8% Uprate in June 2006*
      - *Capacity Factor of 98%*
  - *BV 2*
    - *Current Projection, WCAP 16527 – 36 EFPY*
      - *Fluence – 4.113 E19 n/cm²*
      - *RT_{PTS} – 149 °F*
      - *Assumed 1.4% in 2001, 8% Uprate in June 2006*
      - *Capacity Factor of 98%*

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RCS Materials - Summary

- Materials Considerations
  - *Temperature Assessment*
    - *No Programmatic Impact on Alloy 600 Program*
    - *No programmatic impact on Steam Generator Program*
  - *Fluence Assessment*
    - *No significant impact on Reactor Vessel Integrity*
    - *No significant impact on Reactor Vessel Internals*
- *These small changes in material response to these conditions is addressed through the Materials Management Programs*

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Mechanical Impacts

Mike Testa
(EPU Project Manager)

Mechanical Impacts – Agenda

- Steam Generator
- BOP Heat Exchangers
- Vibration Monitoring Program
- Cooling Water Systems
- Flow Accelerated Corrosion

Steam Generator Vibration

- Thermal-Hydraulic Analysis w/Athos
- Vibration potential in U-Bend & Tube Bundle Entrance
- Potential tube vibration mechanisms
  - Fluidelastic instability
  - Vortex shedding
  - Random turbulence excitation
- Tube wear (U-Bend region)

Tube Bundle Region

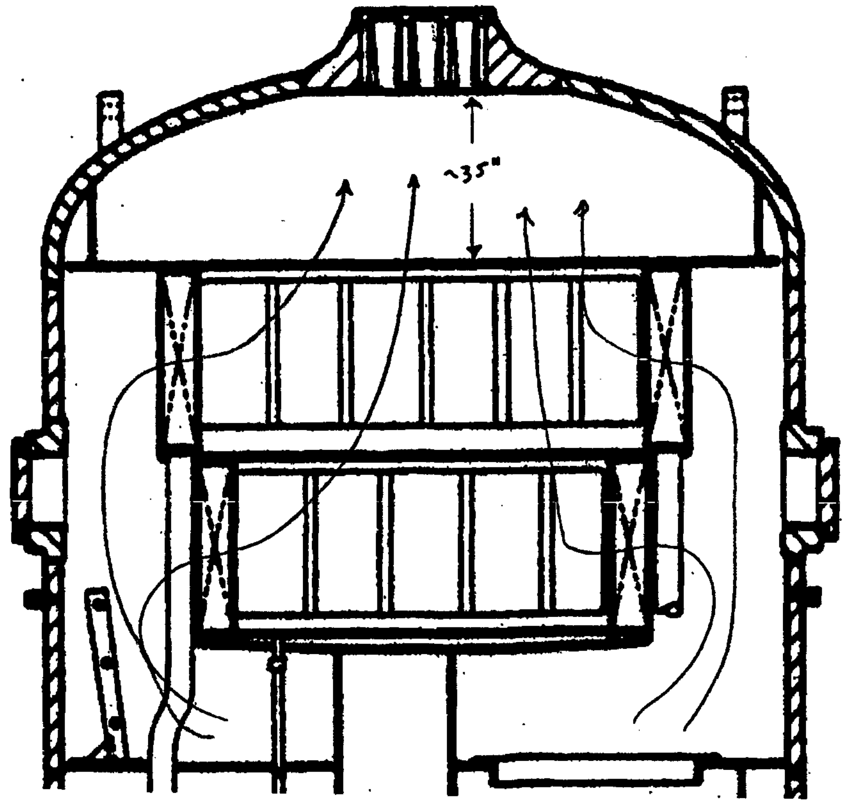
- Unit 1 – Model 54F
  - Steam Generator installed in 1R17
  - Designed for uprated conditions
    - Analysis performed using uprate operating conditions
- Unit 2 – Series 51M
  - Review for Flow Induced Vibration (FIV) affects showed acceptable results
  - Unsupported U-bends reviewed for increased fatigue
  - Increase in tube wear at Anti-Vibration Bar (AVB) interface evaluated

Steam Dryer Region BV

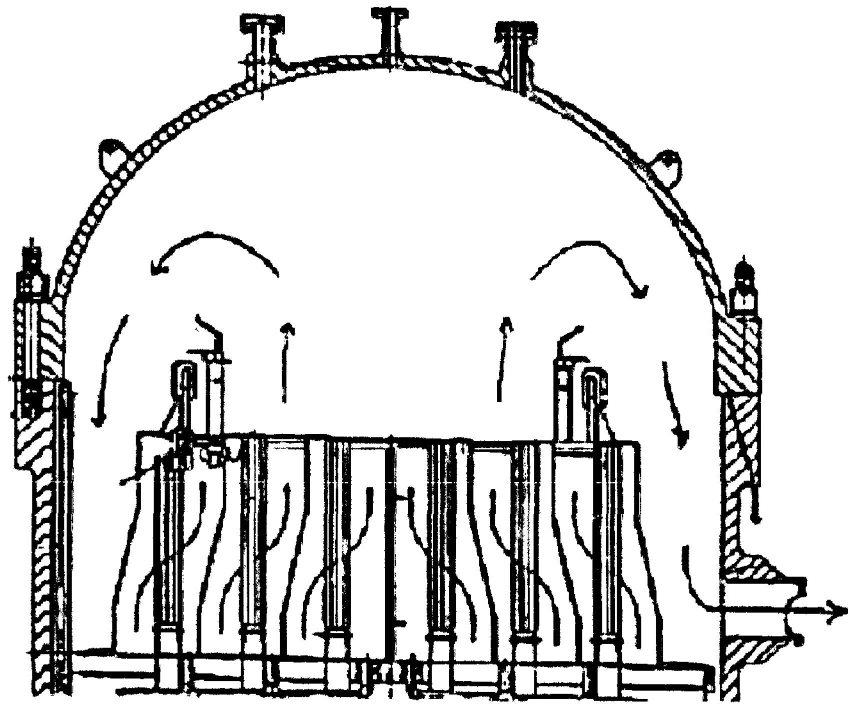
- Series 51/51M
  - Two Tier Arrangement
  - Series 51 M Includes ½" Thick Perforated Plate
  - Peerless Separator Vanes – Carbon Steel
  - Mounted From Top of SG on Support Ring
  - Supports Mid Deck Plate – Robust Structure
- Series 54F
  - Single Tier Arrangement
  - Includes Perforated Plate
  - Peerless Separator Vanes – Carbon Steel
  - Mounted From Top of SG on Support Ring

Steam Dryer Region

Series 51M

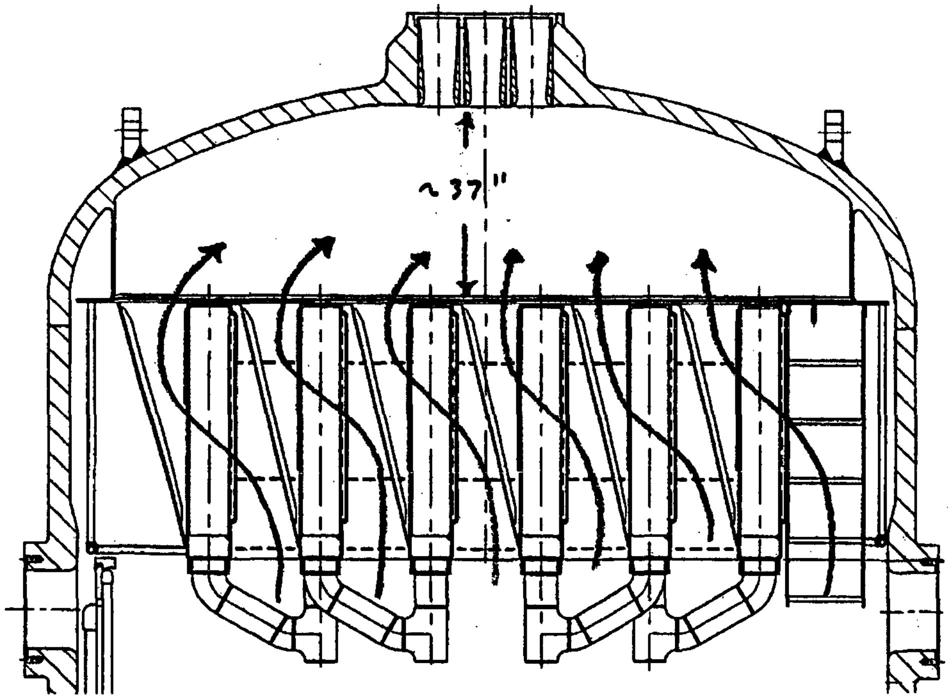


Typical BWR

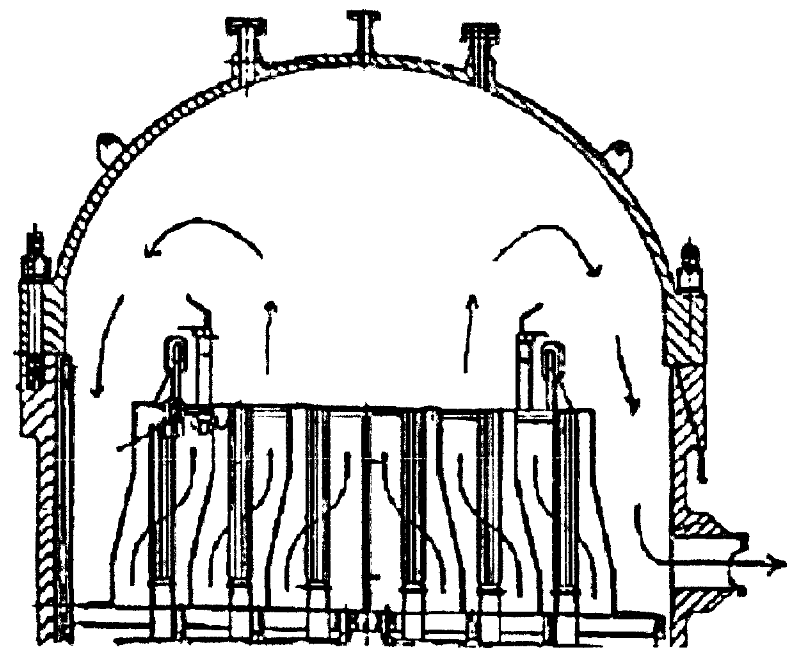


Steam Dryer Region

Series 54F



Typical BWR



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Steam Dryer FIV Comparison

- Series 51/51M
  - Low Flow Rates Near Dryer vs BWR
    - Pre-Uprate – 3.5 ft/sec
    - Post Uprate – 4.1 ft/sec
    - *BWR ~ 100 ft/sec*
  - Low Turbulence Potential Vs. BWR
  - No Operational Issues Reported
    - 22 Domestic Plants
    - 74 Domestic SG
    - Operational from early 70's
- Series 54F
  - Low Flow Rates Near Dryer vs BWR
    - Pre-Uprate – 3.0 ft/sec
    - Post Uprate – 3.5 ft/sec
    - *BWR ~ 100 ft/sec*
  - Low Turbulence Potential Vs. BWR
  - No Operational Issues Reported
    - 6 Domestic Plants
    - 18 Domestic SG
    - Operational from mid 90's

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BOP Heat Exchanger Vibration

- Feedwater Heaters
- Moisture Separator Reheaters
  - Specific analysis confirmed acceptability of increased steam flow
- Condenser Tubing
  - BVPS-1 condenser tubes previously staked
  - BVPS-2 will be staked prior to power uprate

Vibration Monitoring

- Monitor Secondary systems pre and post EPU
  - Baseline walk downs conducted on each plant
  - Areas of interest targeted for inspection under EPU
- Utilize guidance from ASME OM-S/G-2003, Part 3
- Collect and review data at each of the power escalation plateau
- Inspections will be augmented as required with vibration monitoring equipment
- Large equipment (e.g. Reactor Coolant Pump, Turbine) monitored with existing plant instrumentation
  - Secondary pumps will also be monitored

Cooling Systems

- Systems remain capable of dissipating heat loads for normal, shutdown and accident conditions
- Flows are adequate without modification
  - River / Service water systems
  - Component cooling systems
  - Residual heat removal system
  - Safety Injection and Containment Depressurization systems

Spent Fuel Cooling

- Spent fuel cooling previously evaluated for EPU conditions in Amendments 247 and 126 (100 hour minimum offload time)

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Auxiliary Feedwater

- Condensate Storage Tank sizing is based on amount of water required for 9 hours at hot standby conditions
  - New Tech Spec limits for EPU require a minimum useable volume of 130,000 gallons
- 2 auxiliary feedwater pumps required for certain accidents (FLB and LONF)
  - Tech Spec bases for BVPS-1 revised to be consistent with BVPS-2
  - Required due to incorporation of cavitating venturis at BVPS-1

Flow Accelerated Corrosion (FAC)

Dave Grabski

(FAC Program Owner)

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Flow Accelerated Corrosion

- EPU effects evaluated using CHECWORKS
- Turbine extraction steam tee proactively replaced
- Post Uprate Outage inspection sampling increased based on EPU conditions
- Piping systems impacted will continue to be monitored to detect any deviation from predicted wear rates

Risk Impact

Colin Keller
Supervisor, PRA

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Probabilistic Risk Assessment

- Risk Assessment
  - PRA Model Elements
  - Resultant CDF changes for each model

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Probabilistic Risk Assessment

- Initiating Events
  - No new initiators
  - No significant increase in Initiating Event frequencies due to the Power Uprate
- Success Criteria
  - MAAP analyses establishes EPU success criteria
    - Setpoint Changes due to Containment Conversion
    - New Pump Curves
  - No new accident sequences identified

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Risk Assessment

- Component and System Reliability
  - Comprehensive reviews of equipment performed
  - Systems operate within allowable limits
  - No impact on PRA failure rates or results
  - Existing monitoring programs will account for any additional system wear (Maintenance Rule, MSPI)
  - Future model updates will capture any initiating event or equipment failure rate changes

Probabilistic Risk Assessment

- Operator Response Times / HRA
  - MAAP analyses to determine operator action time available
  - Higher decay heat reduced times for some operator actions
  - Most important impacts are:
    - Operator starts AFW given SSPS has failed and no SI signal present
    - Operator initiates bleed & feed
    - Reduction in time to recover from loss of shutdown cooling during reduced inventory

Probabilistic Risk Assessment

BVPS-1 Risk Important Operator Actions						
Operator Action	**Description**	**Pre-EPU Time**	**Pre- EPU HEP**	**Post-EPU Time**	**Post-EPU HEP**	**Confirmation Method**
OPROS6	Operator starts AFW given failure of SSPS for sequences in which there is no safety injection; e.g., turbine trip sequences.	62 minutes	8.15E-04	43 minutes	1.12E-03	Table-top & Simulator Observation
OPRWM1	Operator supplies borated makeup water to the RWST initially from the spent fuel pool, and, in the long term, from blending operations during an SGTR event	>24 hours	7.68E-03	>24 hours	7.68E-03	Table-top & Simulator Observation of Annunciators
OPRBV3	Operators set up and start portable diesel driven fans to cool the emergency switchgear rooms upon failure of the normal switchgear ventilation fans and the emergency switchgear ventilation fans.	30 minutes	7.11E-02	30 minutes	7.11E-02	Table-top & Simulator Observation of Annunciators
OPROC1	Operator trips RCP during loss of Primary Plant CCW.	5 minutes	4.79E-03	5 minutes	4.79E-03	Simulator Observation
OPROB2	Operators initiate bleed and feed operation by initiating safety injection, opening the PORVs, opening the PORV block valves, and verifying HHSI pump operation following failure to restore MFW and Dedicated AFW.	78 minutes	1.53E-02	29 minutes	1.68E-02	Table-top & Simulator Observation

Probabilistic Risk Assessment

BVPS-2 Risk Important Operator Actions						
Operator Action	**Description**	**Pre-EPU Time**	**Pre- EPU HEP**	**Post-EPU Time**	**Post-EPU HEP**	**Confirmation Method**
OPROB1	Operators initiate bleed-and-feed operation by initiating safety injection, opening the PORVs, reopening the PORV block valves, and verifying HHSI pump operation.	78 minutes	1.87E-03	64 minutes	2.15E-03	Table-top
OPRWM1	Operator supplies borated makeup water to the RWST initially from the spent fuel pool, and in the long term, with makeup from service water during an SGTR event.	>24 hours	5.97E-03	>24 hours	5.97E-03	Talk/Walk-thru of similar action for 2" LOCA
OPROF2	Operator opens main feed bypass valves following a partial feedwater isolation event after a plant trip.	78 minutes	2.93E-04	26 minutes	4.96E-04	Table-top
OPROS6	Operator starts AFW given failure of SSPS for sequences in which there is no safety injection; for example, turbine trip sequences.	78 minutes	1.00E-03	43 minutes	1.00E-03	Table-top
OPROT1	Operator pushes the manual reactor trip buttons after the Solid State Protection System (SSPS) fails to automatically actuate reactor trip in response to a plant trip condition.	1 minute	1.37E-03	1 minute	1.37E-03	Table-top

Probabilistic Risk Assessment

- Operator Response Times / HRA
  - Validation of operator time to complete actions was performed
  - Operator actions with small amount of time available can be performed within the time available

Probabilistic Risk Assessment

- Shutdown Risk
  - EPU has no unique or significant impacts
  - No changes to shutdown operations or safe shutdown risk assessment

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Summary (Unit-1)

BVPS-1 Risk Measures	Pre-EPU Model	Post-EPU Model	Change in Risk
Total CDF (/year)	2.25 E-05	2.29E-05	3.36E-07 *
Internal CDF (/year)	6.25 E-06	6.55 E-06	2.97 E-07
External CDF (/year)	1.63 E-05	1.63 E-05	3.95 E-08
Fire CDF (/year)	4.62 E-06	4.66 E-06	3.89 E-08
Total LERF (/year)	4.37 E-07	4.95 E-07	5.83 E-08 *

*Meets the threshold for risk significance as defined by Reg. Guide 1.174.

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Summary (Unit-2)

BVPS-2 Risk Measures	Pre-EPU Model	Post-EPU Model	Change in Risk
Total CDF (/year)	3.30 E-05	3.33 E-05	3.55 E-07 *
Internal CDF (/year)	1.86 E-05	1.89 E-05	2.92 E-07
External CDF (/year)	1.44 E-05	1.45 E-05	6.32 E-08
Fire CDF (/year)	4.89 E-06	4.95 E-06	6.38 E-08
Total LERF (/year)	1.03 E-06	1.07 E-06	4.61 E-08 *

*Meets the threshold for risk significance as defined by Reg. Guide 1.174.

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PRA Conclusion

All PRA model elements reviewed for impact

- The increase in risk, due to the EPU for BVPS-1 and BVPS-2, meets the acceptance criteria as defined by Regulatory Guide 1.174
- Small change in operator time available
- Additional equipment has small impact on risk

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Operations and Testing

Don Durkosh
(Senior Reactor Operator)

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Operations and Testing – Agenda

- Human Factors
- Training
- Test Plan
- Large Transient Testing

Human Factors -- Overview

- Minimal changes to control room (CR)
  - Six accumulator pressure indicators
  - Two containment pressure indicators
- EOPs upgraded to ERGs in 2003
- EPU procedure changes reflect revised operating parameters, limits & setpoints
- Added EOP Attachment for CR purge post-SGTR (existing SLB purge attachment)

Human Factors -- Action Times

- Increased decay heat reduces available time to perform some operator actions:
  - The basic operator actions remain unchanged
  - No new modifications required
  - Most action times have remained unchanged or have increased
  - Procedure enhancements are being incorporated
  - Action times being re-validated (simulator, walk downs, Table-top, etc.)

Reduced Operator Action Times

- ECCS Switchover (hot leg recirculation)
  - BVPS-1, 8 hours to 6.5 hours
  - BVPS-2, 7 hours to 6 hours
  - BVPS-2, 11.5 hours to 9.5 hours
- SGTR – Isolating AFW flow
- Post trip, fire – Restoring AFW flow

SGTR Action Time

- Key Action:
  - Isolate AFW flow to ruptured S/G
- EPU analyses based on crew simulator data from 2002
- EPU validation status:
  - BVPS-1 simulator complete
  - BVPS-2 initial (Table-top) complete
  - BVPS-2 simulator (planned for later this year)

Fire Scenario Action Time

- Key Action:
  - Re-establish AFW flow if lost during a fire incident
- BVPS-1 status:
  - Established operator action times
  - Enhanced the fire-related procedures
  - Completed walk downs to validate action times
- BVPS-2 status:
  - Procedures previously enhanced
  - Walk downs will be performed to validate action times

Operator Training

- Classroom (Design Change packages)
  - Technical Specification & LRM changes
  - Plant (physical) changes
  - Procedure & setpoint changes
- Simulator Focus Areas
  - Demonstrations & hands on training
  - Transient response & EOP execution
- Power Ascension (Just-In-Time)
  - Startup/shutdown

Operator Training (cont.)

- Crew training implemented prior to implementation of EPU-related plant modifications
- Plant-specific simulators are used
- Simulator changes are primarily software & initial condition differences that can easily be configured for current or EPU plant conditions

Test Plan

- Post modification tests
- Low power physics tests
- Collect baseline data
- Power ascension in small increments
  - Perform data projections
  - Collect data at new steady state conditions
  - Review plant data & evaluate anomalies

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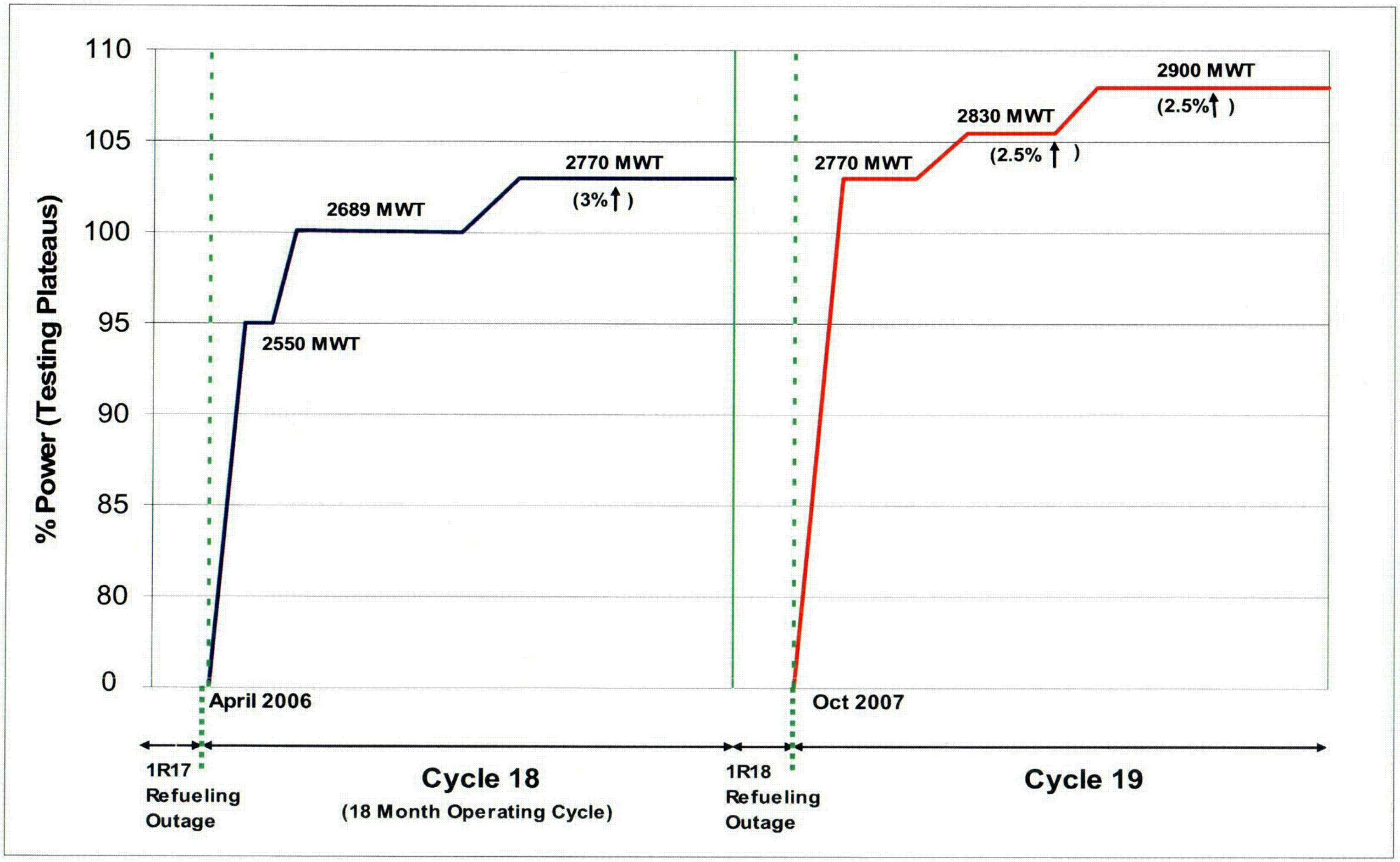
BVPS-1 Power Ascension Profiles

(NOTE - Timelines Not Drawn To Scale)



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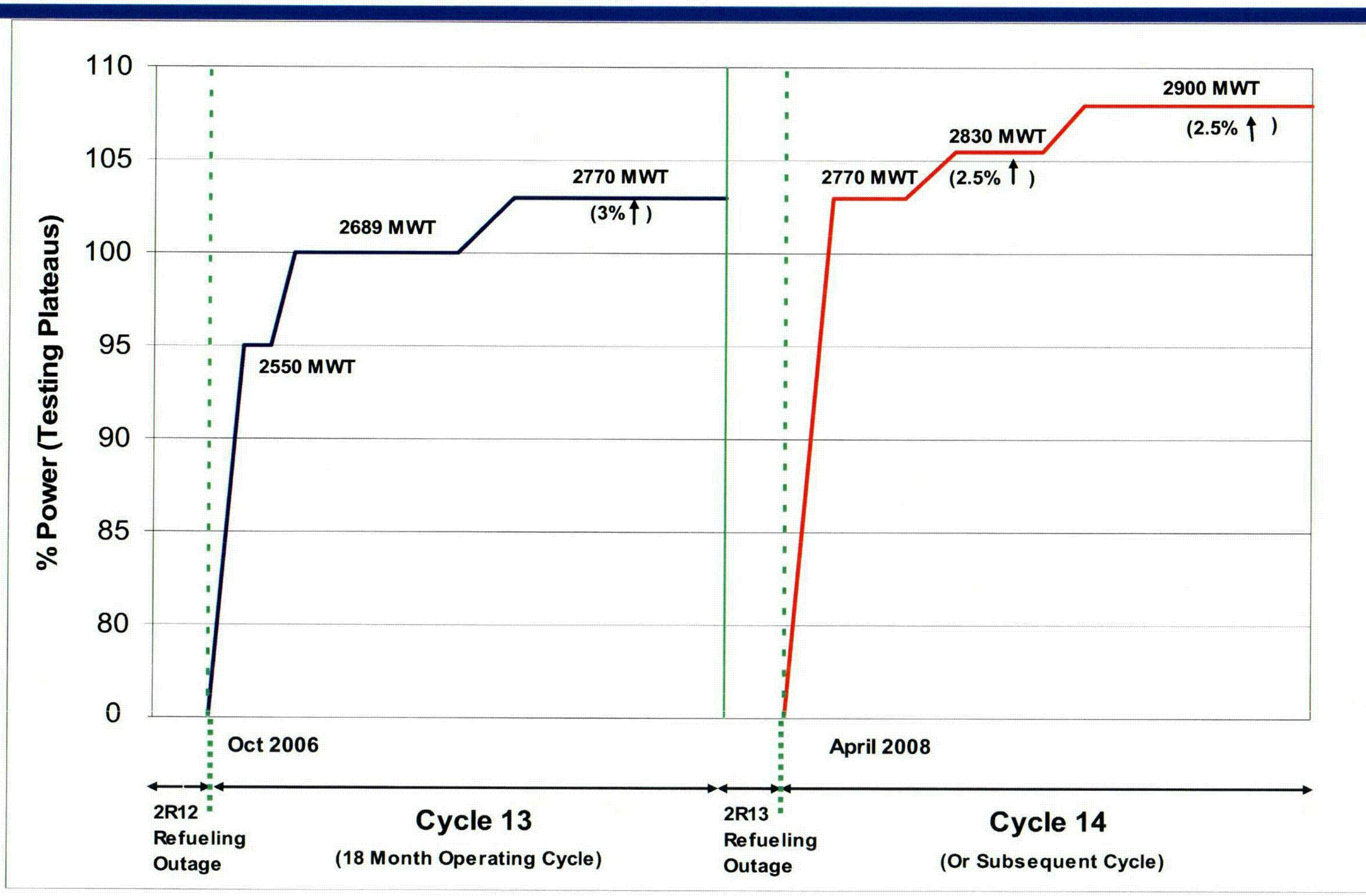
BVPS-2 Power Ascension Profile

(NOTE - Timelines Not Drawn To Scale)



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Transient Testing Considerations

- Evaluated modifications & control changes:
  - Modifications will be fully tested
  - Extensive Owner's review of NSSS Control supporting analyses:
    - No controller functional/logic changes
    - No new control schemes
    - Changes limited to setpoints (optimization)
- Aggregate impact does not adversely affect plant dynamic response

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Planned Testing, BVPS-1

- Monitor control system during start-up
- Perform a S/G level control test
  - Input step-change in "actual" level
  - Monitor controller response
  - Confirm integrated system response

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Large Transient Testing

- Turbine trip > 49% power results in reactor trip
- No functional change in NSSS controls and supporting reactor trip functions
- The NSSS simulation code/model:
  - Supported original plant NSSS control system design
  - Supports current plant NSSS operational analyses
  - Used to benchmark the BVPS simulators
  - Used in current & EPU non-LOCA safety analyses.
  - Used to optimize NSSS controls for EPU conditions
- As such, LTT is not necessary

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Operations & Testing -- Conclusions

- Procedure changes involve primarily operating parameters, limits & setpoints
- Power ascension process will ensure a controlled, closely monitored, conservative approach to the new licensed power level
- Plant modifications & NSSS control changes do not alter the basic design function nor introduce first-of-a-kind type changes that warrant LTT.

Concluding Remarks

Site VP – Jim Lash

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Concluding Remarks

- Detailed and comprehensive reviews have been performed
- No safety issues identified
- Conservative phased approach to power escalation is being employed
- Beaver Valley Power Station safety and reliability will be maintained through plant modifications, procedure changes and training, and adherence to TS / Operating License

End of Presentation

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