Official Transcript of Proceedings

NUCLEAR REGULATORY COMMISSION

Title: Advisory Committee on Reactor Safeguards
Digital Instrumentation and Control Systems

Docket Number: (n/a)

Location: Rockville, Maryland

Date: Monday, November 17, 2014

Work Order No.: NRC-1227 Pages 1-229

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NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

(ACRS)

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DIGITAL INSTRUMENTATION AND CONTROL SYSTEMS

SUBCOMMITTEE

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MONDAY, NOVEMBER 17, 2014

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ROCKVILLE, MARYLAND

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The Subcommittee met at the Nuclear Regulatory Commission, Two White Flint North, Room T2B1, 11545 Rockville Pike, at 1:00 p.m., Dennis C. Bley, Chairman, presiding.

COMMITTEE MEMBERS:

DENNIS C. BLEY, Chairman

RONALD G. BALLINGER, Member

CHARLES H. BROWN, JR., Member

DANA A. POWERS, Member

STEPHEN P. SCHULTZ, Member

GORDON R. SKILLMAN, Member

JOHN W. STETKAR, Member

DESIGNATED FEDERAL OFFICIAL:

CHRISTINA ANTONESCU

ALSO PRESENT:

ROBERT ARITT, EPRI

MICHAEL CHAN*

GORDON CLEFTON, NEI

ROBERT C. DALEY, RIII

SCOTT GREENLEE, NEI

WAYNE JOHNSON, EPRI

MARVIN LEWIS*

G. SINGH MATHARU, NRR/DE/EEEB

ROY MATHEW, NRR/DE/EEEB

KIRK ROBBINS, Exelon Corporation

MARY JANE ROSS-LEE, NRR/DE

RUTH THOMAS*

*Present via telephone

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

(1:01 p.m.)

CHAIRMAN BLEY: The meeting will please come to order.

This is a meeting of the I&C Subcommittee. I=m Dennis Bley, Chairman of this subcommittee meeting. ACRS members in attendance are Charlie Brown, John Stetkar, Steve Schultz, Dick Skillman, and is Harold on the phone? Is he going to be on this one? Okay. He will not be here. Christina Antonescu of the ACRS staff is the Designated Federal Official for this meeting.

The purpose of this meeting is to be briefed by the staff at NRC, NEI, and EPRI on draft Branch Technical Position 8-9, which provides criteria and guidance for the review of licensing actions pertaining to the resolution of open phase issues in electric systems.

I=ll note that the focus of today=s discussion from our point of view is not the precise sequence of events, but the barring event, the detection and response to all the possible fault conditions.

I might also note that you focus have driven a number of the EEs on this subcommittee back to their old textbooks to try to understand this issue a little better.

The subcommittee will gather information, analyze relevant issues and facts, and formulate positions and actions, as appropriate, for deliberation by the full committee.

The rules for participation in today=s meeting have been announced as part of the notice of this meeting previously having been published in the Federal Register. We have received no written comments or requests for time to make oral statements from members of the public regarding today=s meeting.

Also, we have a number of people on the bridge phone line listening in to the discussions. There are representatives of NEI, New Steel, the Nuclear Fleet Common Design, and Dominion Nuclear Projects, and possibly other stakeholders and members of the public.

To preclude interruption of the meeting, the phone line will be placed on the listen-in mode during the presentations and committee discussions. The bridge line will be open at the end of the meeting to see if anyone listening would like to make comments.

A transcript of the meeting is being kept and will be made available as stated in the Federal

Register Notice. Therefore, we request that participants in this meeting use the microphones located throughout the meeting room when addressing the subcommittee. Participants should first identify themselves and speak with sufficient clarity and volume that they are readily heard.

We will now proceed with the meeting, and I call upon Ms. Mary Jane Ross-Lee, Deputy Director of the Division of Engineering in the Office of Nuclear Reactor Regulations to make an opening statement.

MS. ROSS-LEE: Thank you. Good afternoon. As introduced, I am MJ Ross-Lee, the Deputy Director of Division of Engineering in NRR. Staff was requested to provide an informational briefing on open phase conditions in electrical power systems to the subcommittee. With me today is Roy Mathew, team leader from the Electrical Engineering Branch. Roy will brief you on the status of NRC actions and its path forward on resolving this issue.

The staff issued a bulletin, NRC Bulletin 2012-01, Design Vulnerability in Electrical Power Systems on July 27th of 2012. That required a written response from all holders of operating licenses and combined licenses for nuclear power reactors. We asked for a response within 90 days, and all of the licensees met that. The staff reviewed all licensee responses and issued a summary report with its conclusions and recommendations to close out the bulletin.

Since the open phase issue has come up, the staff and industry has proactively engaged to address it for current and new nuclear power reactors. The staff appreciates the demonstrated industry attention and leadership commitment to support resolution.

So far the staff has conducted 11 public meetings and supported an industry initiative to resolve the open phase issue. Industry representatives are here today and will discuss their efforts. The staff has also issued a draft Branch Technical Position 8-9 to provide guidance to the staff in reviewing future licensing actions related to open phase conditions in electrical power systems and shared a draft interim enforcement policy that would finalize the agency=s regulatory action on the open phase issue.

The staff is evaluating the public comments and finalizing these documents. Once completed, the staff will provide a paper to the Commission seeking approval to grant enforcement discretion from applicable requirements.

I want to bring also one other additional issue to the subcommittee=s attention. The staff has prepared a final response to comments provided by the industry in letters dated March 12th of 2014 and August 14th of 2014 from the Nuclear Energy Institute.

The letters explain the industry=s perspective from the -- that the protective system requirements in 10 CFR, Protection Systems, do not apply to the industry=s proposed generic solution that resolves the open phase condition vulnerability and the regulatory issues related to it.

We will provide a copy of the NRC response letters to the ACRS when issued. Roy Mathew will discussed the staff=s position stated in its letter during his presentation today. The public comments we receive from the industry for the Branch Technical Position will also be dispositioned based on staff positions stated in the letter.

I will now turn it over to Mr. Mathew to lead the staff discussion.

CHAIRMAN BLEY: Thanks. Before you begin, Roy, I=d like to note for the record that Dana Powers has joined us.

MR. MATHEW: Thank you. I am -- my mic is on?

CHAIRMAN BLEY: Yes. You=re good.

MR. MATHEW: Okay. Yes. Thank you. Welcome, everybody. I am going to discuss -- by the way, I=m Roy Mathew from Electrical Branch. I am responsible for handling the bulletin issue from the NRC side.

I am going to discuss today several items, bringing you up to speed on the open phase issue. I will go through the agenda. I don=t have to read all of this. Basically, I=m going to go through the, you know, power system basics, safety significance, requirements, NRC actions, staff recommendations, DTP, and I=ll briefly talk about the path forward.

In the second presentation, I am focusing on the BTP comments. I can be part of this meeting, or I can wait, we break, and then come back and do the presentation. Let me know either way.

CHAIRMAN BLEY: Well, let=s see how it goes. But if we could get all that done before that 3:00 -- we=ll try to do it before the break.

MR. MATHEW: Open phase condition. Actually, staff defines the open phase condition as a loss of one of the three phases of AC power system. AC power system is three-phase power system, so loss of one of the phases of the offsite power circuit on the high voltage side of a transformer connecting an offsite power circuit to the transmission system, coincident with the high-impedance ground -- of the fault ground.

The reason why we are saying offsite power circuit, one phase, you know, offsite power circuit, that is the limiting case where, if you have a loss of one phase before a power transformer, that is a worrisome balance you see in the electrical power system.

So when we issued the bulletin, that was the definition we gave, and then we picked up some of the international operating experience which resulted in loss of two phases. So the industry reviewed that issue. That may -- in some cases, may be the worst case or -- so we are defining the open phase as loss of one phase of the offsite power circuit with and without ground, and also loss of two of the three phases.

High-impedance fault -- I just want to define what is high-impedance fault. High-impedance fault is ground fault that produces fault currents which are below the traditional overground protection. If you look at the electric power system, you can see transformers of ground overcurrent protection.

So if it is a true ground fault, without a high impedance in the system, your relay will pick up. So we are defining that aspect.

Also, what does open phase do to the electric power system? Electric power system -- the impact is creating an unbalanced power system. Traditionally, you know, GDC 17 and all the requirements are to maintain power systems with adequate capacity and capability.

So if you had a -- this open phase issue creates an unbalanced voltage, so it has its own issues. Some of the things are based on transformer winding. We say technically the vector configuration of the transformer, some of them are Wye-Wye. We have all kinds of different winding configurations for the electric power system. So some of them are listed here.

Then, the other aspect is grounding. The consumer with the certain winding configuration, Wye-Wye, is grounded solidly or with resistance. That makes a difference.

So I was trying to say there are a lot of parameters that changes the voltage and balance.

CHAIRMAN BLEY: I have just two comments here. One, I have been refreshing some of this for myself, because I haven=t looked at it in a long time, but I guess some transformers can have additional cores that don=t have linings on them that also affect this issue. And I don=t see that mentioned much.

And although the definition in the BTP talks about high-impedance faults, I haven=t seen much on the analysis side that=s looking at that. Can you comment on that?

MR. MATHEW: Yes. My understanding is when the licensees look at part of the bulletin response, they look through with the high-impedance fault, ground fault, normal ground fault, and they showed that if you have a high-impedance ground it is very hard to balance.

CHAIRMAN BLEY: Well, that was my question. I mean, that=s harder to detect.

MR. MATHEW: Okay. So when I go through the presentation, I will mention those aspects as well as industry is going to go through the presentation, which they do a lot of simulations. We will get more information.

CHAIRMAN BLEY: Okay. So we might find more about that from there.

MR. MATHEW: Yeah.

MEMBER BROWN: Can I ask a question relative to the listing we have?

MR. MATHEW: Right.

MEMBER BROWN: You talk about shell or core type transformers. Do you -- I=m trying to remember what you covered, the application of three single-phase transformers connected into a -- that changes the magnetic characteristics relative --

MR. MATHEW: Yeah, yeah.

MEMBER BROWN: -- to how you get your secondary --

MR. MATHEW: Right.

MEMBER BROWN: Did you all cover those at all?

MR. MATHEW: Yeah. I mean, our guidance says, you know, you have to look at the transformer configuration, the winding configuration, the operating/loading configuration, the configuration of the plant, how it=s connected, are they using --

MEMBER BROWN: But you=re not excluding that even though it=s not listed up there.

MR. MATHEW: Yeah.

MEMBER BROWN: That was my question. Okay. Thank you.

MR. MATHEW: I mean, basically, if your power system has certain configuration, you have to take into account all of those configurations. If it=s a single three-phase transformers -- I mean, single phase, three transformers --

MEMBER BROWN: Three single-phase transformers.

MR. MATHEW: Yeah.

MEMBER BROWN: Okay.

MEMBER STETKAR: I had a question, again, about kind of the scope of the guidance. Everything that I=ve read seems to be focusing solely on transformers that connect to the switchyard.

MR. MATHEW: Right.

MEMBER STETKAR: And yet there are plant configurations where I can have a generator circuit breaker where I have a main transformer that connects to the switchyard, and then I have auxiliary transformers that connect to the in-plant buses.

I can have an open circuit on one of those open phase on one of those auxiliary transformers that would have the same effect, and yet the guidance doesn=t seem to address that configuration.

MR. MATHEW: Right.

MEMBER STETKAR: And I=m aware of other plants that have intermediate power transfer buses. Let=s say the switchyard -- I won=t mention the plant names, but the switch yard may be at 345 kV, the intermediate transfer bus might be at 13.8 kV, and then you have step-down transformers from that down to 4.6 kV. It doesn=t seem to address that configuration either.

MR. MATHEW: I mean, what we say -- let me try to explain that. What we tried to say in the BTP, we say qualified -- if you have power sources which are configured differently per the license of the plant, so we have configuration that some of the plant uses generator or output breaker, and they are using the main transformer and the unit aux transformer to backfeed.

That is a qualified power source for that particular plant. So if you have to have an open phase occurring anywhere, you have to address that configuration. If you have a startup transformer or an auxiliary transformer, that is your qualified power source and it=s coming from the switchyard. You have to address that.

So GDC 17 requires you to have qualified power sources, so most of the plants have two sources. So it could be using the backfeed if you have a delayed source, that that=s a licensing basis. If you have two immediate power source, you could have a configuration with a generator output breaker when the transformers are main transformer and UATs.

So it depends on the loading -- I mean --

MEMBER STETKAR: Let me cut to the practical end of this. I don=t read what you=re saying in the BTP, because the BTP says high voltage side of a transformer connecting an offsite power circuit to the transmission system. I have seen people interpret that literally as the connection to the switchyard, and you don=t need to look at any other transformers.

You only need to look at transformers that are connected to the switchyard. And in fact I=ve had discussions with staff reviewers who have said that=s all we need to look at because that=s all addressed -- that=s all that=s addressed in the bulletin, and that=s all that=s addressed in the branch technical position. I=m questioning why that is. And what I=m reading is different from what I hear you saying, so --

MR. MATHEW: Yeah. Remember, the BTP is still in draft. We have so many comments, we are going to --

MEMBER STETKAR: Yes, but the comments -- I=ve read all the comments, and the comments are all the fact that you shouldn=t be looking at it at all. I didn=t read any comments that said you should be looking at more.

MR. MATHEW: Right.

MEMBER STETKAR: I have yet to read a

comment that says you should be --

MR. GREENLEE: Could I say something?

MEMBER STETKAR: Yes.

MR. GREENLEE: I=m Scott Greenlee. I=m the senior executive who has been working with the industry initiative. We looked at that early on and asked ourselves, did we need to look downstream or at other connected plant components. And the answer was no, because once you get down into the lower voltages, you=re at 22 kV or below, you=re going to have an arcing fault if you open up one of those phases and it=s going to go to ground. So you=re going to get the ground protection.

MEMBER STETKAR: Yes. Like Byron had an RP fault that went to ground.

MR. GREENLEE: Yes. That was on the high side.

MEMBER STETKAR: Yes. Well, this is on the high side of that 22 kV to 4 kV transformer that I=m talking about.

MR. GREENLEE: Right. And when we=ve had that -- we=ve actually had those happen at Byron, at Braidwood, our other sites. And because they=re in close proximity in a non-seg bus, you get plasma arcing very quickly and you get a fault.

MEMBER STETKAR: So that you know that every single plant that could possibly have that configuration will always have that fault that is immediately detected.

MR. GREENLEE: I guess I --

MEMBER STETKAR: Because it was at Byron.

MR. GREENLEE: Because it --

MEMBER STETKAR: Because it was not at Byron is my whole point. Until you have the event, you=re not going to have that anomaly that says, AOh, gee, we didn=t think that this thing might have happened.@

MR. GREENLEE: Yeah. We=ve actually had the events at the plants and they --

MEMBER STETKAR: Indeed, you=ve had those events. You=ve not had the one that I=m talking about, which is an open circuit on the 22 -- pick a number, 22 kV side of a 22 to 4 kV transformer that did not present itself as a hard ground. You haven=t had that yet. You=re claiming it cannot happen. I=m claiming that I suspect it can happen; it just hasn=t yet.

MR. GREENLEE: Yeah. And I would say if you look at the industry operating experience, the likelihood is pretty close to zero.

MEMBER STETKAR: Fukushima never had the

big size -- big tsunami until they had the big tsunami. They claimed it wasn=t possible. I=m just saying, why exclude those transformers just because --

MR. MATHEW: Right. Let me try to address, clarify. Like I said before, our regulatory requirements are specified in GDC 17. So GDC 17 says you have to have two qualified offsite power sources. If -- if the main transformers and the unit auxiliary transformers are part of the qualified power source, yes, they have to look at all of the vulnerabilities in that power source.

But based on the response to the bulletin, and all of the interactions with industry so far, an open phase in the medium voltage level is not a concern, because they have done analysis to show that open phase in the medium voltage circuits are not a problem. So the problems are based on the industry operating experience worldwide we determined that the open phase, which is most credible failure, that is going to happen either the high voltage side, extra high voltage circuit to the first transformer.

So if the first transformer is, let=s say, unit aux transformer or a main transformer, they have to take into consideration as part of the qualified offsite power source.

CHAIRMAN BLEY: Let me interrupt you for a minute, Roy. This is so popular we have filled up the bridge line, and now we are opening up a second line. So this will just take us a minute.

MEMBER STETKAR: For those of us sitting more up toward this end of the table, we=re going to have to yell a little bit louder, because the phone that Theron is hooking up now only picks up with these microphones.

MEMBER BROWN: I will not have a problem with that.

(Pause)

CHAIRMAN BLEY: Okay. Roy, we=re back to the meeting.

MR. MATHEW: Okay. Back to the meeting. So the concern is whether we haven=t taken an open phase at the high voltage side or the unit auxiliary transformer.

MEMBER STETKAR: I=m not -- don=t give it a name, because it might be given different names in different plants. I=m talking about the high voltage side of the transformer that drops voltage to the safety bus voltage.

MR. MATHEW: Right.

MEMBER STETKAR: Now that may be given a

different name. It may have different configurations in different plants. That=s the transformer that I=m talking about.

MR. MATHEW: Okay. That=s the transformer, we call it as a unit auxiliary transformer, being used when the plant is operating, but --

MEMBER STETKAR: Roy, different plants have different names and different configurations --

MR. MATHEW: Right, right.

MEMBER STETKAR: -- for those. That=s why I=m not giving it a name.

MR. MATHEW: Okay. That=s --

MEMBER STETKAR: I=m giving it a name of the transformer that drops voltage -- is connected on the low side to a safety bus, and is connected on the high side to some voltage supply.

MR. MATHEW: Right. Okay. So part of the bulletin review open phase issue, what we are looking is if you have an open phase at the input of a high voltage transformer -- in this case, it=s a 22 kV, and it=s a 4 kV going to the safety bus, if that=s 22 kV, it=s your qualified power source from the offsite source. Part of the bulletin, part of the BTP, that is covered under that.

But that=s part of offsite power source to -- it=s part of the power source requirement you have to look at. But if that transformer has nothing to do with providing power to a qualified power source, to the safety bus, then that=s not part of the, you know, open phase issue that we are dealing with.

So there are a lot of transformers on the balance of plant side, which they are not part of the qualified power source to the safety bus, but, you know, some of the newer plants -- and there are about nine plants that there are output breakers, they use the unit power which is 22 kV, that is being stepped down to 4 kV. That becomes part of the qualified offsite power source.

So from that aspect, you know, the power is coming from the high voltage that is coming -- reported as a backfeed.

So to answer the question, if it=s a qualified power source, and it=s 22 kV to 4 kV, if you are assuming a failure at 22 kV, that=s your offsite power source requirement. Then, the open phase should cover that aspect.

MEMBER STETKAR: Okay. I didn=t -- I guess I didn=t read that when I read through the BTP. And in some discussions that I had had in previous meetings with -- I=m trying not to telegraph with whom it was for the purposes of this meeting -- with a licensee or applicant and with the staff reviewers of the issue, I was told that, no, they only needed to look at the connection to the switchyard. They did not need to look at the actual intermediate transformer, because that was outside the scope of this issue.

MR. MATHEW: Yes. Singh, do you want to clarify?

MR. MATHARU: Yes. Hi. My name is Singh Matharu. I also work in the Electrical Branch. Maybe after our break we can have a little single-line diagram, a single --

MEMBER STETKAR: Yes. That --

MR. MATHARU: -- that would illustrate which transformers you=re looking at and which -- what is your specific question, and perhaps we can answer that.

MEMBER STETKAR: That would be real good, Singh. That would be good. Yes.

MR. MATHEW: Okay. The next slide. I thought of giving some idea about the power system basics. Later on, the presenters are going to use some of the jargons. So this is just an exercise going through. If you think that I don=t have to, then I will skip it.

CHAIRMAN BLEY: I think you should.

MR. MATHEW: Okay.

CHAIRMAN BLEY: Not everybody on the committee here are EE background.

MR. MATHEW: Right. The understanding per phase magnitude, angle, or the phase to phase and phase to neutral, and also the sequence currents which are positive in a sequence, those are the electrical parameters that are used when we analyze the unbalance in the offsite power system -- I mean, three-phase offsite power system.

I see no OPC -- open phase condition. I may use some abbreviations. Open phase condition causes unbalance in the three-phase power system. Unbalance generates different three-phase parameters, which is angle will be different from the traditional balanced system, and also the magnitude changes. Mainly the induction motors and similar generators are affected by that balance.

Like I mentioned before, in the electrical power system, sequence -- the whole sequence -- currents, voltage -- that can be best analyzed through symmetrical components, so you can calculate. Nowadays, you have all of these fancy, sophisticated computer programs. You don=t have to do the hand calc anymore. So that=s one good thing about --

MEMBER BROWN: One thing you didn=t say, and I -- just to make sure I understand. If you have a balanced three-phase system, you=ve only got positive sequence voltages. If you have an unbalance is when you introduce the negative and zero sequence components. That=s -- I just finished reading another power analysis book by Anderson from 20 years ago last night. I=m just trying to make sure that when I read through his discussion that --

MR. MATHEW: Yes.

MEMBER BROWN: -- that confirmed what I thought I remembered from years ago, and I wanted to make sure that that -- that I wasn=t off base.

MR. MATHEW: Yeah. That=s an actual -- it=s true. I think the concern is out of the sequence -- sequence voltage of current, negative sequence is the most cause of concern. And also, there is a ratio between negative sequence and the positive sequence, and the industry has -- I will go through the slides again. If the ratio is more than certain percentage, you know, it can damage more --

MEMBER BROWN: Well, another comment on that. Again, you folks over here, you can correct me, I just want to make sure I understand the effect of negative sequence, if you don=t mind. Positive sequence drives the motor, delivers your load, et cetera.

The negative sequence is not ABC, it=s ACB, which tended to try to reverse -- slow down the motor, which can drive you up in terms of the currents. On induction motors, you will get -- I=m trying to remember all the buzz words that go along with it, but drives you up the slope, and it can overheat because you now have circulating currents of other types which you don=t normally -- that don=t deliver any power, and if your wiring, if your current -- if your wire is not designed for that, then you overhead and you can damage the insulation.

And that -- did I get that correct? I=m just doing that for the --

MR. MATHEW: Yeah. That=s --

MEMBER BROWN: -- make sure the other members of the committee have an understanding of why that=s a problem.

MR. MATHEW: Yeah.

MEMBER BROWN: And one other thing just to calibrate them, also make sure I have this right. When you do have an unbalanced -- whether it=s an unbalance due to loss of phase, or it=s an unbalance on the load side, you=re -- now you have a -- your total voltage -- typically on the balanced system the sum of the voltages A, B, and C is equal to zero, if everything is balanced. If it=s not, if it=s unbalanced, they don=t equal zero.

Did I get that right? Okay. That, again -- this is 30 years ago, so it=s very hard. Actually, it=s 45 years ago, so it=s even harder. But, I mean, that=s -- so that=s correct.

So that=s, again, a calibration for what you see on these things. The same thing applies with currents. You get a bigger variation in currents, and that you could actually measure those things, and that=s -- I think that=s the stuff they=ll be talking about at some point. Am I correct also? I=ve got -- I know where the experts are right now. That=s why I=m pointing over there.

Thank you.

MR. MATHEW: So, for example, I mentioned earlier the transformer is the main component that causes unbalance. In some of the typical winding configurations, we have an open phase condition. It=s harder to detect than the other type of configuration. Some of them are Wye-delta, Wye-Wye, so I just want to mention.

This is a typical diagram. I just showed this for -- if you look at one of the phases that=s open, you can see the current flow is different as far as star-delta configuration. The picture is just to show schematically what it is.

Single phase interruption phase diagram -- if you look at on the left side you have a typical 120-degree A, B, C sequence, or here it is L1, L2, L3. And if you have an open phase in L1, you can see the magnitude and the phase angle shifted. So that has a lot of impact on the models. I will talk about that a little later.

This is a symmetrical current. Here is an unbalance in the system that the diagram --

CHAIRMAN BLEY: Let me interrupt again. I=m going to follow up on Charlie=s point for our members who didn=t study this part of this stuff in school. Of course, there was a clever trick, at least the sequence language.

You can take a three-phase system and break it up into three balanced systems. So if you have an unbalanced system, you can represent it as three balanced systems, and the currents and voltages in those three balanced systems are called positive sequence, negative sequence, and zero sequence. So that makes it much easier to understand and to analyze what=s going on.

MEMBER BROWN: Perhaps it=s the only way you could analyze it 50 years ago.

MEMBER STETKAR: It=s easier to understand, too.

MR. MATHEW: If you look at 20, 30 years, you had to do the hand calculation, which the only way you can do is vectorally add all of these symmetrical components to a phase diagram. This slide will show you how you add them.

See, this is the diagram. You break it into symmetrical components, which are -- you know, which are symmetrical, you add on, you look at the phase diagram for the net result. So nowadays you can do it on the computer, which I think -- or EPRI person will mention.

I will be referring to some standard. This is an IEC standard, and also IEEE, NEMA standard also. This is the definition for negative sequence. Power quality, standard by definition, negative sequence percentage is negative sequence voltage or current divided by positive sequence. And IEC guidance will give you, if the ratio is more than one percent, not exceeding one percent of the positive sequence component over a long period, that is a design requirement.

So basically you can say that motors -- big motors can handle up to one percent without any deterioration.

MEMBER BROWN: I would make one observation on that, the one percent.

MR. MATHEW: Yes.

MEMBER BROWN: And I only bring it to you in -- with the big power systems, it=s much easier -- I say this with a little trepidation -- to have and maintain a roughly balanced phase load --

MR. MATHEW: Yeah.

MEMBER BROWN: -- per phase load system. The plants I grew up on in the Navy were small. And if you look at the way operators shift loads around on those plants --

MEMBER STETKAR: It=s never balanced.

MEMBER BROWN: Yes. You could count the number of times it was balanced in a year on no hands. So the experience was, even though these numbers are small -- it=s pretty hard to count them on no hands. But, I mean, that=s just Kentucky slang, okay?

MEMBER STETKAR: You were sophisticated,

though. You used your feet.

MEMBER BROWN: That=s true, because we didn=t have any shoes. My point being is that when you use one percent, one and a half percent, I don=t know about the commercial motor, but I know the stuff we had in the Navy survived. We never -- I never burned up any motors due to load imbalances, and I know we had a lot of imbalances. So, and Dennis is very familiar with that from the enterprise, I=m sure.

So I don=t know what the comparison is, but I don=t think the plants are as vulnerable -- this is personal opinion -- as what is advertised by the standard. That=s all.

MR. MATHEW: Yeah.

MEMBER BROWN: I=m not saying you want to exceed it. I=m just saying I -- it=s just not like you=re on the very edge of breaking all this stuff and melting motors. That=s all.

MR. MATHEW: I mean, I will go through the next slide, which is the -- sorry. This is NEMA standard. This is a percentage voltage unbalance, maximum voltage deviation from average voltage to average voltage times 100.

This is telling -- you know, it can -- it can operate safely at one percent, but if you have values above three percent, five percent, there is going to be -- either the big motors have to be de-rated. There is a big de-rating factors, because the voltage unbalance, if you have a deviation from the maximum to the average, the current is almost six to 10 times the sequence currents.

So if you have a negative sequence voltage, and the voltage unbalance is so much, most likely you will burn the motor out if you have bigger unbalance.

MEMBER STETKAR: This is why on really big motors, circulating water pumps, and --

MR. MATHEW: Right.

MEMBER STETKAR: -- maybe feedwater pumps and reactor coolants and --

MR. MATHEW: Yes, right.

MEMBER STETKAR: -- some people have separate protection relays for those.

MR. MATHEW: Even some of the ECCS pumps like containment spray or large safety injection pumps, it could have bigger impact if you operate for a couple of minutes. I will go through some of the operating experience.

MEMBER BROWN: Are you going to cover in the operating experience on -- the type of damage that was actually seen?

MR. MATHEW: Well, one plant --

MEMBER BROWN: But you=re going to talk about that?

MR. MATHEW: Yes.

MEMBER BROWN: Okay.

MR. MATHEW: Briefly. Briefly.

MEMBER BROWN: That=s fine. You can do it when you get there.

MR. MATHEW: The staff didn=t have international operating experience because -- I will get to that.

System modeling and analysis -- basically, they used the Thevenin equivalent network model, and they had to know the transformer model or all the parameters associated with that. And you have to have the model -- which is different induction models.

If you want to do analysis, you have to get a lot of values. You know, I=m pretty sure the licensees will say they have some challenges in this area, because transformers when they -- when the manufacturer ultimately may not have given all the information, say, for instance, sequence impedance values, if they haven=t provided them, they have to do a, you know, hard look at -- to calculate that impedance probably based on the configuration.

So a lot of data that you need to get to do the simulations -- first of all, you have to model the system for your plant. Unfortunately, all of our 104 plants, we have about 10 or 15 different configurations. So one particular plant=s information cannot be used for the other plant, because your operating configuration is different, your loading configuration, your transformer, you know, network is different, your offsite source is different.

The grid also has a big impact. You know, you have to figure out the substitute impedance, and all -- from the grid also. So there are a lot of -- this is a very complex issue. If you ask any electrical engineers in the industry, it=s really a nightmare because we -- there are a lot of interactions.

EPRI has developed a modeling -- several modeling techniques, and I=m pretty sure Bob Aritt, he is going to go through the presentation.

I already talked about the safety significance. What is the real issue from a safety perspective? If you have an open phase, I think one of the issues -- offsite power system -- is a system that feeds both redundant system, so if you have an open phase, most of the plants are configured with one source going to both trains. Some plants are designed differently. The two independent source goes to two different trains.

But the concern is if you have a bottom-top issue during a design basis event, our regulatory requirements, which was done 40 years ago, 30, 40 years ago, requires this onsite and offsite power system has to perform independently. If your offsite power system is not capable of doing its function, the onsite power system has to do.

If you look at the Byron event, that didn=t happen. So because of the open phase system, that particular configuration, the onsite power system didn=t know what to do.

So loss of safety function, that has happened based on looking at the Byron event. When looking at the other aspect, the quality of power to the engineered safety feature system, that is the fundamental premise for the quality and the capability and the capacity of the offsite as well as the onsite power system.

If you have an optimal power system, you have to provide the required quality of power, which is load, frequency, and current. And if you cannot do that -- a balanced power system will provide that. But if you have an unbalanced power system with all the sequence issues, that is an issue.

So what is the impact of an open phase? You know, like I said, phase angle shift is one, what did we study for, a negative sequence current damage in the motor because the negative sequence current goes in the opposite direction, try to stall the motor. So that has a direct impact on safety system ECS start motors, valves, you know.

Overheating of motors and actuating your protective device, that=s a concern. If you are using the offsite power system and it so happens if you have a design basis event, if these things are looking out, you cannot mitigate the consequence of a design basis event with an onsite power system. So the idea is to detect the open phase condition and with the unbalanced power system due to open phase, you want to, you know, transfer the power of the ESF buses to the onsite power system.

MEMBER SKILLMAN: Right. On that slide -- back one, please. Nowhere in that third group did you identify the time requirement for detection.

MR. MATHEW: Yes.

MEMBER SKILLMAN: When you do have an open phase, what you really end I think is with not enough counter EMF, a very high current, and very high

I-squared R losses. And unless you have enough copper in the motor, you=re going to fry the motor.

MR. MATHEW: Yeah, yeah.

MEMBER SKILLMAN: And so there is a time element here, and you mentioned it in several of your previous slides a minute or a minute and a half or a few minutes, where do you embed the notion of the timeliness for detection and action?

MR. MATHEW: Yeah. Okay. It=s embedded in -- so I will discuss the staff person later on. If you dictate open phase condition automatically, whatever the solution they are implementing, that automatically is the time at which time sequence zero -- if you have -- plant is operating and you are using that transformer to feel your safety buzz, you may have some motor turning. If you have an open phase, you have to detect it, and they have analysis to show that protective devices will not lock out before they go to the second source.

So that=s a part of the automatic detection aspect. The industry has to look at it from a plant-specific basis. So time is a factor. So you have to -- when they develop the solution for these, you have to look at the protective coordination of all of your components in the plant.

So time is essential because they should look at it to see, you know, one percent unbalance or two percent unbalance in certain configuration operating notes that the plant is running. They should have a basis for that.

MEMBER SKILLMAN: Maybe you=ll talk about it later.

MR. MATHEW: Yes.

MEMBER SKILLMAN: thank you.

MEMBER BROWN: Well, the BTP, if I remember, has a -- it discusses -- it has some reference to if it=s not automatic, then you have to have enough operator notifications within -- that they can -- actually, within -- is that what you=re talking about? That is a review request by the -- you know, it=s in the BT -- branch technical position, that they are supposed to review to see that the analysis has been done to show operators have time to respond to the alarms or warnings that come out of there. If that was kind of where your question was going.

MR. MATHEW: Yeah. I mean --

MEMBER BROWN: The same thing applies for the automatic. In the automatic stuff, there=s two things. You don=t want it to trip spuriously, but you want it to trip in time that you don=t damage the remote --

MR. MATHEW: Right. Let=s say, for instance, since you brought up -- so solution, if it=s, let=s say, relay set point, let=s say one percent unbalance to -- whatever the analysis shows, certain current or voltage, or part of the sequence current or voltage, if it reaches that threshold, the time delay to actuate the breaker to isolate, that has to -- you know, they have to take into consideration of that, how long the limiting load in the plant can run with that configuration.

And if the analysis shows that it cannot, you know, run more than, you know, so many seconds or cycles, you have to automatically divorce that source.

MEMBER SKILLMAN: Okay.

MR. MATHEW: So --

MEMBER SKILLMAN: thank you.

MR. MATHEW: Byron Unit 2, I mentioned that loss of safety function. This has both onsite and offsite power system were not able to perform its function. A design basis event concurrent with an open phase condition would likely result in 10 CFR 50.46. In the balance case, they didn=t reach to that level, but our accident sequence precursor review by Research, when they looked at the Byron event their core damage

-- conditional core damage probability was 10 to the minus four.

So this is available in public -- as a public document. It=s covered in a SECY.

There were about 11 operating events, and I think that if you look at that, you know, U.S. had one, two, three, four -- about six, seven operating events. Rest of them are international. And in April of 2014, that was the last event, which was in UK at Dungeness plant.

Most of the issues at the overseas plants, either the breaker -- a three-phase breaker, it=s an air blast circuit breaker or a gas-insulated, you know, circuit breaker. When they were doing maintenance or during realignment of breakers, you know, the internal components of the breakers could be due to loose wires of the controlled schemes for the breakers, or the mechanical loop for all three phases to close at the same time, it didn=t work properly.

So that is international site, at Bruce plant in Canada. That was an event similar to Fitzpatrick and Nine Mile, which is a 400 kV line connection. Because of the fatigue, it -- you know, it was broken, and it was dangling, and it was arcing basically.

So the industry events are just that breaker operation can trigger an open phase condition, and it could be a one-phase issue, it could be two-phase. If it=s a three-phase, there is no problem. So two-phase and single -- one-phase and two-phase, the breaker can trigger open phase.

And in the U.S. side, when we looked at all the operating events, except for South Texas, South Texas was a breaker issue. They were realigning the breaker when the plant was at full power, and one of the breakers closed. So the big pumps like circ water pumps start tripping, and they go to scram.

So actually, before that, they scrammed the plant. So they didn=t have much impact of damages. But if you look at all of the operating events, it=s in the -- it=s either an insulator issue or a physical big high voltage conductor falling or losing its integrity.

So basically, looking at the operating events, I had to conclude that open phase events from a realistic scenario, credit event scenario, it is credible, because if you look at that you have 11 operating events internationally in the last 13 years. So open phase need to be considered as a design basis operating event. When you look at the electrical system design, you should factor that and design to protect against that.

CHAIRMAN BLEY: Roy, before you leave this, if we have a scram, I know we=ll get a report on these events. If you didn=t have a scram, what leads to a report? I mean, could there be a lot more of these vents than you found, that were just solved and fixed and people went on?

MEMBER STETKAR: These events never happen in Russia and Japan for --

MR. MATHEW: See, we don=t know.

CHAIRMAN BLEY: But even in the States --

MEMBER STETKAR: Is there a report to --

CHAIRMAN BLEY: I don=t think so.

MR. MATHEW: We think it is underreported because, you know -- we could talk about a little later because in the U.S. we have different operating configurations. You have offsite power system being a standby system. You are using the unit power through the main transformer, you know. So the unit aux transformer, using the power to use it during the normal operation.

So if the event happens, that=s what happened in Beaver Valley. If you look at the Beaver Valley, they had the open phase even for about 30-plus days. They didn=t know they had an open phase, because offsite power loss of standby. It will transfer from the unit to offsite only if you have a plan for it.

So that=s more serious than having just like the Byron event. Byron had two events. One event was even with just open phase. The other one was also -- didn=t result in an open phase, but the overcurrent and ground relay was able to pick up, but that was a full-blown ground fault.

CHAIRMAN BLEY: These are all really interesting, and -- but my question was, if you don=t have an associated reactor trip, is there any requirement on a plant out there to report such event? Could there have been a lot more of these than we=re looking at?

MR. MATHEW: Yeah. I would say if it=s -- like from a GDC 17, from a regulatory perspective, if you think that if the licensee -- they have an operating event where an open phase resulted in knowingly or unknowingly nothing happened, and you don=t have a power source that should have been feeding the offsite source, if there was a demand, then the offsite power was not operable at that time.

So the reporting criteria is -- you know, we have criteria -- most of the reporting happens only after years of actuation. The diesel has to start. If the diesel doesn=t start, they may not report it probably.

CHAIRMAN BLEY: That=s kind of what I was getting at.

MR. MATHEW: Yeah. Yeah.

CHAIRMAN BLEY: So you found 13 -- or 11 of these, and they have been interesting and have led you to the point we=re at now.

MR. MATHEW: Right

CHAIRMAN BLEY: But my question was, could there have been many more of these that had no consequences that we have seen? And we don=t know. Okay.

MR. MATHEW: Actually, when I issued the bulletin, I didn=t even know about South Texas. So I found out South Texas because we were part of the center of excellence, part of -- New Reactor Review is also part of us. We found out --

CHAIRMAN BLEY: That=s good enough. Okay. Thank you.

MR. MATHEW: So regulatory requirement. I mentioned GDC 17. That=s a bigger requirement. Then, the design criteria for a protection system, the onsite power system, has to meet that requirement.

Then, the tech spec requirements for surveillance and also the limiting condition operation.

NRC actions so far, we had a Region III special inspection. By the way, we have -- Region III branch chief is here. He is responsible for the Byron plant also. They did an inspection at Byron and issued the report. That is available publicly. I have referenced the reference.

We have information notice issued. We have bulletin issued. We got a response from all licensees. That is documented in their summary report, which is also available publicly.

And looking at all of the responses, all plants are vulnerable to open phase condition except Seabrook. Seabrook -- we had issued some RAIs to find out more information why they are not susceptible. We found out for two reasons. One is they have a gas-insulated system. Their switchyard is basically SF6 design, and also from a protection aspect we looked at it to see what kind of protection they have, if they have a breaker malfunctioning.

So what we learned was they have a single pole protection for all high voltage -- extra high voltage circuits in the switchyard. So for those two reasons, we determined that Seabrook is the only plant that is not vulnerable to this design issue. Therefore, we are not proceeding anything further.

Existing protection scheme based on the voltage magnitude cannot identify the, you know, open phase condition. You have to take automatic actuation. That is another recommendation.

And we also recommended that staff act -- take action, regulatory action. That=s what we are doing right now.

Industry will discuss about the industry initiative. There was a lot of industry response part of this bulletin. We have a representative from NEI -- the task force is here, Mr. Greenlee. He is going to discuss the industry initiative.

And we have INPO. There are a lot of actions. INPO required industry to address the response from all licensees, and then follow it up through corrective action reviews.

We also -- from NRC side, we are participating in two working groups. One is IAEA working group to issue a safety report. That just started about two weeks ago. And also, we are supporting an IEEE working group. There is a part written to initiate a standard for this.

So you also asked several RAIs to the

plants to know where they are as part of corrective action. All licensees have taken interim corrective actions. Private industry initiative, they are taking long-term corrective action. Some of the responses confirm that they are taking corrective action. It=s in their corrective action program.

They have measures in place to address the immediate concerns. Long-term corrective actions are to be done per the industry initiative, which is December 31, 2017, that is the plan for the industry to address this issue.

I will shortly discuss about the new reactor issues. We looked at the -- we have four units, two licensees with AP1000 combined operating license. So the bulletin also went to them, and we looked at their response and we came to the conclusion they are not in compliance with the GDC 17. So, therefore, we send NRC letter about two weeks ago requesting them to provide us information to say how they implement the actions for the bulletin. So we -- this is still an open issue with the AP1000 licensees.

Some of the other things we did, we had many public meetings, and we had a good interaction between the industry, and that helped us, both the NRC as well as the industry, in getting through the resolution aspects.

We issued the BTP. We got the comments. I=ll briefly discuss all the comments, high level, in the second presentation.

Part of the regulatory action, we are planning to issue an interim enforcement policy. We shared that information with the industry in the last public meeting. We are finalizing these two documents.

MEMBER SKILLMAN: Before you change that slide, let me ask, for the Part 52 applicants and for the AP1000 licensees, what role does the design certification issuer or developer play in this?

MR. MATHEW: Yeah. AP1000 is already certified, so -- as well as the certification was -- there is nothing to be done. So this is an emergent issue that came after the certification. So to demonstrate compliance with the GDC 17 based on, you know, looking at the new event, it still had to be in compliance with the GDC 17.

Therefore, since AP1000 licensees are not planning to implement as of today, they haven=t provide sufficient justification how they detect an open phase and take action. So the criteria for passive plants are different because the reactor systems and the safety perspectives are -- they are different capacity systems.

But from a regulatory perspective, if you look at the NRC=s regulatory perspective, we need defense in depth. So even if you passive systems, you still need to have the AC power system to do if the systems are available. So, therefore, we have concluded that they have to have offsite power source to, you know, perform its function during normal accident -- even in an accident, if you have normal decay heat systems and other systems, they should be using that.

So that=s what their design basis documentation said in DCD. That=s what -- if we look at their DCD, it says offsite power system will be used for all normal -- all operating conditions, which is normal accident condition. So the design certification, from a big picture, is based on that. So based on the emergent issue, they still had to comply with GDC 17, or they can request a total exemption. So they had to meet the regulatory aspect.

MEMBER STETKAR: This started something. I was going to wait until you get to the next slide, so if you want to flip over to the next slide. I quite honestly, for the life of me -- first of all, is number 3

-- the version of the BTP that we received for this meeting essentially has number 3 under active plants stricken.

MR. MATHEW: Yes.

MEMBER STETKAR: Is that the current --

MR. MATHEW: Yeah.

MEMBER STETKAR: So that -- although it appears on this slide, that=s not consistent with the current draft of the BTP?

MR. MATHEW: No. I think the draft -- let me clarify that. The --

MEMBER STETKAR: Okay. Let me --

MR. MATHEW: Let me go through the slide.

MEMBER STETKAR: Okay.

MR. MATHEW: And then I can come to your --

MEMBER STETKAR: Okay.

MR. MATHEW: Then I can come to your question. After looking at all of the responses from even the new reactor four units as well as all of the other 104 units, the staff recommendation was -- or the public meeting we discussed the staff position, which is we said for operating power plants, as well as the active design for the new reactors, they had to meet three things.

One is you have to have a detection,

automatic detection if you have an open phase. The second thing we said was you need to have an alarm in the control room to indicate the open phase condition.

And the third we said was it has to -- if the offsite power system is degraded, and their analysis is to show that it cannot perform the safety function, then you have to actuate the protective system and mitigate the consequence of an event. Basically, if the offsite power system is not going to perform its function, you have to use the onsite power system to meet its function.

So there are three things we said, so automatic detection, alarm, and protection. And for the passive plant, because of the nature of the design to mitigate the consequence of an accident, the automatic protective feature is not an important factor of consideration for safety. So we said you have to detect it automatically, if you have an open phase, but you have to alarm it, at least an alarm, and it should have procedures and processes established to take manual action.

Even though it=s a passive plant, they still have onsite power system and offsite power system. But it=s all classified as non-plant -- or non-safety related.

So from a defense -- in a defense in depth perspective, you still need to have the capability to go to the diesel manually if you don=t provide any automatic. So the minimum requirement is automatically detecting, alarm for manual action basically.

MEMBER STETKAR: Okay. Finished?

MR. MATHEW: Yes.

MEMBER STETKAR: Okay. Now, I=m staring at a PDF file of the document of the branch technical position that was sent to us for this meeting. And in that file there are words stricken out with blue lines through them, and the words that are stricken out particularly pertain to item number 3 under what you are classifying as active plants.

MR. MATHEW: Yeah, yeah.

MEMBER STETKAR: Well, don=t say Ayeah, yeah@ because what I=m reading is different from what is on the slide here, because you=re saying the active plants must automatically actuate and mitigate the event, and what is stricken out is that requirement, in what I received for this meeting.

MR. MATHEW: Oh, okay.

MEMBER STETKAR: In what I received for this meeting.

MR. MATHEW: No, that -- so --

MEMBER STETKAR: It doesn=t show up in the printed version.

MEMBER BROWN: It showed up in my printed version.

MEMBER STETKAR: Okay. Good. So you have a better printer than I do.

Now, the question is, why is the staff=s position for active plants that it must, as you say on here, automatically actuate today?

MR. MATHEW: Yeah. Because when you look at the reactor design --

MEMBER STETKAR: Okay. And don=t -- stop explaining. AYes@ is good enough.

MR. MATHEW: Yes.

MEMBER STETKAR: Now, my question is, why are we treating active plants different from passive plants? From this perspective, why are we introducing the chance of causing a transient on an active plant and we=re not introducing that possibility on a passive plant?

MR. MATHEW: It=s the --

MEMBER STETKAR: Why are we doing that?

MR. MATHEW: Yeah. Okay. We looked at the open phase issue, and for the new reactor as a fleet, and we said, what is the difference between an active plant, an operating reactor -- active plant for a new reactor versus an operating plant. There is no difference from an electrical perspective.

So, therefore, we said, AOkay. They have to meet the same requirement as operating fleet.@ But the passive plant -- the argument from the industry and the -- in looking at the safety perspective, it=s a -- passive plant could use less -- meaning there is no timing issue.

One of the issues with the active plants, they have to go to automatic actuation and transfer to the diesel because accident analysis assumes, if you look at the plant=s safety analysis, you have to have -- within 10 seconds or 11 seconds, your onsite power system has to be ready to operate, if you have an open phase, you know, coincident with LOCA or an SI signal.

For a passive plant, time is not an issue. So they can take manual action. Then, they are relying on their accident analysis to use the active components. So, therefore, there is some distinction made.

MR. MATHARU: Excuse me. Let me just speak on that question. I think there is two questions being asked here. Are you looking at the transient that is going to be caused because the power is -- unit is generating power? Is that --

MEMBER STETKAR: I=m not looking at any transient right now. I=m looking at a document, and I=m trying to understand whether or not the branch technical position right now for active plants requires number 3 on this slide. That=s all I=m looking at.

MR. MATHARU: Yes. But I --

MEMBER STETKAR: Okay. Thank you.

MR. MATHARU: Yes.

MEMBER STETKAR: AYes@ is good enough.

MR. MATHARU: Yes, yes, yes.

MEMBER STETKAR: Now I understand a distinction between active and passive plants. I=m not saying I agree with it, but I understand the distinction. In the branch technical position, in the document that was sent to the ACRS subcommittee that has that requirement stricken in it, I then looked at active and passive plants and said, AWell, why the heck are we distinguishing?@ Because under active plants you have a long litany of requirements. There is Section 5. And under passive plants, you don=t.

And when I compared the two, with the exception of that one item, there was essentially no functional difference. I couldn=t understand why we were making this big difference.

Now that I understand that this number 3 does apply to active plants, I still don=t know why we are distinguishing in all of those other -- when I look at item number 3 under the active plant, why doesn=t it apply to the passive plants? When I look at number 5 on -- I=m sorry, vice versa. When I look at number 5 under the active plants, why doesn=t it apply to the passive plants? They are all basic functional requirements, and yet there is this huge distinction made in the branch technical position.

The only difference then, functionally, that I can identify -- I have to be careful with the feedback here. The only difference that I can understand -- that I can see then is this item number 3.

MR. MATHARU: Yes.

MEMBER STETKAR: Okay. And my question now is, under item 3, why are we introducing the likelihood of placing a so-called active plant into a transient? You guys assumed that this always works perfectly. I know it doesn=t. Why are you assuming that we are going to make an active plant more vulnerable to an offsite power failure transient than we are for a passive plant? Why are we treating the active plants worse than the passive plants?

MR. MATHARU: Yes. For the active plants, the offsite source is at times zero.

MEMBER STETKAR: Yes. And I=m making it less reliable by saying if I have this fault condition, I=m going to initiate something that works most of the time, but occasionally doesn=t work and may wipe out offsite power, which is really bad for a plant.

So I=m saying, why are you making the active plants more vulnerable automatically to something that is very important to risk, and the passive plants are okay?

CHAIRMAN BLEY: I mean, you could have -- I think where John is going, but I=m not sure if that=s where you=re going, you could have had them start their diesels and transfer power to the diesels on the emergency buses but not --

MEMBER STETKAR: Manually.

CHAIRMAN BLEY: -- manually, but not thrust them into a situation where if it didn=t work right you could be in more trouble than you were to start with.

MR. MATHARU: Well, if you look at the accident analysis for the active plants, the safety analysis will ensure you that you need to have the first few drops of water in the vessel within 50 to 60 seconds.

That=s the timeframe you have during your accident, so --

MEMBER STETKAR: Let me try something else. You=re not -- let me communicate. Suppose I said that if I had any leakage in the reactor coolant system I immediately induced a double-ended guillotine shear of the largest pipe in the reactor coolant system. You=d say, AWell, that would be rather silly.@

I=m saying that the analogy here applies in the electrical thing. You=re creating the possibility of a worse condition by initiating this automatically than you are by perhaps alarming and allowing the operators, on an active plant, to respond, in the same way that you=re allowing them on a passive plant.

MR. MATHEW: No, no. Okay. Let me get back to --

MR. MATHARU: Hold on. Let me just follow the thought process here.

MR. MATHEW: Okay.

MR. MATHARU: What you are -- what the thought process is, that by introducing another detection scheme, which will automatically isolate you from the offsite source, you are making the offsite source less reliable.

MEMBER STETKAR: Exactly.

MR. MATHARU: Okay.

MEMBER STETKAR: Exactly. You=re introducing the possibility of making it less reliable, because that transfer -- that actuation and transfer will not be 100 percent reliable. It just won=t.

MR. MATHARU: And we agree with you. The more components you have in any system, the more likely you will be introducing potential failures. We are not disputing that.

MEMBER STETKAR: Okay.

MR. MATHARU: But the consequences of the event that we are trying to prevent are much more severe than what you are postulating on a failure of a device that we are using to detect the issue.

MEMBER STETKAR: The consequences if you presume a coincident large LOCA, or if you presume a coincident design basis event, in combination with that open phase condition --

MR. MATHARU: Not necessarily.

MEMBER STETKAR: Okay.

MR. MATHARU: Not necessarily. If you look at -- let=s take a simple trip. Let=s assume that you had a circ water pump trip. It=s non-safety. It=s going to take out your condenser. It=s going to take out your turbine. It=s going to take out your generator, and you=re going to transfer your offsite source.

And your offsite source has an open phase condition, and that configuration is where you are feeding redundant safety-related trains from the offsite source.

In the event that happened at Byron, the onsite source -- buses may not detect the open phase condition. So your offsite source is incapable of supporting your normal shutdown equipment. Your onsite source will not automatically actuate. And if you sit there for 10, 12 minutes, you=re going to stay in backup.

MR. MATHEW: Yeah. I mean, the very important factor that we said they need an automatic actuation from open phase condition for active plants and operating plant is -- because the accident analysis assumes if you have an accident at time P plus 10 or 11 seconds, your diesel is there. But if you have an open phase condition, if you are providing only manual capability, you are not going to have an accident mitigation capability. That=s about the main concern about this open phase issue -- loss of safety function.

That is unacceptable. You can have -- if you look at the GDC 17, it says offsite power system has to do the same function as an onsite power system. If onsite power system cannot do its function, offsite power system has to do it. So they are mutually independent, and they have to meet the single failure in terms of system.

So, therefore, not providing automatic action for an active plant, as well as in operating fleet plants is unacceptable from an emergency perspective, and 10 CFR 50.46 aspect.

MEMBER STETKAR: You can go on. I=ve made the point.

MR. MATHEW: Okay. Branch Technical Position, based on the Byron event and additional operating experience, the BTP was issued -- BTP to provide the staff in reviewing future licensing actions related to the open phase condition.

Design criteria specified for both operating and new reactors. We received comments as part of the BTP issued on the FRN. And right now we are looking at the industry comments and dispositioning it. BTP will become part of the Chapter 18 -- Chapter 8 SRP, and then finalized. This should address both the single open phase issue as well as the two open phase issue.

I mentioned earlier on the next slide, regulatory consideration for enforcement discretion. Mentioned about the industry initiative and the industry action so far. That=s a main consideration for issuing enforcement discretion. We shared this enforcement discretion. Enforcement policy will be revised, and it will be captured in Section 9 point -- all probably.

The title will be AEnforcement Discretion for Open Phase Condition.@ It applies to only operating reactors. The licensee will be in full compliance as of December 31, 2017. This is consistent with the industry initiative. Staff will prepare a SECY paper to the Commission seeking approval of this enforcement policy. At the same time, we will be finalizing the BTP, and staff is also planning to issue a regulatory issue summary regarding the availability of these documents.

MEMBER SKILLMAN: Roy, would you go back one, please? What does Ameasured response from INPO@ mean?

MR. MATHEW: Yeah. Okay. When we issued the information notice in the beginning when the bulletin had -- I mean, the open phase issue happened at Byron, INPO issued a Level 2 event report, which required actions from all licensees, and they had done through their INPO program to cover. And we had -- you know, NRC had information what they did.

So during the public meeting, through the industry initiatives, we are getting feedback what the licensees were doing. So we had -- we have information to see where they are from a corrective action perspective, and we thought their responses were read promptly based on the significance of the issue. So that=s what -- the measured response we are referring to.

MEMBER SKILLMAN: Okay. Thank you.

MR. MATHEW: Path forward. This is going to be provided in the letter that MJ was mentioning. We are sending a response letter to the NEI addressing several concerns. One of the concerns was the applicability of the protection system requirement, and the open phase isolation system. For example, they are trying to implement at certain facilities.

They had some questions, and we are providing NRC a response, and part of that response, these are the things they had to provide -- provide a commitment letter to the NRC stating that the OPC issue will be resolved in accordance with the schedule, which is given in the industry initiative. To comply with

GDC 17 or the applicable licensing basis for the plant, which is provided in the FSAR.

Develop and maintain a detailed plant-specific analysis and documentation, which establishes the resolution of open phase condition, including failure mode analysis that is available at the NRC staff for audits or inspections in the future.

They have to provide a closeout letter to NRC from each plant, so we can review and close out the bulletin. These are the schedule as well as the letter that we are sending to -- and I will discuss the rest of the responses that we are providing in the letter from a functional requirement. That will be covered in the BTP discussion.

This concludes my remarks, and I have a second presentation. I can do it now, or I can come back after --

CHAIRMAN BLEY: No. I think this is a good time to go ahead and do it.

MR. MATHEW: Okay.

CHAIRMAN BLEY: We are still on schedule, so --

MR. MATHEW: Okay. The next discussion is about the BTP resolution of public comments. The BTP was issued on June 5, 2015. It=s available in

ADAMS. Public comments were received on July 21st of this year, and we have -- 11 organizations or individual parties responded to the comments. And staff is presently reviewing this. This is a work in progress now.

And the proposed BTP will be revised, so the discussion that we had with the current version will be significantly different based on the comments. So I will be working on that in the next couple of months.

Many comments related to clarifying the guidance, you know, some of them -- Mr. Stetkar mentioned it, you know, the clarifying guidance, such as criteria, you know, section and criteria for new reactors as operating reactors. So we will look at all of those -- yeah. We will look at all of those aspects when we finalize the BTP.

Some of the key comments I will mention from a bigger picture. One of them, which I mentioned before, this was the subject of the NEI letter, protection system requirements. As part of the comment they are saying -- are now referred to the -- referred to the open phase issue, Class 1E detection and actuation secured are not appropriate considering an open phase solution. That should be implemented on the high voltage side of the transformer. And the definition of Class 1E equipment infers requirements for separation of Class 1E versus non-Class 1E.

Interim NRC open phase enforcement policy -- they are asking about questions pertaining to that. Industry argues that the open phase issue is beyond current design and licensing basis.

Another comment is about the technical specification aspect, which is looking at the 50.36. They are arguing that it=s not applicable to open phase foundation. Industry is currently stating that they are in compliance with their current licensing basis.

There is another comment about the new reactors. The staff is incorrectly applying GDC requirements to SSCs that are not reporting to safety.

The last comment on passive plant designs -- they do not refer AC power sources to mitigate design basis events.

So, basically, we will discuss all of these comments. I think, if I understand, there are 168 --

MEMBER STETKAR: There=s a lot of them there.

MR. MATHEW: Yes, 168 line comments, so I am going to discuss each and every one of them. It will be available publicly when it is finalized.

MEMBER SCHULTZ: Roy, on the last slide,

26, the first bullet under Key Comments you noted that=s the response to industry based on separate correspondences from NEI.

MR. MATHEW: Yes.

MEMBER SCHULTZ: Is that information that was received earlier than the comment period? What does that refer to?

MR. MATHEW: Actually, we got two letters. One was in -- earlier than the BTP got finalized. One was after. So basically we are applying the response. That=s what MJ was discussing.

MEMBER SCHULTZ: So those were not part of the public comment.

MR. MATHEW: That=s not part of the public comment. Public comment is separate, yeah.

When we publish it, we provide the comments on FRN -- I meant on BTP specifically.

MEMBER SCHULTZ: Yes.

MR. MATHEW: Yeah.

MEMBER SCHULTZ: I appreciate that. Thank you.

MR. MATHEW: This is in addition to. But the letter is going to discuss the questions that are raised in that letter. We don=t talk about in the BTP comments. That will be handled through the public comment received part of the BTP aspect.

MEMBER SCHULTZ: Thank you.

MR. MATHEW: This is the other portion of the response that we will capture in the NRC response. The staff position is that for any open phase resolution it should meet the following functional requirements. So we have stated four functional requirements.

We are saying the design should address single failure criteria as outlined in GDCs or applicable licensing basis. That=s one requirement. The OPC should not -- should be automatically detected, alarmed in the main control room under all operating electrical system configurations and loading conditions.

Third one is if offsite power circuits are degraded due to open phase condition, the power source should be transferred automatically to the onsite power system within the time assumed in the accident analysis, and without actuating any protective devices, given a concurrent design basis accident -- design basis event.

And the last functional requirement is the technical specification surveillance requirement and limiting condition operation for equipment used for mitigation of open phase condition should be consistent with the operability requirements specified in the existing technical specifications.

So basically they should be looking at the 50.36 requirement. So these are the functional requirements we are specifying. Again, the licensees have to look at how they look at the open phase issue for their plant, and the design, analysis, and modeling they get will be subject to audits and inspection in the future.

We will be issuing an enforcement policy. If the licensee -- any licensee declared their system inoperable in accordance with the technical specification, they will have the enforcement discretion until December 31, 2017.

So that=s what it is in a nutshell. So this concludes my remarks on the BTP.

CHAIRMAN BLEY: Thank you, Roy. Any more questions from the committee? I think -- at this time, we=re 15 minutes early. We=ll recess for 15 minutes and then start up with the industry presentations after that. So we=ll reconvene at 2:35.

(Whereupon, the above-entitled matter went off the record at 2:33 p.m. and resumed at 2:49 p.m.)

CHAIRMAN BLEY: Before we begin, an

announcement for the folks out on the phone lines. If some of your colleagues have had trouble calling in, let them try again. We have 17 people on that second line. We can get 40, so there should be room for others to call in and get on the line.

COURT REPORTER: You might ask them to put in on mute while they're listening.

CHAIRMAN BLEY: Yes. Please put your phones on mute because that helps everybody else even though we have the sound turned off in here.

We're about to turn to the industry, NEI now, and I'll turn it over to Scott Greenlee.

MR. GREENLEE: Okay, good afternoon. I am Scott Greenlee. I'm the Senior Vice President for Engineering and Technical Services for Exelon Corporation, and I'm also the industry's executive sponsor for the Open Phase Initiative through NEI. And then after I get done just giving you a big picture on what we've done in the industry and how our initiative works, Bob Aritt will talk about some of the industry research we've been doing through the Electric Power Research Institute. So, with that we'll go to the first slide.

MEMBER STETKAR: We run a small budget operation here, so you get to push your own buttons.

UNIDENTIFIED: You guys control the output.

MEMBER STETKAR: Somebody else can come help.

CHAIRMAN BLEY: That's your B- no, that's not your slides.

UNIDENTIFIED: Do you want me to run it for you?

MR. GREENLEE: Yes, would you do that?

MEMBER SCHULTZ: That works.

MR. GREENLEE: Steve, thank you. It's one of the B- oh, it's the top B-

UNIDENTIFIED: It's the top one.

MR. GREENLEE: Top one, the 17 November one. And then B-

MEMBER POWERS: This way no accusation can be made that we're cooperating with industry.

CHAIRMAN BLEY: It's part of our self-protection.

MR. GREENLEE: Thank you very much.

UNIDENTIFIED: He's done this before, too.

MR. GREENLEE: All right. So, next slide, please. Okay, this is just the agenda. I think everybody can read that as well as I can, so we'll go move on to the next slide.

The first thing, I'm just going to briefly talk about the Byron Open Phase event, just so you can understand why the industry went the direction that we went. So, if you go to the next slide, we had two issues, one on Unit 2, one on Unit 1 about a month apart, both of them resulting from a failure of an underhung 345 kV insulator, but two very, very different events.

The Unit 2 event was the more significant of the two because when the line separated it fell to the ground on the transformer side so there was no voltage on that part of the line. It grounded out, which influences the way the flux B- the other two phases go through the transformer. And, of course, as everybody knows, that really resulted in all of the motors in the plant that were running stopped, all the ones that tried to start would not start. We lost a number of 480 volt loads on thermal overload, so pretty significant. The only piece of running safety equipment we had was the diesel-driven aux feedwater pump, so we did have feed going to the steam generator, but as you see in the slide we had lost cooling to the RCP seals for about eight minutes, which becomes fairly significant. If you let the cooling B- lack of cooling go on for about another five minutes you can possibly damage the seals and create a LOCA event.

So, luckily the operators within eight

minutes diagnosed the problem, separated from offsite power. At that point, all the 4 kV loads basically came back on their own onto the diesels. The operators had to reset some of the 480 volt loads where the thermal overloads tripped. But the operators, by and large, did a very good job of dealing with the plant. We also had a reactor trip, of course.

MEMBER SKILLMAN: Scott, for perspective, that eight minutes that it took for the operators to diagnose the condition, did that diagnosis come because of the structured flow chart in the control room, or was that just skill of the craft?

MR. GREENLEE: No, these guys were in pure knowledge space, and actually what ended up happening was because of the imbalance on the station auxiliary transformer we got current through the neutral, and the neutral actually started smoking a little bit because the dust on the neutral grounding part of the transformer smoked. They got a report from the equipment operators that something wasn't right with the station auxiliary transformer. They checked voltages, they actually had good voltage on the operating panel. They checked all the voltages, noticed a voltage difference at that point and said hey, something is wrong. We're getting a B-

MEMBER SKILLMAN: So, they were really in knowledge space.

MR. GREENLEE: Oh, total knowledge space.

MEMBER SKILLMAN: Thank you, Scott.

MR. GREENLEE: And I'm going to talk a little bit about that here in a minute and show what the industry comp actions have done from a risk perspective because the industry, of course, has gone forward and done training with our operators. We've changed our procedures, put in alarms, if possible, for open phase conditions.

CHAIRMAN BLEY: Just to follow Dick's question, the first thing they saw were pumps tripping off.

MR. GREENLEE: Yes, everything is tripping off, but they didn't know why. It was because something nobody had really ever seen before like that. And then they put it all together and eight minutes later were able to diagnose it, so it was a pretty phenomenal feat.

MEMBER SCHULTZ: Scott, do you recall the timing of the unusual event declaration?

MR. GREENLEE: It would B- the declaration would have occurred, I believe, within 15 minutes of the opening of the SAT feed breakers.

MEMBER SCHULTZ: Thank you.

MR. GREENLEE: Okay. So, Unit 1 completely different because when the line separated the 345 kV side hit the ground, faulted, fault protection took care of it, isolated the station auxiliary transformer. All the loads on that transformer then shifted over to the unit auxiliary transformer, and actually the plant remained on line. That's the design of the plant, to remain on line with a loss of offsite power under normal conditions, not open phase conditions.

The cause of the failures of the insulators, and I'll show a picture. Let's take it back. I'll show you pictures of the insulators in a minute, but basically Ohio Brass had some sort of manufacturing problem for a while and the insulators were not manufactured correct. They were weaker than design, so they eventually broke after 20, 30 years of operation swinging back and forth and kind of fatigue failure.

And then the bottom line, of course, this kind of opened up the whole industry to see that we just didn't have good designs in our plants to detect this sort of failure. So, next slide.

This just depicts the actual failure with Unit 2. It was the metering circuit that failed. The insulator broke on the metering circuit. You can see on the left it's in tact, on the right-hand side you can see where the line fell down, hit the ground, and that B- since there was no voltage there to drive current, no fault, but B- and that's why the system didn't detect it. Okay, next slide.

Okay. This just shows on the lefthand side actual pictures of the broken insulator, and the collapsed bus. And on the right-hand side you can see what we found when we cut open those insulators and did diagnostics on them. We cut open a number of the insulators, and we found they aren't all this way, but there are a large enough fraction where we've had to go through and remove our highly vulnerable Ohio Brass insulators from our units.

We also early on have tried to put in place some NDE techniques in order to be able to detect this sort of thing in situ. We tried UT, did not work. We currently are using a microwave technology that appears like it's going to work, but we've got to work on the acceptance criteria.

CHAIRMAN BLEY: That means you found some problems using it?

MR. GREENLEE: That means we can see inside these insulators with microwaves and detect that sort of flaw, so we think that will be good for us going forward, and we'll share it with the industry, of course, to be able to in situ test these to see if we have other vulnerabilities on insulators.

Yes, obviously, the population of insulator failures in the country is not hugely high, but it's certainly something in your critical applications where it matters. Next. Okay, next slide.

Okay. This slide kind of gives you when we first had the event what you see on the top is Byron Unit 2, and you see the per unit voltages based on 4kV, so this is what you were seeing on the 4 kV bus. Phase ab was essentially 4kV, and then Phase bc and ca were at about 60 percent of nominal voltage. So, when this first came up we looked at it and said okay, well, shoot, we can redesign the undervoltage circuitry which is two out of two across two different phases. We could redesign that and we can have a voltage solution, but then we started looking a little harder at it, and we plugged into the analysis the lower case, which is the Beaver Valley case where Beaver ran B- you had an unloaded transformer, ran like that for about 30 days, and you can see why they ran like that, because the voltages were normal. So, what we decided was we really needed to go after a solution that can detect an open phase under all conditions rather than just being able to get a certain fraction of the open phase conditions.

So, next slide. So, go one more.

Licensing basis. Royce covered all of this pretty clearly, but what I just want to make sure everybody recognizes is, you know, the original design and licensing basis of the plants were just loss of offsite power. That's the only thing that the original plants were licensed for, so you could detect a complete loss of offsite power, typically designed concurrent with an accident. You know, that's how you did your analysis, LOOP, LOCA, concurrent.

And then, of course, in the 1970s we had some degraded voltage events where the grid started collapsing and safety equipment was impacted. And, of course, we weren't designed to deal with that event, so the NRC put in place requirements for a second level undervoltage set of devices, but again it was based on a collapsing grid versus an open phase. So, at this point, you know, our systems still are not really designed correctly to deal with an open phase. So, go to the next slide.

So, what we B-

CHAIRMAN BLEY: Even the GDC 17, it doesn't flag that. It just tells you what you need to have, and not how you might lose it.

MR. GREENLEE: It does. The third

provision, though, when you look at the GDC because it talks about onsite/offsite, and then it basically talks about interactions between on and offsite. That's really what we call the gap to GDC 17, that we don't have designs that deal with something that can impact both onsite and offsite.

And given, obviously, the significance of the eye-opener at Byron, we decided as an industry we needed to go after this and make sure we prevented another event like Byron. Obviously, have gotten a lot of input from the NRC on what they believe is the proper way to address this, and we have factored that into the initiative as much as possible, but as you can see here we only applied it to the active safety feature plants. NRC has been dealing with passive plants separately. And we also started out addressing only the single open phase, and then the Forsmark event occurred, and we said okay, well, obviously, we can have a dual open phase, so we added that in as a requirement.

And we are, as I think some have discussed, using a non-safety related circuit to do the detection and the isolation because we were not able to up front identify any technology which could reliably detect open phases on the 4kV buses with current technology. You could put some analog circuitry on there. It'll detect some open phase events, but not all conditions. In order to get all of the open phase-type events, you have to put it on the high side of the transformer to reliably detect it.

And as I discussed earlier, you know, we did talk early on as an industry. We got all our industry experts together and we said okay, well, what about downstream? What about the low side? What about all the other points in the plant where we can have an open phase? And although I suppose there is some loading condition which you could postulate like no loading on one of the buses and open phase it, any bus with a load on it is false, and that's been our experience. Because it's lower voltage you get a lot of current. In that non B- I don't know if all of you have seen the bus work, but the typical design at a nuclear plant is called a non-segregated bus, so you have all three of the phases running in this large metal cabinet which is connected to the transformer. And then it runs into the plant, and at that point, again, it's protected but it's still bus work. Our experience has been if you open B- if you start to open one of those phases you get a lot of current, a lot of arcing, a lot of faulting, a lot of plasma, and it'll fault. You'll ground over, so generally speaking the plants are designed B-

MEMBER STETKAR: On the low side of the transformer, I've seen plants that have needed auxiliary transformers with generator breakers, that the high side of the transformer is open conductor, no bus trip, nothing, open conductor.

MR. GREENLEE: This is true. And the plants have to go after those designs if they are using it as a GDC 17 source of power.

MEMBER STETKAR: Okay.

MR. GREENLEE: That is a requirement. You have to get all your GDC 17 even to the point, if you read the initiative, if I want to use backfeed during an outage, I have to meet the requirements of the initiative to insure that that backfeed, if I have an open phase, is not going to impact safety at the plant.

MEMBER BROWN: I need some help technically on the two phase. I guess I didn't have B- if I do have the Forsmark thing, I either didn't read it, or didn't know I had it, one of the two. But a two phase, I just think intellectually B- I don't want to use the word "intellectually," that's not me. But from an engineering standpoint don't you B- it's hard to see if you lose two lines coming in, you've got B- I presume then you've got a grounded neutral, and it would be a live system on the input side. And the other thing I would think you would have to have is it wouldn't be three single-phase transformers, it would be a multi-coil core. I'm just trying to think of the physical application for it, but still get some voltage into one phase on the other side B-

MR. GREENLEE: Right.

MEMBER BROWN: B- on the secondary side. And that would propagate into the other windings, as well. Is that B- am I thinking correctly?

MR. ARITT: Yes. Actually, EPRI did a report with the double open phase to show how each transformer type reacted to that. And you're correct, that they all react different. It really depends on what type of transformer configuration you have.

MEMBER BROWN: And if you don't have a neutral on the B-

MR. ARITT: Right.

MEMBER BROWN: B- high voltage side, then you B- everything is open so you have nothing.

MR. ARITT: You're right. If you have a delta coming in, if you open two phases basically you have one wire and you can't get B- turn it closed with one wire.

MEMBER BROWN: Right.

MR. ARITT: So that voltage collapses.

MEMBER BROWN: The voltage goes away, but the Y after you've got a neutral on the input B-

MR. ARITT: Right. And if you have a Y primary, and interesting enough, the same transformers you have trouble with with the single phase was the same ones you have trouble with the double phase, and that's the Y-grounded primaries. And I talked a little bit about that.

MR. GREENLEE: He's going to actually show you the B-

MEMBER BROWN: All right. I was just trying to get the physical picture from him.

MR. GREENLEE: And it's pretty much a breaker failure that has to occur. I mean, typically, you probably aren't going to drop two lines at the same exact time unless you had a tornado, missile, or something like that. But, yes, it's the breaker failures that really would be the cause of the two loss B-

MEMBER BROWN: Then let me ask another question, because I'm not as familiar with the commercial world breaker setups. In my world, they B- on the Navy side, there was all three phases. There were one constant armature, just everything came open. That doesn't mean something couldn't break off, but some of the stuff I see you've got individual phase breakers, sulfur hexafluoride type stuff for the high voltage side. So, they're not gang is I guess what I'm saying.

MR. GREENLEE: Yes, and even in the gang cases we've had some cases where they're picking up breakers where the poles don't operate simultaneously. You can get one of the phases or two of the phases not connecting B-

MEMBER BROWN: Okay. All right, thank you.

MR. GREENLEE: Okay. Go to the next slide. Okay, just B- these are some of our key milestones in the initiative. By the end of this year, we expect all the plants to analyze their situation, determine whether they're compliant or they have a problem, or not, so not truly a case of compliance, necessarily. It's a gap to GDC 17 that we've identified, a new gap. And if they have it, then they have to lay out their actions going forward. And as Roy discussed, Seabrook is really the plant that doesn't have the vulnerability, because if they have an open phase they fault, so they've got adequate protection.

MEMBER SKILLMAN: Scott, from time to time we discover through meetings like this that there are skill sets in the industry that are very slim, just a few experts basically carry most of the workload. Is this Item 1 one like that?

MR. GREENLEE: I would say that it was for a while, but what Bob is going to talk about is what EPRI has come up with. And I think the EPRI solution makes it a lot simpler than what we've done at Exelon. Our solution is very complicated. As Roy discussed, we had to go and remodel all our transformers. We had to go remodel the grid because you've got to make absolutely sure. We've got a programmable logic relay that we put on the high side and it looks for negative sequence currents. And negative sequence currents get generated by a lot of other things than an open phase. You can get a fault, you can get other grid transients, and the design has to take all that into account so that you never open when it's something else should be protecting the plant versus the open phase. It's got to be a true open phase. So, I would say that we have learned a lot in the development of those models, and I would say the expertise is somewhat limited, if you wanted to just start doing this on your own without going to the vendor that we've been using who developed this. I have 11 of these units in our operating fleet right now, about 20 reactor operating years. I have two of them that are now active because we wanted to make sure B- you know, a big concern is reliability, obviously, because you don't want to separate from offsite power period when you don't need to. So, we put all of our units in a monitoring mode for quite some time and watched how they interacted with the grid, watch how they interact with faults in the plants, watch how B- even had one case where we had a one-switch yard out. We had an open phase event. The relay saw it but it didn't trigger because it wasn't an impact on the plant.

The relay is also extremely intelligent. It runs thousands of tests a second or something on itself, and if it has a problem it stops. I will not B- it will just alarm and say hey, operators, I've got a problem. I don't know what's going on. I'm done, and it will not trip. So, we think that the likelihood of that ever causing a loss of offsite power because the relay malfunctions is extremely low because of the new programmable logic technology. Analog circuits would have been a big concern for us. We probably would have gone B- in the initiative what we allow is you can block that signal unless you have an accident, as long as you can't create a Byron event. So, if you're a plant where you have two separate right-of-ways coming in and you have an open phase event, and all that does is drop out one train of equipment. You still have a full set of safety equipment. We told the industry early on if you're worried about reliability, you can block the isolation function as long as you don't have an accident. If you have an accident, just like the undervoltage, you'll change the B- you'll unblock it and it'll have to separate.

CHAIRMAN BLEY: Automatically unblock it?

MR. GREENLEE: Yes, it has to be automatic. So, what you've have is ESFAS contact like you do in undervoltage, and open, you know, open or close the contact in order to put the circuit B-

MEMBER STETKAR: In that sense, I mean, it would be permanently B- well, I won't say permanently blocked, normally blocked. It only enabled when you had that ESFAS.

MR. GREENLEE: You are correct. It would, essentially, never be in play.

MEMBER STETKAR: Right.

MR. GREENLEE: Now, you have to meet some other provisions, you know, because the intent was that you have to also look at all your protective systems to make sure that your pumps, and motors, and everything are all going to trip off. You're not going to have damage, and the operators can then go reset everything and start it back up if they need that equipment. So, you have to meet those two provisions.

CHAIRMAN BLEY: Scott, before you go ahead, I just glanced through your slides and through Robert's slides, and through Robert's slides, and earlier today the fact that the BTP says you have to at least annunciate if you have high-impedance grounds. And none of you are talking about that. Are you going to talk about it during your B- we could wait until your B-

MR. ARITT: Yes. I actually have a slide I didn't put in here, but we're designed to detect anywhere from zero to infinity all impedance.

CHAIRMAN BLEY: Okay. Well, maybe when you're talking B-

MR. ARITT: Okay.

CHAIRMAN BLEY: And if you can B- did you bring that with you?

MR. ARITT: I can dig it up, but it's not a slide in the slide deck.

CHAIRMAN BLEY: Okay.

MR. ARITT: But we did design to meet that criteria.

CHAIRMAN BLEY: Okay, we'll hear more later.

MR. ARITT: And my folks can correct me if I'm wrong, but if you have, you know, an infinite ground and you've got no current flowing. And as the ground gets worse and you create the imbalance in the system, what'll happen is the relay will pick it up, and it'll trip. It creates kind of an artificial open phase. Did I get that right, Kirk?

MR. ROBBINS: I think sort of.

CHAIRMAN BLEY: Sort of. Probably also in some transmission line got B-

(Off microphone comment)

COURT REPORTER: Your name, please?

MR. ROBBINS: Oh, my name is Kirk Robbins. I'm the Technical Lead for Exelon corporate office. We've done an analysis which shows that the fault impedance for the open phase conditions that we're concerned about is less than what the relay will detect. Okay? So, that we're bound in that sense. We don't need to go look at an infinite Ohm ground fault impedance, so we look at B- and I'm not sure that really answers your question or not?

CHAIRMAN BLEY: I think it confused me more.

UNIDENTIFIED: Did you get it?

MEMBER SKILLMAN: No. Well, I'm trying to get it now because I heard you, Scott, talk about resources and you explained what you're doing in the Exelon fleet. This gentleman just explained the Exelon fleet. I was asking the question in a larger sense than the NEI perspective. Are there resources that are necessary for the industry that aren't there? That was the real question I was asking.

MR. GREENLEE: And I think the answer we're going to give you is with the EPRI solution, it's not going to be a problem.

MEMBER SKILLMAN: Yes, sir.

MR. GREENLEE: Now, if everybody tried to do the Exelon solution, we would probably overload some of the resources that we have working on it right now.

CHAIRMAN BLEY: Now I understand. Thank you.

MEMBER STETKAR: Back to the technical answer. Can you run through that one more time about impedance being B-

MR. ROBBINS: What we did is we did some studies B-

MEMBER STETKAR: Okay.

MR. ROBBINS: B- which showed that the volt impedance would always be less for an open phase grounded or an open phase. For open phase grounded it would always be less than what the relay will be able to detect.

CHAIRMAN BLEY: So, the relay cannot detect that condition.

MR. ROBBINS: So, it will detect it.

UNIDENTIFIED: It will detect it.

CHAIRMAN BLEY: Okay, less confuse me. What you said, that's what got me before.

MEMBER BROWN: You said less than what the relay would detect.

MR. ROBBINS: Correct. The fault impedance is less than what the relay will detect.

CHAIRMAN BLEY: What does that mean? That doesn't operate.

MR. ROBBINS: No, no.

CHAIRMAN BLEY: That's what I understood.

(Simultaneous speech)

MR. GREENLEE: What Kirk is trying to say is that we did studies on the different impedances that we would see during an open phase condition and verified that the relay will pick up all of the open phase conditions.

CHAIRMAN BLEY: All the conditions.

MR. GREENLEE: We bounded it with some stuff.

CHAIRMAN BLEY: Okay. Sorry for the confusion.

MEMBER BROWN: I mean, the less than it

would detect means B-

(Simultaneous speech)

CHAIRMAN BLEY: I got that. Okay. Please go ahead.

MR. GREENLEE: Okay. So, I B- so the end of 2014 know what you're going to do by the end of 2016 implement design changes, but you don't have to put C-because of reliability, because the B- this is exactly what Exelon did. We put everything in a monitoring mode and we watched the performance of the relay to make sure we didn't have unintended consequences with losses of offsite power. We give everybody a year to do monitoring if you want to, and then go active by the end of 2017.

CHAIRMAN BLEY: But you're not likely to have one of these conditions occur during that period of time, so I'm not sure what you're getting.

MR. GREENLEE: What you're getting is making sure that the grid B- here's what originally worried me when we first put in our first installation at Byron Station. We got into the wintertime, had a horrific winter and the grid was all over the place. And you could see the impact of the grid on the relay. And what we wanted to make sure is there was nothing from the grid perspective, we also wanted to go through a B-

MEMBER STETKAR: So, the normal imbalances on the grid aren't going to create faults.

MR. GREENLEE: And lightning strikes, we wanted to make sure that when the relay sees things like that it doesn't misinterpret them. We also wanted to go through a refueling outage so we could start up and shut down all the big loads in the plant, and the relay would see it. It did, didn't have any problems.

We've had faults at our plants that the relays have seen. It has not caused an improper actuation of the relay, so it's really that sort of thing, making sure that if it's going to actuate, it's a real open phase, that nothing else in its operating environment would force it into an actuation.

MEMBER BROWN: So, when you say you monitor it, that doesn't mean you just monitor for whether it actuates or not. You're actually looking at its processes internally to see how they're varying, how close you might get. I just want to clarify what the monitoring is.

MR. GREENLEE: That's correct.

MEMBER BROWN: Nothing ever happening, but you don't know what's going on inside the house, but you do B-

MR. GREENLEE: That's correct. What you do is you put a trigger point inside the relay, and the relay then records operating data for a period of time. It tells you it triggered, and then you go down the operating data.

CHAIRMAN BLEY: You might have this coming up in a minute, but I'm going to ask it now. You can do it later if it fits your talk better.

When it comes time to meet the Branch Technical Positions Requirement for actuation, are you looking at alternatives to what that physically means, the sequence of things that would happen when it actuates, or are we just going to suddenly take away that line?

MR. GREENLEE: Well, what happens physically in the Exelon designs, the other industry designs will likely be similar, is there's already an existing relay associated with transformer protection. We call it the 86 Lockout Relay.

MEMBER BROWN: Right.

MR. GREENLEE: All we've done is taken the relay now B- the relay has B- there's an awful lot of analysis that goes into the time period that that relay has to actuate, again because of the coordination with faults. It's about .5 seconds to .8 seconds at Byron

Station, for example, in order to meet all of the coordination requirements with the grid, with the in plant fault potentials, and to meet the accident analysis so that you can transfer over fast enough so that you meet all the accident analysis for the concurrent situation.

MEMBER STETKAR: But still, at a very high level, Scott, you're still interlocking that transfer with a coincident ESFAS signal or not?

MR. GREENLEE: Well, you're analyzing it coincidentally. There's no interlock. It will B- it automatically B- once it detects an open phase, it will lock out B- it will hit that 86 Lockout B-

MEMBER STETKAR: It'll hit the 86, regardless of what else is going on in the plant.

MR. GREENLEE: Yes. At Byron Station, that's the way it had to work.

MEMBER STETKAR: Oh, okay.

MR. GREENLEE: So, it hits the 86 Lockout Relay, but we force it not to do it immediately to allow for other things to protect if it's not a real open phase. So, if I have a fault on a circ water pump motor, looks kind of like an open phase. That way the circ water pump motor clears and this thing doesn't actually transfer.

MEMBER STETKAR: Okay.

MR. GREENLEE: And it meets all the accident analysis, if you assume it's concurrent, so you have an open phase. Now you have your accident at the same time, .5 seconds later you're on the diesels, everything will work. But there's no B-

MEMBER STETKAR: But the key is in the relaying there is not B- I thought you said earlier there's, effectively, a series contact that would only pick up if you had an ESFAS.

MR. GREENLEE: We gave B- in the initiative, we gave the industry the option because of reliability concerns with detecting faults, losses, open phases. If you can show B- if you have two phases, there are two separate trains coming in to feed your safety buses B-

MEMBER STETKAR: Okay.

MR. GREENLEE: B- so that an open phase on this safety bus leaves you with a full safety bus, you can if you want to disable that function unless you have an ESFAS.

MEMBER STETKAR: Yes. Okay.

MR. GREENLEE: So, if you have one of B-

MEMBER STETKAR: In that particular configuration.

MR. GREENLEE: That configuration.

MEMBER STETKAR: I got you. I got you. Thank you.

MR. GREENLEE: Okay. Then FSARs get updated by the end of 2017. And if you go to the next page, tech specs also have to be either B- if you need a tech spec change, which we don't B- our review shows that B- and we've had a lot of industry experts look at 50.36, don't believe we need a tech spec change. What we're planning on doing is tying operability of the offsite source once you've installed your isolation system. To say your offsite source is operable, the isolation system has to be operable, so if it fails then you would enter your 72-hour action statement, which is typical of most sites for your offsite source not being on. But that wouldn't happen until we get actually through the initiative, install the isolation systems, and then we'll do a tech spec bases change to explain how that impacts operability.

And then the bottom disclaimer there is, you know, one of the B- if for some reason a licensee needs a license amendment to just install the equipment, obviously, the timeline is going to be different for them. We haven't run into that yet, but it's there in case we run into it. Next. Okay, next.

Okay, industry actions. This just gives you some idea B-

MEMBER SKILLMAN: Before you proceed, go back to 14, please. With that disclaimer at the bottom of 14, is that B- should we interpret that to mean that all of this change is being done under 50.59?

MR. GREENLEE: Correct. Yes, sir.

MEMBER SKILLMAN: Thank you.

MR. GREENLEE: Okay, next. Okay. Industry actions. You know, soon as the Byron event occurred, obviously we notified the industry very, very quickly. We had a webcast with the entire industry through INPO to explain what had happened so that everybody knew this vulnerability was out there. And then INPO pretty quickly issued, as Roy discussed, a Level 2 IER which directed the entire industry to look at themselves. Do you have the vulnerability, and establish a timeline for actions to correct the vulnerability. And, obviously, since then we put in place this industry initiative which is really what everybody is now working to from a timeline standpoint.

January 2013, we even B- you're all probably familiar with ETAP which is the standard software we use in the industry. ETAP actually revised their software so that we could analyze single and double open phase conditions through the ETAP software. Before that, we had been primarily using something called EMPT to model transients. Now, the ETAP is not a transient model, but it does tell you steady state what you're going to end up with after the open phase.

And then last year, October of 2013, all the Chief Nuclear Officers in the industry approved the NEI initiative to resolve this issue. That means if more than 80 percent of the Chief Nuclear Officers approve an initiative through NEI, everyone is required to comply with that, so the industry has to go off and fix this vulnerability in accordance with the initiative.

Now, there is a deviation process inherent in that, and we've actually put that out to the utilities at this point, but typically that requires an officer of the company to say hey, here's why I'm deviating, NEI gets notified, we let NRC know that there's a deviation for whatever, an outage schedule, couldn't find a solution because your design was just different, something of that nature.

And then in December 2013 we've issued the Guidance, a more detailed Guidance document for the industry through NEI. And in 2014, we actually met with international nuclear utilities to talk about this, because the international community has the exact same problem. So, I actually went over to Paris with some folks from INPO and met with WANO and WANO Utilities, and started drafting an SOER for the entire world, so to speak, to go address this issue. I've read the latest draft of that. It should be issued here within the next month, I would expect, and it'll basically drive the entire world to do exactly what the U.S. nuclear industry is off doing. Next.

Design considerations. These are fairly straightforward. We have been working with the entire industry through workshops to share operating experience, share the different designs. And the one thing that obviously Roy has challenged us to do, if you look at the second bullet, is we have to document why we think our designs meet the requirements of 10 CFR 50.55a(h), and we've actually put that in writing already to NRC from NEI. That was the first letter that we submitted to them.

The second letter mentions the 10 CFR, but is more focused on GDC and how the industry intends to meet the GDC requirements with our initiative and our designs.

The third bullet there, as I discussed, we did not find any technology available to make this a safety-related solution for all cases. You can get some cases, but not all. And the other part of it that would have been very challenging is if we had ever gotten to that technology, it would have had to have been digital, and now we're into digital installations on safety systems, which become much more lengthy as far as the installations. And we thought that that was just going to delay getting rid of the issue for the industry.

And the last bullet there, I've already mentioned that. That's the part of the GDC that we think is really the biggest gap for us with this vulnerability that we have addressed, is that interaction between the onsite and the offsite circuits. Next slide.

Okay. This is a very important point here. This is the risk profile that we've looked at, and this is specific to Byron Station because we wanted to B- Byron should be bounding for the industry. But what we did is we went back and we said okay, our PRA models never really assumed we had open phase events, so what if we go back before the event and say okay, now we're going to model it in our PRA model. What would the change in CDF be? And you can see down below it's about 3e-6 for Byron, or 7-1/2 percent which is a pretty big chunk for a single issue. So, there is risk-significance associated with the event, but what happens is if B- now, this assumes the operators know nothing about how to address an open phase. Once the industry went and did the training, the procedure changes and all of that sort of stuff B-

CHAIRMAN BLEY: Can you say anything about that? It's been mentioned several times, but what kind of changes were actually made, and what kind of training?

MR. GREENLEE: One of the big things is just the recognition that when you start losing all B- you know, you've got a bus and you start losing all of your motors, you've probably got an open phase condition and it's B-

CHAIRMAN BLEY: Okay, fair enough.

MR. GREENLEE: And we put that in our alarm response procedures at Byron and Braidwood. We changed the alarms, we changed the voltage indications to give the operators quicker diagnosis of an open phase condition. And, of course, we made them aware of it, so B- now, Byron. Byron is active right now. I actually have the open phase circuitry installed active so the operators are only a backup function at this point at Byron. Braidwood will be probably this month or next month, and then we've got a sequence for the rest of our sites.

But if you then go and you do an HRA, a Human

Reliability Analysis, and factor that into the PRA model based on the operators now knowing how to diagnose and open phase condition, you see you get a pretty good drop in the risk down to the 6e-7 range, or 1.5 percent of the baseline CDF. And, by the way, these numbers, we B- when you look at the conditional core damage probability analysis for B- that NRC did, all of this is consistent with that. It's a different analysis when you do a CCDP than it is when you do update your baseline risk, but the numbers are all consistent with what NRC did, so there's not too much there between their numbers and our numbers.

And then what you can see there at the very bottom is what happens once you put the trip in active, and then you have operator backup as B- because the operators are aware of it. You get into the e-8 range as far as risk, so you've now put the issue B- basically, it's gone from a risk perspective or a safety perspective once you do the installations. Next.

Okay. This just again reiterates that the industry has been working together. As a matter of fact, for the Byron design, which was the first one we did, we actually have given that to the industry and told the industry if they want the design, that's their's. We're not treating it as proprietary. We share actively, and then EPRI is going to talk about the work, the research that EPRI's been doing.

But you can see some of the different things that the industry has come up with. There are some differences, but I think what you'll find is the EPRI, to me, is probably one of the most simplistic and elegant that we've been able to identify. Next.

Okay. I will be quiet now and turn it over C-

CHAIRMAN BLEY: Probably not fair to ask you, but if the EPRI solution had been there before you B-

MR. GREENLEE: I would have rather put the EPRI B-

CHAIRMAN BLEY: You'd have gone that way?

MR. GREENLEE: Oh, yes. It's so much simpler, takes away this real big concern with, you know, are all your calculations perfect with the grid, with your transformer. It's just B- it's so much simpler. We're actually going to B- we're so far down the line on all of our units with one exception. We have one unit that we hadn't started on, and we actually couldn't make our solution work in it. We believe the EPRI solution will work, and we're going to install it on that unit.

CHAIRMAN BLEY: Okay. Now we haven't seen anything written on the industry initiative. Is there a document that's available that we might be able to see?

MR. GREENLEE: Absolutely. You can B-

UNIDENTIFIED: Sure, we'll get it to you.

CHAIRMAN BLEY: If you can get it to Christine, that would be great.

MR. GREENLEE: Sure.

CHAIRMAN BLEY: Thank you.

MR. GREENLEE: Okay. Any questions for me before I turn it over to EPRI?

CHAIRMAN BLEY: Okay.

UNIDENTIFIED: I think Roy will provide B-

CHAIRMAN BLEY: Okay.

MR. GREENLEE: You want to key up the EPRI presentation?

UNIDENTIFIED: Sure.

(Off the record comments)

MR. ARITT: I'm Bob Aritt. I'm with EPRI, and we B- we're going to go to the next slide.

EPRI's been involved very early on since the Byron event occurred, and since then we've put out actually five reports, four of which are publicly available. The first report we did was looked at transformer types similar to those at Byron, and we modeled those different transformers to try to see if we can come up with some common means to protect B- to detect an open phase with these transformer types.

The second report we did was we actually modeled an entire plant that had a transformer I would say similar to that of Byron, and also looked at starting motor loads, looked at open phases on the high side of the station auxiliary transformer, and also open voltages downstream, and the low voltage, medium voltage.

And after that, we actually did another paper, a report that we looked at all the various transformer types that weren't done in the first report. And these transformer types included all the list that Roy presented earlier, a sample of each one of the transformer types to be able to determine those transformer responses to an open phase condition.

In the first report folks have been talking about the two open phase, the double open phase. What we did in the fourth report was we went back and redid the first and third report. Instead of a single open phase, we looked at a double open phase to be able to show that characteristics of different particular transformers that represent a sample of those transformers in the switchyard.

And from those reports, and Scott hit on this earlier about that condition of a load, no load state, was really the real vulnerability that's hard to detect, and there really isn't anything B- wasn't anything out there existing that would be able to guard against, or at least detect that event. And I'll show you why that's a troublesome event to detect.

MEMBER BALLINGER: Can we get these reports?

MR. ARITT: Yes, those four are publicly available. I don't know what the B-

MEMBER BALLINGER: I just B- do you have the nine or whatever digit numbers B-

MR. ARITT: Yes, we'll get that to you. Yes.

MEMBER BROWN: We've got one of them. It just three B- one and three we don't have.

CHAIRMAN BLEY: I might have a copy.

MR. ARITT: All right. And this B- to kind of give you some background because it's B- give you some background. This is helpful in understanding what's actually happening, and why this is so very difficult to protect against.

You have a B- and these are transformers that are characteristics of those transformers that you'd find in a switch yard. And those transformers that have this particular problem, on the primary side we've already talked about, have a grounded Y-type connection, but they can either have a core type, or actually a secondary, or a buried delta tertiary. And if you have a three-legged core with B- and I don't want to lose anyone, so just bear with me. I'll get to the B- what I'm getting at, is with the three-legged core it's essentially like having a delta lining. And when you open that phase, and I have a diagram here showing the open phase, essentially what you have is you're putting two phases across that delta and the closed LOOP solution of that has to equal zero.

Well, since we have all displacement of 120 degrees, the only solution to that problem is what exactly that phase voltage, magnitude and phase angle would be as if that phase were still connected. So, basically, you're sitting there with your voltages all at one per unit, no to little load current to detect any unbalance, so that's really what makes this situation very difficult to detect. Okay?

MEMBER BROWN: Hold on.

MR. ARITT: Okay.

MEMBER BROWN: That still assumes that you've B- that's not three single phase B- that's got a common core for all three.

MR. ARITT: Let me show you on the next slide because I do do that.

MEMBER BROWN: I peaked.

MR. ARITT: Okay.

MEMBER BROWN: But I didn't see a picture, I saw a table.

MR. ARITT: Yes, I'll show you the table.

MEMBER BROWN: And my brain is too old for looking at B-

MR. ARITT: All right. If you go down the second row, you see a Y-Y with three single phase cores. So, these B- so, it's really a matter of the lining configuration and also the core configuration. So, if you had a Y-Y shell core, you could see if you were to open a phase, one of those phases would go to zero. And that's very much the way that a Y-Y with three single phase core types react because you do not have that magnetic coupling between the interphases that gives you that cross coupling, that reestablishes that open phase. And you can see also, too, someone talked about a core type with multiple limbs. I have a five-legged core which is out there, and then actually you have some magnetic spots getting into the leg; however, it's not enough to B- because of that fifth leg, you don't have that one per unit flux in that limb, so you get B- can manifest itself an open phase manifest itself as a low voltage condition. And just like a delta-Y type transformer, it doesn't matter what core type you have, you'll get that same reaction where if you get an open phase it'll drop down to 50 percent on that open phase on the primary, and the secondary side you'll see B-

MEMBER BROWN: You mean core type, you mean three single phase?

MR. ARITT: Any core type, three single phase, three B-

MEMBER BROWN: That are connected in the deltaB-

MR. ARITT: Right. It doesn't matter because of the lining configuration. Just like with the Y-delta it doesn't matter what core type you have. You still have that same problem.

MEMBER BROWN: I'm kind of lost now, now that you're totally uncoupled in three separate single phase transformers.

MR. ARITT: Right. But what's coupling it, though, is that delta winding is what couples that. It takes the place of what that core B-

MEMBER BROWN: The delta is the high voltage side, and B-

MR. ARITT: Either the delta is on the high voltage side, or the low voltage side. If you have a Y-delta type transformer it doesn't matter what any core type is. You want to go back to the last slide, you can see here this is a Y-delta. It doesn't matter what core type you have. You'll still get that recreated voltage on there because you don't need the magnetic coupling going on in the B-

MEMBER BROWN: You've got circulating currency.

MR. ARITT: Right, you have circulating current.

MEMBER BROWN: Okay, I got it. Thank you.

MR. ARITT: Okay, go ahead to the table. Oh, go back up. So, those transformer types that are highlighted in red are these transformer types that have this voltage recreation issue where an open conductor condition does not translate into a low voltage condition.

(Simultaneous speech)

MR. ARITT: Right.

MEMBER BROWN: Thank you.

MR. ARITT: Yes. And that's really where B- the no load is the critical thing because you don't have any load current to measure, or even a moderate loading where you're below a threshold of the noise, it's going to be very hard to detect with just current. So, the voltage is recreated, and those other transformer types that aren't highlight, the open phase is translating to a low voltage condition. That's the reason distribution systems you won't see the transformer types in red, you only see the ones in white because an open phase will translate into a low voltage condition that you can protect against.

MEMBER BROWN: Let me ask another question. I guess I still have a little hard time. I understand your point previously, but once you go into these configurations you've got different B- you've got circulating current, but you've still got different exciting current type characteristics; but yet under no load you say it washes out and it doesn't matter.

MR. ARITT: Yes, under no load, that's correct.

MEMBER BROWN: Okay.

MR. ARITT: Even low load, moderate loading conditions, you get the same response with these different B- with the different transformer types. That's the reason it was so critical to go back and look at which transformers were problematic, and which ones that you could B- the open phase will translate to a low voltage condition.

MEMBER BROWN: Did anybody ever B- these are nice calculations. Has anybody ever tried it in real physical B- with real transformers and do that and see B-

MR. ARITT: We have tested some transformers in our lab, just bench top test scaled transformers. We had a three-legged core, different transformer configurations. This is B- we modeled this, and there's other papers out there that match these results, so we're B-

MEMBER BROWN: But could you get that measurement-wise B-

(Simultaneous speech)

MEMBER BROWN: The scale is fine but, I mean, you're able to get B-

MR. ARITT: Yes, you're able to measure this. Yes.

MEMBER BROWN: Okay.

MR. ARITT: And this B- and, again, it matches what's done in industry, again, which transformers and why is what you would use in a distribution system because of the protection issues that the ones in red create. Okay, go ahead.

So, because we highlighted B-

MEMBER BROWN: Backwards again.

MR. ARITT: I'm sorry?

MEMBER BROWN: Go back to the B-

MR. ARITT: Okay.

MEMBER BROWN: A lot of the ones we've looked at in some of the plant design, they're by the main transformers.

MR. ARITT: Yes.

MEMBER BROWN: So, those B- you say those are problem configurations.

MR. ARITT: Well, it depends on how they're operating them, if they're back feeding through them.

MEMBER BROWN: Okay.

MR. ARITT: So, it all depends.

MEMBER BROWN: And there's never B-

(Simultaneous speech)

MEMBER BROWN: I can't imagine them ever being unloaded B-

MR. ARITT: Right. And, again, loading is an issue, too.

MEMBER STETKAR: But there's other problems with B-

(Simultaneous speech)

MR. GREENLEE: B- because they put all their loads over on the main generator, so you don't get the loading until the reactor trips.

CHAIRMAN BLEY: All right.

MR. GREENLEE: And then the generator is gone and everything shifts B-

MEMBER BROWN: Yes, we've looked at one like that. Okay.

CHAIRMAN BLEY: And there are other design reasons for picking different configurations.

MEMBER BROWN: Yes, so for that particular approach you'd never B- that's why those are in red. Those create a problem for you.

MR. ARITT: The problem in detecting that you have an open phase.

CHAIRMAN BLEY: Right. High voltage B-

MR. ARITT: High voltage. I'm just going to show you B-

(Simultaneous speech)

MR. ARITT: Again, getting back to the low voltage side, it depends on what's on the other side of that. And a lot of B- the ones that we looked at in the report, they were delta-Y so you get the response that you get in the fourth row there where it translates to low voltage, so you can detect it with your existing undervoltage relay. Okay, go ahead.

So, as we talked about the difficulty in detecting an open phase under the light to no load condition, it really was at the crux of the matter as far as the difficulty in detecting that. As we identified that in our reports, we set out to try to come up with some means of detecting that.

Part of the strategy in going forward as far as finding a way to defect an open phase, we looked at several options. These are just four that I've highlighted that our list was actually larger than this. These are some of the four prominent ones, I'd say.

We looked at voltage imbalance early on. Again, as I showed in the previous table it works for some transformer types. However, for susceptible transformers that recreate the voltage it gives you no indication of your system capacity. Now, in the next slide I'll show you an example of that.

Sequence current detection, this works well if you have enough load. And, again, the no load is problematic with that because of the B- just the threshold of your transducers.

Phase current detection, just looking at the current on each of the B-

CHAIRMAN BLEY: I'm sorry, go ahead.

MR. ARITT: Okay. On each of the phases,

I'll get to an example what makes that difficult, and the reason that we excluded that from the list. A power line carrier, I'll get into a little bit of that as far as the difficulty that we saw implementing it. Okay?

The voltage imbalance relaying, again, this all goes back to that third slide I showed about how you recreate the voltage. And, again, it gives you no indication of your B- the adequate capacity of your system. This was on the second report we did, is if you get an open phase you're sitting there and all your voltages look normal. Your positive sequence looks good, your voltage magnitudes all look good.

Well, you go to start a motor, in this case a 6,000 horsepower coolant motor, you can't get it up to full speed, so you've got limited capacity, and you had no idea about that beforehand because you didn't realize you had an open phase, just like in the case that went 30 days in open phase.

And also, another thing with this, it's inherently unstable because the motor will trip off, but your voltages go back to normal. It needs some operator interface B-

(Simultaneous speech)

MR. ARITT: B- start again. So, you try to start it up again, and you have the same issue, and you can't get your motor started. Okay, go ahead.

Phase current detection. I talked about the high impedance ground. This is B- this was an issue that we saw with this. You have to have some high custom CTs and it would be hard to retrofit this in the existing system without some change to your existing system. But the biggest challenge that we saw, and it's not necessarily a transducer issue, but it was the problem with the back feed in a very noisy substation environment where you're magnetizing current is mostly harmonic. Is very rich in harmonics so you can't B- you're going to have to be able to sense direction if you were to get an open phase upstream of a high impedance ground fault, or even upstream of say a CVT.

CHAIRMAN BLEY: You also said it was really expensive on your previous slide. Why is it so expensive?

MR. ARITT: Because you have to have three custom-made CTs, and it has B- it's installation that we saw as you had to go B- you had to wait, take the transformer off line, custom fit these into a transformer. We wanted to be able to B- and our goal was to be able to retrofit it as easily and painless as possible.

CHAIRMAN BLEY: Okay.

MR. ARITT: And the issue with the directional current sensing, we saw that as the real technical challenge. At 230 kV it only takes about 10 nanofarads to get current on that order of magnitude as you're magnetizing current. And if you get an upstream of that B- if you get an open phase upstream of CVT, CVT is roughly about 10 nanofarads, you're going to have back feed because, again, you're recreating that voltage and the back feeding into that time impedance so you're going to have to distinguish that between a magnetizing current and a fault current, so we just saw it as a technical challenge. Okay, go ahead.

The PLC, this is something we looked at very early on. It was expensive because, again, you have to have three of everything because you'll have to have it on each phase conductor. But also saw the gap that it left because you need a transmitter and a receiver. You're not going to be able to get that receiver right to the transformer, there's always going to be gap where you have some vulnerability of getting the open phase there, so we dismissed that. Okay, go ahead.

So, what we did was based on the knowledge that we have from doing all the previous studies, we knew the transformer types that have the problem, and we knew that we could exploit these results to have some means of detecting an open phase transformer that would be very reliable and secure. And we came up with, and I'm going to talk a little bit about it, a method of monitoring B- basically, what we're doing, as we talked about earlier, is monitoring the zero sequence network because that network changes when you get the open phase. And we proved this theory out in lab testing and extensive modeling in early 2013. We provided a webcast to our industry B- to the B- we provided the webcast in November of 2013 to show these results. We field tested it in May of 2014, and we released an EPRI document that talks about some of the high impedance ground faults. We'd design it to operate with a single open phase, and a double open phase, all those criteria that we put forward to what we needed to detect. Okay, go ahead.

Get a little bit into the B-

MEMBER BROWN: Go back to that again.

MR. ARITT: Okay.

CHAIRMAN BLEY: All your problem types have dry on the high side.

MR. ARITT: Correct.

CHAIRMAN BLEY: Okay.

MR. ARITT: And that neutral gives you B- is the zero sequence.

MEMBER BROWN: That's what I was going to ask you. So, you're monitoring the neutral B-

MR. ARITT: Yes. Actually, I've got a few slides, and what I'll do is I'll show you B-

MEMBER BROWN: You're going to talk about how you B- what you mean by injection B-

MR. ARITT: Correct.

MEMBER BROWN: There was at least one or two papers that I looked at that talked about zero sequence didn't do you any good under some circumstances. And I don't remember B-

CHAIRMAN BLEY: I remember that, it said you always put the number of sequence current, but you don't always get B-

(Simultaneous speech)

MR. ARITT: It depends on B- that's probably talking about a motor single phasing where it's B-

MEMBER BROWN: No, it was on open circuit, open conduct B- it was an open input.

MR. ARITT: Yes.

MEMBER BROWN: Not B-

(Simultaneous speech)

MEMBER BROWN: It was upstream the transformer, it was input.

(Simultaneous speech)

MEMBER BROWN: Pardon? Yes, the Basler technical paper said something about that, and there was one other one, as well.

MR. ARITT: Right. There's a B- yes, if you single phase a motor where you open one of those phase the way they detect that is with negative sequence current. But, again, that's going to the motor load. This is a little bit different situation than that because we're open phasing the transformer. I just have to look at the paper and understand what you're talking about.

MEMBER BROWN: I don't remember it being motors, but that's B- it was transformers that they were talking about opening the input, so I B- go ahead.

MR. ARITT: Okay. And, again, that's current, and we really don't have current to look at here in the unloaded case. Okay, go ahead.

This is kind of the principle of operation. if you have all three phases intact, what you have is a high reluctance path for your zero sequence flux, which translates to a relatively low zero sequence impedance.

With an open phase you have a very low reluctance path that translates to a very high impedance state, so you're going from a relatively low zero sequence impedance to a relatively high zero sequence impedance. And, actually, when they test the transformer zero sequence impedance, that's the way they test it, is that they short all three phases together and they inject into the neutral to get what that zero sequence impedance is. So, it's a very discernible sequence impedance change that you can detect. Go ahead.

So, when you all three phases intact, you have a relatively low zero sequence impedance. And you can see here this is the injection source that's looking into the neutral. Essentially, what that's doing is monitoring the zero sequence impedance path. Go ahead.

When you open that zero sequence impedance C-when you open one of those phase, your zero sequence gets very large, and it's easily detected. And that's the reason it doesn't depend on a lot of analysis because it's such a discernible change when you open that phase conductor. And the same is true with the double open phase.

CHAIRMAN BLEY: But you're actually putting this injection source on B-

MR. ARITT: It's active protection. You can kind of think of it as on generators that you scatter fault current protection where they're actually injecting into the neutral the generator, but they're looking from a high impedance state going to a low impedance state. We're looking at a low impedance state going to a high impedance state, so it's essentially the same thing, but we're doing a different application. Okay, go ahead.

So, these are some of the design criteria that we had going in. Because of the problems with the B- as I show with the voltage and the low current, we wanted some active detection because we concluded that would be the only secure way of doing it, one of the more secure B- a more secure way of doing it, I should say. And the way that our design criteria was laid out, we wanted a failsafe design, and we wanted to be able to have a redundant detection design if we needed to have that. And because we have the active injection signal, we can test all the components in the system because we have a test button, we're actively injecting the signals, testing the transducer, the measuring device, and everything. And you can do that in system without having to take anything off line. And, again, we're only monitoring a change in signal. We're not looking at absolute magnitudes, so that you don't need all the detailed analysis to realize you're going to have a 40 dB change in the signal.

And we've married this with our passive protection to give us even more security on detection, because when you get B- when you open that phase, that neutral conductor acts like that third phase. It starts carrying your current. We can detect some change in that, we have some B- we can detect the current going up in that, too, it's concurrent with the change in the impedance of usually our sequence network.

And, again, this met all of our design constraints about looking at the single, double open phase with different fault impedances from zero to infinity. And we wanted to use all off-the-shelf components to make up the unit, to reduce lead times and reduce costs, and also to have the parts available. These are very standard parts that we're using that part obsolescence is something that we didn't want to have to deal with. Okay, go ahead.

And, again, we knew we wanted to retrofit this into existing designs, so that's what made it beneficial to use the zero sequence network that you can monitor in the neutral connection outage. Take a plant outage is always an issue so we wanted to be able to put provisions in place to where you can implement this on your schedule, design of ease of installation. We also knew that seismic concerns, again it's mounted on the ground so you don't have the seismic concerns if you're to have something on the high side. And also, the exposure to lightning, very immune to lightning because, again, we're on the ground. We're galvanically isolated from the neutral conductor so we're not making any physical connection, so that gives us the immunity from lightning. Again, we're not exposed to it on the phase conductors. And, again, since we're not on the phase conductors, we don't have any issues with the BIL and the creepage.

MEMBER BROWN: You say you're galvanically isolated but, I mean, you're still connecting something. I mean B-

(Simultaneous speech)

MR. ARITT: It's magnetically coupled. It's not B-

MEMBER BROWN: It's a field.

MR. ARITT: Correct. So, we're not making a galvanic connection.

MEMBER BROWN: I know, you're not hard connecting.

MR. ARITT: Correct.

MEMBER BROWN: But you've still got coupling back into your B- I would think that can be B- so you're saying that's trivial.

MR. ARITT: Yes, that's trivial. It's a very small signal, it's very trivial.

MEMBER BROWN: Some lightning or any other major transient that you would you would not have B-

MR. ARITT: Correct. Again, we're monitoring wires so we're not B- we're immune to the electrical transients going on because we're looking at an impedance.

MR. GREENLEE: But I think it's important, I don't know if it came across clearly, but they're looking for two different things independently, and you only trip if you see both of them, not one of them.

MR. ARITT: To give us the security, yes.

MEMBER BROWN: What are the two things you B-

MR. ARITT: We're monitoring the injection signal along with the passive detection which shows a change in your current in your neutral because, again, when you open that phase, your neutral becomes your third phase conductor, and you see a change in current. And because now the B-

MEMBER BROWN: So, you're monitoring neutral current B-

MR. ARITT: Monitoring neutral B-

MEMBER BROWN: B- in addition to your

injection source?

MR. ARITT: Correct.

MEMBER BROWN: That's not shown on here then, is it?

MR. ARITT: I show it on the previous slide.

MEMBER BROWN: The arrows get B-

MR. ARITT: The electrical controller and that's what monitoring the B- or measuring the neutral current.

MEMBER BROWN: Oh, okay.

MR. ARITT: And that's the passive detection.

MEMBER BROWN: That's the CT B-

MR. ARITT: Yes, the electronic CT, yes, that we're measuring. Go ahead.

And we did retest the prototype at Bellefonte. It was the first ever actual open phase field test, intentional open phase test. This was done on a 161 kV transmission system coming into a 36 MVA station. The test itself took two days because of B- and I have to give TVA a lot of credit for conducting this because it took a lot of logistics doing the transmission, operations, and also the plant, and the test itself took two days, but it only took maybe less than an hour to put the unit in. We just went up, disconnected the neutral conductor, ran one down through the unit, and connected it back up. So, it was very quickly installed, and that was something that we wanted to achieve in our design criteria. You want to go ahead and go to the next slide.

MEMBER BROWN: Before you do that, I'm still lost. I've still got to ask another question.

MR. ARITT: Yes?

MEMBER BROWN: Go back to 12.

MR. ARITT: Slide 12.

MEMBER BROWN: That's 11. Source transformer secondary winding and transformer primary winding.

MR. ARITT: Yes.

MEMBER BROWN: Which is B- where is my coming into, where is my going B-

MR. ARITT: Okay, good question.

MEMBER BROWN: Which is the one off of the transmission system?

MR. ARITT: Good question. The one on your left is a representation of the network, the transmission network.

MEMBER BROWN: The secondary side of the main transformer, if it's coming from your transmission line?

MR. ARITT: Correct.

MEMBER BROWN: It's 365, or 161, or whatever?

MR. ARITT: Correct. And the one on your right where the device would be connected is the one that you're monitoring for the open phase condition, so that B-

MEMBER BROWN: All right. I'm just B- I'm really slow.

MR. ARITT: That's fine.

MEMBER BROWN: I apologize for that. If I look at a plant that's got a big main transformer, it's a Y-connected transformer, might be a Y or a delta on the secondary side. And it's looking back at the transmission system.

MR. ARITT: Correct.

MEMBER BROWN: This is B- I'm just looking at the right-hand side.

MR. ARITT: Yes, just the right-hand side. I don't show the secondary side.

MEMBER BROWN: So, the lefthand side is the trans B- is my big transmission lines.

MR. ARITT: Yes.

MEMBER BROWN: Is that assumed B- is there a neutral out there on that?

MR. ARITT: Yes, it would be connected to the transmission network which is relatively low zero sequence impedance by design to get the ground fault protection to work. And that's B-

MEMBER BROWN: So, I'm just B- I'm not a B- I'm not that type of transmission guy. Okay?

MR. ARITT: Yes.

MEMBER BROWN: I'm trying to understand.

MR. ARITT: Yes.

MEMBER BROWN: When I look up at the cables there's a neutral somewhere floating around in there coming into the plant.

MR. ARITT: Yes, it's multi B- it's a multi-grounded network system.

MEMBER BROWN: That's fine, I've got it.

MR. ARITT: Okay.

MEMBER BROWN: I just didn't B-

MR. ARITT: Understood.

MEMBER BROWN: Connected to the physical world that I'm not familiar with.

MR. ARITT: Understood. Good question.

MEMBER BROWN: Thank you.

MR. ARITT: And we opened the phase at the TVA system, and as predicted we were able to detect the open phase. You could see on the picture the injection signal drop over 40 dB. The passive detection, there we're just looking at the fifth harmonic. It changed by 13 dB. And the fifth harmonic is a good indicator because it's a positive sequence current that doesn't show up when you're neutral normally, so you see that concurrent change and that gives you secure detection of an open phase event.

And something Roy talked about earlier, in doing the analysis the difficulty in coming up with some of these test sheets to find out what the zero sequence impedances of the transformer. The only knowledge that we had going into this test was just the nameplate. And from the nameplate information we were able to come up within the ball park of how much change you're going to get. And, again, that's because we're just looking at delta, not absolute values. So, we knew that we would see a significant change in that injection signal that we don't need all that information.

MEMBER BROWN: Okay. I'm going to be obtuse again.

MR. ARITT: Okay.

MEMBER BROWN: This is afterwards.

MR. ARITT: Correct.

MEMBER BROWN: What did it look like before, was that in the previous B-

MR. ARITT: Well, that shows up in the dB change, so the dB change is a B-

MEMBER BROWN: It was zero before?

MR. ARITT: It was baseline, yes.

MEMBER BROWN: I don't know what that means. is baseline 50, is it 100, is it minus 50, is it minus 100, or was it zero?

MR. ARITT: Well, the injection signal itself was something around 100 milliamps, and it went from 100 milliamps to 41 dB change, and went to basically very little, what that would be, you know, maybe a few milliamp, a milliamp or so. Well, 40 dB is roughly about 100 times difference.

CHAIRMAN BLEY: Is the test demonstration described in that report?

MR. ARITT: Yes, it is.

CHAIRMAN BLEY: I just noticed that's not a public report, but it's not here in NRC now?

MR. ARITT: I'd have to check. The way the reports have been done we've released them and then we went back and made them public. We may be able to do that with this one. Again, maybe something that you'd be able to get.

CHAIRMAN BLEY: I'd sure like to be able to read this to understand this B-

MR. ARITT: Okay.

CHAIRMAN BLEY: B- more of the details behind it. I mean, it looks pretty clever to me, but I'm just getting an overview.

MR. ARITT: Yes.

MEMBER BROWN: That's not one of the four reports you talked about in the beginning.

MR. ARITT: No, because those were publicly available.

MEMBER BROWN: That's why I B-

MR. ARITT: Yes, this report was listed a couple of slides after that. And I'll check on that. Wayne Johnson is here.

CHAIRMAN BLEY: It's not public yet.

MR. ARITT: It's not public yet. Wayne Johnson is here, and we could B-

(Off microphone comment)

MR. ARITT: Yes, we might not make it public.

MEMBER STETKAR: Wayne, you have to come up to the microphone, please.

MR. ARITT: Even if we don't make it public C-

CHAIRMAN BLEY: We've got a transcript so we need your name and organization.

MR. JOHNSON: Wayne Johnson from EPRI, Project Manager for the Open Phase Event. Yes, we made all the previous reports public because it was a situation where we're trying to gain knowledge and every piece of knowledge we gain we want to share with the industry. But this is a device that has been commercialized now, and someone has to build it and supply it to the industry, so this particular report was not made public. This is based on a commercialized device.

CHAIRMAN BLEY: So, when Staff looks at a plant who's going to adopt this design, if this isn't public, how do they get access to the information to be convinced this is going to meet the needs?

MR. JOHNSON: Those typically head over to the MOU between EPRI and B-

CHAIRMAN BLEY: But we don't have that in place yet.

MR. JOHNSON: Yes.

CHAIRMAN BLEY: Is that right?

MR. JOHNSON: Yes, and the customers.

MR. GREENLEE: I think there are methods we can use to let you take a look at the reports. We do it, for example, with the INPO IERs, I give them to NRC all the time, and we just treat them as proprietary.

CHAIRMAN BLEY: Yes, I think that's fine. I just think you need to be able to look at it, or say we don't know how this thing works.

(Simultaneous speech)

MR. DALEY: That's pretty standard inspection practice. We go B-

CHAIRMAN BLEY: We don't this one yet in house with NRC.

MR. DALEY: Oh. I'm Bob Daley. I'm the Region III Branch Chief that Roy mentioned earlier. It's pretty standard inspection procedure. If we B- if the inspectors go out and they're looking at this modification, they're going to ask for supporting equipment. And Scott's folks will sit there and say that it's proprietary, we need to give it back afterwards. So, we could do B- we will be able to look at this.

MEMBER STETKAR: Yes, we've been able to B- don't worry, we can B-

(Simultaneous speech)

MEMBER SKILLMAN: Robert, on that image, is what we are looking at a manually disconnected link to the transformer step?

MR. ARITT: Correct, this was a long process. We tried to get a load break switch but were unsuccessful, so what they did was they just removed the stinger to simulate the open phase condition.

MEMBER SKILLMAN: So, you de-energized, removed the link, and re-energized, and that showed up as the open phase.

MR. ARITT: Correct.

MEMBER SKILLMAN: Got it. Okay, thank you.

MR. ARITT: In the active and the passive detection modes.

MEMBER SKILLMAN: So, you didn't do it in a dynamic manner, you did it in a static manner.

MR. ARITT: Right. We tried to get a load break switch. No one wanted to lend us one. It was a long process, but in order to get the test done this was the most B-

MEMBER SKILLMAN: That's fine, I was just B- that was a good question.

MR. ARITT: Thank you. So, we only had one chance B-

(Simultaneous speech)

MR. ARITT: Yes, we took it. But we were confident in it, so we're very pleased with the collaboration again with TVA in this test. Okay, go ahead, next.

So, these were the completed steps. We completed a prototype for field testing. We wanted to do the field testing even though we felt comfortable with the lab testing. There's always a need to do field testing. We did a laboratory demonstration meeting. We did that so folks could come in, look at the equipment and ask questions. We chose the field site test, which was TVA. We completed that field testing, and we've completed that licensing to make it available for folks to implement it.

Are there any questions that haven't been asked, or maybe something needs further clarification?

MEMBER BROWN: It will help clarify it if we can get your reports.

MR. ARITT: Okay.

(Simultaneous speech)

CHAIRMAN BLEY: I think now we have B- we'll go back to the Staff. There was a comment from this morning B- still morning, from earlier today.

(Off microphone comment)

MR. MATHARU: My name is Singh Matharu, and this morning we offered to bring a single line diagram to look at the transformers of interest. Can I move this?

CHAIRMAN BLEY: I don't know. I don't see it from here.

MR. MATHARU: What B-

MEMBER BROWN: Go ahead. I'll ask my question after you get all of that up, not related to this.

MR. MATHARU: Okay.

(Off the record comment)

MR. MATHARU: Single line diagram, the way this unit would operate normally you would start upB-

UNIDENTIFIED: This is not B-

MR. MATHARU: B- here on both sides is your startup transformers and the aux transformers, so if you start up and getting flows here and you feed your buses from the startup transformers, about 15-20 percent power or somewhere the operators would transfer. Open this breaker or they close this breaker first and then they close this breaker or simultaneous transfer, and then the aux transformers. So, a simple configuration.

MEMBER STETKAR: Which is not the one that I was interested in.

MR. MATHARU: Okay. We can go to the next one also. In this case, the licensee would be looking at this source of the GDC 17 source because upon a unit trip you would go from here to here, use this path as a shutdown path.

MEMBER STETKAR: Okay.

MR. MATHARU: So, we were not forcing anything over here.

MEMBER STETKAR: Right.

MR. MATHARU: In the extreme case, this licensee may opt to back feed from here to this path if you were to take this transformer out and use it as a GDC 17 source during shutdown conditions. With that configuration we would request that they look at this configuration to make sure they monitor it.

The next one B-

UNIDENTIFIED: Sorry.

MEMBER STETKAR: Let him get to the B-

UNIDENTIFIED: Oh, okay.

MEMBER STETKAR: He's got to be able to get to the generator breaker on the next one. Right?

MR. MATHARU: Well, this typical B- this is generator operator breaker, so we only B-

MEMBER STETKAR: Most new plants are installing them.

MR. MATHARU: I'm sorry?

MEMBER STETKAR: Most new plants are installing them.

MR. MATHARU: Yes, most new plants. Let me see if I have that next slide.

(Simultaneous speech)

MR. MATHARU: Okay. So, this is a little bit more detailed drawing, sorry, it's the only one I could find.

MEMBER STETKAR: Right. This one is also uninteresting.

MR. MATHARU: Sorry?

MEMBER STETKAR: This also is not interesting, so let's go to the next one.

MR. MATHARU: That's the two I have.

MEMBER STETKAR: There's no generator breaker in here.

MEMBER BROWN: There's a little bitty breaker in there.

(Simultaneous speech)

MEMBER STETKAR: Oh, I'm sorry.

MR. MATHARU: Okay, so you could B- because this one would be the one source for offsite source, this would be B-

MEMBER STETKAR: No, on this one, and I apologize, I didn't see them in the scribble there since there's all the big boxes and my eyes are bad. Why in this configuration would you, or do you through the Branch Technical Position require monitoring for open phase on the generator size B- side of the auxiliary transformers?

MR. MATHARU: Generator side of the auxiliary transformers?

MEMBER STETKAR: Right there, yes.

MR. MATHARU: Right there? This is what Scott was describing earlier on. This configuration, this is hardwired. And you wouldn't see a fault B-

MEMBER STETKAR: Well, I B-

MR. MATHARU: If you open this phase you will see a fault, and your protection typically at the safety level will detect that.

MEMBER STETKAR: I have seen plants in my life where that enclosed bus configuration does not exist where your fingers were, that they were open wires. I'm saying I have seen plants in my life. They may not necessarily be in the United States, because I have not seen every plant in the United States, but I have seen plants internationally where there are open wires where those transformers sit outside and it's not bus belt.

MR. MATHARU: Well, typically this would be the isophase configuration B-

MEMBER STETKAR: That's B- you said typically. I'm saying are you certain that for every plant in the United States there is isophase bus duct?

MR. MATHARU: I have not seen B-

MEMBER STETKAR: Okay.

MR. MATHEW: We reviewed the bulletin in those forms, and one of the questions in the bulletin is ask the licensee to explain the power pack for the qualified parcels, so if a licensee is using that transformer right in the back, they had to have an analysis to show if an open phase happens at the high side of the main transformer or at the near aux transformer, whichever is the limiting case. They have to show the analysis that is done. So, the question I was referring to, the response earlier when I had the discussion, if it's a coal fired power source, then hard to demonstrate it.

Also, if you look at the vulnerability aspect, there are some buses. You know, we have segregated bus, insular segregated bus, from an actual account of this, these things don't do anything.

(Simultaneous speech)

MEMBER STETKAR: I guess maybe somehow I'm not communicating real clearly. I said that I, John Stetkar, in my experience have seen nuclear power plants, not necessarily in the U.S. because I have not seen every nuclear plant in the U.S., but I have seen nuclear power plants that do not have segregated isophase bus ducts on the high side of the auxiliary transformers in a configuration that does, indeed, have a generator breaker. So, my question is, are you certain that for every plant in the United States that has this type of configuration, that the connection from the main generator to the high side of the auxiliary transformers is, indeed, enclosed in an isophase bus duct, whether it's segregated or however it's configured. If the answer to that question is yes, you are certain, I will buy-in to the notion that you will detect an open phase halt in that configuration.

MR. MATHARU: Yes, the answer is yes.

MEMBER STETKAR: You are. Okay, thanks.

CHAIRMAN BLEY: Okay, we're B-

MEMBER STETKAR: Thanks.

CHAIRMAN BLEY: Would you make sure you leave that file on that computer?

MR. MATHARU: Certainly.

CHAIRMAN BLEY: Thank you, so we have it for our transcript since it's been on the screen here.

MR. MATHARU: Oh, absolutely. She's already asked me to B-

CHAIRMAN BLEY: Oh, okay. She's way ahead of me.

MR. GREENLEE: One thing we can at a minimum do through our working group is go back and ask the question. I doubt it, but it's always possible.

MEMBER STETKAR: I was going to say, I have seen one, but it's not B-

MR. GREENLEE: But there would have to be two conditions. Right? First of all, you'd want B- if you're crediting it as a GDC 17 source, and it has non-hard connections coming somewhere downstream of the B- or upstream of the aux transformer, unit aux transformer, then I understand your concern.

MEMBER STETKAR: Yes, that's the B- I mean, typically, in this kind of configuration the answer to the first question is yes, you are crediting it because there's typically a separate B- that's one of your supplies, the thing that's characterized as a standby transformer is the other one, whether it's normally energized or not.

MR. GREENLEE: It's a good question. We'll take that back to the industry working group and make sure everybody is aware of that concern, and that we take a look at it.

MEMBER STETKAR: Yes, that'll help. Thank you.

CHAIRMAN BLEY: Okay. From the Committee, any more B-

MEMBER BROWN: Yes, I have one more, at

least one more question.

CHAIRMAN BLEY: Do all your questions, Charlie.

MEMBER BROWN: On this little device that EPRI has proposed as their solution which I have two questions on that. This B- all your test data demonstrates that you can sense and detect the open phase, and it would cover, based on your analysis all the conditions you're interested under these Y-Y primary circumstances that you have to deal with.

MR. ARITT: Not just Y-Y, Y on the primary side.

MEMBER BROWN: Y on the primary side.

MR. ARITT: High side.

MEMBER BROWN: Yes, that's what I meant, I'm sorry. Now, if that B- if you're going to do something with that, you need to open up, or there's no actuation circuitry. This is just a detection part of it. There's still more stuff that needs to be done to finish and comply with other needs. I mean, once you got it, you've got to do something with it other than just tell somebody.

MR. ARITT: Correct, yes. We B- it's basically what the plant wants to do with it. We can send a trip signal, and then B-

MEMBER BROWN: Can you generate a trip signal?

MR. ARITT: Yes.

MEMBER BROWN: Okay, so you've got the control outputs which somebody can go use.

MR. ARITT: Correct. And, also, some folks are wanting extra sensing capabilities, it can do that, so it depends on what the plant wants.

MEMBER BROWN: Okay. In order to make sure you don't have spurious stuff, is there multiple channels of this, you've got some coincidencing, or some redundancy in coincidence, one of two, or two of three, or something like that?

MR. ARITT: Right. The prototype unit actually was a dual channel unit that adds some redundancy there. The commercializer offers a full unredundant system if somebody wants that, so there's a lot of B-

(Off microphone comment)

MR. ARITT: Correct. The security in it is you have the active detection and the passive detection which give you the secure B-

MEMBER BROWN: It's the little current, the electronic controller that you called it.

MR. ARITT: Correct.

MEMBER BROWN: You've got to get both of those to get the trip.

MR. ARITT: Correct.

MEMBER BROWN: Okay, so there's two conditions that cause this.

MR. ARITT: Correct, to give you the security.

MEMBER BROWN: All right, thank you.

CHAIRMAN BLEY: Your other questions?

MEMBER BROWN: I didn't know if it was applicable or not, but I mean is this B- have you all been through this with NRC and said they would B- this would meet their requirements, or is this just right now in the proposing stage? I'm not trying to make it one way or the other. I just want to B-

MR. GREENLEE: I would say at this point we haven't gone through each one, every one of the different designs with the NRC. Our goal is to meet the industry initiative criteria which is a performance criteria, and that's what NRC has reviewed, that performance criteria. And that's what they're going to give us this letter back on.

MEMBER BROWN: Okay, so you're waiting for a response.

MR. GREENLEE: Correct.

MEMBER BROWN: Okay. That answers the question, thank you. That was it.

CHAIRMAN BLEY: Only two, okay. Christina, could you B-

MS. ANTONESCU: Yes.

CHAIRMAN BLEY: B- get the lines opened up. While we're waiting to open up the lines, is there anyone in the room who would like to make a comment at this time?

(No response)

CHAIRMAN BLEY: It's awfully quiet out there. If anybody is on the B- oh, I think we've got you now. Somebody out on the listening in line just say hello or something so we know you're there. Anybody?

MS. THOMAS: Hello.

CHAIRMAN BLEY: Good, thank you. Is anybody on the line B- is there anyone on the line who would like to make a comment at this time? We'll do you one at a time.

MS. THOMAS: Yes. Ruth Thomas on the line.

CHAIRMAN BLEY: Okay, thank you.

MS. THOMAS: Can you hear me?

CHAIRMAN BLEY: Yes, please go ahead.

MS. THOMAS: I wasn't able to get in on the phone at the beginning and I heard somebody mention a transcript.

CHAIRMAN BLEY: Ruth, there will be a transcript of the meeting. We always have them. It'll be made public as soon as it's available. It usually takes a week or two before that's available on the NRC website.

MS. THOMAS: Well, I'll have to give you my mailing address because I don't have a computer. I'm with several different B-

CHAIRMAN BLEY: Ruth, can we give you phone number to call? Ms. Antonescu is our representative on this one.

MS. ANTONESCU: Okay, my phone number is (301)415-6792.

CHAIRMAN BLEY: Did you get it, Ruth?

MS. THOMAS: Is that Christina?

MS. ANTONESCU: Yes, it is.

CHAIRMAN BLEY: Yes.

MS. THOMAS: Okay. And then I can give you my mailing address.

MS. ANTONESCU: Sure.

MS. THOMAS: Okay, thank you.

CHAIRMAN BLEY: Okay, thanks. Anyone else with a comment?

MR. CHAN: My name is Michael Chan from

Fermi 2.

CHAIRMAN BLEY: Go ahead, please. Other people keep your phone muted until it's your turn, please. We're getting a lot of noise. Go ahead.

MR. CHAN: I am Michael Chan from Fermi 2. Can you hear me, please?

CHAIRMAN BLEY: Yes, perfectly well. Go ahead.

MR. CHAN: Okay. I have B-

CHAIRMAN BLEY: You're breaking up, if you're on a speaker phone, maybe you could just try the handset.

MR. CHAN: Okay, I pick it up now. Can you hear me better?

CHAIRMAN BLEY: Yes.

MR. CHAN: Okay. I have two questions/points to make. The first one is that I appreciate and applaud the comment made earlier in the first part of the NRC presentation when it was pointed out that we need to focus on the overall plant operational reliability. And the point was made earlier that why is the open phase such a low risk, why do you want to make plant go through that transient? And I think it is important to focus on that point for plants that have very minuscule vulnerability to the open phase either because of their network configuration, their transformer winding configuration, or just the physical size of the open phase footprint. Maybe NRC can consider some flexibility in the BTP to allow such plants to seek deviation from having to monitor alarm and trip, because you might be inducing an unnecessary transient. So, this is my first point.

The second point is that I want to ask EPRI in the Slide 4 of the EPRI presentation it was pointed out that there are two transformer types, the delta-Y transformer, and the Y-Y with the five-legged core does produce enough undervoltage to enable the existing protection system to work. So, maybe if we go back to Slide 16 of NRC's presentation where you said existing protection schemes based on voltage magnitude cannot identify OPC and take appropriate mitigation measures.

Maybe that statement need to be modified in light of the finding and discovery by EPRI, that there are certain transformer types where the existing undervoltage relaying or voltage magnitude relaying scheme can be expected to work.

CHAIRMAN BLEY: Thank you. Your comments will be in our transcript. Your comments will be in the transcript, but this isn't an open question and answer session. Next person? Anybody else want to make comments?

MR. LEWIS: Marvin Lewis.

CHAIRMAN BLEY: Good afternoon. Please go ahead, Marvin.

MR. LEWIS: Thank you. Look, I'm just a little confused about the B- the original problem, the original plant, I'm not too sure which where you had a 30-day before you could do anything about it, or 30 days without anybody noticing what was going on. I believe that was an aging problem where an electrical item probably a resistor was inadequate. And that's C-- and one of the reasons was it was there for like a decade, and nobody was checking on it. And I was wondering if you would then submit this item here, what you're talking about, to the Aging Management people for B- in some kind of incorporation within their Aging Management Plan. I guess that's a comment. Thank you.

CHAIRMAN BLEY: Thank you for the comment. Anyone else care to make a comment?

(No response)

CHAIRMAN BLEY: Going, going, gone. We can close the line again. And at this point I guess I'd like to go around the table and have our members give any final comments they'd like to make. And I'd ask you to consider when we have a full Committee on this in

December.

MS. ANTONESCU: Yes, on the B-

CHAIRMAN BLEY: Maybe if you have a comment about any particular things out of today, it will be good to hear about at that, and then we might have a little discussion at the end with the Staff and industry folks about that. It's going to be on December 4th at 3:30 p.m.

MS. ANTONESCU: One hour and a half.

CHAIRMAN BLEY: Charlie, I won't be there. I'm very sorry about that, but you were here, that's good. Do you have any closing comments?

MEMBER BROWN: I'll make one observation for the full Committee meeting. I think it's B- you need to get the EPRI discussion in. That's my personal opinion on that. I think the B- within the hour and a half or two hours, whatever it is they have, I think it's important to get the detection scheme out on the table and then adjust the other presentations down to meet appropriately the time frame, because there's obviously some stuff being left out.

The other point I thought the presentations were really very, very good, very illuminating and provided good technical information. And I really appreciated particularly the ability to get answers to our simplistic, at least my simplistic technical questions, and the patience with which you all dealt with, and didn't laugh too hard when I was asking them, so that was very much appreciated. That was very good. Thank you.

CHAIRMAN BLEY: Ron?

MEMBER BALLINGER: I agree with Charles with the exception of the last couple of statements that he made. You forced me to go out and buy the electrical engineering handbook, so now I know what a Y and a delta transformer is, and how they work.

MEMBER STETKAR: Well, congratulations. You finally used B- learned something useful in your life.

MEMBER BALLINGER: Yes, yes, yes.

(Simultaneous speech)

MEMBER STETKAR: What it's important for us to understand is this is not B- this is real stuff, not that hard blacksmith technology. Things that never operate --

CHAIRMAN BLEY: It's Ron's turn.

MEMBER BALLINGER: And I agree with him about the full Committee. I think that EPRI presentation and certainly part of the NEI presentation could be sort of integrated into one, and be very, very informative.

CHAIRMAN BLEY: Mr. Stetkar?

MEMBER STETKAR: And, again, thanks to everybody. I think this was really useful. As far as the full Committee presentation, I'd recommend that we downplay the regulatory, and safety analysis part of the discussion, keep it focused on the technical issues because the members of the full Committee will have a difficult enough time grasping the technical issues, and I think we want to focus on that rather than regulatory stuff.

CHAIRMAN BLEY: Dr. Powers. Dick?

MEMBER SKILLMAN: No further comments, thanks.

CHAIRMAN BLEY: Thank you. Steve?

MEMBER SCHULTZ: I agree with the comments with respect to the full Committee presentation. I think that the focus should be on B- I'd like the full Committee to see the portion of the presentation about NEI that showed what happened at Byron and what was learned from that event. And then a short discussion of what has been done by Exelon, and followed by a presentation by the EPRI solution. I think that's very helpful. I do really appreciate the presentations by the Staff, as well as industry today, given a full appreciation of what has been done and what's been accomplished.

CHAIRMAN BLEY: Okay, thank you, Steve. I, too, want to thank the Staff for some very informative tutorial and then detailed discussion. And thanks again to NEI and EPRI, and folks who participated. It's helped us understand what's going on quite a bit. I hope NEI and EPRI could be at our full Committee meeting, and I would think B- I kind of agree with Steve, the key points from the NEI discussion would be important to have. We could cut it down just a bit, and certainly the information on their new detection scheme, and the stuff that led into that from EPRI. I think if we had maybe 20 minutes from NEI and half an hour from EPRI, I'm not sure what calendar time will be assigned, but I would think that it would be on the order of two hours.

UNIDENTIFIED: It's an hour and a half.

CHAIRMAN BLEY: An hour and a half. Yes, that's right. So, maybe 20 minutes, 20 minutes, and the rest of the time back to Staff. It can be much shorter than it was today, but the B- not as much tutorial. I think people who wanted a tutorial should have been here. And if they weren't they can read on their own, so tighten it up to be about 20 minutes. I think that's probably how it works, and some of this will get stretched out. Does that work all right? Okay, good. Dr. Powers?

MEMBER POWERS: Yes, sir?

CHAIRMAN BLEY: Do you have any closing comments?

MEMBER POWERS: I do not.

CHAIRMAN BLEY: Thank you for being here. And thank everyone for being here. It was, for me, a great session. The meeting is adjourned.

(Whereupon, the above-entitled matter went off the record at 4:32 p.m.)

U.S.NRC

UNITED STATES NUCLEAR REGULATORY COMMISSION

Protecting People and the Environment

OPEN PHASE CONDITIONS IN ELECTRIC POWER SYSTEM – REGULATORY ACTION AND PATHFORWARD

ROY MATHEW
Electrical Engineering Branch
Division of Engineering
Office of Nuclear Reactor Regulation

November 17, 2014

U.S.NRC
UNITED STATES NUCLEAR REGULATORY COMMISSION
Protecting People and the Environment

AGENDA

- Open Phase Condition (OPC)
- Power System Basics
- Safety Significance
- Operating Experience
- Regulatory Requirements
- NRC Actions
- Staff Recommendation/Position
- Branch Technical Position (BTP 8-9)
- Draft Interim Enforcement Policy
- Path Forward

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OPEN PHASE CONDITION

- **Loss of one of the three phases** of the offsite power circuit on the high voltage side of a transformer connecting an offsite power circuit to the transmission system coincident with or without a high-impedance ground fault; or
- **Loss of two of the three phases** of the offsite power circuit on the high voltage side of a transformer connecting an offsite power circuit to the transmission system
- **High-impedance faults** – ground faults that produce fault currents below the traditional ground overcurrent pickup level
- **Creates unbalance voltages** in the three phase power system
  - Transformer winding configuration (Wye-Wye-Wye, Delta-Wye-Wye, Wye-Delta-Delta, Wye-Wye-Buried Tertiary Delta, Delta-Wye, Wye- Delta, Wye-Wye-Delta, and Wye-Wye with Delta stabilizing winding)
  - Grounding (solid or resistance ground)
  - Type of transformer core (Shell or Core)
  - Loading condition and operating configuration (standby/no load/lightly loaded)

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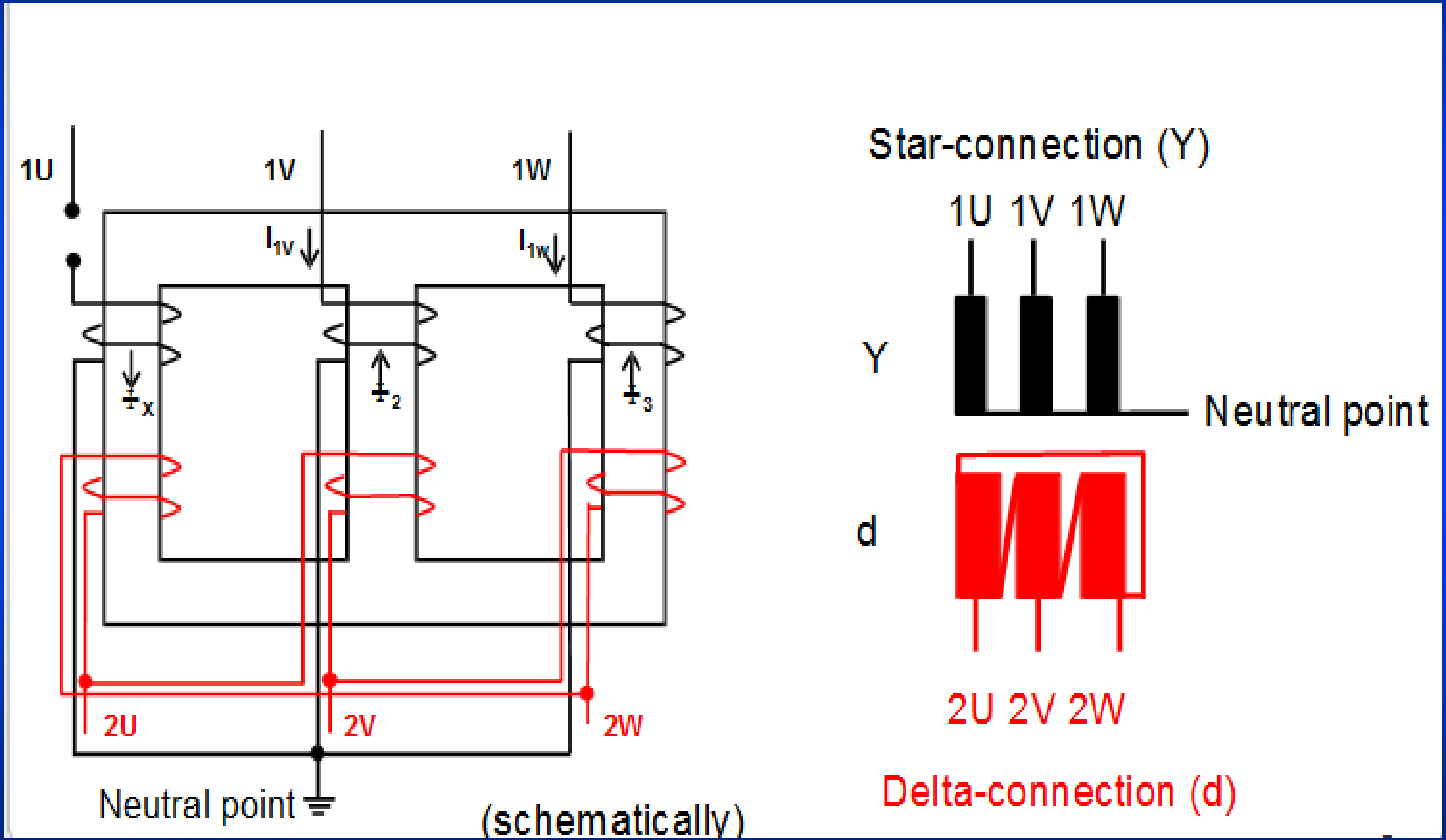
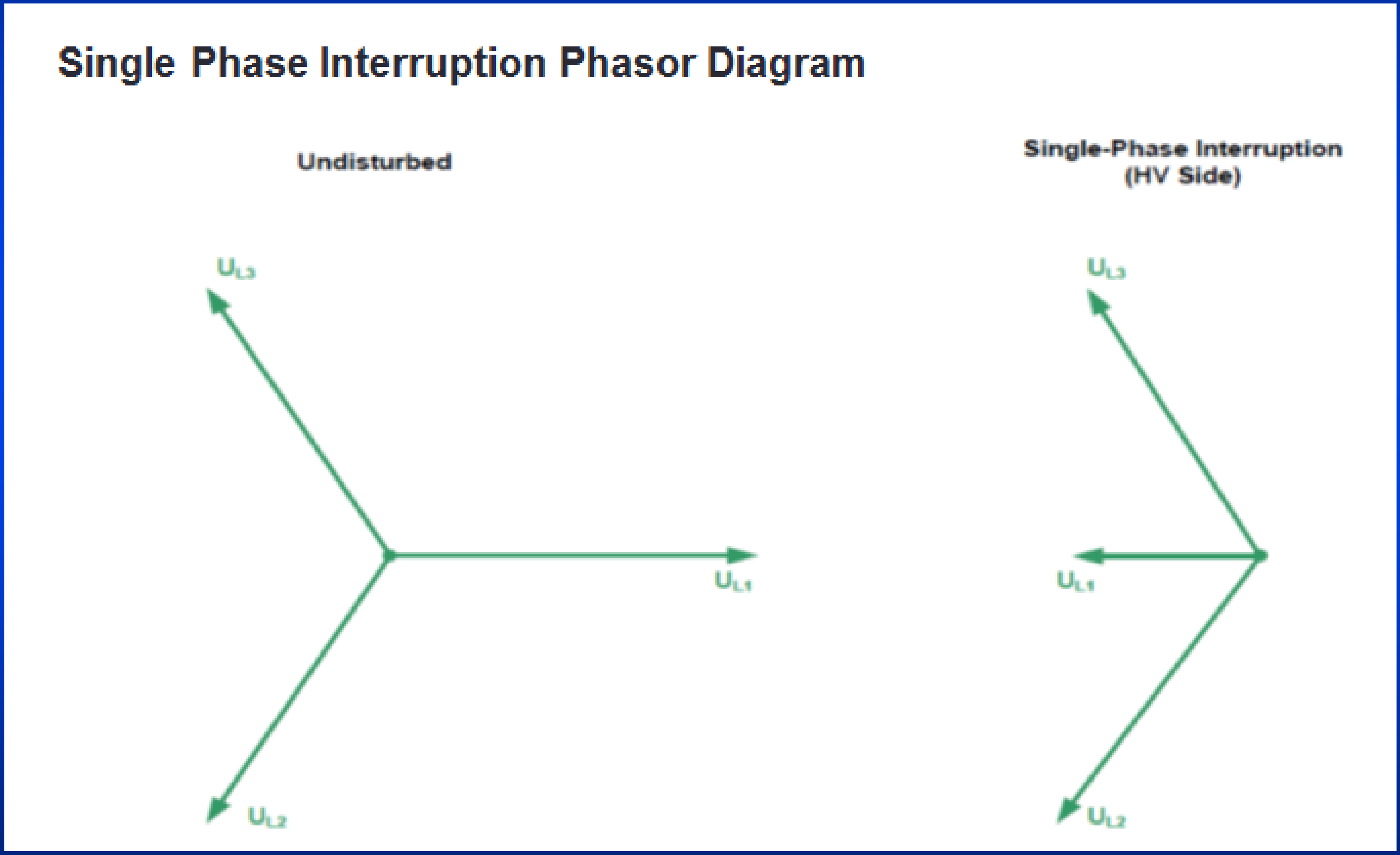
POWER SYSTEM BASICS

- Understanding the per phase magnitude and angle of phase to phase, phase to neutral, positive, negative, and zero sequence voltage and current generated during the loss of one or two phases of a three phase system is essential to properly design a scheme to detect and isolate an OPC
- OPC generates unbalance in the three phase AC power system
- Unbalances generate different amplitude values and phase angles which differs from 120° between the three phases
- Mainly induction motors and synchronous generators are affected by the unbalance
- The symmetrical components method has to be used to calculate unbalanced conditions
- For example, the design of the transformer influences the transfer of unbalances. Especially star-delta connections (Y-d) lead to unbalances which can not easily be detected.

POWER SYSTEM BASICS (cont.)



POWER SYSTEM BASICS (cont.)

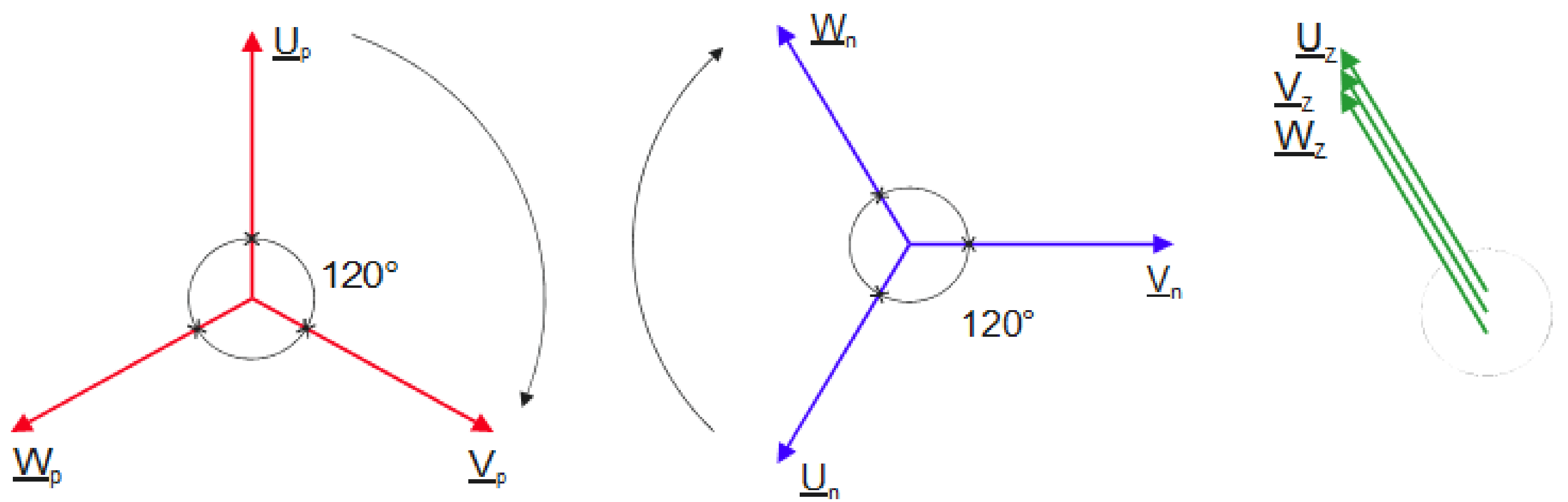


POWER SYSTEM BASICS (cont.)

METHOD OF SYMMETRICAL COMPONENTS:

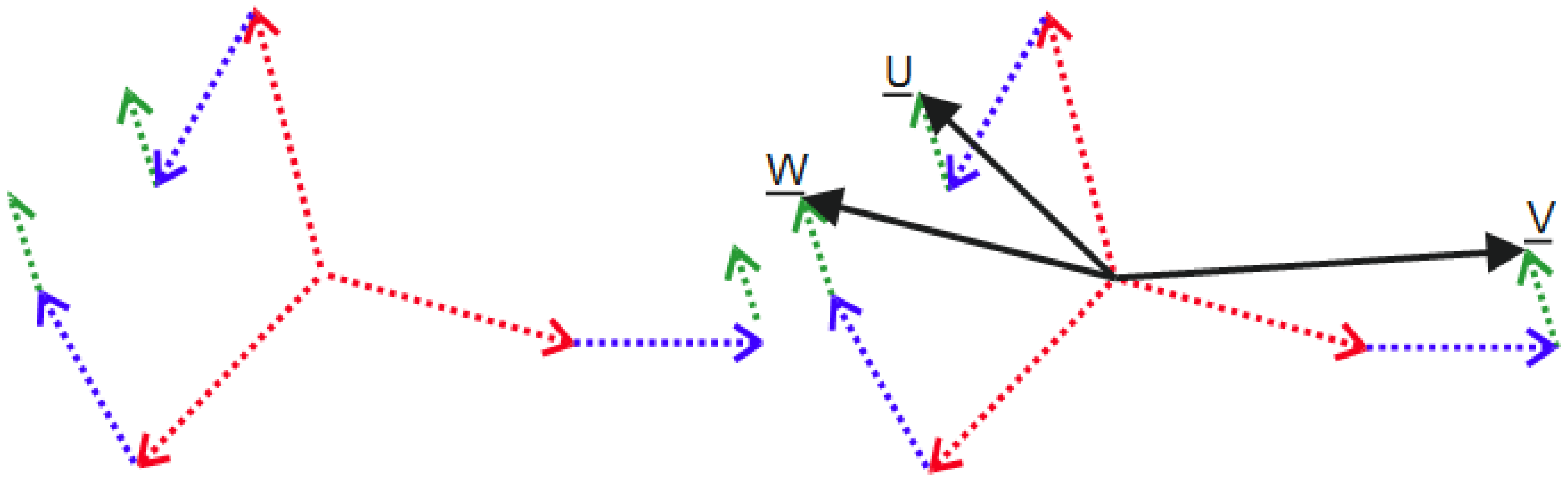
- The method of "symmetrical components" is used for the calculation of unbalanced (voltage or current) in a three phase system.
- The following sequences have to be used:

positive sequence negative sequence zero sequence



POWER SYSTEM BASICS (cont.)

- METHOD OF SYMMETRICAL COMPONENTS
- With superposition of positive, negative and zero sequence unbalanced phases can be calculated



POWER SYSTEM – BASICS (cont.)

- DEFINITION OF NEGATIVE SEQUENCE
- Different definitions are in use to calculate the unbalance in %:
- Power quality standard by definition :

$$\text{Negative sequence (\%)} = \left[\frac{\text{negative sequence (voltage or current)}}{\text{positive sequence (voltage or current)}}\right] \times 100$$

- IEC 60034-26 defines the minimum standard for motor design as follows:

  The induction motors shall be designed robust against a negative sequence voltage component not exceeding 1 % of the positive-sequence voltage component over a long period, or 1.5 % for a short period not exceeding a few minutes, and a zero-sequence voltage component not exceeding 1 % of the positive-sequence voltage

POWER SYSTEM – BASICS (cont.)

Voltage Unbalance

- The National Electrical Manufacturers Association (NEMA) in its Motors and Generators Standards (MG1) part 14.36, defines voltage unbalance as follows:

$$\text{Percent Voltage Unbalance} = \left[\frac{\text{max. voltage deviation from avg. voltage}}{\text{avg. voltage}}\right] \text{X } 100$$

- NEMA states that polyphase motors shall operate successfully under running conditions at rated load when the voltage unbalance at the motor terminals does not exceed 1%. Operation of a motor with above a 5% unbalance condition is not recommended, and will probably result in damage to the motor.
- De-rating of motors based on unbalance is provided in this Std.

POWER SYSTEM – BASICS (cont.)

System Modeling and Analysis

- Thevenin equivalent network model, a detailed transformer model, detailed induction motor models
- Need Sequence Impedance values – positive, negative, and zero sequence
- Various simulations performed for under all operating configurations and loading conditions
- EPRI has developed several modeling techniques and issued several technical reports

SAFETY SIGNIFICANCE

- **Common Cause Failure** – redundant engineered safety features (ESF) systems are fed by one offsite power source for most plants
- **Loss of safety functions** of ESF systems if OPC is not mitigated
- **Quality of Power** to the ESF systems
  - Unbalanced AC power system (sequence voltages and currents)
  - Phase angle shift
  - Reduced starting torque for motors
  - Negative sequence currents
  - Overheating of motors/overload/loss of life/damages to rotating machines
  - Protective device actuation and lock out

BYRON UNIT 2 EVENT

- Loss of safety functions of Engineered Safety Features Systems
  - Both offsite and onsite electric power systems were not able to perform their intended safety functions due to the design vulnerability
  - A design-basis event concurrent with this open phase condition could likely result in exceeding the requirements contained in 10 CFR 50.46
- Accident Sequence Precursor Review*
  - Conditional Core Damage Probability = 1×10^{-4}

*SECY-13-0107 Agencywide Documents Access and Management System Accession No. ML13232A062

OPERATING EXPERIENCE

- **Eleven operating events (2001-2014)**
  - Failure of insulators and switchyard connections
  - Malfunction of breakers

- South Texas Project Unit 2, US – March 1, 2001
- Koeberg, South Africa – November 112005
- Fitzpatrick/Nine Mile, US – December 19, 2005
- Vandellos, Spain – August 9, 2006
- Dungeness A, UK – May 14, 2007
- Beaver Valley Unit 1, US – November 1, 2007
- Byron Unit 2 – January 30, 2012
- Byron Unit 1 – February 28, 2012
- Bruce Power Unit 1, Canada – December 22, 2012
- Forsmark Unit 3, Sweden – May 30, 2013
- Dungeness B, UK - April 2014

REGULATORY REQUIREMENTS

- **General Design Criterion (GDC) 17, "Electric Power Systems," or the applicable principal design criteria in the updated final safety analysis report**

- **Design criteria for protection systems under 10 CFR 50.55a(h)(2) or 10 CFR 50.55a(h)(3)**

- **Technical Specification (TS) requirements**
  - 10 CFR 50.36(c)(2) & (3)
  - TS LCO 3.8.1 – offsite and onsite power systems
  - TS Surveillance Requirements

NRC ACTIONS

- **NRC Special Inspection**[1] at Byron Station
- **Information Notice** 2012-03[2]
- **Bulletin** 2012-01: Design Vulnerability in Electric Power System[3]
- **Summary Report** - documented NRC staff review of licensee responses and staff recommendations[4]
  - All operating nuclear power plants susceptible to OPC except Seabrook Station
    - SF6 insulated Switchyard
    - Single pole breaker failure protection scheme
  - Existing protection schemes based on voltage magnitude cannot identify OPC and take appropriate mitigation measures (i.e., automatically transfer power to ESF buses from an alternate offsite or onsite power source)
  - Staff recommended regulatory action to address the open phase issue
- **Supported development of industry initiative** to resolve OPC
- **Participating in an IAEA effort** to issue a Safety Report and also an IEEE working group to develop a Standard.

1. Agencywide Documents Access and Management System (ADAMS) Accession No. ML12087A213
2. ADAMS Accession No. ML120480170
3. ADAMS Accession No. ML12074A115
4. ADAMS Accession No. ML13052A711

NRC ACTIONS (cont.)

- Requested Additional Information (RAI) from Operating Reactor Licensees
  - interim corrective actions and compensatory measures
  - the status of long-term corrective actions

- Staff review of RAI responses confirmed:
  - licensees have entered OPC issue in their corrective action program
  - licensees have implemented interim corrective actions and compensatory measures to maintain current safety of all operating power plants
  - long-term corrective action schedules consistent with the industry initiative – December 31, 2017

NRC ACTIONS (cont.)

- **RAIs to AP 1000 licensees and Part 52 applicants** for Design Certification and Combined License reviews
  - Staff review indicated that AP 1000 licensees did not meet GDC 17 requirements
  - NRC letter dated November 5, 2014 (ADAMS Accession No. ML14246A167) requested licensees to implement sufficient measures to detect and respond to OPC
- **Eleven Public Meetings** with the industry to-date
- **Issued draft Branch Technical Position** (BTP) for public comment
- **Shared draft Interim Enforcement Policy** (IEP) with industry
- **Finalizing documents** (BTP and IEP)

RECOMMENDATION/POSITION

CURRENT Operating Reactors and ACTIVE New Reactor Designs

Must be able to:

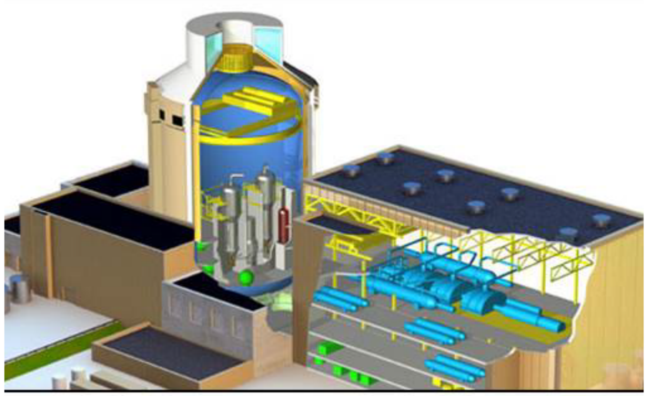
1) Detect an open phase condition on the high side of the transformer connected to the offsite power system;
2) Alarm in the main control room; and
3) Automatically Actuate and Mitigate the event.

Advanced Boiling-Water Reactor (ABWR)

PASSIVE New Reactor Designs

Must be able to:

1) Detect an open phase condition on the high side of the transformer connected to the offsite power system; and
2) Alarm in the main control room.



Advanced Passive 1000 (AP1000)

DRAFT BRANCH TECHNICAL POSITION (BTP 8-9)

- Based on the Byron event and additional operating experience at other nuclear power plants to-date, the staff determined that OPC is a credible event of safety significance and must be considered in the electric power system design for nuclear power plants.

- The purpose of this BTP is to provide guidance to the staff in reviewing future licensing actions related to OPCs in electric power systems

- Design criteria specified for both operating and new reactor fleets

- Comments received from the FRN are currently under staff review and being appropriately evaluated and considered before the BTP is finalized

- The new BTP would be added to Chapter 8 of the SRP when finalized

- The design of the electrical system should address both single and two open phase conditions - with and without high impedance ground fault conditions

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DRAFT INTERIM ENFORCEMENT POLICY

- **Regulatory Considerations for Enforcement Discretion**
  - Industry response and initiatives to address the open phase issue
  - Interim actions taken by licensees to address the safety concerns
  - Measured response from INPO for OPC issue
  - Corrective actions and action plans to address OPC design vulnerabilities

- **Issue Interim Enforcement Policy – Commission approval**
  - Section 9.X - Enforcement Discretion for Open Phase Conditions within Electric Systems
  - Applies to only operating power reactor licensees
  - The licensee will be in full compliance with GDC or the applicable principal design criteria in the updated final safety analysis report by December 31, 2017
  - Issue SECY paper
  - Issue Final Branch Technical Position
  - Issue Regulatory Issue Summary

PATH FORWARD

To continue the NRC and industry's efforts to resolve and close-out Bulletin 2012-01, each licensee should do the following:

- Provide a Commitment letter to the NRC stating that the OPC issue will be resolved in accordance with the schedule established in the industry initiative and how the solution addresses the compliance gap with GDC 17 or the principal design criteria specified in the updated final safety analysis report for their specific nuclear power plant.
- Develop and maintain detailed a plant-specific analysis and documentation which established the resolution of the OPC design vulnerability, including failure mode analysis that is available for NRC staff's audits or inspections.
- Provide a close-out letter to the NRC when full compliance is achieved.

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QUESTIONS ?

Branch Technical Position (BTP 8-9) Resolution of Public Comments

DRAFT BTP 8-9 - PUBLIC COMMENTS

DRAFT BTP dated June 5, 2014 - ADAMS Accession No. ML14057A433 Public comments Received on July 21, 2014			
1. Robert Meyer (ADAMS Accession No. ML14205A446)	2. Madan Goel - (ADAMS Accession No. ML14205A447)	3. STARS Alliance LLC (ADAMS Accession No. ML14206A744)	4. DTE Energy Company (DTE) (ADAMS Accession No. ML14205A007)
5. Technical Specifications Task Force (ADAMS Accession No. ML14198A269).	6. Florida Power and Light Company and NextEra (ADAMS Accession No. ML14206A745)	7. Dominion - (ADAMS Accession No. ML14205A448)	8. Duke Energy - (ADAMS Accession No. ML14223A771)
9. AP1000 Utilities - Integrated Comments provided by Duke Energy for Southern Company; South Carolina Electric & Gas; Florida Power and Light; and Duke Energy (ADAMS Accession No. ML14205A008)	10. Westinghouse Electric Company (ADAMS Accession No. ML14205A445)	11. Nuclear Energy Institute (NEI) (ADAMS Accession No.ML14205A006)	

PUBLIC COMMENTS

- Staff reviewing public comments – **work in progress**
- Many comments related to **clarifying the guidance**
- **Key comments:**
  - Protection system requirements (10 CFR 50.55a(h)(2) or (3)) are not required to resolve OPC – Staff is providing the response to the industry based on separate correspondences from NEI
  - Class 1E detection and actuation circuits are not appropriate considering; 1) an OPC solution should be implemented on the high side of the transformer, and 2) the definition of Class 1E equipment infers requirements for separation from non-Class 1E circuits.
  - The Interim NRC OPC Enforcement Policy implies applicability to current plant licensing bases. The treatment of open phase condition is beyond current plant design and licensing basis. As such, it would not be appropriate to impose new requirements without performing a backfit analysis in accordance with 10 CFR 50.109.

PUBLIC COMMENTS (cont.)

- **Key comments (cont.):**
  - 10 CFR 50.36 is not applicable to Open Phase Protection and GDC 17
  - The industry is currently in compliance with their current licensing basis (CLB) with respect to GDC 17
  - The staff is incorrectly applying the GDC requirements to SSCs that are not important to safety and are not credited with safety functions in the accident analyses (AP1000 utilities)
  - Passive plant designs that do not require ac power sources to mitigate design- basis events may provide adequate time for operators to diagnose and correct an open phase condition without the potential for the condition to propagate into a more serious event (AP1000 utilities)

STAFF'S POSITION

Licensee solution (e.g., OPIS) to address OPCs, should meet the following functional requirements:

- The design should address single failure criteria as outlined in the GDCs or the principal design criteria specified in the updated final safety analysis report for the specific nuclear power plant (i.e., for an OPC, a non-Class 1E circuit should not preclude the onsite electrical power system from being able to perform its safety function given a single failure in the onsite power system).
- The OPC should be automatically detected and alarmed in the main control room under all operating electrical system configurations and loading conditions
- If offsite power circuits are degraded due to OPC, the power source should be transferred automatically to the onsite power system within the time assumed in the accident analysis and without actuating any protective devices, given a concurrent design basis event.
- TS Surveillance Requirement and Limiting Condition of Operation for equipment used for mitigation of OPC should be consistent with the operability requirements specified in the existing plant TSs.

QUESTIONS ?

Advisory Committee on Reactor Safeguards

Open Phase Steering Committee Update

November 17th 2014

Scot Greenlee – Executive Sponsor
Exelon Senior Vice President
Engineering & Technical Services

Agenda

- Byron Station Open Phase Events
- Design Vulnerability
- Licensing Bases
- Industry Open Phase Condition Initiative
- Industry Actions

Byron Station Open Phase Events

Byron Event Description

Unit 2

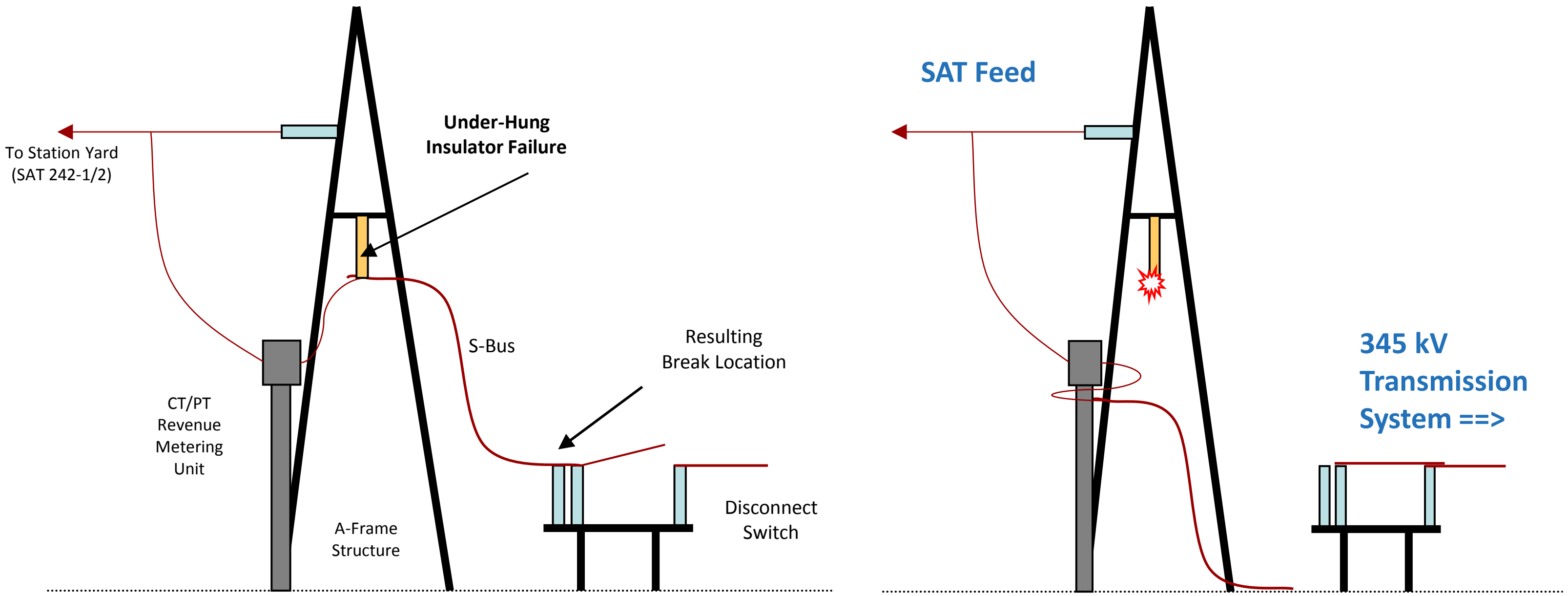
- January 30, 2012
- Mechanical failure of 345 kV under-hung porcelain insulator on system aux transformer (SAT) A-frame structure creating a line to ground fault on the SAT side
- Open phase condition - protective relaying not designed to detect / isolate
- Result was a reactor trip on reactor coolant pump (RCP) undervoltage
- Loss of off-site power (LOOP) resulted
- Unusual Event declared
- Loss of all operating motor driven safety loads
- Loss of RCP seal cooling for eight minutes
- Manual operator action restored safety systems

Unit 1

- February 28, 2012
- Mechanical failure of under-hung porcelain insulator on SAT A-frame structure creating a line to ground fault on the system side
- Protective relaying isolated the faulted component and transferred power to the alternate supply
- Systems worked as designed and Byron station generating units remained on-line
- LOOP resulted
- Unusual Event declared

- **Ohio Brass porcelain insulator manufacturing defect**
- **Design vulnerability - failure to automatically detect / isolate an open phase condition**

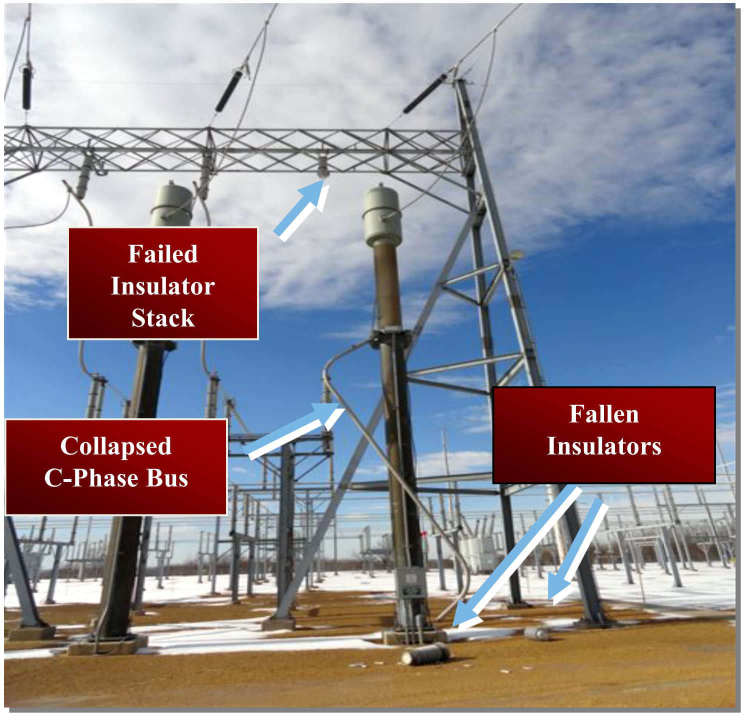
Byron Unit 2 Event Description (January 2012)



Existing A-Frame
Structure Configuration

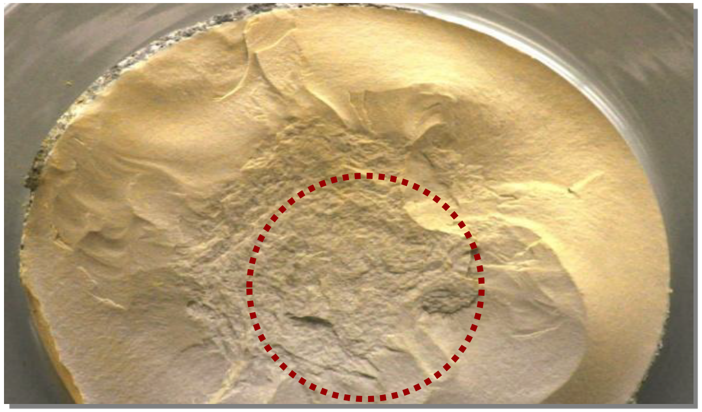
Byron Event Description

Unit 2



Unit 2 Failed Insulator

Unit 1 Failed Insulator



Insulator failure due to poor quality porcelain

Design Vulnerability

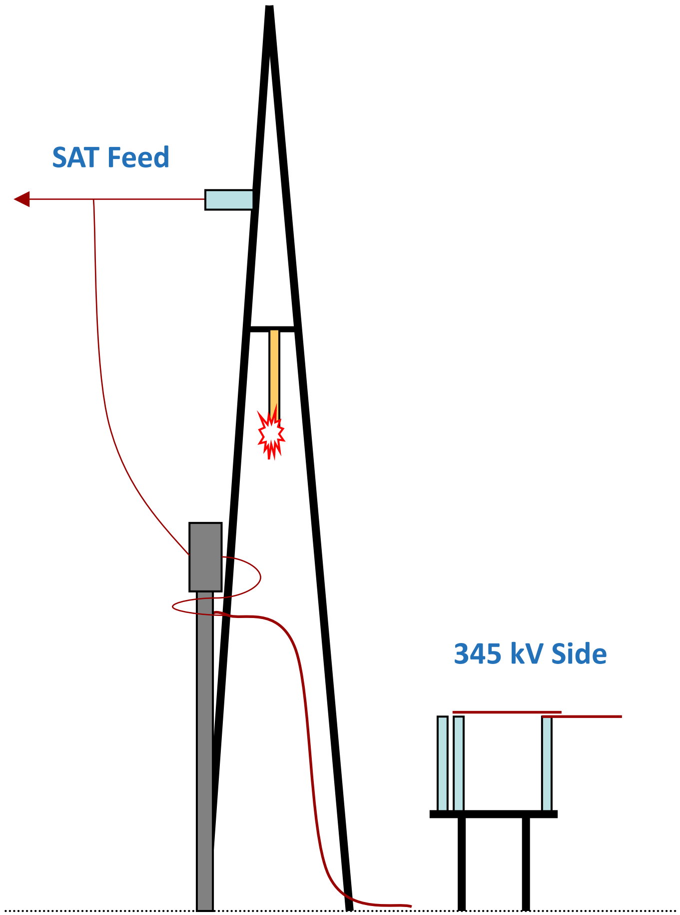
Impact of Open Phase

Grounded – Byron Unit 2

- Significant voltage imbalance due to ground on transformer side
- 4.16 kV safety bus per unit (pu) voltage
  - Vab 1.0142 pu
  - Vbc 0.5912 pu
  - Vca 0.5870 pu

Ungrounded – Byron Unit 2

- 4.16 kV safety bus per unit voltage under light loading
  - Vab 1.0408 pu
  - Vbc 1.0407 pu
  - Vca 1.0180 pu
- Cannot detect by voltage magnitude



Licensing Bases

Licensing Bases

- Before the promulgation of General Design Criterion (GDC) 17, the updated final safety analysis reports set forth criteria similar to GDC 17 for adequate capacity and capability.
- Nuclear Plants, with construction permit applications submitted after the Commission promulgated GDC 17, were initially designed in accordance with GDC 17 for offsite source adequacy (voltage protection) and the total loss of offsite power.
- Industry operating experience identified design vulnerabilities for sustained balanced degraded voltage – this resulted in installation of a second level of undervoltage protection
  - Information Notice 79-04
  - Generic Letter 79-36
  - Branch Technical Position (PSB-1 issued July 1981)

- **Protective relaying scheme was not designed to detect / isolate open phase conditions**
- **Open phase detection was not considered in the licensing process**

Industry Open Phase Condition Initiative

Open Phase Condition Initiative - Goal

An open phase condition (OPC) will not prevent functioning of important-to-safety structures, systems and components. An open phase condition is defined as an open phase, with or without a ground, which is located on the high voltage side of a transformer connecting a General Design Criterion (GDC) 17 off-site power circuit to the transmission system.

- The OPC initiative only applies to "active" safety features plants
- The initiative includes requirements to address two open phases (based on the Forsmark event)
- The initiative allows use of non-safety related circuits

OPC Initiative Key Milestones
Operating Plants

1. December 31, 2014 - Demonstration of compliance with the open phase condition criteria through analysis or identify appropriate actions required to demonstrate compliance.
2. December 31, 2016 - Implementation of design changes, if necessary, to comply with the open phase condition criteria. The "active" actuation features of new technology designs may be installed in a monitoring mode, with adequate justification, to demonstrate reliability.
3. December 31, 2017 - If a monitoring period was deemed necessary, completion of any design adjustments identified during the monitoring period and enabling all "active" actuation features needed to demonstrate compliance with the open phase condition criteria.
4. Updated Final Safety Analysis Report (UFSAR) Updates - Completion in conjunction with the timelines noted above, but no later than December 31, 2017.

OPC Initiative Milestones
Operating Plants

5. Technical Specifications Updates - Submitted by December 31, 2017, if required.
   a) Most solutions will require a Technical Specifications Bases change to describe the requirement for a functional Open Phase detect / isolate system.
   b) If a Technical Specifications Task Force (TSTF) traveler is available, submittal to adopt the TSTF traveler is planned to be within six months of the issuance of the notice of availability of an NRC-approved TSTF traveler.

This schedule assumes license amendments are not required to install any design changes.

Industry Actions

Industry Actions

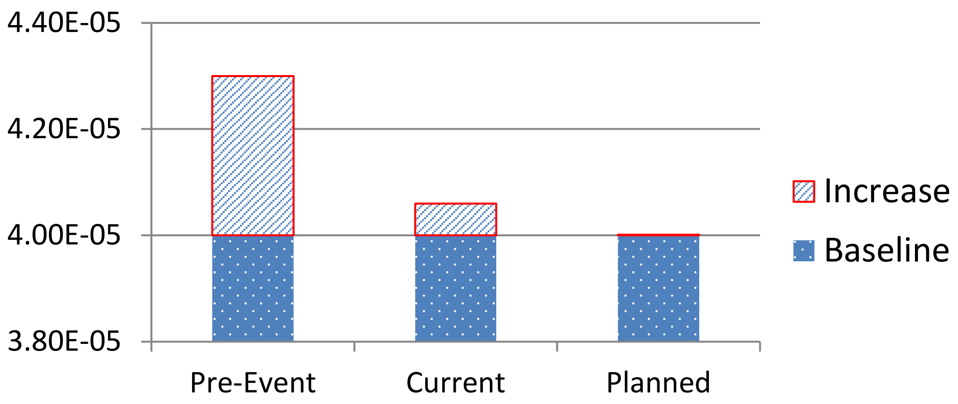
- February 2012 - Posted OE 35219, documenting the Byron event on the INPO website
- February 2012 - Industry briefing via INPO webcast to alert the industry to the vulnerability
- February 2012 - INPO issued Level 2 IER; industry responses by August 2012
- On-going - NEI working group weekly meetings to evaluate vulnerability solutions
- January 2013 - Industry standard ETAP software upgraded to enable single and double open phase conditions
- October 2013 - Industry issues Chief Nuclear Officer approved OPC Initiative
- December 2013 - NEI issued OPC Industry Guidance document
- January 2014 - WANO workshop on open phase for international plans
- On-going - Many industry workshops and NRC public meetings have taken place over the past two years; others are projected
- December 2014 - WANO expected to issue SOER that will drive worldwide actions similar to what is being done in the U.S.

Design Considerations

- The designs presented at the workshop close the gap discovered through operating experience and ensure that an OPC on the transmission system feeds to a station do not result in the coincident failure of the onsite electric power system or prevent it from performing its safety function.
- The industry will address the applicability of 10CFR50.55a(h)(2) to OPC designs in UFSAR updates.
- An OPC on a non-class 1E circuit should not preclude the onsite electrical power system from being able to perform its safety function, given a single failure in the on site power system.
- 10CFR50 Appendix A, GDC 17 states, in part, "Provisions shall be included to **minimize the probability of losing electric power** from any of the remaining supplies as a result of, or coincident with, the loss of power generated by the nuclear power unit, the loss of power from the transmission network, or the loss of power from the onsite electric power supplies."

Byron Station Risk Profile Example

Core Damage Frequency (CDF) Impact as a Function of Plant Configuration



Condition	Failures Modeled	Approximate Increase in CDF
Pre-Event	Operator action	3E-6 or 7.5%
Current Configuration	Alarm or operator action	6E-7 or 1.5%
Planned Configuration	Automatic actuation and operator backup	1E-8 or 0.03%

Industry OPC Designs

- The Open Phase Steering Committee held a two-day workshop on September 17 & 18, 2014, to provide the industry with access to the vendors, A&Es, and utilities that have developed workable open phase detect / isolate system designs.

- Five different system designs were presented:
  - Transformer High-side Detection with Magnetic Sensors (PCS2000)
  - Transformer High-side Detection with Programmable Relay
  - Transformer High-side Detection with Optical Sensors (Alstom/AREVA)
  - Class 1E Bus ABB 60Q Phase Unbalance Relay
  - Transformer Neutral Injection Detection (EPRI, PssTech)
  - Combination Monitoring

Open Phase Steering Committee Update

Questions ??

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EPRI Open-Phase Detection (OPD)

Bob Arritt / Wayne Johnson
Project Manager - Power Systems Studies / NMAC Sr. Project Manager

November 17, 2014

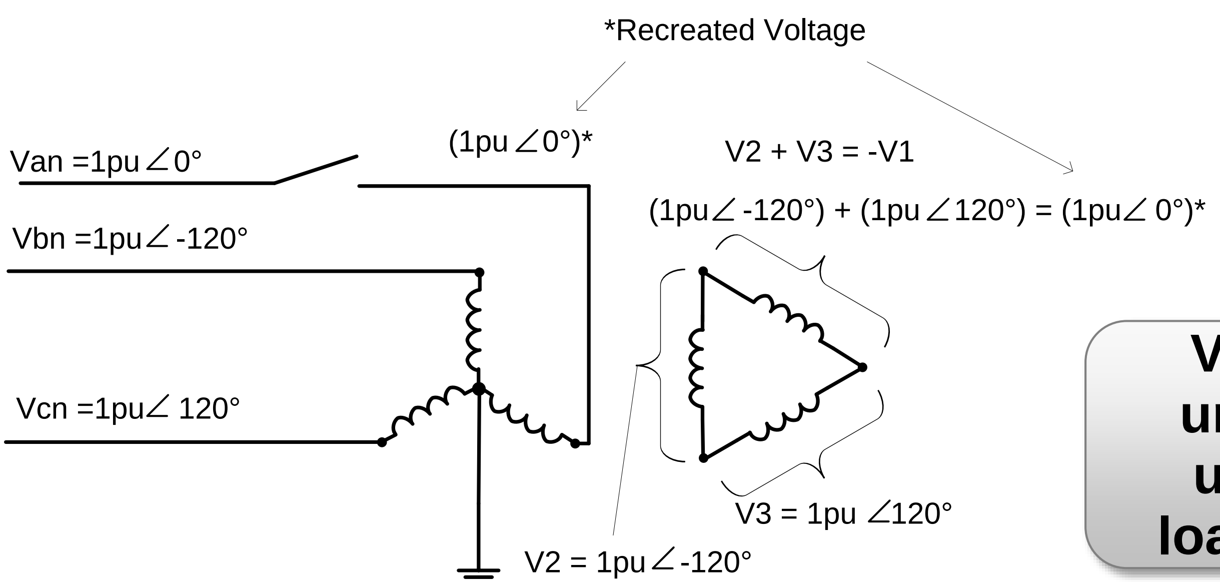
EPRI Research – Initial Projects

- Address many of the technical issues associated with detecting an open-phase condition of a station auxiliary transformer (SAT)
  - Identified difficulty in detecting event during a low or no-load level state.
  - Low and no-load condition is the prevalent condition for most SATs.

Released 4 publicly available documents on the open-phase issue since the Byron event.

Problem Description

- Transformers with wye connected primaries that have a zero-sequence impedance path i.e. secondary/tertiary delta or 3-legged core



Voltage remains undistorted even under moderate loading conditions

Problem Transformers (No Load)

- Phase A opened on high side

Identified which transformer types exhibited this issue

	Primary Voltage (pu)			Secondary Voltage (pu)		
	Phase A	Phase B	Phase C	Phase A	Phase B	Phase C
Wye-Wye (Shell Core)	**0**	1.0	1.0	**0**	1.0	1.0
Wye-Wye (3-Single Phase Cores)	**0**	1.0	1.0	**0**	1.0	1.0
Wye-Wye* (5-Legged Core)	**0.54**	1.0	1.0	**0.54**	1.0	1.0
Delta-Wye (Any Core Type)	**0.5**	1.0	1.0	**0.5**	1.0	**0.5**
Wye-Delta (Any Core Type)	1.0	1.0	1.0	1.0	1.0	1.0
Wye-Wye (3-Legged Core)	1.0	1.0	1.0	1.0	1.0	1.0
Wye-Delta-Wye (Shell Core with Buried Delta)	1.0	1.0	1.0	1.0	1.0	1.0

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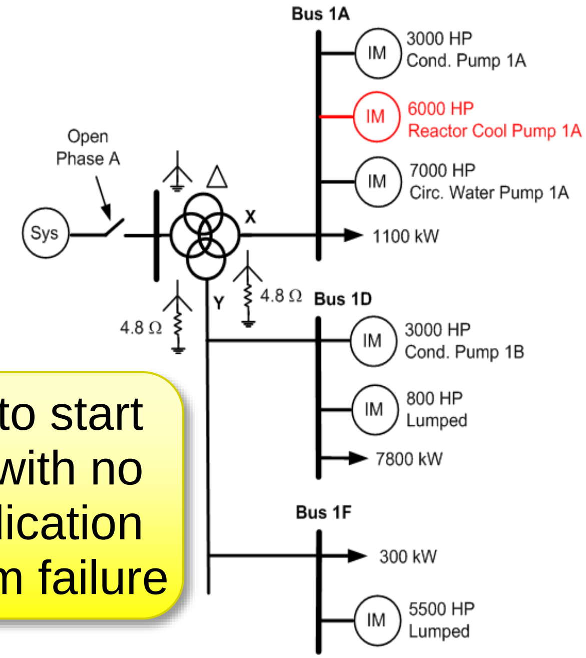
Industry Survey of Detection Methods

- Voltage Imbalance
  - Works for some transformer types for all loading conditions.
  - For susceptible transformers:
    - Cannot detect whether or not the electrical system provides sufficient capacity.
- Sequence-Current Detection
  - Acceptable for loaded conditions; however, would not work at moderate, low, or no-load.
- Phase-Current Detection
  - Very complex, costly, and unreliable design due to measuring low level currents in presence of backfeed and system noise.
- Power Line Carrier Capacitive-Coupled Method
  - Cannot obtain 100% coverage
  - Installation cost was a concern

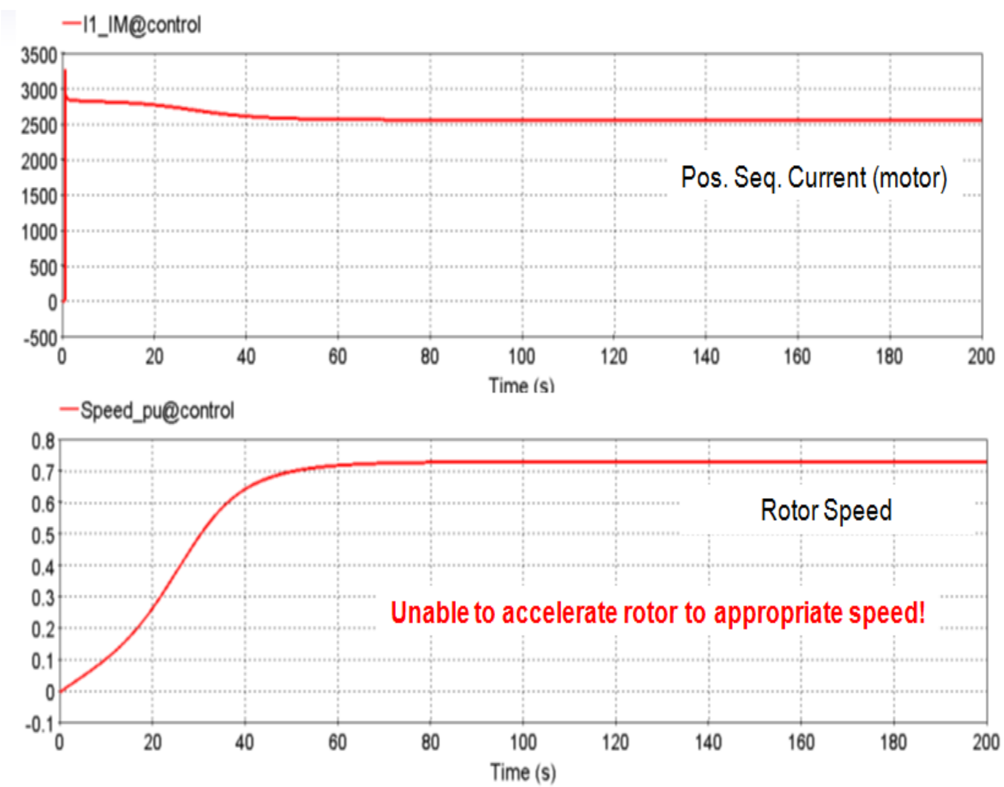
Researched multiple solution approaches.

Industry Survey of Detection Methods, cont.

- Voltage imbalance relaying
  - No indication of system capacity.



Unable to start motors with no prior indication of system failure



Negative Sequence Voltage on X & Y Bus = V2/V1 =2%

	I0 (%I1)	I2 (%I1)
X	0.0	2%
Y	0.0	7%

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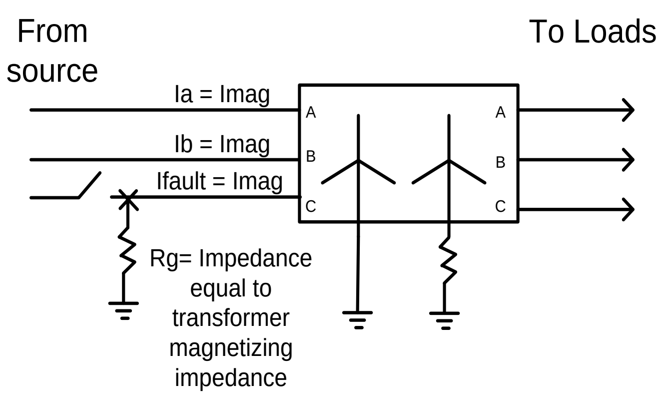
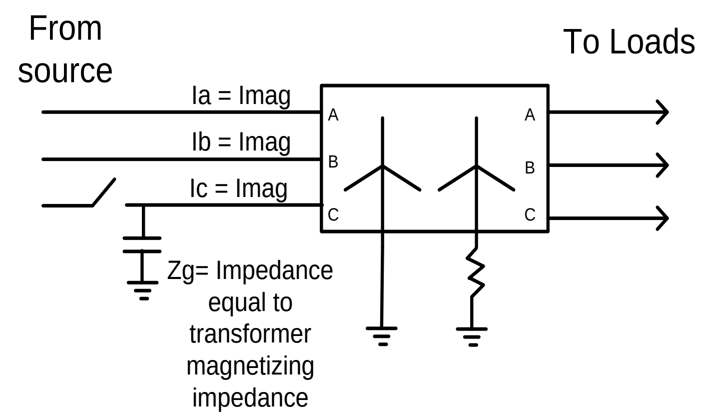
Industry Survey of Detection Methods, cont.

- Phase-Current Detection
  - Custom high voltage CTs would have to be designed.
  - In the presence of an open phase, this detection method becomes very difficult due to back-fed current.
  - Directional current sensing at these low magnitudes would be unreliable.

Very complex and unreliable design

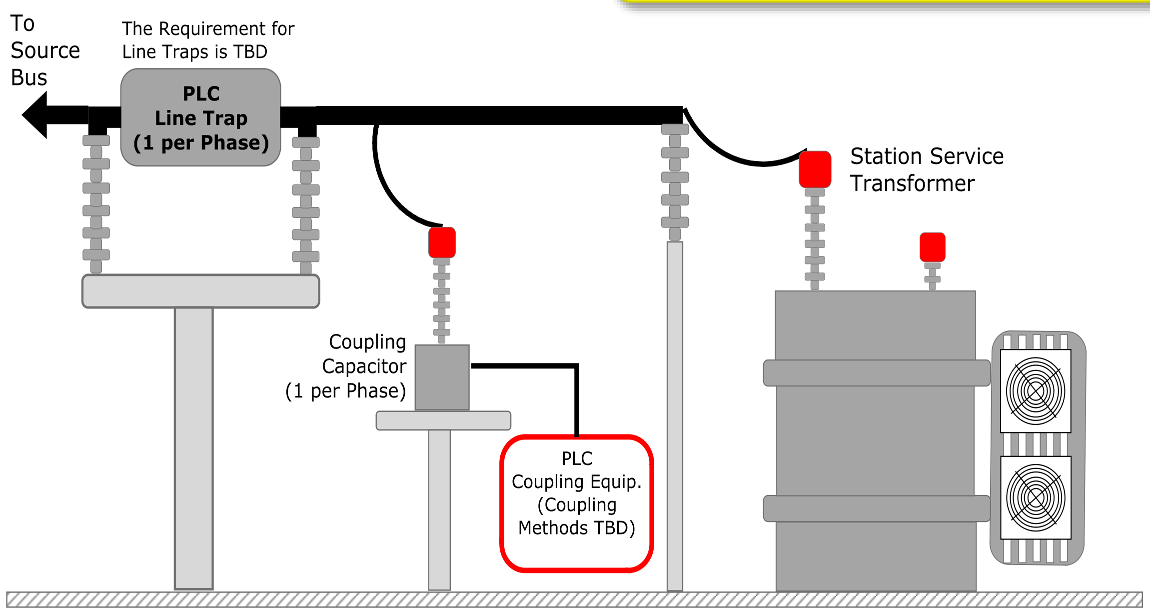




Industry Survey of Detection Methods, cont.

- Power Line Carrier Capacitive-Coupled Method
  - This method was dismissed because the technique left gaps where the conductor was not protected.

Cannot achieve 100% coverage

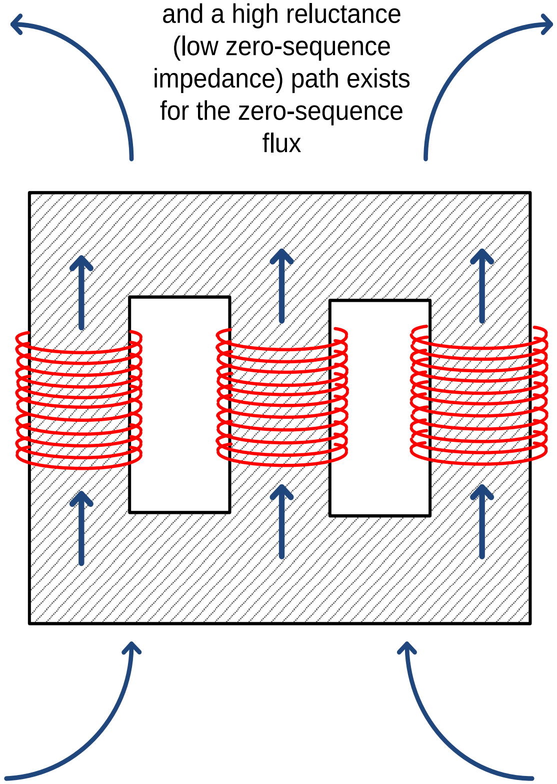


EPRI Open Phase Detection

- Transformer Neutral Injection/Detection
  - Takes advantage of the known characteristics of the transformer.
  - To exploit these results in developing an open-phase detection scheme, a transformer neutral current injection/detection method was developed.
    - Proved theory with lab testing and extensive modeling in early 2013
    - Provide Webcast in November 2013
    - Field Tested in May 2014
    - Released EPRI Technical Document in 2014 – 3002004432

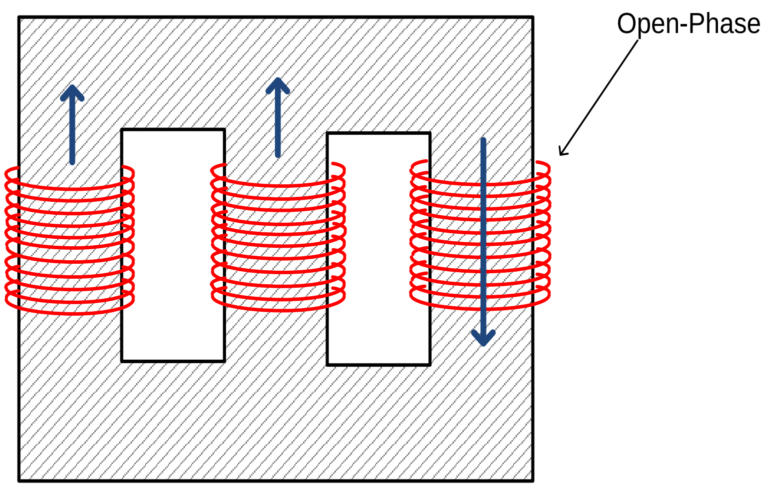
Principle of Operation

With no open phase



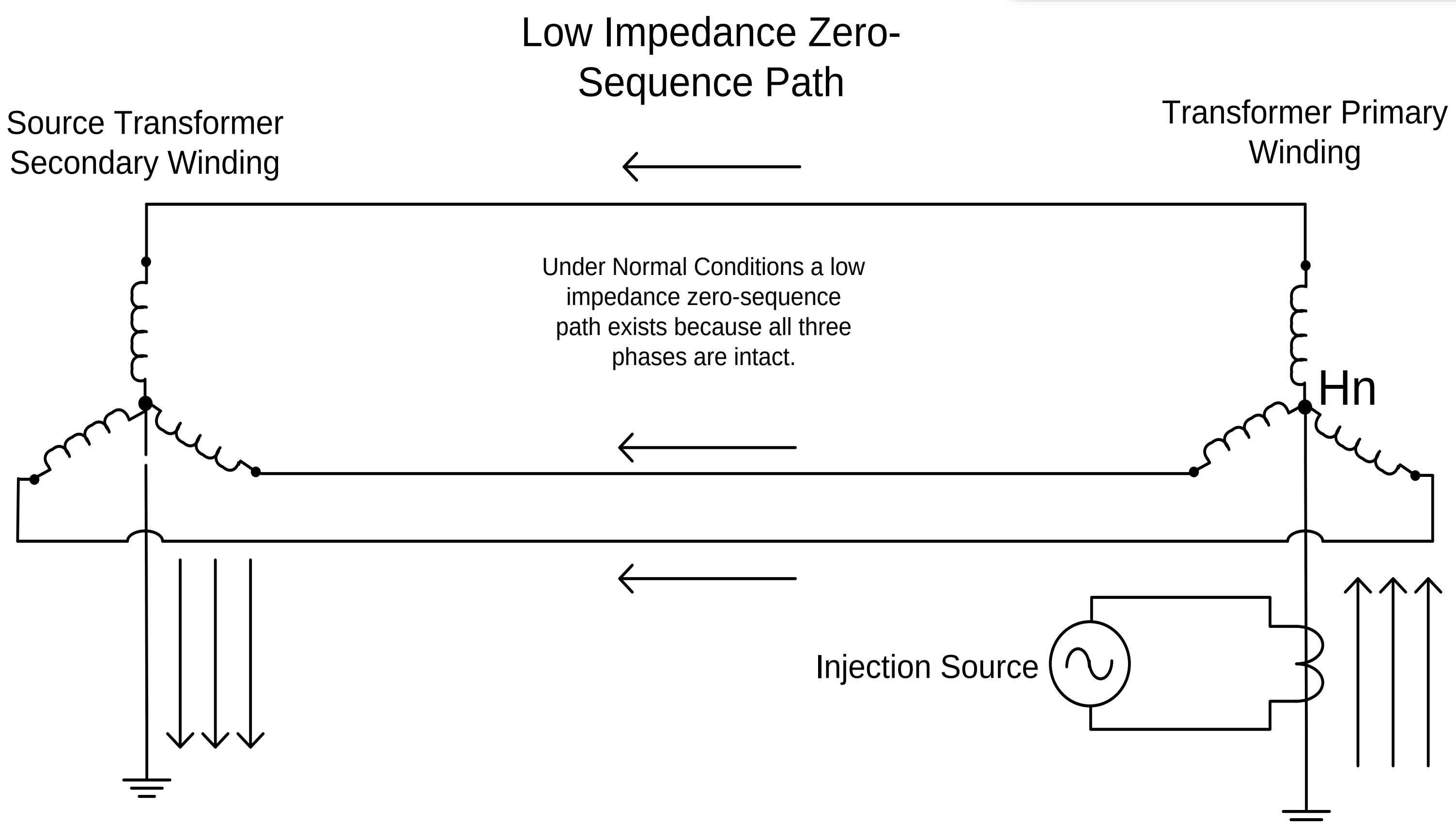
With an open phase

With one or more phases open the zero-sequence flux path now has a very low reluctance path (high impedance path)



Transformer Neutral Injection

Immune to normal system imbalances



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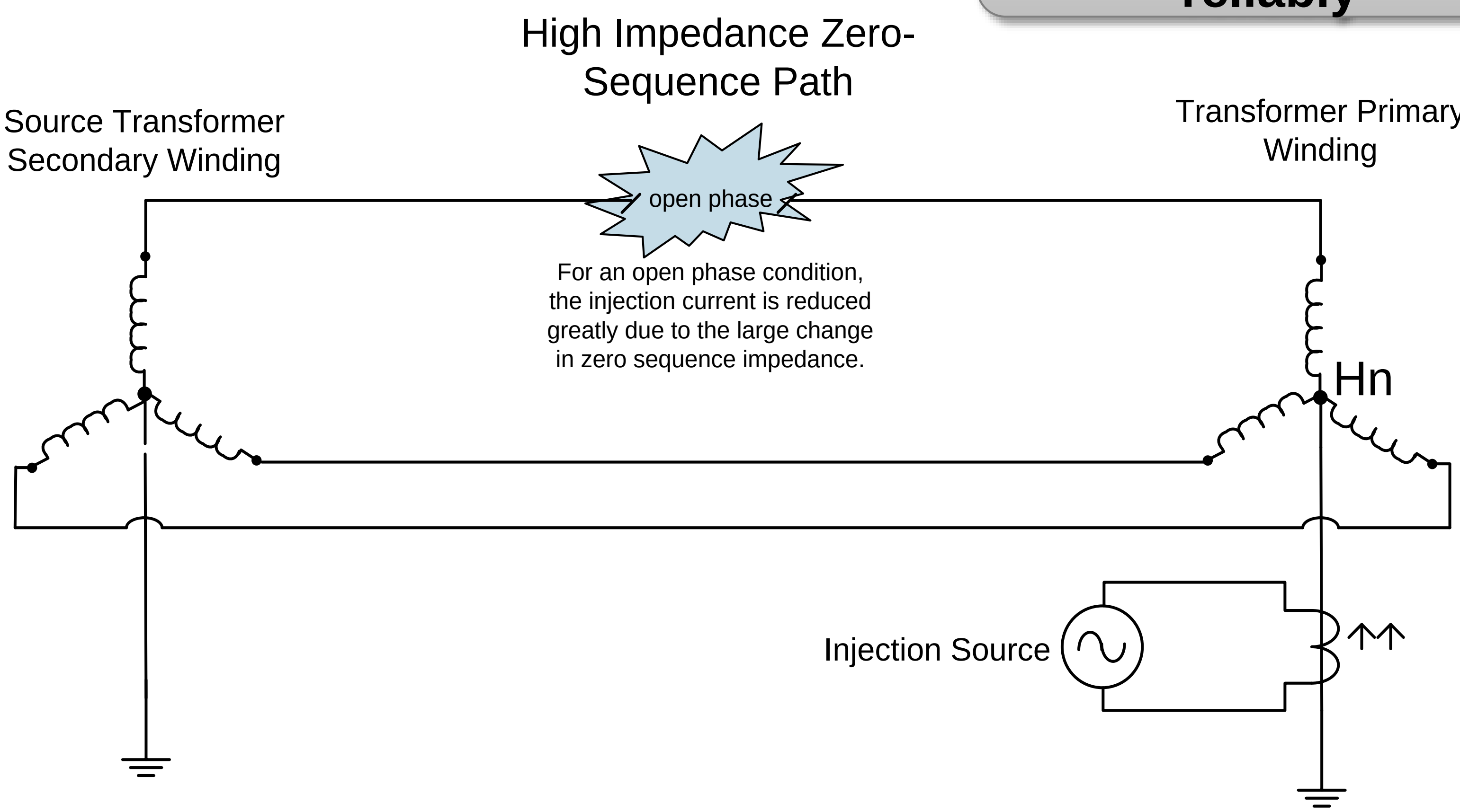
Transformer Neutral Injection

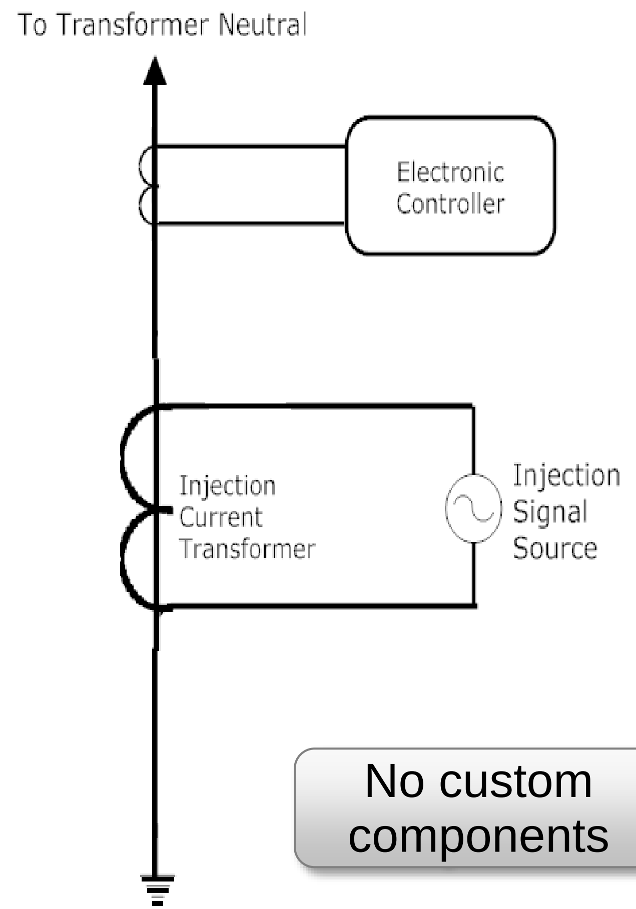
Detects an open phase condition reliably



Neutral Detection/Injection

- Combined the neutral detection along with neutral injection to provide a robust/secure detection system.
  - Benefits of active detection
    - Allows for a fail safe and redundant detection design.
    - Allows for a system test scheme to monitor all major system components.
    - Only requires monitoring of a change in signal level.
    - Active protection is the preferred method over passive only protection.
- Design meets all project constraints and goals.
- Uses all commercial-off-the-shelf components.
  - Reduces cost and lead times
  - Minimal maintenance
  - Easily replaced parts to reduce downtime

Drastically reduces modeling and analysis required



No custom components

Open Phase Detection Implementation, cont.

- Installation utilizes neutral conductor only.
  - Requiring minimal outage time and minimal maintenance
  - Design for ease of installation
  - No seismic concerns for transformer’s high voltage bushings
  - Much lower fault current level exposure compared to phase conductors
  - Less exposure to lightning
  - No impact on the BIL, creepage, and clearance of the transformer’s high voltage bushings

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Field Demonstration

- Conducted at Bellefonte Nuclear Plant
- First ever actual open phase field test
  - TVA opened a 161 kV conductor to a 36 MVA Station Auxiliary Transformer (SAT).
  - Test took 2 days for reconfiguration after months of planning.
- Many TVA individuals supported the effort on-site at Bellefonte and TVA management made the testing possible

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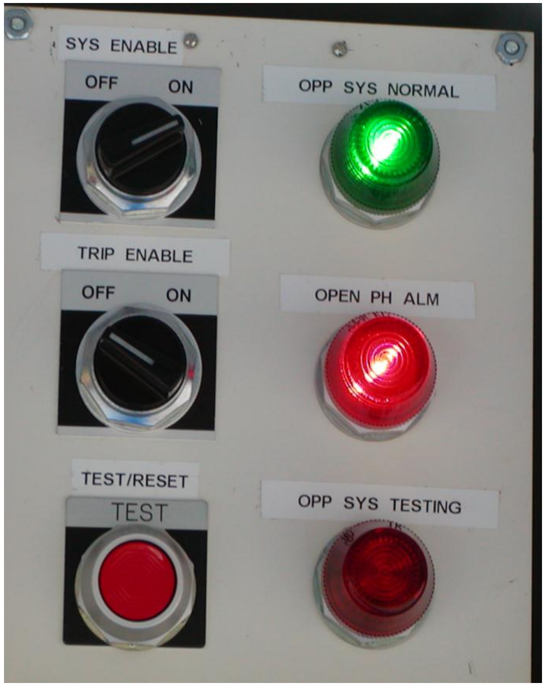
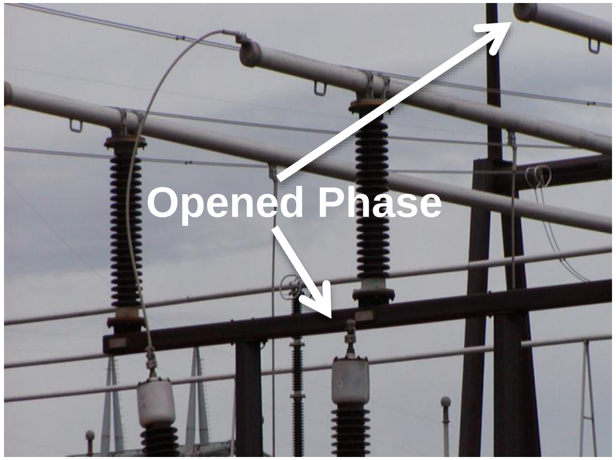
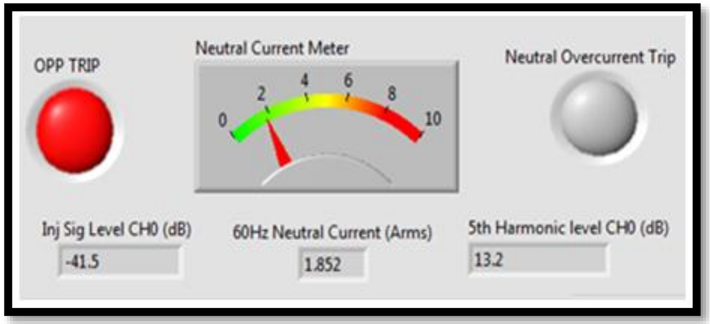
Field Demonstration – Successful Detection

- Successfully detected an open-phase event under no-load and loaded conditions.







Only previous knowledge before test was nameplate of transformer.

Worked as predicted.

Completed Steps

- Construct prototype for field testing ✓
- Laboratory demonstration meeting ✓
- Choose a representative field test site ✓
- Complete field testing ✓
- Complete commercial licensing ✓

Questions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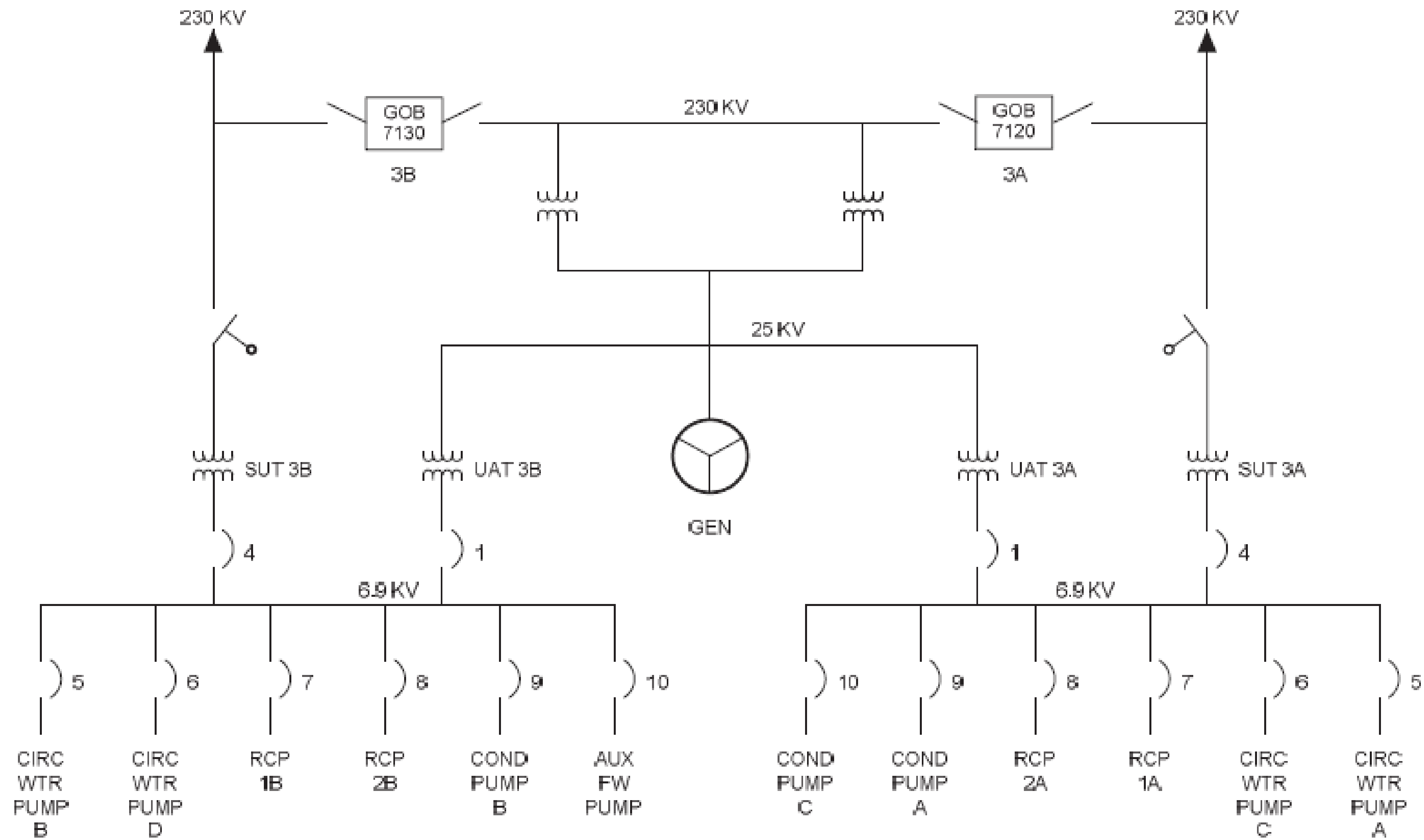
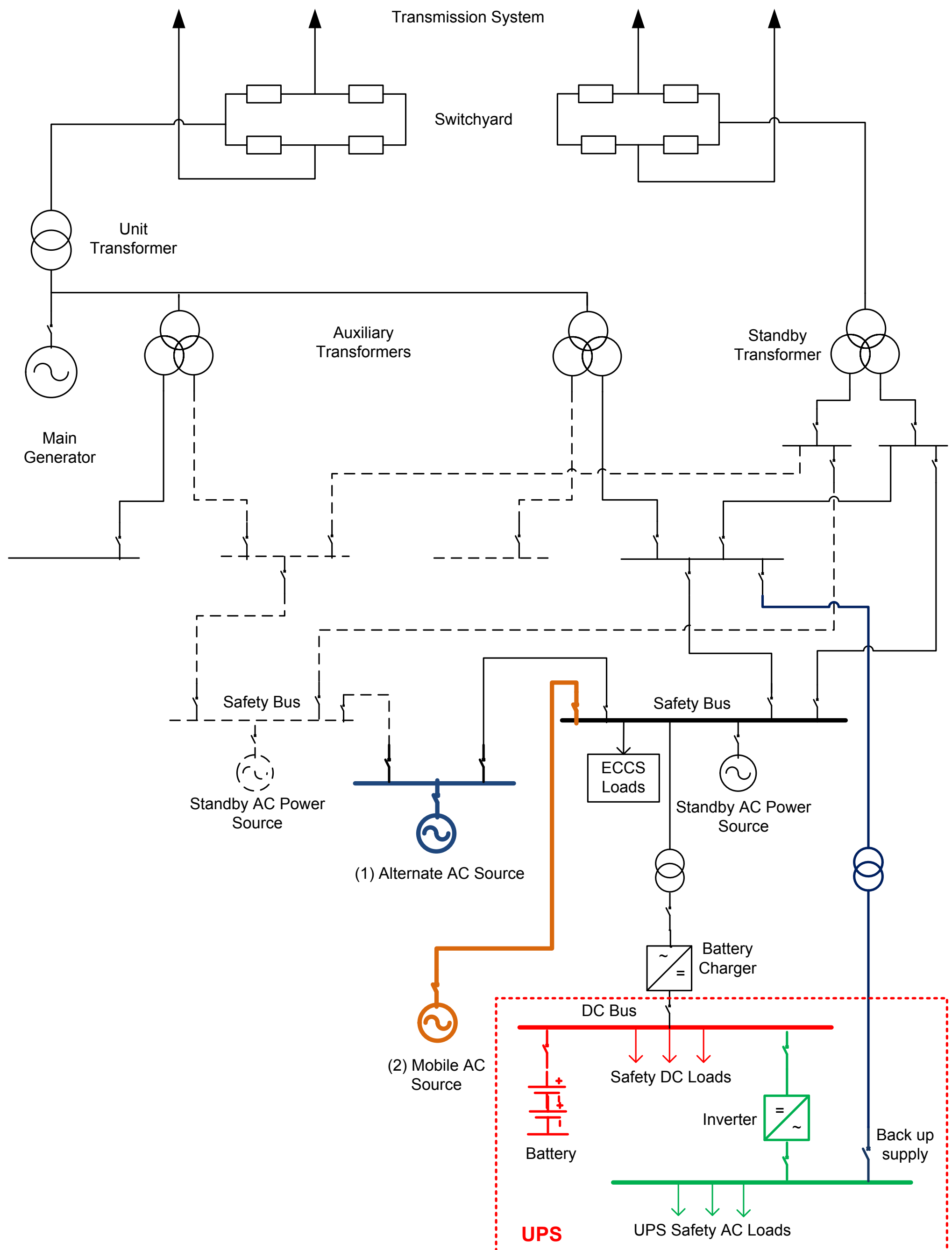
Together…Shaping the Future of Electricity

Single Line


230 KV
230 KV
GOB 7130
3B
230 KV
GOB 7120
3A
25 KV
SUT 3B
UAT 3B
GEN
UAT 3A
SUT 3A
4
1
1
4
6.9 KV
6.9 KV
5
6
7
8
9
10
10
9
8
7
6
5
CIRC WTR PUMP B
CIRC WTR PUMP D
RCP 1B
RCP 2B
COND PUMP B
AUX FW PUMP
COND PUMP C
COND PUMP A
RCP 2A
RCP 1A
CIRC WTR PUMP C
CIRC WTR PUMP A


Transmission System
Switchyard
Unit Transformer
Auxiliary Transformers
Standby Transformer
Main Generator
Safety Bus
Safety Bus
ECCS Loads
Standby AC Power Source
Standby AC Power Source
(1) Alternate AC Source
Battery Charger
DC Bus
(2) Mobile AC Source
Safety DC Loads
Battery
Inverter
Back up supply
UPS Safety AC Loads
UPS