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Risk insights map an efficient approach to aging management

Any method that can enhance safety, reduce risk, and lower costs is worth a second look. When that method proves it has the potential to optimize aging management at any nuclear power plant, it's time to spread the word.

In 2019, a small team focused on selective leaching began looking for a way to use risk insights to optimize the implementation of deterministic aging management programs (AMPs). What they started soon grew into a large team effort by Constellation, Ameren, the Electric Power Research Institute (EPRI), and the Nuclear Energy Institute (NEI), along with contractors Enercon and Jensen Hughes, to develop a generic framework and then test it in two very different pilot applications.

After carrying out those pilots—at Constellation's Limerick plant for the selective leaching AMP and Ameren's Callaway Energy Center for medium-voltage cables under the inaccessible cables AMP—the team concluded that over a 20-year period of extended operation, Constellation could see a combined $2 million in savings and Ameren could see $600,000 in savings. What's more, the team is confident the framework can be applied to the deterministic requirements of other AMPs, estimating that savings of over $200 million could be realized if the framework is implemented at all U.S. nuclear power plants. EPRI published a final technical report, *Leveraging Risk Insights for Aging Management Program Implementation: 2022 Plant Engineering Program* (EPRI 3002020713), and is now working with the NEI's License Renewal Task Force on a how-to guide for other utilities that see potential in risk-informing their AMPs during long-term operation.

Nuclear News staff writer Susan Gallier talked with three members of the team: Barry Thurston, manager of non-component programs engineering at Constellation, who served as a Constellation senior staff engineer and corporate aging management coordinator while the framework was being developed; Drew Mantey, a principal project manager for EPRI focused on plant engineering electrical and research lead for cable aging management; and Justin Hiller, supervising engineer of regulatory affairs risk management at Ameren. (See page 52 for a list of all team members.)

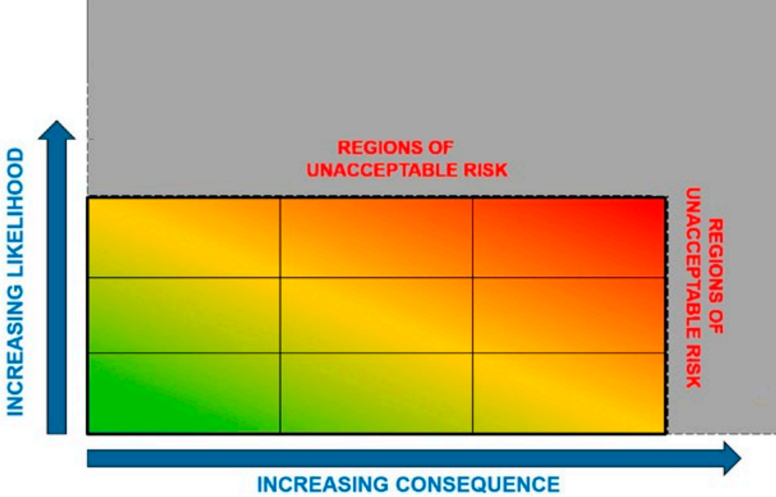

Fig. 1. Heat map of likelihood versus consequence.

In simple terms, what is the risk-informed aging management framework you've developed?

Mantey: As part of an industry working group dealing with AMP implementation, a small group proposed the idea of risk-informing AMPs, not by coming up with a new PRA [probabilistic risk assessment] but by using existing risk tools and operating experience data on the likelihood of component failure and blending them into a heat map or risk matrix based on likelihood and consequence of failure (see Fig. 1).

Thurston: Once we had that framework together, we piloted it by applying it to the selective leaching AMP for Limerick and the inaccessible medium-voltage cables AMP at Callaway to work those AMPs through the process to get a heat map. We then used that result to risk-inform the deterministic aging management strategies from both GALL Rev. 2 [*Generic Aging Lessons Learned* (NUREG-1801)] and SLR GALL [*Generic Aging Lessons Learned for Subsequent License Renewal* (NUREG-2191)]. It was an effort that probably took the better part of two years.

Where did the initial idea for the framework come from?

Thurston: In early 2019 I was the chair of NEI's License Renewal Implementation Working Group [LRIWG, now the License Renewal Task Force], and we had worked with EPRI on what we called the Selective Leaching Task Force. We were looking at a number of topics related to selective leaching, and one subtopic was applying a risk-informed approach to selective leaching.

Emma Wong at EPRI was the real integrator in the beginning because she had access to all of the EPRI expertise needed for the project. As the work progressed, we began to realize a risk-informed framework wouldn't apply to just selective leaching; it could apply to all license renewal AMPs, or at least a good number of them (see Fig. 2). The concept was organically

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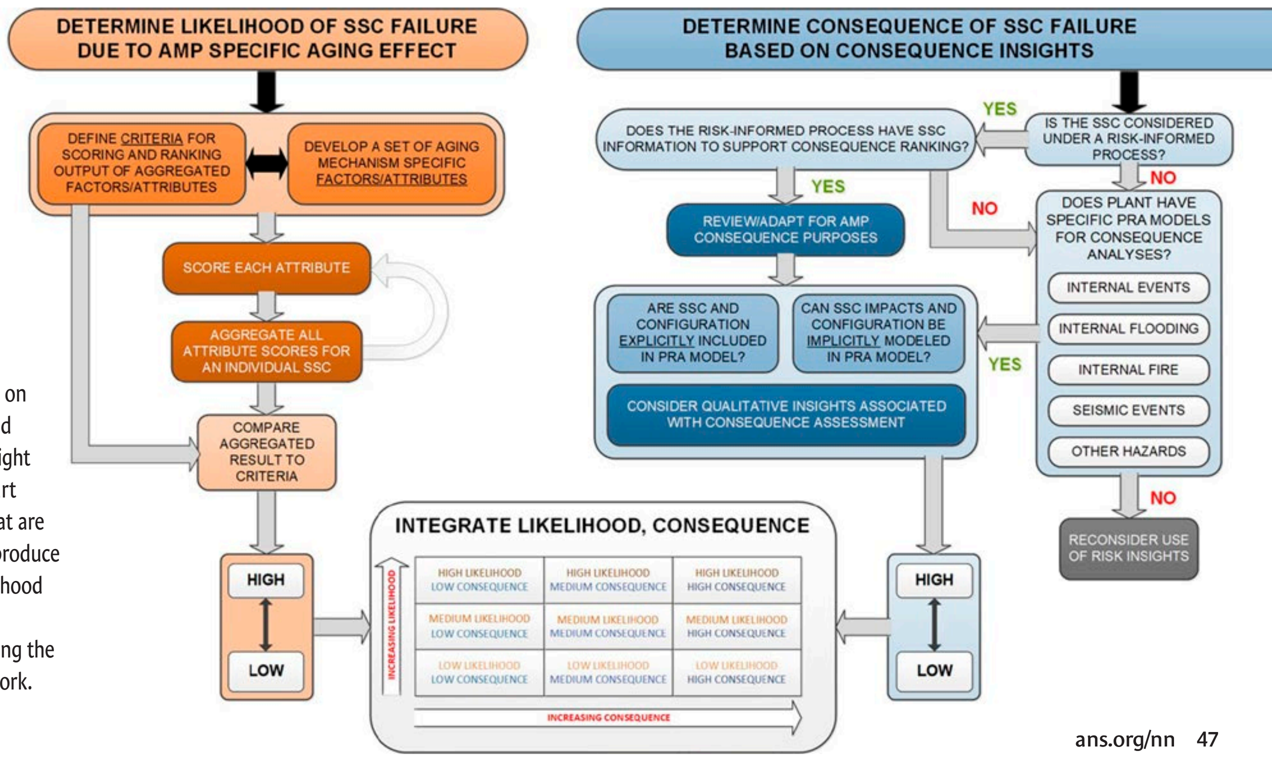

Fig. 2. With likelihood on the left (in orange) and consequence on the right (in blue), this flow chart displays the inputs that are typically required to produce and evaluate the likelihood and consequence of a component failure using the risk-informed framework.

derived, in the sense that we started small, and then thought, "Well, wait a minute, can't we go a little broader here with more than just selective leaching?"

Emma Wong and Drew Mantey pointed out that the Cable Aging Management Group—another subgroup of the LRIWG—had a potential framework application and suggested we do pilots of these two very diverse AMPs. One pilot was electrical, and one was mechanical; one was being implemented at a PWR and the other at a BWR. Limerick had been through the 50.69 [10 CFR 50.69, *Risk-Informed Categorization and Treatment of Structures, Systems and Components for Nuclear Power Reactors*] process and had an approved safety evaluation report, whereas Callaway had only a traditional probabilistic risk analysis. We have different types of risk information available, so it was very serendipitous that Ameren came in when they did.

Limerick (Photo: Constellation)

Callaway Energy Center (Photo: Ameren)

Did you have regulatory hurdles to meet before you could use the framework?

Mantey: We focused on implementation of the AMPs only. We did not want to challenge the scoping and screening for license renewal. Existing regulations and statements of consideration that the Nuclear Regulatory Commission has put out indicate that risk insights could be used for aging management programs. We felt we had a strong potential to have regulatory acceptance, because we weren't doing anything that they didn't give us the leeway to do in the first place.

Thurston: Yes, and that seemed to align very well with the NRC's opinion of where we could use risk insights versus going through scoping and screening for Part 54 [10 CFR 54, *Requirements for Renewal of Operating Licenses for Nuclear Power Plants*], which codifies the license renewal process itself. We were definitely steering clear of that because we wanted to do everything we could without having to go through the rulemaking process.

Understanding that you weren't looking at scoping and screening, do you have all permissions that you need from the NRC to apply this framework during the period of extended operation (PEO)?

Thurston: I would say yes and no. The "yes" is that we had a follow-up public meeting in early June that was related to AMP markups for these two AMPs that we gave to the NRC back in January of this year. We came away from that meeting with a firm belief that we could use the 50.59 [10 CFR 50.59, *Changes, Tests and Experiments*] process to change the way we implement our AMPs.

That being said, the regulator still has some technical questions. They may perform audits of our two pilot projects, or we may have questions to address during the pre-PEO inspections.

Let me be clear: I'm not saying we would push ahead regardless of NRC feedback. When Emma and I kicked off this project, one of the things we knew we had to do was consistently and clearly communicate with the key stakeholders, and the NRC is definitely one of the most important stakeholders. So, from the get-go, we scheduled a series of communications—formal and informal—to clearly explain what the framework was and how it was intended to be used. They have been involved all along the way to understand what we're doing.

Cable testing underway at Ameren's Callaway Energy Center. (Photo: Ameren)

The pilots were conducted at Callaway and Limerick. Both plants were approved for license renewal but haven't entered their first 20-year PEO. How is this framework applied ahead of the PEO?

Thurston: Limerick is still two years out from entering the PEO in 2024, but there are prescribed inspections that have to occur prior to entering the PEO that we can apply the framework to. You can start doing selective leaching inspections up to five years prior to PEO. Under the selective leaching AMP, if you don't find the condition at all during your pre-PEO examinations, you don't have to do anything in the PEO. But in the case of Limerick, they found some selective leaching, so we were using this as an opportunity to influence both what we do for extent of condition as well as what we need to do with inspections that will occur in the PEO.

Was Limerick chosen for the pilot based on the selective leaching that was spotted?

Thurston: Yes, but we have a couple of plants we could have chosen. We tried to anticipate when we would have a useful product and when they would go into PEO so we could get the most benefit from it. We had one other site that just entered PEO recently, so the framework was developed too late to be able to use it effectively there.

What is different at Callaway, where cable testing frequency was the focus of the pilot?

Hiller: Callaway's status is almost identical to Limerick, meaning we also enter the PEO in 2024—in October—and the timing of this pilot fit neatly into our implementation schedule. The difference is that we're going to test all the cables in the AMP prior to entering the PEO. In fact, during the outage this spring we actually found a reactor coolant pump (RCP) cable that was bad and had to do an emergent replacement. I want to be clear that the cable failed the test acceptance criteria for very low frequency (VLF) Tan Delta testing—it didn't fail in service. Finding this cable before it failed in service shows that our inaccessible cable AMP is working as intended and is providing a good baseline for entering the PEO.

Can you explain the existing deterministic programmatic requirements for cables and for selective leaching, and how a risk-informed approach could change how they're implemented? Let's take cables first.

Mantey: In the case of cables, 100 percent of cables in scope of the AMP must be tested prior to the PEO. Deterministic program requirements, both pre-PEO and in the period of extended operation, include inspections, nondestructive examinations (NDE), or condition monitoring. We use condition monitoring to determine if a cable is degraded from its environment.

EPRI has collected VLF Tan Delta testing data—as much as we could get, probably about 60 percent of the tests done by the industry—on a whole range of cables. And we knew from that data that a cable that tested in the good category did not, in most cases, progress into a medium-yellow category or a red category, which is the point where a repair or replacement would be needed. There were no in-service failures of cables either in the good or the yellow categories when testing at a six-year frequency, so we knew that the six-year frequency was more than enough to manage degradation and we did not project any increase in failure rate by extending the testing to every 10 years.

In practice, you first determine whether the cable insulation is good through a test. And then if you have a second test that also indicates that it is good, you can extend the test frequency to 10 years. In that case, during the period of extended operation you might

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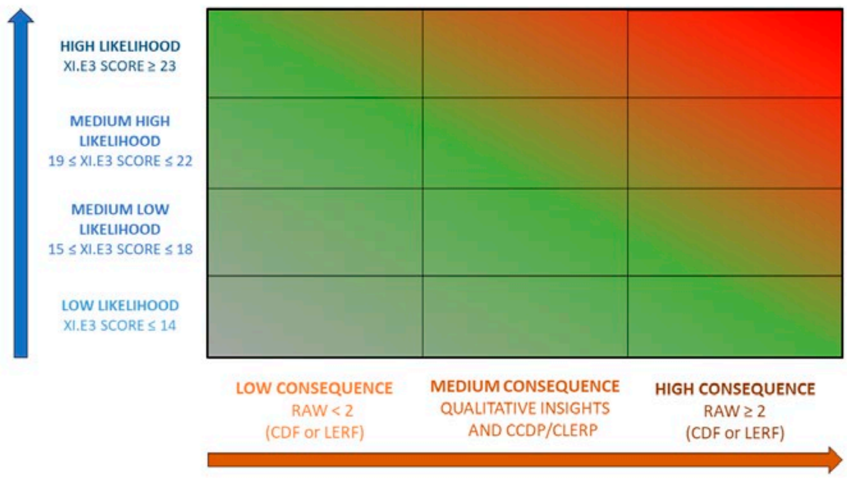

Fig. 3. Heat map of the consequence (x-axis) and likelihood (y-axis) of component degradation.

do the test two times instead of three for a low-risk, low-consequence cable. Along the green-to-red line in the heat map, you could extend the green portion to 10 years and the red portion would remain at six years (see Fig. 3).

What is different about the deterministic requirements for the selective leaching AMP?

Thurston: Deterministic programmatic requirements for mechanical inspections will require that you go out and, for example, periodically inspect either 20 percent or 25 components in your sample population (whichever is lower), regardless of what you found before. There's no consideration of the risk of failure of those components to determine which ones you inspect.

Our goal here is to use risk insights to alter our risk management and the aging management strategies to most efficiently apply our resources to maintaining the components based on their risk to the plant. There are some very compelling reasons you don't want to just keep inspecting the same components.

Instead, as long as we know their rate of degradation and know that by a certain date we need to replace them, we can use targeted inspections of components that have the same likelihood but less consequence. That way, we can test a component that's pretty benign to plant safety, and it should give us an indication of the health of the high-consequence component without us having to perform the riskier move of taking that component out of service to complete the inspection.

How did you ensure that any qualitative risk assessments that feed into the matrix were justified? Did team members ever disagree about consequences or likelihood?

Thurston: Limerick had 50.69 risk categorizations that we were able to take advantage of. We used the results of those analyses, which included large amounts of valuable risk information and were subjected to multiple reviews. Part of that process included the integrated decision-making panel that got together and went through all of the qualitative risk assessment discussions or arguments that need to be made as part of the 50.69 process. So, I would say that all those evaluations and arguments had already been hashed out by the time we used the information.

When we established the three different bins for consequence review—low, medium, and high—and we chose the thresholds from low to medium and medium to high, we had a discussion about the PRA numbers and agreed that if the numbers come to within 10 percent of those thresholds, we would be conservative and bump them up a level because of the potential uncertainty.

Hiller: I have one more point on the semiqualitative adjustments we made concerning consequences. At least in the cable case, some cables are tied to components that don't actually have a mitigation function for post-accident scenarios. It's more related to an initiating event that could propagate into an accident.

The RCP cable I mentioned earlier is an example of that. The RCPs, in the PRA, don't have a mitigation function, but they will certainly cause a reactor trip if they fail. In the case of a cable-component combination that was low risk but was associated with an initiating event, we would consider bumping it to medium.

This gray cast iron gate valve body from the fire system at Constellation's Peach Bottom plant shows selective leaching. It would be scheduled for replacement or repair prior to failure if returned to service. (Photo: Constellation/EPRI)

LIKELIHOOD INDEX

	5	4	3	2	1	0
Insulation Type	XLPE, Butyl rubber, compact				Pink/Brown EPR, TR-XLPE	PILC
Inaccessibility	Can't keep dry		Occasional wetting	Historically wet, but now kept dry	Always dry	
Shield Type			Zinc - wet	Zinc - dry	Copper, Concentric, etc.	
Splices			Multiple splices	One splice	No splices	
Voltage Stress Ratio (V rating/ service V)	<1		≥1 & ≤3 with 100% insulation rating *if shielded and unknown, assume 100%	≥1 & ≤3 with ≥133% insulation rating if shielded and unknown, assume ≥133%	>3	
Energization			>50% energized	≥25% & ≤50% energized	<25% energized	Never energized (installed spare)
Test Data	Action required	Further study required	No data - wet *assume previous wet cases until tested otherwise	No data - dry	One good test	Multiple good tests

Fig. 4. Representative cable degradation likelihood table.

Was the process for assessing likelihood data any different?

Mantey: I'll speak about likelihood. Jessica Bock and I had both industry- and site-specific operating experience. Industry operating experience came from all the research work EPRI did with cable testing evaluations and medium-voltage cable failure mechanisms. Jessica's knowledge and records of the insulation types at Callaway and the cable testing they had already performed provided internal operating experience. Once we had a draft likelihood table (see Fig. 4) that we felt good about, we got other people from the EPRI Cable Users' Group to look at it, and they provided a couple of things we had not considered. We ran test cases of what we considered to be the best and worst conditions and agreed that the likelihood ranges that we had set up for the cables put them into the correct range.

Thurston: For Limerick, on the likelihood side, we brought in EPRI subject matter experts for the selective leaching degradation mechanism to help us set up the different likelihood categories and decide how to weight them. As we evaluated the components in the Limerick selective leaching AMP, we had strategic engineers and plant operators help us make sure we assessed each component correctly against the established criteria for parameters such as fluid flow rates and temperatures.

What have you learned about the applicability of this framework to different sites or AMPs?

Mantey: We learned that the framework worked on two disparate components, and it should work on other components as well. We believe that the likelihoods could be used by others for the same AMPs with maybe slight modifications if, for example, a site has an insulation not described in the cable likelihood category. There is no need to recreate a likelihood table every time the framework is applied for the same AMP.

Hiller: I'll pile on to Drew's point about other applications. The PWR Owners Group is looking at different requirements that could possibly be risk informed in the future. We have identified over 50 ideas so far that we're investigating. Certainly, a majority of them could use this framework, and it's relatively simple. I think it adds consistency too, and that's good for the regulator and good for sharing operating experience within the industry. Using two different approaches to develop the consequence showed that the framework itself is flexible and allows sites that have different capabilities in the risk area to still apply the same framework.

In a project summary the team has stated that using risk insights for aging management was considered impractical just two years ago. Why was that?

Thurston: There was a kind of paradigm of, "Oh well, it's license renewal, the GALL says what it says and you just do that and you have no leeway." We began looking into it, and as Drew mentioned earlier, while Part 54 doesn't specifically address the use of risk insights, the statements of consideration for Part 54, for Part

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54 Rev.1, and for 50.69 do talk about license renewal and the way that AMPs could be risk informed during implementation. So I think we just hadn't really put a lot of thought into it yet.

Mantey: For one thing, it was perceived as too complicated. There was concern that there would be limited or no benefit or return on investment, and nobody really knew what level of risk data and SSC [systems, structures, and components] data was available to inform consequence and likelihood. Basically, people looked at those unknowns and were skeptical that it would be successful. We needed the pilots to pull this all together. The framework was there, and the pilots proved it could be cost beneficial, optimize use of resources, and still maintain low risk to plant reliability and safety.

You've presented your work multiple times at industry meetings. What questions do you tend to get asked?

Thurston: I think there tend to be questions about whether the NRC has accepted the framework, and about the time that it takes. If you're going to use the two AMPs that have been piloted it won't take nearly as much time, because the likelihood criteria have already been set up. In fact, we're starting another project to risk-inform the inaccessible medium-voltage cables AMP at another station using Callaway's likelihood scaling factors. If we need to make changes due to plant-specific operating experience or conditions we can, but that's how we're starting.

Hiller: I'd say the question I get asked the most is "What's the real level of effort?" This is mostly coming from non-risk professionals, so they're not familiar with the risk side of it and they think it's a lot of work. In this particular application it's truly not too much work, especially because the framework is so flexible that you can use consequence analyses you may have already done for 50.69 or another risk-informed application.

What are the team's next steps?

Thurston: We're working now on an NEI technical document of guidelines for applying the framework. It will be a how-to guide, if you will, that will tell a prospective user, "If you want to use risk insights, this is generically what you do, and how it can be applied to the GALL AMPs as they are currently written." We hope to have that to the NRC by the end of 2022 for their review. With help from NEI we're hoping to get the NRC's endorsement following that review.

Any final thoughts?

Hiller: I think we would be remiss if we didn't mention that the main point of risk-informing something is to shift the balance of effort required to implement some requirement toward the areas that are more important, from a risk perspective. And that's a benefit to risk and nuclear safety. This program wasn't put together just to allow us to save money and be more flexible with our requirements. It actually focuses the level of effort toward safety, and that's the major benefit of pretty much any risk-informed application.

Mantey: I think I'm speaking for all of us if I close by saying that the team we put together was a pleasure to work with. Everybody was able to bring their unique talents, and we're all just blown away with the results and what it could mean to the industry if applied more universally.

THE TEAM

Ameren

Jessica Bock, former aging management engineer, cable aging management (now employed at EPRI)
Justin Hiller, supervising engineer of regulatory affairs risk management (PRA)
Isaac Mulhern, PRA engineer

Constellation

Barry Thurston, senior staff engineer and aging management coordinator
Nina Lacome, risk management engineer
Seth Rios, senior staff engineer
Deven Strabala, programs engineer

EPRI

Emma Wong, principal technical leader
Fernando Ferrante, risk and safety management program manager
Andrew Mantey, principal project manager
Pat O'Regan, technical executive, Non-Destructive Evaluation Reliability team
Dylan Cimock, senior technical leader

Enercon

Burns Cunningham, license renewal lead
Anthony Ploplis, license renewal consultant
Gary Adkins, license renewal manager

Jensen Hughes

Larry Lee, principal engineer 1
Grant Teagarden, principal engineer 2
Andrew Williamson, engineer 3
Don MacLeod, senior engineer 1