THE *NUCLEAR NEWS* INTERVIEW

# The NRC's Brian Sheron: On reactor vessel degradation

*The possibility of corrosion and cracks in reactor pressure vessels has the industry involved in in-depth inspection programs.*

When extreme corrosion was found on the reactor vessel head at FirstEnergy Nuclear Operating Company's Davis-Besse nuclear power plant, in Oak Harbor, Ohio, the industry and the Nuclear Regulatory Commission set out to assure that such reactor vessel degradation would not occur again. The degradation at the Davis-Besse plant was caused by a buildup of leaking boric acid. Corrosion as a result of the boric acid buildup created a hole approximately 7 in. by 5 in. in area and 6.5 in. deep in the reactor's vessel head, leaving only the thin ($\frac{3}{8}$-in. thickness) stainless steel cladding as the pressure retaining boundary.

In response to the incident, the NRC in August 2002 issued Bulletin 2002-02, "Reactor Pressure Vessel Head and Vessel Head Penetration Nozzle Inspection Programs," which directed operators of pressurized water reactors to increase the frequency and thoroughness of inspections of reactor vessel heads as susceptibility to degradation increased. The NRC even created a grading chart, ranking each reactor head's susceptibility to degradation by category—low, medium, or high—determined by a combination of factors, including operating time and temperature.

The NRC then, in February this year, issued an order requiring that PWR operators conduct bare metal visual examinations of the entire vessel head surface, along with nonvisual examinations of each head penetration.

As of early April, 27 PWRs were in the NRC's high-susceptibility category (see chart on page 30), 16 in the medium category, and 26 in the low category. Three PWRs—Davis-Besse and North Anna-1 and -2—already have replaced their vessel heads, while operators at 21 other PWRs have publicly stated they plan to replace their vessel heads.

**Sheron:** "It probably would be worthwhile for high-susceptibility plants to replace their vessel heads."

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Sheron has been with the NRC for 27 years, and he spent more than two years with the NRC's predecessor agency, the Atomic Energy Commission. He was a principal architect of many of the NRC's regulatory documents, including the revised Emergency Core Cooling Rule, the Generic Letter on Individual Plant Examinations, and the Revised Severe Accident Research Plan.

Sheron talked about reactor degradation issues with Rick Michal, *NN* senior associate editor.

*Do you think all high-susceptibility plants will replace their reactor vessel heads?*

I can't speak for every plant, but in my opinion, from an economic standpoint, head replacement probably would be the preferred course of action for the high-susceptibility plants. The reason is that the reactor vessel head inspection requirements for high-susceptibility plants for every outage have a significant cost, in money and in occupational dose. Thus, over the long haul, it probably would be worthwhile for high-susceptibility plants to replace their vessel heads rather than to continue doing costly inspections.

*Since the NRC's order on reactor head inspections was issued, have utilities reported any surprises along the way? Has the NRC gained any lessons learned?*

TVA Nuclear's Sequoyah-1, which is a low-susceptibility plant, saw traces of dried boron on the vessel head around nozzle penetration no. 3. While initially it was thought to result from a CRDM [control rod drive mechanism] crack, TVA Nuclear concluded, from radiochemistry analysis of the deposits, that they were from a conoseal leak that happened a number of years ago.

*What's going on at South Texas Project-1?*

Very recently, STP Nuclear's South Texas Project-1 reported boron residue on two lower head instrument tube penetrations. The preliminary conclusion is that the boron originated from a leak in the instrument tube penetration. However, the licensee is in the process of determining the root cause and associated extent of condition.

*What if there is a crack in STP-1's lower vessel?*

Depending upon the cause of the crack, it could be significant. If the crack is fatigue-induced and results from a unique situation at STP, then there may be no generic implications for the industry. However, if they find a stress corrosion crack and the circumstances are not unique to STP, there may be significant generic implications for the industry in terms of the need for increased and enhanced inspection capabilities for lower vessel penetrations. But until the licensee determines the root cause of the boron residue, it is premature to speculate on the implications.

*The NRC's order that was issued in February requires "100 percent inspection" of the reactor pressure vessel surface. The industry has said that rarely is 100 percent coverage achieved. Is there an interpretation of that 100 percent?*

I think in the context of the ASME Code, there's been an interpretation that "essentially 100 percent" means about 90 percent. In other words, if a licensee can inspect 90 percent, then it meets ASME Code requirements.

## High-Susceptibility Plants

The NRC grades each PWR vessel head's susceptibility to degradation by category—low, medium, or high—as determined by a combination of factors, including operating time and temperature.

There are 26 units in the low susceptibility category, 16 in the medium category, and 27 in the high-susceptibility category. (Davis Besse and North Anna-2 were initially identified as high-susceptibility plants, but both recently replaced their reactor heads, and were therefore moved into the low-susceptibility category.) Below is the list of high-susceptibility plants and their plans for possible reactor head replacement.

| Plant | Head replacement |
|---|---|
| ANO-1 | September 2005 |
| Beaver Valley-1 | Spring 2006 |
| Calvert Cliffs-1 | Evaluating replacement |
| Calvert Cliffs-2 | Evaluating replacement |
| Crystal River-3 | Fall 2003 |
| D.C. Cook-2 | Information not available |
| Farley-1 | Fall 2004 |
| Farley-2 | Fall 2005 |
| Fort Calhoun | Considering replacement in 2006 |
| Ginna | Fall 2003 |
| North Anna-1 | April 2003 |
| Oconee-1 | Fall 2003 |
| Oconee-2 | Spring 2004 |
| Oconee-3 | Spring 2003 |
| Point Beach-1 | Fall 2005 |
| Point Beach-2 | Spring 2005 |
| Robinson | Information not available |
| San Onofre-2 | Information not available |
| San Onofre-3 | Information not available |
| St. Lucie-1 | Fall 2005 |
| St. Lucie-2 | Spring 2006 |
| Surry-1 | Spring 2003 |
| Surry-2 | Fall 2003 |
| TMI-1 | Fall 2003 |
| Turkey Point-3 | Fall 2004 |
| Turkey Point-4 | Spring 2005 |
| Waterford | Information not available |

In the case of the NRC order, when we said 100 percent, that is what we meant. We didn't mean "essentially 100 percent." We told the industry that if there were legitimate reasons why a nuclear plant could not get 100 percent but still demonstrated that it was meeting the safety objectives of the order, we would consider relaxation of the order on a plant-specific basis. We told the licensees that they would need to come in and apply for relaxation. This was all explained in the order.

*The industry has claimed that nozzle cracks cannot develop fast enough to justify the NRC's latest inspection requirements. What is your response to that?*

Let's talk about a nozzle crack that could propagate from an axial crack to a circumferential crack. The industry would say that even from the time a crack goes through the wall and starts to show visible signs of leakage, axial crack rates are such that the crack would not go circumferential and grow to an extent that it would put the CRDM in jeopardy of being ejected during a cycle. My understanding is that the industry does have data to support their position—that the time it would take for a crack to go through the wall, to the time it would propagate in a circumferential manner to where it would jeopardize ejecting the penetration, would be considerably longer than one or two operating cycles.

The industry's position is that, therefore, a plant would always see signs of leakage during a bare-metal visual inspection, and that this would result in a repair being made before the crack became a safety problem. That may be the case, but the piece that the industry has not addressed yet is the corrosion issue. The NRC made this clear to the industry.

As a matter of fact, we had a meeting with industry representatives last summer. They came in and presented their proposed inspection program. We acknowledged their work, but it neglected to address the corrosion issue. The representatives agreed, and said we needed to consider it a work in progress that needs more effort. The representatives left the meeting with the promise that they would provide more information. We have not received anything as yet. We were originally told they would come in with a revised inspection program in the spring of this year. Now my understanding is that we may not see anything until the summer. We are waiting for the industry to propose the technical basis for altering what is in the order.

*I would suspect that some would say that bare-metal visual examinations are sufficient for inspections every outage. What do you think?*

For that type of examination, all that can be detected is a through-wall crack that is already leaking. It cannot detect cracks that have initiated but have not gone through-wall. So, for example, if a plant were shut down during an outage to look at the reactor vessel head, but there were no signs of boron, it would not mean there could not be a crack developing. In an extreme case, that crack could be 99 percent through the wall but not yet broken through to start leaking. I could postulate that during the next operating cycle when the plant started up and went to operating temperature and pressure, the crack could grow through-wall and begin leaking. The concern is that the industry has been unable to explain under what conditions a leaking nozzle will or will not produce corrosion on a vessel head.

In the case of the Davis-Besse plant, which had a leak for a long time, when they did their root-cause evaluation, they did not do any kind of quantitative analysis that could relate under what conditions corrosion of the vessel head would or would not occur: Under what leak rates? For how long? etc.

Following the discovery at Davis-Besse, I encouraged the industry to think about doing some laboratory experiments to better understand the phenomena. I don't know how that effort is progressing. But the point is that from a corrosion standpoint, once there is a through-wall crack, there is potential for corrosion. That is the primary concern.

*What about the use of Alloy 690 as compared with Alloy 600 as a material for vessel head penetration nozzles? The industry is saying there is considerable data from France on Alloy 690. From what I've read, the industry is saying the NRC doesn't recognize Alloy 690 as being a superior, crack-resistant alloy.*

The NRC recognizes that there is a lot of information that would suggest Alloy 690 is a much tougher material and much more resistant to stress-corrosion cracking than Alloy 600. But it's qualitative. We don't have any long-term data. Let me explain why. Thirty years ago, the industry told us that Inconel, or Alloy 600, was a very tough, fracture-resistant material. It was in widespread use in the current generation of nuclear power plants. The problem was they couldn't foresee 25 or 30 years into the future. They are now learning that 25 and 30 years later, Alloy 600 does in fact become susceptible to stress-corrosion cracking.

With Alloy 690, while it appears to be a much tougher material, we do not have any long-term data on its behavior—for example, after 25 or 30 years of service. We have suggested to the industry that they may want to do accelerated aging tests as one means of better understanding Alloy 690 behavior over time.

I wrote a letter to the Nuclear Energy Institute's director of engineering last fall and brought this to his attention—while we recognize that Alloy 690 has all the indications of being a much more fracture-resistant material, we did not have any solid data on it over a long term. We suggested for plants that are replacing their reactor vessel heads and using nozzles of Inconel 690 and the better weld material, such as Alloy 182, that for now, those plants would move into the low-susceptibility category.

The one thing I did suggest was that the industry may wish to propose a program similar to what they proposed in response to Generic Letter 97-01, which was the NRC's response when small axial cracks were first

*Continued*

discovered in some of these plants. In that letter, we asked the industry to submit information on how they intended to monitor this cracking to make sure it did not become a safety concern. The industry proposed at that time to categorize plants in terms of susceptibility and suggested that periodically, different plants would inspect their heads. No single plant was being required to inspect every outage, but perhaps every outage or every other outage a different plant within a group would do an inspection.

The idea was that if we worked on the premise that all plants within a susceptibility group would be expected to behave similarly, then by just monitoring different plants at different times, we'd be keeping our finger on the issue to determine whether or not there is a problem. That was suggested to the industry in my letter to them last fall.

If we took all the plants that were replacing their vessel heads using Alloy 690, we might be able to group them into different susceptibility categories based on head temperature and time of replacement. For example, let's say there are eight plants replacing their heads in approximately the same time frame, and they have roughly the same head temperatures. Those eight plants could work together and propose an inspection program whereby every other outage a different plant will do an inspection. No single plant would then have to inspect more than once every 16 years. I use that as an example.

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We told the industry that they would have to provide a technical basis for what they proposed, but we would be receptive to some sort of inspection program like that.

*Utilities have requested relief from requirements of the NRC's order. Could you give some examples?*

The nature of a relief request is unique to that specific plant, and much has to do with accessibility. For example, the Calvert Cliffs plant has thermal sleeves, or guide tubes, in the penetrations of their two reactors' heads. In order for that plant to do an under-the-head UT [ultrasonic test], they need to put the probe in the annulus between the guide tube and the actual CRDM penetration, which is a very narrow annulus. It turns out that when they manufactured the reactor vessels, some of these guide tubes were not perfectly concentric within the penetration. So, when the probe is put up between the guide tube and the penetration in that annulus region, and the guide tube is off-center and touching the CRDM tube wall, the probe may not be able to make a complete 360-degree scan.

Constellation Nuclear, which operates Calvert Cliffs, asked if some percentage of complete coverage with the probe would be sufficient. We told Constellation Nuclear that it may very well be sufficient, but they needed to come in and tell us exactly, for all their penetrations, what percentage could be inspected and what percentage could not, and why that was considered acceptable from a safety perspective. Calvert Cliffs subsequently overcame those difficulties and did not need to request a relaxation of the requirements.

Regarding Dominion's Millstone plant, I understand it has tight-fitting insulation on the head that is difficult to remove and, therefore, they prefer not to do a bare-metal visual examination. They have requested to do an under-the-head UT thickness measurement as an alternative to a bare-metal visual. That may or may not be sufficient for the long term. I don't want to preempt our staff in terms of their review, but those are examples of the kinds of reliefs that have been requested.

Other plants have requested relaxation based on geometric issues with their nozzles that either prevent access by the inspection probe to an area covered by the order; on limited ability of the probe to make contact with the nozzle; or on interferences that make data interpretation impossible. A large number of plants may need to request relaxation based on these geometric issues that relate to the original design of the nozzle.

*What was the premise of the NRC's order for inspecting reactor vessel heads?*

There are two things I would like to point out. One is that the underlying, technical issue with the order is that the NRC staff was not comfortable with visual inspections alone. The reason is that we did not and still don't have a good understanding of the corrosion issue. The order, in essence, is saying that we want reasonable assurance that plants will not develop leaks while they are operating. If a plant is a high-susceptibility plant, the reason we are making that plant go under the head and do a UT [ultrasonic testing] is because we want cracks found that may have initiated but have not grown through the wall. We want those cracks repaired before they go through the wall. The whole idea is that we want to have a high likelihood that when a plant is in its operating cycle, it's not going to have a crack that will go through the wall and begin leaking. We're not trying to make the probability zero, obviously. Otherwise we would have required every plant to do that. But we want reasonable assurance.

We recognize there is some evidence that says a head is not going to start corroding the minute it starts leaking. We've seen that in the plants that have already had leaks. Progress Energy's Crystal River and Duke Power's Oconee are examples of two plants that did not find any corrosion. Basically, that's the premise of the order.

*Is the order a permanent piece of the NRC landscape?*

It's an interim measure. We are expecting that the industry, in conjunction with ASME, will come forward and propose an inspection program that may not be as restrictive as the NRC's but it will be technically justified.

The NRC's position right now is, once the industry's inspection program is submitted, we would review it and, if we found it acceptable, we would amend the order so as to allow licensees to use the industry inspection plan. We would then expect the ASME to develop a code case or modify Section 11 of the ASME Code, in order that we could endorse it via rulemaking to revise 10 CFR 50.55a and thereby incorporate that inspection program into our regulation. At that point the NRC could rescind the order.

If, however, the industry doesn't come forward with anything that we can find acceptable, our thoughts right now are that we would not like to leave an order in place as an indefinite measure. At some point we would have to consider incorporating the order into the regulations.

*Switching from the reactor head to the lower portion of the reactor vessel, and apart from what is going on at STP-1—is investigation ongoing by the NRC on lower-vessel cracking?*

There have been a couple of things going on. There have been a number of plants that as part of their outage inspections have actually gone in and looked at the lower reactor vessel. Davis-Besse, in fact, removed the insulation from the lower reactor vessel and saw some streaking they thought was coming as spillover from the reactor cavity seal. The streaking just ran down, followed the contours of the reactor vessel to the lowest point and then ran down the instrument penetration in the bottom center of the vessel. The trouble was that they were unable to confirm that the streaking was actually from a spillover, as opposed to coming from a potential crack on the lower vessel penetration.

Their plan is to load fuel and bring the plant up to normal operating temperatures and pressures using the remaining decay heat in the fuel and pump heat. They will hold it at those conditions for about one week, then reduce temperature and pressure and go underneath the vessel and see if there are any signs of leakage.

*Are the concerns greater for a crack in the lower portion of the reactor vessel than one in the head?*

The safety concerns are greater with the lower reactor vessel penetrations. One concern is that these penetrations are much more difficult to access than the upper portion of the vessel. On the upper portion, the head can be removed, placed on a stand, and then equipment can be put underneath to inspect it.

But with the lower portion of the vessel, there is no ease of access. There is the need to go down through the top of the vessel. The penetrations are also smaller.

If we look at a safety analysis, a failure in the lower portion of the vessel has the potential to be more serious than a failure in a higher elevation. One instrument tube failing can certainly be accommodated by the safety systems. However, more than one tube failure could be a potential problem.

In a LOCA [loss-of-coolant accident], especially a small break LOCA, what recovers the inventory loss in a plant is when the break transitions from a liquid to steam discharge. When it's discharging liquid, there is a loss of a lot of mass and relatively very little energy from the system. When mass is lost, the vessel water level goes down. When the break transitions to steam, there suddenly is very little loss of mass but an increase in the loss of energy. At that point, the pressure drops down quickly and the safety injection systems start and pump emergency core coolant into the reactor.

But if there is a leak or hole in the bottom of the vessel, there is never a transition to steam discharge. Thus, the core will eventually uncover if the safety injection systems cannot make up the rate of coolant loss through the break. To recover the core with liquid, the injection must exceed the loss of liquid from the break plus the boil off due to decay heat.

*What about corrosion of the lower vessel?*

If the lower portion of the vessel is insulated and there is a leak, leakage would evaporate, leaving dry boron in the vicinity of the penetration leak and between the insulation and the lower reactor vessel. If sufficient boron were to accumulate undetected, the question is, "Is a situation being set up similar to Davis-Besse in which there could potentially be a corrosive environment?" That's another issue we're looking at.

One of the items from our lessons-learned task force that our staff is working on is to look at current leak detection in PWRs to determine whether we need to make any enhancements. For example, if there was a leak in the lower reactor vessel, could we detect it? Do we need to enhance our detection methods?

That's work that will be done by our Office of Nuclear Regulatory Research. They will be looking to answer those questions and recommend changes resulting from their research.

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*What about the NRC's stance toward corrosion control programs at nuclear plants?*

One of the requests that we made, in Bulletin 2002-01, was for the industry to tell us about their boric acid corrosion control programs. The first set of responses received to that bulletin varied in terms of detail. Some licensees provided a lot of detail about their programs; others didn't provide very much. It may have been the NRC's fault in not being specific enough in the request as to the exact level of detail we wanted.

We issued a Request for Information in November 2002. The purpose of that was to clarify exactly what we were looking for in the way of information. In response, the industry provided more exact information, and we are currently in the process of reviewing it.

There are two staff members in our Division of Engineering who will visit several plants and do a more in-depth audit of their programs. The whole objective is to determine whether or not the current industry programs on boric acid corrosion control are sufficient to assure they would preclude any kind of corrosion occurring not only in the reactor vessel head, but also in other places in the primary system, including the lower reactor vessel. Based on that review, the staff will decide if we need to take any interim actions with the industry on boric acid control programs. NN