Denton

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

OCT 0 5 1982

Ms. Jane Lee
183 Valley Road
Etters, Pennsylvania 17319

Dear Ms. Lee:

Your letter of September 1, 1982, to Commissioner Gilinsky has been referred to me for response. You raised five questions pertaining to the corrosion problems in the TMI-1 steam generators. All of the concerns raised in your letter are being reviewed by the staff as part of our safety evaluation prior to approval of restart for TMI-1. We anticipate that our review will be completed during January, 1983. SER.

Because we have not completed our full evaluation of the corrosion problem at TMI-1, we cannot at this time fully respond to each of your concerns. However, sufficient preliminary data are available to provide some information in relation to each of your concerns.

Questions No. 1 and No. 3

NO EXCLUSIONARY EVIDENCE

The concerns raised by these two questions relate to once through steam generator (OTSG) tubing sensitization and GPUN's determination that sodium thiosulfate is the most probable causative agent. We have reviewed GPUN's information in detail and believe that a preponderance of information indicates that sodium thiosulfate is the causative agent for the OTSG corrosion. This determination is based on evidence which shows a pathway for the sodium thiosulfate to enter the reactor coolant system and the presence of sodium thiosulfate in the pathway waters, at sufficient concentrations to have caused the corrosion. Additionally, laboratory tests have demonstrated that the concentration of sulfur as sodium thiosulfate, found in the reactor coolant, was sufficient to have caused the corrosion. None of the other potential sources for sulfur would appear to have provided sufficient concentrations of sulfur or the necessary reduced sulfur chemical forms to cause the observed corrosion.

DATA?

possible not proven

Did the sulfur really cause the problem? DATA?

The word "sensitization", which you questioned, is a metallurgical term used to describe the microstructural characteristics of the OTSG tube material. Specifically, for the OTSG tubes which are manufactured from INCONEL-600, sensitized microstructure refers to the preferential carbide precipitation along grain boundaries and the presence of lower chromium content region, with respect to the bulk chromium content, adjacent to the grain boundaries in the tubing alloy.

This area was as low as 8%. alloy is 20%. Gross sensitization. Unusual. Hard to believe merely sensitization

of 4pp

8211010431

XA XA Copy Has Been Sent to PDR

During the manufacturing and fabrication process, thermal mechanical effects can lead to the precipitation of chromium carbides and the redistribution of chromium atoms along and adjacent to the grain boundaries which, in turn, change the mechanical strength and the corrosion resistance of the tubing. By controlling the heat treatment conditions, it is possible to control the shape, amount, and distribution of carbides along grain boundaries, and the degree of chromium depletion in surrounding areas. In this manner, it is possible to improve resistance to specific types of corrosion. Conversely, a material structure which is controlled by heat treatment to improve resistance to some specific types of corrosion, can be more susceptible to other types of corrosion. When selecting a material for a specific application, the grain structure, carbide morphology and distribution, and grain boundary region chromium content are controlled to provide resistance to the types of corrosion which are typically anticipated under the intended service conditions. The sensitized tubing used at TMI-1 was selected to provide good strength and other mechanical properties, and resistance to the typical forms of corrosion that would be anticipated in a nuclear steam generator. The sodium thiosulfate which was introduced into the reactor coolant is not a typical corrodent in nuclear steam generators. Therefore, the tubing did not have a high degree of resistance to corrosion by a reduced sulfur species.

describe how did it happen

How many other not be typical corrodents will GPU put in?

The proposed repairs for TMI-1 OTSG's do not include any changes in tubing heat treatment or grain boundary structure. Instead, the focus is on removing the corrodent and ensuring that it cannot be reintroduced to the reactor coolant system.

all or just thio sulphate

The chloride which was found during examination of the tubing is normally present in trace quantities in water and is typically found during any corrosion examination. The chloride reported in the TMI-1 steam generator status report, in our opinion, was not a causative agent in the corrosion process.

- questionable?

Question No. 2

This question relates to the presence and potential effect of sodium thiosulfate on other system materials (reactor internals). A thorough examination of the reactor internals was conducted including removal and destructive examination of some components. These examinations were witnessed by NRC personnel and our consultants. No evidence of sulfur-induced corrosion was found. Strange. Any other corrosion found? If no other corrosion - improbable!

Sulfur has been detected in the protective oxide layer on most system surfaces. GPUN is conducting an extensive program to determine if the concentrations of sulfur which have been found can cause further corrosion. If a significant potential for future corrosion exists, the sulfur will be removed prior to restart. The staff and our consultants are following these programs closely.

but did this S come from thiosulphate or other source? Very small amt. found

The most probable explanation of why corrosion was found on the steam generator tubes and not other system materials is that the tubes were under tension. The degree of tension in the steam generator tubes was sufficient to fracture their protective oxide film and permit the sulfur to attack the base metal. This concern will be addressed in detail in our safety evaluation.

? a little bit

Question No. 4

The concern you expressed in the question relates to the potential for a "Ginna Type" tube rupture due to tube pullout potential in the tubesheet and pressurized thermal shock. The 50°F temperature difference between the tube sheet and tubing within the tubesheet is very conservative. Under all normal plant operations this difference is only a few degrees. For the worst case postulated accident (main steam line break), a maximum of approximately 30°F can be predicted. Therefore, testing at a 50°F temperature differential is conservative. Additionally, GPUN will not expand the bottom two inches of tubing within the tubesheet which provides an additional physical tubing restraint in the event of further corrosion.

ΔT not imp. ΔPressure! OR ΔT & ΔP! together.

Pressurized thermal shock is being reviewed by the staff as Generic Issue A-49. We are currently scheduled to have A-49 resolved by late 1983. Preliminary information indicates that the potential for significant thermal shock due to a steam generator tube rupture is small. UNDER NRC's assumptions!

Question No. 5

This questions the suitability and reliability of the kinetic expansion repair process. An extensive amount of testing is being conducted by GPUN to qualify the proposed repair process for returning the steam generators to service. In addition to monitoring this testing, the NRC is having independent testing of the repair process conducted by our contractors. Preliminary information indicates that kinetic expansion is the best repair method. Accelerated life cycle testing of mockups in the laboratory has shown no problems in meeting technical specifications for steam generator tube leakage for up to a five-year period. These tests are continuing and will provide life cycle data for a period of 35 years.

assumes low # of transients & other challenges.

with or without tube expansion?

We appreciate your interest and wish to assure you that we are thoroughly evaluating the corrosion problem which has occurred at TMI-1. We will require whatever steps are necessary to protect the health and safety of the public.

Sincerely,

HR Denton

Harold R. Denton, Director
Office of Nuclear Reactor Regulation

OAK RIDGE NATIONAL LABORATORY
OPERATED BY
UNION CARBIDE CORPORATION
NUCLEAR DIVISION

POST OFFICE BOX Y
OAK RIDGE, TENNESSEE 37830

NUCLEAR SAFETY INFORMATION CENTER
615/574-0391
FTS 624-0391

NUCLEAR SAFETY JOURNAL
615/574-0377
FTS 624-0377

August 20, 1982

Ms. Jane Lee
183 Valley Road
Etters, Pennsylvania 17319

Dear Ms. Lee:

I am receipt of your letter received July 27, 1982, requesting detailed information regarding steam generator corrosion under a variety of conditions. A complete response to the many points raised in your letter could involve considerable effort. Although we operate the Nuclear Safety Information Center for the Nuclear Regulatory Commission, our services are available at no cost only to NRC personnel and their direct subcontractors. While the NRC has asked us to implement a cost recovery service so that we might respond to inquiries such as yours (assuming that you were willing to pay the cost), that arrangement has not yet received DOE approval (required since ORNL is a DOE Laboratory). However, in order that your request not be entirely in vain, I am enclosing a copy of NUCLEAR SAFETY 22(5) which contains an annual report on steam generator tube performance. (Subscription information is on the back cover.)

Sincerely yours,

Wm. B. Cottrell

Wm. B. Cottrell, Director
Nuclear Operations Analysis Center

WBC:ap

Enclosure: As noted

Callers Jam Switchboards

Mild Earthquake Scares Countians

By DEBORAH DUNLAP
Intelligencer Journal Farm Writer

A mild earthquake, which rumbled about 10 seconds before climaxing with a loud clap, roused many southwestern Lancaster County residents out of bed Sunday morning to see if their furnaces had exploded or trees had fallen against their houses.

The 2:39 a.m. quake, which registered 3.0 on the Richter scale, rattled glassware and occasionally cracked plaster walls but apparently caused little damage.

However, frightened residents awakened by the rumbling noise and trembling houses, jammed telephone lines at local police stations and media offices soon after the tremor.

It was the first measurable earthquake in Pennsylvania during the past two years, said Dr. Benjamin Howell, a geophysicist at Pennsylvania State University.

It also apparently is the first tremor above a new underground fault.

The most recent quake felt in the Lancaster area was Feb. 28, 1973, which was centered near Philadelphia some 60 miles east.

Dennis Eckenrode, who was desk operator Sunday morning at Lancaster State Police Barracks, said an E[illegible] Petersburg Township resident first called to ask about the noise and then "the switchboard was solid" with calls.

"People were kind of panicky, wondering if there had been a big explosion or a train wreck," Trooper Eckenrode said, adding that he received about 150 calls while he was on duty.

"Everybody wondered what the hell it was," he said.

Most calls came from an area between Route 222 on the east, Route 372 on the south, the Susquehanna River on the west and just north of Lancaster City, Trooper Eckenrode reported.

He said area police received an unconfirmed report of uprooted trees.

John Minsch, a U.S. Geological Survey geophysicist in Boulder, Colo., told the Intelligencer Journal Sunday night that "even a large earthquake doesn't cause uprooting of trees."

A quake that registers 3.0 is "minor" and can be felt in a 20- or 30-mile area, he said. People "could have cracked plaster" walls, the geophysicist said, but even that is unlikely.

Minsch said he went to his office early Sunday to check the strength of the quake after a Lancaster radio station and an Associated Press reporter in Philadelphia called him to verify the tremor.

"I was a bit skeptical because we had all those reports of 'boom things' on the East Coast" in the past six months, he said.

But he said he "got the reading from a recording in Blacksburg, Va.," which confirmed that the trembling had been caused by "a real earthquake."

Minsch said he probably will check the Virginia reading today with stations at Penn State, Columbia University in New York and New Jersey.

Earthquakes in the East are "not rare but certainly infrequent," Minsch said, adding that minor quakes had been reported earlier this year in northern New Jersey and along the Pennsylvania-West Virginia border.

Dr. Howell at Penn State said Pennsylvania "is in a very inactive area" and that Sunday's rumbling was "very, very unusual."

"We don't have any understanding of what causes earthquakes in the eastern United States," Dr. Howell said.

"Most earthquakes occur along the borders of large blocks of the earth's crust," he said, adding that "the whole of North America and part of the Atlantic Ocean constitute one of these blocks."

He said the Penn State observatory is part of the national network "that hopes

More EARTHQUAKE Page 2

Pipsqueak Quakes Often Occur Here

By JEFFREY SCHEIB
Intelligencer Journal Staff

The earthquake which rattled windows and roused sleepers in Lancaster County early Sunday morning was the first to shake the area in five years, but apparently it was not that unusual an occurrence.

Although many countians were startled by loud bangs and shaking houses, one scientist says Lancaster County has earthquakes with some frequency. However, most of them are so mild that they go unnoticed.

Dr. Benjamin F. Howell Jr., a Penn State University geophysicist, made that statement after a small quake that rattled Lancaster County crockery in December, 1972. That quake registered 2.9 on the Richter scale.

Sunday's quake registered slightly higher, 3.0, but both are still in the pipsqueak range for earthquakes. A major quake is defined as having a reading of 7 or above according to the Richter measurement.

A "big boom" accompanied Sunday's quake. It was similar to one that startled residents in the northwestern part of the county when a quake shook the area on the evening of Thursday, December 7, 1972. Both then and now many ran to check their furnaces, fearing an explosion.

The seismograph at Penn State recorded that quake at 10:01 p.m. that evening. It registered 2.9 on the Richter scale. The epicenter was located somewhere between Lancaster and Harrisburg.

Just under three months later, on Feb. 28, 1973, another tremor shook the county. Windows were rattled and knickknacks tossed from shelves by that quake, which measured between 3 and 4 on the Richter scale according to Penn State's seismograph.

The February quake struck about 3:30 a.m., rousing many countians from

More PIPSQUEAK Page 2

Earthquake Scares Many Countians

Continued From Page One

to locate earthquake-prone [illegible] and eventually predict the [illegible]. He said Sunday night he had not [illegible] the seismograph for a reading on the [illegible]ter quake.

Paul Nichols, head of the earth sciences department at Millersville State College, agreed Sunday that a record of earthquakes for the past 100 years shows that Lancaster is "a low-risk area."

The nearest high-risk areas are Charleston, S.C. and the southeast corner of Missouri, Dr. Nichols said.

"It's a matter of relative age of the mountains," he said, adding that most quake movement takes place "along an old fault" that has "had movement before."

"Mountain-building (along the Appalachian range) took place years ago, and the crust of the earth has settled down," he said.

The weekend quake was caused by a "gravity fault," in which "one block slides downward" against another.

Primary, or fast-traveling, waves move horizontally from the fault, Dr. Nichols said, and the slower secondary waves move vertically.

Both kinds of waves "travel back and forth" along the same path, he said. When they meet, they send out destructive surface waves.

In every earthquake, he said, there is a ground break, but the break generally is underground in minor tremors, he said.

Dr. Nichols said the epicenter, or small area where the underground waves hit the surface, has not been determined for the weekend tremor.

"It'll take about a day to track it down," he said, noting that measurements are taken from at least three recording areas and then plotted.

The paper on the [illegible] drum at Millersville ran out shortly before the quake, Dr. Nichols said. But he said recordings at Penn State, University of Delaware and New Jersey stations can be used to determine the quake's origin.

The fault "apparently is new," he said.

Sunday's earthquake "opens the question about how many of these faults are dormant," Dr. Nichols said, adding that he believes "any fault is a potential movement. You wouldn't want to build a nuclear reactor on one. Any big structure" could be shattered by a solid quake, he said.

At Safe Harbor Water Power Plant Corp. along the Susquehanna River, shift operator Tony Alexander said workers reported that "the building shook" but no alarms sounded.

Residents at Peach Bottom, where a nuclear power plant is operated, also reported ground tremors.

Mabel Bauer, who lives just south of Holtwood, said "it sounded like a sonic boom, and the house quivered."

Lancaster civil defense director Paul Leese reported, "We were flooded with calls at the communications center" in the county courthouse.

But he said police and [illegible], who normally would notify him of a [illegible], told him there apparently were no injuries.

Ironically, Leese said he [illegible] [illegible] [illegible] hazards, [illegible] the state disaster program. "I'll have to change that [illegible]," he said.

[illegible] so unusual here that [illegible] consider it the reason for the [illegible] rumblings.

"It sounded like an [illegible] explosion," said Pat [illegible]. "It was over so quickly."

Although she formerly had lived in quake-prone California, she said she did not think the "explosion" was an earthquake because "they don't [illegible] in this area."

Guy Kleckner, who lives just [illegible] Conestoga, said the [illegible] woke him up.

"Oh, my gosh, that was terrible. I was scared, and I'm not the scary type," Kleckner said. "There was one big [illegible], and I thought one of those big [illegible] through the road."

Kleckner said his house is surrounded by some [illegible] trees.

After the "bang," the Conestoga man said he went downstairs, where his [illegible] parakeets "were really upset, flying all over their cage."

He said he went outside, and everything was so still and quiet. I [illegible] see if a car had hit the house. [illegible] church. I found that others heard the early-morning tremor.

Claire [illegible] of the [illegible] north of Willow Street said she was in the living room watching television [illegible] hear "a roar, like thunder going [illegible] sky."

"It kept getting louder and louder. It was scary," she said, adding that "the house vibrated."

A Martic [illegible] man said he "thought the furnace blew up." He said he [illegible] downstairs and outside, where [illegible] "just lying. I thought [illegible] my wife and kids were still asleep."

An hour later, he said, "it started rumbling again."

Pat [illegible], who lives [illegible] Providence, said, "The house [illegible] shook. I wasn't sure if it was [illegible] or what. I couldn't figure out what it was."

The house trembled "just for a few seconds," she said.

Jenny [illegible], who was working the switchboard at [illegible] early Sunday, reported that "[illegible] just shook like [illegible]. I thought there was a [illegible] that just swaying suddenly."

The switchboard is [illegible] windowless building, Miss [illegible] said, adding that "I didn't think [illegible] it until I got all those phone calls."

A Franklin and Marshall [illegible] security guard said he thought [illegible] the student center "might collapse" from the tremor.

"It woke me out of bed. It makes me shake when I think about it," a Millersville woman said Sunday night. "The only thing I could think of was a sonic boom. But this was more severe."

Although the earthquake created a stir in [illegible] Lancaster, Dr. Nichols of MSC said the western U.S. has minor tremors often. "This is almost a daily occurrence in California," he said.

Mild Tremor Jars Lancaster County

LANCASTER (AP) — A mild earthquake shook a portion of Lancaster County Friday afternoon, jars buildings but apparently causing little damage, officials said.

State police said they had received no reports of damage some 2½ hours after the tremor.

Dr. Paul Nichols of the Millersville State College earth sciences department said the epicenter of the tremor apparently was in the Furnace Hills area in northern Lancaster County, about 15 miles north of Lancaster.

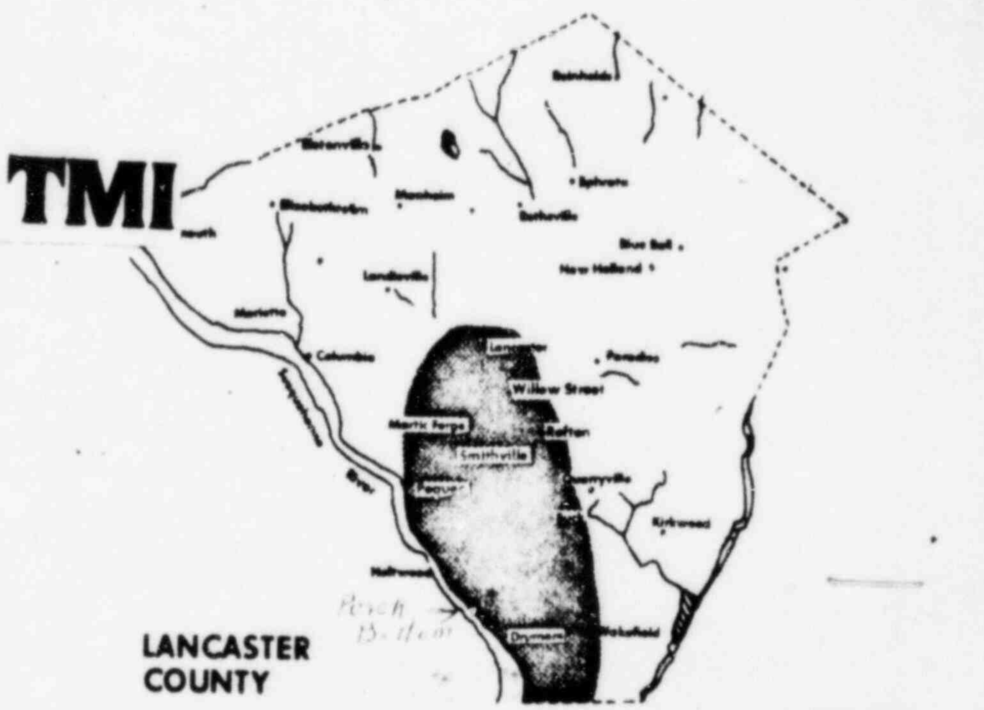
Kathy Barnett of Lancaster, who works in a two-story office building about three minutes from town, said the building shook very hard. She said passersby appeared unaware of the tremor, however.

It was the second quake to strike the area this year. An earlier tremor with a magnitude of 3.0 on the Richter scale was reported on July 16.

"It was like last summer but it was louder. It was really shaking. It was weird. We didn't have anybody call in reports of damage, though," said Connie Kepchar, a dispatcher at the state police station in Lancaster.

The magnitude of Friday's quake was 3.1, said Dr. Chuck Langston at Pennsylvania State University's department of geosciences.

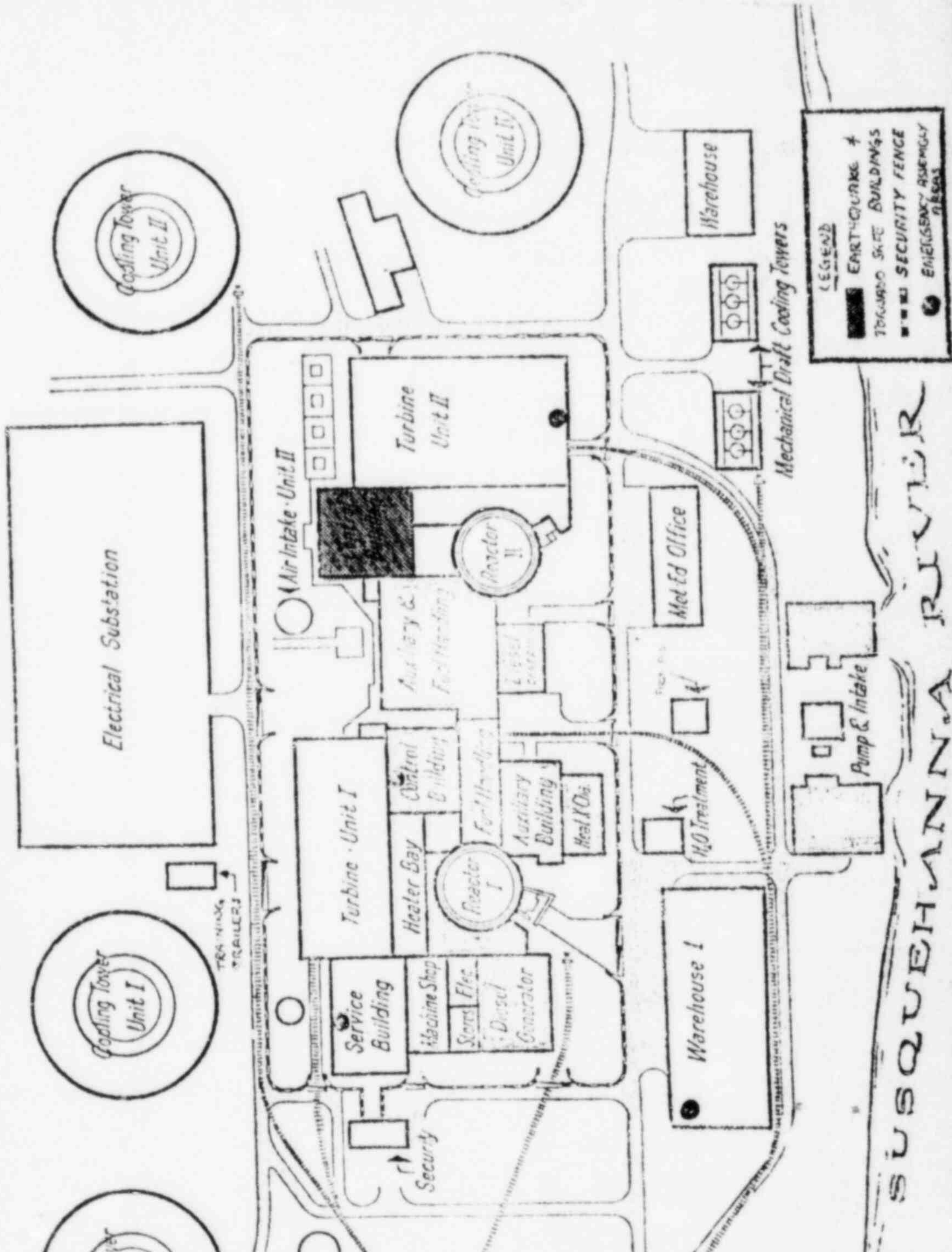
The Richter scale is a gauge of energy released by an earthquake, as measured by the ground motion recorded on a seismograph. For every increase of one whole number, say from 5.5 to 6.5, the magnitude is 10 times greater.



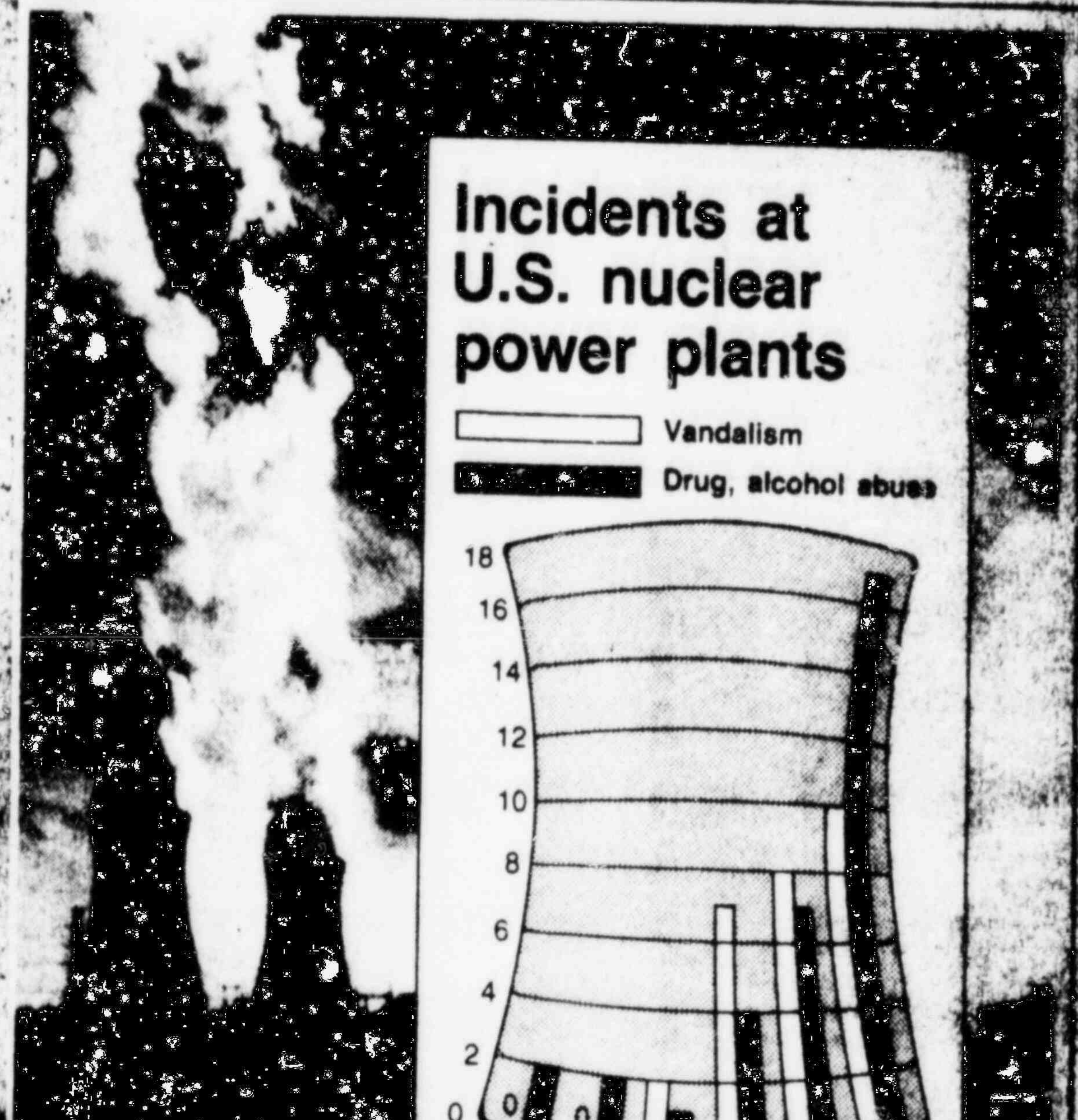
The shaded portion of the map shows the section of Lancaster County where Sunday morning's earthquake ... the most in the Southern section of the county south of

Only ONE Building Is Earthquake & Tornado Proof At TMI!

Actual Reproductions Of TMI Material



In documents brought to the attention of the Paxton Herald, which were dated April 10, 1979.....which were obtained quite by accident by a Middletown resident, we print below the photographic reproduction of the **proof** that 1 building and **only 1 building** at TMI is earthquake and tornado proof!


Incidents at U.S. nuclear power plants
Vandalism
Drug, alcohol abuse
18
16
14
12
10
8
6
4
2
0
0
0
1976
'77
'78
'79
'80
'81
Chicago Tribune Graphic;
Source: Nuclear Regulatory Commission

Sabotage: Achilles heel of nuclear plants

By TERRY ATLAS
Chicago Tribune

Last month, an alert worker at the Maine Yankee nuclear power plant noticed metal shavings on a motor that provides cooling water to the radioactive core.

A closer look revealed that some of the small metallic chips had been dropped inside the oil reservoir that lubricates the motor's bearings. If the motor had been operating, metal shards would have caused substantial damage to the motor and perhaps triggered the automatic shutdown of the nuclear reactor. (The reactor was being refueled at the time of the discovery.)

The apparently deliberate effort to sabotage a piece of equipment in the normally secured reactor containment building "is viewed as a serious matter," said Maine Yankee spokesman Donald Vigue.

The threat of inside sabotage has lurked for years in the background of discussions on nuclear power plant safety. Safety studies generally have not included sabotage in their statistical risk analysis.

"The problem is they don't really know how likely it is," said Steven Sholly of the Union of Concerned Scientists in Washington. "And no one wants to estimate how likely it is."

But records on file with the Nuclear Regulatory Commission in Washington document instances in which vandalism, tampering and sabotage apparently have been done by employees despite strict security measures, which include background checks, psychological evaluations and in-plant measures such as locked doors, detectors and security guards.

"We are aware that these things have occurred, not frequently but often enough so the question isn't academic," said Larry Soth, supervisor of Station Support Services at Commonwealth Edison Co.

In the case of Maine Yankee, at least 100 company employees and outside contractors had access to the reactor containment building during refueling, far more than when the plant is operating. So far, though, investigations by the company and the Nuclear Regulatory Commission have failed to identify a culprit. "There's not a lot at this point," Vigue said.

The incident was the second there in 18 months, although company officials say the two are believed to be unrelated. In July, 1981, officials found a message sprayed on the floor of the spent fuel area that said, "Bomb will go off July 31, 1981." The company told the NRC that a note found nearby read: "So you think your (expletive deleted) security is so good ... try to find the bomb."

There was no bomb, and the investigation that followed at the Wiscasset, Me., reactor never developed "to the point where we could prosecute anybody," Vigue said.

Critics call inside sabotage the Achilles heel of nuclear power and warn that a malicious act by one individual has the potential to cause tremendous damage.

Since 1978 the NRC has documented 27 cases of vandalism at the nation's 150 nuclear plants in operation or under construction. And there have been other mysterious incidents that could have been the work of insiders, although their cause was never identified.

"Surely, you can have sabotage or vandalism in other industries, but not with the same potential impact to the public health and safety," said Richard A. Udell, nuclear research director for the House Interior Subcommittee on Oversight and Investigation.

And the NRC's outside Advisory Committee on Reactor Safeguards has urged the commission to budget more money to study plant designs to make sabotage more difficult. "We want to make sure that one guy by himself can't do a core melt," said committee chairman Paul Shewmon, a professor at Ohio State University.

A. David Rossin, director of the industry-sponsored Nuclear Safety Analysis Center in Palo Alto, Calif., said existing security safeguards are more than adequate to ensure public health and safety.

"It is obviously a concern and not to be taken lightly," said Rossin, formerly director of research at Commonwealth Edison and a participant in a classified NRC study of reactor security. "But it is extremely difficult for an insider to create by some kind of sabotage an incident that would affect the health and safety of the public."

Commonwealth Edison's Soth, who spent several years as assistant superintendent at the Chicago utility's Zion reactor, said he ranks the likelihood of inside sabotage well below the other risks associated with plant operation, such as equipment failure and human error.

Only in rare instances has an individual been identified and prosecuted. Three years ago two operator trainees at Virginia Electric and Power Co.'s Surry nuclear plant in Gravel Neck, Va., were convicted of a felony for pouring a corrosive chemical on nuclear fuel rods.

The Nuclear Regulatory Commission has received numerous studies on the matter, some of which are classified because they examine nuclear plant vulnerability.

ACCIDENT RELEASES

PHYSICAL EVIDENCE

The subject of releases of Iodine-131 into the environment as a result of the accident at Three Mile Island is one which has caused much debate in the press and among the various investigatory committees. Due to the unique nature of our own investigation, we were able to obtain numerous documents to support our findings...documents which were not released to other investigations.

It is our finding based on our personal knowlege surrounding the initial recovery operation at TMI Unit II in the particular area of release monitoring, that Iodine-131 in amounts exceeding the normal limits for such releases did in fact occur as a result of the accident.

Please note the NRC Preliminary Notification document dated March 29, 1979, (PNO-79-67A):

> "Airborne Iodine levels of up to 1×10^{-8} mCi/ml have been detected in Middletown, Pennsylvania, which is north of the site."

NOTE: The level of airborne Iodine quoted here is 100 times the normal in-plant Iodine limits.

The releases of Iodine-131 were ongoing and steadily increasing throughout the month of April, 1979.

This finding is specifically referred to in the inter-office memo circulated among top-level management personnel at TMI dated April 16, 1979.

The memo is written and signed by a sub-contracted Health Physics expert. It is signed in concurrance by the Met-Ed Supervisor of Radiation Protection and Chemistry, a Met-Ed vice-president, and others. It states:

> "1. Due to the recent increase in Iodine-131 Source Release Term, I believe that we should reduce our emergency monitoring teams from 4 to no less than 2. Essentially one on-site and one off-site.
>
> 2. We need one site boundary and one closest residence (Iodine-131) charcoal air sample taken each hour in the center of the downwind plume. This data is necessary

to prove that we are not causing significant off-site exposure."...

NOTE: The definition of the Source Term mentioned in the memo can be found in the summary of the Public Health and Safety Task Force report to the Kemeny Commission, page 6:

> "This total release of radioactivity, known as the Source Term, was one way to determine the radiation doses to the entire population."

This particular memo obviously shows that, a) there was Iodine being released, and b) the amount of Iodine being released was increasing.

Beyond the obvious, the memo becomes even more interesting. The reduction in monitoring teams, and the necessity to "prove" no off-site exposure, are actions to be taken due to the recent increase in Iodine-131 release.

P.S. The other enclosed evidence is the cover sheet to the GPU "Sequence of events" that we obtained while at TMI. RA

GPU Service

Trailer City - TMI
GPU Service Corporation
260 Cherry Hill Road
Parsippany New Jersey 07054
201 263-4900
TELEX 136-482

April 16, 1979

TO: R. C. Arnold

FROM: R. L. Long

PRELIMINARY SEQUENCE OF EVENTS
TMI 2 ACCIDENT OF MARCH 28, 1979

Attached is a Preliminary Sequence of Events spanning the first approximately
twenty hours following the TMI-2 accident which was initiated at 4:00 a.m. on
March 28, 1979.

For this chronology of events, a reference clock was established with the time
of the turbine trip, 0400:37, defined as time zero. The time of each event in
the sequence is given as the number of hours, minutes and seconds relative to
0400:37, followed in parenthesis by the real time using a 24-hour clock. For
example, 1:52:43 p.m. on March 28 would be written "9:52:06 (1352:43)."
Depending upon the accuracy of the source of data for each event, the times
appear alone or with the notation "approximate."

The sequence has been reconstructed from various information and data sources,
including control room logs, strip chart recorders, alarm printouts and
reactimeter printouts. Please note, however, that the alarm printer was out
of service from 01:13:27 (0513:59) to 02:47:31 (0648:08) and during the course
of the accident was running well behind the actual time of events. Efforts to
annotate this chronology and to develop graphs of various plant parameters as
a function of time are underway. This additional information will be provided
as soon as it is available and we will keep you informed of our progress.

R L Long

R. L. Long
GPU

CC: H. Dieckamp
J. Herbein
R. Wilson
Industrial Advisory Group
Data Reduction and Management
M. Bezilla
L. Harding
G. Kunder
J. Logan
G. Miller

20

6

PRELIMINARY NOTIFICATION

March 29, 1979

PRELIMINARY NOTIFICATION OF EVENT OR UNUSUAL OCCURRENCE--PNO-79-67A

This preliminary notification constitutes EARLY notice of event of POSSIBLE safety or public interest significance. The information presented is as initially received without verification or evaluation and is basically all that is known by IE staff on this date.

Facility: Three Mile Island Unit 2
Middletown, Pennsylvania (DN 50-320)

Subject: NUCLEAR INCIDENT AT THREE MILE ISLAND - UNIT 2

This supplements PNO-79-67 dated March 28, 1979.

As of 3:30 p.m., on March 28, 1979, the plant was being slowly cooled down with Reactor Coolant System (RCS) pressure at 450 psi, using normal letdown and makeup flow paths. The bubble has been collapsed in the A Reactor Coolant Loop hot leg, and some natural circulation cooling has been established. Pressurizer level has been decreased to the high range of visible indication, and some heaters are in operation. The secondary plant was being aligned to draw a vacuum in the main condenser and use the A Steam Generator for heat removal. The facility plans to continue a slow ([illegible]°F/hr) cooldown, until the Decay Heat Removal System can be placed in operation at 350 psi RCS pressure, 350°F RCS temperature in 15-18 hours.

IODINE

As of 3:30 p.m., a plume approximately ½ mile wide and reading generally 1 mr/hr was moving to the north of the plant. The ARM's helicopter is being used to define the length of the plume. Airborne iodine levels of up to 1×10^{-6} µCi/ml have been detected in Middletown, Pennsylvania, which is located north of the site.

Media interest is continuing. The Commonwealth of Pennsylvania is being kept informed by plant personnel.

Contact: EKlingler, IE x28019 FNolan, IE x28019 SEBryan, IE x28019

Transmitted H St 10:30

Distribution:
Chairman Hendrie
Commissioner Kennedy
Commissioner Gilinsky
Commissioner Bradford
Commissioner Ahearne
S. J. Chilk, SECY
C. C. Kammerer, CA
(For Distribution)

Transmitted: MNBB 10:25
L. V. Gossick, EDO
H. L. Ornstein, EDO
J. J. Fouchard, PA
N. M. Haller, MPA
J. G. Ryan, OSP
H. K. Shapar, ELD

10:32
P. Bldg
H. R. Denton, NRR
R. C. DeYoung, NRR
R. J. Mattson, NRR
V. Stello, NRR
R. S. Boyd, NRR
SS Bldg 10:36
W. J. Dircks, NMSS

J. G. Davis, IE
Region I 10:33

(MAIL)
J. J. Cummings, OIA
R. Minogue, SD

~~7904110346~~

Reactor Accident Consequences

PLANT/LOCATION	PEAK EARLY DEATHS[1]	PEAK EARLY INJURIES[2]	PEAK FATAL RADIUS IN MILES[3]	PEAK INJURY RADIUS IN MILES[3]	SCALED FINANCIAL CONSEQUENCES IN BILLIONS[4]
Arkansas 1(O), Russellville, Ark	2,550	6,010	17.5	35	$64.1
Arkansas 2(O), Russellville, Ark					84.9
Beaver Valley 1(O), Shippingport, Pa	24,400	271,000	20	55	122.0
Bellefonte 1(C), Scottsboro, Ala	3,300	6,900	10	30	86.1
Bellefonte 2(C), Scottsboro, Ala					87.7
Big Rock Point (O), Charlevoix, Mich	3,450	6,030	17.5	40	13.7
Braidwood 1(C), Joliet, Ill	6,750	63,300	15	40	127.9
Braidwood 2(C), Joliet, Ill					122.0
Browns Ferry 1(O), Decatur, Ala	19,400	47,700	20	30	67.3
Browns Ferry 2(O), Decatur, Ala					69.1
Browns Ferry 3(O), Decatur, Ala					73.0
Brunswick 1(O), Brunswick, N.C	10,100	33,700	20	45	56.5
Brunswick 2(O), Brunswick, N.C					53.9
Byron 1(C), Rockford, Ill	9,050	79,300	15	60	114.0
Byron 2(C), Rockford, Ill					114.0
Calvert Cliffs 1(O), Lusby, Md	7,090	23,900	20	35	87.4
Calvert Cliffs 2(O), Lusby, Md					92.0
Catawba 1(C), Rock Hill, S.C	41,900	87,400	20	30	101.0
Catawba 2(C), Rock Hill, S.C					93.7
Clinton (C), Clinton, Ill	1,940	44,700	15	60	92.8
Comanche Peak 1(C), Glen Rose, Tex	1,210	13,800	25	35	117.0
Cook 1(O), Bridgman, Ill	2,060	92,700	15	70	91.9
Cook 2(O), Bridgman, Ill					101.0
Cooper (O), Brownville, Neb	2,270	5,420	25	35	57.7
Crystal River 3(O), Red Level, Fla	1,160	6,630	20	35	53.8
Davis Besse (O), Ottawa, Ohio	1,790	110,000	15	70	84.0
Diablo Canyon 1(O), San Luis Obispo, Calif	10,600	12,400	17.5	35	155.0
Diablo Canyon 2(O), San Luis Obispo, Calif					158.0
Dresden 1(O), Morris, Ill	34,600	71,400	15	60	23.5
Dresden 2(O), Morris, Ill					87.4
Dresden 3(O), Morris, Ill					89.6
Duane Arnold (O), Palo, Iowa	6,790	37,800	25	35	71.8
Farley 1(O), Dothan, Ala	15,100	19,600	20	40	52.2
Farley 2(O), Dothan, Ala					54.1
Fermi 2(C), Lagoona Beach, Mich	8,150	349,000	15	70	136.0
Fitzpatrick (O), Scriba, N.Y	1,520	28,800	17.5	40	103.0
Fort Calhoun (O), Washington, Neb	8,980	179,000	25	35	47.5
Fort Saint Vrain (O), Fort St. Vrain, Colo	17,200	32,800	17.5	65	38.8
Callaway 1(C), Callaway, Mo	11,300	31,200	17.5	35	110.0
Ginna (O), Ontario, N.Y	5,480	98,900	12.5	40	61.0
Grand Gulf 1(O), Vicksburg, Miss	3,890	8,220	20	40	83.0
Grand Gulf 2(C), Vicksburg, Miss					70.7
Haddam Neck (O), Haddam Neck, Conn	60,600	144,000	17.5	50	74.1
Hatch 1(O), Baxley, Ga	972	8,280	20	70	51.0
Hatch 2(O), Baxley, Ga					56.0
Indian Point 2(O), Buchanan, N.Y	56,600	227,000	17.5	50	274.0
Indian Point 3(O), Buchanan, N.Y					314.0
Kewaunee (O), Carlton, Wis	2,190	53,200	12.5	40	46.9
LaSalle 1(O), Ottawa, Ill	14,900	13,900	15	60	118.0
LaSalle 2(C), Ottawa, Ill					120.0
La Crosse (O), La Crosse, Wis	3,090	14,600	15	35	16.0
Limerick 1(C), Montgomery, Pa	77,700	710,000	20	35	213.0
Limerick 2(C), Montgomery, Pa					197.0
Maine Yankee (O), Wiscasset, Maine	11,600	19,400	15	35	78.5
Marble Hill 1(C), Jefferson, Ind	12,300	158,000	15	60	87.2
Marble Hill 2(C), Jefferson, Ind					83.8
McGuire 1(O), Cornelius, N.C	11,600	19,400	15	35	106.0
McGuire 2(C), Cornelius, N.C					110.0
Midland 1(C), Midland, Mich	10,300	36,200	12.5	40	56.1
Midland 2(C), Midland, Mich					80.4
Millstone 1(O), Waterford, Conn	23,600	28,800	20	65	91.5
Millstone 2(O), Waterford, Conn					135.0
Millstone 3(C), Waterford, Conn					174.0
Monticello (O), Monticello, Minn	1,310	30,900	15	35	44.6
Nine Mile Point 1(O), Scriba, N.Y	1,520	28,800	12.5	40	46.2
Nine Mile Point 2(C), Scriba, N.Y					134.0
North Anna 1(O), Mineral, Va	2,290	9,320	20	35	66.0
North Anna 2(O), Mineral, Va					69.3
Oconee 1(O), Seneca, S.C	5,630	76,400	20	30	56.8
Oconee 2(O), Seneca, S.C					58.3
Oconee 3(O), Seneca, S.C					58.3
Oyster Creek (O), Toms River, N.J	24,300	36,700	17.5	35	79.8
Palisades (O), South Haven, Mich	1,700	15,000			32.6
Palo Verde 1(C), Maricopa, Ariz	2,580	29,500	30	60	84.7
Palo Verde 2(C), Maricopa, Ariz					86.1
Palo Verde 3(C), Maricopa, Ariz					79.5
Peach Bottom 2(O), Peach Bottom, Pa	74,300	50,900	30	55	119.0
Peach Bottom 3(O), Peach Bottom, Pa					119.0
Perry 1(C), Painesville, Ohio	4,960	166,000	15	70	102.0
Perry 2(C), Painesville, Ohio					86.8
Pilgrim (O), Plymouth, Mass	5,170	72,800	20	65	81.8
Point Beach 1(O), Two Creeks, Wis	3,290	39,000	12.5	40	41.4
Point Beach 2(O), Two Creeks, Wis					42.8
Prairie Island 1(O), Red Wing, Minn	3,700	13,400	15	35	48.3
Prairie Island 2(O), Red Wing, Minn					49.5
Quad Cities 1(O), Cordova, Ill	16,800	76,400	15	60	65.1
Quad Cities 2(O), Cordova, Ill					65.1
Rancho Seco (O), Clay Station, Calif	35,700	50,400	20	45	113.0
Robinson (O), Hartsville, S.C	2,400	19,600	20	30	42.5
St. Lucie 1(O), Ft. Pierce, Fla	7,510	12,400	20	20	54.3
St. Lucie 2(C), Ft. Pierce, Fla					59.1
Salem 1(O), Salem, N.J	102,000	75,700	20	35	135.0
Salem 2(O), Salem, N.J					[illegible]
San Onofre 1(O), San Clemente, Calif	27,800	24,300	17.5	[illegible]	58.0
San Onofre 2(O), San Clemente, Calif					186.0
San Onofre 3(O), San Clemente, Calif					172.0
Seabrook 1(C), Seabrook, N.H	6,680	26,800	30	65	161.0
Seabrook 2(C), Seabrook, N.H					150.0
Sequoyah 1(O), Daisy, Tenn	29,500	60,600	20	30	46.6
Sequoyah 2(O), Daisy, Tenn					46.6
Shearon Harris 1(C), Apex, N.C	12,400	46,300	20	30	48.5
Shearon Harris 2(C), Apex, N.C					47.8
Shoreham (C), Wading River, N.Y	52,600	130,000	17.5	50	[illegible]
South Texas 1(C), South Texas, Tex	15,200	8,710	25	25	112.0
South Texas 2(C), South Texas, Tex					[illegible]
Summer (O), Fairfield, S.C	6,280	110,000	20	30	66.2
Surry 1(O), Gravel Neck, Va	41,900	69,300	20	35	56.3
Surry 2(O), Gravel Neck, Va					57.8
Susquehanna 1(O), Berwick, Pa	70,600	52,900	20	35	143.0
Susquehanna 2(C), Berwick, Pa					137.0
Three Mile Island 1(O), Middletown, Pa	56,100	90,800	20	55	102.0
Three Mile Island 2(O), Middletown, Pa					122.0
Trojan (O), Prescott, Ore	1,110	14,300	17.5	35	89.7
Turkey Point 3(O), Florida City, Fla	48,300	106,000	20	20	47.3
Turkey Point 4(O), Florida City, Fla					48.6
Vermont Yankee (O), Vernon, Vt	10,300	11,100	15	35	68.8
Vogtle 1(C), Burke, Ga	241	40,000	20	70	70.3
Vogtle 2(C), Burke, Ga					67.3
Waterford 3(C), St. Charles, La	90,400	253,000	20	40	131.0
Watts Bar 1(C), Rhea, Tenn	3,340	11,100	20	30	86.8
Watts Bar 2(C), Rhea, Tenn					81.3
Wppss 1(C), Richland, Wash	216	17,000	17.5	30	80.6
Wppss 2(C), Benton, Wash	300	14,700	17.5	30	77.3
Wppss 3(C), Olympia, Wash	173	13,800	17.5	30	73.7
Wolf Creek (C), Burlington, Kan	1,100	3,130	25	35	105.0
Yankee Rowe (O), Rowe, Mass	11,200	16,800	17.5	30	21.4
Zimmer (C), Moscow, Ohio	12,390	196,000	20	30	94.5
Zion 1(O), Zion, Ill	14,300	181,000	15	70	146.0
Zion 2(O), Zion, Ill					146.0

(O) INDICATES THE PLANT IS COMPLETE (C) INDICATES THE PLANT IS UNDER CONSTRUCTION

All figures taken from CRAC2 computer run microfiche performed by Sandia National Laboratories under contract to the U.S. Nuclear Regulatory Commission. All consequence figures except cost are based on an 1120-megawatt reactor, the occurrence of a "Group 1" release, and "summary evacuation." Cost figures are scaled according to reactor size. "Peak" values are the maximum calculated consequences for early deaths, early injuries, cancer deaths, fatal radius, and injury radius.

[1] Early deaths are deaths that occur within one year of exposure. [2] Early injuries are radiation-related injuries which appear within a year of exposure and which require medical attention.

[3] The peak fatal radius and peak injury radius are the maximum distances from the plant at which early deaths and early injuries are projected to occur.

[4] Scaled costs are in 1980 dollars. Several classes of accident-related costs are not included in these estimates, such as socioeconomic costs, health care costs, and "incidental costs" (e.g., shutdown of adjacent reactors, loss of industrial capacity and jobs, etc.).

NRC ADMITS SEVERITY OF ACCIDENTS

The NRC Report on Reactor Accident Consequences was released to the press on November 1, buried and neglected by all but the Washington Post on the day before the midterm elections. The Consequence Report was conducted by Sandia National Laboratories; it is based upon a complex, sophisticated computer code, CRAC-2, using comprehensive population, meteorological, and economic data to assess the impacts of a catastrophic reactor accident.

The version obtained by U.S. Congressman Ed Markey (D-Mass) is based on the assumption of a very severe core melt, failure of essentially all safety systems and breach of containment, with a large radioactive release to the atmosphere. The Washington Post stated that the figures it was publishing on deaths, injuries, and financial damages are not "worst-case" numbers.

News from ECNP is reproducing the complete table of consequences as it appeared in the Post. We urge you to "spread the word," especially because many newspapers have printed only NRC's subsequent obfuscations that attempt to belittle the vast importance of this Sandia Consequence Study. Note that it is not a study of the probability of accidents, although the Post states that NRC has estimated the probability of such an accident as 1 in 100,000 reactor-years of operation -- a 2% chance before the year 2000, given the number of U.S. reactors.

The "Group 1" scenario for Salem could produce 102,000 "early deaths." At Peach Bottom, Susquehanna, and Limerick over 70,000 early fatalities. Some 56,000 at TMI; 24,000 at Beaver Valley. The financial consequences from one such accident at Indian Point are estimated at a stunning $314 billion. (Recall that Price-Anderson nuclear liability coverage remains at a mere $560 million.) And socioeconomic and health care costs are excluded as are losses of industrial capacity. These data largely confirm the 1964-65 Revision of the Brookhaven Report.

Source: Washington Post, 11/1/82

UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF INSPECTION AND ENFORCEMENT
WASHINGTON, D.C. 20555

October 14, 1982

IE BULLETIN NO. 82-03: STRESS CORROSION CRACKING IN THICK-WALL, LARGE-DIAMETER, STAINLESS STEEL, RECIRCULATION SYSTEM PIPING AT BWR PLANTS

Description of Circumstances:

During a primary system hydrotest in March 1982 at Nine Mile Point Unit 1 (NMP-1), leakage was visually detected at two of the ten furnace-sensitized, recirculation system safe-ends. Further visual inspection revealed three pinhole indications and a single ½-inch-long axial indication, all of which were located in the heat-affected zone of the welds where the safe-end joined the pipe. About nine months before the leak, these safe-ends were ultrasonically (UT) inspected; at that time, the inspection did not disclose any reportable indications. Subsequent to the leak, the UT procedure was modified; UT

examination of the two affected safe-ends and one other safe-end confirmed the presence of indications of intermittent cracking around the pipe's inside diameter (ID). Additional examinations revealed cracking in heat affected zones of recirculation pump discharge welds. Dye penetrant examination confirmed these crack indications. The UT examinations were extended to other welds in the five loops of the recirculation system. The results of these examinations disclosed ID cracking in a large number of the welds examined.

Two boat samples removed from the area of the through-wall cracks in one safe-end were sent for evaluation -- one to General Electric Co. and the other to Battelle Laboratories. In addition, a boat sample from the crack region of the elbow weld was evaluated by Sylvester Associates, consultants to the licensee. The results of these metallurgical evaluations concluded that the degradation resulted from intergranular stress corrosion cracking (IGSCC) in the sensitized region of the weld's heat affected zones.

Based on the fact that NMP-1 has furnace-sensitized safe-ends, the licensee decided to replace all 10 recirculation system safe-ends without further investigation beyond that described above. Based on recirculation system findings, the licensee decided to also replace all recirculation system piping while the facility was shut down for safe-end replacement.

On September 16, 1982, a meeting was held between General Electric, BWR licensees, and NRC staff to review past IGSCC experiences and the general implications of NMP-1 IGSCC degradation in main recirculation piping welds. The staff had the benefit of the metallurgical evaluation of the NMP-1 event and an update of the general IGSCC experiences relative to all operating BWR plants.

On September 27, 1982, a meeting was held between BWR licensees and the NRC staff to discuss the extent and results of examining welds in the recirculation system for all BWR licensees with plants currently in or scheduled to be in a refueling mode or extended outage through January 31, 1983. As a result of this meeting, the NRC staff has determined that additional information is needed to assess the effectiveness of the UT methods employed or planned to be used and to determine whether such piping should be designated "service-sensitive" in accordance with NUREG-0313, Rev. 1, issued by NRC letter dated February 26, 1981.

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SSINS No.: 6820
OMB No.: 3150-0094
Expiration Date: 11/30/85
IEB 82-04

UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF INSPECTION AND ENFORCEMENT
WASHINGTON, D.C. 20555

December 3, 1982

IE BULLETIN NO. 82-04: DEFICIENCIES IN PRIMARY CONTAINMENT ELECTRICAL PENETRATION ASSEMBLIES

Description of Circumstances:

Several deficiencies in containment electrical penetrations supplied by Bunker Ramo, have been identified. A summary of these deficiencies is provided below:

1. On January 15, 1979, Consumer Power Company submitted 10 CFR 50.55(e) report No. 78-12 for the Midland nuclear facility identifying deficiencies associated with #10 AWG and smaller wire terminations located in the inboard terminal boxes of Bunker Ramo penetration assemblies. The deficiencies identified included improper lug crimps, incorrect lug types, and loose connections on terminal blocks. These deficiencies were attributed, in part, to an inexperienced employee at Bunker Ramo.

2. On March 26, 1980, Union Electric Company submitted 10 CFR 50.55(e) report No. 80-03 for the Callaway nuclear facility identifying deficiencies associated with electrical penetration assemblies supplied by Bunker Ramo. The deficiencies included improperly crimped lugs and improperly identified penetration cables. During hand-pull tests, at least 38 wires separated from their lugs. It was reported that this deficiency resulted when Bunker Ramo overcrimped and undercrimped lugs.

3. On June 12, 1980, the NRC was informed by Standardized Nuclear Unit Power Plant Systems (SNUPPS) that additional inspections at the Wolf Creek nuclear facility identified further concerns regarding the quality and integrity of Bunker Ramo electrical penetration terminations. Deficiencies identified at the Wolf Creek facility included improperly crimped lugs and incorrectly sized lugs.

4. On October 2, 1980, Commonwealth Edison submitted 10 CFR 50.55(e) report No. 80-02 for the LaSalle County Station Unit 2 facility identifying cracked or missing insulation (exposing bare copper) on small-diameter conductors as they enter/exit the epoxy module portion of the Bunker Ramo electrical penetrations. The report stated, in part, "The cracking was determined to have resulted from stress points in the insulation created by a mechanical bond between the potting compound (used to form the over-mold portion of the module) and the insulation. Movement of the conductors entering or exiting the modules produced cracks along the stress points."

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5. On March 31, 1982, the NRC was advised through a 10 CFR 21 report that deficiencies have been identified in Bunker Ramo electrical penetrations installed at the Midland nuclear facility. The deficiencies involve #2, #6, #8, #10, #14, and #16 AWG splices and cracks in the insulation of some conductors as they emerge from certain types of modules. The deficiencies were reported to have occurred when site personnel moved cables to inspect for rodent damage.

6. On April 8, 1982, Consumers Power Company submitted 10 CFR 50.55(e) report No. 82-02 for the Midland nuclear facility identifying deficiencies in Bunker Ramo electrical penetrations. The identified deficiencies included cracks in conductor insulation at the conductor-module interface (resulting in some exposure of the module copper conductors) and inadequately crimped butt splices (resulting in several #2 AWG butt splices being pulled apart). These deficiencies were observed in installed electrical penetrations. In addition, similar deficiencies were observed in crated electrical penetrations and spare module assemblies stored in warehouse facilities. The cracked insulation was reported to have probably been caused by a chemical/mechanical reaction between the module materials, mechanical stresses resulting from the module design, and a lack of explicit handling/packing instructions reflecting the fragility of the electrical penetrations/modules. The inadequately crimped butt splices were reportedly caused by a breakdown in the fabrication/design of the module assemblies.

The above deficiencies have all been identified on Bunker Ramo electrical penetrations utilizing a hard epoxy module design. In addition to the above construction sites, Bunker Ramo has identified the Comanche Peak, Byron and Braidwood sites as using this design. These deficiencies could result in failures of Class 1E equipment essential to the safe operation and shutdown of nuclear facilities. The potential failures which could occur include electrical short-circuits, localized circuit overheating, adjacent circuit cross-talk, and circuit discontinuities.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF INSPECTION AND ENFORCEMENT
WASHINGTON, D.C. 20555

July 22, 1982

IE INFORMATION NOTICE NO. 82-26: RCIC AND HPCI TURBINE EXHAUST CHECK VALVE FAILURES

Addressees:

All boiling water nuclear power reactor facilities holding an operating license or construction permit.

Purpose:

This information notice is provided as an early notification of a potentially significant problem pertaining to reactor core isolation cooling (RCIC) and high pressure coolant injection (HPCI) turbine exhaust check valve failures. It is expected that recipients will review the information for applicability to their facilities. No specific action or response is required at this time.

Description of Circumstances:

A number of RCIC turbine exhaust check valve failures that have occurred during the past 20 months are outlined below.

1. On December 10, 1980, Carolina Power and Light Company reported (LER 80-101/03L) a RCIC system turbine trip at Brunswick Steam Electric Plant, Unit 2, while conducting a RCIC system test. The turbine tripped on high turbine exhaust pressure due to the turbine exhaust swing check valve failing in the closed position. Inspection revealed the check valve disc stem had broken off where it connects to the valve hinge assembly. This allowed the disc to fall into the discharge part of the valve and isolate flow. An examination of the check valve disc and hinge assembly indicated the disc had been rotating inside of the hinge bore area and caused excessive wear of both components. In addition, indications that the valve disc had been striking the upper part of the valve body while in the open position were noted. To return the check valve to normal operability, the valve seat was lapped, the valve disc replaced, and the valve was tested satisfactorily.

   This LER also referred to a similar failure (LER 79-074/03L) at Brunswick Steam Electric Plant, Unit 1. This time, disassembly of the RCIC steam exhaust check valve showed that the stud and nut on the back of the disc had broken and the disc had separated from the hinge and had lodged in the valve inlet. A new valve was ordered and installed upon arrival. The valve failure prevented the RCIC turbine, which had been used intermittently throughout the day for vessel level control, from starting following a reactor scram.

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2. On May 29, 1981, Pennsylvania Power and Light Company reported (ERs 100450/100508) the failure of the RCIC turbine exhaust swing check valve at Susquehanna Steam Electric Station, Unit 1, while conducting a RCIC system test. The stud (integrally cast with the disc) which attached the disc to the valve hinge broke off. In a subsequent report on February 5, 1982, they indicated that turbine exhaust steam flow conditions experienced during testing caused the valve disc to cycle violently open and close. Since the check valve was sized for full flow, operational testing of the system at low flow caused the disc function to be erratic. As a result, the end of the disc stud gradually wore a hole in the valve bonnet (cover) which served as the stop. This additional travel allowed the disc edge to impact against the valve body due to a lack of clearance. The loads and stresses experienced by the disc resulted in a disc stud fracture. The failure was a brittle fracture. A second disc, taken from Unit 2, was put in service to replace the fractured disc. This disc also failed at approximately the same section as the first. Therefore, they concluded that with both the valve and system as presently designed, a swing check valve disc will fail for this service application. This was further evidenced by three more replacement discs that eventually broke in a similar fashion in spite of the provision of a specially designed "anvil" nut to replace the original nut. They are planning on either replacing the existing valve with a lift type check valve design having an inherent damping action in the opening position or modifying the existing valve and/or piping system so that the valve will function properly under both low and high flow conditions. (See IE Information Notice No. 82-20.)

3. On December 10, 1981, Georgia Power Company reported (LER 81-112/03L) a RCIC isolation at Edwin I. Hatch Nuclear Plant, Unit 2, while conducting a RCIC rated flow test. An investigation revealed that the turbine exhaust check valve had internal damage creating a block in the line causing the rupture diaphram to fail. The valve was repaired and the diaphram replaced. A design change has been approved to replace the check valve with a better design. The new valve has been ordered and will be installed as soon as possible.

   A generic review, by the licensee, revealed that the HPCI system has the same valve type in a similiar configuration and that a design change has been approved to replace the valve.

4. On March 9, 1982, Long Island Lighting Company reported a deficiency concerning two check valves located in the RCIC turbine exhaust line at Shoreham Nuclear Power Station. The deficiency was identified while testing the turbine and pump using auxiliary steam at low flow conditions. Examination of the valves disclosed that the slamming and cyclic action of the valve resulted in wear to the swing check bushings, the anti-rotation pins, and the swing checks. The valve bodies showed rubbing marks from the interaction with the swing check. A systems review of the valve failures, by the licensee, indicated that damage to these components could have an

impact on the turbine exhaust back pressure thereby causing the turbine to trip. All damaged components of the RCIC exhaust check valves will be replaced and the valves will be rebuilt to assure properly conditioned and working valves are installed.

Discussion:

All of the above failures deal only with the RCIC turbine exhaust check valve. However, as noted by Georgia Power Company, the HPCI exhaust system has the same type valve in a similiar system configuration. Thus it is reasonable to expect similiar problems with the HPCI turbine exhaust check valve also. In fact, both services have been identified in the generic correspondence by General Electric pertaining to this topic.

The first of the generic correspondence is Services Information Letter (SIL) No. 30, "HPCI/RCIC Turbine Exhaust Line Vacuum Breakers," dated October 31, 1973. In this SIL, General Electric identified the problem of possible damage to the exhaust line check valve and recommended the installation of vacuum breakers based on tests conducted at Browns Ferry and Peach Bottom.

The second of the generic correspondence is Application Information Document (AID) No. 56, "High Pressure Core Injection and Reactor Core Isolation Cooling Turbine Exhaust Check Valve Cycling," dated December 18, 1981. In this AID, General Electric identified the possible causes of failure as improper system operation, improper check valve sizing, inadequate check valve design, or inadequate exhaust line design. To minimize the possibility of future problems, they recommend that:

1. Manual starts and monthly system surveillance testing should be performed in accordance with the Operating and Maintenance Instructions (specifically, gradually increasing the turbine speed until the rated pump discharge flow is achieved is not recommended).

2. The exhaust check valve, the exhaust line vacuum breaker, and the exhaust line sparger should be designed in accordance with the requirements/recommendations given in the GE system design specification.

3. System operation below the recommended turbine rated speed should be minimized.

4. The exhaust check valve should be located as close as possible to the containment.

5. The turbine exhaust check valve internals should be visually inspected on a routine schedule such as at every refueling outage.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF INSPECTION AND ENFORCEMENT
WASHINGTON, D.C. 20555

July 23, 1982

IE INFORMATION NOTICE NO. 82-28: HYDROGEN EXPLOSION WHILE GRINDING IN THE VICINITY OF DRAINED AND OPEN REACTOR COOLANT SYSTEM

Addressees:

All nuclear power reactor facilities holding an operating license (OL) or construction permit (CP).

Purpose:

This information notice is provided as a notification of an event that may have safety significance. It is expected that recipients will review the information for applicability to their facilities. No specific action or response is required at this time.

Description of Circumstances:

On April 10, 1982, a hydrogen explosion occurred at Unit 1 of Arkansas Nuclear One while maintenance personnel were grinding a recently cut high-pressure injection (HPI) pipe, approximately 18 inches from the nozzle connecting the HPI pipe to the reactor coolant system (RCS) piping. At the time of the explosion, the RCS was partially drained and the water level in the reactor coolant piping was just below the HPI nozzle to permit radiography of the nozzle and subsequent repair. (IE Information Notice No. 82-09 provides details concerning the cracking problem in HPI piping at Babcock & Wilcox plants.) The reactor coolant temperature was being maintained at approximately 100°F by the decay heat removal system, and nitrogen cover gas was being maintained in the reactor coolant piping. These conditions existed since the RCS was depressurized and partially drained on March 29, 1982.

At approximately 1240 hours on April 10, 1982, the craftsmen, who were grinding on the HPI pipe in preparation for welding, observed a bright flash at the outlet of the HPI line and heard a loud "bang". The craftsman actually performing the grinding was physically blown away from the HPI pipe a distance of about three feet. Personnel in other areas of the Unit 1 containment building heard the explosion and felt the resulting concussion and mechanical vibration. Additionally, some personnel outside of the containment building, including operators in the Unit 1 control room reported that they heard the explosion and felt varying degrees of vibration. Although there were no physical injuries as a result of this event, it should be mentioned that the craftsman's life was endangered as he was working on a scaffold that was over 30 feet high. X

The most recent RCS measurement of dissolved gas in reactor coolant had been taken on March 26, 1982, just before commencing the plant cooldown and shutdown. It indicated 39 standard cc of total gas/liter of coolant. The hydrogen

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concentration was 43% of this total. Because the total gas concentration exceeded the maximum allowed by plant procedures (30 cc/liter) for RCS depressurization, the RCS was degassed for approximately 14 hours as cooldown progressed. The total gas concentration was not measured after degassing had been terminated because the RCS had been depressurized and the sampling method is effective only when the RCS pressure is greater than several hundred psig. Atmospheric samples had not been taken to measure hydrogen and oxygen concentrations in the vicinity of the open HPI pipe. (This had been done at other Babcock and Wilcox plants which were undergoing nozzle repair.)

The reason for the presence of an explosive concentration of hydrogen is unknown. It could have been caused by (a) inadequate degassing, (b) failure to purge the HPI pipe with nitrogen, or (c) failure to temporarily plug the open HPI pipe. How long can we afford these guessing games? J.T.L.

Subsequent inspection of the affected HPI line, the first upstream check valve in the HPI line, and the corresponding nozzle and safe-end on the RCS cold leg indicated no signs of damage as a result of the explosion.

No written response to this information is required. If you need more information about this matter, please contact the Regional Administrator of the appropriate NRC Regional Office or this office.

Robert Baer

for Edward L. Jordan, Director
Division of Engineering and
Quality Assurance

Technical Contact: W. Marinelli
301-492-9654

Attachment:
List of Recently Issued IE Information Notices

UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF INSPECTION AND ENFORCEMENT
WASHINGTON, D.C. 20555

July 23, 1982

IE INFORMATION NOTICE NO. 82-29: CONTROL ROD DRIVE (CRD) GUIDE TUBE SUPPORT PIN FAILURES AT WESTINGHOUSE PWRS

Addressees:

All nuclear power reactor facilities holding an operating license (OL) or construction permit (CP) using a Westinghouse-designed NSSS.

Purpose:

This information notice is provided as notification of an event that may have safety significance. It is expected that recipients will review the information for applicability to their facilities. No specific action or response is required.

Description of Circumstances:

Since 1978, several failures of the control rod drive (CRD) guide tube support pins have occurred. Westinghouse has notified NRC of these occurrences by the following correspondence:

1. June 11, 1979, NS-TMA-2099, Letter to D. Eisenhut from T. M. Anderson concerning support pin and flexure failures in Japan.
2. March 14, 1980, NS-TMA-2214, Letter to Victor Stello from T. M. Anderson; Title 10 CFR Part 21 notification concerning CRD Guide Tube Support Pin Failures at Foreign Plants.
3. April 23, 1980, NS-TMA-2235, Letter to Stephen S. Pawlicki from T. M. Anderson summarizing Westinghouse/TVA/NRC meeting on May 20, 1980 on Sequoyah guide tube support pins.
4. June 10, 1980, NS-TMA-2254, Letter to Stephen Pawlicki from T. M. Anderson concerning inspection of support pins.
5. May 20, 1982, NS-EPR-2251, Letter to Victor Stello from E. P. Rahe, Jr., concerning a pin failure at Graveline 1.

Prior to May of this year, at which time a guide tube pin failed at North Anna 1, these failures had occurred only at foreign reactors (Japan and France). The pins are used to align the bottom of the CRD guide tube assembly into the top of the upper core plate. Two support pins are bolted into the bottom plate of each lower guide tube, and are inserted into the top of the upper core plate in a manner that provides lateral support while accommodating thermal expansion of the guide tube relative to the core plate (see attached pin assembly diagram). The pins are about 3½ inches long and have a diameter of 0.507 or 0.537 inch (depending on reactor design). The pin assembly includes (1) a bolt section

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to which a nut (sleeve) is threaded to anchor the pin to the guide tube, (2) a collet that rests against the guide tube, and (3) a leaf spring section with the leaf shaped somewhat like a clothespin. The material is Inconel X-750, which, depending on the manufacturer and the fabrication date, has been solution heat treated and age hardened at various temperatures and for various times. For example, the solution heat treatment temperatures and times ranged from 1625°F to 2100°F and from ½ hour to 24 hours; age hardening temperatures and times ranged from 1148°F to 1544°F and from 8 hours to 20 hours, respectively.

The first failures were detected in early 1978 at Mihama Unit 3 in Japan, at which time the top portion of a support pin with the shank and lock nut engaged was found in a steam generator. Subsequent ultrasonic testing (UT) showed a possibility of cracks in 103 out of 105 pins at the bolt to collet transition region of the pin. Seven of the Mitsubishi-supplied pins were then removed and inspected, confirming the UT results. All pins were subsequently replaced and UT inspection was conducted at other Japanese plants. In all, there have been at least eight support pin failures where a pin has actually broken. These occurred with both Westinghouse and Mitsubishi-supplied pins.

In a recent failure at Fessenheim Unit 1 in France,part of a broken pin caused considerable damage to a steam generator within 72 hours of its failure. It is estimated that the plant will be shutdown for about a year to repair the steam generator. Although the broken part consists of the bolt section including the nut, only the lock nut of the pin has been found and the bolt portion is still missing. Previous to the Fessenheim failure, a leaf from a support pin was found in an accumulator check valve at Graveline 1 in France. It is not known how the leaf traveled to the check valve.

The only domestic pin failure occurred in May 1982 at North Anna 1. The lock nut of a support pin was found in steam generator "A" and a smaller piece of material, also identified as part of a support pin, was found in steam generator "C." Damage to the steam generators is considerable, with about 75% of the tube ends sustaining damage. It is our understanding that the plant was shutdown in less than 24 hours after detecting the loose parts in the steam generators. It is also our understanding that the reactor internals will be video inspected to determine the status of the remaining support pins.

Westinghouse's analysis indicated that the failures are caused by stress corrosion cracking (SCC) of pins that are solution heat treated at less than 1800°F after which they are age hardened, and then highly stressed (60,000 psi nominal on the shank and 130,000 psi on the leaf spring section of the pin). The solution heat treatment of the North Anna 1 support pin was 1625°F for 1 hour followed by an age hardening treatment. The torque on the nut was 210 ft-lb. Westinghouse now recommends that the pins be solution heat treated at 2000°F for 1 hour and age hardened at 1300°F for 20 hours to minimize the SCC problem. Westinghouse also recommends that the torque on the lock nut be reduced to 130 to 140 ft-lb.

The consequences of pin failure for plants with the upper head injection (UHI) design was originally considered to be more acute than those for non-UHI plants. This concern resulted from the potential for CRD misalignment in UHI plants on pin failure. However, domestic operating UHI plants now have support pins meeting the recommended material process standards and the pin body design has been revised to prevent control rod misalignment on pin failure.

Westinghouse does not consider CRD misalignment as credible in non-UHI plants. The safety consequence of a support pin as a loose part, however, is still under consideration by NRC. It is important to note that, although a single-pin failure is of limited safety significance, the common-mode failure mechanism of stress corrosion cracking could cause several pins to fail. We are concerned that, if not properly detected, multiple pin failures may occur that could affect redundant safety systems.

If you have any questions regarding this matter, please call the appropriate regional administrator or this office.

Robert Baer

for Edward L. Jordan, Director
Division of Engineering and
Quality Assurance

Technical Contact: I. Villalva, IE
301-492-9635

Attachments:
1. Pin Assembly Diagram
2. List of Recently Issued IE Information Notices

SSINS No.: 6835
IN 82-31

UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF INSPECTION AND ENFORCEMENT
WASHINGTON, D. C. 20555

July 28, 198_

IE INFORMATION NOTICE NO. 82-31: OVEREXPOSURE OF DIVER DURING WORK IN FUEL STORAGE POOL

Description of Circumstances:

On June 1, 1982, while installing fuel rack support plates in the Indian Point Unit No. 2 fuel storage pool, a contractor diver received an exposure of about 8.7 rems to the head. A second diver, also working in the pool on June 1, received a whole body dose of about 1.6 rems.

Upon exiting the pool the most highly exposed diver's 500 mR and 5-R pocket dosimeters (worn on the head) were off-scale. The licensee suspended all diving operations, read the multiple TLD's (thermoluminescent dosimeters) worn on other body locations, and initiated an investigation of the incident. The fuel storage pool modification work had been ongoing for about three months, with daily exposures averaging about 50 millirems per diver.

A review of the incident by licensee and NRC personnel found several factors that contributed to the overexposure:

(1) An irradiated fuel assembly was mistakenly transferred to a location two to four feet from the subsequent divers' work location. A poor-quality copy of the fuel transfer procedures was apparently a factor in the improper fuel transfer. Limited visability in the pool caused by cloudy water and a lack of pool underwater lighting may have prevented visual detection of the misplaced fuel assembly. No QA (quality assurance) reviews were required or conducted of the irradiated fuel assemblies locations between fuel movements and the exposure incident.

(2) The prior-to-work radiation survey of the pool was performed with an underwater ionization chamber connected by a long cable to the detector. These surveys failed to detect the misplaced fuel assembly's radiation field of several hundred R/hr within two feet of the divers work area. Intermittent, erratic underwater survey instrument behavior had been observed during previous dives. The licensee attributed the survey instrument's erratic behavior to a buildup of moisture in the underwater detector chamber housing.

(3) Radiation monitoring devices used during the underwater operations failed to function properly. Alarming dosimeters, mounted inside the divers' helmets, failed to alarm at the 200 mR set point. These dosimeters were under the control of the diving contractor and were not source checked on the day of the incident. The licensee monitored the dive with the same ionization chamber instrument used for the pre-dive survey, and failed to detect any radiation fields in excess of 1 R/hr in the diver work area.

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UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF INSPECTION AND ENFORCEMENT
WASHINGTON, D. C. 20555

SSINS No.:
IN 82-43

November 16, 1982

IE INFORMATION NOTICE NO. 82-43: DEFICIENCIES IN LWR AIR FILTRATION/ VENTILATION SYSTEMS

Description of Circumstances:

Within the past 2-1/2 years, air filtration/ventilation systems at five facilities were found to have serious deficiencies, ranging from overloaded prefilters to evidence of a wetted high-efficiency particulate air (HEPA) filter bank, to penetration of HEPA filter banks by substantive quantities of radioactive resin beads. Deficiencies occurred in both safety-related and non-safety-related systems.

In June 1982, radioactive spent resin was found on the grounds and roof areas at Pilgrim 1. Principal radionuclides were Co-60, Cs-137, Cs-134, and Mn-54; contamination ranged from 20,000 dpm/100 cm^2 to 100,000 dpm/100 cm^2. The contamination penetrated damaged filters in a non-safety-grade HEPA filter plenum. The degraded condition of these filters was not detected in a timely manner because of a lack of surveillance or testing of the filtration system. The HEPA filter failure occurred possibly as an end result of a combination of high dust loadings and mechanical damage resulting from the impact of disintegrating prefilters, as well as the probable warping or distortion of HEPA filter frames under prolonged exposure to water and high humidity.

In December 1980, the SGTS trains at Brunswick 1 were found to be operating at close to 100% humidity, and condensation was observed on the interior walls. Regulatory Guide 1.52 recommends operation at humidity of 70% or less; operation at high humidity is known to cause substantial degradation of the iodine-retention capacity of charcoal adsorbers. Also, in December 1980, both filter trains in the turbine building filter system at Brunswick were found to be operating with the upstream HEPA differential pressure gauges offscale high. Also, in the turbine building filter system, 43% of the upstream HEPA filters were improperly installed.

In August 1980, filters and charcoal adsorbers in the Surry 1 process vent exhaust air treatment system were determined to have been half submerged in water, and the HEPA filters were caked with dust. No pressure drop instrumentation was provided across the filter banks to ascertain their state of loading. Also, in August 1980, pressure drop gauges across the HEPA filter banks in the ventilation exhaust treatment system of the auxiliary building at Surry 1 exceeded 5 inches, which is offscale high; this condition had existed since May 1980.

In May 1980, the normal containment building exhaust filters at Turkey Point were found to be overloaded with dust to such an extent that the filter medium was separated from its frame in more than 50% of the filters. This apparently allowed radioactive contamination resulting from explosive plugging of steam generator tubes to be transported to the southeast sector of the plant site.

In March 1980, it was determined that HEPA filters in the Big Rock Point offgas and chemistry laboratory exhaust treatment systems were not being tested for leakage in place. No records were maintained of pressure differential across the laboratory HEPA filters which had not been replaced for at least five years.

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SSINS NO.: 6835
IN 82-41

UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF INSPECTION AND ENFORCEMENT
WASHINGTON, D. C. 20555

October 22, 1982

IE INFORMATION NOTICE NO. 82-41: FAILURE OF SAFETY/RELIEF VALVES TO OPEN AT A BWR

Description of Circumstances:

On July 3, 1982, Georgia Power Company's Hatch Unit 1 was operating at 100% power when a spurious high-pressure signal caused a reactor scram. The variation in pressure with time is shown in Figure 1. The main turbine had not tripped when a Group 1 isolation* occurred. High-pressure coolant injection (HPCI) and reactor core isolation cooling (RCIC) auto-started and injected and the recirculation pumps tripped. The main turbine was then manually tripped. When vessel water level recovered and reached the high water level trip set point, HPCI, RCIC, and the feedwater pump turbines tripped.

Gradual vessel repressurization continued beyond the high-pressure scram setpoint on a 0.5 psi/sec ramp without relief valve actuation. About 1180 psig, three safety/relief valves (SRVs) automatically actuated, relieving vessel pressure rapidly. Upon the SRVs' closure, the main steam isolation valves were manually reopened and the reactor was cooled and depressurized to cold shutdown. During cooling and depressurizing, the remaining eight SRVs were manually actuated and functioned properly.

The SRVs installed on Hatch 1 are the two-stage Target Rock model number 7567F (see Figure 2). All three SRVs that opened automatically were located on the same steam line and were the only valves on that line. Their setpoints were 1080, 1080, and 1090 psi. The remaining eight SRVs were set at 1080,

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*Closure of main steam isolation valves, main steam drain isolation valves, and recirculation loop sample isolation valves.

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1090, or 1100 psi. All had been refurbished and steam set at Wyle Labs during the previous refueling outage and had most recently been actuated in August of 1981.

Following the July 3, 1982 event, the top works or pilot section (see Figure 3) of all the SRVs were removed and sent to Wyle Labs, where they were tested in the as-received condition. Six passed their first test, four passed on retest, and the final valve passed on the second retest -- all without setpoint spring adjustment. The average first actuation pressure was 0.9% above nameplate with the highest pressure required being 4.1% above nameplate. No abnormal leakage characteristics were observed for any of the valves. No apparent mechanical failure was found in the top works at Wyle Labs or the valve bodies inspected at Hatch.

Three additional licensees--TVA, Northeast Nuclear Energy Company, and Boston Edison--had reported that two-stage Target Rock valves, tested in the as-received condition at Wyle Labs, failed to actuate within 1% of the setpoint. (Reference LER 50-259/81-25, 50-296/81-74, 50-293/81-62, 50-260/82-27). (The excessive leakage and the damaged internals of the Pilgrim valves may present quite a different problem from that of Hatch, Browns Ferry, or Millstone.) The Hatch 1 event of July 3, 1982 was potentially the most significant in terms of both (1) the fraction of valves that failed to open at their setpoint, and (2) the pressure above setpoint required to open the valves.

The General Electric Company (GE) and the Target Rock Company have joined Georgia Power in attempting to determine the cause of the failure of the valves to actuate. A GE analysis suggests that the most likely cause of the high actuation pressure is some combination of friction in the labyrinth seal area and/or sticking of the pilot disc in its seat. The slow repressurization ramp and the extended period during which the valves were not actuated are also considered possible contributors to the incident.

To define the problem and to improve the probability of actuation of the SRVs, Georgia Power has instituted a program at Hatch whereby nine of the eleven Unit 1 valves will be exercised regularly. Two valves will not be exercised and will be utilized for possible future testing. Unit 2 valves will be subjected to a similar program. Also, Georgia Power has arranged with GE and with cooperating licensees for screening tests to be done on additional SRVs at Wyle Labs. Valves which are pressurized at the 0.5 psi ramp to 103% of nameplate rating without actuating are to be candidates for diagnostic testing to determine the magnitude of forces in the disc-to-seat interface and the labyrinth seal area. Further, examination of interior surfaces will be conducted to locate any physical damage. Two such candidates were found in the recent testing of three SRVs belonging to Northeast Nuclear Energy Company's Millstone Unit 1.

SSINS No.: 6835
IN 82-37

UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF INSPECTION AND ENFORCEMENT
WASHINGTON, D. C. 20555

September 16, 1982

IE INFORMATION NOTICE NO. 82-37: CRACKING IN THE UPPER SHELL TO TRANSITION CONE GIRTH WELD OF A STEAM GENERATOR AT AN OPERATING PRESSURIZED WATER REACTOR

Description of Circumstances:

The Power Authority of the State of New York (PASNY) reported that, while Indian Point 3 was shut down for refueling in the spring of 1982, a leak was observed in the upper shell to transition cone girth weld of steam generator #32. Subsequent ultrasonic examinations of these welds on all four steam generators revealed that each generator had extensive indications of cracking. There was an average of 170 indications per steam generator, typically 3/4-inches deep by 4 to 6 inches long. One through-wall penetration was observed in steam generator #32. PASNY examined selected sections of other steam generator welds in accordance with inservice inspection requirements and found no other reportable indications.

The upper shell to transition cone weld is a difficult final closure weld. It had a local post weld heat treatment rather than a furnace post weld heat treatment. It is located just below the feedwater ring in the normal operating water level zone where it may be subjected to thermal cycling. This condition may be generic to all Westinghouse plants. The cracks have no apparent geometrical correlation with the configuration of the feedwater ring. Although there is a slight tendency for cracks to cluster near large weld repairs, most cracks do not occur at weld repairs. Nearly 40% of the cracks are reported to occur in weld metal. This weld was made by the submerged arc welding (SAW) process from the outside with the root backgouged and welded with the shielded metal arc welding (SMAW) process using 8018-C3 electrodes. No reportable indications were found in a 1978 ultrasonic inspection of 3 feet of this weld.

A preliminary metallurgical evaluation of boat samples containing cracks from steam generator #32 has tentatively established certain elements of the cracking to be characteristic of corrosion-fatigue. A full cross-section of the shell containing the leaking crack is currently being examined to further determine other possible causes that may have contributed to the cracking.

The Indian Point Unit 3 steam generators have experienced both fabrication and operational problems that may have accelerated the initiation and propagation of cracks. In regard to fabrication, the affected welds were subject to numerous weld repairs, after which a post weld heat treatment was performed locally rather than being given a furnace heat treatment to achieve the desired tempering and stress relief. In regard to operation, a long history of condenser events resulted in poor oxygen control. In January 1981, a turbine blade failed and fragments entered the condenser causing a massive intrusion of chlorides reaching 325 ppm. To date, the synergistic conditions that were primarily responsible for the cracking remain to be firmly established.

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SSINS NO. 6835
IN 82-45

UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF INSPECTION AND ENFORCEMENT
WASHINGTON, DC 20555

November 19, 1982

IE INFORMATION NOTICE NO. 82-45: PWR LOW TEMPERATURE OVERPRESSURE PROTECTION

Description of Circumstances:

In August of 1976, the issue of low temperature overpressure protection was raised and licensees initiated procedures and proposed systems to mitigate postulated overpressure events. The main concern was with the low temperature modes of cooldown and heatup, during which overpressurization could cause brittle fracture of the reactor vessel. In most cases, licensees proposed a manually enabled low pressure setpoint on the existing pressurizer power-operated relief valves (PORVs) supplemented by procedures and technical specifications.

The low temperature overpressure events at Turkey Point Unit 4, on November 28 and 29, 1981 have been designated by the Commission as abnormal occurrences. These events were described in IE Information Notice No. 82-17. The events were caused by failure of the backup train of the low temperature overpressure protection system (LTOPS) because of inadequate surveillance and valve lineup procedures. Following the Turkey Point events, investigation of the contributing factors led to a review of the Turkey Point Unit 4 LTOPS surveillance procedures which showed that the surveillance requirement did not include a test of the complete instrument channel.

Staff review of LERs indicates that no overpressure events similar to those at Turkey Point have occurred at operating PWRs since 1978. However, events have occurred in which both trains of LTOPS have been inoperable simultaneously, apparently from common cause factors. The following causes have each resulted in both LTOPS trains being inoperable at the same time.

1. Operation with both PORVs isolated (block valves closed) because of known PORV leakage.

   ★ On June 12 and again on June 18, 1981 at the Salem 2 plant, the PORV block valves were closed because of leaking LTOPS PORVs, thus rendering both trains inoperable. Also, on December 12, 1978 at the Ft. Calhoun plant, during plant heatup, a technician troubleshooting the failure of one train of LTOPS pulled fuses which caused both PORVs to open. To stop the discharge, both PORV block valves were closed, disabling the LTOPS. The PORVs were returned to service within 15 minutes.

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2. Operator error during maintenance.

   On May 21, 1981 at the Surry 2 plant, one train of LTOPS was inoperable because of a wiring error while the isolation valve for the pressure transmitter for the second train of LTOPS was closed. Also, on May 6, 1980 at the Ginna plant, during post-installation test of the reactor vessel head vent, DC power switches for both trains of LTOPS were found in the off position.

3. Isolation and venting of instrument air to the PORV actuators during integrated leak rate testing. (ILRT)

   On June 18, 1980 at the Zion 2 plant, the accumulators for both PORVs were vented and the instrument air source was isolated, rendering both trains of LTOPS inoperable. To prevent recurrence, a procedure change was made to block both PORVS open during the ILRT. Also, on May 27, 1980 at the Surry 2 plant the LTOPS was inoperable due to ILRT.

4. Low nitrogen pressure to both PORV actuators.

   On numerous occasions at North Anna 1 and 2, leakage in the backup nitrogen supply to the PORVS degraded the nitrogen supply pressure and rendered the LTOPS inoperable.

The events involving low nitrogen pressure were caused by excessive leakage from the pneumatic system coupled with a limited supply of bottled nitrogen. Although, these events occurred in a LTOPS where the backup air supply is bottled nitrogen, the events could have direct applicability to those systems which employ air accumulators to provide opening force for the PORVS in case of loss of air. Because these air-operated systems are normally continuously supplied from the plant air compressors, even when in shutdown, the lack of effectiveness of the pneumatic system and the air accumulators may not be discovered unless the plant experiences a loss-of-air event or unless the normal air supply to the accumulators is deliberately interrupted to perform an operability check. In these cases, periodic inspection or surveillance may be needed to detect excessive leakage and to ensure operability of the backup pneumatic supply.

In addition to instances in which both LTOPS trains were found to be inoperable, some LTOPS may have been in a degraded condition as a result of failure to update the LTOPS setpoints to correspond to changes in the Appendix G temperature pressure limits. This condition was found at both Kewaunee and Turkey Point.

SSINS No.: 6835
IN 82-50

UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF INSPECTION AND ENFORCEMENT
WASHINGTON, D.C. 20555

December 20, 1982

IE INFORMATION NOTICE NO. 82-50: MODIFICATION OF SOLID STATE AC UNDERVOLTAGE RELAYS TYPE ITE-27

Description of Circumstances:

Solid State AC Undervoltage Relays Type ITE-27 Series 211B and Series 211L manufactured by Brown Bovery Electric, Inc. are used on Class 1E switchgear and require a source of DC control power for proper operation. When the DC control power in these relays is lost, or temporarily interrupted because of a DC bus transfer, an alarm and feeder breaker trip sequence is initiated without actual bus undervoltage.

This condition could lead to the inadvertent isolation of a Class 1E switchgear. If this were to occur at a time when offsite power was not available, the supply breaker would be locked out and the switchgear would have to be reconnected manually. This condition could lead to a situation whereby no power was available for a period of time until the switchgear could be manually reconnected; this condition could adversely affect plant safety.

It should be noted that the ITE-27 Series 211B and 211L relays are operating as designed. The problem is one of misapplication. In the plants noted below, the function of the ITE-27 Series 211B and Series 211L relays are to monitor AC bus undervoltage conditions. The Series 211R relay rather than the Series 211B and Series 211L should have been used for this application, since the Series 211R does not drop out upon on loss of DC power.

On August 5, 1982, TVA reported this condition under 10 CFR Part 21 for the Bellefonte Nuclear Plants, Units 1 and 2. Bellefonte returned the relays to the vendor for internal circuit modification to the Type ITE-27 Series 211R to prevent dropout on loss of DC power. Other TVA plants are presently under review to determine if similar conditions exist.

Similar conditions were found at:

Duke Power Company - McGuire, Oconee, and Catawba Nuclear Plants
Rochester Gas and Electric - Ginna Nuclear Plant
Houston Light and Power Company - South Texas Project

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SSINS No.: 6835
IN 82-48

UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF INSPECTION AND ENFORCEMENT
WASHINGTON, D. C. 20555

December 3, 1982

IE INFORMATION NOTICE NO. 82-48: FAILURES OF AGASTAT CR 0095 RELAY SOCKETS

Description of Circumstances:

Since 1978 several deficiencies on Agastat CR 0095 relay sockets have been identified:

1. On December 21, 1978, Northern States Power Company submitted a Licensee Event Report (LER) for the Monticello nuclear facility. While performing a surveillance test during normal operation, a high pressure instrument channel relay failed to energize. A CR 0095 Agastat relay socket contact was disengaged from the socket and not making contact with the mating Agastat relay contact.

2. On January 5, 1979, Alabama Power Company submitted an LER for Farley 1 nuclear plant. During a diesel generator operability test, while at 100% power level, a sequencer failed to pick up Step 6 (battery charger). After the Agastat relay socket was replaced, the test was satisfactorily completed.

3. On April 6, 1979, Northern States Power Company submitted an LER for the Monticello nuclear facility. During a surveillance test a motor generator field breaker trip relay failed to trip the breaker. A CR 0095 Agastat relay socket contact was disengaged from the socket and not making contact with the mating Agastat relay contact.

4. On December 7, 1979, Detroit Edison submitted a 10 CFR 50,55(e) report No. EF 2-50-658 for the Enrico Fermi 2 nuclear facility. In their two primary containment monitoring system cabinets, problems were experienced with Agastat relay assemblies. When the relays are plugged into the socket, the terminals are pushed back and this sometimes results in no contact between the relay pin and the socket terminal.

5. On June 11, 1981, Florida Power Corporation submitted an LER for Crystal River 3 nuclear facility. During a monthly functional test of engineered safeguards, the load sequence block 3 trip circuit would not reset following the actuation test. The cause was identified as a loose connection in the Agastat relay mounting block.

SSINS No.: 6835
IN 82-51

UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF INSPECTION AND ENFORCEMENT
WASHINGTON, D.C. 20555

December 21, 1982

IE INFORMATION NOTICE NO. 82-51: OVEREXPOSURES IN PWR CAVITIES

Description of Circumstances:

Commonwealth Edison's Zion Unit 1 was in cold shutdown for refueling and maintenance. Incore instrumentation thimble retraction started during the evening shift on March 23, 1982, and was completed about six hours later at approximately 0400 hours on March 24. The governing maintenance procedure for retracting and inserting incore instrumentation thimbles required that all access doors to the reactor cavity be locked and all incore detectors be in the storage position before the thimbles were retracted. Control of keys to the locks was administratively assigned to the shift engineer on duty.

After thimble retraction was completed on March 24, the licensee began to flood the refueling cavity in preparation for refueling. At about 1030 hours, it was determined that the water level in the refueling cavity was decreasing. At about noon, a shift foreman entered the reactor cavity in an effort to

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locate the leakage source. The shift foreman saw that the leakage was massive. The licensee decided to lower the water in the refueling cavity, reinstall the reactor vessel head, and investigate the leakage source. At about 2300 hours, the licensee found an excore nuclear instrumentation cover gasket had slipped and was apparently the cause of the leak.

After the gasket was replaced, the licensee raised the vessel head and partially flooded the refueling cavity. At about 1800 hours on March 25, the shift engineer entered the reactor cavity to determine if there was further leakage. During this entry which only took about 70 seconds, the shift engineer received a whole-body radiation dose of approximately five rem.

"Power Reactor Events", Vol. 4, No. 4, published in November, 1982 describes the event at Zion in more specific detail."

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The Zion overexposure resulted from failure to follow good radiation protection practices and programmatic weaknesses in the radiation protection program. The following specific weaknesses contributed to the overexposure:

1. Failure of Shift Operations Personnel in Leadership Positions to Exhibit Good Radiation Protection Practices

   Shift operations personnel in leadership positions failed to exhibit good radiation practices. On March 24, a shift foreman entered the unsurveyed cavity area without observing survey instrument readings until he had descended the cavity ladder; at the bottom of the ladder (a 50 R/hr radiation field) the shift foreman noted his survey instrument was offscale high. On March 25, a shift engineer entered an unsurveyed area (moved closer to the bottom of the reactor vessel) fully aware that exposure rates would increase significantly as he approached the reactor vessel. Of all the personnel directly involved in the two cavity entries, these two managers were the most knowledgeable of the specific cavity radiological hazards.

2. Lack of Preplanning and Communication Among Individuals and Work Groups

   There was a lack of preplanning and briefing of all participants prior to the start of the job. No Radiological Work Permit (RWP) was completed which could have: defined the intended actions (the shift engineer went further into the cavity than expected); communicated the "stay time" allowed (the shift engineer was not told his "stay time"); assured that precautions were identified (the plant health physicist and radiation/chemistry foreman each assumed the other had discussed precautions with the shift engineer); and provided for proper equipment (the shift engineer only had a film badge and a [0-200 mr] self-reading pocket dosimeter). Under Zion's procedures an RWP was not required since a radiation/chemistry technician (RCT) was to provide continuous job coverage.

3. Lack of Understanding by Radiation Protection Personnel of Reactor Cavity Radiological Hazards

   The RCT and foremen involved had a general lack of understanding of the reactor cavity's specific radiation hazards. The RCT and RCT trainees providing job coverage for the cavity entries were not familar with the nature and strength of the radiation sources present with the incore thimbles withdrawn. RCT training prior to the overexposure described reactor cavity hazards only in general terms, with no specific description of the radiation sources or the expected exposure rates. The RCT thought the radiation source strength was uniformly distributed along the length of the incore tubes (which run the entire length of the reactor cavity); thus, the RCT, did not warn the engineer to stop advancing into higher radiation fields.

SSINS No.: 6835
IN 82-53

UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF INSPECTION AND ENFORCEMENT
WASHINGTON, D. C. 20555

December 22, 1982

IE INFORMATION NOTICE NO. 82-53: MAIN TRANSFORMER FAILURES AT THE NORTH ANNA NUCLEAR POWER STATION

Addressees:

All nuclear power reactor facilities holding an operating license (OL) or construction permit (CP).

Purpose:

The purpose of this information notice is to describe seven main transformer failures, including one that resulted in a fire and one that caused extensive damage to the main generator, at the North Anna Nuclear Power Station, to alert other nuclear power facilities to the causes.

Description of Circumstances:

The North Anna main transformers consist of three 330MVA single-phase Westinghouse transformers for each unit which are cooled by a forced oil/forced air cooling system. The 22kv low-voltage windings of these transformers are supplied from the main unit generator by an isolated phase bus system. The 500kv voltage windings supply power to the transmission system by an overhead line to the station switchyard.

The North Anna main transformers have experienced seven failures in the past two years, the first five of which involved the Unit 2 transformers and the last two involved the Unit 1 transformers. Of these, the third and seventh caused the most damage and also posed the greatest threat to the health and safety of plant personnel. The third failure generated sufficient forces and heat to rupture the transformer's casing and an oil line. The oil that erupted from these two breaks ignited and the resulting fire engulfed and shorted out an overhead three-phase bus system that supplies offsite power to the normal and emergency buses of the North Anna facility from a reserve station transformer. The seventh failure also generated sufficient forces to rupture the transformer's casing; however, the rupture was at the upper portion of the transformer such that the total oil discharged was significantly less than that of the third failure. Although no fire ensued in the immediate vicinity of the transformer, the total damage and risk to personnel posed by the seventh failure were greater than those of any of the previous events. For example, the effects of the fault were propagated to the main generator where significant damage was done to the main generator and its appendages (e.g., the neutral grounding transformer and its feeder cable and enclosure were destroyed, the neutral enclosure was severely damaged with the north side being blown out,

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UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF INSPECTION AND ENFORCEMENT
WASHINGTON, D. C. 20555

December 28, 1982

IE INFORMATION NOTICE NO. 82-55: SEISMIC QUALIFICATION OF WESTINGHOUSE AR RELAY WITH LATCH ATTACHMENTS USED IN WESTINGHOUSE SOLID STATE PROTECTION SYSTEM

Description of Circumstances:

Virginia Electric and Power Company (VEPCO) reported that one of the two types of latch mechanisms used with the Westinghouse type AR relay is not qualified for seismic Category 1 use. The licensee reports that both types of latch mechanisms are used in the Westinghouse solid state protection systems (SSPS) at both units of the North Anna Nuclear Power Station.

One type of latch attachment, W ARLA performs the latch function by mechanical means; and the other type, W ARMLA performs the latch function by magnetic means. The ARMLA relay is a product replacement for the discontinued ARLA relay. The type ARMLA relay, used as a replacement for the type ARLA relay unit, was found by W to be seismically unqualified for use in the safety-grade SSPS.

On December 14, 1982, Westinghouse Nuclear Service Division (NSD) issued Revision 1 of Technical Bulletin No. NSD-TB-82-03 to Westinghouse-supplied nuclear plants using the SSPS, apprising them of the problem. An extract from W NSD-TB-82-03 is attached for your information and appropriate use (Attachment 1).

The technical bulletin specifies an acceptable replacement unit, qualified by Westinghouse, which has been provided with an adaptor base for mounting in place of an AR relay unit.

It is well to note, that since the AR relay is not unique to Westinghouse PWR power plants, the problem may also exist at other nuclear power plants. Therefore, it is advisable for all nuclear power plants to review their replacement and spare parts records to ascertain that no W ARMLA units have been installed, or are being held as spare parts, for safety-related applications.

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UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

1982

TO ALL PRESSURIZED WATER REACTOR PLANT LICENSEES

Gentlemen:

SUBJECT: POTENTIAL STEAM GENERATOR RELATED GENERIC REQUIREMENTS (GENERIC LETTER NO. 82-32)

The NRC staff has identified potential steam generator related generic requirements and is currently subjecting them to a value impact analysis. A major element of the staff's value impact will be an analysis being prepared by our contractor, Science Applications, Inc. A copy of this draft report is provided for your information and use. This report is currently under staff review and will be modified to consider multiple steam generator tube ruptures in combination with other events along with single tube rupture scenarios.

Any comments you may care to make, either individually or through Owners Groups, on the SAI report and on the probability and consequences of multiple tube rupture scenarios would be considered in the staff's final value impact analysis if they can be provided within 30 days of the date of this letter.

Sincerely,

Darrell G. Eisenhut

Darrell G. Eisenhut, Director
Division of Licensing

Enclosure:
SAI Report

~~8208190263~~

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

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Darrell G. Eisenhut, Director
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Enclosure:
SAI Report

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