Indiana Michigan
Power Company
500 Circle Drive
Buchanan, MI 49107 1395

INDIANA MICHIGAN POWER

September 15, 2003

AEP:NRC:3691-05
10 CFR 50.4

Docket Nos: 50-315
50-316

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Mail Stop O-P1-17
Washington, D.C. 20555-0001

Donald C. Cook Nuclear Plant Units 1 and 2
STEAM GENERATOR INSPECTION – REQUEST FOR ADDITIONAL INFORMATION (TAC NOS. MB8121 and MB8122)

Reference Letter from S. A. Greenlee, Indiana Michigan Power Company, to Nuclear Regulatory Commission Document Control Desk, AEP:NRC:3691-01, "2002 Annual Operating Report," dated February 28, 2003.

The referenced letter transmitted the Donald C. Cook Nuclear Plant (CNP) Annual Operating Report to the Nuclear Regulatory Commission (NRC). Included in that report were summaries of the CNP Unit 1 and Unit 2 steam generator inspections that were performed in 2002. Subsequent to that submittal, NRC staff members, via electronic mail dated June 30, 2003, requested that Indiana Michigan Power Company provide additional information regarding the inspections. The attachment to this letter provides the response to the request for additional information.

This letter contains no new commitments. Should you have any questions, please contact Mr. Brian A. McIntyre, Manager of Regulatory Affairs, at (269) 697-5806.

Sincerely,

John A. Zwolinski
Director of Design Engineering and Regulatory Affairs

RV/rdw

A001

c: K. D. Curry, Ft. Wayne, w/o attachment
J. E. Dyer, NRC Region III
J. T. King, MPSC, w/o attachment
MDEQ-WHMD/HWRPS, w/o attachment
NRC Resident Inspector
M. A. Shuaibi, NRC Washington, DC

bc: M. J. Finissi, w/o attachment
D. W. Jenkins, w/o attachment
J. A. Kobyra, w/o attachment
C. R. Lane/P. W. Monk
B. A. McIntyre, w/o attachment
J. E. Newmiller
D. J. Poupard
R. P Powers
M. K. Scarpello, w/o attachment
T. K. Woods, w/o attachment
J. A. Zwolinski

ATTACHMENT TO AEP:NRC:3691-05

Steam Generator Inspections
Request for Additional Information

By letter dated February 28, 2003, Indiana Michigan Power Company (I&M) provided the Nuclear Regulatory Commission (NRC) with a copy of the Donald C. Cook Nuclear Plant (CNP) annual operating report. Included in that report were summaries of the Unit 1 and Unit 2 steam generator inspections that were performed in 2002. Subsequent to that submittal, NRC staff members, via electronic mail dated June 30, 2003, requested that I&M provide additional information regarding the inspections. The NRC questions and I&M responses are provided below. A list of terms and abbreviations used throughout the responses is provided in the glossary at the end of the response.

NRC Question 1

In several locations in your reports, reference is made to tube support structures (e.g., fan bar 5) and tube locations (e.g., R53/C53). In order for the staff to better understand the location of the indications and the tubes, please provide (1) sketches of the Unit 1 and 2 steam generators that depict the tube support naming conventions and (2) tubesheet maps that depict the rows and columns of the tubes. In addition, please provide a general description of the replacement steam generators for both Units 1 and 2. Include in this general description the total number of tubes, tube diameter, tube wall thickness, tube material, tube pitch, tube support (including fan bar/anti-vibration bar) material and configuration (e.g., quatrefoil broached hole), tube support thickness, tube manufacturer, steam generator manufacturer, tubesheet expansion method (e.g., hydraulic) and any other noteworthy design characteristics from a steam generator tube integrity standpoint (e.g., full length stress relief of the row 1 through row 10 tubes). In addition, discuss whether measurements from a tube support are from the middle of the support or the edge of the support (e.g., does fan bar 5 plus 0.61 inches, indicate an indication 0.61 inches from the top edge of the fan bar).

Response to NRC Question 1

Schematics of the Unit 1 and Unit 2 steam generators are provided in Figures 1 and 3, respectively. Diagrams of the Unit 1 and Unit 2 tubesheets are provided in Figures 2 and 4, respectively. Table 1 provides the details of the Unit 1 steam generator, and Table 2 provides the details of the Unit 2 steam generator.

The convention for providing tube locations is to measure from the middle of the tube support. Thus, the location 05H + 0.50 is 0.50 inches above the middle of the fifth tube support on the tube hot leg side.

NRC Question 2

For both Units 1 and 2 there were a number of steam generator dents and dings reported. Please provide the bobbin voltage amplitudes for these dents and dings (a graph depicting the distribution of amplitudes is acceptable). In addition, discuss whether these dents/dings were present since the baseline inspection. If the dents/dings were not present since the baseline inspection, discuss the possible root cause. For Unit 1, only one of the 6 dents/dings was examined by a rotating probe. Please discuss the basis for selecting this one indication for rotating probe testing. For Unit 2, 20 percent of the dents/dings were tested with a rotating probe. Please discuss how the 20 percent sample was selected (e.g., random, all indications above 5 volts with a random sample below 5 volts, etc.). Please discuss whether the method used to size the dents/dings is consistent with standard industry practice (alternatively provide a summary of the calibration method).

Response to NRC Question 2

Unit 1

The bobbin voltage amplitude distributions for the dent/ding signals reported during the 2002 inspection are presented in Figure 5.

A review of the Unit 1 data noted that of the six indications, five were present in the baseline examination record and had not changed. The sixth tube, SG 14, R34/C26, was found to have a small ding indication (2.15 volts) in the U-bend region that was not present in the baseline data. This indication was most likely caused by either probe interaction when traversing the U-bend region or by steam generator movement during shipping (Note: The baseline examination was performed in the factory and no additional inspections were performed until 2002).

The planned 2002 Unit 1 rotating coil inspection for dents and dings consisted of a random 20 percent sample of all dent/ding indications above two volts. When the inspection results were obtained, it was noted that of the six dents/dings reported, five of the indications were in the U-bend area. However, due to an oversight, a U-bend rotating probe was not available to perform the one additional indication inspection necessary to comply with the 20 percent sample. A decision was made to inspect the accessible freespan indication and to defer the U-bend inspection of the one additional indication until the next scheduled inspection, the Unit 1, Cycle 19 refueling outage. This decision was judged to have no adverse impact on tube integrity due to the small signal amplitudes of the U-bend indications, the limited operating time of the Unit 1 steam generators, the enhanced design features and the degradation resistant properties and operating experience with the alloy 690 thermally treated tubing material. I&M plans to inspect a sample (inclusive of SG 14, tube R34/C26 discussed above) of U-bend dent/ding indications with a rotating coil during the Unit 1 Cycle 19 refueling outage.

Unit 2

The bobbin voltage amplitude distributions for the dent/ding signals reported during the 2002 inspection are presented in Figure 6.

A review of the Unit 2 data provided reasonable assurance that all of the dent/ding indications reported during the 2002 inspection were present in the baseline examination and had not changed. A portion of the baseline data, which was originally recorded on cartridge tape, is unavailable for review because of problems encountered when duplicating the data from the obsolete cartridge tapes to the current industry standard data media (optical discs). Therefore, a review of 100 percent of the indications could not be performed. Over ninety eight percent of the indications were reviewed, and no signal changes were identified. The results of the data review provide confidence that the dents/dings are not service induced. Of the 221 reported dent/ding signals from the 2002 inspection, 217 were confirmed in the baseline data and indicated no change. The traceability of these signals to the baseline data coupled with design features such as the quatrefoil stainless steel support structures and full depth expanded tubesheet are felt to provide reasonable assurance that service induced dents/dings are not occurring in these steam generators.

The Unit 2 rotating coil inspection for dents and dings was based upon a 20 percent random sample of all dent/ding indications above two volts in the freespan region. The inspection consisted of tubes with both single indications and tubes with multiple indications. No U-bend indications were tested. While no degradation is expected in any of the U-bend dent/ding indications due to the service time of the Unit 2 steam generators and the enhanced design features/degradation resistance offered by the alloy 690 thermally treated tubes, I&M plans to inspect a sample of U-bend dent/ding indications with a rotating coil during the Unit 2 Cycle 15 refueling outage.

Calibration

In both the Unit 1 and Unit 2 inspections, the dents and dings were sized based upon the CNP approved data analysis guidelines that govern voltage setup for the bobbin coil. The four 20 percent through-wall flat bottom holes of the American Society of Mechanical Engineers' calibration standard (manufactured from archive tubing) are set to 4.0 volts on Channel 1 (400 kHz prime frequency). The voltage scale is then applied to the balance of the other frequencies. This is standard industry practice and is in accordance with the EPRI PWR Steam Generator Examination Guidelines (EPRI report TR-107659-V1-R5).

NRC Question 3

Four tubes in Unit 1 were plugged because of signal amplitude changes (1.0 to 2.5 volts) associated with MBMs/MBIs/MBHs. The MBIs were determined to have arisen from tube buffing operations during the manufacturing process after further investigation by EPRI. Although the indications may have been attributed to manufacturing, it is not clear why the signal amplitudes changed. Please provide a summary of your root cause analysis for why the indications changed in amplitude (or a description of what actions you may be planning to take to investigate the reason for the amplitude change). Please discuss whether any additional diagnostic testing was performed on these indications (e.g., ultrasonic testing, in-situ pressure testing, tube pulls, etc.). For the criteria used to determine if a manufacturing signal exhibits little or no change, discuss how the criteria was determined (e.g., was test repeatability evaluated for these types of indications such that the criteria would identify a signal change when the change was greater than normal test repeatability).

For Unit 2, it was indicated that several freespan indications were identified during the bobbin coil examination. In addition, it was indicated that indications that could not be reviewed in the original baseline or exhibited significant change were called MBIs. Please clarify the portion of the statement "that indications that could not be reviewed in the original baseline" were called MBIs. Does this statement imply that the baseline data was not available or that the indications were not present in the baseline data? If the latter, please discuss the nature/cause of the signal. If the former, discuss why the data is not available. For the 5 MBI indications in Unit 2, discuss whether they exhibited significant change or whether there was no prior data for review. If the indications exhibited change, please address the questions in the first half of this question for Unit 1.

Response to NRC Question 3

Unit 1

Subsequent to the February 28, 2003 submittal, Babcock & Wilcox (original equipment manufacturer) completed a review of the CNP MBI indications. The results of their review were presented at the July 2003 Steam Generator Non-destructive Examination Workshop sponsored by EPRI. Babcock & Wilcox attributed the signal amplitude changes to differential thermal aging of the tube material. The thermal aging occurred over the first cycle of operation in freespan, non-heat treated sections of the tubing. It was termed a one-cycle phenomenon (the initial cycle would in effect heat treat the tube bundle and preclude additional indications) and a benign condition.

At the time of discovery, select rotating coil examinations were performed. However, no additional diagnostic testing was performed. The indications were discussed with the lead level III analyst and the integrity engineer to assess the need for using an alternate probe or in-situ testing to gain further insight into the indications. Examinations using alternate probe types were judged unlikely to provide any additional information. In-situ testing was also judged unnecessary as the eddy current examination failed to identify any signs of degradation that would indicate a potential burst or leakage issue. The tubes were conservatively plugged. Currently there are no plans to unplug these tubes.

The criteria for determining whether a signal had changed was developed by the lead level III analyst and concurred with by an independent level III analyst. The criteria, which are based upon industry experience, are illustrated in Figure 7.

Unit 2

The Unit 2 baseline examination was performed in 1988 and was recorded on cartridge tape. These tapes were subsequently transferred to the current industry standard media, i.e. optical discs. During this conversion, some areas of the cartridge tape were found to be degraded and as a result could not be copied over to the optical discs. Therefore, a small portion of the baseline data is not available for baseline review. The MBIs reported in 2002 were in degraded areas of the original baseline tapes and the absence of changes could not be verified. Therefore, all of the MBIs were examined with a plus point probe to provide assurance that no degradation was present. These examinations confirmed the absence of degradation and as a result the associated tubes were left in service, and the five MBI indications were reclassified MBMs.

NRC Question 4

Several tubes were reported to have bulge indications in Unit 2. Please discuss the size, location, and cause of these bulges (e.g., discuss if they were present since manufacture or if it is a service induced condition). Since a bulge can result in increased stresses which in turn increase the potential for stress corrosion cracking, please discuss whether these locations were examined with a rotating probe and whether the integrity of these locations has been assessed for the planned period of time between inspections.

Response to NRC Question 4

Table 3 summarizes the bulge indications that were reported during the 2002 Unit 2 inspection.

Because of the location of the bulge indications (all are located in the tubesheet) all signals are believed to be a result of the initial tubesheet drilling and tube expansion process. During tubesheet fabrication, a slight drill wobble is postulated to have occurred, and the tube was then expanded into this irregularity causing the bulge. The bulges' sizes are judged to be minor. The bulge in SG 21 is traceable to the baseline examination. The two remaining bulges (SG 24) are in an area of corrupted data (See Unit 2 response to Question 3) in the original baseline examination tapes and, therefore, their presence during the baseline examination could not be confirmed. However, based on the similarity of the SG 24 signals to the SG 21 signal, the SG 24 signals are believed to be additional examples of the same condition.

No rotating coil inspections/specific integrity evaluations were performed on these indications in 2002 based upon the following factors:

- The indications are considered typical for a steam generator design with hydraulically expanded tubesheets.
- The indications are located in alloy 690 thermally treated tubing which offers significant resistance to stress corrosion cracking. Note that this conclusion has been further supported by a recent industry review that found alloy 690 thermally treated tubing to be essentially immune to primary water stress corrosion cracking and to have very limited exposure to outside diameter stress corrosion cracking.
- No primary-to-secondary leakage has occurred in these steam generators since they were placed in service in 1989.

While only three bulge indications were reported during the 2002 inspection, additional bulge indications were identified in the Unit 2 baseline examination. A total of 97 bulges were conservatively reported during the 1988 baseline examination (SG 21: 36 indications, SG 22: 34 indications, SG 23: 7 indications and SG 24: 20 indications). A data review has provided assurance that these signals have not changed. The data review was limited to 93 of the 97 indications because of corruption in a portion of the original baseline data. However, based upon consistent results for the 95 percent of the indications that could be reviewed, I&M concludes that no new bulges are developing. A true bulge condition is considered a local increase (plastic deformation) in the tube's diameter, which is not characteristic of the noted indications. All of these indications are located within the tubesheet and are attributed to tubesheet drilling/tube expansion abnormalities as discussed above. As such, they are not considered true bulges and were not typically identified as such during the 2002 examination.

NRC Question 5

In Unit 2 several tubes were reported as not having been hydraulically expanded. Since the crevice between the tube and tubesheet can result in a highly aggressive chemical environment, discuss whether the integrity of these locations was assessed for the period of time between inspections. In addition, discuss whether any additional corrective actions (i.e., other than full length rotating probe inspections) are planned in response to finding these unexpanded tubes (e.g., expanding the tubes full length in a future outage, preventive plugging, etc.).

Response to NRC Question 5

The non-hydraulically expanded tubes were evaluated under a station condition report and an associated "Use-As-Is" evaluation with input from the original equipment manufacturer (Westinghouse). As the initial conditions were found during the 2002 Unit 2 inspection that consisted of a 50 percent base bobbin coil inspection, the extent of condition for this evaluation was expanded (post outage) to examine previous data for the existence of similar indications. This investigation led to the discovery of three additional tubes that were not hydraulically expanded. Therefore, the total population of tubes impacted is seven. Specific tube identification is presented in Table 4.

This evaluation of these indications considered the results of the rotating coil inspection (i.e., no degradation occurring on the four indications identified during the 2002 inspection), the lack of any experience related to corrosion degradation of alloy 690 thermally treated tubing, and Westinghouse specific operating experience that indicated similar steam generators have operated for cycles lacking tube-to-tubesheet expansion. These factors and the lack of any indication of primary-to-secondary leakage support the decision to leave the tubes in service until the Unit 2, Cycle 15 refueling outage. I&M plans to continue monitoring the tubes listed in Table 4 via full-length tubesheet rotating coil inspections during each scheduled steam generator eddy current examination. Currently, there are no plans to expand or plug the tubes unless future eddy current examinations suggest evidence of degradation.

NRC Question 6

In Unit 2, 3 tubes were identified with INR calls in 2002 which had low level support plate wear indications in 1997. Please discuss whether these indications were inspected with a rotating probe in 1997 or in 2002 and the results of any examinations performed.

Response to NRC Question 6

The three indications that were coded INR were all located in SG 21 on tube R6/C53 (two indications) and tube R6/C54 (one indication). The two indications in tube R6/C53 were examined with both a bobbin coil and a rotating coil in 1997 and 2002. The indication in tube R6/C54 was examined with both a bobbin coil and rotating coil in 1997. However, in 2002, the examination of this indication was limited to the bobbin coil probe. As the bobbin coil technique is considered the qualified technique for both detection and sizing of support plate wear and examinations of similar indications by the rotating probe provided no additional information, no enhanced inspections were conducted on this indication in 2002.

The bobbin coil examinations identified the presence of low level throughwall tube wear (i.e., a range of 4-7 percent for the three indications). These indications are not abnormal and are well below the Technical Specification 4.4.5.4.a.6 plugging limit of 40 percent throughwall.

NRC Question 7

Discuss whether the permeability indications were examined with a rotating probe and the results of any examinations performed.

Response to NRC Question 7

The two permeability indications that were identified in the Unit 2 report were examined as part of the special interest rotating coil (plus point) inspection. This examination found no degradation at either location. Please refer to Table 5 for a summary of the indication information.

Glossary

When the following terms and abbreviations appear in the text, they have the meanings provided below.

Term/Abbreviation	Meaning
1C, 2C etc.	First Cold Leg Support, Second Cold Leg Support, etc.
1H, 2H etc.	First Hot Leg Support, Second Hot Leg Support, etc.
AV1, AV2, etc.	First Antivibration Bar, Second Antivibration Bar, etc.
BLG	Bulge
Col	Column
EPRI	Electric Power Research Institute
FB1, FB2, etc.	First Flat Bar Restraint, Second Flat Bar Restraint, Etc.
INR	Indication Not Reportable
MBH	Manufacturing Burnish Mark - History
MBI	Manufacturing Burnish Mark - Indication
MBM	Manufacturing Burnish Mark
NDF	No Detectable Degradation Found
PVN	Permeability Variation
PWR	Pressurized Water Reactor
R53/C43 (typical)	Tube Location (for example row 53/column 43)
SG XY	Steam Generator, Unit X, Steam Generator Number Y
TEC	Tube End Cold
TEH	Tube End Hot
TSC	Tube Sheet Cold
TSH	Tube Sheet Hot

Table 1
Unit 1 Steam Generator Characteristics

Total Number of Tubes per SG	3496
Tube diameter	0.875 Outside diameter (OD)
Tube wall thickness	0.049 inches
Tube material	Alloy 690, thermally treated
Tube pitch	1.1875 inch triangular
Tube support material	SA-240-410S-modified stainless steel
Tube support configuration/thickness	*
Tube manufacturer	Sumitomo Metal Industries LTD
Steam generator manufacturer	Westinghouse – steam domes Babcock and Wilcox – lower assembly and moisture separator units
Tubesheet expansion method	Full depth hydraulic

*See Figure 1. The tube support structure consists of eight stainless steel lattice grid assemblies and four sets of flat bar (also called fan bar) restraints. Each lattice grid consists of interlocking "high" (3.15 inches high and 0.135 inches thick) and "low" (1.0 inches high and 0.135 inches thick) bars that form a lattice pattern to provide lateral support in the straight section of the tube. The flat bar restraints are made of the same material and provide support in the U-bend area.

Noteworthy design characteristics

The tubes in rows 1 through 13 are stress relieved. Additionally, the tube bundle has an increased bend radius (e.g., row 1 radius is 4.750 inches versus 2.19 inches for the old steam generators) to reduce stress concentration.

Table 2
Unit 2 Steam Generator Characteristics

Total Number of Tubes per SG	3592
Tube diameter	0.875 inches (OD)
Tube wall thickness	0.050 inches
Tube material	Alloy 690, thermally treated
Tube pitch	1.225 inch square
Tube support material	Type 405 stainless steel
Tube support configuration/thickness	*
Tube manufacturer	Sandvik Steel Inc.
Steam generator manufacturer	Westinghouse
Tubesheet expansion method	Full depth hydraulic

*See Figure 3. The tube support structures consist of seven 1.12 inch thick support plates with quatrefoil holes and six anti-vibration bars that are located in the U-bend region of the tubes. There is also a flow distribution baffle located between the tubesheet and the first support plate. The flow distribution baffle is 0.75 inches thick with octofoil holes. The support plates, anti-vibration bars, and the flow distribution baffle are all constructed of type 405 stainless steel.

Noteworthy design characteristics

The tubes in rows 1 through 8 are stress relieved. Additionally, the tube bundle has an increased bend radius (e.g., row 1 radius is 3.141 inches versus 2.19 inches for the old steam generators) to reduce the stress concentration in the U-bend area.

Table 3
Unit 2 2002 Bulge Indications

SG	Tube	Bobbin Indication	Bobbin Voltage
21	Row 13, Col 58	BLG @ TEC + 20.37	72.9
24	Row 14, Col 64	BLG @ TSC – 0.05	63.71
24	Row 11, Col 78	BLG @ TEH + 20.79	37.37

Table 4
Unit 2 Non-hydraulically Expanded
Tube Identification

SG	Tube	Tubesheet Impacted
22	Row 15, Col 36	Cold
22	Row 44, Col 66	Cold
22	Row 44, Col 65	Cold
23	Row 35, Col 38	Hot
23	Row 45, Col 42	Hot
23	Row 35, Col 31	Hot
23	Row 38, Col 49	Hot

Table 5
Unit 2 Steam Generator Permeability Indications

SG	Tube	Bobbin Indication	Bobbin Voltage	Comments
21	Row 4 Col 42	PVN @ 4H + 27.49	6.32	Indication reviewed by plus point with an examination extent of 5H to 4H. Results were "NDF", i.e., no degradation found.
24	Row 9 Col 72	PVN @ 6H + 14.74	6.83	Indication reviewed by plus point with an examination extent of 7H to 6H. Results were "NDF", i.e., no degradation found.

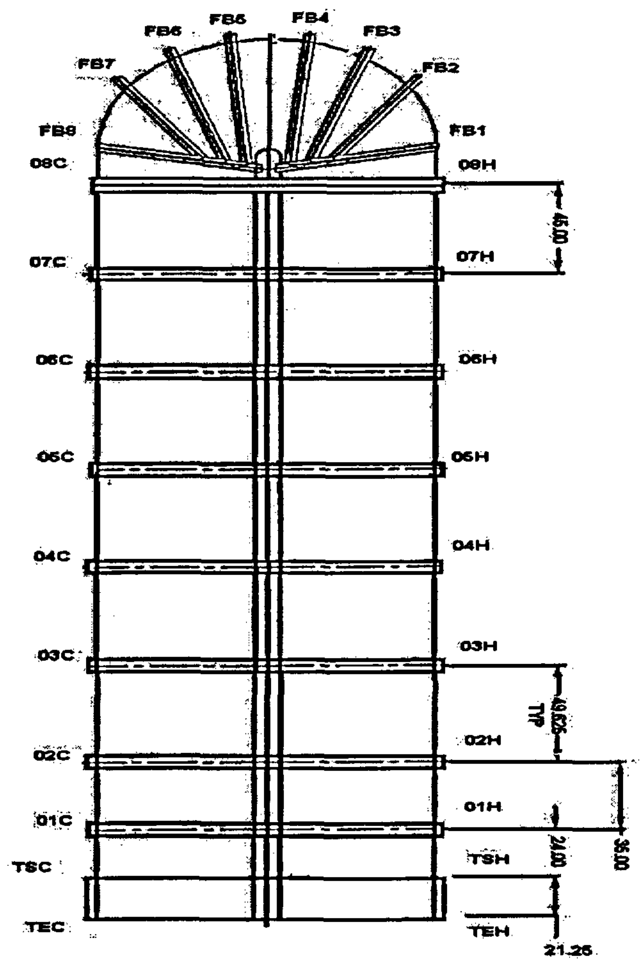

Figure 1
Unit 1 Steam Generator

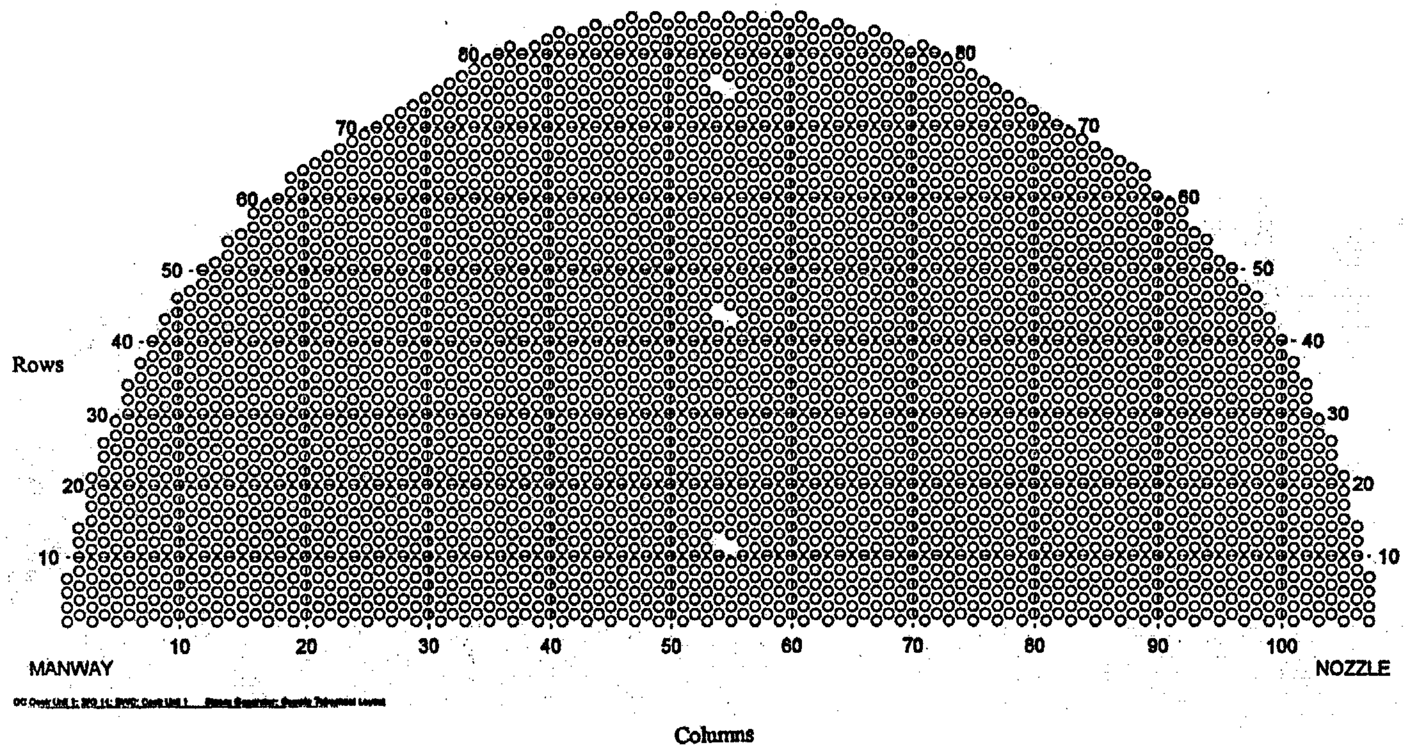

Figure 2
Unit 1 Tube Sheet Map

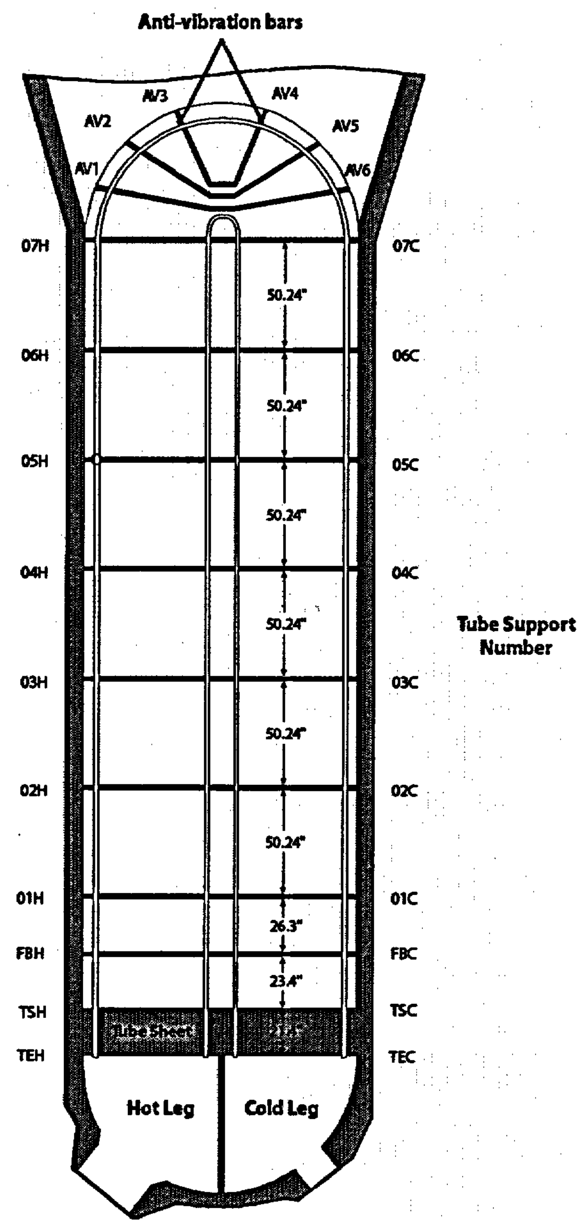

Figure 3
Unit 2 Steam Generator

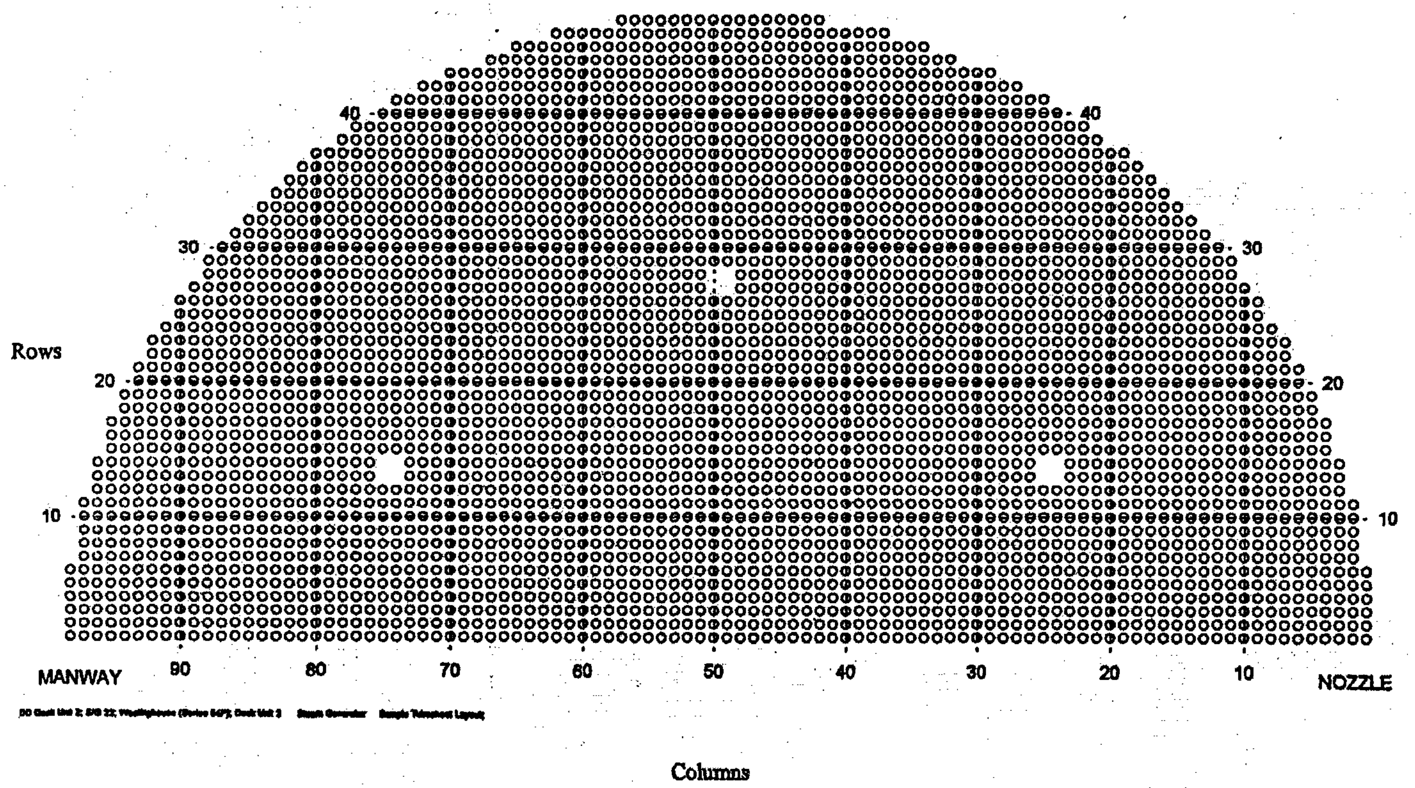

Figure 4
Unit 2 Tube Sheet Map

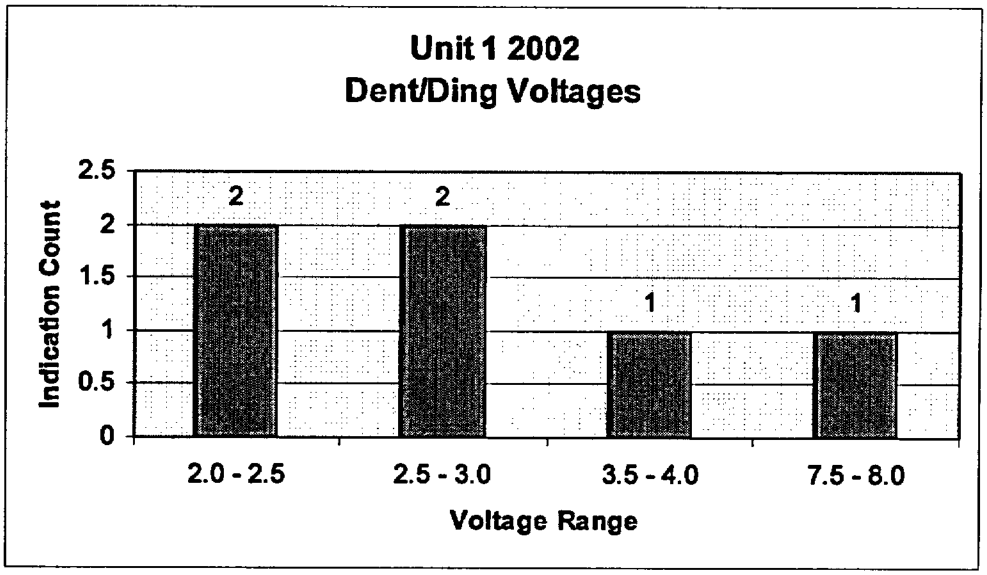

Figure 5
Unit 1 Bobbin Voltage Amplitude Distribution

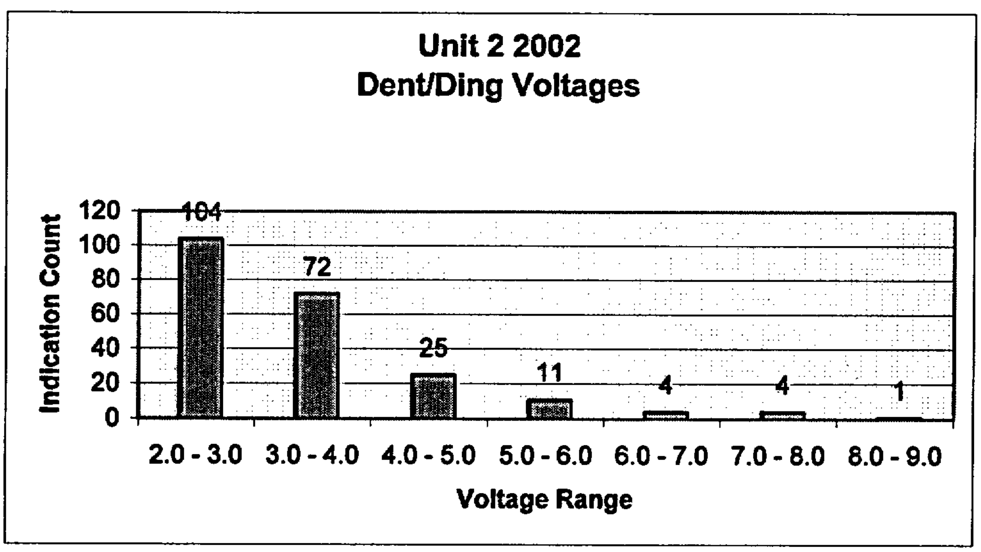

Figure 6
Unit 2 Bobbin Voltage Amplitude Distribution

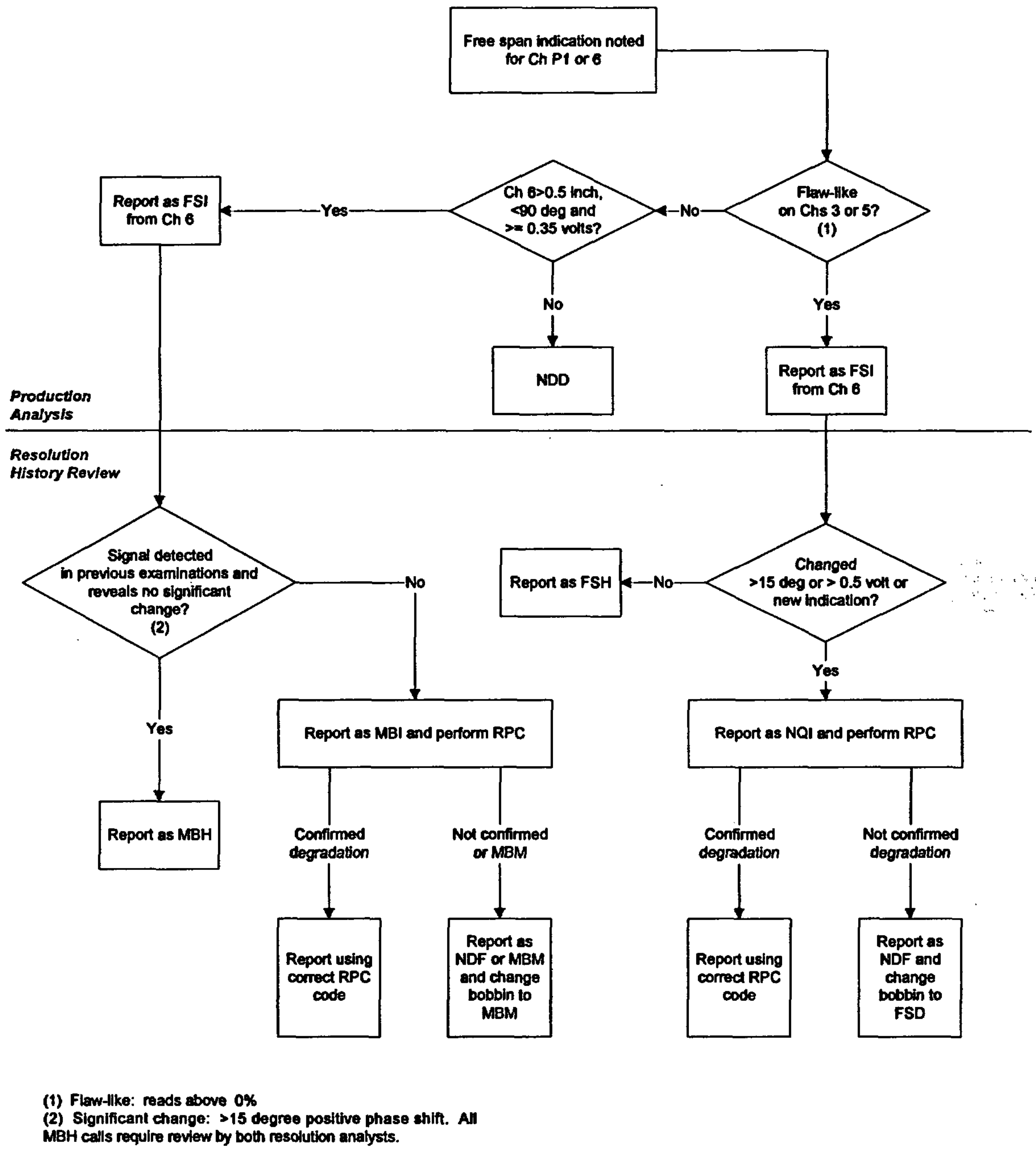

Figure 7
Decision Flowchart