Steam Generator Outage Summary Report

McGuire Unit 1 1999
Outage EOC 13

Location: Hwy. 73, Cowans Ford, North Carolina 28216

NRC Docket No. 50-369

National Board No. 44

Commercial Service Date: December 1, 1981

Owner: Duke Energy Corporation
526 South Church St.
Charlotte, N.C. 28201-1006

Revision 0

Prepared By: Gerald D. Crump Date: 1/31/00

Reviewed By: Danny E Kuna Date: 1.31.00

Approved By: Mona Sample Date: 2-2-00

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Electronic	Steam Generator Desktop

FORM NIS-1 OWNER'S DATA REPORT FOR INSERVICE INSPECTIONS

As required by the Provisions of the ASME Code Rules

1. **Owner:** Duke Power Company, 526 S. Church St., Charlotte, NC 28201-1006
   (Name and Address of Owner)
2. **Plant:** McGuire Nuclear Station, 12700 Hagers Ferry Rd., Huntersville, NC 28078
   (Name and Address of Plant)
3. **Plant Unit:** 1 4. **Owner Certificate of Authorization (if required)** N/A
5. **Commercial Service Date** December 1, 1981 **6. National Board Number for Unit** 44
7. **Components Inspected:**

Component or Appurtenance	Manufacturer or Installer	Manufacturer or Installer Serial No.	State or Province No.	National Board No.
1A Steam Generator	B&W Canada	7701-04	N/A	157
1B Steam Generator	B&W Canada	7693-01	N/A	146
1C Steam Generator	B&W Canada	7701-03	N/A	155
1D Steam Generator	B&W Canada	7701-02	N/A	154

Note:Supplemental sheets in form of lists, sketches, or drawings may be used, provided (1) size is $8^1/_2$ in. x 11 in., (2) information in items 1 through 6 on this data report is included on each sheet, and (3) each sheet is numbered and the number of sheets is recorded at the top of this form.

FORM NIS-1 (Back)

8. Examination Dates 9/29/99 to 10/8/99

9. Inspection Period Identification: 3rd Period of the 2nd Interval

10. Inspection Interval Identification: 2nd Interval

11. Applicable Edition of Section XI 1989 Addenda None

12. Date/Revision of Inspection Plan: 9/15/99 Rev.0

13. Abstract of Examinations and Test. Refer to Attached Steam Generator Outage Summary Report

14. Abstract of Results of Examination and Tests. Refer to Attached Steam Generator Outage Summary Report

15. Abstract of Corrective Measures. Refer to Attached Steam Generator Outage Summary Report

We certify that a) the statements made in this report are correct b) the examinations and tests meet the Inspection Plan as required by the ASME Code, Section XI, and c) corrective measures taken conform to the rules of the ASME Code, Section XI.

Certificate of Authorization No. (if applicable) N/A Expiration Date N/A

Date Jan 12 19 2000 Signed Duke Power Co. By Mowen Sample
Owner

CERTIFICATE OF INSERVICE INSPECTION

I, the undersigned, holding a valid commission issued by the National Board of Boiler and Pressure Vessel Inspectors and the State of Province of North Carolina employed by * The HSBI&I Co. of HARTFORD, CT. have inspected the components described in this Owners' Report during the period 7-2-98 to 2-10-00, and state that to the best of my knowledge and belief, the Owner has performed examinations and tests and taken corrective measures described in the Owners' Report in accordance with the Inspection Plan and as required by the ASME Code, Section XI.
By signing this certificate neither the Inspector nor his employer makes any warranty, expressed or implied, concerning the examinations, test, and corrective measures described in this Owners' Report. Furthermore, neither the Inspector nor his employer shall be liable in any manner for any personal injury or property damage or a loss of any kind arising from or connected with this inspection

Klein Commissions NB7728, NC 853, N-I
Inspector's Signature National Board, State, Province, and Endorsements

Date 2-10 19 2000

* The Hartford Steam Boiler Inspection & Insurance Co.
200 Ashford Center North
Suite 300
Atlanta, GA. 30338

McGUIRE NUCLEAR STATION UNIT 1

STEAM GENERATOR MANAGEMENT PROGRAM
OUTAGE SUMMARY REPORT

1EOC13

SEPTEMBER – OCTOBER 1999

I. EXECUTIVE SUMMARY

The second in-service inspection of the CFR80 Replacement Steam Generators began on September 28 with the removal of the primary manways. The eddy current inspection was completed in seven days that allowed for a nine-day manway to manway window. DE&S personnel were contracted to perform project management, audio and video, maintenance, and eddy current acquisition and analysis functions. Framatome Technologies Inc. personnel performed the secondary side video inspection and removal of the stuck primary manway studs. This outage was extremely successful from all aspects as seen in the following categories with their actuals vs goals: 0/0 recordable injuries, 0/8 personnel contamination events, 17.7/22.8 Rem total exposure, 8.4/9 days schedule, housekeeping rating of 4, and under the adjusted budget by $40K.

As was experienced in the first in-service inspections, primary manway studs were stuck and required drilling out. FTI successfully removed the six stuck studs without damaging any female threads. Gasket removal from the primary diaphragms was extremely difficult. As a result, three gasket-seating surfaces were scratched that required those diaphragms to be replaced. Nozzle covers were used instead of dams due to the split pin mod. The eddy current bobbin inspection included 30.64% of the tubes in-service of which 20% was a random sample. All indications identified with bobbin were inspected with MRPC (+point/pancake coils). DE&S completed probe inventory and u-bend RPC projects prior to the outage that greatly enhanced their performance in these areas. Essentially no probe pushing problems were encountered using the modified Zetec 0.560 MULC 4" beaded bobbin probe and probe driving equipment setup enhancements. Improvements in the radiological worker practices and using an improved vacuum system configuration minimized platform contamination and radiation levels. Eleven wear indications were identified none of which required the tube to be removed from service. The primary manways were installed with an increased stud preload to preclude any seepage during plant cooldown. All studs were successfully turned in and backed out the required amount. Only one stud had to be single tensioned since its elongation was below the tolerance. This was a replacement stud that also had to be changed out since its non-threaded portion would not allow the single stud tensioner to be positioned correctly. The second replacement stud was tensioned properly. The elongation variance on all the primary manways was 0.002" or less which is excellent.

DE&S maintenance technicians inspected all the RSG penetrations for any signs of leakage with the insulation removed and none was identified. Various secondary side

components of the 'A' RSG were inspected by FTI with remote video. We were unsuccessful in reducing the hydrazine levels to the point where the FTI crew could access the steam drum to perform the majority of this inspection. As a result, the entire video inspection was completed from outside the secondary manway and #9&10 handholes that resulted in a reduced scope. However, all components inspected showed no sign of erosion, corrosion, or scale buildup. The secondary side of the tubes at the tubesheet appeared very clean with a slight dusting of sludge in the areas inspected. During the installation of the secondary manway, two stud's elongation was low out of tolerance. Using the maximum allowed pressure by procedure, we were unable to loosen the nut in order to remove the stud for inspection. SGM and BWC Engineering approved an increase in stud load in order to break the nut loose. The studs, nuts, and holes were inspected. No anomalies were identified and the studs were single tensioned to the proper elongation.

II. WORKSCOPE

ACTIVITY	A		B		C		D	
	H/L	C/L	H/L	C/L	H/L	C/L	H/L	C/L
TUBE EXAMINATIONS								
0.560 MULC Bobbin ECT								
a) Full Length Random Sample	20%		20%		20%		20%	
b) Additional Full Length Inspection								
- Rows 1 thru 5	347		348		348		348	
- 2 Tubes Deep Around Periphery	Yes		Yes		Yes		Yes	
- Tubes Around Plugged Tubes	3		12		26		21	
- Tubes With Previous Indications	57		75		104		60	
- Indications in Straight Section	29	28	34	40	30	76	31	26
- Indications in U-Bends	2		3		4		3	
TOTAL TUBES	2017		2024		2069		2017	
0.520, 0.540, or 0.560 +Pt MRPC								
- Straight Sections	23	13	50	21	31	71	47	38
- OXP/NEX – total per S/G	1		43		9		9	
- U-bend Sections	2		2		12		5	
- Plugs			1	1	1	1		
- Plugs, Visual Only	1	1	1	1	4	4	4	4
TUBE PLUGGING - 0								
SECONDARY SIDE								
Steam Drum Inspection	Yes	Yes						
Hand Hole and Manway Inspection	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
MISCELLANEOUS								
Nozzle Dam Installation	No	No	No	No	No	No	No	No
Diaphragm Gamma Spec	Yes	Yes						

III. INSPECTION & REPAIR SUMMARY

A. Primary Manway Removal & Replacement

This task included: inspecting the diaphragm seating surfaces for evidence of seepage during cooldown; using the HTI multi-tensioning system to de-tension the primary manway studs; sleeving the studs and storing in the lower laterals with the bell nuts; removing the gaskets from the diaphragms and inspecting their seating surfaces for damage; pumping residual water from the bowls; cleaning and inspecting the studs, nuts, and holes; installing and tensioning the primary manway cover and studs. DE&S Maintenance Technicians performed these tasks with FTI Technicians removing the stuck primary manway studs.

The initial seating surface inspection prior to manway removal identified minor seepage at one location; 'A' hot leg between the 1:00 and 2:30 position. An investigation by BWC and SGM engineering of the occurrence of this type of seepage during C1EOC10 and M1EOC12 concluded that it occurred during cooldown. BWC recommended an increase in primary manway bolt preload and provided a new calculation (222-7693-B248) to justify. Corrective Minor Mod MGMM11121 was completed prior to this outage to increase the bolt preload from 89,900# to 104,000#. This increase appears to have corrected the seepage at CNS1 as none was identified during C1EOC11. Reference PIP# M-99-4332 for additional information.

All primary manway covers and diaphragms were successfully removed, however, six studs were stuck and had to be drilled out. FTI personnel and equipment were deployed to remove the following stuck studs; 'B' hot leg - #'s 3, 9, 10, 13; 'B' cold leg - # 19; 'D' cold leg - # 3. All studs were successfully drilled out with no female thread damage thus the installation of threaded inserts was not required. The QC visual inspection, go gauge, and no go gauge testing of all stud hole threads was deemed acceptable per FTI procedure 127507A Rev.4 (RSG Primary Manway Stuck Stud Removal). The corrective actions detailed in PIP G-99-0107 were not in place when these studs were installed during M1EOC12 that should minimize the potential for future stuck studs. 'B' RSG does have the oversized primary manway studs (2 5/8" vs 2 ½") as a result of a manufacturing error. During the first in-service inspection, M1EOC12, 'B' cold leg experienced one stuck stud at the #3 location. FTI successfully drilled out this stud and tapped all holes in this leg only. Since we had an additional stuck stud in 'B' cold leg this outage, it somewhat discredits our engineering judgement that tapping all the holes would significantly reduce the potential for a stuck stud. It is very doubtful based on this event that we will spend the dose, time, and money to tap the remaining holes. All the studs, nuts, and holes were successfully cleaned and inspected using the new procedure enhancements. Reference PIP M-99-4322 for additional information.

As has been experienced in the previous outages, the diaphragm gaskets were extremely difficult to remove despite additional training and different removal tools. The Flexitallic graphite spiral wound gaskets reside in a diaphragm groove. Prior to tensioning the manway cover, the ID and OD clearances between the gasket and groove is approximately 0.034" that goes to zero after tensioning. Over an operating cycle, the gaskets essentially become baked in place and are impenetrable. Three diaphragms had to be replaced due to their gasket groove seating surfaces being scratched during gasket removal. This occurred as the maintenance technicians used the only removal method plausible; a screwdriver between the OD of the gasket and groove to pry out the gasket. A corrective minor mod will be written to repair the scratches and to install two pick holes that straddle the groove OD to allow a tool to get under the gasket and pick it out of the groove. BWC has provided drawing changes to reflect the allowed machining tolerances to remove the scratches and to install the pick holes. All installed diaphragms will have pick holes installed during their next scheduled outages. Reference PIP M-99-4525 for additional information regarding the scratched diaphragms.

The residual bowl water was pumped to lower containment sump floor drains using an electric Simer Utility Pump. No problems were encountered.

All primary manways, studs, and nuts were installed and tensioned using the new procedure enhancements that were incorporated to preclude manway seepage during subsequent cooldowns and stuck studs during their next removal. No problems were encountered installing the primary manway studs. Tensioning of the eight manway covers was extremely successful this outage with the majority of the stud elongation readings being 0.015" – 0.016" (allowed range of 0.0145" to 0.0185"). Having such a small variance is excellent and can be primarily attributed to a detailed equipment refurb, procedure enhancements, and training. Only one stud, 'B' cold leg #19, was low out of tolerance and required single stud tensioning. This location had a stuck stud drilled out this outage and a new replacement installed. When attempting to install the single stud tensioner over this stud, it would not seat properly on the cover. An investigation revealed that the tensioner hydraulic cylinder ID was measured at 2.027" while the non-threaded portion of the stud between the reaction nut and bell nut threads measured 2.037". The original studs installed in 'B' S/G measured 2.0" in this area while the second generation of spare studs all measured approximately 2.035". Drawing MCM 1201.01-0806 does not specify a dimension in this area, but does reflect a 2"-8UNR-2A Full Thread TYP for the bell nut. A replacement stud was located with the 2.0" dimension in this area that was successfully elongated. BWC is investigating why there is a difference in dimensions for this area and HTI has provided a letter authorizing the single stud tensioner ID to be enlarged to 2.100" to accommodate the larger studs. Reference PIP M-99-4492 for additional information regarding the over-sized stud.

The completed original NIS-2 Forms documenting the use of replacement studs in 1B & 1D S/G's as described above are included with the Station's ISI Summary Report. Copies are included in Appendix H.

B. Nozzle Covers

Nozzle dams were not required this outage due to the use of a reactor vessel cover associated with the split pin modification. Nozzle covers were installed without incident and provided adequate FME for the NC system.

C. Eddy Current Inspection

DE&S personnel performed the eddy current acquisition, analysis, data management, and system administration under their QA program. FTI QA Inspector, R.L. Rawlings, was contracted to perform the eddy current oversight as required by the EPRI Examination Guidelines. This assessment included review of the DE&S eddy current procedures, personnel qualifications, equipment and material certifications, and overall quality of DE&S performance. There wasn't any nonconforming items identified during this assessment. A hard copy of FTI's Surveillance Report is attached. SGM&E personnel dispositioned all indications confirmed with RPC as described in the SGMP.

The eddy current bobbin inspection plan for this second in-service inspection included a 20% random sample (every fifth column), tubes around previously plugged tubes, tubes with previous indications, all periphery tubes two deep, and all tubes in rows 1-5. The periphery tubes were included due to a loose part identified in the tube free lane during C1EOC10 outage and the remote potential for tube wear associated with the tube proximity issue. During M1EOC12 outage, rows 1-5 u-bends could not be inspected due to probe pushing problems. In an effort to minimize personnel exposure associated with swinging the SM-22 trunk, its exclusion zone was removed from this plan and will be acquired next outage. This inspection plan evaluated 30% of the total number of tubes in all four RSG's.

A Zetec 0.560" heavy wall 4' beaded MULC tuned bobbin probe was used for this inspection. Due to probe failures during C1EOC10, Zetec modified the two connections between the large poly, probe head, and the small poly. No failures were experienced this outage. DE&S used four eddy current systems for bobbin acquisition commencing in 'A, C, D' hot legs and 'B' cold leg (stuck stud removal in the hot leg). The Zetec 4x4 probe drivers were used as well. Bobbin was run full-length in rows higher than row ten. The low rows were run piece-meal with the u-bends acquired from the hot legs and straight sections from the cold leg. This approach was used to minimize the potential time loss associated with probe pushing problems in the low rows. Essentially no probe pushing problems were encountered this outage.
All indications identified with bobbin were inspected with the Zetec 0.540" & 0.520" RPC +point/pancake probe. The 0.520" U-bend RPC probe proved to be very successful this outage. The tubesheet OXP & NEX calls made during

baseline were also inspected with RPC with the exception of the ones in 'B' cold leg due to schedule constraints and no indications had been identified in these areas to date. A qualified sizing technique using the RPC pancake coil was used to size all wear indications. Below is a summary of the wear indications left in service. Reference Appendix C for the DE&S Outage Summary Report and Appendix E for the Degradation Assessment that includes the Condition Monitoring and Operational Assessments.

					LENGTH (INCHES)	
RSG	TUBE	LOCATION	HISTORY	% TW	AXIAL	CIRC
A	83/60	FB4 -0.60	New	8	0.71	0.21
	94/77	FB4 +0.50	Previous @ 6%	7	0.33	0.23
B	5/72	7H +1.45	New	7	0.25	0.25
C	73/60	FB4 -0.73	*Previous	8	0.84	0.18
	77/60	FB4 -0.68	*Previous	8	0.89	0.18
	83/60	FB4 -0.62	New	8	0.75	0.27
	85/60	FB4 -0.68	New	13	1.11	0.31
	95/60	FB4 -0.66	*Previous	11	1.27	0.17
	117/58	9C +1.50	*Previous	8	1.37	0.25
D	15/142	7H +0.41	New	3	0.24	0.28
	76/85	FB4 +1.07	New	3	0.28	0.29

Total: 11 Wear Indications, 1 reported 1st ISI, 8 @ FB's, 3 @ LG's

* Review of previous history showed a non-reportable indication at this location

There wasn't any pit-like wear indications identified that had a corresponding fan bar anomaly as was identified in the U-1&2 first in-service inspections. No tubes were required to be removed from service. There hasn't been any wear identified through the first two in-service inspections at CNS1. The eddy current inspection was completed within the scheduled 7 day window and under the exposure goal by 6 Rem with 0 PCE's.

The completed NIS-1 Form is included in Appendix H as required by Section XI 1989 Edition documenting the examination and results with any corrective measures.

D. Steam Drum Inspection

In order to verify that the Replacement Steam Generator's secondary side components are performing as designed, a video inspection will be performed in one steam generator every other calendar year rotating between MNS1&2 and CNS1. Due to the redundancy of the secondary side components essentially operating in the same environment, a sample of the following components will be evaluated to determine if any concerns are present; primary and secondary separators, steam outlet venturis, access doors, u-bend support structure, main feed ring, shroud and its supports, and top of tubesheet. FTI was contracted to perform this inspection during M1EOC13. CNS completed the first secondary side inspection during 1EOC10. All components appeared to functioning normally with no signs of corrosion or erosion.

DE&S Maintenance Technicians removed the 'A' RSG secondary manway and #9 & 10 handhole covers to allow access for this inspection. During the removal of the secondary manway cover, a tensioner reaction nut became stuck on the #2 stud. The cover was successfully detensioned with the #2 stud being removed with the reaction nut attached. A new stud was used to install the cover at this location.

A 1500 cfm Copus blower was used to ventilate the upper steam drum area to allow personnel access to perform the separator inspection and open the upper and lower access doors. However, after three shifts of various ventilation configurations, the hydrazine levels remained above the limit that allows personnel access (0.016 vs 0.010 ppm). The decision was made to reduce the scope of the inspection and perform it from outside the manway and handholes. Initial feedback indicates that the layup hydrazine level was 150 ppm versus 75 ppm at CNS1 where they were able to reduce levels to the point to allow access. The SGM&E Group will be working with the Chemistry Department to determine the cause since CNS1 was able to reduce levels to allow access.

FTI used fiber optics to inspection the internals of a primary and secondary separator from outside the #10 handhole and secondary manway. Parts of the main feed ring, shroud, tubesheet, and various support structures were inspected from the #9 handhole. All inspected components appeared to be functioning normal with no signs of corrosion or erosion. A sight dusting of sludge was seen on the secondary face of the tubesheet in the area inspected. Reference Appendix D, FTI Steam Drum Inspection Report, for details and pictures of the inspection.

The #9 & 10 handhole covers were installed and tensioned without any problems. During the tensioning of the secondary manway cover, two studs were below the acceptable elongation range (0.007-0.012"); #16 at 0.006" and #19 at 0.003". Per the installation procedure, the single stud tensioner is used to detension, remove, inspect, and retension the studs in question. Neither stud would detension at 12,800 psig hydraulic pressure. Engineering instructions were provided in the procedure to allow an increase in hydraulic pressure to 13,200 psig. #16 stud was successfully detensioned at this pressure and #19 was not. The stud was removed with the hole, nut, and stud inspected for any anomalies. None were identified and the stud was successfully retensioned with the single stud tensioner to 0.009". BWC, HTI, and SGM&E Engineering discussed the situation with the #19 stud. BWC and HTI provided documentation that allowed an increase in the single stud tensioner pressure to 14,800 psig to detension the stud. The tensioner pressure was increased from 13,200 psig in 200 psig increments and the nut became loose at 14,400 psig. The stud, nut, and hole were inspected with no anomalies identified. A new stud and nut were used and successfully tensioned to 0.009".

Reference PIP # M-99-04575 for documentation regarding the detensioning of #19 stud.

The completed original NIS-2 Forms documenting the replacement of the 1A Secondary Manway #2 & #19 studs and #19 nut are include with the station ISI Summary Report. Copies are included in Appendix H.

E. Secondary Side Penetration Inspection

All secondary side handhole and manway cover's insulation was removed and the joints inspected for any signs of leakage. None were identified.

IV. BUDGET

Not included with this copy.

V. RECOMMENDATIONS/LESSONS LEARNED

Refer to PIP M-99-05355 for tracking of the outage lessons learned.

A. Emphasize importance of timely and accurate setup for nozzle dam, tensioners, and manway cover handling device setup pre-outage refurb in site orientation.
B. Modify primary manway single stud tensioner to accommodate the 2.035" non-threaded portion of the 2 5/8" studs.
C. Follow PIP # M-4629 for adequate resolution of the decon pit ownership and preparation for post-outage equipment decon.
D. Incorporate several enhancements into the primary, secondary, and handhole installation procedures.
E. Emphasize the importance of verbatim reading of procedures when being performed from the control stations, i.e. removal/installation of the primary manways.
F. Develop a definite plan with RP for the covering of the S/G platforms prior to the outage.
G. Use the inexpensive gray corrugated vacuum hose for each entire system.
H. Modify vacuum hose connection at the vacuum cleaner.
I. Re-design the vacuum lead shielding to allow easy access for bag change-out.
J. Only use the 0.520 U-bend MRPC probe versus 0.540.
K. Establish policy with regard to work hour extensions based on duration and number of workers prior to outage.
L. Evaluate possibility of sharing the ice condenser air compressors.
M. Evaluate with the chemistry department the inability to lower secondary hydrazine levels to the point to allow personnel access for the steam drum inspection.
N. Specify that the primary manway studs are initially placed in the lower laterals until the cleaning process starts versus the storage boxes.
O. DE&S to resolve the network data wrap and MIZ30 overheating problems.
P. Continue to use a board to deflect the CACFU exhaust away from the platforms.
Q. Continue to use only one penetration (A/D) and revise the procedure to allow the annulus flange cover to be removed first.
R. Procure additional spare tensioner hydraulic hoses.
S. Establish dedicated communication lines for any work associated with the secondary manways.
T. Fabricate spacers for the bottom of the primary manway bins in order to position the manway covers near the top of the bins.
U. Evaluate with RP and Ops options to prevent breathing air from getting too hot.

VI. Appendices

Not included with this copy. Available upon request.