AMAG ROOT CAUSE

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K-3

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AMAG ROOT CAUSE - FINAL

[redacted] Report

1. Title: [redacted] Ultrasonic Flow Measurements Caused by Low Frequency Velocity Signals Result in Exceeding Licensed Maximum Power Level at Byron and Braidwood Stations

40AS

2. Unit(s): Byron Station Units 1 and 2
Braidwood Station Unit 2

Event Date: 8/28/03
Event Time: 1743 hrs

3. Action Tracking Item Number: 173510-14
Report Date: [redacted]

4. Investigators:

Team Lead	Don Brindle (Byron Engineering)
Facilitator	Mike Ryterski (Byron Regulatory Assurance)
SME's	Jeff Drowley (Cantera Engineering)
	Joe Wolff (Braidwood Engineering)
	Chip French (Westinghouse)
	Vahid Askari (AMAG)
Support Staff	Steve Scibona (Instrument Maintenance)
	Bryan Currier (Byron Reactor Engineering)
	Nick Holhut (Byron Engineering)
	Kevin Ramsden (Cantera Engineering)
Qualified RC Investigator	Jim Harkness (Byron Engineering)

5. Executive Summary:

1.

2. REASON FOR THE INVESTIGATION

The reason for this Root Cause Investigation was to determine the cause of the past overpower condition on Byron Units 1 and 2 and Braidwood Unit 2 due to the AMAG installation. This condition was identified due to differences in feedwater venturi correction factors (CF) seen between the individual feedwater loops and a similar AMAG installation on the common Feedwater header. Subsequent evaluations by AMAG indicate that the potential historical overpower condition on Byron Unit 1 was +1.56% or a total of 101.56%. Similar evaluations for Byron Unit 2 and Braidwood Unit 2 indicate that the maximum potential historical overpower condition for Byron Unit 2 is +0.33% and for Braidwood Unit 2 is +0.21%. The basis for this determination is the difference between the individual feedwater loops AMAG calculation and the common header AMAG calculation for the same statepoint conditions.

3. SCOPE OF THE REVIEW

The scope of this root cause includes determining the causes for (1) CFs varying with changes in power level, (2) CFs not linear with feedwater venturi output, (3) AMAG flow signal contamination (noise), and (4) difference between the sum of the individual loop flows and the common header flow greater than the acceptable statistical limitation of the AMAG installation. This investigation will also address why the apparent condition was not identified upon initial installation or subsequent evaluations of the AMAG instrumentation. In addition, an evaluation for 10 CFR Part 21 applicability and a risk assessment associated with the apparent historical overpower condition will also be included in the report. Although the scope of this review was aimed at the technical issues associated with the source of the noise contamination, several organizational and programmatic causal factors were identified. These causal factors are pointed out in the text and addressed in section 8.B.B.

ROOT CAUSE

The root cause of this event was noise contamination of the AMAG ultrasonic signal. The cause of the noise contamination was determined to be acoustic resonant response of the feedwater piping system. The ultrasonic signal noise contamination caused the AMAG system to indicate a lower than actual feedwater flowrate which resulted in a non-conservative calorimetric result. This signal noise contamination was not identified during initial installation of the AMAG installations at Byron or Braidwood or during subsequent reviews of the installation. This phenomenon was identified during reviews that were performed on Byron Unit 1 during late August 2003. The reason the noise on the ultrasonic signal was not identified until August 2003 is discussed in Attachment K.

4. CORRECTIVE ACTIONS

Corrective Actions to Prevent Recurrence involve writing/revising procedures to require checking the AMAG sensor signals for noise prior to use. Other corrective actions include "qualifying" the common header sensors for use (the final decision to implement the use of correction factors developed from the common headers will be made by site Senior Management.), developing an electronic filter to remove the noise from the sensor signal, modifying the AMAG DIAGNOSE program for use by station personnel to evaluate signal noise, and improving communications and system knowledge. See section 8.B.C for details. Due to the problems associated with the AMAG system, over the past several years, Cantera Engineering developed a Project Plan earlier this year. Byron MRC/PORC requested that Cantera re-evaluate its AMAG Project Plan based on the information obtained during this Root Cause. The CNO of Exelon has commissioned a Root Cause to perform a broad review of the AMAG management decision-making process. This review will include a report directly to the CNO. Additional action have been added to this RCR to disposition any additional actions coming from that review. This additional review is being tracked under this Condition Report (173510).

5. EXTENT OF CONDITION

A review of the AMAG installations at Braidwood and Byron indicated the presence of ultrasonic signal noise contamination on several, but not all, of the individual feedwater line measurements. AMAG personnel reviewed the signal/data from the installed feedwater common feedwater header locations and determined the ultrasonic signal noise contamination was not present on any of the common headers. This issue has been evaluated under 10 CFR Part 21 and has been determined to be applicable to other plants utilizing ultrasonic instrumentation. This issue will be reported under the Licensee Event Responses (LERs) due on 9/28/03 for Byron and 9/30/03 for Braidwood.

6. RISK ASSESSMENT

The safety significance of the AMAG overpower issue was evaluated by Westinghouse and NFM. The Westinghouse evaluation provided in Letter CAE-03-76 for Byron and Letter CCE-03-85 for Braidwood, and covered the following concerns:

1. Design Transients
2. Operating Margin to Trip
3. Neutron Fluence Projections, Reactor Vessel Integrity and LTOP
4. LOCA Containment Integrity
5. Steamline Break Containment Integrity
6. Non-LOCA Events
7. Large Break LOCA
8. Small Break LOCA
9. Post-LOCA
10. LOCA Forces
11. Offsite and Control Room Doses
12. Fuel Evaluation

The evaluations were performed for a power level of 102.62% for both Byron and Braidwood, plus a 2% uncertainty where applicable. The evaluation covers the time period from August 2000 through August 2003. (The 102.62% power is conservatively based on actual venturi flow, with no AMAG correction.) The evaluations concluded that the applicable regulatory acceptance criteria were met for all the events evaluated above. A Byron/Braidwood evaluation (Calculation PSA-B-03-05, Rev. 0) was performed by Nuclear Fuels for the Steam Generator Tube Rupture (SGTR) event at a power level of 102.62% for Byron 1 Cycles 11 and 12, Byron 2 Cycles 9, 10 and 11, and Braidwood 2 Cycles 8, 9 and 10. The evaluation concluded that the B/B Unit 1 Margin to Overfill (MTO) was 195 ft^3; the cycle-specific Tavg was sufficient to offset the overpower condition. For B/B Unit 2, the MTO was 240 ft^3; the cycle-specific Tavg and SG tube plugging levels were sufficient to offset the overpower condition. Because there is more than a 50% margin to the regulatory limits for offsite dose, it was judged that a 2.62% overpower condition would not result in exceeding the regulatory limits for SGTR. Therefore, it is concluded that the maximum historical overpower condition is acceptable from a safety analysis standpoint.

7. REPORTABILITY

Byron notified the NRC on 8/28/03 of a potential violation of licensed maximum power level on Units 1 and 2 and Braidwood notified the NRC on 8/31/03 of a potential violation of licensed maximum power level on Unit 2. Byron and Braidwood will both provide written notification of this event to the NRC in a 30 day LER. Byron LER 454-2003-003-00 and Braidwood LER 457-2003-002-00 will meet the Part 21 reportability requirement as discussed in Exelon procedure LS-AA-1110, "Reportable Event SAF".

8.

9. PREVIOUS EVENTS

There were no previous occurrences of a violation of licensed maximum power level due to the AMAG system ultrasonic noise. Byron reported an overpower of 0.12% on Unit 1 and 2 due to personnel error while using the AMAG system (LER 2001-

001-01).

10. LESSONS LEARNED

The following items are the lessons learned that other sites using the CROSSFLOW system should consider.

a) AMAG signals should be checked for noise prior to using AMAG to implement feedwater flow correction factors whether being used periodically or continuously.

b) If AMAG is being used continuously, it needs to be checked for noise following major plant changes to the feedwater system (i.e., feedwater pump swap, feedwater heater operation).

6. Condition Statement:

AMAG ultrasonic signal noise contamination impacted the calculated CF causing an overpower condition on Byron Units 1 and 2 and Braidwood Unit 2. The significance of this event was an overpower condition (potentially since May 2000) on Byron Units 1 and 2 and an overpower condition (potentially since June 1999) on Braidwood Unit 2. The safety consequences of this event are minimal. As discussed above, Westinghouse and Nuclear Fuels evaluated the overpower condition for both Byron and Braidwood and concluded that the maximum historical overpower condition is acceptable from a safety analysis standpoint.

7. Event Description:

Advanced Measurement and Analysis Group, Inc. (AMAG) and Westinghouse Electric Company LLC manufacture and market the ultrasonic flow measurement system used at Braidwood and Byron Stations. The ultrasonic flow measurement system, known as CROSSFLOW™ (but more commonly referred to as AMAG at Byron), uses ultrasonic technology coupled with cross-correction statistical techniques to measure feedwater flow by determining the displacement of time it takes for flow turbulences to travel a known distance in the feedwater piping. The AMAG system uses two sets of transducers externally mounted on the common header feedwater piping or on each of the four individual feedwater loops. A high frequency signal is sent to the two sets of transducers and as the signal passes through the fluid, it is modulated by the flow turbulences in the fluid (referred to hereafter as "eddies"). These same eddies also modulate the second ultrasonic signal located approximately one foot further downstream. The difference between the two modulated signals is the displacement in time that it takes for the eddies to travel between the two sets of transducers. The fluid velocity is then calculated by dividing the known distance between the two sets of transducers by the time delay. A more detailed description of AMAG system operation is included as Attachment E to this report.

The AMAG system installation was completed at Braidwood in April 1999 and at Byron in May 1999. Following system testing and review of results, Braidwood Units 1 and 2 implemented AMAG in June 1999 and Byron Units 1 and 2 implemented AMAG in May 2000. AMAG is utilized as a calibration tool to correct feedwater venturi flow measurements through use of "correction factors" to recover lost megawatts due to venturi inaccuracy issues. The feedwater venturis are periodically checked using a set of portable AMAG electronics and the venturi flow correction factors (CFs) are updated in the process computer as a manual input by Operations. Following implementation of AMAG at Braidwood and Byron, the periodic AMAG measurements indicated a difference between the Braidwood and Byron feedwater venturi flowrates and venturi CFs, resulting in different megawatt electric recoveries between the two stations with Byron Unit 1 generating more megawatts electric than Braidwood Unit 1 (reference Byron Letter 99-109 (7/28/99)). Additional reviews (Exelon NGG Senior Management, NSRB, and PORC) were subsequently performed. A decision to implement feedwater venturi correction factors using AMAG was made at Byron in May 2000. The failure of these additional reviews to identify a potential overpower condition was a missed opportunity to identify this condition at an earlier date (Causal Factor 1).

The Byron thermal performance engineer subsequently wrote Condition Reports (CRs) 78729 (10/5/01) and 80251 (10/16/01) identifying issues concerning power uprate results. As a result of plant parameter differences and the megawatt electric discrepancies, reviews of plant performance parameters and the AMAG system installations at Byron were performed (reference CR 91771 (1/17/02) for documentation of reviews).

Westinghouse/AMAG technical reviews at Byron performed in 2002 indicated that the AMAG instrumentation behavior observed on Unit 1 did not exhibit the consistent performance seen in other industry AMAG installations. Specifically, the calculated venturi CF varied unexpectedly as a function of power and the CFs appeared to change after power uprate was implemented. Based on the data available at that time, the results of AMAG testing and evaluations indicated that the AMAG components were performing in an appropriate manner and that the test criteria for acceptable AMAG performance were being met. As part of the technical review, an AMAG bracket was installed on the feedwater common header at Byron Unit 1 in late February 2002. A test was performed on Byron Unit 1 on 3/10/02 that indicated the sum of the flows in the four feedwater loops plus tempering lines equaled the flow in the feedwater common header at the high end of the calculated allowable statistical limit (b)(4) (b)(4) at the prevailing power level of approximately 91% (reference Calc 059-PENG-CALC-084 Revision 1 dated 4/24/02). A similar test, performed prior to AMAG optimization, was performed at approximately 95% power on 2/27/02 and 2/28/02 and indicated differences of 1.1-1.3%. The failure to question the differences in the results of these two tests was a missed opportunity to identify a potential overpower condition at an earlier date (Causal Factor 1).

Westinghouse/AMAG recommended additional data be gathered to further investigate these anomalies. During this timeframe, CR 101618 (3/29/02) was written by the Byron thermal performance engineer to document an unexplained change in the Byron Unit 2 CFs. At that time, the last two consecutive 2A loop CFs changed nearly 1 percent. Westinghouse issued letter CAE-03-4 on 1/30/03 to address the issues identified on the Byron 2A loop. This report did not identify a specific cause of the 2A loop discrepancies and recommended additional data be collected for a minimum period of six months for each of the Byron units to correlate the unexpected changes in CF to specific plant operating conditions and to identify the reason for the CF variation. The failure to further investigate the cause of the discrepant 2A loop results was a missed opportunity to identify a potential overpower condition at an earlier date (Causal Factor 1).

In May 2003, as a result of an Exelon corporate initiative to resolve Byron and Braidwood megawatt electric discrepancies, an AMAG bracket and instrumentation was installed on the feedwater common header at Braidwood Unit 1 to compare the flow in the common header to the sum of the flows in the four feedwater loops. The results of this test, documented in Westinghouse calculation CN-PS-03-18, Revision 0, indicated the independent measurements yielded results with a relative difference of 0.021% which was well within the expected uncertainties. Because the Exelon data gathering equipment was installed on Byron Unit 2, additional data gathering equipment, lent to Byron Station by AMAG, was installed on Byron Unit 1 in May 2003 with modem access to permit AMAG to continuously retrieve and trend Unit 1 AMAG data remotely. Plant data (venturi flows, feedwater temperature, etc.) was also provided to AMAG to allow comparison to the AMAG data. An additional AMAG bracket and instrumentation was then re-installed on the feedwater common header at Byron Unit 1 on 8/20/03 and connected to the AMAG-owned computer. The purpose of this activity was to once again compare the flow in the common header to the sum of the flows in the four individual feedwater lines at the 5.0% uprated power condition and to collect continuous data during the coast down into the planned B1R12 refueling outage to determine whether there was/is a change in CF with power level.

The results at full uprated power operation for the Byron Unit 1 common header test, documented in Westinghouse letter CAE-03-069 dated 8/28/03, reported the difference between the sum of the AMAG measurements in the four feedwater loops and the common header was outside the acceptable statistical limits (b)(4) (b)(4) (b)(4) Review of the current and past collected information indicated that the CF had a history of unexpected changes in the four individual feedwater loops. In addition, CF appeared to vary as a function of power (not consistent with expected behavior) and individual feedwater loop flow measurements were non-linear with respect to the venturi output (again not consistent with expected behavior). Westinghouse/ AMAG stated that the variations were associated with noise contamination of the signal, creating a bias, either positive or negative, affecting the measured results (Causal Factor 2). Westinghouse/AMAG also recommended in Westinghouse letter CAE-03-70, dated 8/29/03, that the flow measurement in the Byron Unit 2A loop be returned to the venturi due to noise contamination. These issues were documented in CR 173510. As a result of the notifications from AMAG/Westinghouse on 8/28/03 and 8/29/03, Byron Station Management made a decision to return the AMAG correction factors to 1.0 on both units, pending resolution of the issue. This action returned the plant power level to the feedwater venturis only.

Braidwood Units 1 and 2 were reviewed on 8/30/03 as documented in Westinghouse letter CCE-03-78 dated 9/2/03. Although some noise contamination was seen on Braidwood Unit 1, Westinghouse/AMAG recommended Braidwood Unit 1 continue to operate in its current condition since the common header test performed in May 2003 verified the composite flow being measured by the four feedwater loops was accurate and valid (within 0.021%) and the CF had not been corrected or changed since that test. Westinghouse also recommended that the flow measurement in the Braidwood Unit 2A and 2B loops be returned to the venturis, since noise was seen on these loops, but there was no common header data at that time to provide confirming data on the accuracy of the individual loops. These issues were documented in CR 173819 at Braidwood Station which implemented the recommendations from Westinghouse for Braidwood Unit 2.

Based on the results of the Westinghouse/AMAG review documented in the three previously identified Westinghouse letters, Byron notified the NRC on 8/28/03 of a potential violation of maximum power level on Units 1 and 2 (Event 40117) and Braidwood notified the NRC on 8/31/03 of a potential violation of maximum power level on Unit 2 (Event 40123). An Event and Causal Factor flowchart is included as Attachment A to this report. A detailed historical timeline for this root cause is included as Attachment D to this report.

Westinghouse/AMAG review and evaluation of these issues, documented in the three previously identified Westinghouse letters, led to a preliminary conclusion that the inconsistent measurements in the four feedwater loops were being driven by a variable affecting the ultrasonic flow signals (and ultimately the calculated time delay) measured by the AMAG electronics. Using frequency spectrum analysis, the variability in the time delay measurement was determined to potentially be the result of ultrasonic signal noise contamination. A review of the AMAG installations at Braidwood and Byron indicated the presence of ultrasonic signal noise contamination on several, but not all, of the individual feedwater line measurements as follows: Byron 1A through 1D (letter CAE-03-069), Byron 2A (letter CAE-03-070), Braidwood 1A and 1B (letter CCE-03-078), and Braidwood 2A and 2B (letter CCE-03-078). Subsequent data acquisition also identified noise on the Byron 2B loop. This noise appeared at varying magnitudes at frequencies of approximately 5, 10, 15, and 20 hertz. The ultrasonic signal noise contamination was absent from the two installed feedwater common header locations at Byron Unit 1 and Unit 2, and Braidwood Unit 1. See Attachments L and M, Byron Unit 1 and Unit 2 Spectrum Results, and Braidwood Unit 1 and Unit 2 Spectrum Results, for examples of the noise.

Numerous causes for the apparent noise were considered and investigated. This evaluation is documented in Attachment F to this report. Detailed evaluation by the Root Cause Team of this event determined that the root cause was noise contamination of the AMAG ultrasonic signal caused by acoustic resonant response of the feedwater piping system. Potential resonant frequencies were predicted using several theoretical methods. Dynamic pressure measurements were taken on each of the four Byron Unit 2 feedwater lines at a low point drain located near the flow measurement venturi. Analysis of the dynamic pressure data shows agreement between the theoretical methods and actual plant response and suggesting that the principal resonance is likely that of the segment of piping between the feedwater regulating valve and the steam generator. Data analysis also supports the existence of low frequency resonant system response consistent with the noise frequencies and reflects the magnitude of noise differences in the four feedwater loops (i.e., noise is highest in loop 2A). A detailed discussion of the acoustic response of the Byron feedwater lines is included as Attachment G to this report. The evaluation shows that the Byron feedwater lines natural frequency is below 25 Hz. Computer modeling discussed below supports an adverse impact on the CF at frequencies below 25 Hz.

AMAG provides a diagnostic program, DIAGNOSE, with the system. Contained in DIAGNOSE is a tool for frequency spectrum analysis. This tool was used in the late August 2003 to identify the noise contamination. The noise contamination was not identified prior to August 2003 because the DIAGNOSE program is not a required part of the AMAG installation process procedure (Causal Factor 3). It is only implemented if noise is suspected. Noise was not suspected at the time of installation, nor in March 2002. AMAG had no basis for suspecting noise. In March 2002, they were preoccupied with investigating hardware issues; they did not identify any reason at that time to suspect noise or to utilize the DIAGNOSE program. Until recently there was no common header installation to allow calculation of statistical variance. Refer to Attachment K for a list of interview questions on this topic.

Pressure waves, induced by the resonance previously discussed, introduced phase shifts into the ultrasonic signals that were treated by the AMAG system as eddies. However, the additional phase shifts were independent of the velocity of the fluid in the pipe (i.e., the fluid velocity remained the same). AMAG performed testing to estimate the effect of the noise on the performance of the AMAG ultrasonic flow measurement. This was done by electronically contaminating a simulated demodulated signal using simulated noise with a similar characteristic on the spectrum to that of the noise observed on the Byron feedwater loops. The resulting signals were then analyzed to obtain a cross correlation peak that is used to determine the time delay. The resulting flow was then compared to the expected flow that corresponded to the uncontaminated signal. These calculations were performed for a number of combinations of time delays (different power level or flowrate) and noise frequency spectrum. The base time delay was modified to cover a range of 100% flow to 80% flow. The simulated cases for the calculation of the time delay with and without contamination of the flow demodulated signal with noise show that there is an effect on the calculated time delay. The results of the simulations are summarized as follows:

a. The noise affects the calculation of the CFs by changing the time delay calculation. However, the specific amount and direction cannot be predicted.
b. The variance in the time delay calculation is dependent on noise structure (frequency spectrum, intensity) and the actual time delay for the plant conditions at which the data is being taken.
c. The presence of this type of noise could cause a dependency of the calculated CF on the power level, which is the result of the noise effects on the calculated time delay at different power levels discussed in 2. above.

A detailed discussion of the effect of the resonance induced phase shifts on the AMAG system is included in Attachment H to this report.

The change in time delay lowered the calculated fluid velocity and therefore lowered the AMAG measured feedwater flowrate. After the CFs calculated from the lower measured AMAG feedwater flowrate were input into the calorimetric program, the resulting reduced feedwater flow caused a lower (non-conservative) calorimetric power measurement which caused an overpower condition when reactor power was adjusted to match the calorimetric power. It is believed this condition has potentially existed since AMAG was put in service at Braidwood (June 1999) and Byron (May 2000).

For Byron, a comparison of the DIAGNOSE program noise frequency peaks (Attachment L) against the acoustic frequencies of the piping for the Byron units (Attachments G and O) has demonstrated that the loops have frequencies in common between the sets.

The frequencies in common between Attachments L, G and O are listed below (from the acoustic model):

Loop Number	Frequency 1	Frequency 2	Frequency 3	Frequency 4
1A	10.0	16.2	23.3	

1B	5.9	9.9		
1C	5.3	8.9	12.5	16.0
1D	9.4	15.6	21.9	
2A	9.3	15.5		
2B	13.5	17.4		
2C	9.3			
2D	9.7			

From the data above, it can be seen that the most susceptible loops are on Unit 1 at Byron, where all loops are seeing frequencies that correspond to at least two of the acoustic frequencies for the piping. On Unit 2, only loops A and B see as many as two frequencies that correspond to the pipe acoustic frequency. The two or greater frequency agreements corresponds to the loops where noise is causing data problems on both units. Pressure testing to confirm the acoustic model is warranted on Unit 1.

For Braidwood, the following frequencies predicted by the acoustic model (Attachment P) are in the range seen by the AMAG DIAGNOSE software (Attachment M):

Loop Number	Frequency 1	Frequency 2	Frequency 3	Frequency 4
1A	9.61	16.02	22.42	
1B	5.86	9.76	17.57	
1C	8.47			
1D	15.42	21.58		
2A	15.29			
2B	5.77	9.62		
2C	5.40			
2D				

For Braidwood, no pressure testing has been performed to validate the acoustic model. However, the model has been validated on Byron Unit 2. This would suggest that Braidwood Unit 1 is susceptible to CF error on loops A, B, and D, and that Braidwood Unit 2 is susceptible on loop B. Further testing work is warranted on these units.

Attachment G also indicates that the Byron Unit 2 common header piping also has natural frequencies in the range of concern (<25 hz), however, there is no large pressure drop to act as a driver. This is supported by data taken on Byron Unit 2 during a power decrease for TV/GV testing on 9/14/03 (Attachment N) that shows that the CF determined using the Byron Unit 2 common header is essentially constant between 82% and 100% power.

The evaluations discussed above are based on extensive data on Byron Unit 2. Somewhat less extensive data was available on Byron Unit 1. Less data yet was available for Braidwood Units 1 and 2. Other differences between the units (FRV's operating at different points, FW heater bypass valves open/closed, FW79 check valve differences, etc.) cannot be entirely ruled out, although it is felt at this time that these differences may only impact the degree of noise and/or the amount of influence the noise has on the AMAG time delay. Therefore, the conclusion that a pressure driver (assumed to be the FRV) is exciting the individual feedwater lines at their natural resonant frequency, thereby inducing noise in the AMAG sensor, while believed to be applicable to Byron Unit 1 and Braidwood Unit 1 and Unit 2, cannot be positively determined at this time. Further data must be collected for these units. Therefore, additional actions have been developed to collect and evaluate this data. See section 8.B.C.4.

8. Evaluation:

A. Investigation and Root Cause Analysis Techniques

The Root Cause Investigation Team Charter is included in this report as Attachment C.

Root Cause Analysis Techniques:

The major root cause investigation techniques used in this analysis were Interviewing, Event and Causal Factor (E&CF) Charting, TapRoot and Cause and Effect Analysis (combined with Troubleshooting).

Interviewing: Interviews were conducted with key personnel throughout the troubleshooting aspects of this investigation. Key personnel included various AMAG equipment industry experts from Westinghouse and AMAG, Exelon corporate mechanical piping design analysis engineers, Byron Station vibration, acoustic and AOV monitoring experts, the Byron Station thermal performance engineer and other personnel familiar with the historical aspects of this event. The questions and answers covered a wide range of topics and appear as information statements throughout this report. In particular, specific interview questions relating to why the noise was not discovered earlier are included in Attachment K.

Event and Causal Factor Charting/TapRoot Event Tree: The analysis utilized E&CF Charting in conjuction with TapRoot Event Tree analysis. The following inappropriate actions or equipment failures were identified as causal factors during this review:

1. Management missed opportunity to address AMAG concerns prior to implementation.
2. AMAG flow signal (noise) contamination noted on most of individual flows.
3. AMAG Diagnostic program "DIAGNOSE" is not a required part of installation process.

A hard copy of the E&CF chart is included in this report as Attachment A. A hard copy of the TapRoot Event Tree analysis is included in this report as Attachment B. A more detailed description of the event timeline is included in this report as Attachment C.

Cause and Effect Analysis: A Cause and Effect Analysis review was performed to verify the adequacy of the troubleshooting activities conducted during the Root cause investigation phase. In this case, the Cause & Effect Analyis was applied to the following five issues identified upfront in the Charter for the RC Team:

1. AMAG flow signal contamination (noise).
2. Difference between the sum of the individual loop flows and the common header flow greater than the acceptable statistical limitation of the AMAG installation.
3. CFs varying with changes in power level.
4. CFs not linear with Feedwater venturi output.
5. Why the apparent condition was not identified upon initial installation or subsequent evaluations of the AMAG instrumentation.

   A summary of the cause and Effect Analysis is included in this report as Attachment J.

B. Summary of Causes and Corrective Actions

Root Cause # 1: The root cause of this event was noise contamination of the AMAG ultrasonic signal. The cause of the noise contamination was determined to be acoustic resonant response of the feedwater piping system. The ultrasonic signal noise contamination caused the AMAG system to indicate a lower than actual feedwater flowrate which resulted in a non-conservative calorimetric result.

A. CAP Trend Codes

Trend codes have been reviewed and updated commensurate with Causal Factors associated with this event. This review included condition and problem types, error precursors, and failed defenses. These trend codes were appropriately related to the process and causing organizations

B. Causal Factors

1. Management missed opportunity to address AMAG concerns prior to implementation.

People - Work Practices (PWP)
Issue Not Communicated Effectively (WPC)
Configuration Change Acceptance Testing Criteria (CC107)
Risk Awareness - Questioning Attitude (WPRA)
Management System (3M)
Configuration Management (CC20)

a. Individual Defense

Questioning Attitude (J)
Supervision/Management (M)

b. Error Precursor

Human Nature (HPH) — Assumptions (03), Mindset (05)

c. Cause

Contributing Cause - The lack of a questioning attitude during AMAG implementation and subsequent reviews.

d. Bases

There was conflicting information between plant data and AMAG data and a decision was made to implement AMAG and to continue its use without resolving these conflicts.

There was no knowledge of the AMAG DIAGNOSE program that could have potentially identified this issue at an earlier date.

e. Corrective Actions

Establish a communication protocol (timing/frequency of communications, minimum information to be communicated, personnel required to be in attendance, etc) with the involved organizations to improve the working relationships and effectiveness of the groups through effective sharing of relevant information (from Attachment I, Independent Assessment). This is an interim action for future AMAG discussions until the overall decision-making review is complete. - see CA9, 10, and 11 .

2. AMAG flow signal (noise) contamination noted on most of individual flows.

Equipment-Instrumentation and Control (EQIC)
Sensor (ICS)
Component/Part Design Application Deficiency (C3S)
Design Adequacy (CC22)

a. Individual Defense

Not applicable, not a human performance issue.

b. Error Precursor

Not applicable, not a human performance issue.

c. Cause

Root Cause - The root cause of this event was noise contamination of the AMAG ultrasonic signal.

d. Bases

The cause of the noise contamination was determined to be acoustic resonant response of the feedwater piping system. The ultrasonic signal noise contamination caused the AMAG system to indicate a lower than actual feedwater flowrate which resulted in a non-conservative calorimetric result. This signal noise contamination was not identified during initial installation of the AMAG installations at Byron or Braidwood or during subsequent reviews of the installation. This phenomenon was identified during reviews that were performed on Byron Unit 1 during late August 2003.

e. Corrective Actions to Prevent Recurrence

Revise BVP 800-44/BwVP 850-20 and initiate a new procedure BVP 800-47/BwVP 850-26 for the common header, to include in a step to check AMAG for noise. If noise exists that contaminates the signal, do not use AMAG to establish new correction factors (CF's). Include in the procedure an acceptance criteria for determining if the AMAG signal contains noise that adversely affects the AMAG results. - see CAPR1 and 2.

"Qualify" (i.e., appropriately install the sensor, complete the applicable Westinghouse certification calcs and Byron/Braidwood Calorimeteric Uncertainty calc (NED-I-EIC-0233, Rev. 1A), complete BVP 800-47/BwVP 850-26, implement the requirements of letter CAE-03-75/CCE-03-82, etc.) the common headers on each Byron/Braidwood unit for use as an approved sensor for determining CF's - see CA1 and 2. (The final decision to implement the use of correction factors developed from the common headers will be made by site Senior Management.)

Pursue modifications of the AMAG system to filter the noise and allow "qualification" of the individual loops for determination of loop CF's - see CA3 and 4.

3. AMAG Diagnostic program "DIAGNOSE" is not a required part of installation process.

Equipment-Instrumentation and Control (EQIC)
Sensor (ICS)
Operating Procedure or Practice Deficiency (C4WIO)
Design Adequacy (CC22)
People - Work Practices (PWP)
Application of Skill, Technique, or Tools (WPK)
No Communication or Not Timely (4NC)
Configuration Change Acceptance Testing Criteria (CC107)

a. Individual Defense

Questioning Attitude (J)
Document Preparation (L)

b. Error Precursor

Human Nature (HPH)	Habit Patterns (02)
	Assumptions (03)

c. Cause

Contributing Cause - The failure to use the diagnostic program (DIAGNOSE) contributed to the failure to identify a potential overpower condition at an earlier date.

d. Bases

The AMAG diagnostic program, DIAGNOSE, is a tool for frequency spectrum analysis. This tool was used in the late August 2003 to identify the noise contamination. The noise contamination was not identified prior to August 2003 because the DIAGNOSE program is not a required part of the AMAG installation process procedure. It is only implemented if noise is suspected. Noise was not suspected at the time of installation, nor in March 2002. AMAG had no basis for suspecting noise. In March 2002, they were preoccupied with investigating hardware issues; they did not identify any reason at that time to suspect noise or to utilize the DIAGNOSE program. Until recently there was no common header installation to allow calculation of statistical variance.

e. Corrective Actions

Pursue changes to the DIAGNOSE program to make it user-friendly for Byron/Braidwood station personnel to use to determine if noise is present on the AMAG sensors. AMAG to establish, and provide to Exelon for review, an acceptance criteria for determining if the AMAG signal contains noise that adversely affects the AMAG results. - see CA5, 6, 7 and 8.

C. Corrective Actions

1. Immediate and Interim Corrective Actions

Byron Units 1 and 2 and Braidwood Unit 2 reactor power was reduced to 100% consistent with feedwater flow as measured directly by the venturis without using the AMAG correction factors upon notification from Westinghouse/AMAG (2A and 2B loops only for Braidwood Unit 2).

Completed 8/29/03 - Byron Units 1 and 2
Completed 8/31/03 - Braidwood Unit 2

2. CAPRs

CAPR1 Action: Revise BVP 800-44 and initiate a new procedure BVP 800-47 for the common header, to include in a step to check AMAG for noise. If noise exists that contaminates the signal, do not use AMAG to establish new correction factors (CFs). Include in the procedure an acceptance criteria for determining if the AMAG signal contains noise that adversely affects the AMAG results.
Responsible Organization: Byron PED (A8830NESTT)
Due Date: 10/17/03

CAPR2 Action: Revise BwVP 850-20 and initiate a new procedure BwVP 850-26 for the common header, to include in a step to check AMAG for noise. If noise exists that contaminates the signal, do not use AMAG to establish new correction factors (CFs). Include in the procedure an acceptance criteria for determining if the AMAG signal contains noise that adversely affects the AMAG results.
Responsible Organization: Braidwood PED (A8930TT)
Due Date: 10/17/03

3. Corrective Actions

CA1 Action: "Qualify" (i.e., appropriately install the sensor, complete the applicable Westinghouse certification calcs and Byron/Braidwood Calorimeteric Uncertainty calc (NED-I-EIC-0233, Rev. 1A), complete BVP 800-47, implement the requirements of letter CAE-03-75/CCE-03-82, etc.) the common headers on both Byron units for use as an approved sensor for determining CF's. (The final decision to implement the use of correction factors developed from the common headers will be made by site Senior Management.)
Responsible Organization: Byron PED (A8830NESTT)
Due Date: 10/31/03

CA2 Action: "Qualify" (i.e., appropriately install the sensor, complete the applicable Westinghouse certification calcs and Byron/Braidwood

Calorimeteric Uncertainty calc (NED-I-EIC-0233, Rev. 1A), complete BwVP 850-26, implement the requirements of letter CAE-03-75/CCE-03-82, etc.) the common headers on both Braidwood units for use as an approved sensor for determining CF's. (The final decision to implement the use of correction factors developed from the common headers will be made by site Senior Management.)
Responsible Organization: Braidwood PED (A8930TT)
Due Date: 10/31/03

CA3 Action: Pursue modifications of the AMAG system to filter the noise and allow "qualification" of the individual loops for determination of loop CF's.
Responsible Organization: Byron PED (A8830NESTT)
Due Date: 4/30/04

CA4 Action: Pursue modifications of the AMAG system to filter the noise and allow "qualification" of the individual loops for determination of loop CF's.
Responsible Organization: Braidwood PED (A8930TT)
Due Date: 4/30/04

CA5 Action: Pursue changes to the DIAGNOSE program to make it user-friendly for Byron station personnel to use to determine if noise is present on the AMAG sensors. AMAG to establish, and provide to Exelon for review, an acceptance criteria for determining if the AMAG signal contains noise that adversely affects the AMAG results.
Responsible Organization: Byron PED (A8830NESTT)
Due Date: 4/30/04

CA6 Action: Pursue changes to the DIAGNOSE program to make it user-friendly for Braidwood station personnel to use to determine if noise is present on the AMAG sensors. AMAG to establish, and provide to Exelon for review, an acceptance criteria for determining if the AMAG signal contains noise that adversely affects the AMAG results.
Responsible Organization: Braidwood PED (A8930TT)
Due Date: 4/30/04

CA7 Action: Until CA5 is complete, provide access to the CROSSFLOW measurements in order for AMAG to perform a frequency spectrum analysis to confirm the absence of signal contamination whenever such checks are necessary. AMAG to establish, and provide to Exelon for review, an acceptance criteria for determining if the AMAG signal contains noise that adversely affects the AMAG results.
Responsible Organization: Byron PED (A8830NESTT)
Due Date: 4/30/04

CA8 Action: Until CA6 is complete, provide access to the CROSSFLOW measurements in order for AMAG to perform a frequency spectrum analysis to confirm the absence of signal contamination whenever such checks are necessary. AMAG to establish, and provide to Exelon for review, an acceptance criteria for determining if the AMAG signal

contains noise that adversely affects the AMAG results.
Responsible Organization: Braidwood PED (A8930TT)
Due Date: 4/30/04

CA9 Action: Establish a communication protocol (timing/frequency of communications, minimum information to be communicated, personnel required to be in attendance, etc) with the involved organizations to improve the working relationships and effectiveness of the groups through effective sharing of relevant information (from Attachment I, Independent Assessment). This is an interim action for future AMAG discussions until the overall decision-making review is complete.
Responsible Organization: Byron Engineering (A8830EM)
Due Date: 10/15/03

CA10 Action: Establish a communication protocol (timing/frequency of communications, minimum information to be communicated, personnel required to be in attendance, etc) with the involved organizations to improve the working relationships and effectiveness of the groups through effective sharing of relevant information (from Attachment I, Independent Assessment). This is an interim action for future AMAG discussions until the overall decision-making review is complete.
Responsible Organization: Braidwood Engineering (A8930AD)
Due Date: 10/15/03

CA11 Action: Establish a communication protocol (timing/frequency of communications, minimum information to be communicated, personnel required to be in attendance, etc) with the involved organizations to improve the working relationships and effectiveness of the groups through effective sharing of relevant information (from Attachment I, Independent Assessment). This is an interim action for future AMAG discussions until the overall decision-making review is complete.
Responsible Organization: Cantera Engineering (A8064MW-DR)
Due Date: 10/15/03

CA12 Action: Potential knowledge gaps should be identified, evaluated and actions taken to improve the Byron Engineers' technical expertise on Crossflow. Additional training may be required (from Attachment I, Independent Assessment).
Responsible Organization: Byron PED (A8830EM)
Due Date: 10/27/03

CA13 Action: Potential knowledge gaps should be identified, evaluated and actions taken to improve the Braidwood Engineers' technical expertise on Crossflow. Additional training may be required (from Attachment I, Independent Assessment).
Responsible Organization: Braidwood PED (A8930AD)
Due Date: 10/27/03

CA14 Action: Potential knowledge gaps should be identified, evaluated and actions taken to improve the Cantera Engineers' technical expertise on Crossflow. Additional training may be required (from Attachment I, Independent Assessment).
Responsible Organization: Cantera Engineering (A8064MW-DR)
Due Date: 10/27/03

EFR1 Action: Perform Effectiveness Review of CAPR1.

Responsible Organization: Byron PED (A8830NESTT)
Due Date: 10/17/04

MRC1 Action: Take the Effectiveness Review of CA15 to MRC.
Responsible Organization: Byron PED (A8830NESTT)
Due Date: 10/25/04

EFR2 Action: Perform Effectiveness Review of CAPR2.
Responsible Organization: Braidwood PED (A8930TT)
Due Date: 10/17/04

MRC2 Action: Take the Effectiveness Review of CA17 to MRC.
Responsible Organization: Braidwood PED (A8930TT)
Due Date: 10/25/04

4. Additional Action Items (ACITs)

The following additional actions should be taken to obtain further data on the Byron and Braidwood units to provide further support of the root cause discussion above and address other issues discussed in the Executive Summary:

ACIT1 Action: At 100% power, obtain pressure sensor data on the Byron Unit 1 feedwater lines between the AMAG sensor and the FRV and on the Unit 1 and Unit 2 common headers.
Responsible Organization: Byron PED (A8830NESTT)
Due Date: 10/31/03

ACIT2 Action: At 100% power, obtain pressure sensor data on the Braidwood Unit 1 and Unit 2 feedwater lines between the AMAG sensor and the FRV, and on the Braidwood Unit 1 and Unit 2 common headers.
Responsible Organization: Braidwood PED (A8930TT)
Due Date: 10/31/03

ACIT3 Action: Evaluate the Byron and Braidwood pressure sensor data, from AA1 and AA2 above, against the natural frequency calculated for the feedwater lines and the AMAG noise spectrum and review these results against this Root Cause report and determine any further actions that may be necessary.
Responsible Organization: Cantera Engineering (A8064MW-DR)
Due Date: 12/15/03

ACIT4 Action: Re-evaluate the existing AMAG Project Plan based on the information in this Root Cause Report.
Responsible Organization: Cantera Engineering (A8064MW-DR)
Due Date: 10/31/03

ACIT5 Action: Disposition any actions coming from the CNO-commissioned review of the AMAG management decision-making process.
Responsible Organization: Byron Engineering (A8830EM)
Due Date: 12/15/03

ACITA6 Action: Disposition any actions coming from the CNO-commissioned review of the AMAG management decision-making process.
Responsible Organization: Braidwood Engineering (A8930AD)
Due Date: 12/15/03

9. Extent of Condition:

A review of the AMAG installations at Braidwood and Byron indicated the presence of ultrasonic signal noise contamination on several, but not all, of the individual feedwater line measurements as follows: Byron 1A through 1D (letter CAE-03-069), Byron 2A (letter CAE-03-070), Braidwood 1A and 1B (letter CCE-03-078), and Braidwood 2A and 2B (letter CCE-03-078). Subsequent data acquisition also identified noise on the Byron 2B loop. AMAG also reviewed the data from the installed feedwater common header locations at Braidwood Unit 1 and Byron Unit 1 and determined the signal contamination was not present on the common header data. Westinghouse issued Technical Bulletin TB-03-6, "CROSSFLOW Ultrasonic Flow Measurement System Signal Issues," to all CROSSFLOW users on 9/5/03. The Technical Bulletin states Westinghouse and AMAG "... have recently identified a potential for contamination of the signals used to determine feedwater flowrate". The Technical Bulletin goes on to further state "At this time, Westinghouse/AMAG believe this situation is unique to the affected plants and plant specific hardware, and therefore is not a generic CROSSFLOW performance issue." Because the source of the noise appears to be associated with the natural frequency of the feedwater piping, it cannot be proven to be unique to Byron and Braidwood. Therefore, this issue is considered to be a significant safety concern in accordance with 10 CFR Part 21. Byron and Braidwood will both provide written notification of this event to the NRC in a 30 day Licensee Event Report (LER). The completion of Byron LER 454-2003-003-00 and Braidwood LER 457-2003-002-00 will meet the 10 CFR Part 21 reportability requirements.

10. Risk Assessment:

As discussed above, the safety significance of the AMAG overpower issue was evaluated by Westinghouse and NFM. The evaluations were performed for a power level of 102.62% for both Byron and Braidwood, plus a 2% uncertainty where applicable. The evaluation covers the time period from August 2000 through August 2003. (The 102.62% power is conservatively based on actual venturi flow, with no AMAG correction.) The Westinghouse evaluations (CAE-03-76 for Byron, CCE-03-85 for Braidwood) concluded that the applicable regulatory acceptance criteria were met for all the events evaluated above. The NFM evaluation (Calculation PSA-B-03-05, Rev. 0) SGTR event, at a power level of 102.62% for Byron 1 Cycles 11 and 12, Byron 2 Cycles 9, 10 and 11, and Braidwood 2 Cycles 8, 9 and 10, concluded that the B/B Unit 1 Margin to Overfill (MTO) was 195 ft^3; the cycle-specific Tavg was sufficient to offset the overpower condition. For B/B Unit 2, the MTO was 240 ft^3; the cycle-specific Tavg and SG tube plugging levels were sufficient to offset the overpower condition. Because there is more than a 50% margin to the regulatory limits for offsite dose, it was judged that a 2.62% overpower condition would not result in exceeding the regulatory limits for SGTR. Therefore, it is concluded that the maximum historical overpower condition is acceptable from a safety analysis standpoint.

11. Programmatic/Organizational Issues:

A copy of the independent assessment of the decision making process associated with the decision to continue utilization of the AMAG CFs in the Spring of 2002 is included in Attachment I of this report.

12. Previous Events:

An INPO database search was performed using narrative words "ultrasonic" and "feedwater" and component "transmitter, detector, element" with "feedwater" system. The search results were reviewed and three events (OE 9892, OE 12322, and OE 14441) used the AMAG system, two event (Foreign Event Report ER03101-00-02-23 and OE 16521) were indirectly applicable based on a potential for similar occurrences in the AMAG system, and the remainder were not applicable/did not use the AMAG system. A short review of the five events listed above is as follows:

Palisades - OE 9892 - Ultrasonic Flow Measurement Inaccuracy
Event Date - 2/7/99

The ultrasonic flow measurement (UFM) probe support frame dimensions were altered while attempting to remove a stuck main feedwater loop B UFM probe. Following probe replacement and frame reinstallation, the measured spacing between the UFM upstream and downstream probes exceeded allowable tolerance by less than 100 mils. Probe and frame threads were galled and the force required to remove the probe from the frame caused permanent distortion of the aluminum frame altering the probe spacing. Corrective actions included removing the insulation from the probes and recalibrating the UFM signal to account for the as-left spacing. This event is not applicable to this root cause since this event occurred with an earlier probe installation design and a bracket type not similar to the current design. Also, the spacing at Byron has been verified as documented in the Westinghouse "Summary of Recent Crossflow Related Activities to Support Byron Station," dated April 2002.

Point Lepreau - ER-03101-00.02.23 - Feedwater Flow Measurement Anomaly
Event Date - 2/23/00

Ultrasonic feedwater flow measurements were taken, which when analyzed, were found to be approximately 1.3% higher than the feedwater flow indication from station instrumentation. Additional measurements were taken at power levels from 86 to 95 percent power to provide more data to resolve the anomaly. It was determined that the deviation was due to inaccuracy of the Flow Profile Correction Factor (FPCF) being applied. Flow measurements had historically been taken annually at 99-100 percent power applying an empirically-based FPCF curve. The initial measurements were taken at approximately 94 percent power which placed flow conditions at a different point on the FPCF curve. This event is not applicable to this root cause since the current AMAG system uses NRC approved flow profile correction factors. The flow profile correction factors used during this operating experience event were determined by the utility and not reviewed/approved by the NRC.

Byron - OE 12608 - Improperly Entered Data in Calorimetric Calculation Results in Errors
Event Date - 5/15/01

Station personnel determined the data used in calibrating the main feedwater flow venturi was incorrect. The error resulted in a non-conservative calculation of reactor power of approximately 0.12 percent. The error existed in the external density correction and thermal expansion coefficient used in a spreadsheet. The apparent cause of the event was the use of non-validated input for the feedwater flow constants. A formal engineering process was not used; consequently, appropriate reviews and approvals were not performed to minimize errors. This event is not applicable to this root cause since it was caused by an error in the spreadsheet density correction factor and appropriate actions have been completed to prevent recurrence.

Hope Creek - OE 14441 - Potential to Exceed Licensed Power Level Due to Malfunction of The Crossflow Correction Factor Instrumentation
Event Date - 6/28/02

It was discovered that a malfunction of the crossflow instrumentation correction factor caused the plant to operate by as much as 0.47 percent overpower. The cause of the event was attributed to a malfunction of the crossflow correction factor instrumentation as a result of cracked insulation (Cal-Sil) becoming lodged between the crossflow transducer clamp and the pipe. Corrective actions included removing crossflow from service and reducing power by about 1.4 percent, the installation of new crossflow transducers and validation of existing crossflow performance, and a change to the transducer mounting configuration. This event is not applicable to this root cause since this condition does not exist at Braidwood and Byron. Both stations use blanket insulation over the brackets, not Cal-Sil. The correct installation has been previously verified at Byron, both units, as documented in the Westinghouse "Summary of Recent Crossflow Related Activities to Support Byron Station," dated April 2002.

River Bend - OE 16521 - Licensed Thermal Power Limit Was Exceeded Due To An Error In Feedwater Flow Measurement
Event Date - 5/10/03

The reactor feedwater flow instrumentation used to calculate reactor power at River Bend was determined to be non-conservative resulting in operating slightly in excess of the licensed thermal power limit. During the last refueling outage, a new, more accurate, measurement system was installed to replace the existing system. Following the startup from the refuel outage, the indicated feed flow data was reviewed against feedwater venturi data and further analysis concluded that the station had operated slightly in excess of the 102 percent analyzed limit by a factor of .07 percent. The causes of this event were 1) there were non-conservative assumptions made regarding calibration of the instrument, 2) changes that occurred when feedwater flow was significantly increased due to a 5 percent power uprate produced non-conservative feedwater flow indication error, and 3) a measurement error during installation resulted in non-conservative error in the indicated flow reading. The external system was removed during the last refueling outage and is no longer being used to determine reactor core thermal power. A new computer point will be developed to continuously calculate a best statistical estimate for core thermal power based on eighteen independent parameters.

Causes 1 and 3 above are not applicable to this root cause because the equipment calibration and measurement of equipment setup parameters was previously performed with acceptable results as documented in the Westinghouse "Summary of Recent Crossflow Related Activities to Support Byron Station," dated April 2002. Cause 2 above may be indirectly applicable to this root cause since the symptoms noted are similar to the symptoms noted at Byron and Braidwood, but River Bend uses a different vendor ultrasonic flow measurement system (Caldon).

13. Other Issues:

Attachment A - Event and Casual Factor Chart (hard copy only)
Attachment B - TapRoot Analysis (hard copy only)
Attachment C - Charter
Attachment D - AMAG Detailed Timeline
Attachment E - AMAG System Description and Operation
Attachment F - AMAG Noise Possible Causes
Attachment G - Byron Unit 2 Feedwater Piping Resonance Evaluation
Attachment H - AMAG Noise Evaluation
Attachment I – Independent Assessment Report
Attachment J – Causes and Effects Analysis
Attachment K – Questions from Mngr, Mech Systems, Exelon
Attachment L – Byron Unit 1 and Unit 2 Spectrum Results
Attachment M – Braidwood Unit 1 and Unit 2 Spectrum Results
Attachment N- Byron Unit 2 TV/GV Test Report – Common Header
Attachment O - Byron Frequency Comparison
Attachment P – Braidwood Frequency Comparison

Attachment A - Event and Casual Factor Chart

Attachment B - TapRoot Analysis

Attachment C
AMAG Overpower Issue
Root Cause Investigation Charter (Page 1 of 2)

Sponsoring Manager:

Brad Adams	Byron Engineering Director

Team Investigator(s):

Lead	Don Brindle (Byron Engineering)
Facilitator	Mike Ryterski (Byron Reg. Assurance)
SME's	Jeff Drowley (Cantera)
	Joe Wolff (Braidwood Engineering)
	Chip French (Westinghouse)
	Vahid Askari (AMAG)
Support Staff	Steve Scibona (Instrument Maintenance)
	Bryan Currier (Byron Engineering)
Qualified RC Investigator	Jim Harkness (Byron Engineering)

Scope:

The scope of this Root Cause Investigation is to determine the cause of the apparent overpower condition on Byron Units 1 and 2. This condition was identified due to differences in correction factors (CF) seen between the individual FW loops on Byron Units 1 and 2; including

- CFs varying with changes in power level
- CFs not linear with Feedwater venturi output
- AMAG flow signal contamination (noise)
- Difference between the sum of the individual loop flows and the common header flow greater than the acceptable statistical limitation of the AMAG installation

This investigation will also address why the apparent condition was not identified upon initial installation or subsequent evaluations of the AMAG instrumentation. In addition, an evaluation for Part 21 applicability and a risk assessment associated with the apparent historical overpower condition will also be included in the report.

Braidwood is participating on the team. Other Exelon sites will be provided with Lessons Learned as applicable.

A separate team chartered by the Byron Site Vice President (SVP) has been tasked with evaluating the historical decision-making process associated with AMAG implementation. It is expected that this team will generate a report directly to the SVP. This report will be included as an addendum to this Root Cause Evaluation and any identified corrective actions will be included here for completeness.

AMAG ROOT CAUSE - FINAL

Attachment C
AMAG Overpower Issue
Root Cause Investigation Charter (Page 2 of 2)

Interim Corrective Actions:

No specific Corrective Actions are required at this time. As a compensatory action, both Byron units have been reduced in power and the AMAG correction factor has been rescaled to 1.0, effectively taking the AMAG system out of the calorimetric calculation for both units.

Root Cause Report Milestones:

1. Event Date	8/28/03
2. Completion of Charter	9/2/03
3. Screening Date	9/3/03
4. MRC Update	9/12/03
5. Sponsoring Manager Report Approval	9/15/03
6. Review by PORC	9/19/03
7. Approval by Station Manager	9/19/03
8. Final Root Cause Investigation Due Date	9/19/03

Prepared By: D. Brindle 9/2/03

Approved By: B. Adams 9/2/03

AMAG ROOT CAUSE - FINAL

Attachment D - AMAG Detailed Timeline (Page 1 of 4)

Jan 1998 - Three of four Byron Unit 1 venturis cut out, calibrated, and re-installed. Re-scaled flow transmitters under SSCR 97-059.

Fall 1998 - ComEd Nuclear Project Review Board (NPRB) approval for purchase of AMAG system (i.e., brackets, one set of transducers, one set of electronics, installation, and training.)

Fall 1998 - AMAG Contracts Issued

May 1999 - AMAG installations complete-all Braidwood/Byron units.

5/10/99 - Byron Unit 2 AMAG Test SPP-99-017. Results in AMAG indicating FW flow ~ 1.89% below in-plant instrumentation, resulting in ~ 98.11% reactor power instead of 100%, or a change of ~ 23 MWe.

5/12/99 - Byron Unit 1 AMAG Test SPP-99-016. Results in AMAG indicating FW flow ~ 2.14% below in-plant instrumentation, resulting in ~ 97.86% reactor power instead of 100%, or a change of ~ 26 MWe.

June 1999 - AMAG Implemented at Braidwood. Braidwood Unit 1 ~0.68% below in-plant instrumentation, resulting in ~99.32% reactor power instead of 100%, or a change of ~8.2 MWe. Braidwood Unit 2 ~0.58% below in-plant instrumentation, resulting in ~99.42% reactor power instead of 100%, or a change of ~7.1 MWe.

June 1999 - Braidwood Unit 1/Unit 2 increased in power based on AMAG results.

July 1999 - Additional bracket installed at Byron Unit 1 D loop. Used separate computer, SCU, and short cable, all equipment in Unit 1 main steam tunnel. Results on that loop agree within 0.06%.

7/29/99 - Byron Letter 99-109 documents potential Braidwood/Byron difference in post-AMAG implementation. First documented review of AMAG discrepancies. SPP 99-016 and 99-017 results indicate both Byron units would be over calculating FW flows by approximately 2%. Plant parameters indicate Byron units will operate approximately 1% higher than Braidwood power if AMAG is implemented.

Sept 1999 - March 2000 - Studies of Byron and Braidwood thermal performance.

March 2000 - Recommendation to Byron Site Management to implement AMAG.

April 2000 - Presentation to Corporate executives recommends implementation.

Attachment D - AMAG Detailed Timeline (Page 2 of 4)

May 2000 - * **Causal Factor 1** * Byron AMAG implementation; Test data taken: Unit 1 1.68%, Unit 2 1.7%.

May 2000 - Braidwood/Byron Thermal Kit review and PORC Complete, Byron Unit 1/Unit 2 increased in power based on AMAG results.

6/1/00 - CR B2000-01571 Byron Unit 2 governor valves full open at full power.

AMAG ROOT CAUSE - FINAL

7/28/00 - CR B2000-02147 Byron Unit 2 reduction main gen output 3-4 MWe. Change in AMAG correction factor of 0.3% following B2F21 results in Unit 2 gross generator output of ~ 3-4 MWe lower than pre-trip levels. CF = 0.986, 1.40 % power. (Within statistical limit.)

Sept-Oct 2000 - B1R10 1FW079 check valves replaced with new design at Byron Unit 1 (EC 79164). Post outage CF = 0.9845, 1.55% power.

April 2001 - B2R09 2FW079 check valves replaced with new design at Byron Unit 2 (EC 79165). Post outage CF = 0.986, 1.40 % power.

5/15/01 - Byron Unit 2 Power Uprate test, CF = 0.981, 1.91% power

5/17/01 - Byron Unit 1 Power Uprate test, CF = 0.9777, 2.23% power

6/28/01 - CR B2001-02940 Reduced Byron Unit 2 generator output following forced outage. AMAG constants revised 1.69, resulting in ~ 2 MWe loss.

10/5/01 - CR 78729 Evaluation of Braidwood Unit 1 pre-power uprate test results. Braidwood Unit 1 19 MWe < Byron Unit 1. This result was predicted and accepted by management.

10/16/01 - CR 80251 Braidwood Unit 1 achieves full power after power uprate. Byron Unit 1 turbine flow capacity < Braidwood Unit 1 by at least 1%. Byron Unit 1 Tave increase from 586 degree F to 588 degree F is planned. Byron 1 CF = 0.9942, 0.58%.

1/17/02 - CR 91771 Unplanned AMAG difference between Braidwood/Byron. Byron Unit 1 projected to be 1.5% to 2.5% higher than Braidwood Unit 1 after B1R11.

2/27-28/02 - Testing on Byron Unit 1 at 94.73% power indicated differences between the individual loops and the common header of 1.1-1.3%. (Not considered valid, due to system not yet tuned, and not at full power.)

3/10/02 - Test performed at 91% power to compare Byron Unit 1 common header flow with sum of flows from the four feedwater loops plus tempering line flow. Results

Attachment D - AMAG Detailed Timeline (Page 3 of 4)

(documented 4/24/02) indicate four loops equal flow from common header but at high end of calculated allowable statistical limit (0.699% with acceptance criteria of 0.706%)

3/29/02 - CR 101618 Unexpected/unexplained Byron Unit 2 FW venturi calibration data. Unit 2 AMAG calculation suggests 0.6% increase in power => not implemented because

it was not supported by plant data. Data taken as a 9 month periodic test. AMAG had recently stated not to implement new constants if there are unexplained changes more than 0.2-0.3%. A review of plant data did not support the observed 0.6% change. Therefore, the constants were left unchanged.

4/1/02 - CR 102396 Failure to achieve 100% power on B1R11 Power Ascension. B1R11 "power uprate" power ascension stopped at 1288.2 MWe, RTP ~ 99.0%, GV 4 ~ 46% open.

4/24/02 - * **Causal Factor 1** * First Byron Unit 1 common header test results from test performed on 3/10/02 (Calc 059-PENG-CALC-084, Rev. 01). Six months of continuous data taking recommended.

6/28/02 - Unit 2 Post B2F23 testing CF = 0.9831, 1.69% power.

1/22/03 - RAI Set 1 NRC Letter to Exelon "Byron Unit 1 may be operating above its licensed thermal power level."

1/23/03 - CR 140753 Documents NRC Concern that Byron Unit 1 may be exceeding 100% power.

1/30/03 - * **Causal Factor 1** * Westinghouse Report of Byron Unit 2 "A" FW loop variability (CAE-03-4). (NOTE: this report is tied to 3/29/02 event).

2/5/03 - Response to 1/22/03 RAI's Set 1. Letter Exelon to NRC "Byron Station Unit 1 License Power Limit Verification," (RS-03-025).

May 2003 - AMAG bracket installed on Braidwood Unit 1 common header to compare common header to sum of loop flows.

May 2003 - Westinghouse Calculation CN-PS-03-18, Revision 0, documents Braidwood Unit 1 *common header test results well within expected uncertainties* (0.021%)

7/8/03 - RAI Set 2 NRC Letter to Exelon "Byron Unit 1 may be operating above its licensed thermal power level."

7/18/03 - CR 168199 AMAG constants Byron 2A loop greater than "as found." Overall change of ~ 0.2% is within 0.69% instrument random error.

8/8/03 - CR 170818 AMAG constant calculation Byron Unit 1 OOT. Current: 0.97555, previous 0.97415, correlates to 0.14% increase in reactor power.

8/15/03 - Response to 7/8/03 RAI's Set 2. Letter Exelon to NRC "Byron Station Unit 1 License Power Limit Verification," (RS-03-149).

8/28/03 -* Causal Factor 2 * Westinghouse Letter CAE-03-69, "Preliminary Results from Byron Unit 1 CROSSFLOW Verification Program," was issued. Westinghouse/ AMAG stated that the variations were associated with noise contamination of the signal, creating a bias, either positive or negative, affecting the measured results.

8/28/03 - CR 173510 Results of Westinghouse Byron Unit 1 AMAG Investigation. Noted 1.49% difference between loop and common header flows, maximum allowable per calculation is 0.70%.

8/28/03 - CR 173548 Braidwood extent of condition review for Byron CR 173510.

8/29/03 - Westinghouse Letters CAE-03-70 Byron Unit 2 and CAE-03-77 Braidwood Units 1 & 2, "Status of Extent of Condition Evaluation for CROSSFLOW Verification Program," were issued.

8/29/03 - Byron ENS phone call (Event 40117) - reference CR 173510.

8/31/03 - Braidwood ENS phone call (Event 40123) - reference CR 173819.

9/2/03 - Westinghouse Letter CAE-03-78 Braidwood Units 1 & 2, "Status of Extent of Condition Evaluation for CROSSFLOW Verification Program," was issued.

9/5/03 - Westinghouse Technical Bulletin TB-03-06, “CROSSFLOW Ultrasonic Flow Measurement System Signal Issues,” was issued.

(b)(4)

Exemption 4
Actual page numbers are 30 through 31.

Attachment F - Possible AMAG System Noise Causes Considered (Page 1 of 8)

<u>AMAG CABLE EFFECTS:</u> cable length/cable shake/mercury lamp/ham radio

AMAG electronics uses a synchronized demodulator circuitry for demodulation of the receiver signal to obtain the flow signal for flow calculation. The cable length could affect the quality of the signal and create an increase in cable crosstalk signal. The cable crosstalk does not have any effect on the system measurement and it would only cause an increase in the data rejection. Also, noise due to the cable shake is not an issue since bundle cables are used in all measurements. Moreover, mercury lamp or ham radio signals would not appear in the measurement signal because of the synchronized demodulator circuitry in Crossflow electronics. In addition, CR 91771 documents that the continuity of the AMAG cables was tested and found to be acceptable. Note that this CR refers to Westinghouse Report "Summary of Recent Crossflow Related Activities to Support Byron Station," April, 2002. It was concluded that there are no AMAG cable effects.

<u>AMAG HARDWARE ERROR:</u> bracket length, transducer pressure on pipe, transducer alignment, transducer torque, transducer cleanliness (see also AMAG cable affects).

CR 91771 documents that the transducer installation characteristics were checked. Note that this CR refers to Westinghouse Report "Summary of Recent Crossflow Related Activities to Support Byron Station," April, 2002. It was concluded that there is no AMAG hardware concern.

<u>AMAG SOFTWARE ERROR:</u>

CR 91771 documents that the CROSSFLOW software was checked and compared to verify it was the most recent revision and that the rest of the test measurements verified the software was performing properly. Note that this CR refers to Westinghouse Report "Summary of Recent Crossflow Related Activities to Support Byron Station," April 2002. The testing performed rotated the Braidwood, Byron, and Westinghouse/AMAG electronics through the Unit 2, Unit 1 individual loop, Unit 1 common header installations with no apparent changes. It was concluded that there is no AMAG software errors.

<u>PIPE NATURAL RESONANCE/VIBRATION:</u>

2FW079A, B, C, and D vibration and acoustic data taken on 9/5/03 was inconclusive. AMAG probe area vibration data taken on 9/4/03 was inconclusive. Main Feedwater Regulating Valve (FWRV) body vibration data taken on 9/4/03 was similar in frequency to the noise seen by the AMAG sensors. Pressure data taken with an oscilloscope on 9/4/03 was inconclusive.

Attachment F - Possible AMAG System Noise Causes Considered (Page 2 of 8)

The root cause of this event was found to be noise contamination of the AMAG ultrasonic signal caused by acoustic resonant response of the feedwater piping system. Dynamic pressure measurements were taken on each of the four Byron Unit 2 feedwater lines at a low point drain located near the flow measurement venturi on 9/9/03. Potential resonant frequencies were predicted using several theoretical methods. Analysis of the dynamic pressure data showed agreement between the theoretical methods and actual plant response and suggested the principal resonance is likely that of the segment of piping between the feedwater regulating valve and the steam generator. Data analysis also supports the existence of low frequency resonant system response consistent with the noise frequencies and reflects the magnitude of noise differences in the four feedwater loops (i.e., noise is highest in loop 2A). See Section 7 above for further discussions. Note that this conclusion is not yet directly applicable to Byron Unit 1 and Braidwood Unit 1 and Unit 2, as discussed in Section 7.

PIPE INSIDE DIAMETER:

CR 91771 documents that additional pipe wall thickness, outside diameter, and spacing between transducer measurements were taken and verified as acceptable, and are presented in Calculation 059-PENG-CALC-084, rev. 01, "Feedwater Flow Measurement Using the CROSSFLOW Ultrasonic Flowmeter at ComED Byron Unit 1." Note that this CR refers to Westinghouse Report "Summary of Recent Crossflow Related Activities to Support Byron Station," April, 2002. The conclusion reached was that there were no significant differences with the original setup values at either Byron unit.

PIPE LAYOUT: bypass lines, tempering lines, drain lines, etc.

CR 91771 documents that the FW piping isometrics were reviewed for the four loops and the common header and the piping was walked down in the field. Note that this CR refers to Westinghouse Report "Summary of Recent Crossflow Related Activities to Support Byron Station," April, 2002. No significant issue was identified with respect to piping geometry other than its impact on the resonance discussed above.

FEEDWATER REGULATING VALVES (FW-510, -520, -530, & -530):

Under troubleshooting activity 1 on 9/3/03, the 2A FWRV was taken to manual and vibration measurements and AMAG data was taken. Placing the FWRV in manual did not affect the noise signal seen in AMAG. Under troubleshooting activity 2 on 9/4/03, the 2A through 2D FWRV body vibration measurements, along with the venturi locations and the common header, were taken. The AMAG data showed that the noise was still present, while the plant data showed that the venturi flow oscillations that are normally present with the FWRV in automatic disappeared when the FWRV was taken to manual. In other words, the venturi flow was essentially flat lined for the entire period of the test. The conclusion is that the slight movement of the FRV is not the driver of the noise

Attachment F - Possible AMAG System Noise Causes Considered (Page 3 of 8)

(although the large pressure drop through the FRV may be the driver, as discussed elsewhere).

FEEDWATER PUMP DISCHARGE CHECK VALVES (FW-001A/B/C):

Under troubleshooting activity 2 on 9/4/03, vibration measurements were taken on the common header. No significant vibrations were noted. Additionally, the common header AMAG signal was reviewed and the noise characteristics noted in the branch feedwater lines were not present on the common header signal. These check valves are the same at Byron and Braidwood, except for one at Braidwood. It does not appear that these check valves are influencing this issue.

FEEDWATER LOOP CHECK VALVES (FW-079A/B/C/D):

Vibration and acoustic monitoring data was taken on the Unit 2 FW loop check valves on 9/5/03. No significant vibrations or acoustic noise were noted. Byron has "Noz-check" check valves, while Braidwood has swing-type check valves. This may have an influence on the natural frequency of the piping.

POWER LEVEL AFFECTS:

Refer to Attachment H, AMAG Noise Evaluation.

BYRON/BRAIDWOOD FEEDWATER VENTURI CLEANING AND INSPECTION:

Both Byron and Braidwood inspect their Feedwater flow venturis every refueling outage in accordance with Station procedures (Byron 1/2BVSR 4.1.4-2 and Braidwood BwVS 2.3.5-2). If debris is noticed during inspection, cleaning is then performed. The only difference between the sites with respect to cleaning of the venturis is that Braidwood performs pressure washing every refueling.

Braidwood's cleaning of the Feedwater flow venturis consists of pressure washing and scrub brushing. Byron does not perform pressure washing, only scrub brushing. At Braidwood, the pressure washing is performed 10 diameters upstream and 5 diameters downstream of the venturi (as a minimum) at a pressure of approximately 1000 psig. The pressure washing work is performed by contractors. After pressure washing, the System Engineer inspects the venturi and removes any remaining debris by scrub brushing (Reference Work Order 413250-01).

The pressure Braidwood uses for pressure washing is well below the pressure that could cause any structural damage to the venturi based on testing performed at Commonwealth Edison's SMAD facility. The maximum pressure washing pressure allowed by SMAD is 3000 psig.

Attachment F - Possible AMAG System Noise Causes Considered (Page 4 of 8)

Although Byron does not pressure wash their venturis, they are cleaned and inspected to ensure no debris is present that would affect the Feedwater flow instrumentation. During inspection, both Sites verify that the venturis exhibit no deposit, scale, fouling, erosion, pitting, plating, or film. Therefore, the venturis at Byron and Braidwood are expected to perform in a similar manner and according to the specifications obtained during laboratory testing.

1.2.1.1.A.1.1.1.1. Byron Unit 1 Feedwater Venturi Refurbishment

Byron Unit 1 had Feedwater flow venturis 1FE-0510, 1FE-0530, and 1FE-0540 refurbished and benchmarked in January 1998 due to erosion (damage) of the inner surface upstream of the throat (Reference 18 of SSCR 97-059). After the venturis were repaired, laboratory tests were performed by Alden Research Laboratory to determine the new venturi flow characteristics (design input 3 of SSCR 97-059). Comparing the test results (i.e. the flow characteristics) from the original flow tests performed by BIF Corporation (design input 2 of SSCR 97-059) to that of Alden Research Laboratory revealed no significant change in the venturi flow constants (e.g. beta ratio and discharge coefficient) used for scaling purposes. In the determination of flow versus differential pressure for transmitter scaling, both units at Byron have all sixteen feedwater flow transmitters scaled in a similar manner using the ASME feedwater flow rate versus venturi tube differential pressure equation (design input 1 of SSCR 97-059). Based on review of the venturi data provided in SSCR 97-059 (Unit 1) and SSCR 98-021 (Unit 2), all sixteen feedwater flow transmitters are scaled properly using the appropriate venturi flow characteristics determined from laboratory flow tests.

1.2.1.1.A.1.1.1.2. Byron Unit 1 Feedwater Venturi behavior:

As a part of the root cause, it was determined that the effect of the venturi behavior in the uprated and potentially overpowered condition needed to be evaluated. The specific question that was evaluated was, "Does the venturi contribute to the apparent power effect on the AMAG correction factor?"

It was determined that the venturi has no significant effect on the AMAG correction factor, as discussed below. Further, the minimal impact that it would have is cancelled out in the calorimetric, so it could not have impacted the potential overpower.

The Stone and Webster (SWEC) Power Uprate evaluations for BOP and I&C were reviewed and the venturis were not specifically named. Discussions were held with SWEC, and it was determined that the original data sheet covered a range that the power uprate did not exceed and further, that the MCR recorder has a range of 4800 Klb_m/hr, and the Valves Wide Open (VWO) Power Uprate flow is within 90% of the span. The uprate was therefore evaluated to leave the instrumentation at <90% of span and thus was acceptable. SWEC was questioned on whether they confirmed the linearity of the venturi for the Reynolds number range. They had not.

Attachment F - Possible AMAG System Noise Causes Considered (Page 5 of 8)

A review of the data sheets and the calculation for the venturis shows that they were calibrated for a range of 80,000 to 3,000,000 Reynolds Number (N_{RE}), but are being used at a range of 16,000,000 N_{RE}.

Westinghouse provided a flat calibration curve from 75,000 to 100,000,000 N_{RE}. With this curve they provided tolerances that started out flat on the upper tolerance but increased after the 3,000,000 N_{RE}, "Since at higher Pipe Reynolds Numbers the discharge coefficient may increase slightly,..."

A check with the Instrumentation and Control Engineering personnel at Byron confirmed that the tolerances from the curve are not used in the calorimetric uncertainty calculation.

Correspondence with BIF (the venturi manufacturer) in the calculation package shows that the venturis are treated as having a flat calibration curve. To support the position, BIF attached an ASME paper presented to the ASME Research Committee on Fluid Meters at the Winter Annual Meeting, November, 1973. The purpose of the paper was to evaluate drawbacks in previous "Flow Tube venturis" and present an improved design that had substantially improved characteristics, thereafter named "Universal Venturi Tube", or UVT. From an examination of the data provided in the paper, test results were limited to an upper range of 5,000,000 N_{RE}, and the examination of 51 UVT's gave a 0.9797 average C factor. Here the C factor was defined as follows:

$$C = \sqrt{(1-\beta^4)/(\alpha_d - \alpha_D\beta^4 + H_L)}$$

Where: $\beta = beta\ ratio$

and $\alpha_d = kinetic\ energy\ factor\ in\ the\ throat,\ approaches\ 1 > a\ certain\ \mathrm{Re}ynolds\ number\ (N_{RE})$

and $\alpha_D = kinetic\ energy\ factor\ in\ the\ inlet\ cross\ \mathrm{section},\ approaches\ 1\ above\ a\ certain\ N_{RE}$

and $H_L = head\ loss\ factor\ in\ the\ throat\ \mathrm{section}$

The data from low N_{RE} presented demonstrated that the discharge coefficient became constant between 80,000 and 100,000. This was taken as the point where the α_d and α_D approached 1.

Further, the paper presented a curve for H_L that showed at low β ratio, H_L is .04 and this number decreases with β down to 0.028 at β = .8. The actual β for the Unit 1 Byron venturis is a minimum of 0.5963, which would lead to a H_L of 0.037 per the curve in the paper. The C factor equation would thus reduce to:

$$C = \sqrt{(1-\beta^4)/(1-\beta^4+0.037)}.$$

From this equation, one may conclude that there are no Reynolds Number effects on the coefficient of discharge of the venturis.

The C correction factor % change provided in Calc 323 (Byron SSCR 97-059, Design Input 2) is based on throat Reynolds numbers. The throat Reynolds number is the pipe Reynolds number divided by the β ratio. In this case, use 16.489 million as the Reynolds number, and .5963 as the β ratio, for a throat Reynolds number of 27.7 million. Per the

correction curve, this corresponds to a correction in C of 0.113%. This is an insignificant effect on the AMAG correction factor.

Attachment F - Possible AMAG System Noise Causes Considered (Page 7 of 8)

Summary of Differences Matrix:

Item	1A	1B	1C	1D	2A	2B	2C	2D
FW Line Length	Short	Long	Long	Short	Short	Long	Long	Short
FW079 Valve type	Nozzle check @ B1R10				Nozzle check @ B2R09			
Venturi L/D (nominal Diameter)	45.24	43.95	46.08	48.33	47.93	46.56	47.23	48.33
UFM L/D (nominal Diameter)	31.74	30.45	30.60	32.85	32.00	29.09	29.75	32.63
Venturi to UFM L/D (nominal Diameter)	13.49	13.49	15.48	15.48	15.93	17.48	17.48	15.71
Venturi Handhole configuration (from iso)	Vertical	Vertical	30° right of vertical looking downstream	Vertical	Vertical	Vertical	30° left of vertical looking downstream	Vertical
Tempering line configuration	Around FWRV/FWIV to top of S/G (Feed Ring) [100%]				Around FWRV/FWIV to top of S/G (No Feed Ring)[10%]			
Preheater bypass Configuration	Yes				No			
Drain Configuration	3'6"	10'6"	11'6"	5'9"	5'9"	10'8"	13'8.5"	5'9.5"
FW Flush configuration	All Similar							
Venturi ΔP configuration	Linear discharge coefficient							
Venturi discharge coefficient	.9925/.9938	.9816/.9825	.9877/.9863	.9870/.9884	.9858/.9835	.9802/.9790	.9829/.9846	.9826/.9810
Venturi Calibration	All calibrated by same procedure							
FW Pump check valve	TLC Check installed pre-1999							
Nominal Pipe ID	13.562	13.562	13.562	13.562	13.562	13.562	13.562	13.562
Actual Pipe ID (from Westinghouse calc)	13.5874	13.6418	13.6316	13.6475	13.5183	13.6059	13.5824	13.5831
FW temperature error (calc) [multiply x reading]	0.01341	0.01341	0.01341	0.01341	0.01341	0.01341	0.01341	0.01341

Attachment F - Possible AMAG System Noise Causes Considered (Page 8 of 8)

Item	1A	1B	1C	1D	2A	2B	2C	2D
FW temperature error (measured x calc error)	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8
FW Temperature plant data current 9/5/03 4:45PM	433.1	433.2	433	432.9	433.6	433.8	433.7	433.4
Coefficient of Discharge of Venturis (Tap 1)	0.9925	0.9816	0.9877	0.987	0.9858	0.9802	0.9829	0.9826
Coefficient of Discharge of Venturis (Tap 2)	0.9938	0.9825	0.9863	0.9884	0.9835	0.9790	0.9846	0.9810
High end of Venturi test Reynolds Numbers	3.71E+06	3.00E+06	3.71E+06	3.73E+06	3.00E+06	3.00E+06	3.00E+06	3.00E+06
Venturi beta ratio – original	0.6007	0.6015	0.6012	0.6010	0.6008	0.6010	0.6011	0.6010
Venturi beta ratio – current	0.5963	0.6015	0.5979	0.5984	0.6008	0.6010	0.6011	0.6010

1.3. Introduction

Recent investigations into signal processing errors in the AMAG ultrasonic flow measurement system at Byron and Braidwood have suggested that there are fairly strong low frequency velocity components being detected and included in the flow measurement process. These low frequency velocity components have the potential to introduce errors in the flow measurement process. The most likely source of low frequency components is acoustic resonant response of the piping system. This evaluation will consider the piping acoustic response with the intent of developing the most likely acoustic response modes of the piping system.

1.4. Description of the Feedwater System

A diagram of the feedwater system is shown on the next page. The system consists of a main feedwater pump discharging into a common header. Lines to each steam generator branch off of the common header. Each line contains a feed regulating valve, a flow measurement venturi, and a check valve. The ultrasonic flow measurements are taken in each line at a location upstream of the venturis, after the common header. Two of the feedwater lines are considerably longer, since they have to traverse the steam tunnel to the far side of the containment. The principal pressure drop in the feedwater lines occurs at the feed regulating valve, and is approximately 100 psi. The flow venturi also would yield some additional pressure drop, but considerably less than the feed reg valves. The check valves are designed to have fairly minimal pressure loss.

1.5. Discussion of Acoustic Response

The acoustic response of a piping system is principally determined by its geometry and the speed of sound in the fluid. If the fluid velocity is high relative to the speed of sound, convective effects may also be experienced. For the feedwater system, the fluid is compressed subcooled liquid inside thick walled piping, which will exhibit a sound speed of approximately 4600 fps. [Reference: ASME waterhammer course notes] The velocity of the fluid in the piping is approximately 20 fps at a flow rate of 4 million pounds per hour per line at full power. Based on the small velocity of the fluid compared to the sound speed, convective effects can be safely ignored for this evaluation.

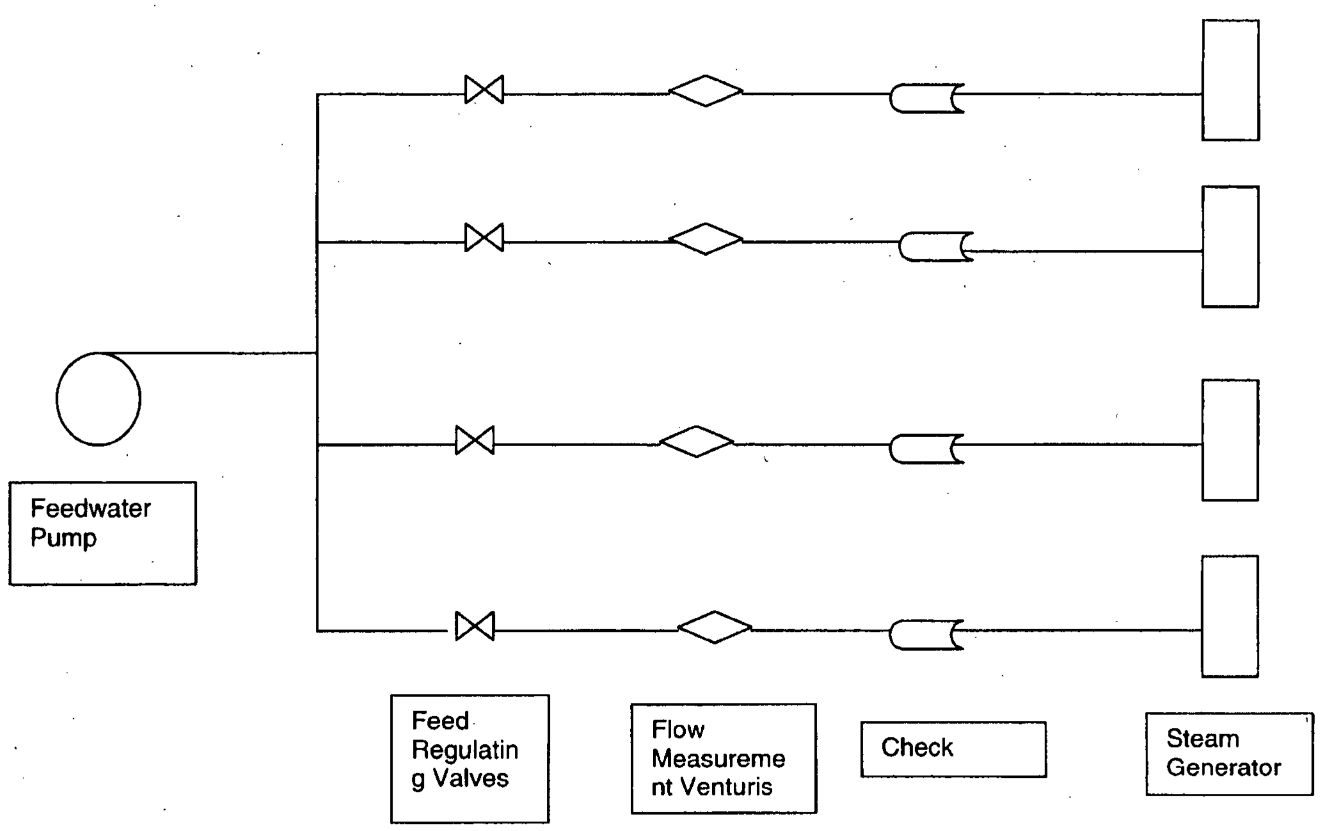
Piping systems will experience resonant response when a driver occurs to excite the system at its natural acoustic frequencies. Any location where large pressure drops occur can serve to create a driver. Blevins suggests that 1 to 2 percent of the pressure drop can become broad band noise that can cause excitation of the system. For the Byron feedwater system, the most likely points of excitation are the feed regulating valves and

$$f = \frac{c \times i}{2 \times L}$$

the flow venturis. The feedwater piping is basically an open-ended system, and will have fundamental acoustic modes characterized by the following relationship:

Where
c= sound speed, fps
L= length of pipe
f= frequency
and i=1,2,...n

Typical Feedwater Line Schematic



1.5.1.1.A.1.1.1.1. CALCULATION OF PIPING ACOUSTIC FREQUENCIES

The feedwater piping frequencies can be determined, based on the relationship presented above for open ended systems. Generally the higher modes are not of interest since their energy levels drop off considerably. Therefore the first four modes will be generated for this evaluation. The frequencies of several sections of the piping will be calculated:

1) feed reg valve to the venturi
2) feed reg valve to the steam generator
3) venturi to the check valve
4) venturi to the steam generator

The following tables provide the frequency response information in hz for each line for both units.

BYRON UNIT 1A FW LINE

Mode	Frv to venturi (hz)	Frv to sg (hz)	Vent to check (hz)	Venturi to sg (hz)
1	21.5	6.7	17.5	9.7
2	42.99	13.4	35.05	19.4
3	64.5	20.04	52.57	29.07
4	85.98	26.72	70.1	38.76

BYRON UNIT 1B FW LINE

Mode	Frv to venturi (hz)	Frv to sg (hz)	Vent to check (hz)	Venturi to sg (hz)
1	17.89	3.86	6.55	4.92
2	35.8	7.72	13.11	9.85
3	53.7	11.58	19.67	14.77
4	71.6	15.44	26.22	19.69

BYRON UNIT 1C FW LINE

Mode	Frv to venturi (hz)	Frv to sg (hz)	Vent to check (hz)	Venturi to sg (hz)
1	18.33	3.56	6.41	4.4
2	36.65	7.12	12.82	8.8
3	54.98	10.68	19.23	13.26
4	73.31	14.25	25.64	17.68

BYRON UNIT 1D FW LINE

mode	Frv to venturi (hz)	Frv to sg (hz)	Vent to check (hz)	Venturi to sg (hz)
1	20.24	6.23	22.66	9
2	40.47	12.46	45.32	18
3	60.7	18.7	67.98	27
4	80.94	24.9	90.64	36

BYRON UNIT 2A FW LINE

mode	Frv to venturi (hz)	Frv to sg (hz)	Vent to check (hz)	Venturi to sg (hz)
1	21.26	6.24	18.46	8.84
2	42.53	12.48	36.92	17.67
3	63.79	18.73	55.38	26.5
4	85.05	24.97	73.85	35.34

BYRON UNIT 2B FW LINE

mode	Frv to venturi (hz)	Frv to sg (hz)	Vent to check (hz)	Venturi to sg (hz)
1	17.69	3.87	6.873	4.95
2	35.38	7.73	13.75	9.89
3	53.08	11.6	20.62	14.84
4	70.77	15.46	27.49	19.79

BYRON UNIT 2C FW LINE

mode	Frv to venturi (hz)	Frv to sg (hz)	Vent to check (hz)	Venturi to sg (hz)
1	22.49	3.73	6.4	4.47
2	44.98	7.46	12.8	8.95
3	67.48	11.2	19.2	13.43
4	89.97	14.93	25.6	17.9

Attachment G - Byron Feedwater Piping Resonance Evaluation (Page 5 of 28)

BYRON UNIT 2D FW LINE

mode	Frv to venturi (hz)	Frv to sg (hz)	Vent to check (hz)	Venturi to sg (hz)
1	19.9	6.46	22.98	9.56
2	39.8	12.91	45.96	19.11
3	59.7	19.37	68.94	28.67
4	79.6	25.83	91.92	38.23

What is readily apparent is that the B and C lines for each unit yield the lowest fundamental frequencies. This is expected since they have the longest piping runs. The most likely candidates for low frequency excitation in the vicinity of the AMAG sensors are the feed reg valve to steam generator columns and the venturi to steam generator column. These yield the lowest frequencies, and both columns have excitation sources (pressure drops) connected directly to them.

1.6. Consideration of Boundary Conditions

The feed regulating valve may act as a closed acoustic connection. This would imply that a different set of frequencies would occur in the segments including the FRV. The relationship for determining the frequencies of a closed-open system is:

$$f = \frac{c \times i}{4 \times L}$$

Where
c= sound speed, fps
L= length of pipe
f= frequency
and i=1,3,5,...n

applying this relationship to the segments connecting the FRV to the steam generator yields for the Unit 2 Lines:

BYRON UNIT 2A FW LINE

mode	Frv to sg (hz)
1	3.121
2	9.362
3	15.604
4	21.845
5	28.087

BYRON UNIT 2B FW LINE

mode	Frv to sg (hz)
1	1.933
2	5.799
3	9.665
4	13.531
5	17.397

BYRON UNIT 2C FW LINE

mode	Frv to sg (hz)
1	1.866
2	5.599
3	9.332
4	13.065
5	16.797

BYRON UNIT 2D FW LINE

mode	Frv to sg (hz)
1	3.228
2	9.684
3	16.14
4	22.596
5	29.053

These frequencies represent the response that would be expected for oscillation of the feed line between the feed regulating valve and the steam generator, assuming the system behaved as a closed-open network. This is the most likely mode of oscillation, based on the pressure drop at the feed reg valve and the relatively open path to the steam generator. The other modes calculated above are also possible, but would be expected to be less significant.

1.6.1.1.A.1.1.1.1. ACOUSTIC IMPEDANCE METHOD

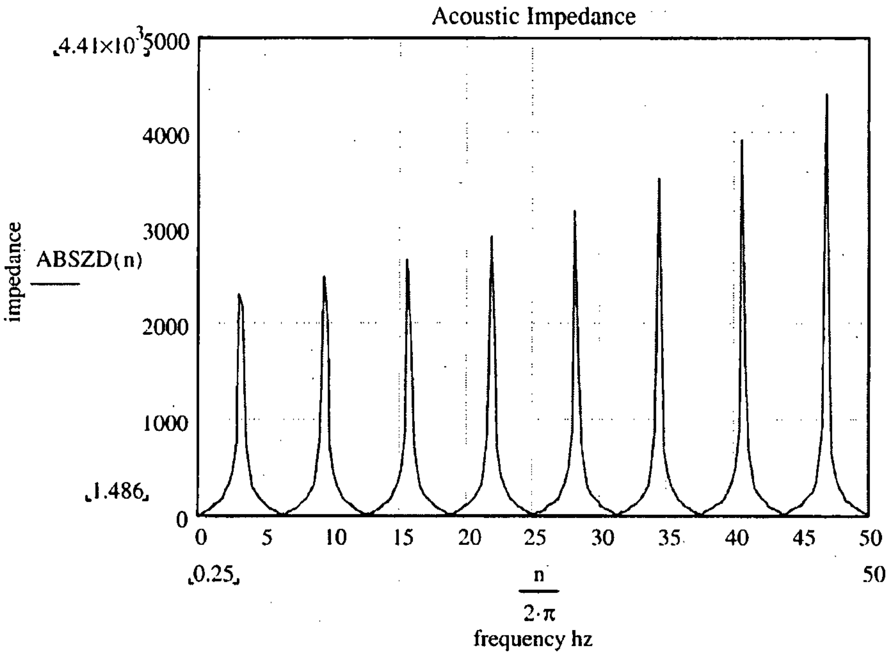
As an additional check of potential frequency response, the acoustic impedance program developed in Wylie and Streeter, Chapter 12 was used to calculate the acoustic impedance for the path from the feed reg valves to the steam generator for the Unit 2 configuration. The program was run using the following inputs:

Flow rate=4E6 lbm/hr
Pipe Dia=13.362 inches (16 inch Sch 120)
Darcy Friction Factor=0.013
Speed of Sound=4600 fps

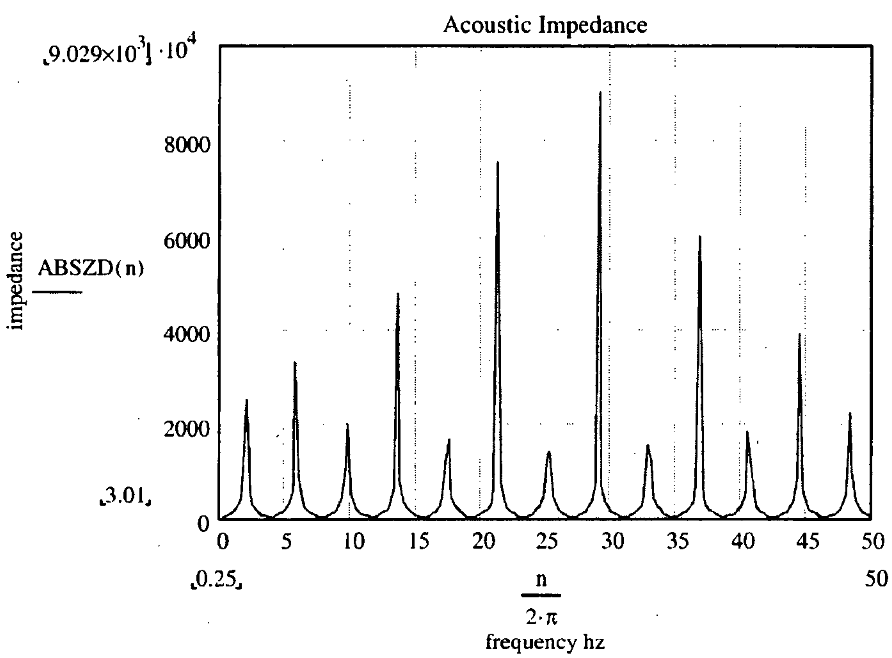
As noted in Wylie, plotting the modulus of hydraulic impedance vs. frequency is an effective way to determine which frequencies would be most susceptible to resonant response, with the highest dynamic heads expected at the largest impedances. Plots of hydraulic impedance vs. frequency are provided below for each Unit 2 feed line.

What is readily apparent on comparison of these plots to the modal frequencies calculated above is that the closed –open relationship yields very good agreement with the impedance methods. The other point to note is that the different lines can be expected to yield significantly different magnitudes of acoustic response for a given driving function.

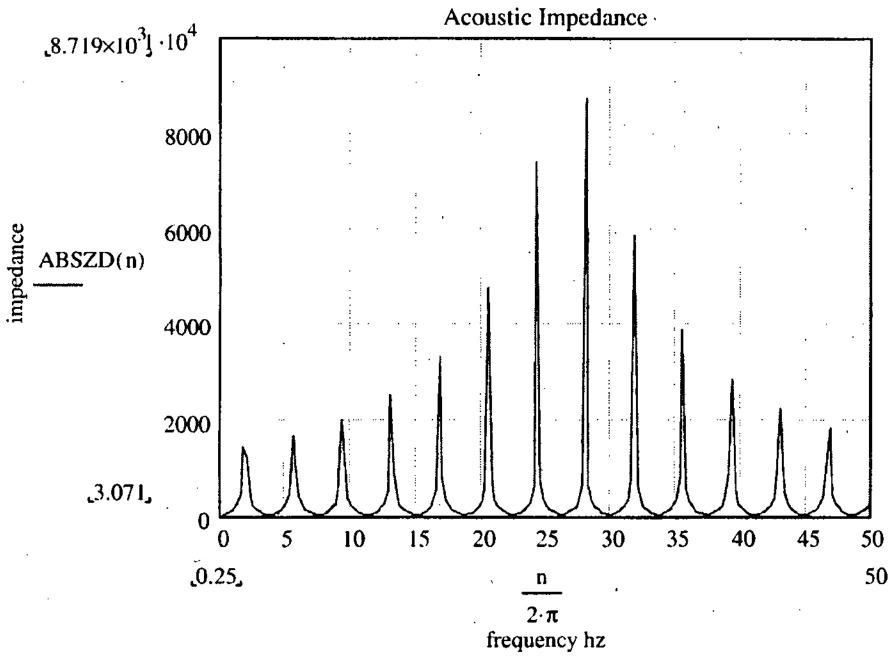
Byron Unit 2 A FW line hydraulic impedance



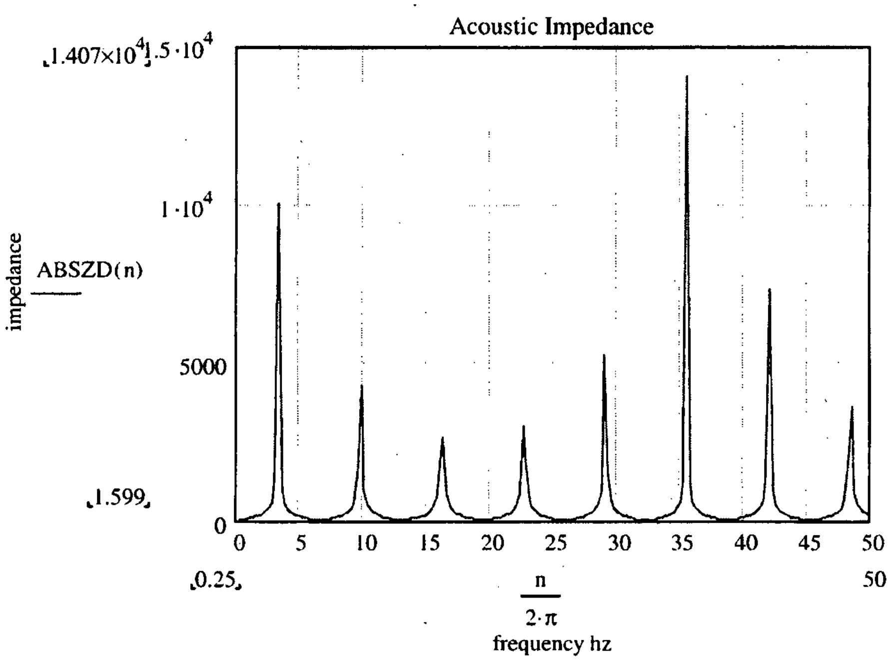
Byron Unit 2 B FW Line Hydraulic Impedance



Byron Unit 2 C FW Line Hydraulic Impedance



Byron Unit 2 D FW Line Hydraulic Impedance



1.6.1.1.A.1.1.1.2. DYNAMIC PRESSURE MEASUREMENT

Dynamic pressure measurements were taken on September 9, 2003 on all four feedwater lines on Unit 2. The measurements were taken from a low point drain located near the flow measurement venturi. Data was taken at 200 hz, allowing a Nyquist limit of 100 hz frequency resolution during Fast Fourier Transform data reduction. Data was also taken at reduced power during TVGV testing, capturing the 2A and 2D feedwater lines at approximately 82% and 91% power. The following tables provide details regarding the statistical aspects of the data taken.

Data taken at 100% power

Line	Number of points	Mean (psi)	Standard Deviation
2A	38490	967.80431	3.6327
2B	27297	971.6253	2.95647
2C	27297	947.54651	4.17127
2D	38940	945.349	3.48188

Data taken at 82% power

Line (Time Label)	Number of points	Mean (psi)	Standard Deviation
2A (08:15)	30721	911.14678	3.1296
2A (08:22)	29717	910.82595	3.06808
2D (08:15)	30721	935.37402	3.29642
2D (08:22)	29717	935.56834	3.34073

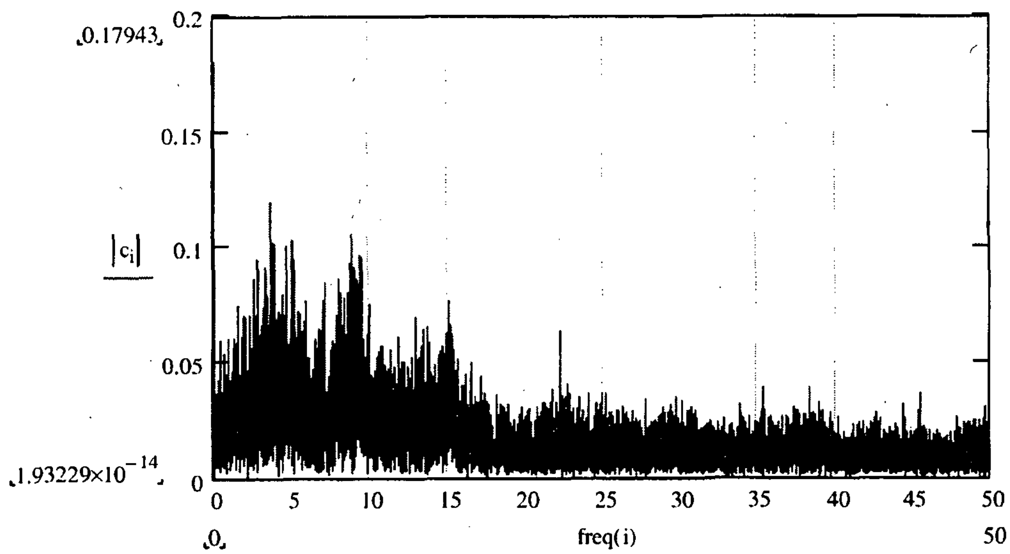
Data taken at 91% power

Line (Time Label)	Number of points	Mean (psi)	Standard Deviation
2A (10:24)	29762	868.76276	3.53268
2A (10:30)	30006	871.96367	3.54429
2D (10:24)	29762	892.41979	3.62713
2D (10:30)	30006	895.41641	3.60067

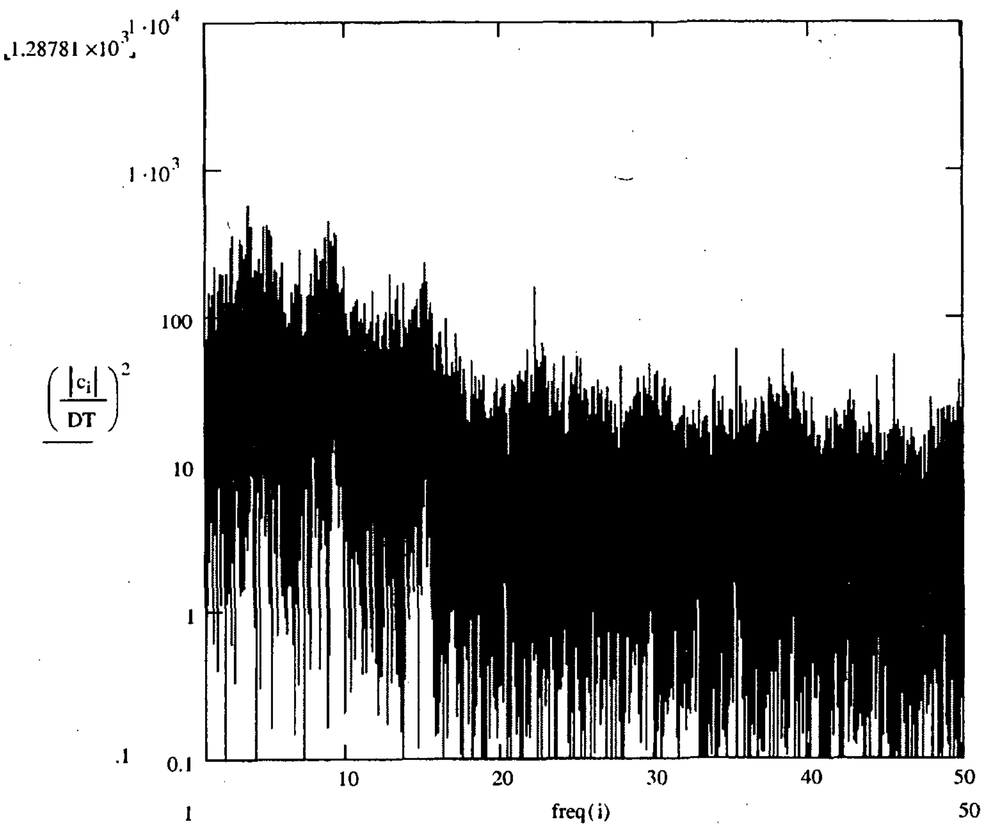
The data was reduced using the Mathcad software program in the following way. First the mean was subtracted from the entire data set. The result was then transformed using complex FFT algorithms. A plot of Fourier coefficients vs. frequency was generated as well as the Power Spectral Density for each set of data. These are provided on the following pages.

Byron Unit 2 A FW Line Data

Fourier Coefficients vs. Frequency.

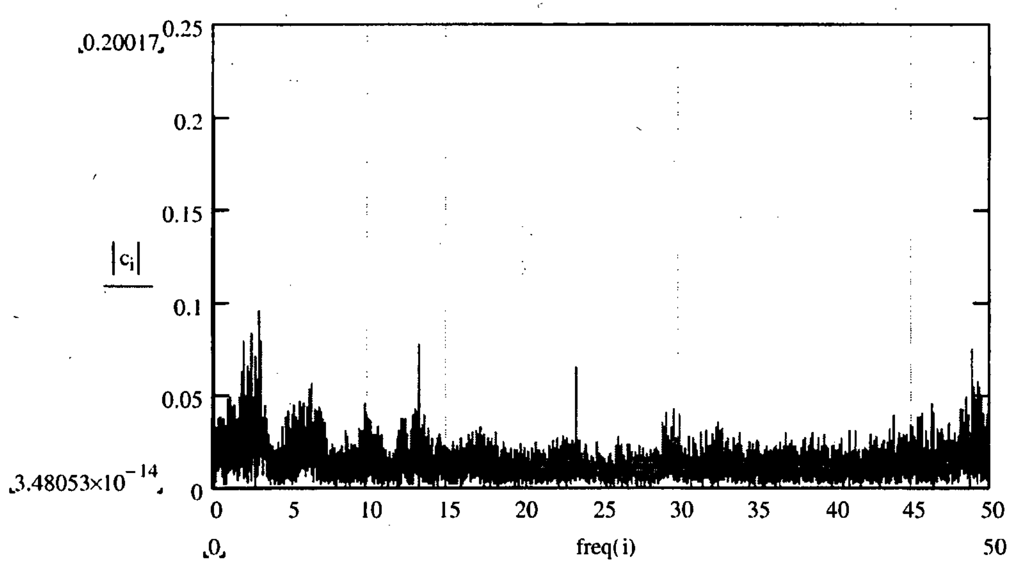


Power Spectral Density

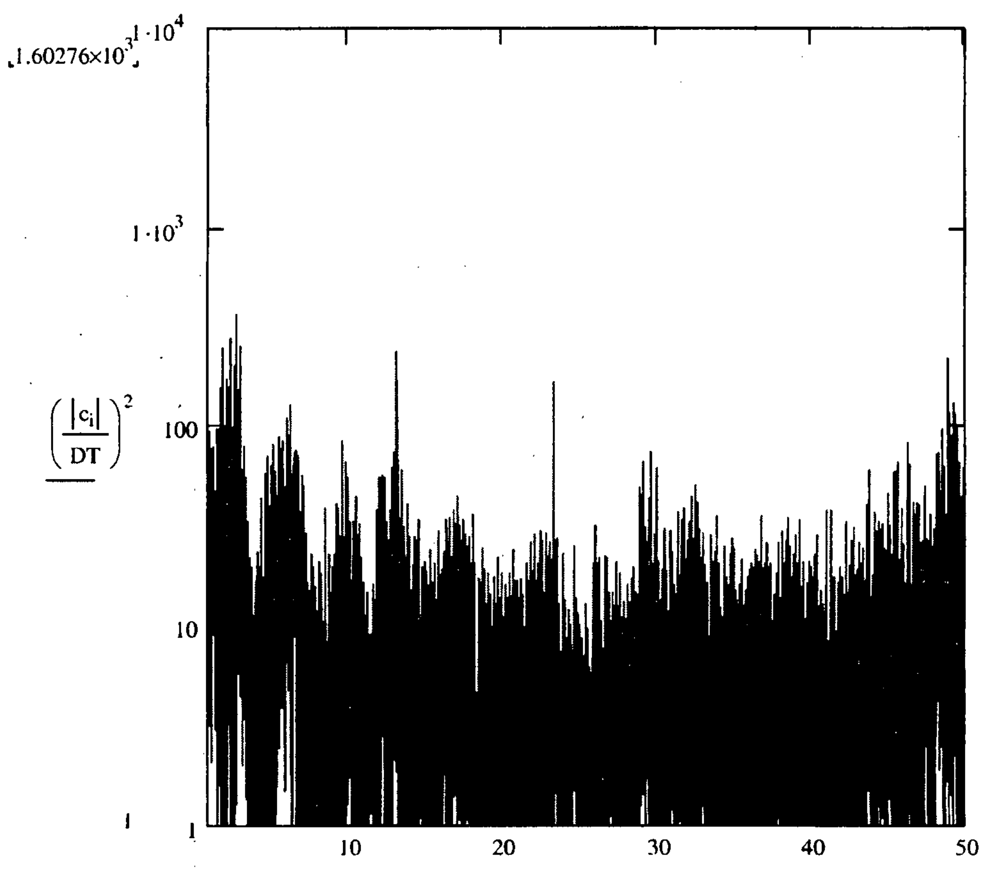


Byron Unit 2 B FW Line Data

Fourier Coefficients vs. Frequency



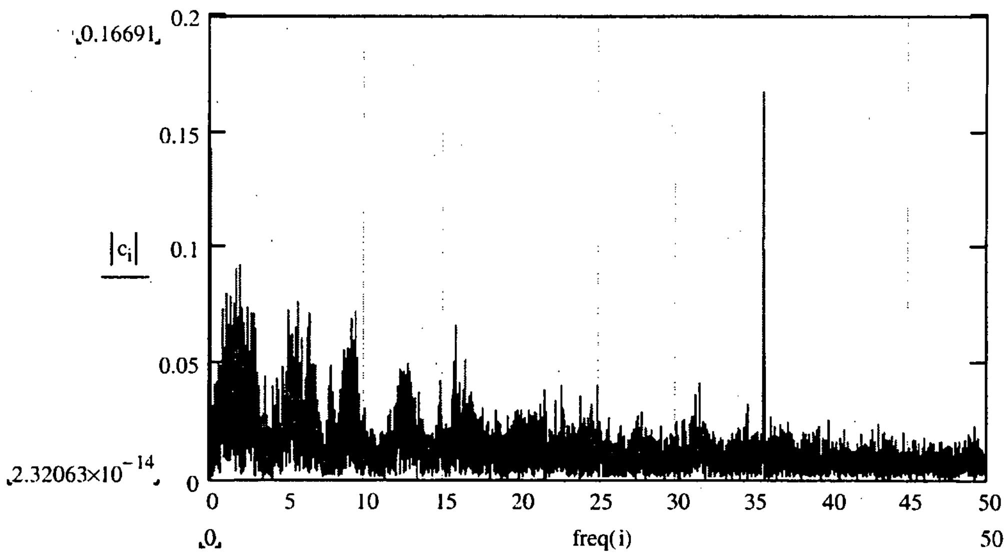
Power Spectral Density



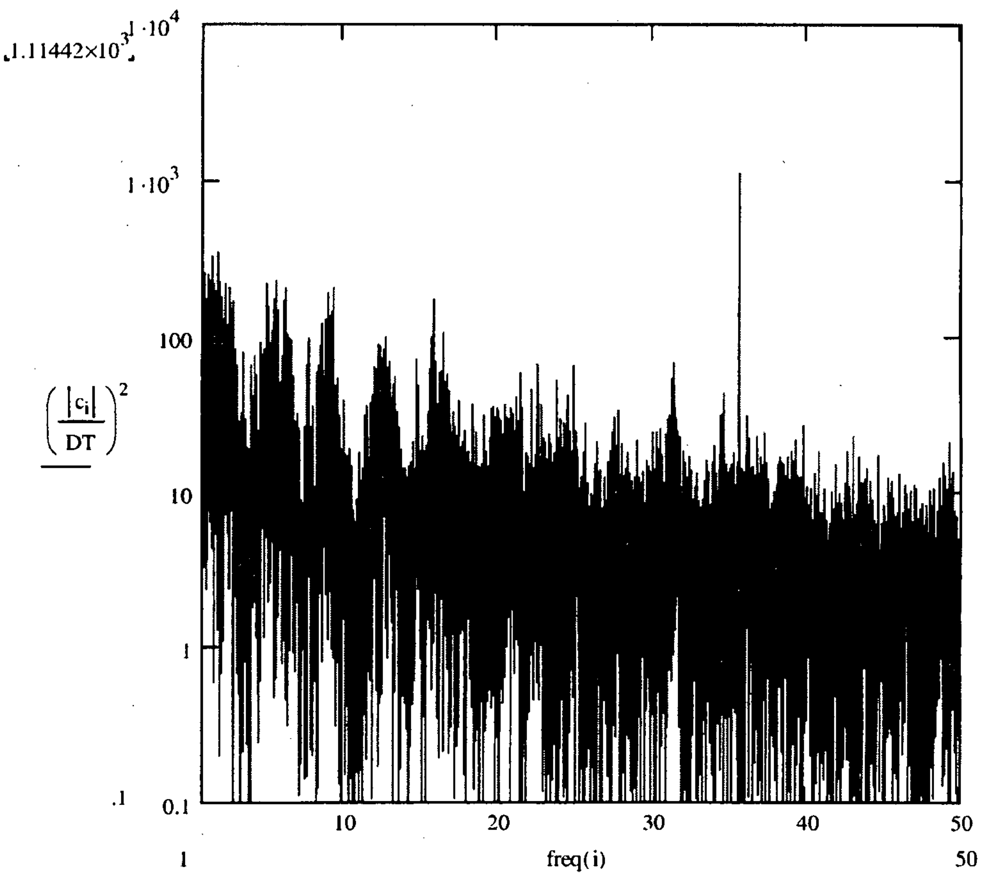
Attachment G - Byron Feedwater Piping Resonance Evaluation (Page 13 of 28)

Byron Unit 2 C FW Line Data

Fourier Coefficients vs. Frequency

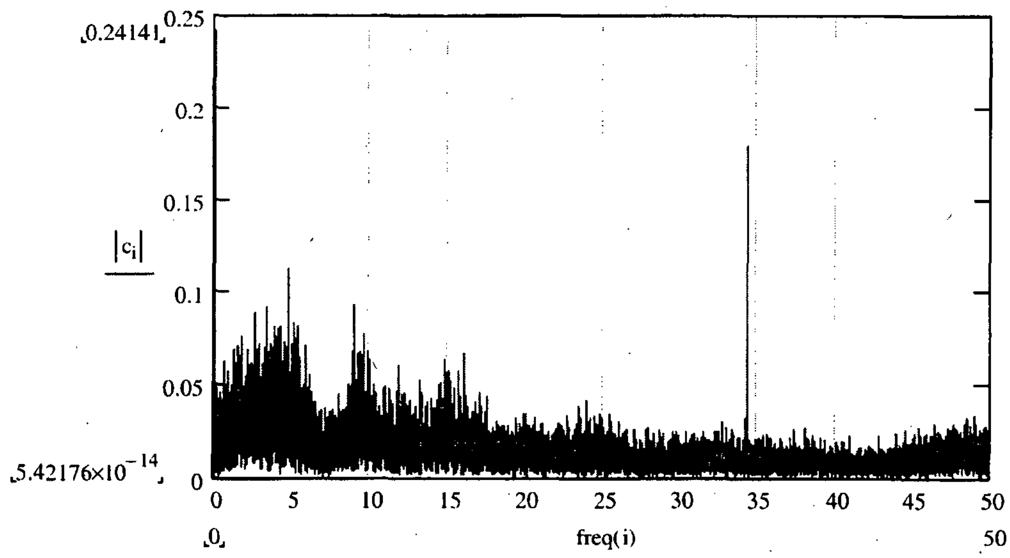


Power Spectral Density

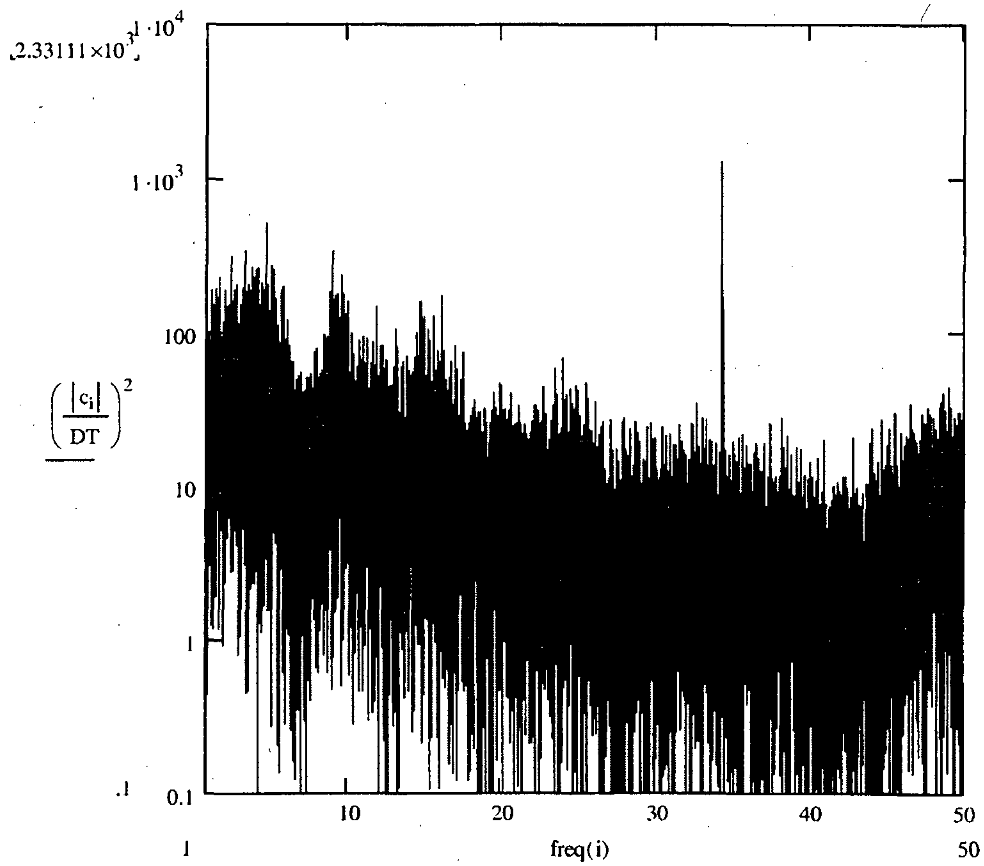


Byron Unit 2 D FW Line Data

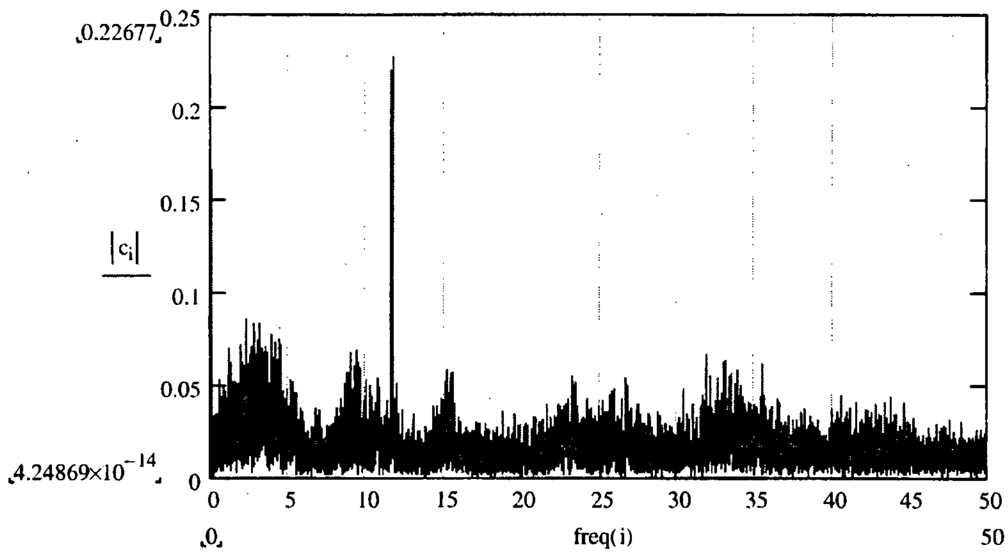
Fourier Coefficients vs. Frequency



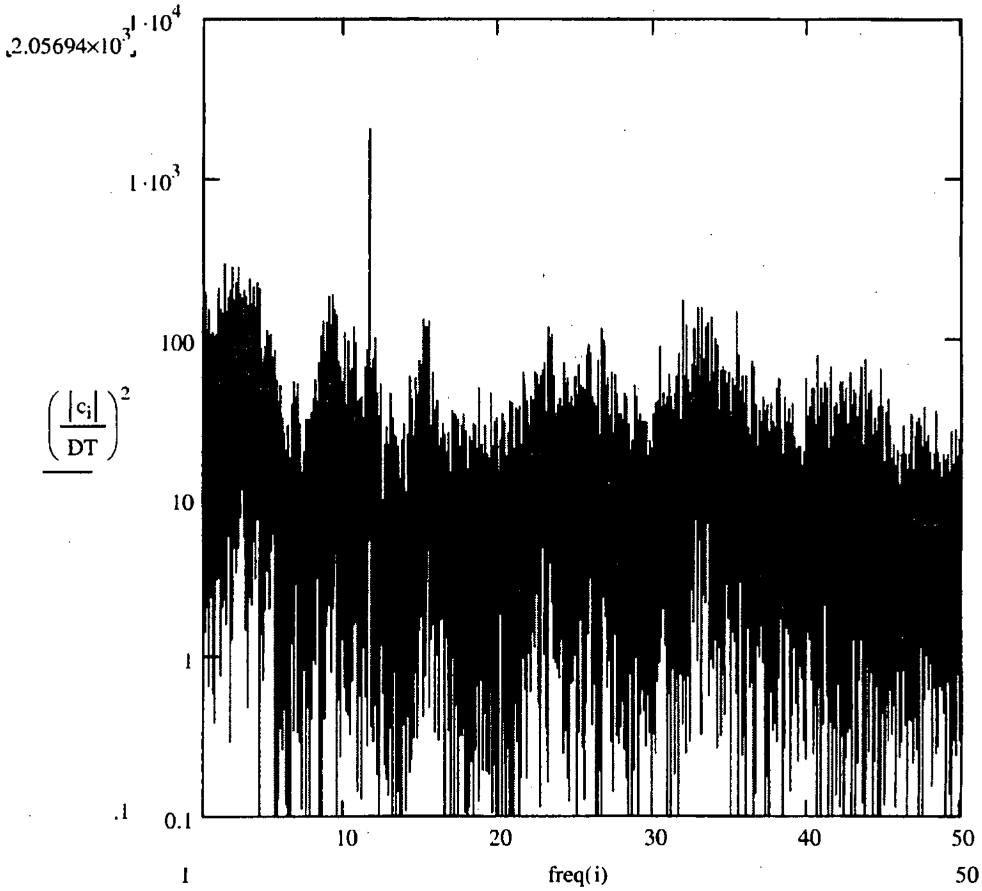
Power Spectral Density



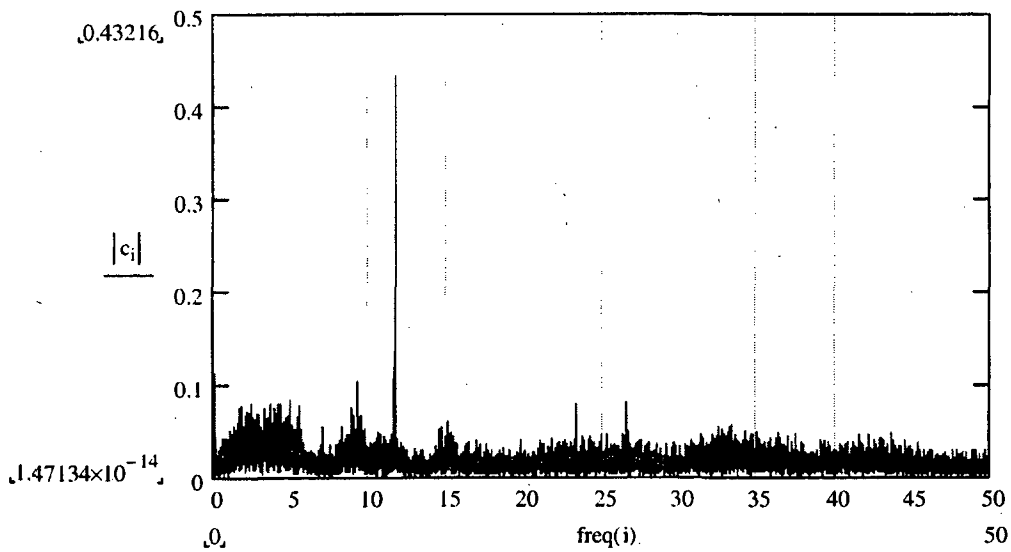
Line 2A FFT Transform 82% (0815) Data



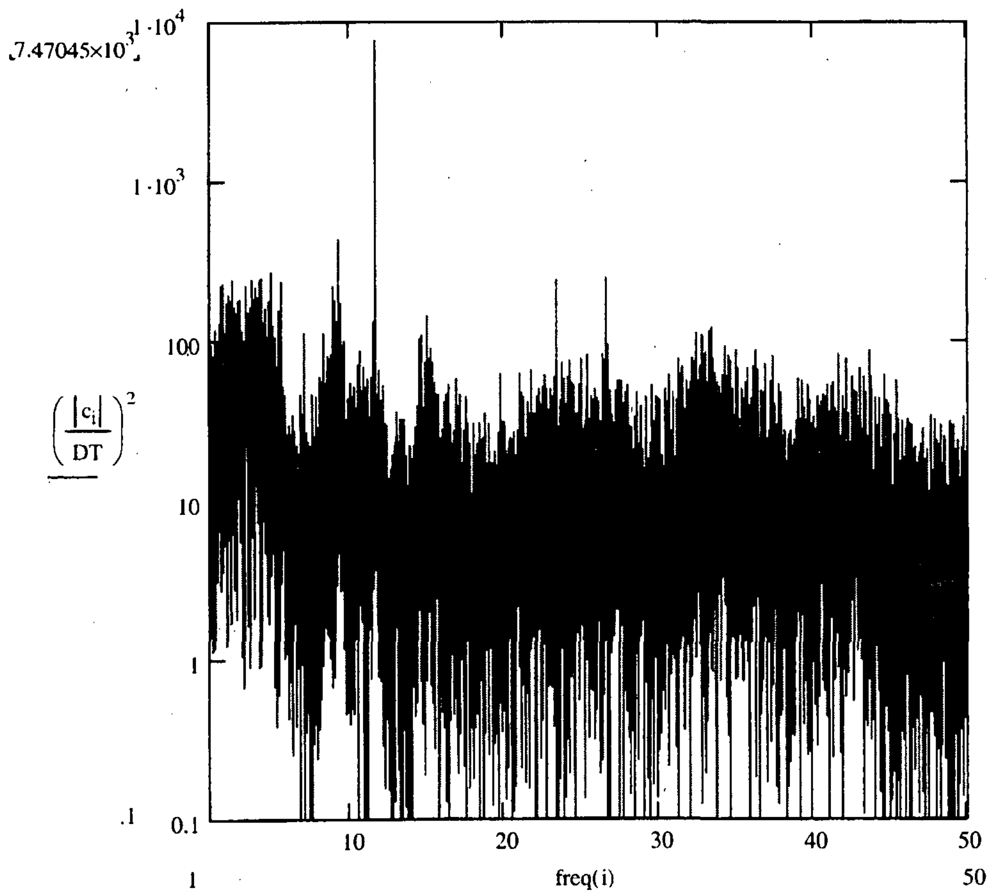
Line 2A FFT Transform Power Spectral Density 82% (0815) Data



Line 2A FFT Transform 82% (08:22) Data

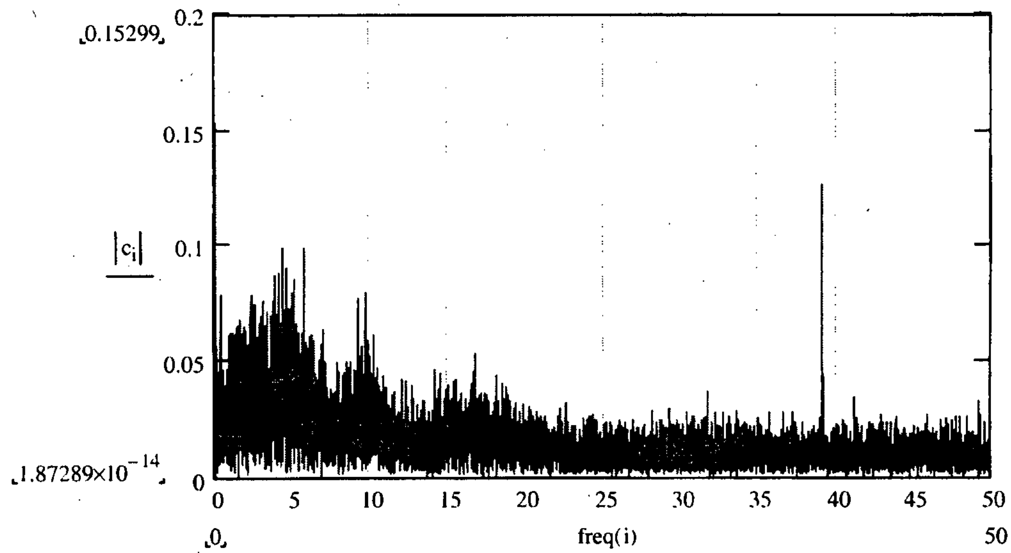


Line 2A FFT Transform Power Spectral Density 82% (0822) Data



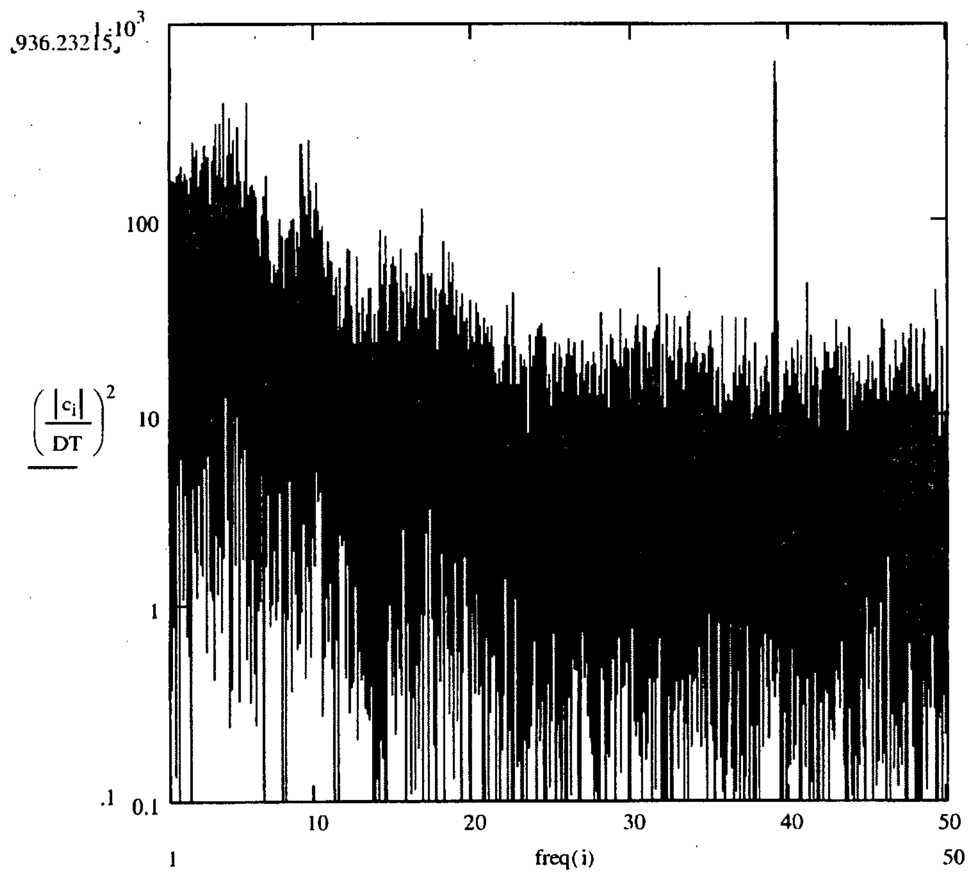
Attachment G - Byron Feedwater Piping Resonance Evaluation (Page 17 of 28)

Line 2D FFT Transform 82% (0815) Data



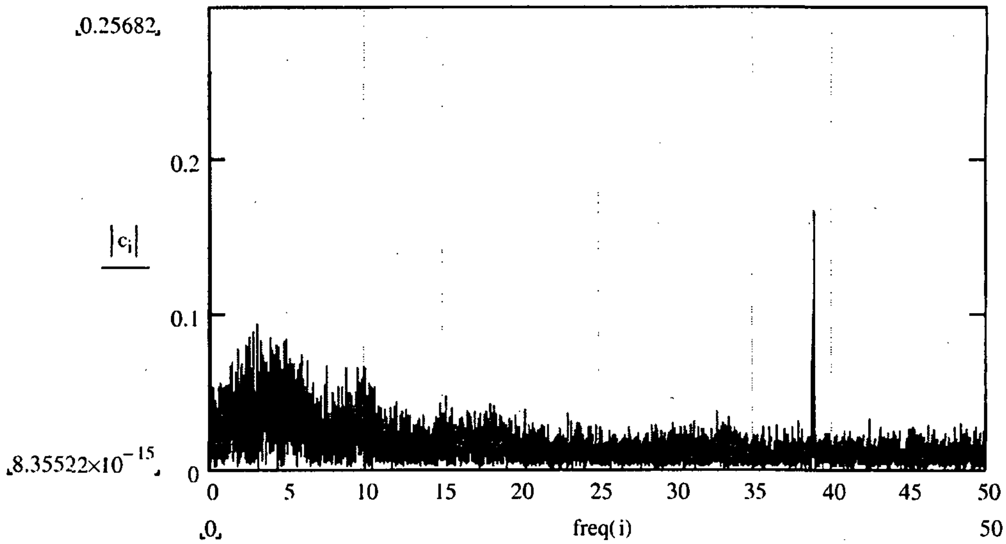
Line 2D FFT Transform Power Spectral Density 82% (0815) Data

Attachment G - Byron Feedwater Piping Resonance Evaluation (Page 18 of 28)

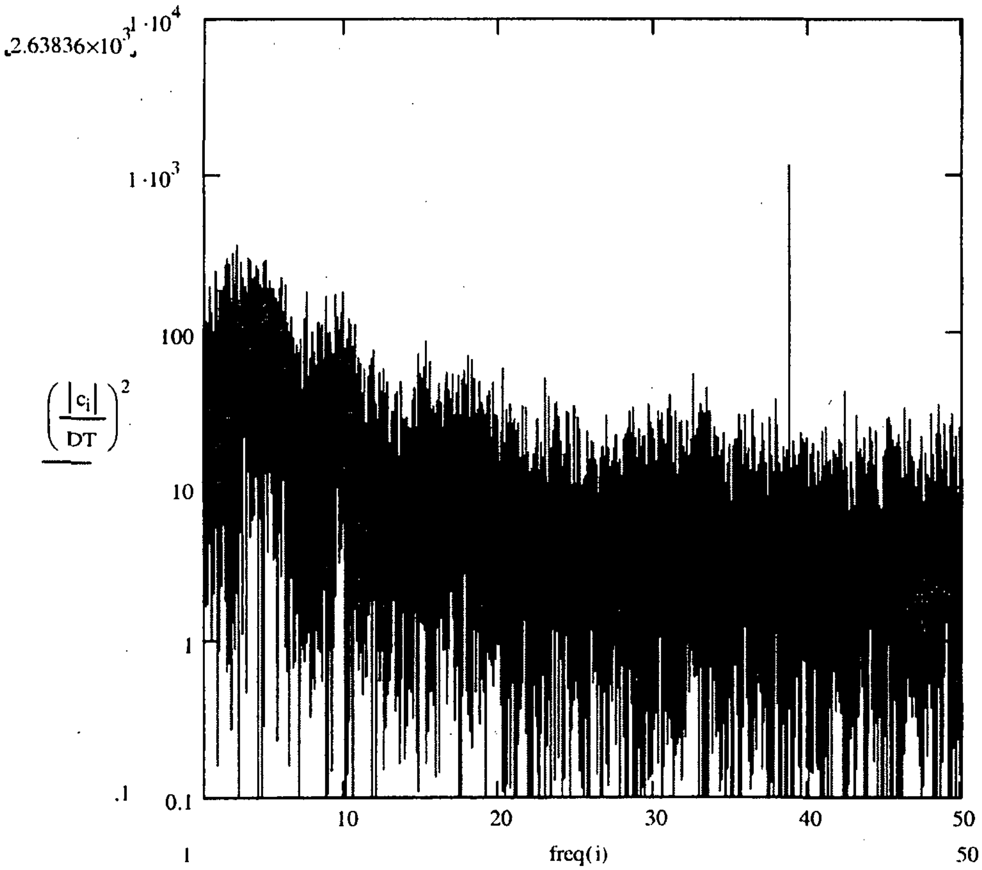


AMAG ROOT CAUSE - FINAL

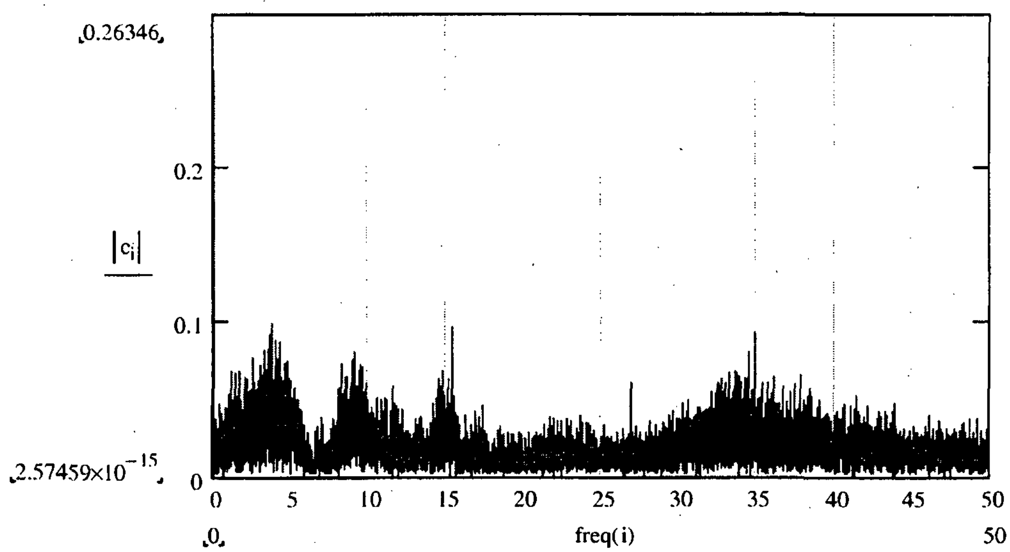
Line 2D FFT Transform 82% (0822) Data



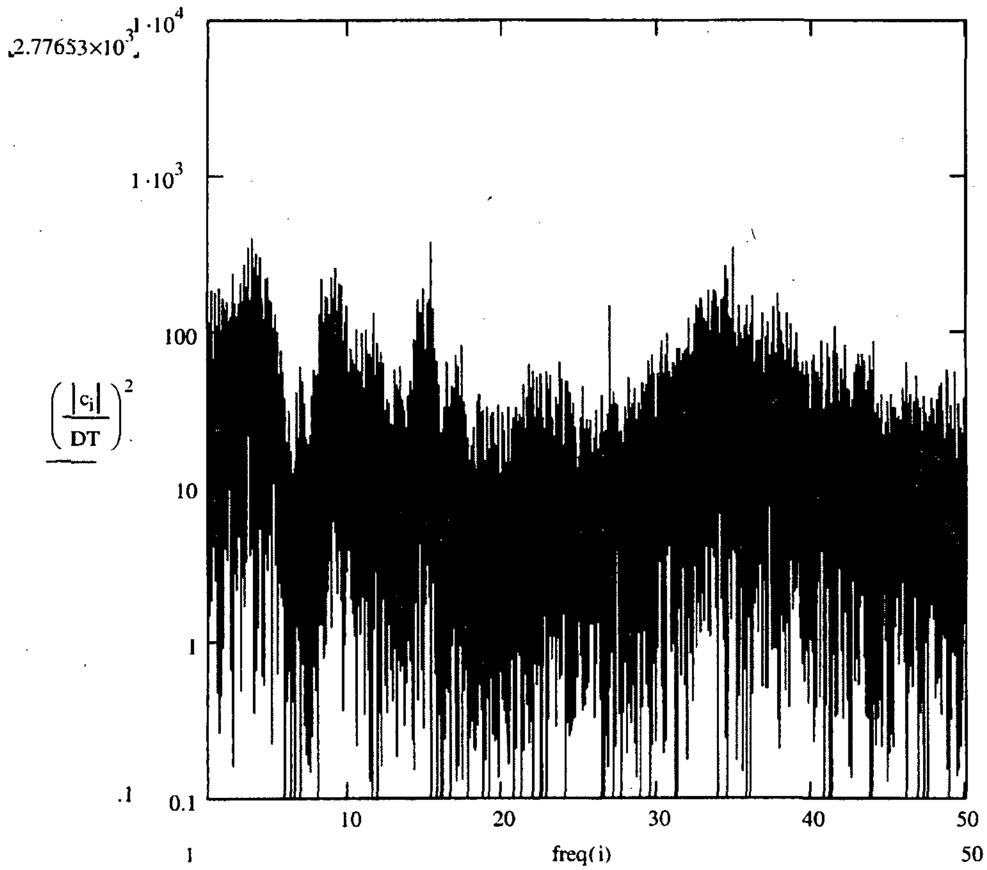
Line 2D FFT Transform Power Spectral Density 82% (0822) Data



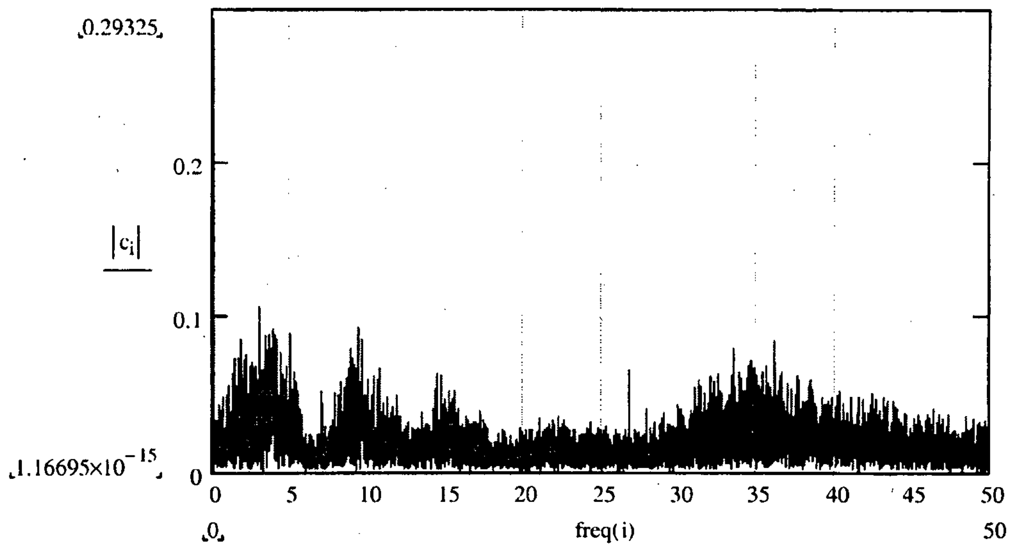
Line 2A FFT Transform 91% (1024) Data



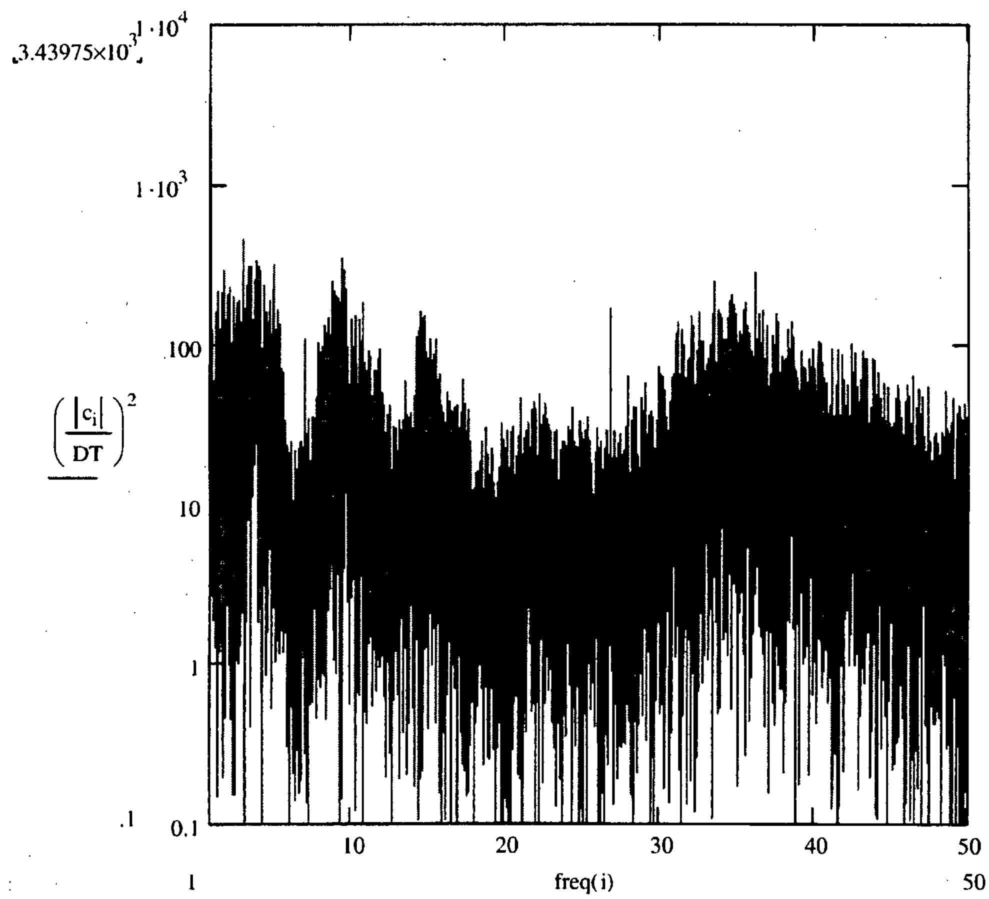
Line 2A FFT Transform Power Spectral Density 91% (1024) Data



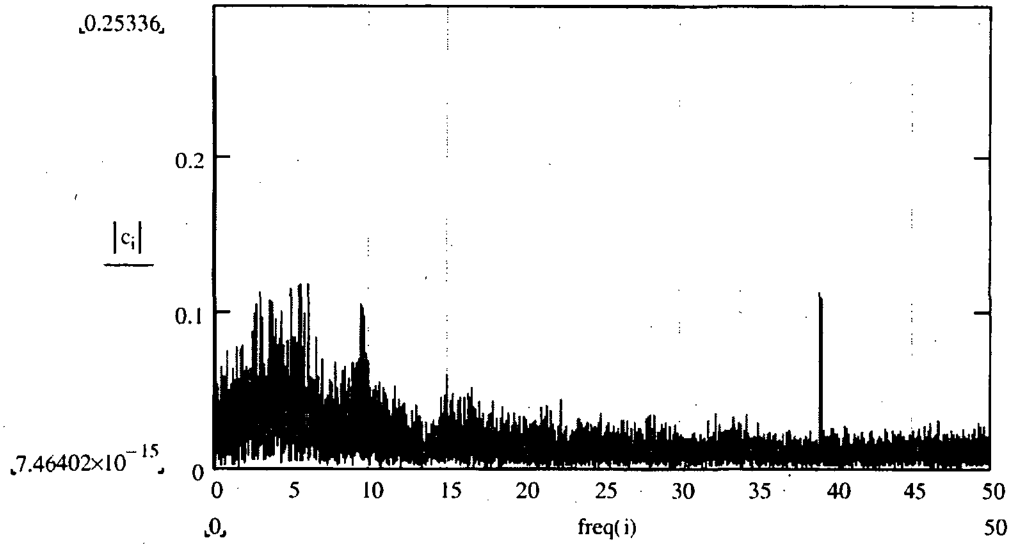
Line 2A FFT Transform 91% (1030) Data



Line 2A FFT Transform Power Spectral Density 91% (1030) Data



Line 2D FFT Transform 91% (1024) Data



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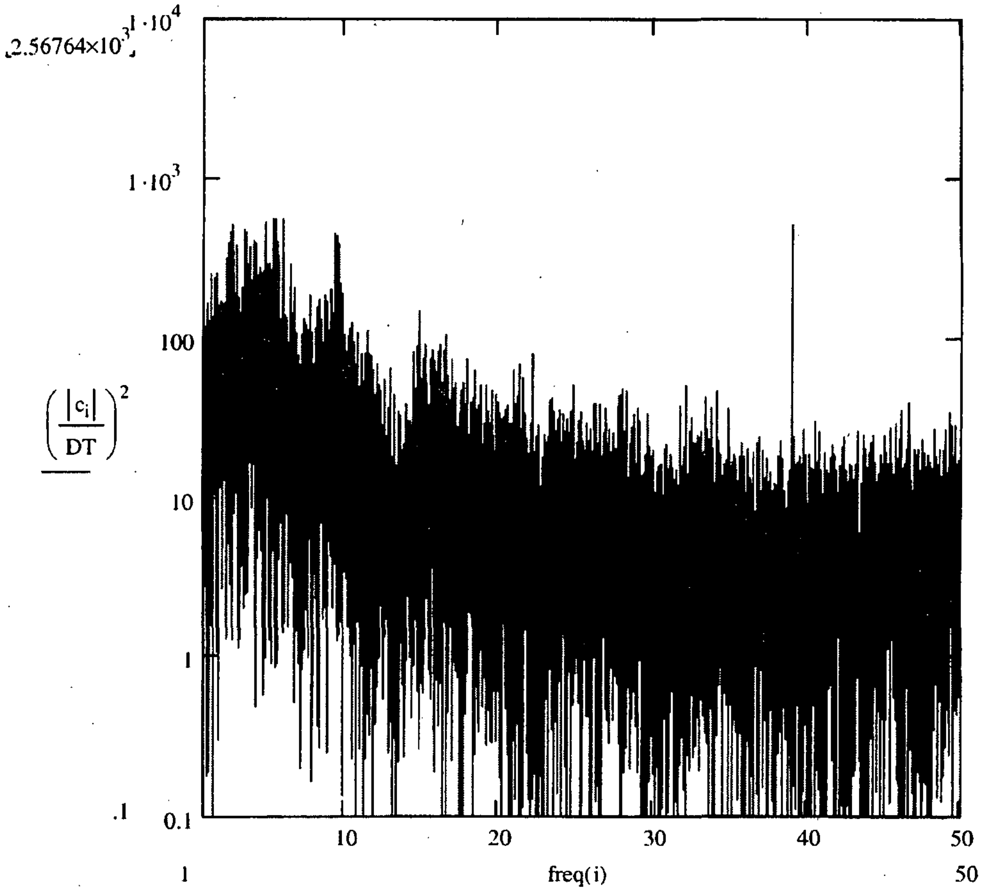

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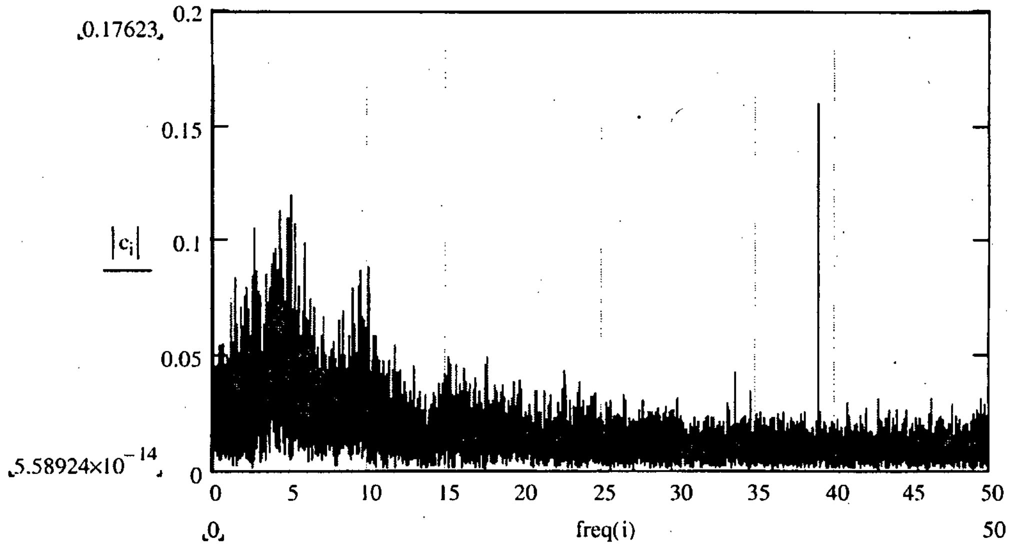
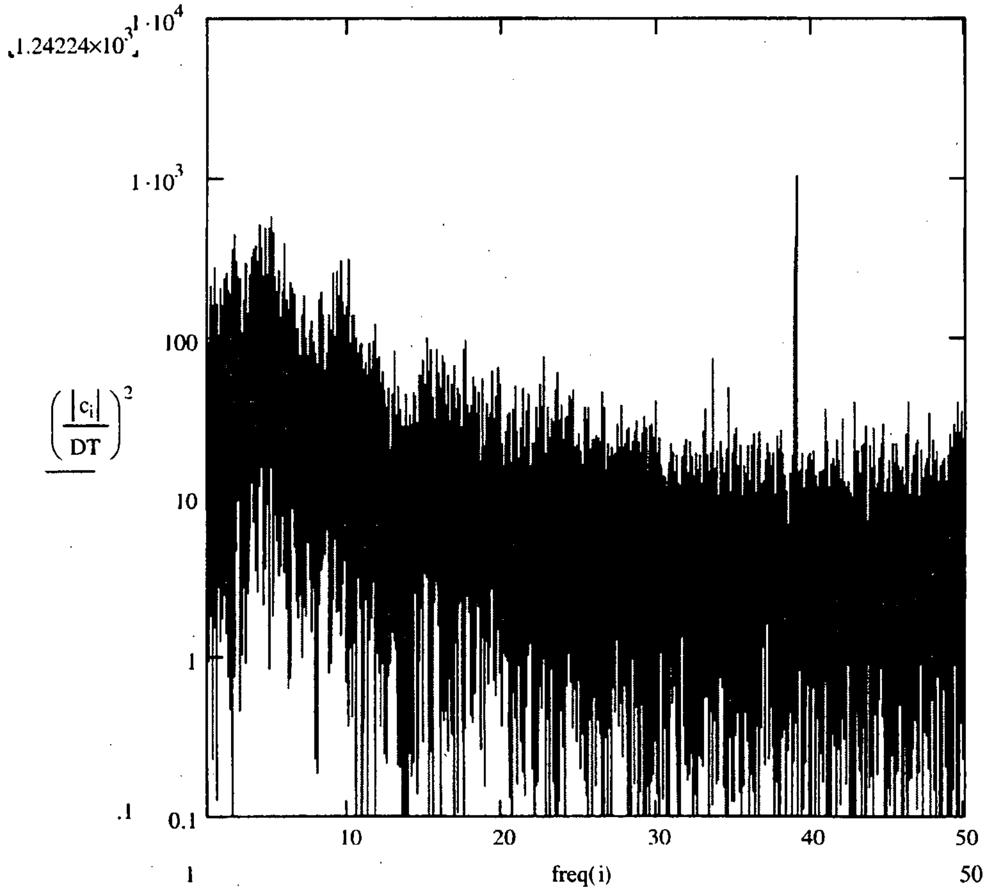


Line 2D FFT Transform Power Spectral Density 91% (1030) Data



Data Analysis/Evaluation

A review of the statistical data provides the following observations:

1) The standard deviation of the pressure appears to decrease with reduction in power. This would be expected, since the dynamic head is reduced with flow velocity. It should also be noted that with a nominal full flow velocity of 20.6 fps, the dynamic head would be approximately 2.5 psi.
2) The variation in mean pressure is anomalous and suggests that the absolute calibration or the zero setting of the pressure instrument has varied between successive measurements. Steam generator pressure should be lowest at full power and increase with decreasing power. Since the analysis is based on variation from the mean, the absolute value is not paramount, but if scaling varies between tests, this would have potential implications with respect to the magnitude of the Fourier coefficients calculated. Sensor calibration or zero drift issues would not affect the frequency response, the primary parameter of interest in this evaluation.

Comparison of the Fourier Coefficient plots to those generated at full power conditions shows that the basic frequency components appear to be maintained at the reduced power conditions. Specifically the frequency components for the first several modes below 25 hz are very similar, and exhibit similar trends in power spectral density to the full power cases. The coefficients for the reduced power cases appear to be slightly less than at full power, which would agree with the reduction in pressure fluctuation standard deviation observed.

Two changes were observed between the reduced and full power frequency responses:
1) The reduced power cases for line 2A exhibit a strong, nearly pure response at approximately 12 hz that was not observed at full power.
2) The reduced power cases for line 2D exhibit a spike in the higher frequency range near 38hz, where the full power cases had a similar spike at 34hz.

One possible explanation for these changes would be that both are emanating from the feed regulating valve as a direct source, rather than being acoustic mode responses from the piping. The feed regulating valve position and differential pressure would have been different at the reduced power conditions than at full power and this may be responsible for the observed changes. This hypothesis is also supported by the close proximity of the pressure measurement to the feed regulating valve discharge.

1.6.1.1.A.1.1.1.3. DISCUSSION

The measured data clearly shows that some acoustic response is occurring in the Byron 2 feedwater lines. Comparison of plant data to the frequency predictions supports that the closed-open model and the impedance approach appear to capture the most significant peaks. The impedance approach also appears to reflect the magnitude differences

reasonably well. For Line 2A, the frequency plot shows clusters of response centered on approximately 3, 9, 15, and 22 hz, which agree very well with the impedance predictions. Line 2A data appears to have relatively stronger response compared to the other lines, particularly in the range of 5 to 15 hz. The line 2B data also shows good agreement with the impedance predictions, and displays a response at 22 hz that coincides with a high impedance prediction. Line 2C data shows responses that match the impedance frequencies quite well through 20 hz. Relatively little response is seen above 20hz, with the exception of a very strong response at 36 hz which is a predicted resonance point, but not the most responsive one. The line 2D data shows the best match to the impedance predictions, with the largest response being at 34 hz, almost exactly matching the frequency with the highest predicted impedance. The power spectral density plots demonstrate that the power falls off fairly rapidly with frequency, which is expected. They also support that the responses at higher frequencies noted above are in fact significant. The general trend in the power densities also supports that line A has higher response through 15 hz before decreasing, compared to the other lines. The data collected at reduced powers exhibit similar frequency response to the full power data, which further supports the conclusion that acoustic excitation of the feedwater lines is occurring.

It should be noted that the feed regulating valves were in automatic mode during the data collection. This may have implications with respect to the driving function for the response of the system. Specifically, motion of the feed regulating valves may be responsible for some of the broadening of response observed.

1.7. Conclusions

The potential for acoustic resonance response of the Byron feedwater lines has been postulated as a potential source of signal contamination in the AMAG flow measurement system. The potential resonant frequencies were predicted using several theoretical methods. Dynamic pressure measurements taken on Byron Unit 2 support the existence of low frequency resonant system response. The agreement between approximate theoretical methods and actual plant response is quite good, and suggests that the principal resonance is likely that of the segment between the feed regulating valves and the steam generator.

1.7.1.1.A.1.1.1.1.

1.7.1.1.A.1.1.1.2. AN ADDITIONAL REVIEW OF THE BYRON UNIT 2 COMMON HEADER WAS PERFORMED AS DISCUSSED BELOW.

1.7.1.1.A.1.1.1.3. ACOUSTIC RESPONSE OF BYRON UNIT2 FEEDWATER COMMON HEADER

An alternate location for feedwater flow measurement is the common header located upstream of the feed regulating valves. This header is 30 inch diameter pipe, approximately 295 feet long, and connects the A/B feedwater heaters with the feed regulating valves. The feedwater heaters can be considered an open boundary condition for the header with the feed regulating valves forming a closed boundary. There are no significant pressure drops between the heaters and the common header to act as drivers for acoustic resonance. One additional path that can be postulated is the feed pump discharge piping to the bypass line around the feed heaters and into the common header piping. This path would also tend to act as an open- closed system. The only potential driver for resonant behavior would be the feedwater pump itself, which might be expected to yield some high frequency oscillations due to the rotational speed, (ie. Vane pass pulsation) but probably not any significant low frequency ones. The characteristic frequencies of the piping can be calculated using the following relation:

$$f = \frac{c \times i}{4 \times L}$$

Where
c= sound speed, fps
L= length of pipe
f= frequency
and i=1,3,5,...n

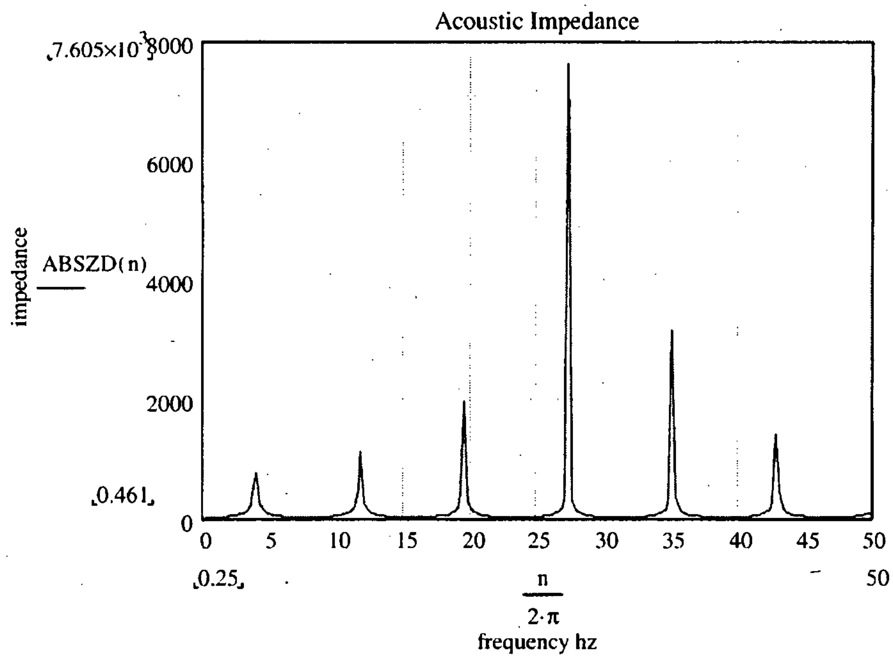
employing this relation for the common header and the pump/bypass/common header combined length yields the following :

BYRON UNIT 2 FW LINE

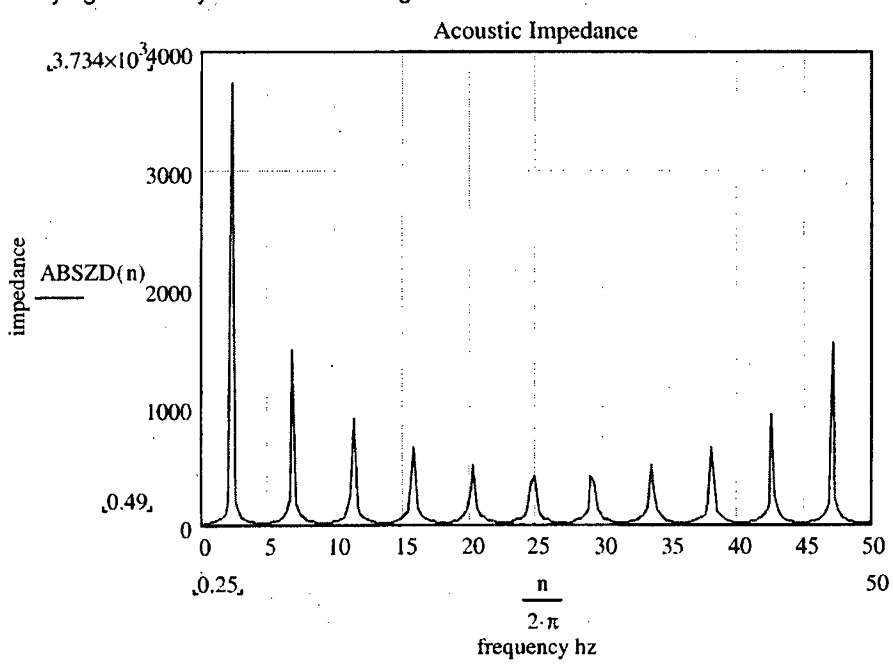
mode	Common header only (hz)	Pump discharge/bypass/common header (hz)
1	3.898	2.242
2	11.695	6.725
3	19.492	11.209
4	27.288	15.692
5	35.085	20.175

Attachment G - Byron Feedwater Piping Resonance Evaluation (Page 26 of 28)

The frequency response can also be characterized using acoustical impedance methods as delineated in Wylie "Fluid Transients in Systems". Employing this approach for the common header yields the impedance as a function of frequency as shown on the next page:



This plot shows agreement with the frequencies predicted using open-closed formulas for the common header, and suggests that the most significant mode for excitation of the common header would be approximately 27 hz at full flow conditions. A similar calculation for the combined pump discharge, bypass line, and common header, treated as a single diameter pipe carrying full flow yields the following results:



This result also compares favorably with the frequencies predicted by the open-closed formulation generated above. It should be noted that this approach is a simplified one, and that the actual system contains parallel paths carrying significant flows that could be expected to result in similar frequency predictions, but significantly different magnitudes of the impedances at specific frequencies than shown in the above figure.

DISCUSSION

The vendor of the ultrasonic flow measurement equipment has noted that it would be preferable if no acoustic resonant response occurs at frequencies below 25 hz. The acoustic modes of the common header itself as well as the potential combined pump discharge, heater bypass line, plus common header have been investigated analytically. There are a number of potential acoustic resonant modes predicted, based solely on the geometry of the system. As noted above, no high pressure drop conditions exist in this piping and the feedwater pump is not expected to provide low frequency excitation. Therefore, while resonant modes exist, no resonant response is anticipated. If ultrasonic flow measurement of the common header piping is planned for future application the following recommendations should be considered:

1) Diagnostic software within the ultrasonic flow measurement equipment should be run initially and subsequently at some periodic interval to confirm that no acoustic resonant behavior is present that could affect the flow measurement process.
2) Dynamic pressure measurements should be taken if possible to further confirm that no resonant response is exhibited in the frequency range of interest.
3) The above actions should also be performed with the feedwater bypass valve open, if that mode of operation is contemplated in the future.
4) More detailed acoustical analysis of the feedwater header may prove of value, but should augment and not supplant the routine diagnostic and dynamic pressure measurement actions.

This piping resonance evaluation was prepared by Kevin Ramsden (Cantera) and reviewed by Chris Brennan (Kennet Square).

Pages 66 through 78 redacted for the following reasons:
- -
Exemption 4

September 11, 2003

Independent Assessment Report

For the Overpower Condition At Byron Station
Related to Crossflow (AMAG) Utilization

At the request of Steve Kuczynski, Byron Site Vice President, an independent team was assembled, separate from the root cause team, to evaluate decisions made in the spring of 2002 related to Crossflow Ultrasonic Flow Measurement System. The specific charter was as follows:

> "Determine the appropriateness of the decision made in the spring of 2002 to continue utilization of the AMAG (Crossflow) correction factors based upon the flow measurement comparison between the individual loops and the common header. "

Process

The assessment team members were:

- Ken Hansing, Byron Nuclear Oversight
- Ted Bell, Quad Cities Engineering
- Hank Sepp, Westinghouse Regulatory Compliance and Plant Licensing
- Armando Lopez, Advanced Measurement & Analysis Group, Inc.
- Frank Bursic, Advanced Measurement & Analysis Group, Inc.

The assessment team reviewed the results from the testing performed in February and March of 2002 as documented in calculation 059-PENG-CALC-084 Rev. 1 and summarized in Westinghouse report titled "Summary of Recent Crossflow Related Activities to Support Byron Station, April 2002". The team also reviewed the Apparent Cause Evaluation from Condition Report #91771 related to unexplained differences between Byron and Braidwood, and letters dated 7/9/03 and 8/30/03 from Mr. Meister to Mr. Lopriore titled "Review of Byron AMAG Feedwater Flow Instrumentation Installation and Performance".

The team interviewed the following personnel that were involved in the testing, analysis, communications and decisions:

- Jeff Drowley, Exelon Cantera Engineering
- Dave Eder, Byron Plant Engineering
- Ronda Doney, Westinghouse
- Tim Jaeger, Westinghouse
- Brad Adams, Byron Engineering
- Bob Tsai, Exelon Nuclear Fuels
- Rob Young, Exelon Nuclear Fuels
- Armando Lopez, Advanced Measurement & Analysis Group, Inc.

Conclusions

The team concluded that the decisions made in the spring of 2002 and affirmed in subsequent reviews later in the summer to continue to implement the Crossflow correction factors were appropriate. The following points support that conclusion:

- The AMAG Crossflow ultrasonic flow measurement system is NRC licensed and industry proven technology for accurate measurement of Feedwater flow.
- The AMAG Crossflow installation at Byron was confirmed as properly installed and functioning acceptably.
- The test comparing flow in the common header to the individual loops met the pre-established test acceptance criteria.
- Nuclear Fuels review in February of core burnup could neither confirm nor repudiate the AMAG results. Core energy utilization and boron letdown trends continued to be within expected norms.
- Review of the AMAG data and installation by Exelon MWROG Engineering recommended that Crossflow continue to be used at Byron.

Key Findings

Through interviews, the team concluded there was no reluctance by involved personnel to identify concerns.

With the exception of the Byron Thermal Engineer, no individuals identified any undocumented or unresolved issues or concerns related to the specific testing performed to compare the flow in the common Feedwater header to the flows in the individual loops.

The Byron Thermal Engineer's concerns, documented in Condition Report 91771, were not resolved to his satisfaction. However, he indicated that there was no additional data to validate his concerns. The Thermal Engineer felt that the correction factors may change with power levels but did not have data to substantiate the concern and believed that measured venturi flow was potentially non-linear. The Thermal Engineer also questioned the need to optimize the common header Crossflow system in February 2002 prior to taking the test data on March 10, 2002, as the first set of data did not meet the acceptance criteria but the second set of data was acceptable. While not addressed in the Crossflow information reviewed by the Engineer, AMAG explained that optimization of the system is a standard process when the instrumentation system is first installed. Data taken prior to optimization shall not be used to

Attachment I Independent Assessment Report (Page 3 of 6)

make any plant performance changes (section 7.5 of 059-PENG-CALC-084, Rev. 1).

Although the team determined that the decision was appropriate in 2002, they also felt that there was a missed opportunity to identify the potential power dependency of the Crossflow system at Byron. The team identified four indications that should have raised the <u>urgency</u> to gather and analyze additional Crossflow data, as was recommended in the spring of 2002. This action to gather continuous data has only recently begun. The four indications were:

- The pre and post power uprate correction factors increased (reference Feb. 5, 2003 letter from K. Jury to the NRC regarding Byron Station, Unit 1, Licensed Thermal Power Limit Verification). Assuming the venturis behave linearly as normally is the case, the correction factor from Crossflow is not expected to be power dependent. The correction factors increased on all four Byron and Braidwood units.
- The data gathered in February and March of 2002 that compared the common header flow to the individual loop flows was performed at different power levels and yielded different results. AMAG discounts the first set of data because the Crossflow system was not optimized, but the Cantera Engineer and the Byron Thermal Engineer believe, in hindsight, that it may have been an indication of power dependency and should have been pursued further.

- The results (Para 7.2, Table 2 of Calc 059-PENG-CALC-084, Rev. 01) from the March 10, 2002 test were at the upper end of the pre-established acceptance criteria and were above expected mean values based on AMAG industry experience.
- Byron correction factors fluctuated without explanation. Byron and Braidwood are unique in that snapshots of data, every nine months for Byron, are used for determining correction factors while most Crossflow users gather continuous data and do not experience such fluctuations. This long period between calibrations made it difficult to track the cause of these changes.

The team identified numerous communication weaknesses through interviews with the involved personnel. It was evident that there was limited flow of information to and from the involved parties at Byron Engineering, Cantera Engineering, Westinghouse, and AMAG. Communication weaknesses hindered the timely resolution of concerns related to Crossflow performance at Byron. Examples of the communication weaknesses include:

- AMAG was not aware of the specific details of the thermal system performance concerns in the spring of 2002 when they were investigating the Crossflow system performance.

- AMAG was not aware of plant parameters, such as power level, when they analyzed Byron data so they were not able to identify any power dependency issues.
- AMAG was not aware of the pre and post power uprate correction factor changes on all Byron and Braidwood units, which may have been an indication of potential power dependency issues.
- The urgency of the recommendation to gather continuous data was not communicated effectively from AMAG, through Westinghouse, to Exelon. This recommendation was of high importance to AMAG and Westinghouse but was not a high priority by the time it reached Byron Engineering, although Cantera Engineering appreciated the urgency of this request. The recommendation from the spring of 2002 was not acted upon until the summer of 2003.
- While highly frustrated with the lack of information from Exelon, Westinghouse acknowledged they did not push implementation of recommendations or improvements in communications.
- Potential Crossflow issues identified at Byron in Condition Reports were not routinely shared with Westinghouse and AMAG.

The team also reviewed the extent of training on the Crossflow system. Through discussions with the Exelon Engineers and AMAG personnel it became evident that there were potential knowledge gaps that should be evaluated to improve Exelon's use of the Crossflow systems and our ability to detect anomalies and resolve them through interaction with AMAG. Examples of knowledge gaps identified include:

- Awareness of the diagnostic tools, including frequency spectrum analysis.
- Understanding of the Crossflow system optimization process.
- Recognition that Crossflow correction factors should not be power dependent.

Recommendations

1) Establish communication expectations and processes with the involved organizations to improve the working relationships and effectiveness of the groups through effective sharing of relevant information.

2) Potential knowledge gaps should be identified, evaluated and actions taken to improve the Cantera and Byron Engineers' technical expertise on Crossflow. Additional training may be required.

Prepared by: K.J. Hansing
Byron NOS Manager

Attachment 1
Timeline

May 1999 – AMAG installations complete-all B/B units.

June 1999 – AMAG Implemented at Braidwood. Braidwood U1/U2 increased in power based on AMAG results.

May 2000 – Byron AMAG implementation U1 1.09%, U2 1.7%.

January 17, 2002 – CR#91771 Unplanned AMAG difference between B/B. Byron U1 ~ 1.5% to 2.5% higher than Braidwood U1.

February 27-28, 2002 - Crossflow installed on Unit 1 common Feedwater header, data gathered and system optimized. Data indicated 1.1-1.3 % difference between common header and individual loops.

March 10, 2002 – Crossflow data gathered with system optimized and acceptable results obtained

April 24, 2002 – First common header test results finalized (Calc 059-PENG-CALC-084, Rev. 01).

June 2002 (approximate time) – Westinghouse report titled "Summary of Recent Crossflow Related Activities to Support Byron Station, April 2002" was issued.

July 9, 2002 – Meister letter to Lopriore issued recommending that the AMAG Crossflow meter continue to be used at Byron Station.

August 30, 2002 - Meister letter to Lopriore issued, supplementing the July 9, 2002 letter, with the same conclusion that the AMAG Crossflow meter continue to be used at Byron Station.

Attachment I Independent Assessment Report (Page 6 of 6)

Attachment 2
Reference Documents Reviewed

1. Westinghouse calculation # 059-PENG-CALC-084, Rev.1
2. Byron Apparent Cause Evaluation for Condition Report 91771
3. Westinghouse report "Summary of Recent Crossflow Related Activities to Support Byron Station, April, 2002"
4. Westinghouse letter CAE-02-27 dated March 15, 2002 from C.S. Hauser to J. Drowley titled "Crossflow System Performance Review".
5. Exelon letter from J. Meister to R. Lopriore signed July 9, 2002, subject – "Review of Byron AMAG Feedwater Flow Instrumentation Installation and Performance"
6. Exelon letter from J. Meister to R. Lopriore dated August 30, 2002, subject – "Review of Byron AMAG Feedwater Flow Instrumentation Installation and Performance"
7. Byron PORC #02-062 minutes
8. Exelon letter to the NRC dated February 5, 2003, subject – "Byron Station, Unit 1, Licensed Thermal Power Limit Verification".
9. Westinghouse letter CAE-03-69 dated August 28, 2003 from C.S. Hauser to B. Adams titled "Preliminary Results from Byron Unit 1 Crossflow Verification Program".

Attachment J: Cause and Effect Analysis (Page 1 of 3)

EFFECT/SYMPTOM	WHY	CAUSE/REASON
AMAG FLOW NOISE		
AMAG Flow Noise	→ ←	Reviewed list of potential causes (Attachment F)

AMAG ROOT CAUSE - FINAL

Reviewed list of potential causes (Attachment F)	→	Narrowed down potential causes to piping configuration that produces acoustic resonance response
	←	
Narrowed down potential causes to piping configuration that produces acoustic resonance response	→ ←	Combination of pipe length, flow, and pressure drops
Combination of pipe length, flow, and pressure drops	→	Physical design, layout, and constraints of the plant

AMAG Difference between the sum of the individual loop flows and the common header flow

AMAG difference between the sum of the individual loop flows and the common header flow.	→ ←	Loops see noise, common header does not. Therefore they don't match.
Why don't they match?	→	Refer to AMAG noise Analysis (above).

Attachment J: Cause and Effect Analysis (Page 2 of 3)

EFFECT/SYMPTOM	WHY	CAUSE/REASON

AMAG CFs varying with changes in power level

AMAG CFs varying with changes.	→	Noise impacts AMAG value.
	←	
Why does Noise impacts AMAG	→	Magnitude of the impact of the noise on the calculated

	←	time delay is different at different power levels.
Why is the magnitude of the impact of the noise on the calculated delay is different at different power levels	→	The change in time delay due to the noise is a time constant, while the time delay itself changes with power level.

AMAG FLOW CFs not linear with feedwater venturi flow output

AMAG CFs not linear with feedwater venturi flow output	→	Noise impacts AMAG value.
	←	
Why does Noise impacts AMAG	→	Magnitude of the impact of the noise on the calculated time delay is different at different power levels.
	←	
Why is the magnitude of the impact of the noise on the calculated delay is different at different power levels	→	The change in time delay due to the noise is a time constant, while the time delay itself changes with power level.

Attachment J: Cause and Effect Analysis (Page 3 of 3)

EFFECT/SYMPTOM	WHY	CAUSE/REASON

AMAG apparent condition not identified upon initial installation or subsequent evaluations of the AMAG instrumentation

AMAG apparent condition not identified upon initial installation or subsequent evaluations of the AMAG instrumentation	→	DIAGNOSE program is not a required part of the installation process procedure.
	←	
DIAGNOSE program is not a required part of the installation	→	It is only implemented if noise is suspected. Noise was not

process procedure.	suspected at the time of installation, nor in March 2002.
Why no reason to suspect noise at the time of installation, nor in March 2002?	AMAG had no basis for suspecting noise, they were preoccupied with investigating hardware issues and were not aware of plant power levels associated with the data (we did not tell them in order to prevent biasing their response); they did not identify any reason to suspect noise or to utilize the DIAGNOSE program.
Why did AMAG have no basis for suspecting noise?	Until recently there were no common header installations to allow calculation of statistical variance.

Attachment K - Questions from Mngr, Mech Systems, Exelon (Page 1 of 4)

(1) I understand that at the time of the original implementation the diagnostic tool was routinely used (but not documented) in the original installation of the CROSSFLOW circa 1999.

a. At the time of the installation in 1999, AMAG utilized a program called DIAGNOSE to check the frequency spectrum to identify if there was potential noise interference that may affect the CROSSFLOW system. However, it was not part of the installation procedure, and it was used only to perform a qualitative review to determine if there was significant noise interference. Since it was not part of the installation procedure at that time, it was up to the discretion of the AMAG technical expert to use or not to use it.

Typically, DIAGNOSE was utilized under the following conditions:

(1) if a significant distortion/asymmetry in the cross-correlation curve is noticed, which usually results in a high rejection rate during data collection activities a frequency spectrum analysis would be performed and

(2) If there were several loops, AMAG may run the DIAGNOSE program in just one loop and if no noise was detected, all locations would be assumed to be acceptable.

During the initial installation at Byron and Braidwood, AMAG believes that the DIAGNOSE program may have been run in one loop at each of the sites and seeing nothing, the other loops were likely not checked.

(2) I understand that we noted the noise in the late August 2003 timeframe at Byron 1. I also understand that the current (pre-bulletin) installation procedure has the diagnostic tool that captures the noise signal documented.

AMAG: The DIAGNOSE Program was run in late August 2003 timeframe at Byron 1. The DIAGNOSE program has always been available as part of several diagnostic tools used by AMAG, although, it is not used routinely and is not currently part of the formal installation procedure. As a note, the DIAGNOSE tool is introduced to CROSSFLOW users during the training course.

(3) In the tuning and testing that was done to support the original Byron commissioning in May 2000, why wasn't this captured?

Honestly, at that time, it wasn't identified as a value-added activity – the CROSSFLOW Team missed an opportunity. It was believed that DIAGNOSE was utilized on at least one of the loops during the initial installation. CROSSFLOW

experience indicates that if noise is not identified during the initial installation, there is no need to repeat it the DIAGNOSE test again. However, based on the issues in Byron, the CROSSFLOW team clearly has to reconsider this approach. Going forward, the plan is to modify the DIAGNOSE software so it can be utilized by CROSSFLOW users with an associated procedure to verify the absence of contamination. This will be similar to the RSSI test that CROSSFLOW users currently perform during periodic measurements or after plant outages.

(4) When was the installation procedure revised to capture this diagnostic specifically and why? When documentation of the diagnostic was added to the installation procedure, why weren't we notified?

AMAG: The DIAGNOSE Program is not currently part of the formal installation or check-up procedure. It is implemented when there is a suspicion that there may be some noise interference. Noise interference may or may not be easily discernible because its effect depends on several signal characteristics.

AMAG runs the DIAGNOSE Program when the following symptoms are observed:

1. A significant distortion/asymmetry in the cross-correlation curve is identified, which usually results in a high rejection rate during data collection activities. It should be noted that an observed increase in rejection rates could also be due to cabling and transducer interface.
2. If there were several loops, AMAG may run the DIAGNOSE program in just one loop and if no noise was detected, all locations would be assumed to be acceptable.

Since the DIAGNOSE Program is not currently part of the formal installation procedure, the CROSSFLOW Team normally does not inform clients about when this program is used. This program is currently intended for use within AMAG since its application is not straightforward and should be interpreted in conjunction with other parameters such as signal quality etc.

(5) Why wasn't this diagnostic looked at in the work that was done – 18 months ago, when we examined the physical installation, cables, frequencies, etc.?

AMAG did not have a basis for suspecting the presence of noise.
As discussed earlier, the CROSSFLOW Team was pre-occupied with looking at the hardware and didn't identify a reason to suspect

contamination or to utilize the DIAGNOSE tool. The activities were focused on the difference between Byron and Braidwood in terms of the CROSSFLOW installation. In addition, the unique bistable plant flow readings mislead the focus to the plant instrumentation as the source of the nonlinearly.

(6) Why wasn't this captured when we started the 6-month continuous data run?

During the 6-month continuous data run the flow and corresponding Cf was very stable. Although various plant data was provided and reviewed there wasn't enough information to understand where a potential discrepancy was coming from. That is primarily what drove the decision to collect more data by installing an additional bracket on the common header. During the course of continued review of plant provided data occasional asymmetry in the cross-correlation curve was first noticed. Although it was not there all the time, it was noted that there might be enough events in the occurrence of the asymmetric cross-correlation curve to cause problems in the measured time delay and create a potential bias. Also, the opportunity to reinstall the common header bracket and have an extra point at 100% power provided the definite answer that the source of the problem was within the individual loops. At this point, it was decided immediately to run the DIAGNOSE Program to determine if the presence of noise could be detected which may be causing the distorted peak.

(7) If we had sent people to the training in Mississauga, would it be reasonable to expect that we would have known enough to capture this noise signature?

During the formal CROSSFLOW training, AMAG briefly covers some of the diagnostic tools that are available, including the DIAGNOSE Program. However, since it is intended for AMAG use, AMAG typically just informs the customers of its existence, unless specific individuals showed great interest. CROSSFLOW users are not trained to capture this noise signature, however, they typically are aware of the DIAGNOSE Program and with what it does (at least at the time of the training). For customers that utilize continuous monitoring in first, it would be much easier to capture trends or changes and troubleshoot the causes in a much more timely manner than the team was able to do for EXELON.

Attachment K - Questions from Mngr, Mech Systems, Exelon (Page 4 of 4)

(8) In calculation 059...., why wasn't this flag as a failure of the SRSS criteria? Why wasn't the individual line CF dependence on power noted (1.1-1.3% at 94.7% power vs 0.7% at 91% power)?

AMAG: The test performed during February 27-28 was not the official test and the system was not setup for the data gathering with the final configuration parameters that was planned for the March 10 test. Hence, the data collected could not be used as an official data for comparison as planned. Furthermore, since AMAG was not aware of the plant data (e.g. reactor power), they would not have been able to correlate the Cf with the reactor power level at that time.

It should also be mentioned that the pre-uprate and post-uprate data indicated changes in the Cf. the CROSSFLOW team first became aware of this after the Exelon letter to the USNRC was received. Since AMAG was not involved during the uprate process and since AMAG had no access to plant data, they were not knowledgeable on the magnitude or frequency of these changes. It may still not have triggered an explanation for the Byron/Braidwood discrepancy, but it would have been a point to consider as a flag for what could be wrong.

The reason for the continuous data monitoring which was requested after the first common header installation in Byron 1 in March 2002 was that although the CROSSFLOW Team was aware of the concerns at the plant, there wasn't comprehensive CROSSFLOW-Plant data available to evaluate.

Pages 91 through 101 redacted for the following reasons:
- -
Exemption 4

BYRON UNIT 2 TV/GV TEST REPORT (CALCULATION OF CF AT DIFFERENT POWER LEVEL) SEPTEMBER 16, 2003

A set of data was collected during the period of TV/GV test on Sunday September 14, 2003 for installed Crossflow system on Common Header in Byron Unit2. The purpose of this data collection is to show the behavior of calculated CF (Crossflow reading / Plant flow reading). To calculate the CF at different power level, the test period is divided into 5 different sections. The calculated CF for each section is plotted as a function of power. The results show no dependency in the calculated CF as a function of power that was observed in the previous data collection using the individual four loops.

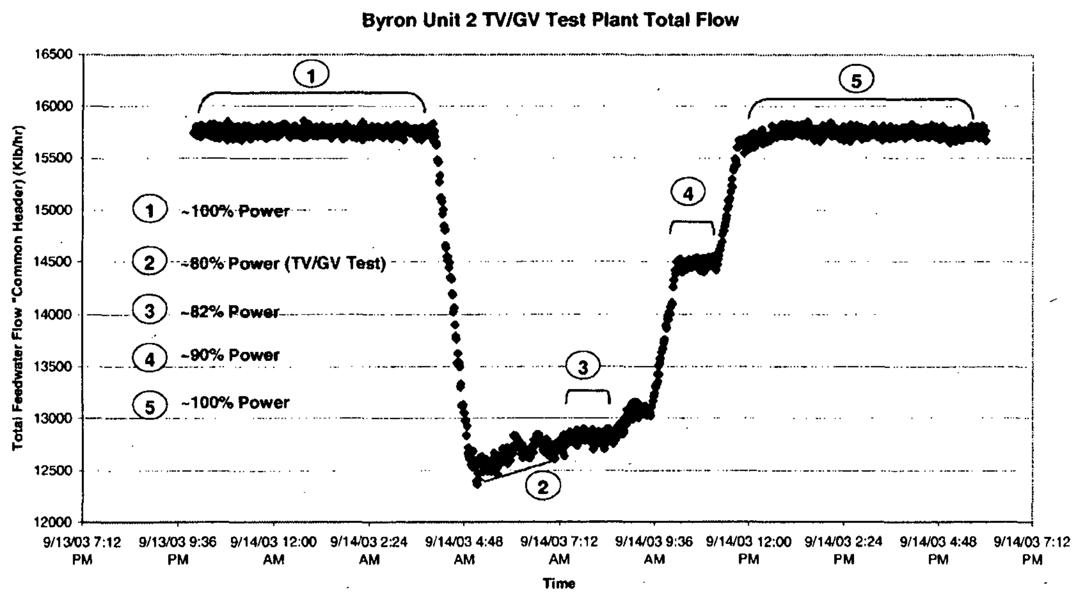


Figure 1. Analyzed data portion for Byron Unit 2 TV/GV collected data

Table 1. Common header Crossflow measurement comparison with plant total feedwater flow (Venturis + Temper lines)

Byron Unit2 Common Header Measurement (TV/GV Test Data)

Data Portion #	Start	End	~%Power	UFM (Lb/hr)	Plant (Lb/hr)	CF=(UFM/Plant)	% Difference
1	9/13/03 10:00 PM	9/14/03 3:50 AM	100	15516877	15753717	0.9850	-1.50%
2	9/14/03 5:02 AM	9/14/03 7:20 AM	80	12480903	12666320	0.9854	-1.46%
3	9/14/03 7:50 AM	9/14/03 8:25 AM	82	12610782	12811938	0.9843	-1.57%
4	9/14/03 10:10 AM	9/14/03 10:50 AM	90	14244559	14462136	0.9850	-1.50%
5	9/14/03 1:00 PM	9/14/03 6:00 PM	100	15511430	15747984	0.9850	-1.50%
					Average	0.9849	-1.51%
					%STD	0.0004	0.0004

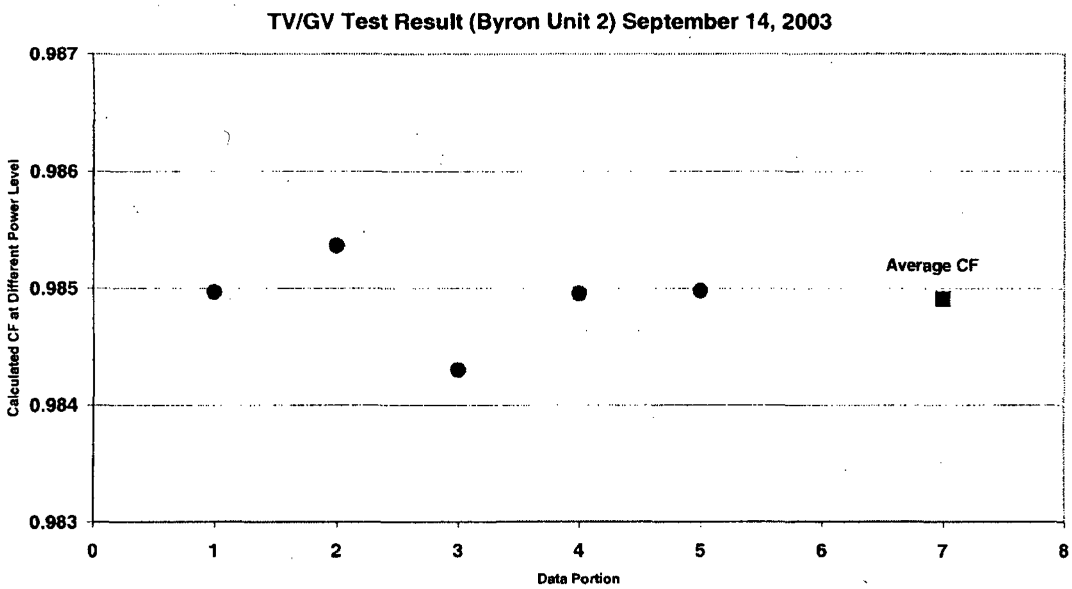


Figure 2. Calculated CF value for different data portion (Note: average CF is the average of all 5 calculated values).

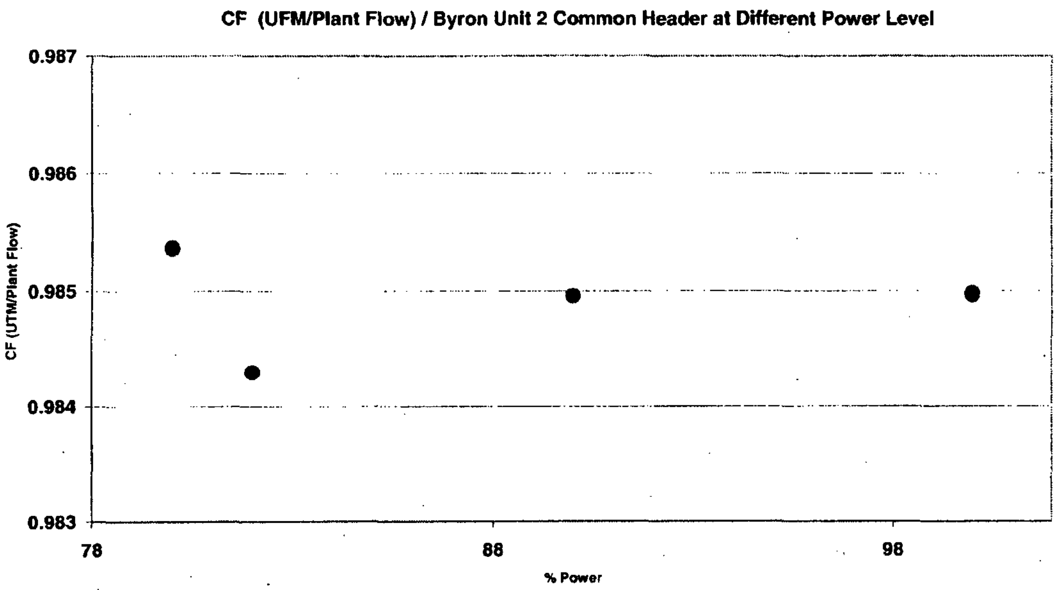


Figure 3. CF behavior as a function of power (Note: there are two points (CF for data portion 1 and 5) on top of each other at 100% power)

AMAG DIAGNOSE program noise peaks										
Unit	Byron 1					Byron 2				
Loop	A	B	C	D	Common	A	B	C	D	Common
1st frequency peak	5.2	6.0	5.5	5.2	1.4	4.9	7.3	9.0	6.0	
1st frequency width	3.4-6.7	5.5-7.6	4.5-6.9	3.4-6.9		3.8-6.3	6.0-8.3	8.8-10.0	4.0-6.7	
2nd frequency peak	10.0	10.0	8.6	9.7		9.3	14.0	14.0	10.0	
2nd frequency width	9.0-11.0	9.0-10.5	6.9-9.6	8.3-12.4		9.1-10.5	12.0-14.7	12.0-14.3	9.3-11.3	
3rd frequency peak	16.2	12.8	12.8	15.2		15.5	18.0		17.3	
3rd frequency width	14.5-19.0	12.4-13.4	12.1-14.4	14.5-16.2		14.3-15.8	17.3-19.3		16.7-18.0	
4th frequency peak	23.3	15.2	16.2	17.5					20.0	
4th frequency width	22.9-24.6	14.8-15.5	14.8-16.9	17.2-18.3					19.3-21.3	
5th frequency peak		16.7	19.6	21.7						
5th frequency width		16.6-16.8	19.0-21.0	20.6-23.4						
6th frequency peak		19.3	22.4							
6th frequency width		19.0-20.0	21.7-22.8							

Vibration data peaks on Unit 2 venturi hangers E-W										
Unit	Byron 1					Byron 2				
Loop	A	B	C	D	Common	A	B	C	D	Common
1st frequency peak						9.44	4.82	3.32	4.8	
1st frequency width										
2nd frequency peak						10.67	6.8	3.95	5.43	
2nd frequency width										
3rd frequency peak						13	7.06	4.33	6.48	
3rd frequency width										
4th frequency peak						13.59	7.82	6.03	6.56	
4th frequency width										
5th frequency peak						14.04	16.08		15	

Vibration data peaks on FW Regulating Valve										
Unit	Byron 1					Byron 2				
Loop	A	B	C	D	Common	A	B	C	D	Common
1st frequency peak						6.3	9.54	9.68	6.18	
1st frequency width										
2nd frequency peak						15.3			9.83	
2nd frequency width										
3rd frequency peak									11.82	
3rd frequency width										
4th frequency peak										
4th frequency width										
5th frequency peak										

Natural piping frequency response theory										
Unit	Byron 1					Byron 2				
Loop	A	B	C	D	Common	A	B	C	D	Common
1st frequency peak	3.34	1.98	1.78	3.12		3.12	1.93	1.87	3.23	
1st frequency width										
2nd frequency peak	10.03	5.92	5.34	9.38		9.36	5.8	5.6	9.68	
2nd frequency width										
3rd frequency peak	16.72	9.86	8.9	15.63		15.6	9.67	9.33	16.14	
3rd frequency width										
4th frequency peak	23.4	13.81	12.46	21.88		21.85	13.53	13.06	22.6	
4th frequency width										
5th frequency peak	30.09	17.75	16.02	28.12		28.09	17.4	16.8	29.05	

Piping Frequency data results											
Unit		Byron 1					Byron 2				
Loop		A	B	C	D	Common	A	B	C	D	Common
1st frequency peak							3.5	2.5	2	3.5-4	
1st frequency width											
2nd frequency peak							9	6.25	6	9	
2nd frequency width											
3rd fre3quency peak							15	10	9	15-16	
3rd frequency width											
4th frequency peak							22.5	13.5	13.5	22.5	
4th frequency width											
5th frequency peak							N/O	N/O	16	N/O	
5th frequency width											

Attachment P – Braidwood Frequency Comparison (Page 1 of 1)

AMAG DIAGNOSE program noise peaks										
Unit	Braidwood 1					Braidwood 2				
Loop	A	B	C	D	Common	A	B	C	D	Common
1st frequency peak	4.8	7.0	6.0	5.9	12.8?	5.2	5.8	5.2	5.2	
1st frequency width	3.0-7.0	5.0-8.0	5.0-7.5	3.4-6.7		3.8-6.3	5.5-6.9	3.2-6.8	4.0-6.9	
2nd frequency peak	9.8	10.0	9.0	10.2	16.2?	10.1	10.0	17.8		
2nd frequency width	8.5-10.5	9.0-10.5	8.0-9.8	9.8-12.0		9.1-11.5	9.0-10.5	17.0-19.0		
3rd frequency peak	16.2	12.8	20.0	15.2		15.2	12.7			
3rd frequency width	15.0-17.0	12.4-13.2	19.0-21.0	14.5-16.2		14.8-16.8	12.0-14.1			
4th frequency peak	23.3	18.0		20			19.0			
4th frequency width	22.0-25.0	17.0-19.0		19.5-22.0			17.3-20.0			
5th frequency peak							22.4			
5th frequency width							21.0-23.0			
6th frequency peak										
6th frequency width										

Natural piping frequency response theory (FWRV to SG)										
Unit	Braidwood 1					Braidwood 2				
Loop	A	B	C	D	Common	A	B	C	D	Common
1st frequency peak	3.20	1.95	1.69	3.08		3.06	1.92	1.80	3.25	
1st frequency width										
2nd frequency peak	9.61	5.86	5.08	9.25		9.18	5.77	5.40	9.75	
2nd frequency width										
3rd frequency peak	16.02	9.76	8.47	15.42		15.29	9.62	9.00	16.24	
3rd frequency width										
4th frequency peak	22.42	13.67	11.86	21.58		21.41	13.46	12.60	22.74	
4th frequency width										
5th frequency peak	28.83	17.57	15.24	27.75		27.53	17.31	16.20	29.24	

AMAG ROOT CAUSE - FINAL

NOTES
1. This quality checklist is to be completed by the evaluator and reviewed by management.
2. The completed Root Cause Report Quality Checklist shall be included in the MRC/ PORC review package (per LS-AA-125-1006).

Root Cause Report Quality Checklist

CONDITION REPORT NUMBER: 173510
CONDITION REPORT TITLE: Results of Westinghouse Unit 1 AMAG Investigation

A. Critical Content Attributes	YES	NO
1. Is the condition that requires resolution adequately and accurately identified?	X	
2. Are inappropriate actions and equipment failures (causal factors) identified? *(For human performance casual factors, the inappropriate action portion should state which group failed to do what.)*	X	
3. Are the causes accurately identified, including root causes and contributing causes?	X	
4. Are there corrective actions to prevent recurrence identified for each root cause and do they tie DIRECTLY to the root cause? AND, are there corrective actions for contributing cause and do they tie DIRECTLY to the contributing cause?	X	
5. Have the root cause analysis techniques been appropriately used and documented?	X	
6. Was an Event and Causal Factors Chart properly prepared?	X	
7. Have cause Codes been identified for equipment problems, human performance, and organizational weaknesses, and have all applicable trend codes been identified and documented in the report and entered into the Condition Report Trend/Cause Panel TIMA017 in Action Tracking?	X	
8. Does the report adequately and accurately address the extent of condition?	X	
9. Does the report adequately and accurately address plant specific risk consequences? (will be documented in LERs for this event)	X	
10. Does the report adequately and accurately address programmatic and organizational issues? (not in Root Cause charter - see Attachment I)	X	
11. Have previous similar events been evaluated?	X	
B. Important Content Attributes	**YES**	**NO**

AMAG ROOT CAUSE - FINAL

1. Are all of the important facts included in the report?	X	
2. Does the report explain the logic used to arrive at the conclusions?	X	
3. If appropriate, does the report explain what root causes were considered, but eliminated from further consideration and the bases for their elimination from consideration?	X	
4. Does the report identify contributing causes, if applicable?		X
5. Is it clear what conditions the corrective actions are intended to create?	X	
6. Are there unnecessary corrective actions that do not address the root causes or contributing causes?		X
7. Is the timing for completion of each corrective action commensurate with the importance or risk associated with the issue?	X	
C. Miscellaneous Items	**YES**	**NO**
1. Did an individual who is qualified in Root Cause Analysis prepare the report?	X	
2. Does the Executive Summary adequately and accurately describe the significance of the event, the event sequence, root causes, corrective actions, reportability, and previous events?	X	
3. Do the corrective actions include an effectiveness review for corrective actions to prevent recurrence?	X	
4. Has an Operating Experience database search been performed to determine whether the problem was preventable if industry experience had been adequately implemented?	X	
5. Are the format, composition, and rhetoric acceptable (grammar, typographical errors, spelling, acronyms, etc.)?	X	

Root Cause Investigator / Date

Department Head / Date

Sponsor Manager / Date