Out of Scope

CR to perform root cause investigation. Use the template provided in the Action Tracking Ole panel. Ensure generation of an Event & Causal Factors chart.

Contact Reg. Assurance for guidance on the type of Risk Assessment that needs to be conducted for the Root Cause.

Report author, Senior Manager Sponsor/ Department Head, and CAPCO must review and evaluate RCR for quality against the Root Cause Quality Checklist. Report author and Senior Manager Sponsor/Department Head will sign Root Cause Quality Checklist.

Resp Group: A8830EM
Due Date: 9/19/03

NOTES

1. Extension of this assignment requires MRC approval.
2. Remove the *italicized* text below upon completion.
3. During the performance of an ACE and upon completion of the investigation, investigators should reevaluate Operability, Reportability, Extent of Condition Reviews, and the need to generate a Operating Experience for the issue. Investigations can reveal new aspects of an event that may change the original disposition of an issue. For example, additional investigation such as power labs testing of a component may change the original evaluations of Operability.

Revision 1 incorporates changes based on an independent review of Rev. 0 of this Root Cause Report by General Electric Nuclear Energy (GENE). GENE's report and our response is provided in Appendix Q. Revisions to other sections of the Root Cause Report were made based upon the resolution of issues raised by GENE in their report, as discussed in Appendix Q-2. In addition, the Corrective Actions in 8.C have been revised to provide their sub-assignment numbers and the most current status and due dates. ACIT7 was added at the request of Byron MRC.

Root Cause Report

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

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: 9/26/03

Information in this record was deleted in accordance with the Freedom of Information Act.
Exemptions 4
FOIA/PA 2008-0046

K-1

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:

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 +1.70% or a total of 101.70% (see Att. Q). Similar evaluations for Byron Unit 2 and Braidwood Unit 2 indicate that the maximum potential historical overpower condition for Byron Unit 2 is +0.41% (see Att. Q) and for Braidwood Unit 2 is +0.39%. 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.

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.

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).

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.

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.

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".

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).

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)	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:

1. The noise affects the calculation of the CFs by changing the time delay calculation. However, the specific amount and direction cannot be predicted.
2. 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.
3. 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 conjunction 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 Analysis 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 Calorimetric 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: 12/19/03
ATI 173510-47

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: 1/31/04
ATI 173510-48

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: 12/19/03
ATI 173510-23

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: – Complete (procedure changes tracked under CAPR2 above)
ATI 173510-24

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
ATI 173510-25

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
ATI 173510-26

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
ATI 173510-27

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
ATI 173510-28

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
ATI 173510-29

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
ATI 173510-30

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: Complete
ATI 173510-31

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: Complete
ATI 173510-32

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: Complete
ATI 173510-33

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: Complete
ATI 173510-34

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: Complete
ATI 173510-35

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: Complete
ATI 173510-36

EFR1 Action: Perform Effectiveness Review of CAPR1.
Responsible Organization: Byron PED (A8830NESTT)
Due Date: 10/17/04
ATI 173510-37

MRC1 Action: Take the Effectiveness Review of CA15 to MRC.
Responsible Organization: Byron PED (A8830NESTT)
Due Date: 10/25/04
ATI 173510-38

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

ATI 173510-39

MRC2 Action: Take the Effectiveness Review of CA17 to MRC.
Responsible Organization: Braidwood PED (A8930TT)
Due Date: 10/25/04
ATI 173510-40

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: Complete
ATI 173510-41

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: Complete
ATI 173510-42

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
ATI 173510-43

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: Complete
ATI 173510-44

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
ATI 173510-45

ACIT6 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
ATI 173510-46

ACIT7 Action: Complete the AMAG Re-Implementation Project Plan.
Responsible Organization: Cantera Project Mgmt (A8070PM)
Due Date: 04/05/04
ATI 173510-83

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 Q – Resolution of GENE Report Issues

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.

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

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.

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

(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."

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

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.

Pages 36 through 38 redacted for the following reasons:
- -
Exemption 4

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

AMAG CABLE EFFECTS: 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.

AMAG HARDWARE ERROR: 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.

AMAG SOFTWARE ERROR:

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.

PIPE NATURAL RESONANCE/VIBRATION:

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.

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

(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 0rder 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.

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.

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.

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: β = *beta ratio*

and α_d = *kinetic energy factor in the throat, approaches* 1 > *a certain* Re*ynolds number* (N_{RE})

and α_D = *kinetic energy factor in the inlet cross* sec*tion, approaches* 1 *above a certain* N_{RE}

and H_L = *head loss factor in the throat* sec*tion*

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.

Attachment F - Possible AMAG System Noise Causes Considered (Page 6 of 8)

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

Attachment G - Byron Feedwater Piping Resonance Evaluation (Page 1 of 28)

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.

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.

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.

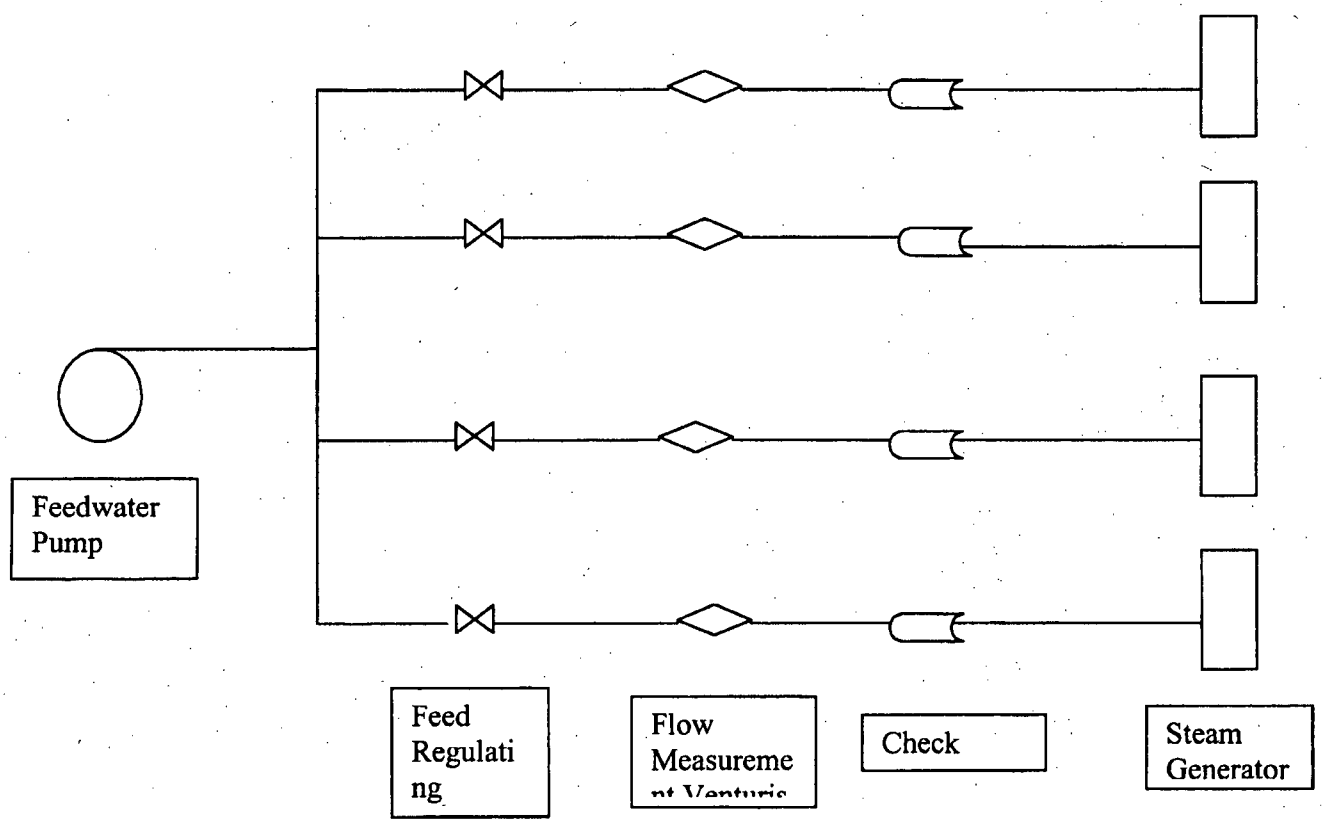
Piping systems will experience resonant response when a driver occurs to excite the system at its natural acoustic frequencies. Any location where large pressure drops occur can serve to create a driver. Blevins suggests that 1 to 2 percent of the pressure drop can become broad band noise that can cause 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



Attachment G - Byron Feedwater Piping Resonance Evaluation (Page 3 of 28)

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

Attachment G - Byron Feedwater Piping Resonance Evaluation (Page 4 of 28)

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

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.

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.

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:

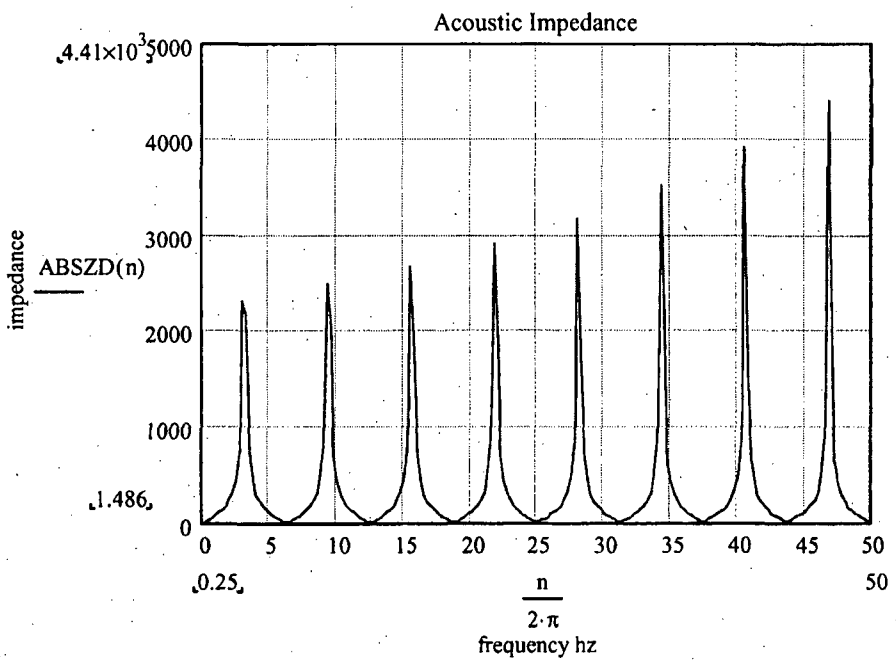
Flow rate=4E6 lbm/hr
Pipe Dia=13.362 inches (16 inch Sch 120)
Darcy Friction Factor=0.013
Speed of Sound=4600 fps

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.

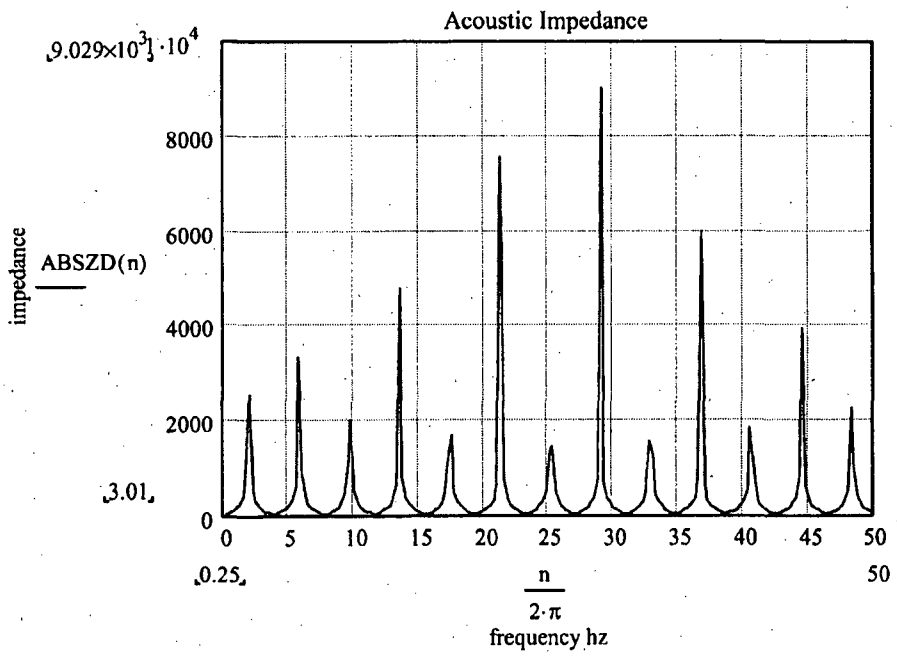
What is readily apparent on comparison of these plots to the modal frequencies calculated above is that the closed –open relationship yields very good agreement with the impedance methods. The other point to note is that the different lines can be expected to yield significantly different magnitudes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

Attachment G - Byron Feedwater Piping Resonance Evaluation (Page 8 of 28)

Byron Unit 2 A FW line hydraulic impedance

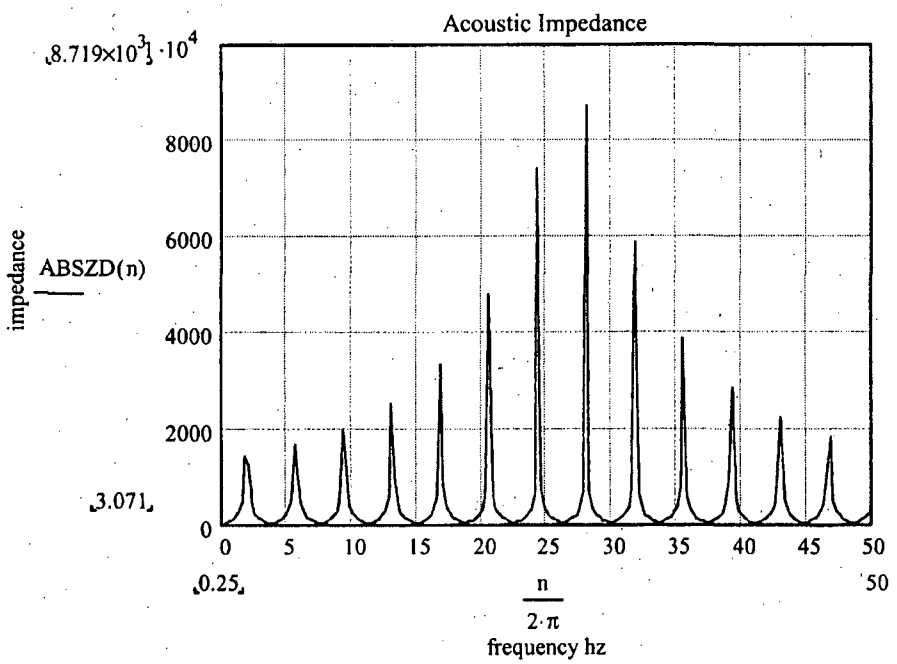


Byron Unit 2 B FW Line Hydraulic Impedance

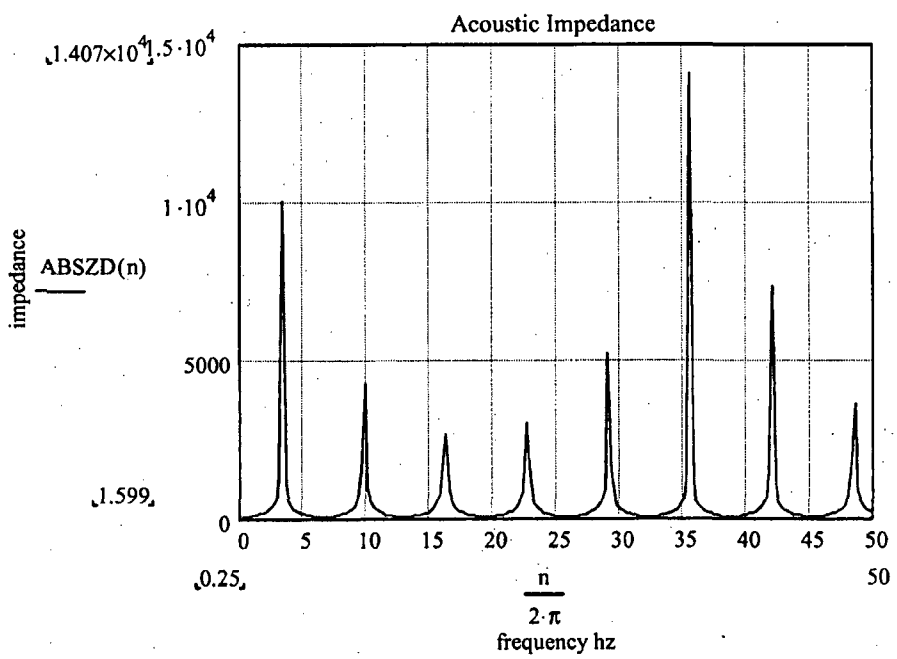


Attachment G - Byron Feedwater Piping Resonance Evaluation (Page 9 of 28)

Byron Unit 2 C FW Line Hydraulic Impedance



Byron Unit 2 D FW Line Hydraulic Impedance



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

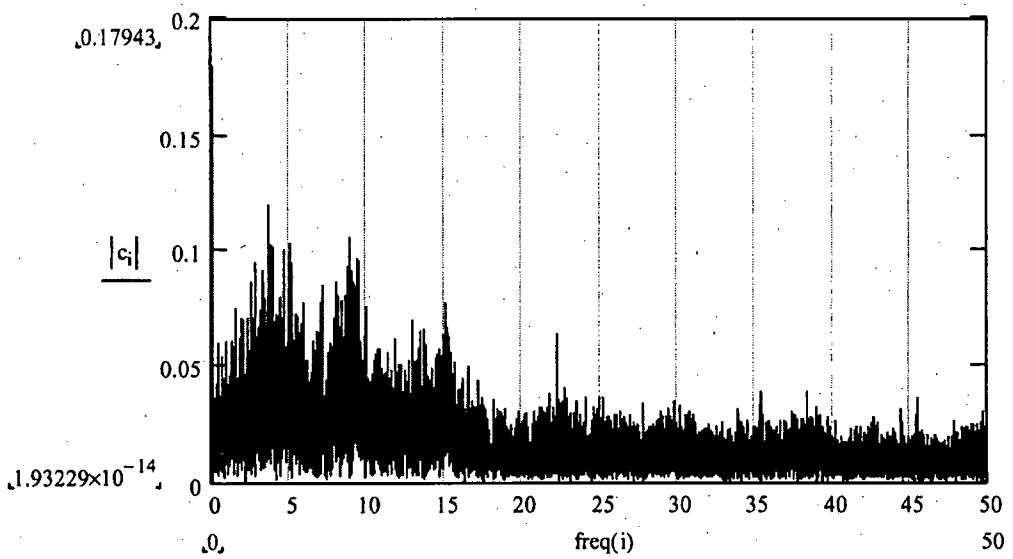
Line (Time Label)	Number of points	Mean (psi)	Standard Deviation
2A (10:24)	29762	868.76276	3.53268
2A (10:30)	30006	871.96367	3.54429
2D (10:24)	29762	892.41979	3.62713
2D (10:30)	30006	895.41641	3.60067

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.

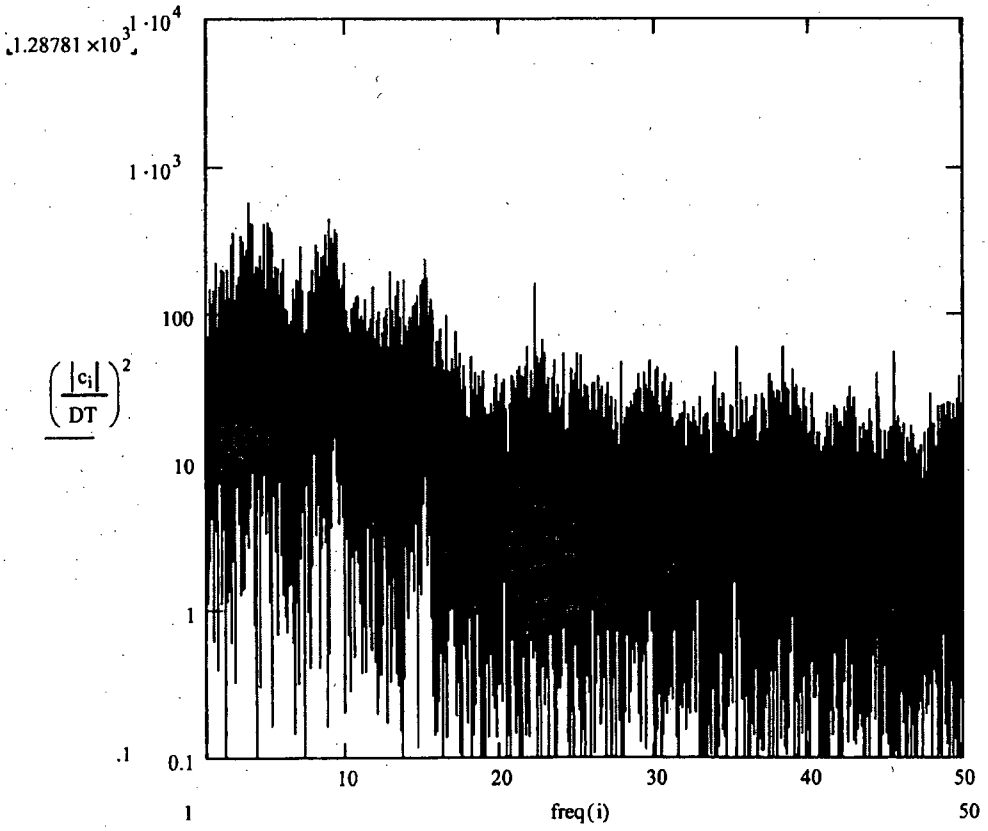
Attachment G - Byron Feedwater Piping Resonance Evaluation (Page 11 of 28)

Byron Unit 2 A FW Line Data

Fourier Coefficients vs. Frequency.



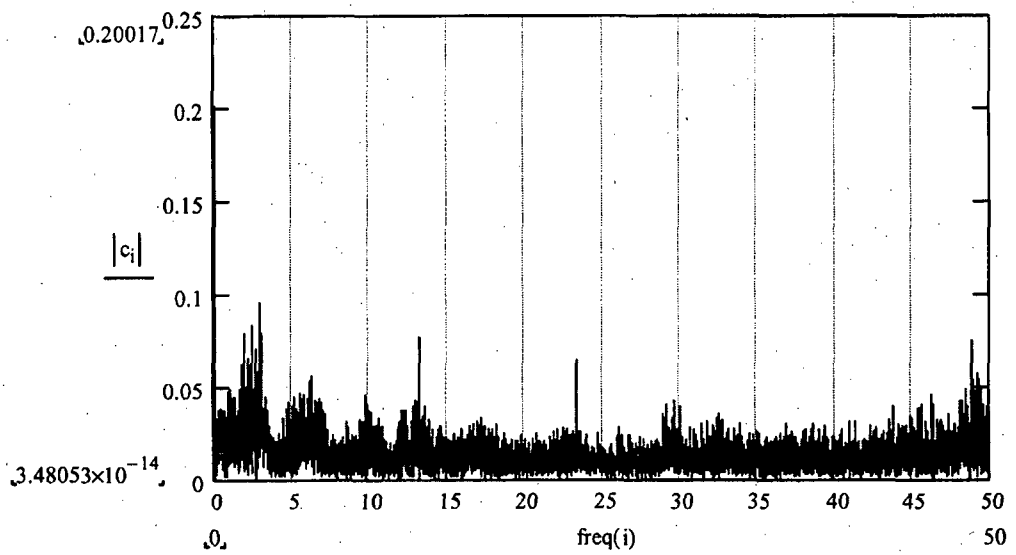
Power Spectral Density



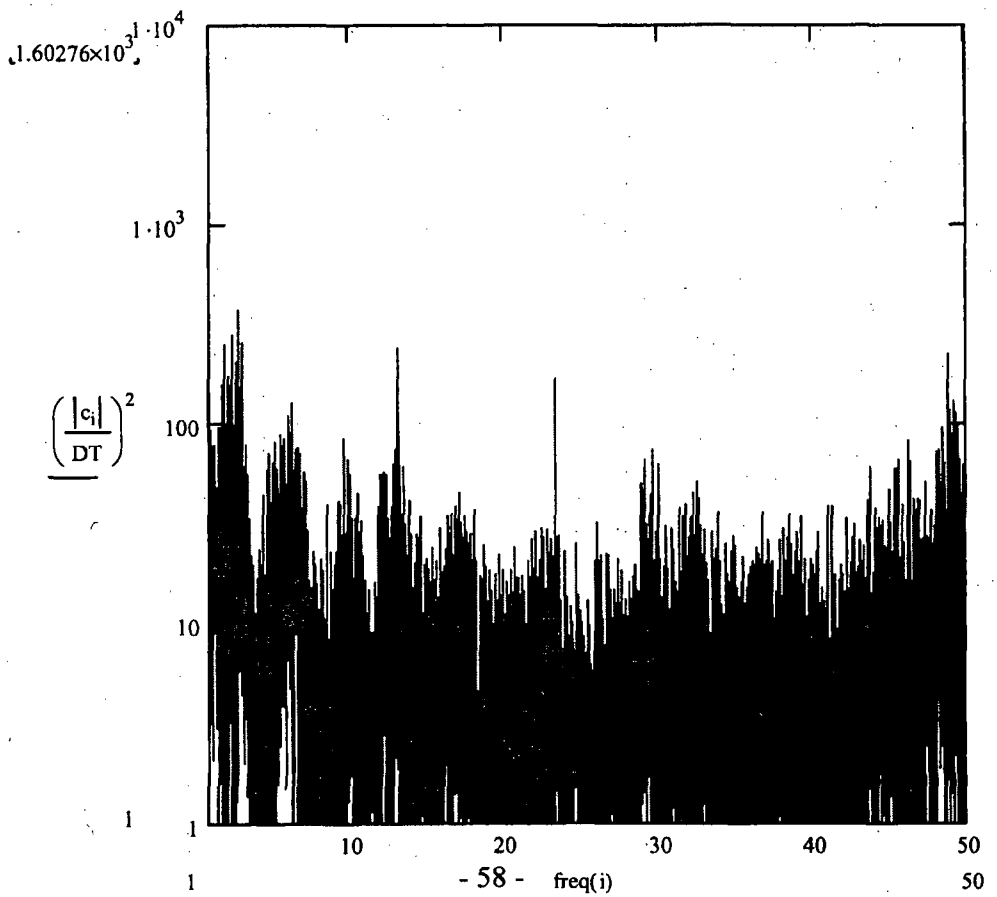
Attachment G - Byron Feedwater Piping Resonance Evaluation (Page 12 of 28)

Byron Unit 2 B FW Line Data

Fourier Coefficients vs. Frequency



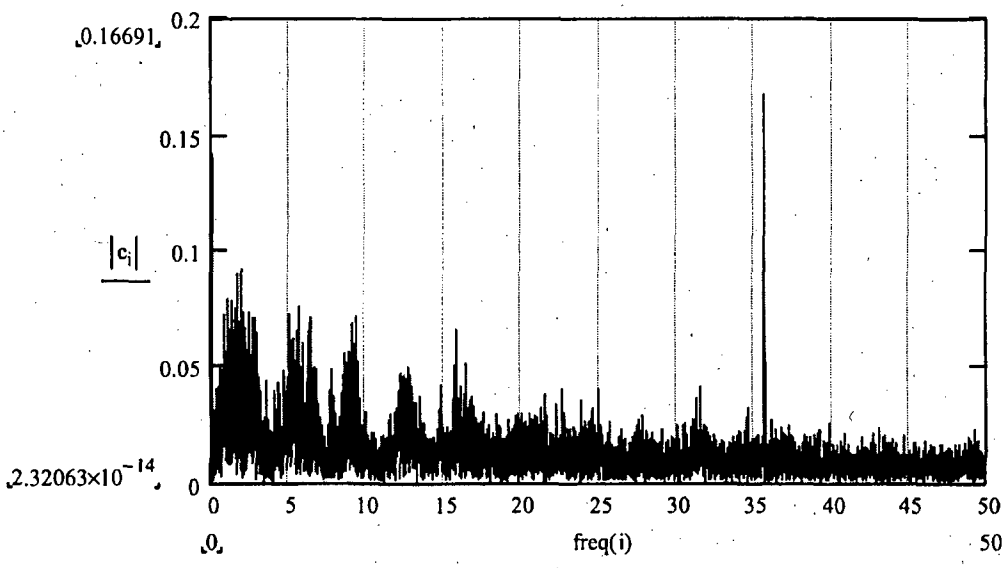
Power Spectral Density



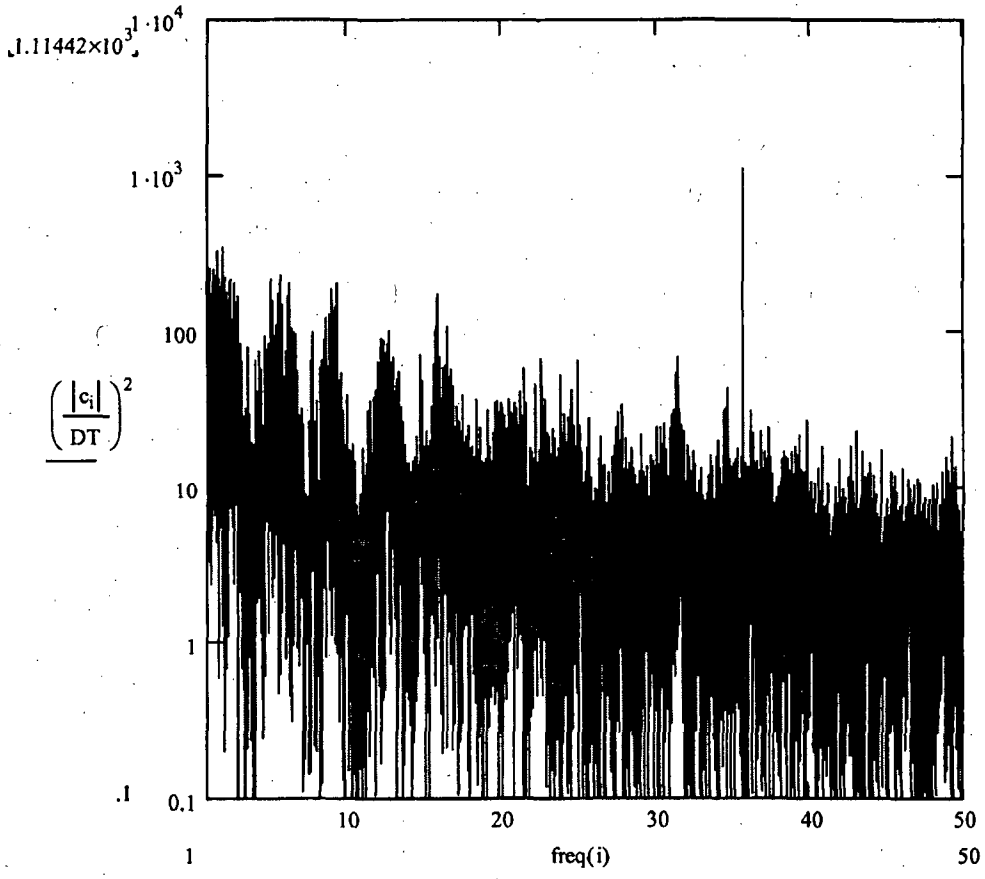
Attachment G - Byron Feedwater Piping Resonance Evaluation (Page 13 of 28)

Byron Unit 2 C FW Line Data

Fourier Coefficients vs. Frequency



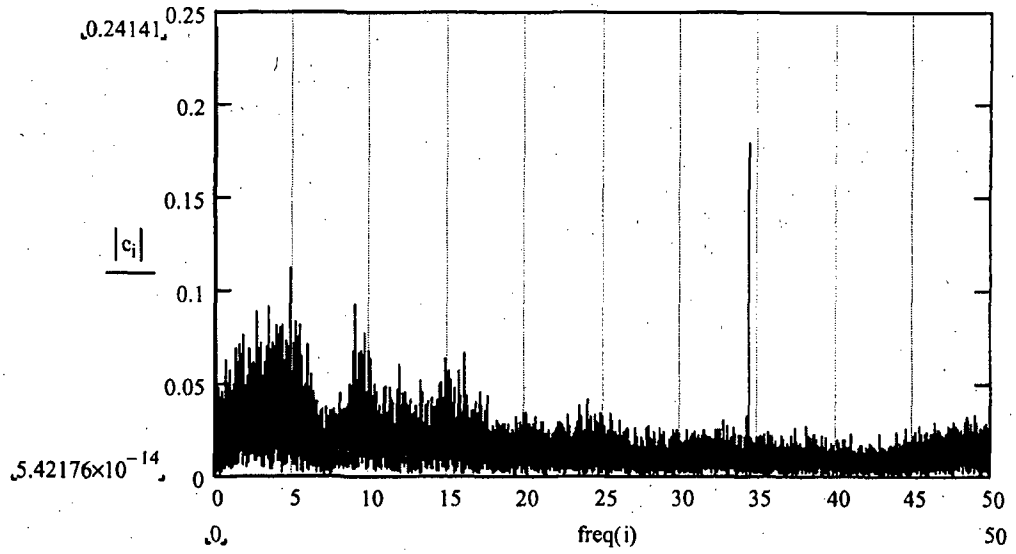
Power Spectral Density



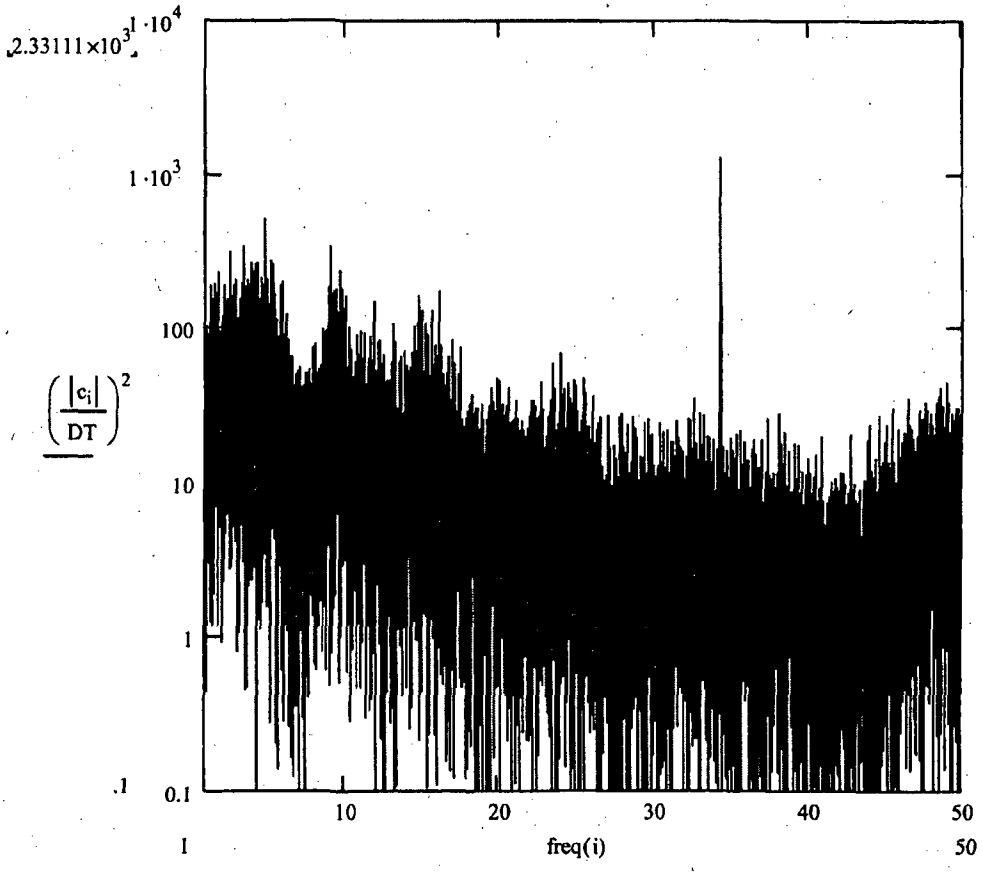
Attachment G - Byron Feedwater Piping Resonance Evaluation (Page 14 of 28)

Byron Unit 2 D FW Line Data

Fourier Coefficients vs. Frequency

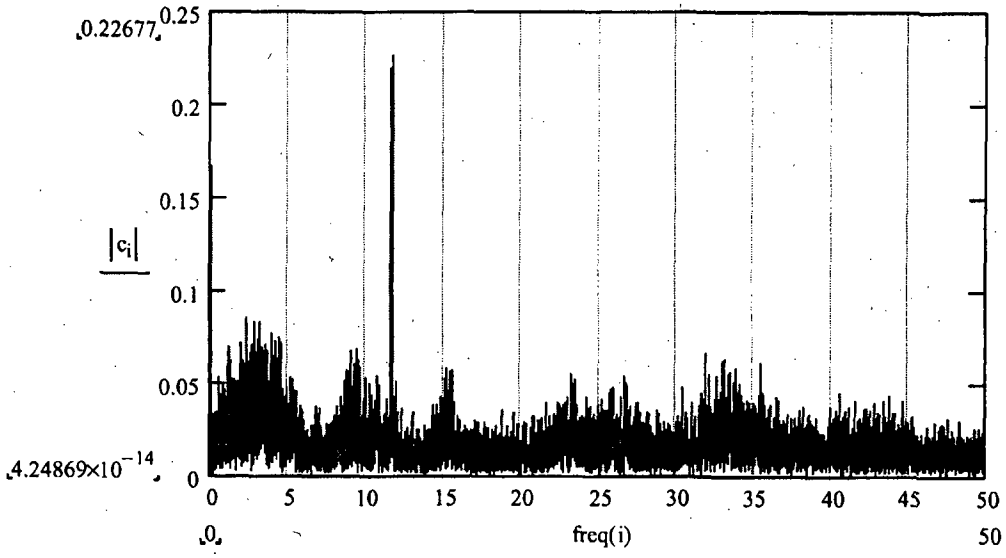


Power Spectral Density

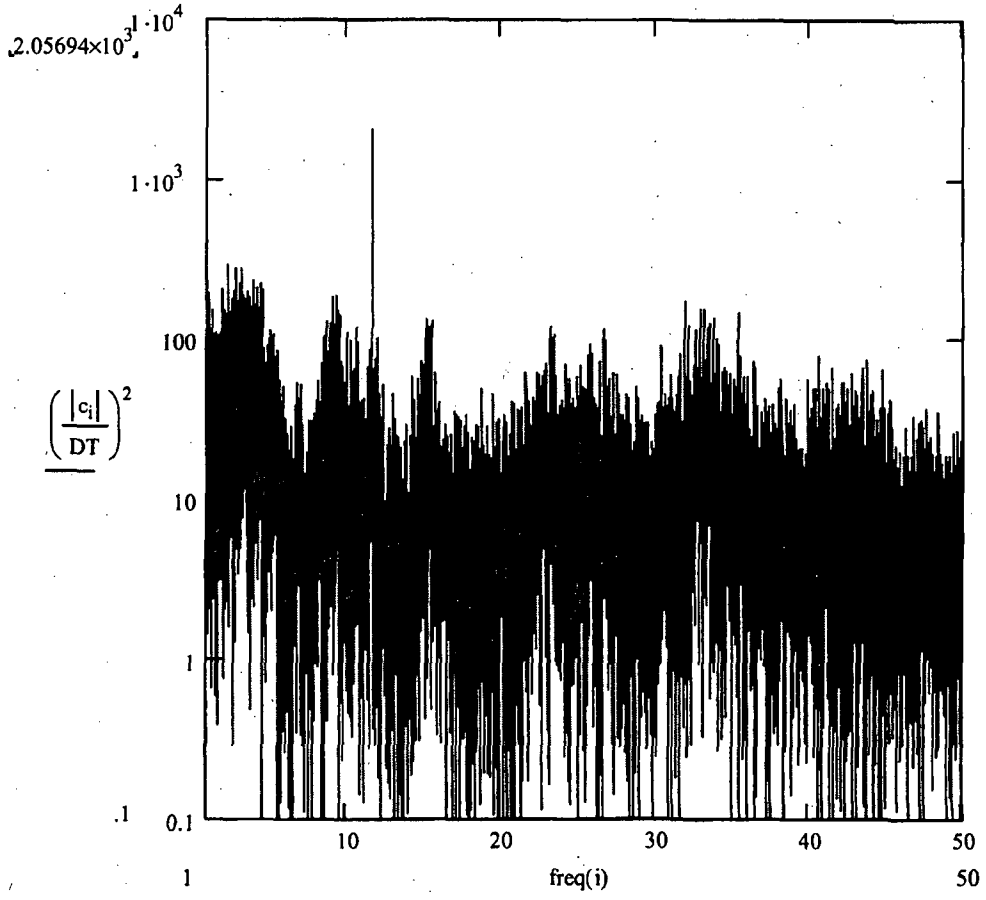


Attachment G - Byron Feedwater Piping Resonance Evaluation (Page 15 of 28)

Line 2A FFT Transform 82% (0815) Data

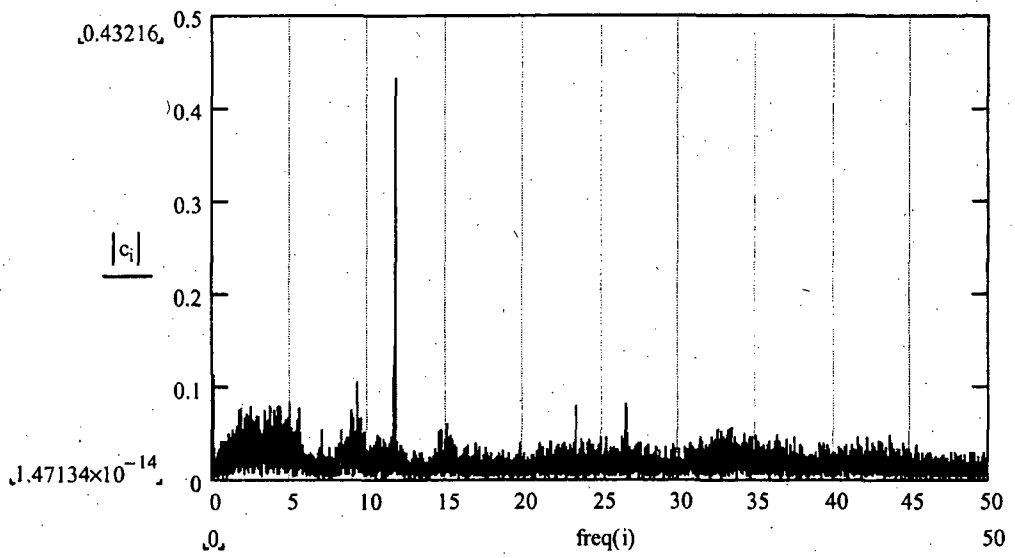


Line 2A FFT Transform Power Spectral Density 82% (0815) Data

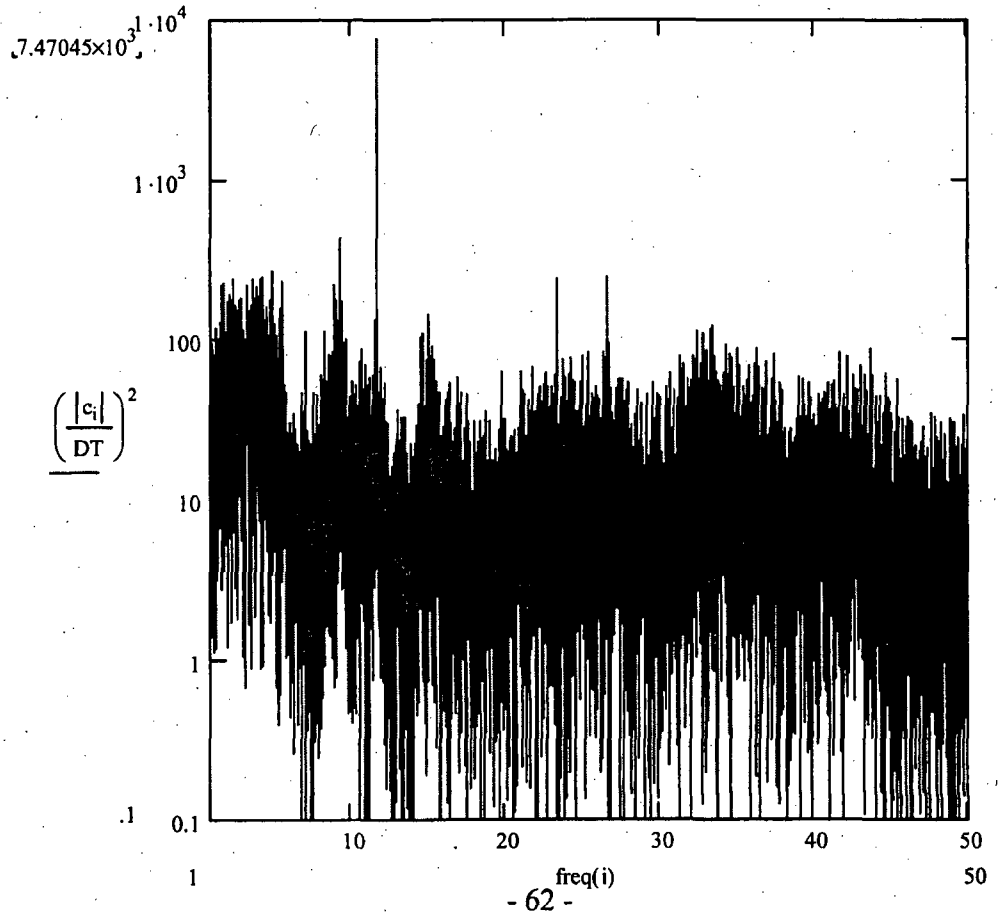


Attachment G - Byron Feedwater Piping Resonance Evaluation (Page 16 of 28)

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

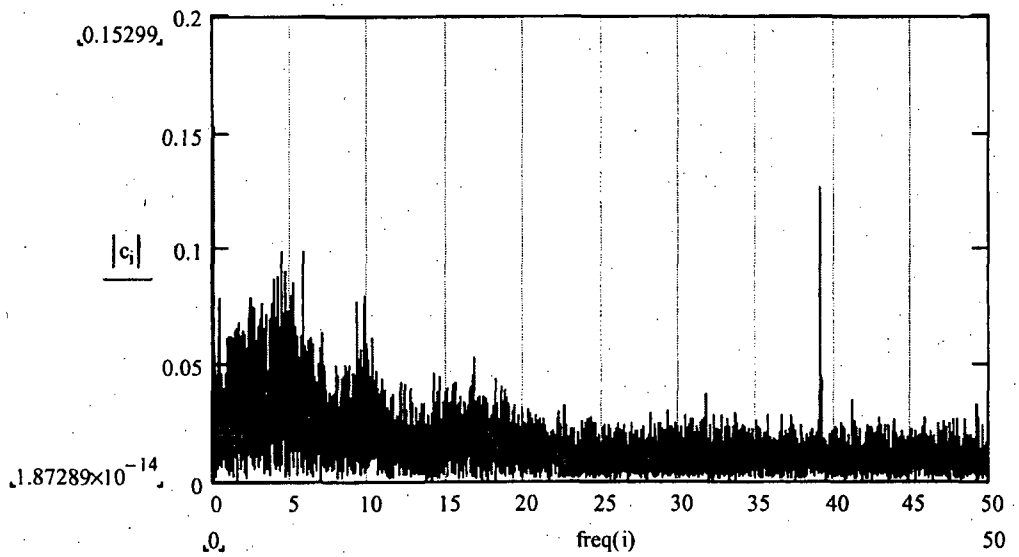


Line 2A FFT Transform Power Spectral Density 82% (0822) Data

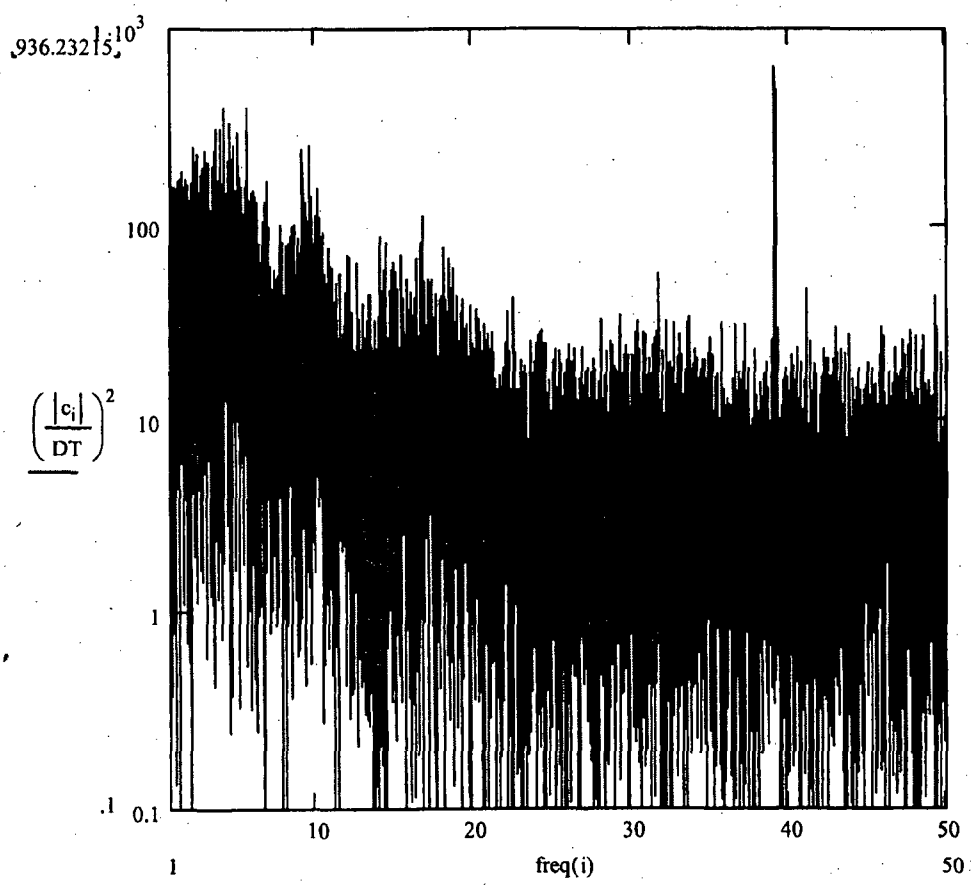


Attachment G - Byron Feedwater Piping Resonance Evaluation (Page 17 of 28)

Line 2D FFT Transform 82% (0815) Data

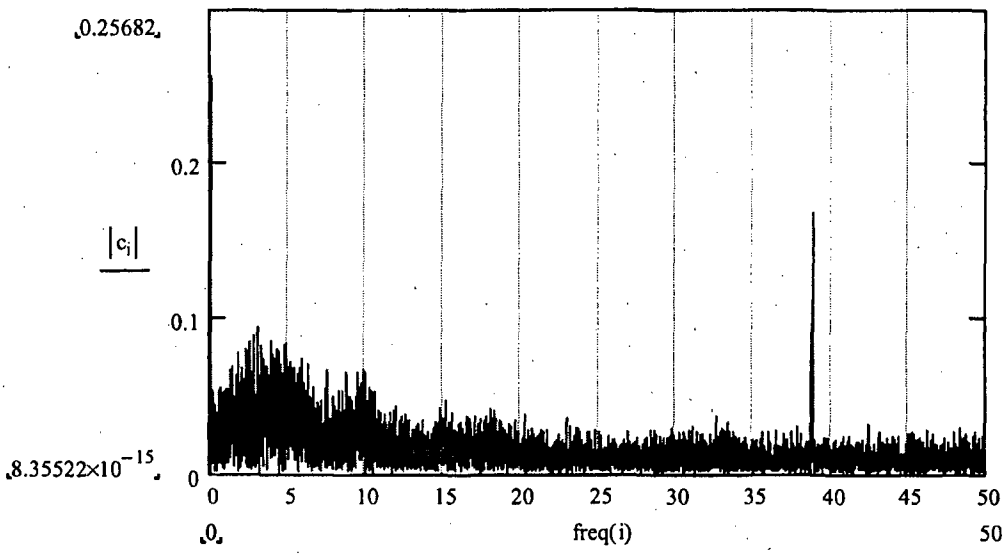


Line 2D FFT Transform Power Spectral Density 82% (0815) Data

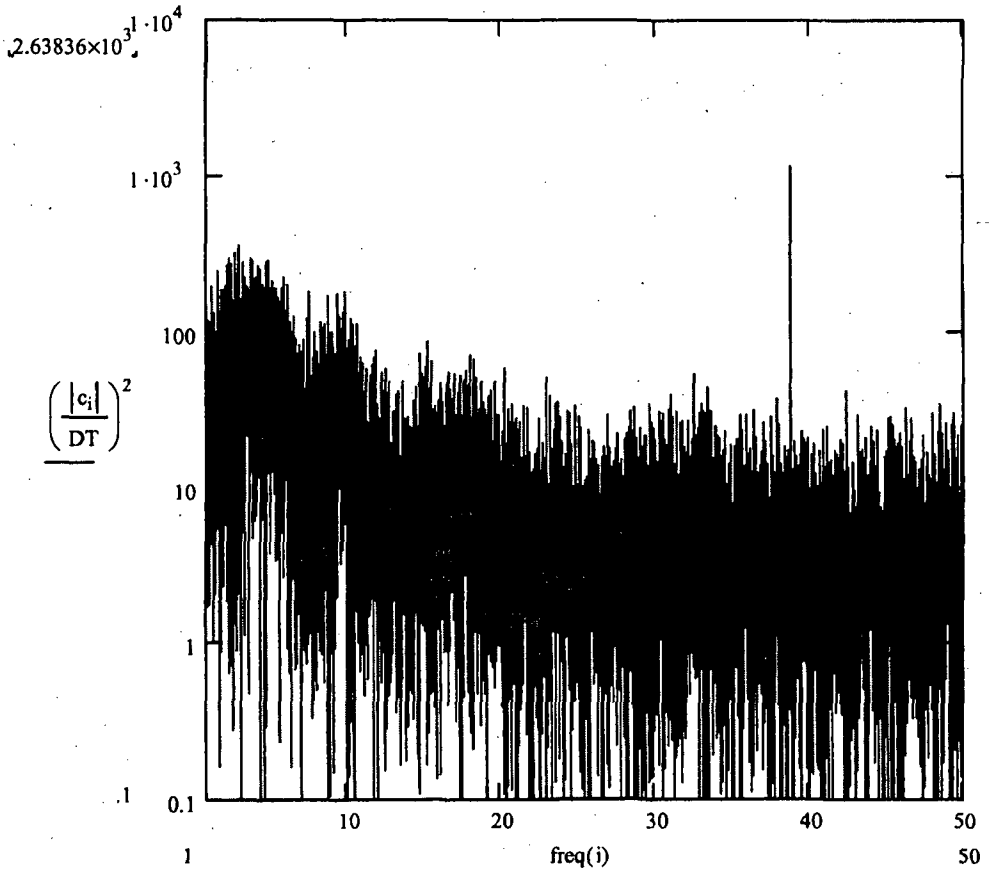


Attachment G - Byron Feedwater Piping Resonance Evaluation (Page 18 of 28)

Line 2D FFT Transform 82% (0822) Data

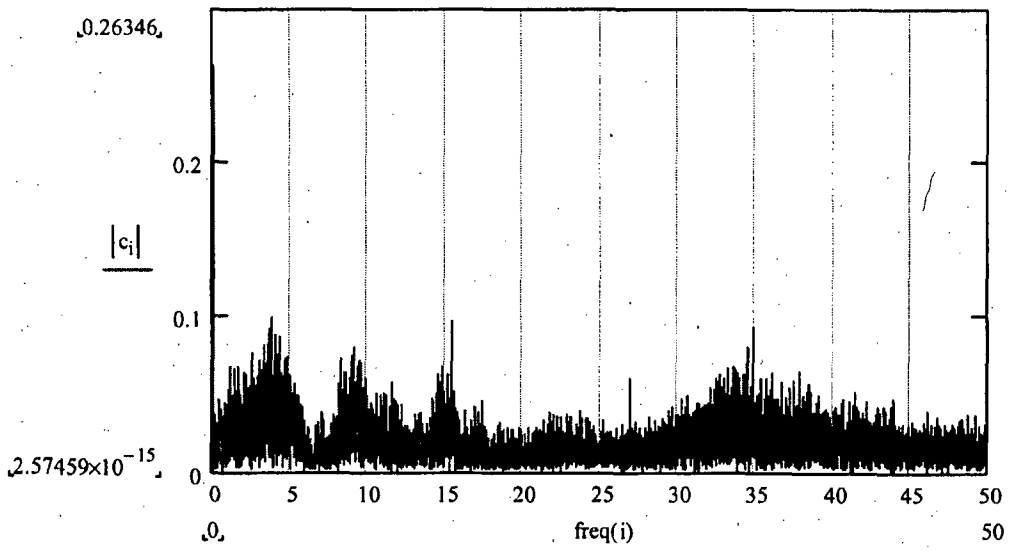


Line 2D FFT Transform Power Spectral Density 82% (0822) Data

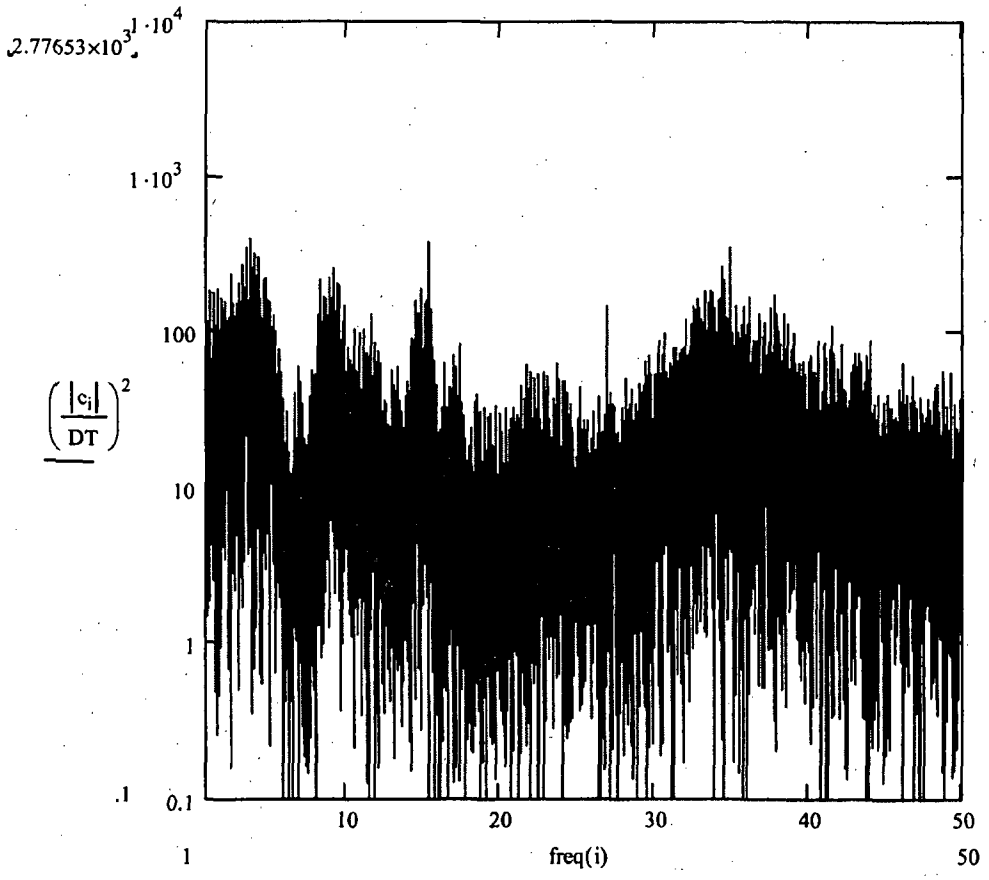


Attachment G - Byron Feedwater Piping Resonance Evaluation (Page 19 of 28)

Line 2A FFT Transform 91% (1024) Data

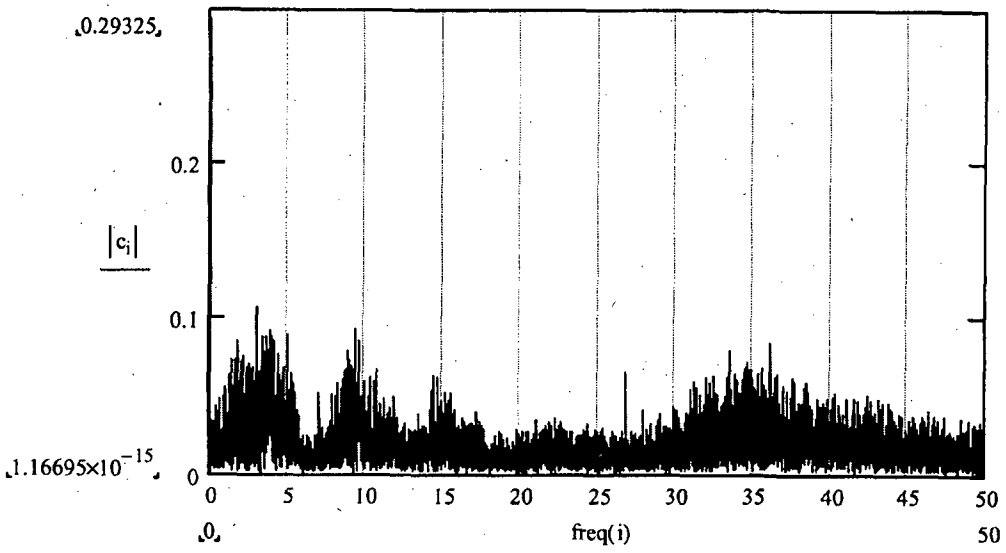


Line 2A FFT Transform Power Spectral Density 91% (1024) Data

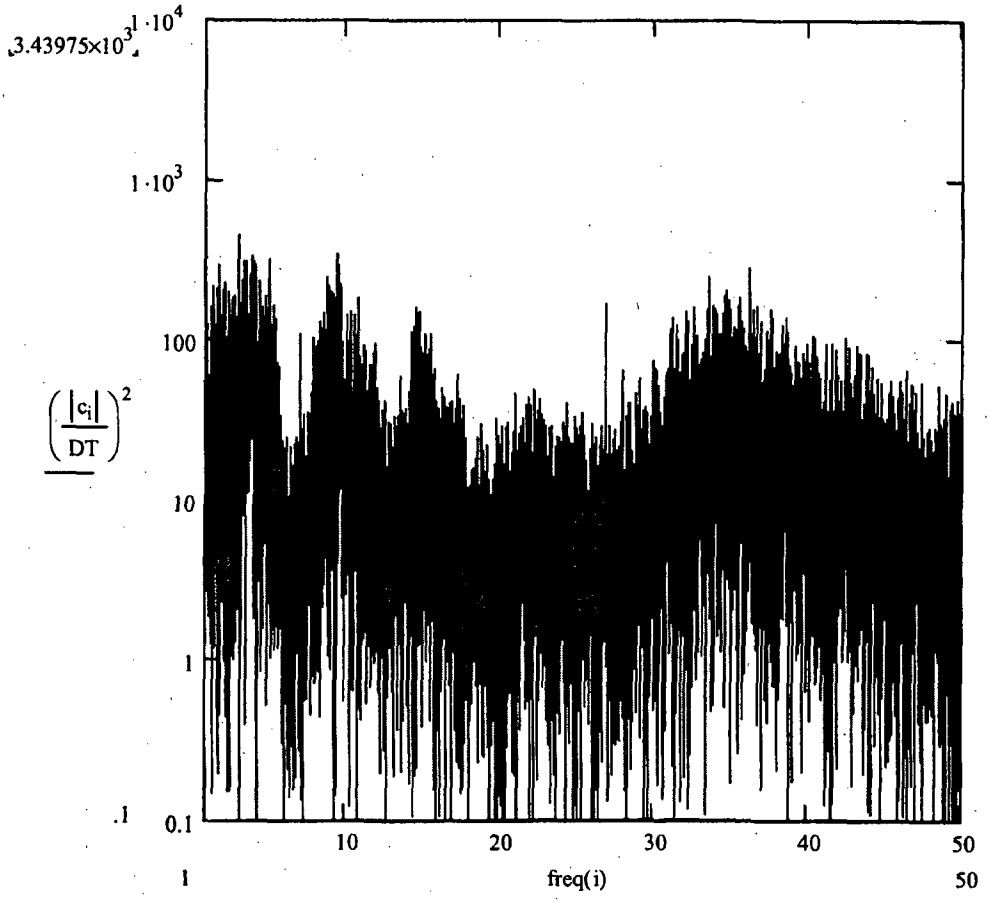


Attachment G - Byron Feedwater Piping Resonance Evaluation (Page 20 of 28)

Line 2A FFT Transform 91% (1030) Data

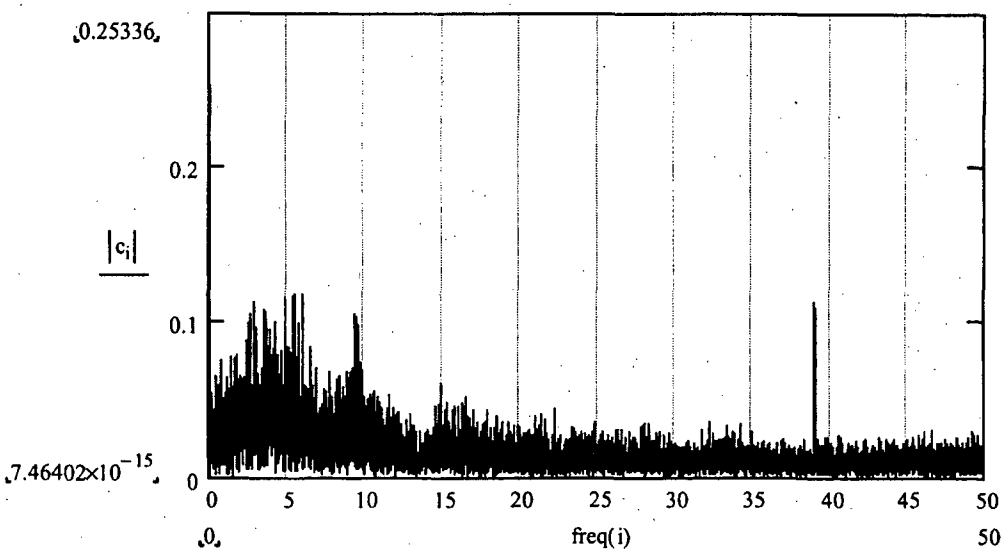


Line 2A FFT Transform Power Spectral Density 91% (1030) Data

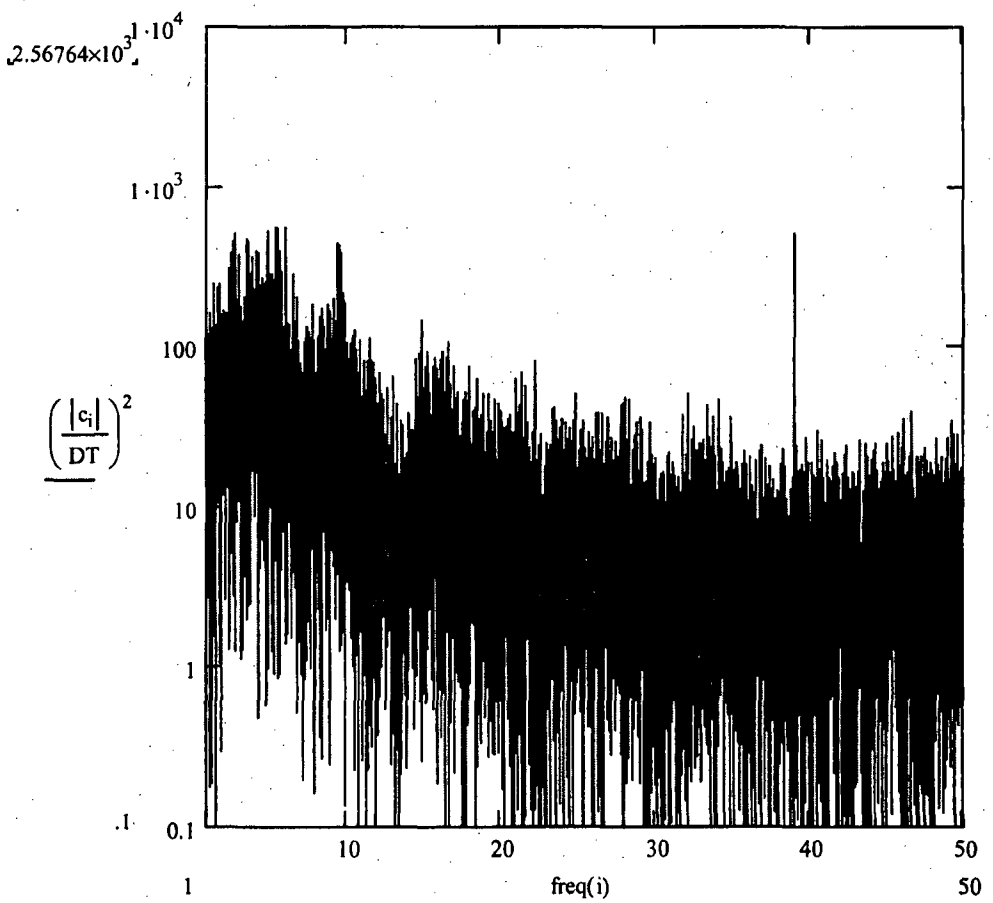


Attachment G - Byron Feedwater Piping Resonance Evaluation (Page 21 of 28)

Line 2D FFT Transform 91% (1024) Data

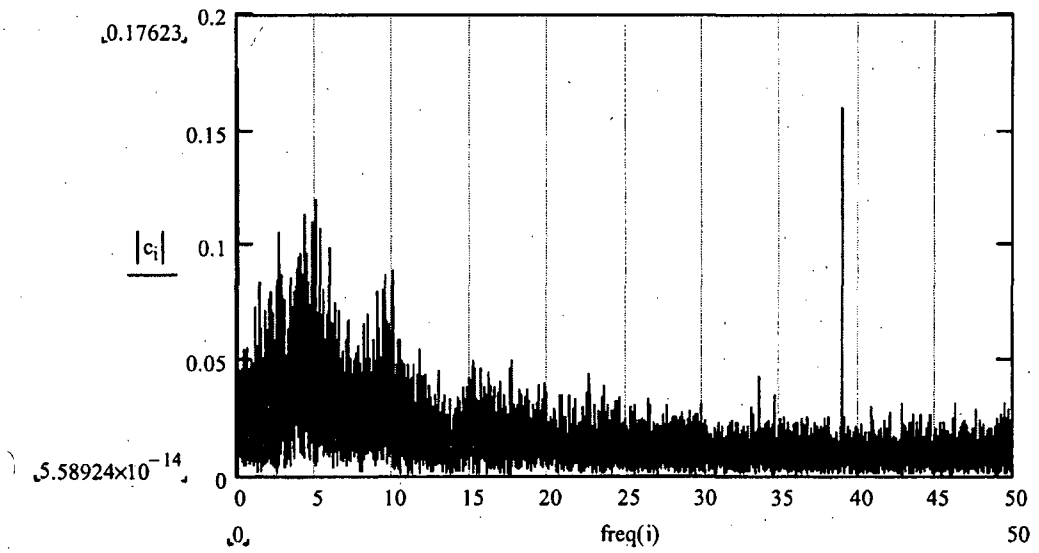


Line 2D FFT Transform Power Spectral Density 91% (1024) Data

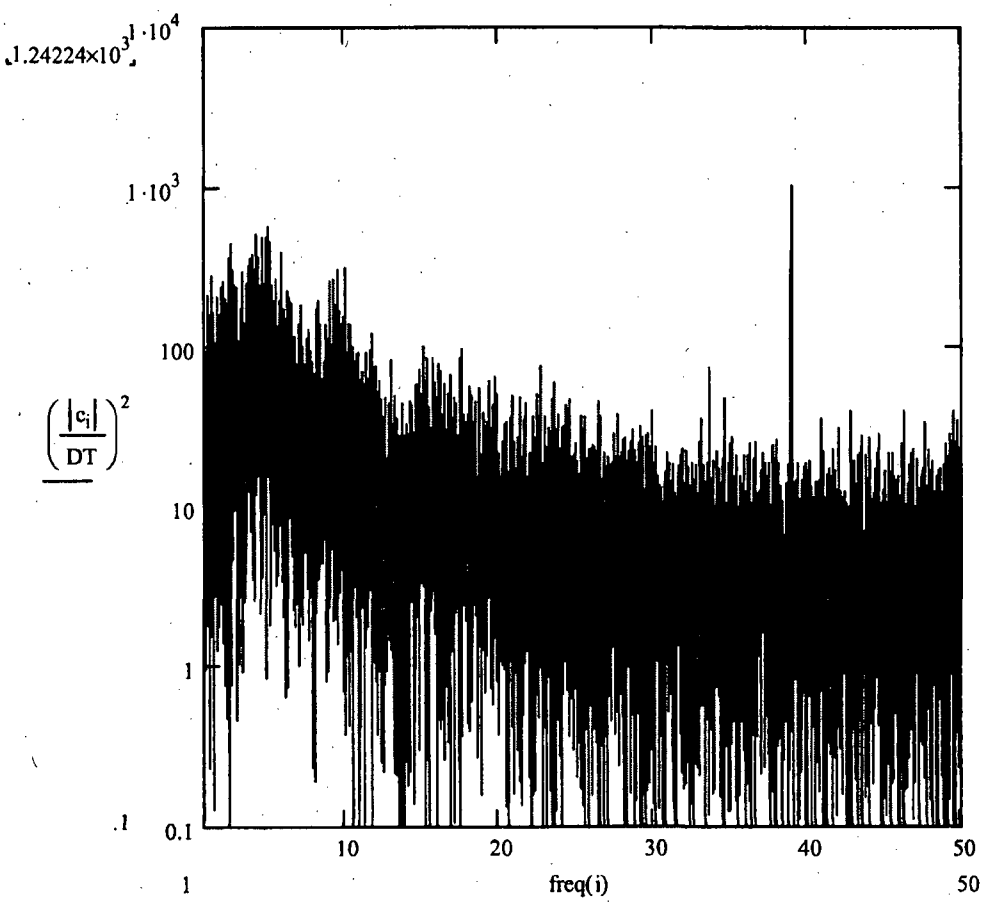


Attachment G - Byron Feedwater Piping Resonance Evaluation (Page 22 of 28)

Line 2D FFT Transform 91% (1030) Data



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.

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.

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.

Attachment G - Byron Feedwater Piping Resonance Evaluation (Page 25 of 28)

An additional review of the Byron Unit 2 Common Header was performed as discussed below.

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 :

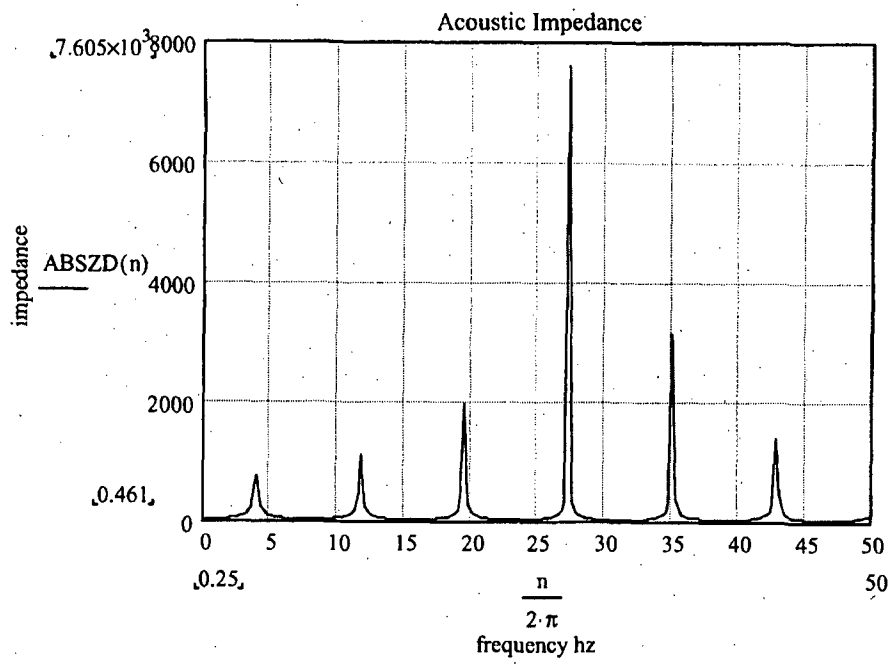
BYRON UNIT 2 FW LINE

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

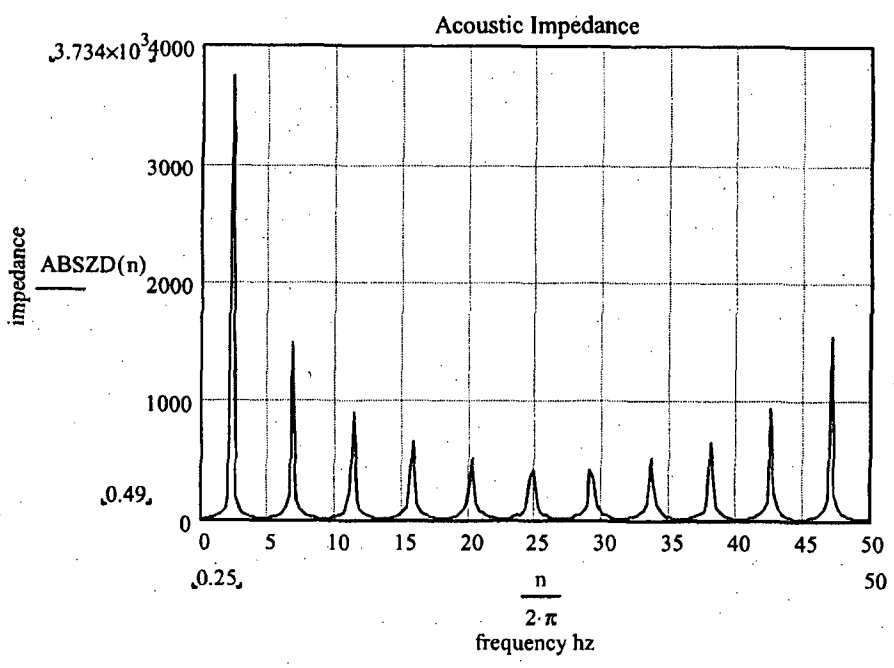
Attachment G - Byron Feedwater Piping Resonance Evaluation (Page 26 of 28)

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:

Attachment G - Byron Feedwater Piping Resonance Evaluation (Page 27 of 28)



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 75 through 87 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

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 urgency 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 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)
	←	
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 process procedure.	→ ←	It is only implemented if noise is suspected. Noise was not 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 101 through 110 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.

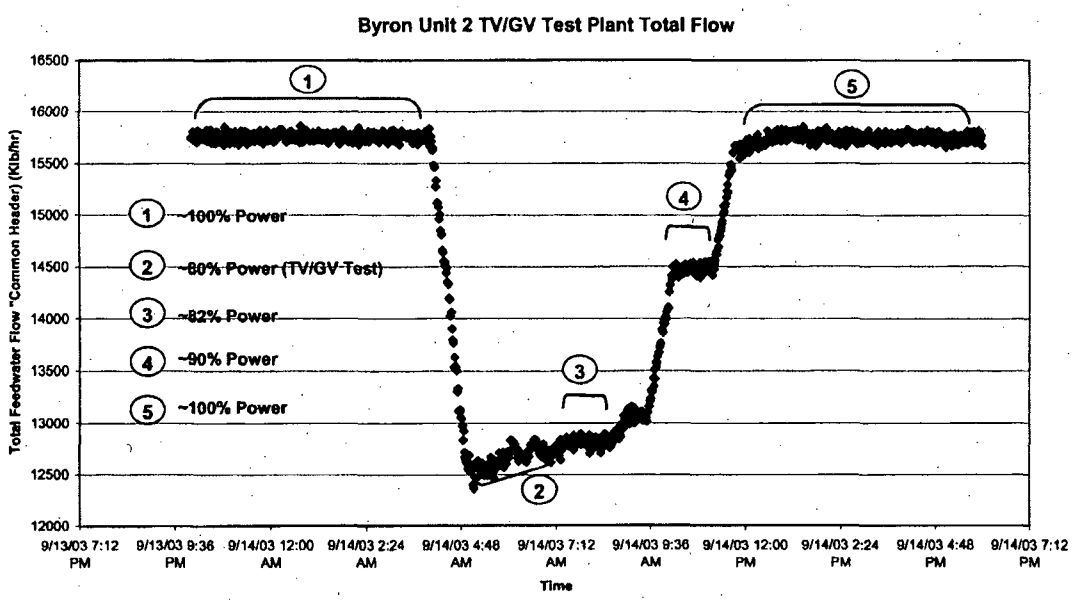


Figure 1. Analyzed data portion for Byron Unit 2 TV/GV collected data

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

Attachment N- Byron Unit 2 TV/GV Test Report – Common Header (Page 1 of 2)

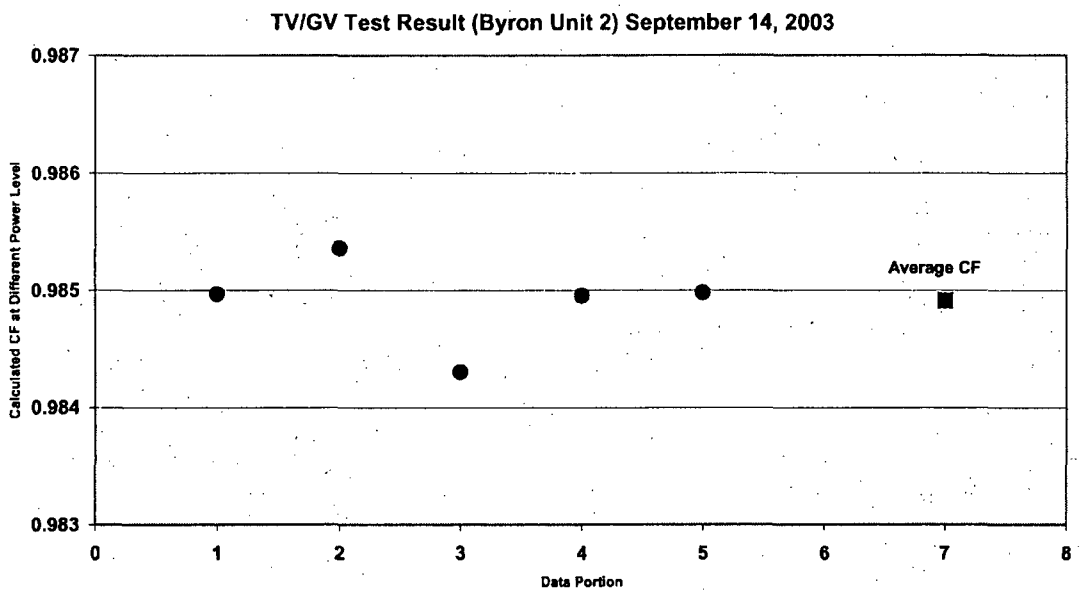


Figure 2. Calculated CF value for different data portion (Note: average CF is the average of all 5 calculated values).

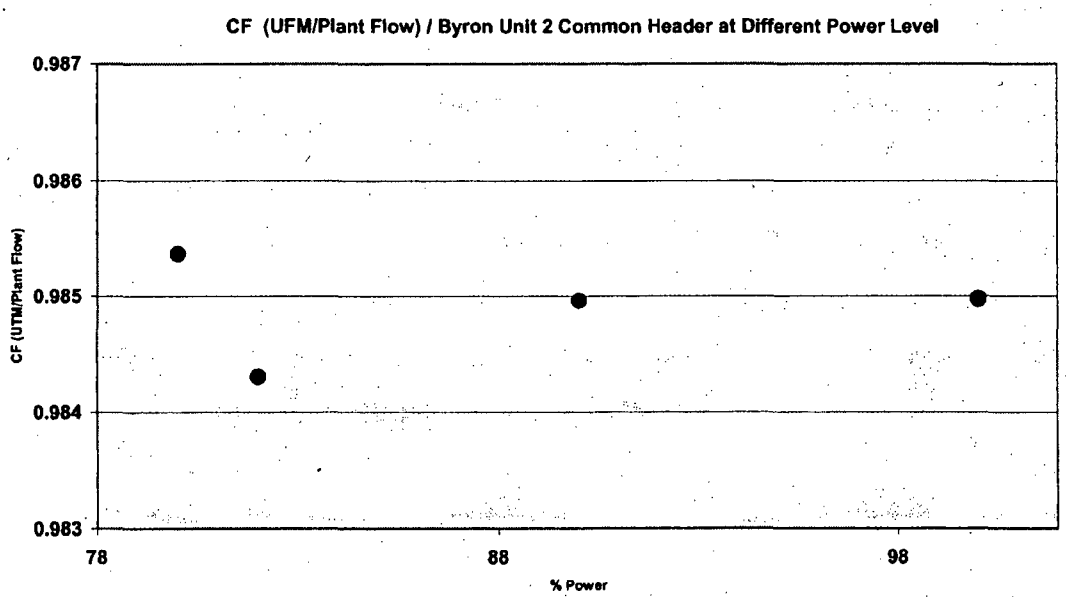


Figure 3. CF behavior as a function of power (Note: there are two points (CF for data portion 1 and 5) on top of each other at 100% power)

Attachment O – Byron Frequency Comparison (Page 1 of 3)

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	

Attachment O – Byron Frequency Comparison (Page 2 of 3)

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	

Attachment O – Byron Frequency Comparison (Page 3 of 3)

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	

Attachment Q – Resolution of GENE Report Issues

Following completion of Rev. 0 of this Root Cause Report, Senior Management requested that the Root Cause Report be independently reviewed. A contract was set with General Electric Nuclear Energy (GENE) to perform this review, which was completed on Nov. 10, 2003. The GENE report is attached as Attachment Q-1. In their report, GENE concurred with the technical root cause, however, this concurrence was contingent on demonstrating that the actual noise seen gives the actual CF error for a minimum of two loops (one noisy and one not). This was demonstrated as shown in Attachment Q-4.

GE also made several recommendations to improve the quality of the report, but which were not required to validate the root cause (see items #19 through 28 in Attachment Q-2). The first three are "brainstorming ideas", the next four are root cause suggestions for enhancement, and the last three are other ideas on the Feed Water (FW) system measurements.

Attachment Q-2 provides each recommendation from the GENE report and the Exelon resolution for each recommendation.

Index of Sub-attachments

Attachment Q-1,	GE-NE-0000-0021-8155-01
Attachment Q-2,	Response to GENE Issues
Attachment Q-3,	Root Cause Logic
Attachment Q-4,	AMAG –REP-EN-034-00, Effect of Pressure Wave Noise in Byron U2 (Run of App. H w/ actual data)
Attachment Q-5,	Piping Takeoffs
Attachment Q-6,	Overpower Analysis
Attachment Q-7,	Spectral Analysis of Braidwood FW Piping
Attachment Q-8,	Spectral Analysis of Byron 1 FW Piping
Attachment Q-9,	Byron and Braidwood AMAG Noise Evaluations
Attachment Q-10,	Dresden/Clinton/LaSalle AMAG Noise Evaluations
Attachment Q-11,	Frequency Summary At Various Sound Speeds
Attachment Q-12,	White Paper On How Plant Acoustics Affect UFM
Attachment Q-13,	Byron Updated Frequency Comparison
Attachment Q-14,	Braidwood Updated Frequency Comparison

Rev. 1

GE-NE-0000-0021-8155-01
Class I
November 2003

Independent Review of Exelon Report: "Inaccuracies in Feedwater Ultrasonic Flow Measurements Caused by Low Frequency Velocity Signals Result in Exceeding Licensed Power Level at Byron and Braidwood Stations"

GE Nuclear Energy
November 10, 2003

GENE 0000-0021-8155-01
Rev. 0
Contains Unverified Information

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Executive Summary

Exelon Nuclear Corporation (Exelon) requested that GE Nuclear Energy (GENE) provide an independent review of their report, "Inaccuracies in Feedwater Ultrasonic Flow Measurements Caused by Low Frequency Velocity Signals Result in Exceeding Licensed Power Level at Byron and Braidwood Stations". In this report, the root cause established by Exelon was described as follows:

> "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 flow rate which resulted in a non-conservative calorimetric result."

This conclusion was based primarily on a comparison of the loop and common header feedwater flow rates at Byron unit 1. Since acoustic noise is known to influence the accuracy of AMAG instrumentation, additional investigations were conducted which identified resonant frequencies below 25 hertz, which correspond with the natural frequency of the feedwater lines between the feedwater regulating valves (FRVs) and the steam generators. These resonant frequencies were then identified as the most probable root cause of the non-conservative calorimetric result.

The GENE team was satisfied that the Exelon root cause analysis is adequate, and GENE concurs with the Exelon conclusions. However, GENE also concluded that while noise contamination of the AMAG ultrasonic signal is a likely root cause of the event, it alone may not be sufficient to explain the magnitude of the correction factors established over time.
This report documents the evaluations performed by GENE that provide the basis of the above conclusion. The initial GENE review also uncovered opportunities to strengthen the analysis and documentation performed by Exelon and Westinghouse/AMAG. These opportunities are also included in this report.

1. Background

On October 1, 2003, Exelon Nuclear provided GE Nuclear Energy a copy of their report, "Inaccuracies in Feedwater Ultrasonic Flow Measurements Caused by Low Frequency Velocity Signals Result in Exceeding Licensed Power Level at Byron and Braidwood Stations", (Reference 1). For brevity, this document is referred to as the "Root Cause Report", or "RCR" in the remainder of this document. The RCR contains evaluations and analyses, performed by Exelon and others, to determine the cause of past overpower conditions on Byron Units 1 and 2, and Braidwood Unit 2. Exelon has requested that GENE perform an independent review of this work. All GENE evaluations are based solely on the information provided by Exelon. Since this is an independent review, not a separate root cause evaluation, no formal verification activities have been performed by GENE with regard to this work, and are not required under GE Engineering Operating Procedures.

Exelon prepared this Root Cause Investigation to determine the cause of the past overpower condition on Byron Units 1 and 2 and Braidwood Unit 2 following the AMAG ultrasonic flow meter 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. 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.

The root cause established by Exelon in the AMAG Root Cause report was described as follows:

> "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 flow rate which resulted in a non-conservative calorimetric result."

This report documents the GENE evaluations, conclusions, and recommended further actions.

2. GENE Review Process

A multi-disciplinary team of GENE engineers performed this independent review. The team consisted of a technical team lead; principal mechanical engineers with significant acoustic resonant phenomena experience, an instrument engineer, a flow meter specialist, a TapRoot process expert, and lead system principal engineers. The team was supplemented by consultants with expertise in acoustics provided by the GE Global Research Center (GRC). The GRC consultants reviewed only the non-proprietary data provided by Exelon.

The review was provided in two phases – an initial review of the documentation provided by Exelon resulting in a draft document identifying the preliminary GENE conclusions and identified potential improvements. Exelon and Westinghouse/AMAG then addressed these identified items, and the same GENE team reviewed their responses.

The first phase of the review was performed between October 1 and October 17, 2003. During this initial review phase, all team members reviewed the RCR. The team then met, and brainstormed a list of questions that required responses in order to confirm or invalidate the conclusions of the Exelon root cause analysis. Each of these questions (except as noted below) was assigned a lead evaluator, to individually address the specific questions and to draft specific sections of this report, commensurate with their area of expertise. In some cases, the lead evaluator was assisted by other team members in preparation of the responses. The identified questions are:

1. Is it possible/plausible for a low frequency acoustic standing wave (<25 Hz) in the piping system to affect the output of the AMAG ultrasonic flow meter?

2. Does the analysis provided by Exelon support the potential for acoustic standing waves (<25 Hz) being present in the feedwater system?

3. Do the pressure measurements in the feedwater system support the existence of acoustic standing waves?

4. Are the presence or absence of evidence of acoustic standing waves in a specific unit/loop consistent with the observed behavior of the ultrasonic flow meters?

5. Are there other identified phenomena that could have affected the flow measurements that have not been adequately addressed?

6. Are the identified Corrective Actions appropriate?

7. Are the identified Additional Actions appropriate?

It was determined that three questions - Numbers 5 through 7- could best be addressed through open discussion to address the issues involved. Following completion of the initial review, and documentation of preliminary answers to Questions Number 1 through 4, the review team held a formal meeting to brainstorm potential items for Question Number 5, and to discuss and reach consensus on Action Item appropriateness. This meeting was led by a trained GENE facilitator (who was not a member of the evaluation team), and was held on Thursday October 16. Responses to each of the questions are provided in Section 3 of this report.

An evaluation report was then drafted and disseminated to all team members for their review and comment. All internal team comments were addressed and resolved. The draft report, including the identification of weaknesses in the root cause analysis and documentation was forwarded to Exelon.

The second phase of the review took place between October 20 and November 10. During this time, Exelon and Westinghouse/AMAG and GENE personnel discussed the GENE findings and recommendations, corrected misunderstandings, and addressed the identified areas where the analysis and documentation in the RCR could be strengthened. Several of the identified items will be addressed by addition of information and analysis to the root cause report. Commitments for additional analysis by Exelon were also made. Given successful conclusion to these items, the GENE team was satisfied that the Exelon root cause analysis is adequate, and GENE concurs with the Exelon conclusions.

3. Specific Reviews and Conclusions

3.1. Evaluation of Exelon Reported Root Cause

In Reference 1, the root cause established by Exelon was described as follows:

> "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 flow rate which resulted in a non-conservative calorimetric result.

This conclusion was based primarily on a comparison of the loop and common header feedwater flow rates at Byron Unit 1. Since acoustic noise is known to influence the accuracy of AMAG instrumentation, additional investigations were conducted which identified resonant frequencies below 25 hertz, which correspond with the natural frequency of the feedwater lines between the feedwater regulating valves (FRVs) and the steam generators. These resonant frequencies were then identified as the most probable root cause of the non-conservative calorimetric result.

In order to perform the requested review, the GENE review team established some key questions, the response to each of which would either support or contradict the Exelon root cause conclusion. These questions and the GENE evaluations are provided in the following paragraphs.

3.1.1. Question 1 - Is it possible/plausible for a low frequency acoustic standing wave (<25 Hz) in the piping system to affect the output of the AMAG ultrasonic flow meter?

Yes. The AMAG flow measurement is based on determination of the time for flow eddies to traverse from the upstream acoustic sensors to the downstream acoustic sensors. The time determination is made by cross-correlation of the demodulated acoustic signals from the upstream and downstream sensors for various time delays, and determining that delay which gives the highest crosscorrelation (cross-correlation peak). The time delay corresponding to the peak is the time it takes for the flow to travel the known distance between the upstream and downstream sensors. Using this time determination, the flow rate is calculated from the pipe geometry and water density, and a pre-calculated
Velocity Profile Correction Factor (VPCF), which is dependant upon the Reynolds number.

The pressure fluctuations inherent in an acoustic noise wave traveling transversely through the feedwater line may affect the AMAG flow rate measurement because the acoustic "noise" could change the modulation of the

upstream and downstream acoustic carrier signals and potentially change the time at which the cross-correlation peak occurs. The change in cross-correlation peak due to acoustic noise would cause an error in the subsequent velocity and flow calculation. The GENE evaluation concurred with the conclusions in the RCR that the acoustic wave generated by the pressure oscillations could affect the AMAG cross correlation measurement by changing the modulation of the AMAG carrier wave by the flow eddies.

Appendix H provides the proprietary analysis by AMAG of the potential for acoustic noise to affect the measurements. In Appendix H, AMAG flow meter performance is compared in situations where the AMAG de-modulated flow signal is "contaminated" with periodic noise signals of 6 and 8 Hz. A cross-flow simulation is performed to determine how much error the noise can produce in the cross-flow measurement. The approach presented in Appendix H seems technically valid. Figure 7 of Appendix H shows that calculated correction factors somewhat typical of those seen in plant operation may be developed given certain specific assumptions regarding noise frequency and magnitude, and the delay (or transit) time based on flow rate. However, it was not clearly demonstrated that the magnitude and frequency of acoustic noise actually observed at the plants caused the observed error in plant AMAG readings.

Based on the results of the GENE review of Appendix H, GENE concludes that it is plausible that the presence of a low frequency standing acoustic wave in the piping system has the potential to affect the output of the AMAG flow meter.

The signal spectrums used to determine the effects of the noise on the calculated correction factors (CF) were synthesized from random numbers with the addition of very specific noise having a period of 6 and 8 Hz. The results are shown to be very sensitive to both the amplitude of the noise signal and to the expected time delay. The statement is made in the conclusion section of Appendix H, "There is an effect in the time delay calculation if the flow signal "demodulated signal" is contaminated with noise distorting the flow signal frequency spectrum. *The effect cannot be quantified easily, but it is clear that it is a function of the noise and signal flow intensities."* (GENE Italics)

Comparison of the spectrums used in Appendix H with the DIAGNOSE noise spectrums taken from the plants and presented in Appendix L and M of the root cause report, showed significant differences. For example, comparison of Appendix H, Figure 3 with the Byron, Unit 1 Loop A spectrum in Appendix L showed overall amplitudes which are different by an order of magnitude, and different frequency spikes for the noise (approximately 10, 18, and 26 Hz in Appendix H, compared with 5, 10, and 18 Hz in Byron Unit 1 Loop A provided in Appendix L). Reference 3 subsequently resolved the magnitude questions between attachments L and H to the RCR. Similarly, the Appendix H synthesized spectrums are significantly cleaner, the signal to noise ratios are more consistent, and the noise bandwidths are broader compared with the "real" noise spectrums.

RECOMMENDED ACTION - GENE Recommends that the Appendix H model be run with actual data from at least two plant loops (preferably all four loops from one plant), but, at a minimum, one with and one without noise contamination to demonstrate that the calculated loop CFs are consistent with the actual loop noise content, and that the loop flows after correcting for the effect of "noise contamination", match the header flow measurement without "noise contamination". The observed bias in the calculated CFs also should be demonstrated to be consistent with the actual plant data.

As of the date of issue of this report, Exelon had committed to perform this additional analysis, but the analysis has not been completed, and GENE has not reviewed any results. The GENE overall conclusions as written are based on the assumption that this action is completed successfully.

3.1.2. Question 2 – Does the analysis provided by Exelon support the potential for acoustic standing waves (<25 Hz) being present in the feedwater system?

Yes. Appendix G of the AMAG Root Cause report presents two separate analyses that provide information on potential acoustic modes in the various feedwater piping paths. In the first instance, potential resonant frequencies are identified assuming open-open end boundary conditions, using

$$f = \frac{Ci}{2L} \qquad (1)$$

where *f* is the natural frequency, *C* is the speed of sound, L is the piping length, and *n i* ..... 3 , 2 , 1 is the resonant mode number. Assuming closed-open boundary conditions the resonant frequencies are calculated using

$$f = \frac{Ci}{4L} \qquad (2)$$

where the terms are identified in the same manner, except that only odd values (*i*=1,3,5....n) are allowable in this case.

Potential natural frequencies are identified for each of the Byron lines. Many frequencies in the zone of interest are identified.

Acoustic impedance calculations were also carried out based on Chapter 12 of Reference 2, modeling the piping from the FRV to the steam generator. The process used is difficult to evaluate based on the level of detail provided.[1] Most

[1] Details such as what impedance boundary condition is assumed at what end (FRV end or steam generator end) and for what location the impedance shown on pages 54 & 55 are plotted, or how

likely this analysis is an acoustic circuit analysis, albeit for a restricted length of pipe (from the FRV to the steam generator with some type of boundary conditions assumed at the FRV and steam generator ends). The key conclusion is that these acoustic impedance calculations identify potential natural frequencies similar to those from the simple formula (2) using the length from the FRV to the steam generator.

Critique of Acoustic Analysis

If a comprehensive acoustic circuit analysis (ACA) were available, much of the uncertainty in the above discussion could be eliminated. However, such analysis is difficult and expensive to perform, and would model each of the lines from the upstream common header to the steam generator using approximate boundary at the upstream header and at the downstream steam generator ends. Elements such as the FRV, venturi and check valve should be treated via matching conditions applied to the wave systems present at the upstream and downstream ends of these elements rather than by the simplified open-open or open-closed boundary conditions used in the simplified resonant frequency analysis. Given this cost and complexity, and the findings in the following sections, this approach is not recommended.

While some might criticize the simplified acoustic analysis for it's various assumptions and approximations, it is generally true that the FRV behaves (especially at reasonable steady pressure drop across it) as a "closed end" and that the steam generator & upstream header ends behave as "open ends". Therefore, quarter wave resonances may occur corresponding to pipe lengths between the FRV and the steam generator and between the upstream header and the FRV. In case of the pipe length between the FRV and the steam generator, this gives natural frequencies, in case of Byron 2, of roughly 3, 9,15, 22, 28, etc. Hz in the A & D lines, and about half these values in case of the B & C lines as described on pages 52 and 53 of the RCR. This data provides a reasonable estimate of the eigenfrequencies of the specific elements of the Byron feedwater system.

<u>Based on the results of the GENE review of Appendix G, GENE concludes that there are potential acoustic natural frequencies (<25 Hz) present in the feedwater system.</u>

While GENE concurs that eigenfrequencies of less than 25 Hz exist for the feedwater flow system, it is very important to recognize that this is a necessary but insufficient condition for such frequencies to actually be excited. Fluid mechanical sources driving at these frequencies and the locations of such excitations also should be identified. A pressure source located at a pressure node of a mode can potentially excite large amplitudes whereas a pressure

the venturi and check valve were handled in terms of matching conditions across them would aid in the evaluation.

source located at a pressure antinode of a particular mode will not excite high amplitudes. The inherent damping present in a particular mode will also determine the likelihood of excitation of such a mode.

3.1.3. Question 3 – Do the pressure measurements in the feedwater system support the existence of acoustic standing waves?

Yes. Appendix G of the AMAG Root Cause report provides an extensive pressure data set from the Byron plant. Data was taken in all four feedwater loops in Unit 2. Pressures were recorded in all four loops at 100% power, and at reduced power in two of the four loops. The measurement location was described as, "a low point drain located near the flow measurement venturi." The data was processed by first calculating a mean pressure (from on the order of 30,000 data points), then this mean was subtracted from the entire data set, and Fourier coefficients and power spectral density (PSD) of the fluctuating component generated from the residual. The Fourier coefficients and PSD are presented in plots on pages 57 through 68 of the RCR

Based on our initial review of the Root Cause Report, GENE could not completely agree with the conclusions drawn from the data as provided on page 69 of the RCR. Several GENE reviewers have very significant experience in pressure oscillation frequency domain analysis, and in our collective experience, the results "just don't look right". While several of the Fourier Coefficient plots show indistinct peaks at frequencies near values predicted for the potential eigenfrequencies, in most cases, an observer would not likely draw the conclusion that there is much evidence of resonance from these plots without prior knowledge of the presupposed frequencies. Further, in our experience, frequency content is normally much more evident in PSD plots than in Fourier coefficient presentation. The PSD results, in particular, are much more representative of broad-band noise than of resonant standing waves. Resonant acoustic modes are generally much more pronounced and evident when they occur than are apparent in the PSD plots provided in Appendix G.

Likewise, there is a weakness in the link between the pressure data presented in Appendix G and the noise measurements from DIAGNOSE presented in Appendix L (for Byron) and M (for Braidwood). The overall logic of the root cause analysis is that the pressures from the standing acoustic wave (as presented in Appendix G) causes the plant and loop-specific noise spectrums (presented in Appendix L and M), and that those magnitude and noise frequency contents are sufficient to cause the deviations in CF (presented in Appendix H). As noted previously, given the sensitivity of the Appendix H results to the inputs, the cause and effect tie between the pressure measurements from Byron provided in Appendix G and the corresponding noise spectrums provided in Appendix L is necessary to move the characterization of the root cause from "plausible " to "probable". While a similar activity for Braidwood would be desirable, GENE recognizes that the lack of pressure data makes this impossible

until such data might be taken, and probably is not absolutely necessary for the root cause determination.

To strengthen the RCR conclusions, GENE recommended that the data presented in Appendix G and Appendix L for Byron be compared on a loop-by loop basis, using consistent scales and formats, to demonstrate a cause-and effect relationship between the measured pressures and the DIAGNOSE acoustic spectra.

On October 29, Exelon provided, "White paper on how plant acoustics effects UFM[2]" (Reference 3). It is our understanding that this document will be added to the Root Cause Report as an attachment. The GENE team reviewed the material presented in this white paper, and concluded that a cause-and-effect relationship between the pressure data and noise spectra has been demonstrated.

GENE concludes that the data presented in Appendix G augmented by Reference 3 (to be included in the root cause report) provides sufficient information to conclude that an acoustic resonance is likely present in at least the A and D loops of Byron, Unit 2, and that a cause-and-effect relationship has been demonstrated between the measured pressures and the acoustic noise spectrum (from DIAGNOSE) in the locations studied.

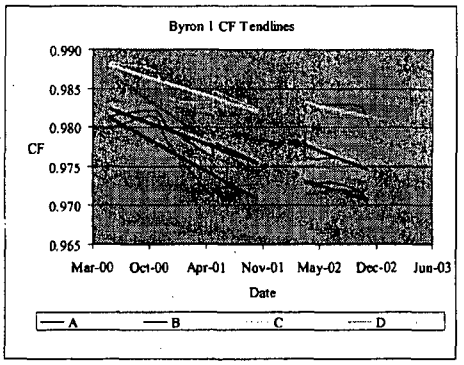
3.1.4. Question 4 – Are the presence or absence of evidence of acoustic standing waves in a specific unit/loop consistent with the observed behavior of the ultrasonic flow meters?

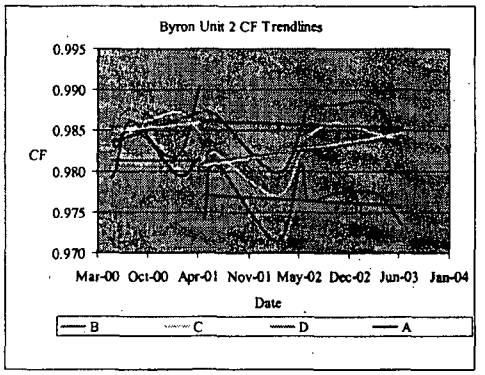
The data is inconsistent. Byron and Braidwood have increased the rated reactor power based on the calorimetric improvements resulting from the AMAG implementation and the observed difference between the AMAG and Venturi readings. The loop correction factors (ratio of AMAG to Venturi reading) are used in the calorimetric calculation. The basis for this approach is that the AMAG is more precise than the venturi.

The loop correction factor trends (Byron Correction Factors.xls) between installation and September 2003 were reviewed, separating the data before and after refueling outages. The data appear to show a reasonably constant trend at both Byron units (see figures below). However, if standing waves are more predominant in Loops A and D at Byron 2, one would not expect the relatively low CFs in Loops B and C. The data also appear to indicate that the correction factors decline following each outage. If cleaning the venturis were effective, the correction factors should have increased. However, it should be noted that there

[2] The title is a misnomer – the white paper addresses the relationships between the pressure measurements and the acoustic spectra, and does not address the ultrasonic flow measurement in any way.

is significant scatter in the CF data, and also few data points, so the slope of the trend lines do not have a high confidence level.

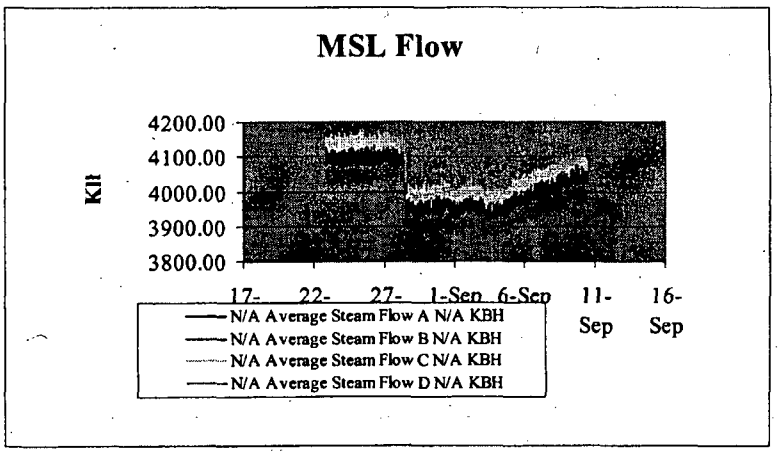




The potential steady decline in the correction factor could be a result of venturi corrosion buildup or gradual changes in the venturi discharge coefficient. No evidence was provided in Reference 1 that the venturi discharge coefficient had been measured.

<u>Because of these inconsistencies in the data, GENE concludes that there may be other factors influencing the correction factor that could be investigated further.</u>

Review of the process instrumentation (PI) data in the Byron Unit 1 loops provides some indication of the amount of process noise in the system. Based on the plant data between 8/22 and 9/10, there are three distinct periods of interest: 1) 8/22 to 8/28 with the plant at 100% power and correction factor was applied, 2) 8/28 to about 9/4 with the plant at a lower but steady steam flow and 3) from 9/4 to 9/10 where a slow ramp up of steam flow is occurring.



During these periods the process noise in the Feedwater line between the FRV and the Steam generator (as measured by the standard deviation of the pressure downstream of the FRV) was reviewed. The results, shown in the table below, appear to show a very quiet system during steady state operation with little evidence of the presence of an acoustic standing wave. It is acknowledged that use of this PI data can be misleading since the data are not true point data, but they show the type of evaluation that could be conducted to enhance the RCR.

Feedwater Pressure Downstream of the FRV

	Loop A	Loop B	Loop C	Loop D
Full Power				
Pressure (psi)	1091	1099	1103	1090
Std Dev (psi)	1.6	1.5	1.3	1.3
Std Dev (%)	0.15%	0.13%	0.12%	0.12%
After Downpower				
Pressure (psi)	1098	1107	1108	1097
Std Dev (psi)	2.3	2.2	2.7	2.7
Std Dev (%)	0.21%	0.20%	0.24%	0.24%
Slow ramp				
Pressure (psi)	1076	1085	1087	1075
Std Dev (psi)	14.5	14.6	13.9	14.2
Std Dev (%)	1.34%	1.35%	1.27%	1.32%

<u>GENE also concludes that the plant instrumentation measurements could be further discussed in the report to enhance the conclusion that the postulated standing wave is in fact influencing the AMAG indication.</u>

3.1.5. Question 5 – Are there other identified phenomena that could have effected the flow measurements that have not been adequately addressed?

No. Appendix A contains the results from the brainstorm session held on October 16, as part of the phase 1 review, and transmitted to Exelon on October 17. During the Phase 2 review, Exelon responded that all of these items have been internally investigated and resolved. In general, GENE has not reviewed the Exelon closure documentation. They are presented in Appendix A to complete the record of what was done during the review, and the resolution is not critical to our conclusions within this report.

3.2. Evaluation of Root Cause Analysis Process

The method of review employed by GENE did not involve doing an independent root cause analysis. Instead, GENE used the Taproot Root Cause Analysis methodology as a guide, to answer the following questions:

3.2.1. Question 6 - Did the Exelon analysis apply appropriately the TapRoot methodology?

Yes. GENE concludes that the Exelon Root Cause team applied the appropriate tools in attempt to determine root cause.
The analysis is rigorous and shows a great deal of effort devoted to understanding the circumstances and issues related to the event sequence, and particularly the chain of events associated with the implementation decisions, post-implementation investigations and ultimate reaction to the problem.

3.2.2. Question 7 - Does the root cause analysis appear to adequately pursue all opportunities to uncover root cause?

No. The root cause report deals extensively with the events following AMAG installation and the lost opportunities to react to the AMAG problems. The Root Cause is determined to be "Noise contamination of the AMAG ultrasonic signal." The implication of this conclusion is a belief that the noise contamination was an unknown phenomenon prior to this event. While GENE access to the information surrounding this event is limited to that provided in the report, it does not appear that the possibility of noise was unknown. In addition, while the particular nature of the noise may not have been anticipated, the effect of the Signal to Noise ratio is a well-known and common aspect of instrument loop design and calibration.

While not required by the Exelon root cause charter, this leads GENE to question whether the Root Cause might lie further upstream in the event process, either in the engineering evaluations leading to the installation or in the adequacy of instrument loop calibration and testing done at the time of installation.

3.2.3. Question 8 - Does GENE believe the report successfully arrives at root cause (i.e., has the Exelon team delved deep enough into the event)?

While not required by the Exelon root cause charter, the key observations of this GENE review are as follows:

- This event can fundamentally be viewed as an unsuccessful implementation of AMAG. As such, the key direction that the root cause investigation needs to take is greater focus on the activities leading up to implementation.

- It is not clear from the information provided whether Exelon engineering resources were adequately involved in validating inherent assumptions of the AMAG installation.

- The level of Exelon involvement in the AMAG installation, at the detail level, is not clear from the report. Examples which are not addressed and which could identify additional root causes are:

    - How does AMAG calibrate their device?
    - Do AMAG calibration methods fully validate assumptions?
    - Do they encompass an adequate range of flows and power levels?).

Largely in line with the observations made above, the TapRoot analysis is silent on the activities leading up to the installation of AMAG. As with any important engineered system, normal industry practice would review the planned installation to assure it will be properly integrated into the plant and meet the plant operating requirements. Typically this might include:

- Engineering expert review of the planned installation

    - Identification of potential impact on the plant
    - Identification of key parameters to examine (such as instrument loop error terms, signal to noise ratio, etc.)

- Identification and validations of Design inputs and Assumptions
- Identification of appropriate installation and testing requirements

    - Assurance that testing would validate assumptions

- Engineering Design Review
- Review of installation test results
- Acceptance of the as-installed product

All of the above activities are typically relied upon to assure adequacy of engineering work, and presumably were done in this case. However, it is not clear why the TapRoot Analysis does not pursue this avenue as a means of figuring out how this event could have been prevented.

While the timeline for the event, as presented in the Root Cause evaluation, begins in January 1998 (venturi calibration) the first focus on potential root cause appears to be the May 10, 1999 AMAG results. There is no mention of the sequence of events leading to the installation and acceptance of the equipment. It might be beneficial to examine the events leading to the implementation wherein Exelon engineering involvement might have been expected to surface

key risks. For example, engineering reviews, examination of inherent assumptions, verification of assumptions, reviews of installation and calibration procedures, etc.

3.3. Evaluation of Causal Factors Assessments

The Cause and Effect Analysis presented in Attachment J to the Root Cause Report appears to be weak in terms of the depth of pursuit for potential issues. Specifically, the Cause and Effect Analysis *does* identify "AMAG apparent condition not identified upon initial installation...." As an issue to investigate, but the investigation is limited to the issue of why the DIAGNOSE program was not used. The pursuit of the DIAGNOSE program issue is certainly appropriate. However, the questions related to cause and effect should be broadened to include other key installation questions. For example:

1. How was AMAG calibrated?
2. Why did the calibration not reveal the unexpected behavior of CF vs. flow?
3. Was the calibration equal to or better than that performed for other plant instrumentation?
4. Did the calibration cover an adequate range of plant conditions?
5. Did the calibration validate all assumptions (e.g. linearity, constancy of CF with flow, other assumption...)?
6. Were all known potential sources of error in AMAG assessed relative to the Exelon installation?

<u>In general, it appears that the Cause and Effect analysis does not pursue the potentially fruitful avenue of Exelon engineering involvement and Exelon plant knowledge (relative to AMAG) to understand how the apparent defects managed to escape detection during initial installation.</u>

3.4. Evaluation of Corrective Action Appropriateness

The GENE review team met as a committee to address the corrective actions (CA's) provided in the AMAG Root Cause report. Each CA was addressed separately. GENE finds that all of the CA's are appropriate, except:

- CA Number 2 – Investigate Common Feedwater Header for Noise

  This action presupposes that the root cause is correct. For the AMAG instrumentation to be correct, the lack of acoustic resonance noise is a necessary, but insufficient condition. GENE is concerned that several times during discussions with Exelon/Westinghouse/AMAG the statement was made that the AMAG ultrasonic flow meter will only be used in situations where "there is no noise present", however the definition of "no noise" was never quantified. CAs 5, 6, 7 and 8 will provide quantification of this issue and address this concern.

- CA Number 3 – Implement Correction Factors based on Common Header AMAG measurements

  This action may be considered as the "implementation" activity following a positive finding from CA Number 2. The GENE comments with regard to CA Number 2 also apply here.

3.5. Evaluation of Additional Action Appropriateness

The GENE review team met as a committee to address the additional actions (AA's) provided in the RCR. Each CA was addressed separately. GENE provides the following comments on the AA's:

- AA Numbers 1 & 2 – Obtain additional pressure data

  GENE concurs with the appropriateness of these items, but notes the desirability to validate the overall accuracy of the measurement system used.

- AA Number 3 – Compare pressure data and AMAG noise spectrum and improve Root Cause report as necessary.

  GENE concurs with the appropriateness of this item, as it echoes our findings with regard to the root cause report. Specific recommendations for additional analysis and documentation are presented in Sections 3 and 4, and Appendix B of this report.

GENE concurs with all other Additional Actions.

3.6. Evaluation of Safety Assessment Inputs

The risk assessment for the RCR is based on a maximum operating power level of 102.62% power. The report does not provide a derivation of the selection of power level used in the risk assessment. This power level is identified as being based on the actual venturi flow, with no AMAG correction. This approach is considered appropriate and should lead to a conservative assessment of the impact of plant operation above the licensed power level. It is recommended that the evaluation that led to the selection of the maximum power level be included as an appendix to the RCR or a reference to the supporting evaluations provided.

The risk assessment also states that the evaluations were performed with an additional 2% uncertainty as applicable. The use of a 2% uncertainty is consistent with the current NRC regulatory guidance and is considered acceptable. Without further detail, it is not possible to determine whether or not the uncertainty has been applied to an appropriate set of events. However, if it

has been applied the specific events evaluated consistent with the current safety analysis, it is considered acceptable.

A wide spectrum of events was identified as having been evaluated as a part of the risk assessment. This spectrum of events is very comprehensive. However, the basis for the selection of the events has not been documented, nor have the results of the individual event evaluation been documented. To strengthen the RCR, it is recommended that these evaluations be included as an appendix to the report or a reference to the supporting evaluations provided.

3.7. Overall Report Completeness and Usefulness Assessment

There is a great deal of excellent technical work included in the Root Cause report. However, the GENE review has identified the following items that Exelon might wish to address to improve the overall quality of the report:

- The report does a much better job of documenting the "Is" in the root cause than the "Is-Not".
- Additional technical details in the analysis sections would assist the reader in understanding the basis for the conclusions.
- The logic taking the reader through the entire process from feedwater system eigenvalues to the pressure measurements, noise spectrum analysis and finally the CF effects (and the data behind them, as noted in the Recommended Action) needs strengthening.

4. Conclusions and Recommendations

In Reference 1, the root cause established by Exelon was described as follows:

> "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 venturi which resulted in a non-conservative calorimetric result."

The GENE review did not uncover any evidence that would invalidate this determination. The initial review identified unexplained trends in the root cause analysis and documentation.

- RECOMMENDED ACTION - GENE Recommends that the Appendix H model be run with actual data from at least two plant loops (preferably all four loops from one plant), but, at a minimum, one with and one without noise contamination to demonstrate that the calculated loop CFs are consistent with the actual loop noise content, and that the loop flows after correcting for the effect of "noise contamination", match the header flow measurement without "noise contamination". The observed bias in the calculated CFs also should be demonstrated to be consistent with the actual plant data.

With technical closure and documentation of the Recommended Action, GENE concurs that the identified technical root cause is probably correct.

GENE also comments that while the *technical* root cause is probably correct, the true, overall Root Cause might lie further upstream in the event process, either in the engineering evaluations leading to the installation or in the adequacy of instrument loop calibration and testing done at the time of installation.

Appendix B provides additional observations that Exelon may wish to incorporate in the Root Cause Report, but are not critical in our concurrence with the identified root cause. Appendix C provides additional comments on other actions that Exelon might wish to evaluate for improvement of the overall feedwater system.

5. References

1. Exelon Report, "Inaccuracies in Feedwater Ultrasonic Flow Measurements Caused by Low Frequency Velocity Signals Result in Exceeding Licensed Power Level and Byron and Braidwood Stations", Action Tracking Number 173510-14, September 26, 2003.
2. Wylie, E.B. & Streeter, Fluid Transients, FEB Press, 1982
   e-mail, jeff.drowley@exeloncorp.com to Bouchie, Daryl J. (PS, NE); McIntyre, Terry R. (PS, NE), dated Wed 10/29/2003 9:14 AM, "White paper on how plant acoustics effects UFM"

Appendix A – Other Potential Phenomena Brainstorm Results

There are numerous parameters that can impact the assessment of reactor power. While Feedwater flow may be the dominant factor, slight changes in other factors such as steam flow or steam generator pressure may influence the final value. The overpower conditions discussed in this root cause report are small (< 2%) and other inaccuracies in the contributing parameters could be as important as the feedwater flow measurement error. The GENE Review Team has identified the following as potential factors, which could influence the overall calorimetric calculation. Exelon may wish to pursue further:

- The possibility exists that the flow turbulence down stream of the FRVs could also influence the AMAG instrumentation. The AMAG qualification was not conducted at Reynolds numbers consistent with the plant applications. It is possible that there are still turbulent effects, although admittedly small, that have not been demonstrated. This should be considered as an additional potential cause of a power dependent impact.

- After a few years of operation feedwater venturi flow meters normally collect an iron oxide, gradually deposited on the surface of the nozzle throat. This causes the apparent flow to increase proportionally to the decrease in the throat's diameter. The correction factors account for this trend. However the lack of precise flow calibration measurement could lead to additional errors that have not been taken into account. It is important to determine the precise value of each of the four feedwater flows by a third method, which validates the AMAG readings before establishing the root cause. A chemical tracer test using sodium or rubidium has been effectively used in BWR applications.

- In BWR plants, the total FW system accuracy for the BWR/4/5/6 plants ranges between +/-0.8%-+/-0.9% with venturi hardware accuracies requirements of +/-0.25% calibrated to the ASME-PTC-6 Code. The report did not reveal the accuracy of the existing venturi after refurbishment or the AMAG instruments in comparison with the ASMEPTC-6 calibration standard which requires an accuracy of +/- 0.25%. Without such a comparison, the correction factors could be incorrect since neither indication is precisely known. The report would be strengthened if it addressed the accuracy requirements for total FW system and the specific accuracy requirements for the AMAG hardware.

Appendix B – Other Potential Actions – Root Cause Analysis

GENE also makes the following observations that Exelon may wish to incorporate in the Root Cause Report, but are not critical in our concurrence with the identified root cause:

- All the pressure data presented was obtained from Byron Unit 2. While the geometric similarity between the plants and units makes the presence or absence of the observed noise likely in all the units, additional measurements confirming this are desirable.

- The overall accuracy of the pressure measurements provided in Appendix G could be addressed to assure that the measurements are physically meaningful, and taken at a location where the mode of interest is near its maximum amplitude.

- The historical overpower condition is characterized as 1.56% at Byron 1, 0.33% at Byron 2 and 0.21% at Braidwood 2. No basis for these values is provided in the root cause evaluation. They do not appear to be consistent with the average correction factors at Byron 1 and 2. The cause for the higher overpower at Byron 1 should be established to further understand the significance of any acoustic interference.

- The Cause and Effect analysis should consider the potentially fruitful avenue of Exelon engineering involvement and Exelon plant knowledge (relative to AMAG) to understand how the apparent defects managed to escape detection during initial installation.

Appendix C
Other Potential Actions – Feedwater System Characterization

Other actions that Exelon might consider are provided below. These are provided outside the specific root cause review, and represent general comments by the GENE team:

- Determination of the precise value of the total feedwater flow by a third method, which calibrates the AMAG readings could be performed. A chemical tracer test using sodium or rubidium has been effectively used in BWR applications.

- The physical condition of all feedwater venturi flow meters could be ascertained, and a monitoring program initiated aimed at providing definitive evidence of buildup of or erosion of material in the venturis over time.

- Calibration of the flow venturis and transmitters could be carefully reviewed to determine if there is a basis for the flow measurements to be biased high, as inferred by the AMAG measurements.

Appendix D – Qualification Summary of Principal Contributors

Walt Cooley - GENE Quality Blackbelt
35 years nuclear experience (6 years U.S. Naval Reactors, Reactor Design Branch and 29 years GE Nuclear). BS Chemical Engineering (University of Southern California), MS Nuclear Engineering (Catholic University of America), Registered Professional Engineer (Nuclear Engineering) in California and graduate of the Bettis Reactor Engineering School (Navy PWR technology). Prior experience in Navy PWR reactor equipment design, stress analysis, BWR systems design, and BWR domestic and European plant licensing. Expert in the GENE Instrument Setpoint methodology Program. Currently Quality Blackbelt within GENE Engineering responsible for implementation of Product Data Management systems.

Yogi Dayal - Principal Engineer
Principal engineer in Systems Engineering with over 35 years experience in technical design and plant performance evaluation of BWR instrumentation and control systems. MS and PhD in Engineering Physics - Illinois Institute of Technology - Chicago. Expertise in management and development of in-core sensors, neutron and radiation monitoring systems, and instrument setpoint methodology. Experienced in plant process measurements (including water level, pressure, steam flow, water flow, and temperature), and statistical analysis of plant instrument data.

Ron Engel – Lead Engineer
Lead engineer in Systems Engineering responsible for balance of plant systems, instrument setpoints and probabilistic risk assessments. Over 39 years nuclear experience. BSME (University of California – Berkeley). Expert in safety analysis, system design and analysis, plant and fuel licensing, and instrument setpoints. Former President of S. Levy Inc. an engineering consulting firm primarily involved with nuclear engineering and analysis.

Don Knecht - Lead Engineer
Lead engineer in Systems Engineering responsible for NSSS and NSSS Support system design. Over 35 years nuclear experience. BS Engineering (Stanford University) and MS Nuclear Engineering (UC Berkeley). Expert in safety analysis, system design and analysis. Lead System Engineer for Composite Nuclear System and supervises lead system engineers.

Kam Khuzaie – GENE retiree
Retired from GE Nuclear Energy, 35 years experience in nuclear piping design, analysis and installation. Designer of venturi flow meters for the BWR main steam, feedwater and ECCS systems. MS (mechanical engineering) with California Professional Engineering license. Active member of the ASME main committee on operation and maintenance of nuclear facilities (O&M). Presently, working as a consultant for GENE pre-op and startup and installation of piping and equipment for the Lungmen ABWR project.

John Lynch – Principal Engineer
Principal engineer in Dynamic and Seismic Analysis, expert in Fluid-Structure Interaction and Computational Fluid Dynamics, with 28 years experience in various aspects of engineering. BS in Mechanical Engineering from Carnegie-Mellon University, MS in Mechanical Engineering from University of Pittsburgh. First identified acoustic phenomena as primary oscillating pressure loading on steam dryer. Authored two papers on piping/vessel acoustic interactions with mechanical components. Experienced in many aspects of fluid flow and acoustics, in addition to structural dynamics.

Terry McIntyre – GENE Retiree (Technical Lead)
Retired from GE Nuclear Energy, 35 years nuclear experience. Professional Engineer (Mechanical Engineering) in California. BS Engineering Science (San Francisco State University), MSME (University of California – Berkeley), 60 units post Masters (Leland Stanford Jr. University). Expert in fluid mechanics and heat transfer. Experience includes testing and analysis of containment and ECCS performance. 25 years management experience in home office and field engineering positions. Retired as Manager – Special Projects, reporting to the GENE Chief Engineer.

Ramani Mani - Chief Technologist- Aeroacoustics - GE Global Research
34 years experience at GE in unsteady fluid mechanics and acoustic issues related to propulsion and power generation businesses of GE. BE - Mechanical Engineering - University of Bombay, Bombay, India. MS and PhD in Mechanical Engineering - California Institute of Technology, Pasadena, Calif. Expertise in noise and flow induced vibration problems as they arise in power generation equipment (gas and steam turbines) and in aircraft engines. Experience includes management of a group of about 20 technical staff (for over 25 years) engaged in fluid mechanics research and development at GE Global Research. A primary activity of this group in recent years has been computational fluid dynamics (CFD).

Attachment Q-2, Response to GENE Issues

Item	Location	Description	Resolution
1	Pg 8, 2nd para	**3.1.1. Question 1 - Is it possible/plausible for a low frequency acoustic standing wave (<25 Hz) in the piping system to affect the output of the AMAG ultrasonic flow meter?** However, it was not clearly demonstrated that the magnitude and frequency of acoustic noise actually observed at the plants caused the observed error in plant AMAG readings.	See Resolution for Item #2.
2	Pg 9, 1st para	**3.1.1. Question 1 - Is it possible/plausible for a low frequency acoustic standing wave (<25 Hz) in the piping system to affect the output of the AMAG ultrasonic flow meter?** RECOMMENDED ACTION - GENE Recommends that the Appendix H model be run with actual data from at least two plant loops (preferably all four loops from one plant), but, at a minimum, one with and one without noise contamination to demonstrate that the calculated loop CFs are consistent with the actual loop noise content, and that the loop flows after correcting for the effect of "noise contamination", match the header flow measurement without "noise contamination". The observed bias in the calculated CFs also should be demonstrated to be consistent with the actual plant data.	This recommendation was performed. See Att. **Q-4**.
3	Pg 9, footnote	**3.1.1. Question 1 - Is it possible/plausible for a low frequency acoustic standing wave (<25 Hz) in the piping system to *affect the output of the AMAG ultrasonic flow meter?*** [1] Details such as what impedance boundary condition is assumed at what end (FRV end or steam generator end) and for what location the impedance shown on pages 54 & 55 are plotted, or how the venturi and check valve were handled in terms of matching conditions across them would aid in the evaluation.	Impedance boundary was described as open (for the S/G) and closed (for the FRV). This is still true. Spectral analysis of the noise data has been analyzed for Braidwood Units 1 and 2, see Att. Q-7 and for Byron Unit 1, see Att. Q-8, similar to that done for Byron Unit 2 in Att. G.
4	Pg 12, 2nd para	**Question 3 – Do the pressure measurements in the feedwater system support the existence of acoustic standing waves?** To strengthen the RCR conclusions, GENE recommended that the data presented in Appendix G and Appendix L for Byron be compared on a loop-by loop basis, using consistent scales and formats, to demonstrate a cause-and effect relationship between the measured pressures and the DIAGNOSE acoustic spectra.	This data was sent to GE during their evaluation and is provided in Att. Q-12.

5	Pg 12, 4th para	**Question 3 – Do the pressure measurements in the feedwater system support the existence of acoustic standing waves?** GENE concludes that the data presented in Appendix G augmented by Reference 3 (to be included in the root cause report) provides sufficient information to conclude that an acoustic resonance is likely present in at least the A and D loops of Byron, Unit 2, and that a cause-and-effect relationship has been demonstrated between the measured pressures and the acoustic noise spectrum (from DIAGNOSE) in the locations studied.	GE had requested that we consider doing the GENE Report Ref. 3 evaluation (Att. Q-11) and the revised Att. H for all lines. We told them we would do 2 lines only for the latter and none of the former from new data. When we got into it, we actually did all four Unit 2 lines, vice only two. See Att. Q-4.
6	Pg 14, 2nd para	**3.1.4. Question 4 – Are the presence or absence of evidence of acoustic standing waves in a specific unit/loop consistent with the observed behavior of the ultrasonic flow meters?** GENE also concludes that the plant instrumentation measurements could be further discussed in the report to enhance the conclusion that the postulated standing wave is in fact influencing the AMAG indication.	GENE was concerned that the plant PI data didn't support the standing wave theory due to lack of a high standard deviation. When they understood the PI rules, they wanted a comparison using Point History. (i.e., take Point History data and statistically analyze AND show that the standard deviation is consistent with standing waves. GE concurred that this was not required if Item 2 proved the point, which it did (See Att. Q-4).
7	Pg 15, 5th para	**3.2.2. Question 7 - Does the root cause analysis appear to adequately pursue all opportunities to uncover root cause?** While not required by the Exelon root cause charter, this leads GENE to question whether the Root Cause might lie further upstream in the event process, either in the engineering evaluations leading to the installation or in the adequacy of instrument loop calibration and testing done at the time of installation.	The "Skolds Report" (Braidwood/Byron AMAG Investigation of Organizational Effectiveness and Decision Making, (see ACITs #5 & #6) contains two recommendations, (Obj. #5, Item #4, bullets #3 and #4) associated with Exelon's modification and procurement processes. ATI's 173510-45 and 46 (ACIT5 and ACIT7), and -50 will track assignment of these two recommendations.
8	Pg 15, last bullet	**3.2.3. Question 8 - Does GENE believe the report successfully arrives at root cause (i.e., has the Exelon team delved deep enough into the event)?** This event can fundamentally be viewed as an unsuccessful implementation of AMAG. As such, the key direction that the root cause investigation needs to take is greater focus on the activities leading up	See Item #7.

		to implementation.	
9	Pg 17, 3rd para	**3.3. Evaluation of Causal Factors Assessments** In general, it appears that the Cause and Effect analysis does not pursue the potentially fruitful avenue of Exelon engineering involvement and Exelon plant knowledge (relative to AMAG) to understand how the apparent defects managed to escape detection during initial installation.	See Item #7.
10	Pg 17, last para	**3.4. Evaluation of Corrective Action Appropriateness** CA Number 2 – Investigate Common Feedwater Header for Noise This action presupposes that the root cause is correct. For the AMAG instrumentation to be correct, the lack of acoustic resonance noise is a necessary, but insufficient condition. GENE is concerned that several times during discussions with Exelon/Westinghouse/AMAG the statement was made that the AMAG ultrasonic flow meter will only be used in situations where "there is no noise present", however the definition of "no noise" was never quantified. *CAs 5, 6, 7 and 8 will provide quantification of this issue and address this concern.*	No response required.
11	Pg 18, 1st para	**3.4. Evaluation of Corrective Action Appropriateness** CA Number 3 – Implement Correction Factors based on Common Header AMAG measurements This action may be considered as the "implementation" activity following a positive finding from CA Number 2. *The GENE comments with regard to CA Number 2 also apply here.*	See Item #10.
12	Pg 18, 3rd para	**3.5. Evaluation of Additional Action Appropriateness** AA Numbers 1 & 2 – Obtain additional pressure data GENE concurs with the appropriateness of these items, but notes the desirability to validate the overall accuracy of the measurement system used.	The Validyne DP15 pressure measurement equipment accuracy is ± 0.25% of full scale of 1250 psi, therefore, ± 3.125 psi. The Yokogawa recorder used is normally calibrated to ± 0.5 VAC. Although not pre- and post-cal'd for this particular job, the IM's have stated that these recorders are usually "right on" when pre-and post- cal'd for other jobs. (Because the data was electronically captured, the recorder chart speed accuracy is not a concern.)

13	Pg 18, 4th para	**3.5. Evaluation of Additional Action Appropriateness** AA Number 3 – Compare pressure data and AMAG noise spectrum and improve Root Cause report as necessary. GENE concurs with the appropriateness of this item, as it echoes our findings with regard to the root cause report. Specific recommendations for additional analysis and documentation are presented in Sections 3 and 4, and Appendix B of this report.	Rev 1 to this Root Cause Report addresses this item (i.e., the responses in this matrix). Specifically, Att. O and P were updated. See Att. Q-13 and Q-14.
14	Pg 18, 5th para	**3.6. Evaluation of Safety Assessment Inputs** The report does not provide a derivation of the selection of power level used in the risk assessment. .... It is recommended that the evaluation that led to the selection of the maximum power level be included as an appendix to the RCR or a reference to the supporting evaluations provided.	The basis for the overpower numbers was the difference between the CF on the common header and the CF on the sum of the individual loops as they were known at that time. See Att. Q-6 for determination of the final overpower values. (The numbers as given in the 30-day LER report were based on the difference between the CFs of the individual loops and a CF of 1.0 (i.e., no AMAG)).
15	Pg 19, 2nd para	**3.6. Evaluation of Safety Assessment Inputs** A wide spectrum of events was identified as having been evaluated as a part of the risk assessment. This spectrum of events is very comprehensive. However, the basis for the selection of the events has not been documented, nor have the results of the individual event evaluation been documented. To strengthen the RCR, it is recommended that these evaluations be included as an appendix to the report or a reference to the supporting evaluations provided.	No action required. Section 5, Risk Assessment, clearly references the Westinghouse letter providing the risk assessment.
16	Pg 19, 4th para	**3.7. Overall Report Completeness and Usefulness Assessment** The report does a much better job of documenting the "Is" in the root cause than the "Is-Not".	Att F and CR 91771 provide a detailed evaluation of the "Is-Not" analysis. GENE was offered the opportunity to review CR 91771, but they declined. No further action is necessary.
17	Pg 19, 5th para	**3.7. Overall Report Completeness and Usefulness Assessment** Additional technical details in the analysis sections would assist the reader in understanding the basis for the conclusions.	Piping Takeoffs are provided in Att. **Q-5**. Topical Report CENPD-397-P-A, Rev. 01, May 2000 generally addresses this, section 5.6 in particular. GE had this document for review.

18	Pg 19, 6th para	**3.7. Overall Report Completeness and Usefulness Assessment** The logic taking the reader through the entire process from feedwater system eigenvalues to the pressure measurements, noise spectrum analysis and finally the CF effects (and the data behind them, as noted in the Recommended Action) needs strengthening.	Att. Q-3 provides an overview of the Root Cause Logic used in development of this Root Cause Report.
19	Pg 22, 1st bullet	***Appendix A – Other Potential Phenomena Brainstorm Results*** The possibility exists that the flow turbulence down stream of the FRVs could also influence the AMAG instrumentation. The AMAG qualification was not conducted at Reynolds numbers consistent with the plant applications. It is possible that there are still turbulent effects, although admittedly small, that have not been demonstrated. This should be considered as an additional potential cause of a power dependent impact.	All flow measurement devices feel the effects of upstream disturbance. To provide accurate flow measurement, the effect of this upstream disturbance must be accounted for and established via installation criteria that have to be met to achieve the specified accuracy. For example, the specific flow meter has to be installed at a certain distance downstream of the disturbance. This issue (the consideration of additional flow turbulence downstream of the FRV's) is addressed in the Topical Report CENPD-397-P-A, Rev. 01, May 2000, section 4.2 that GE had for review. It was addressed in the criteria for this installation. [~~PROPRIETARY~~].
20	Pg 22, 2nd bullet	***Appendix A – Other Potential Phenomena Brainstorm Results*** After a few years of operation feedwater venturi flow meters normally collect an iron oxide, gradually deposited on the surface of the nozzle throat. This causes the apparent flow to increase proportionally to the decrease in the throat's diameter. The correction factors account for this trend. However the lack of precise flow calibration measurement could lead to additional errors that have not been taken into account. It is important to determine the precise value of each of the four feedwater flows by a third method, which validates the AMAG readings before establishing the root cause. A chemical tracer test using sodium or rubidium has been effectively used in BWR applications.	The purpose of the installation of the CROSSFLOW meter was to enable correction for the effects of iron oxide deposits. Since these deposits have an overly conservative effect on the venturi flow readings (causing them to read high and the plant to throttle back to stay within their thermal power limit), correction of the venturi readings was expected to show a gain in megawatts for the plants. The contention that there was a lack of a precise flow calibration measurement, or that a THIRD methodology is required is not borne out by the industry or current

			standards. CROSSFLOW and other UFMs are used to monitor flow and do not routinely see use of tracer testing to validate the numbers generated. Topical reports were issued and NRC reviewed/approved on both commonly used UFMs without requiring such a step. By way of comparison, venturis are normally installed and left without added in situ methodology. Where tracer testing is performed, additional monitoring methods are not required to validate the tracer testing. The accuracy of the CROSSFLOW installation was provided by the vendor in the installation calculations, on a unit/line basis.
21	Pg 22, 3rd bullet	***Appendix A – Other Potential Phenomena Brainstorm Results*** In BWR plants, the total FW system accuracy for the BWR/4/5/6 plants ranges between +/-0.8%-+/-0.9% with venturi hardware accuracies requirements of +/-0.25% calibrated to the ASME-PTC-6 Code. The report did not reveal the accuracy of the existing venturi after refurbishment or the AMAG instruments in comparison with the ASMEPTC- 6 calibration standard which requires an accuracy of +/- 0.25%. Without such a comparison, the correction factors could be incorrect since neither indication is precisely known. The report would be strengthened if it addressed the accuracy requirements for total FW system and the specific accuracy requirements for the AMAG hardware.	The venturis were recalibrated at Alden Labs to ±0.25%. The overall venturi calorimetric accuracy is ±1.72%. This is documented in the existing stations calculation NED-I-EIC-0233, Revision 1A and SSCR 97-059. These documents were offered to GE, but refused on the basis that it was enough that the issue was raised and we had the answer. Therefore the issue was moved from the main body of the report to "Appendix A, Other Potential Phenomena Brainstorm Results."
22	Pg 23, 1st bullet	***Appendix B – Other Potential Actions – Root Cause Analysis*** All the pressure data presented was obtained from Byron Unit 2. While the geometric similarity between the plants and units makes the presence or absence of the observed noise likely in all the units, additional measurements confirming this are desirable.	All the Byron and Braidwood units have now had pressure data taken as required by the root cause report ACIT1 and ACIT2. This comment was redundant to existing commitments in the root cause report.
23	Pg 23, 2nd bullet	***Appendix B – Other Potential Actions – Root Cause Analysis*** The overall accuracy of the pressure measurements provided in Appendix G could be addressed to assure that the measurements are	Exelon's Byron and Braidwood stations have limited points where pressure measurements can be taken, as noted

		physically meaningful, and taken at a location where the mode of interest is near its maximum amplitude.	during conversations with GE. The original purpose of the actual pressure was to validate that our model was correct. While Exelon could address the overall accuracy of the pressure measurements in Appendix G, it is not seen as a value added activity at this point. The data obtained was believed to be reasonable for the purpose of confirming the existence of piping acoustic behavior, with the limitations recognized. The overall accuracy could be considered an enhancement or lessons learned to improve our process. GE concurred with these observations, and moved the point into the "Appendix B, Other Potential Actions- Root Cause Analysis" as something the Exelon 'may wish to incorporate in the Root Cause Report, but are not critical to... GE]...concurrence with the identified root cause."
24	Pg 23, 3rd bullet	***Appendix B – Other Potential Actions – Root Cause Analysis*** The historical overpower condition is characterized as 1.56% at Byron 1, 0.33% at Byron 2 and 0.21% at Braidwood 2. No basis for these values is provided in the root cause evaluation. They do not appear to be consistent with the average correction factors at Byron 1 and 2. The cause for the higher overpower at Byron 1 should be established to further understand the significance of any acoustic interference.	See Item #14.
25	Pg 23, 4th bullet	***Appendix B – Other Potential Actions – Root Cause Analysis*** The Cause and Effect analysis should consider the potentially fruitful avenue of Exelon engineering involvement and Exelon plant knowledge (relative to AMAG) to understand how the apparent defects managed to escape detection during initial installation.	See Item #7.

26	Pg 24, 1st bullet	***Appendix C - Other Potential Actions – Feedwater System Characterization*** Other actions that Exelon might consider are provided below. These are provided outside the specific root cause review, and represent general comments by the GENE team: Determination of the precise value of the total feedwater flow by a third method, which calibrates the AMAG readings could be performed. A chemical tracer test using sodium or rubidium has been effectively used in BWR applications.	Exelon concurs that determination of the value of the total feedwater flow by a third method, which could be used to "calibrate" the AMAG readings could be performed. The reasons that this is not required are given in the response to Item #20 above.
27	Pg 24, 2nd bullet	**Appendix C - Other Potential Actions – Feedwater System Characterization** Other actions that Exelon might consider are provided below. These are provided outside the specific root cause review, and represent general comments by the GENE team: The physical condition of all feedwater venturi flow meters could be ascertained, and a monitoring program initiated aimed at providing definitive evidence of buildup of or erosion of material in the venturis over time.	The physical condition of all feedwater venturi flow meters is ascertained during each refueling outage by use of "predefines" for physical cleaning and internal inspections of the existing venturis. This serves to meet the description of "a monitoring program initiated aimed at providing definitive evidence of a buildup of or erosion of material in the venturis over time."
28	Pg 24, 3rd bullet	**Appendix C - Other Potential Actions – Feedwater System Characterization** Other actions that Exelon might consider are provided below. These are provided outside the specific root cause review, and represent general comments by the GENE team: Calibration of the flow venturis and transmitters could be carefully reviewed to determine if there is a basis for the flow measurements to be biased high, as inferred by the AMAG measurements.	Historical data on calibrations of the flow venturis and transmitters was provided to GE. This Exelon documentation review recommendation was proposed as an enhancement to the root cause as a general comment of something that Exelon might consider performing. It is recommended for feedwater system characterization, not for the technical root cause. Although Exelon concurs that this could be done, it is not a value-added activity from a root cause standpoint.

ROOT CAUSE LOGIC

A root cause team was chartered to determine the causes for: 1) the Correction Factors (CF) varying with power level; 2) the CF's not being linear with feedwater venturi output; 3) the AMAG flow signal contamination source; and 4) why the difference between the sum of the individual loop flows and the common header flow exceeded the acceptable statistical limit of the AMAG installation.

The root cause concluded that the error in feedwater flow measurement was due to noise on the demodulated ultrasonic flow signal, and further, that it came from acoustic resonant response from the feedwater piping system. This signal noise causes a phase shift error in the demodulated signal that is then used to calculate the time delay for an eddy to pass between the planes of the ultrasonic signals. It was speculated that, due to regular spacing of the noise signals on the AMAG DIAGNOSE software that the noise was caused by acoustic effects from the piping. To examine this, an acoustic model was put together for the feedwater piping, and the cyclic noise signal was seen. The best fit for the acoustic model was for an "open-closed" system (open at the Steam Generator (S/G) and closed at the FW Regulating Valves (FWRVs)). Within this open-closed system model, the only significant pressure drop, and therefore the driver of the acoustic noise, was the FWRVs, thus answering item #3. It was concluded from this that the speculated cause was potentially credible, and actual plant data was taken on Byron Unit 2. This actual plant data showed that acoustic noise was present at the frequencies seen in the AMAG DIAGNOSE software. Additionally, a model was assembled for the AMAG clean signal and for a typical noise signal as seen on DIAGNOSE. When the noise was introduced to the clean signal, it caused an error in the time delay calculation. Sensitivities performed found that the magnitude of the error was dependent on the amplitude of the noise, the frequency of the noise and the specific time delay for the Crossflow installation. It was also demonstrated that the error increased with increasing power. This supplied the answer to items #1 and #2.

In parallel with the acoustic modeling and the AMAG noise simulation, other potential causes for the signal error were reviewed and determined not to apply. This included such items as cabling length, cable looseness, mercury lamp or ham radio signals, cable continuity, transducer alignment and pressure on the pipe, transducer torque, transducer cleanliness, transducer capacitance and inductance, software errors, physical measurement errors. Where these had been previously examined and documented, the data was reviewed and conclusions drawn. Att. F and CR 91771 document these evaluations. These other potential errors did not provide any contributors.

It was determined that the prior common header measurement compared to the sum of the individual loops was performed at a reduced power level due to coastdown into B1R11. This original measurement had fallen just within the acceptance limit. The modeling performed that demonstrated noise effects increased with increasing power levels explains why the increase in error occurred at full power, and answers item #4, provided that the common header was reading accurately. Noise data taken with the AMAG DIAGNOSE software showed that the common header had no noise, so the CF from this source would be expected to remain constant over the power range from the coastdown value (92% power) to full power, while the individual loop CF

errors would be expected to increase for the same increase in power. To test this, CF data was taken on Byron Unit 2 during a TV/GV test from the main header CROSSFLOW bracket for a downpower to ~80%, and at ~85% power, ~90% power and before and after the TV/GV test at full power. The power level was to be held constant at the various levels to allow the AMAG statistics to become meaningful. When the actual data was taken, the power levels at full power and at ~90% were held nearly constant, while the power levels crept up over time at the 80% power and at ~82% power levels. Despite this, the percent standard deviation was 0.0004% for the entire test. The CF was demonstrated to be identical at the 90 and 100% power levels, and had minor deviations from this CF at the 80 and 82% power levels that are attributable to fluctuations in the power level. This provided assurance that the cause of the change in common header vs. sum of individual loops with changing power came from the individual loops.

Pages 154 through 167 redacted for the following reasons:

Exemption 4

App Q-5, Piping Takeoffs (Pg 1 of 31)

Byron 1 Loop A							
feet	inches	sixteenths			12	16	
15	8	0	S/G				
11	9	4					
15	0	4			need 5 ms sample on acoustics		
6	2	2					
6	5	2				Sensotech probes	
24	0	8				Yokogawa recorders	
3	0	0	WALL			x2955 Mike Cray	
3	9	10					
7	0	14					
4	0	0					
2	7	0		106	1	0	
4	0	8		4	4		
2	5	12	inlet of FW079 Check	102	45	64	
18	2	4					
1	5	3					
3	0	0					
14	1	7					
9	3	0					
23	6	0					
19	0	0					
3	6	0					
6	9	0					
9	0	0					
17	0	0		131	2	14	
5	0	0	Column P	3	0		
1	6	0	outlet venturi weld	128	38	14	
12	0	0	Inlet venturi weld				
3	6	0	Column N				
9	0	0	Column M				
26	0	0	Column L				
3	6	0					
1	9	0					
18	0	0	vertical				
13	6	0		107	0	0	
12	9	0		3	0	0	
7	0	0	outlet of FW reg valve	104	36	0	
			total length	344	3	14	

App Q-5, Piping Takeoffs (Pg 2 of 31)

Byron 1 Loop B							
feet	inches	sixteenths			12	16	
30	8	10	S/G				
10	6	6					
11	8	6					
3	0	0					
2	4	0					
1	10	0					
24	7	0					
3	0	0					
10	10	10					
4	0	0					
2	7	0		111	8	4	
4	0	8		5	3		
2	5	12	Inlet to FW 079 Check Valve	106	65	52	
1	10	8					
6	0	0					
0	10	0					
2	9	0					
1	11	0					
23	8	8					
14	8	0					
2	2	10					
25	5	12					
26	7	3					
16	10	8					
1	3	0					
8	5	0					
26	6	6					
26	0	8					
8	11	0					
17	11	0					
15	0	0					
3	10	12					
26	3	0					
11	10	13					
11	7	3					
19	0	0					
7	3	0					

App Q-5, Piping Takeoffs (Pg 3 of 31)

6	0	0		338	1	11	
19	3	0		13	5		
6	0	0	Outlet weld from venturi	325	152	91	
11	11	10	Inlet weld from venturi				
4	0	6	Column Line N				
9	0	0	Column Line M				
26	0	0	Column Line L				
3	6	0					
17	3	0					
3	2	8					
3	2	0					
18	8	8					
13	0	0					
4	0	0		133	7	0	
16	9	0		3	2		
3	0	0	FW Reg valve outlet	130	41	32	
			Total pipe	583	4	15	

App Q-5, Piping Takeoffs (Pg.4 of 31)

Byron 1 Loop C								
feet	inches	sixteenths			12	16		
15	8	0	S/G					
16	9	14						
9	5	4						
10	5	2						
7	0	14						
13	8	0						
7	0	14						
12	1	0						
12	0	4						
12	2	12						
14	4	8						
7	10	0						
0	8	0						
2	0	0						
7	1	0						
4	0	0						
2	7	0		161	6	12	FW 79 valve to S/G	
4	0	8		6	5			
2	5	12	inlet to check valve	155	73	92		
9	3	10						
16	11	10						
2	5	2						
23	9	14						
2	0	0						
8	8	6						
86	10	4						
92	6	0						
14	6	0						
6	0	0						
19	0	0						
9	3	0						
23	6	0						
19	0	0						
3	6	0						
15	0	0		358	9	14	Venturi to 79 valve	
5	0	0		6	2			
1	6	0	outlet weld of venturi	352	79	46		

12	0	0	inlet weld to venturi					
3	6	0						
9	0	0						
26	0	0						
3	6	0						
18	0	0						
6	10	0						
19	1	0						
12	9	0						
4	0	0						
7	10	0		125	6	0		
0	6	0		4	0		FW Reg valve to venturi	
2	6	0	Outlet of FW reg valve	121	54	0		
			total length	646	10	10		

App Q-5, Piping Takeoffs (Pg 6 of 31)

Byron 1 Loop D									
feet	inches	sixteenths			12	16			
8	9	14	S/G						
14	1	4							
18	2	8							
11	0	0							
4	9	4							
13	10	6							
12	8	4							
14	8	8							
6	2	4							
14	9	0							
7	10								
12	9	8							
2	1			153	10	0	S/G to FW 79 check valve		
9	6	8		7	5				
2	5	12	FW 79 Inlet	146	89	80			
10	0	12			12	16			
1	5	13							
2	10	0							
11	7	3							
19	0	0							
7	3	0							
7	6	0							
10	6	0							
6	0	0		101	5	12	Venturi to check valve		
19	3	0		3	1				
6	0	0	Venturi outlet weld	98	40	28			
11	11	13	Venturi Inlet weld						
4	0	3	Column N						
9	0	0	Column M						
26	0	0	Column L						
3	6	0							
1	9	0							
17	3	0	Vertical						
11	3	0		113	8	0	FW Reg valve to Venturi		
13	0	0		3	1				
15	11	0	FW Reg valve outlet	110	43	16			
			total length	368	11	12			

App Q-5, Piping Takeoffs (Pg 7 of 31)

Byron 1 Comon Header							
feet	inches	sixteenths					
3	8	first tee	Feed Reg Valve inlet common				
8	7		Feed Reg Valve inlet common				
3	8	last tee	Feed Reg Valve inlet common				
6	2	7	Cleanup loop				
20	3	15					
4	8	4					
8	3	12					
16	9	12			Common Bracket		
5	4	6					
9	1	12					
1	9						
24	4	8					
24	4	8					
24	4	8					
12	4	8					
22	7	0					
14	7	2					
11	10	0					
13	6	0					
25	0	0					
6	5	0					
5	7		B heater takeoff				
14	7	4		295	8	14	
2	6	6	A heater takeoff	11	7		
5	0	14	30x20 reducer to heater bypass line	284	133	126	
25	2	2	to elbow downstream of reducer				
29	3	0					
6	6	0					
10	7	8					
3	2	8		86	8	2	
3	5	0		2	1		
8	6	0	to 30x30x20 Tee on inlet side of FW heaters	84	31	18	
19	4	8					
17	3	0					
24	4	0					
20	4	8					
1	0	0					

1	0	0					
2	0	0					
5	5	4					
6	4	10					
7	10	12					
5	9	0					
7	4	0	includes 30x24 reduction to pump pipe	132	3	10	
9	2	0		4	2		
5	0	0	to pump	128	49	42	
TOTAL COMMON LINE FROM PUMP TO FWRV				514	8	10	
FW Heater A branch line							
6	1	0	Vertical				
12	6	0	Horizontal				
5	0	0	45° down				
5	0	0	Horizontal				
1	10	0	horizontal to valve				
3	2	0	Valve				
5	7	0	from valve	51	0	0	
8	2	0	to 55° bend	3	0		
3	8	0	FW heater nozzle	48	36	0	
51	0	0					
FW Heater B Branch line							
7	9	0	Vertical				
8	10	0	Horizontal				
5	0	0	45° down				
1	7	0	Horizontal				
2	7	8	horizontal to valve				
3	2	0	Valve				
6	7	0	valve to elbow	47	0	8	
7	10	0	to 55° bend	5	0		
3	8	0	FW heater nozzle	42	60	8	
47	0	8					

App Q-5, Piping Takeoffs (Pg 9 of 31)

Byron 2 Loop A						
feet	inches	sixteenths			12	16
3	3	10	S/G			
5	3					
11	10	12				
16	8					
13	10	12				
5	10	10				
13	8					
6	2	4				
6	5	2				
23	0	6				
7	10					
1	10	8				
7	1	0	3" pipe tap BDC			
4	0	0				
2	7	0				
1	0	0	3" pipe tap TDC			
0	4	8	6" pipe tap BDC	135	9	12
2	4	8		8	5	
2	5	12	inlet to FW 079 check valve	127	100	92
13	8	11				
14	1	8				
61	11	10				
9	0	2		124	7	1
19	3	2		2	2	
6	6	0	Outlet venturi weld	122	29	33
12	0	0	Inlet venturi weld			
3	6		Column line N			
9	0	0	Column Line M			
26	0	0	Column Line L			
5	3	0				
18	0	0				
12	7	0				
12	9	0		108	2	0
7	1	0		2	0	
2	0	0	Outlet of FW Reg Valve	106	26	0
			total length	368	6	13

App Q-5, Piping Takeoffs (Pg 10 of 31)

Byron 2 Loop B						
feet	inches	sixteenths			12	16
3	3	4	S/G			
4	9	10				
12	5	8				
10	7	3				
7	5	4				
9	8	6				
3	9	14				
13	8	7				
7	4	13				
4	3	8				
22	10	12				
7	10	0				
1	9	6	1" Pipe tap TDC			
7	1	0	3" pipe tap BDC			
4	0	0				
2	7	0				
1	4	0	6" pipe tap BDC	130	3	11
2	10	0		10	6	
2	5	12	Inlet FW 79 check valve	120	117	107
9	5	4				
2	9	12				
1	11	0				
23	10	8				
86	11	4				
106	9	6				
75	11	6				
6	0			334	8	12
15	0	4		5	2	
6	0	0	Outlet venturi weld	329	66	44
11	11	10	Inlet venturi weld			
39	11	10				
17	3	8				
3	3	0				
18	9	0				
13	0	8				
4	0	0		130	0	4
19	9	0		4	2	

2	0	0	Outlet FW Reg valve	126	46	36
			Total length	595	0	11

Byron 2 Loop C						
feet	inches	sixteenths			12	16
1	3	8	S/G			
2	8					
3	3	14				
10	8	0				
17	1	2				
10	5	8				
7	0	8				
13	8	3				
7	0	12				
12	1	0				
12	0	4				
12	2	12				
14	3	0				
7	10	0				
1	10	0	1" pipe tap TDC			
7	1	2	3" pipe tap BDC			
4	10	0				
2	7	0				
1	0	0	3" pipe tap TDC			
0	3	8	6" pipe tap BDC	154	6	13
2	9	0		8	5	
2	5	12	Inlet FW 079 check valve	146	97	93
10	0	9				
45	3	1				
95	11	1				
112	6	1				
74	2	15		359	5	15
15	0	4		2	1	
6	6	0	Venturi outlet weld	357	28	31
12	0	0	Venturi inlet weld			
3	6	0	Column Line N			
9	0	0	Column line M			
26	0	0	Column Line L			

App Q-5, Piping Takeoffs (Pg 12 of 31)

3	6	0				
18	9	0				
12	9	0				
4	0	0		102	3	0
10	9	0		3	0	
2	0	0	Outlet of FW Reg Valve	99	39	0
			total piping length	616	3	12

App Q-5, Piping Takeoffs (Pg 13 of 31)

Byron 2 Loop D						
feet	inches	sixteenths			12	16
2	8	0	S/G			
1	3	0				
3	3	12				
10	2	8				
12	0					
14	4					
4	9					
13	8	8				
12	8	6				
14	8	12				
6	2	9				
14	8	12				
7	10	0				
1	10		1" vent TDC			
7	1		3" pipe BDC			
4	0	0				
2	7	0				
1	0	0	3" pipe TDC			
0	6	0	6" pipe BDC	140	7	1
2	8	2		9	5	
2	5	12	Inlet to FW 079 Check valve	131	110	81
9	3	15				
1	5	13				
2	10	0				
45	4	4				
16	6	8		100	9	10
19	3	2		2	2	
6	0	0	Venturi Outlet weld	98	31	42
12	0	0	Venturi Inlet weld			
4	0	0	Column Line N			
9	0	0	Column Line M			
26	0	0	Column Line L			
5	3	0				
17	3	0				
11	3	0	fraction illegible			
13	0	0		115	7	4
16	1	4		1	0	

1	9	0	Outlet of FW Reg Valve		114	19	4
			total pipe length		356	11	15

Byron 2 Common Header						
3	8	0	first to 2nd reg valve			
8	7	0	2nd to 3rd tee			
3	0	0	third to 4th tee			
7	2	4				
25	1					
8	1	10				
16	0	0				
14	11	2				
87	3	4				
8	6	0				
13	9	0				
14	8	10				
11	9	2				
13	6	0				
11	11	14				
19	3	0				
5	10	12	to 2B heater tee	295	5	10
17	2	8	to 2A heater tee	8	4	
5	0	8	to reducer	287	97	74
1	10	12	Reducer			
23	2	2	from reducer			
29	3	2				
6	4	8				
11	2	4				
5	0	0		86	5	4
1	0	8		2	2	
8	6	0		84	27	36
			total downstream of htrs	381	10	14
Heater A						
7	8	4				
11	0	0				
4	11	8				
4	10	12				
5	1	0		41	10	8
3	3	0		2	1	
5	0	0		39	33	24

App Q-5, Piping Takeoffs (Pg 15 of 31)

Heater B						
6	0	0				
12	6	0				
4	11	4				
6	1	12				
5	1	0		42	8	0
3	0	0		1	1	
5	0	0		41	19	16

App Q-5, Piping Takeoffs (Pg 16 of 31)

Brwd 1 Loop A							
feet	inches	sixteenths		Based on drawing 1FW-02 From SG-1A back to FW-079 valve		12	16
15	8	0	SGA				
11	9	1					
15	0	4					
11	8	0					
6	2	0					
7	2	0					
1	8	8					
3	9	8					
19	1	8					
7	7	8					
1	9	0					
6	1	4					
1	0	0					
3	0	0					
1	0	0					
2	7	0			120	8	9
2	0	0			6	2	
3	7	0	FW-079A		114	78	41
0	9	0		Duplicate			
2	2	8	wall	Duplicate			
17	9	0					
1	8						
2	9	8					
14	1	8					
60							
9					141	0	0
17	8				3	1	
18				Inlet of venturi	138	35	16
44	4						
18	2						
12	6						
11	7						
4	1				97	0	8
3	0	0			2	0	
3	4	8		FWRV outlet	95	24	8
				total	358	9	1

App Q-5, Piping Takeoffs (Pg 17 of 31)

Brwd 1 Loop B							
feet	inches	sixteenths		Based on drawing 1FW-03 From SG-1B back to FW-079 valve		12	16
15	8	0	SG 1B				
10	6	6					
15	10	10					
11	8	0					
7	6	14					
4	2	8					
6	11	10					
2	2	6					
15	2	0					
7	7	8					
0	5	4					
1	9	14					
4	3	12					
2	9	4					
3	0	0					
0	4	4					
0	2	6					
0	1	10					
2	11	0			118	8	12
1	8	8			10	7	
3	7	0	1FW-079B		108	121	124
2	10	10	wall	Duplicate			
1	11						
6	6						
0	7						
2	10						
1	6						
23	9	14					
193	10	4					
75	0						
6	0				349	4	2
19	4				5	1	
18	0		Venturi		344	63	18
42	3						
17	6						
6	9						
18	8						

App Q-5, Piping Takeoffs (Pg 18 of 31)

13	0						
3	1						
13	8	8			121	4	0
3	0				3	1	
3	4	8	FWRV		118	39	16
				Total	589	4	14

App Q-5, Piping Takeoffs (Pg 19 of 31)

Brwd 1 Loop C							
feet	inches	sixteenths		Based on drawing 1FW-04 From SG-1C back to FW-079 valve		12	16
15	8	0	SG 1C				
16	9	11					
9	5	4					
10	5	12					
7	2	8					
13	8	4					
7	1	8					
12	0	12					
3	7	8					
8	8	8					
12	4	12					
8	0	4					
6	5	2					
7	10	0					
1	11	0					
2	7	0					
4	6	0					
3	0	0					
1	0	0					
2	7	8			160	7	13
1	11	8			10	6	
3	7	0	FW-079C		150	121	109
2	9	7	to wall	Duplicate			
2	4						
6	0						
1	0						
48	3	10					
28	1	10					
208	6	10					
74	8				402	5	14
15	0				2	1	
18	6		Venturi		400	28	30
41	8						
18	2						
6	9						
19	2						

App Q-5, Piping Takeoffs (Pg 20 of 31)

11	7						
4							
7	10	8			115	7	0
3					3	1	
3	4	8	FWRV		112	42	16
				TOTAL	678	8	11

App Q-5, Piping Takeoffs (Pg 21 of 31)

Brwd 1 Loop D							
feet	inches	sixteenths		Based on drawing 1FW-01 From SG-1D back to FW-079 valve		12	16
8	9	14	SG-1D				
14	4	4					
18	2	8					
11	0	0					
4	9	0					
13	8	6					
12	8	4					
5	8	0					
8	0	4					
0	11	0					
6	1	4					
11	3	8					
3	6	8					
7	7	8					
1	9	4					
7	0	10					
3	0	4					
0	11	12					
2	6	6			147	8	8
0	11	8			10	7	
4	8	8	FW-079D		137	121	120
0	6	0	to wall	Duplicate			
10	8						
1	8						
2	10						
45	4						
16	6				114	4	0
19	4	0			3	0	
18	0	0	Venturi		111	40	0
42	3						
7	9	6					
16	11						
11	3						
13							
3							

10	1	4			110	8	2
3	0				2	1	
3	4	8	FWRV		108	31	18
				Total	372	8	10

NOTE: Braidwood Unit 1 Common Header isometric drawings were illegible. Byron Unit 1 dimensions were used for Braidwood Unit 1.

App Q-5, Piping Takeoffs (Pg 23 of 31)

Brwd 2 Loop A							
feet	inches	sixteenths		Based on drawing 2FW-02 From SG-2A back to FW-079 valve		12	16
3	3	6	SG 2A				
2	1	10					
3	1	0					
12	1	12					
16	8	0					
13	10	8					
5	11	4					
13	8	0					
6	2	2					
6	5	2					
2	8	0					
7	5	4					
13	0	0					
7	2	0					
1	7	8					
5	0	14					
2	0	0					
4	0	0					
2	7	0			134	6	6
2	0	0			7	4	
3	7	0	FW-079A		127	86	70
3	0	4	to wall	Duplicate			
14	8						
3	8						
1	6						
2	10						
13	6						
62	0	12					
9	0						
9	0	2			130	8	14
8	0				3	0	
6	6		Venturi out		127	44	14
12	0						
37	11	12					
6	9						

App Q-5, Piping Takeoffs (Pg 24 of 31)

18	0	12					
12	6						
12	9						
2	6						
1	7				110	6	0
3	0				4	2	
3	4	8	FWRV		106	52	32
				Total	375	9	4

App Q-5, Piping Takeoffs (Pg 25 of 31)

Brwd 2 Loop B							
feet	inches	sixteenths		Based on drawing 2FW-03 From SG-2B back to FW-079 valve		12	16
3	3	2	SG-2B				
4	9	0					
12	5	4					
10	7	4					
7	5	6					
9	8						
3	10	14					
13	8	0					
4	3	0					
11	3	0					
5	8	2					
6	2	0					
7	8	10					
5	6	8					
6	0	12			121	9	14
5	10	0			8	3	
3	7	0	2FW-079B		113	102	62
1	9	0	to wall	Duplicate			
9	5	4		Used Byron 2 data, Bwd data illegible			
2	9	12		Used Byron 2 data, Bwd data illegible			
1	11	0		Used Byron 2 data, Bwd data illegible			
23	10	8		Used Byron 2 data, Bwd data illegible			
86	11	4		Used Byron 2 data, Bwd data illegible			
106	9	6		Used Byron 2 data, Bwd data illegible			
75	11						
6	0						
9	0				338	11	2
10	3				5	2	
6	0		Venturi out		333	69	34
11	11						
42	6	8					
17	3						
6	9						
18	9						
13	0						

App Q-5, Piping Takeoffs (Pg 26 of 31)

4	0				137	4	0
19	9				4	1	
3	4	8	FWRV		133	51	16
				Total	598	1	

App Q-5, Piping Takeoffs (Pg 27 of 31)

Brwd 2 Loop C							
feet	inches	sixteenths		Based on drawing 2FW-04 From SG-2C back to FW-079 valve		12	16
1	4	0	SG 2C				
2	8	0					
3	3	6					
3	6	0					
7	2	10					
5	0	10					
12	0	8					
10	5	6					
7	0	2					
13	8	4					
7	1	0					
12	1	0					
11	6	14					
12	8	0					
14	5	10					
7	3	12					
1	9	4					
7	0	12					
2	9	0					
1	3	0					
2	7	0			152	5	10
2	0	0			8	6	
3	7	8	2FW079C		144	95	106
2	10		to wall	Duplicate			
10	0	9		Copied from Byron 2C			
45	3	1		Copied from Byron 2C			
95	11	1		Copied from Byron 2C			
112	6	1		Copied from Byron 2C			
74	1	8					
7	0	8			359	4	12
8	0				2	1	
6	6		Venturi		357	27	28
12	0						
42	1						
18							

App Q-5, Piping Takeoffs (Pg 28 of 31)

6	9						
19	3						
12	9						
4	0						
3	3						
4	6				128	11	8
3	0				2	0	
3	4	8	FWRV		126	35	8
				Total	640	9	14

App Q-5, Piping Takeoffs (Pg 29 of 31)

Brwd 2 Loop D							
feet	inches	sixteenths		Based on drawing 2FW-01 From SG-2D back to FW-079 valve		12	16
3	3	6	SG 2D				
6	4	0					
3	10	8					
11	11	12					
14	3	12					
4	9	0					
13	8	0					
9	1	14					
3	6	8					
14	8	8					
6	2	2					
10	0	6					
4	8	10					
7	10						
3	10						
4	11	4					
2	9						
1	3						
2	7				135	5	2
2	1				11	6	
3	7	8	2FW 079D		124	131	98
2	9	8	to wall	Duplicate			
9	3	15		Copied from Byron 2D			
1	5	13		Copied from Byron 2D			
2	10	0		Copied from Byron 2D			
45	4	4		Copied from Byron 2D			
16	6	8		Copied from Byron 2D	100	9	10
19	3	2		Copied from Byron 2D	2	2	
6	0	0	Venturi	Copied from Byron 2D	98	31	42
12	0	0		Copied from Byron 2D			
4	0	0		Copied from Byron 2D			
9	0	0		Copied from Byron 2D			
26	0	0		Copied from Byron 2D			
5	3	0		Copied from Byron 2D			
17	3	0		Copied from Byron 2D			
11	3	0		Copied from Byron 2D			

App Q-5, Piping Takeoffs (Pg 30 of 31)

13	0				117	2	8
16	1				1	0	
3	4	8	FWRV		116	14	8
				TOTAL	353	5	4

App Q-5, Piping Takeoffs (Pg 31 of 31)

Brwd 2 Common Header							
25	2	2	FW Htr bypass				
5	0	14					
17	3						
5	9						
19	3						
12	0						
13	6						
11	9						
14	9						
22	3						
87	3						
14	10	3					
8	1	9					
16	3						
22	7						
6	8						
3	0						
3	8						
8	7				323	2	12
3	8				9	1	
1	10		Cap	Total	314	109	28

Attachment Q-6, Determination of AMAG Overpower Level (Pg 1 of 2)

In support of the AMAG root cause investigation, the amount of potential overpower was required to be determined. The presentation below details how the amount of overpower was determined as well as a summary of transmittals to Westinghouse.

Due to the AMAG correction factor effectively being a multiplier upon the feedwater mass flow rate, the following equation was utilized to remove AMAG corrections from the calorimetric calculation to determine a maximum overpower condition utilizing only the uncorrected feedwater flow signal.

$$Power = \frac{Calorimetric}{C_f}$$

where: *Power* is the overpower condition
Calorimetric is the 8 hour average calorimetric reading
C_f is the average of all AMAG correction factors in place at the time of the calorimetric

The most limiting value for overpower (peak overpower) is the maximum value of calorimetric corresponding to a given minimum correction factor (C_f). Data to support this calculation was obtained from PI for 3 years of operation on both Byron units and resulted in the following bounding value:

$$Power = \frac{99.967529}{0.9741499} = 102.62\ \%$$

This value of 102.62 % power is the peak overpower possible and was utilized in confirming the safety parameters for both Byron units. The specific values given above in this calculation occurred on 5/9/03 for Byron Unit 1. This value of overpower (i.e. 2.6%) was found to be a bounding value for all plants under which the safety analysis was performed for the period during which AMAG was implemented.

The analogous value for Byron Unit 2 is:

$$Power = \frac{99.917755}{0.980875} = 101.87$$

For both Byron Unit 1 and Unit 2, to determine a more realistic value of overpower, the overpower values obtained from the calculation above were multiplied by the common header correction factors determined as part of the root cause investigation. The correction factors utilized were 0.991 and 0.9857 for Byron Units 1 and 2, respectively. For example, the highest realistic overpower condition based upon the common header for Byron Unit 1 is determined to be:

$$CommonHeader = 102.62 * 0.991 = 101.70\,\%$$

Attachment Q-6, Determination of AMAG Overpower Level (Pg 2 of 2)

The analogous value for Byron Unit 2 is:

$$CommonHeader = 101.87 * 0.9857 = 100.41$$

For clarification, the values detailed above are the worst-case values; specific calculations for each day in which AMAG correction factors were not equal to 1 were determined. The results presented here represent the worst-case values from the calculations performed.

A summary table of formal design information transmitted from Byron to Westinghouse to support the safety evaluation for Byron units follows.

TODI Number	TODI Title	Purpose
BYR-03-028 Rev. 1	Best Estimate Values for Byron Unit 1 Cycle Depletions – Revision 1	This Transmittal provides data regarding the Byron Station Unit 1 for cycle depletion to account for AMAG overpower conditions. To provide plant data to support B1C13 nuclear design.
BYR-03-030 Rev. 0	Byron Unit 1 Safety Analysis Parameters	This Transmittal provides data regarding Byron Station Unit 1 for safety analyses from the AMAG constant overpower conditions. The data provided includes Steam Generator tube plugging and RCS flow, power and temperatures.
BYR-03-031 Rev. 0	Best Estimate Byron Unit 2 Safety Analysis Parameters	This Transmittal provides data regarding Byron Station Unit 2 for safety analyses from the AMAG constant overpower conditions. The data provided includes Steam Generator tube plugging and RCS flow and power.
BYR-03-032 Rev. 0	Byron Unit 1 and 2 Safety Analysis Parameters	This Transmittal provides data regarding Byron Station Unit 1 and Unit 2 for safety analyses from the AMAG constant overpower conditions. This data concerned load rejection events and plant response/ramp data.
BYR-03-033 Rev. 0	Best Estimate Values for Byron Unit 1 Cycles 11 and 12 RCS Parameters	This Transmittal provides data regarding the Byron Station Unit 1 operation for cycles 11 and 12. This data was detailed thermal hydraulic parameters for Byron Unit 1 Cycles 11 and 12 for use in Safety Analysis evaluation.
BYR-03-035 Rev. 0	Best Estimate Values for Byron Unit 2 Cycles 9 -11 RCS Parameters	This data was detailed thermal hydraulic parameters for Byron Unit 2 Cycles 9 through 11 12 for use in Safety Analysis evaluation.
BYR-03-036 Rev. 0	Overpower for Evaluation of Byron Unit 1 Cycle 10 and 11 and Byron Unit 2 Cycles 9 -11	This information explains the derivation of the overpower values utilized in the evaluation for past operation for Byron Units 1 and 2.
BYR-03-037 Rev. 0	Best Estimate Values for Byron Unit 2 Cycle Depletions	This Transmittal provides data regarding the Byron Station Unit 2 for cycle depletion to account for AMAG overpower conditions. To provide plant data to support B2C12 nuclear design.
BYR-03-039 Rev. 0	Data for Overpower Evaluation of Byron Unit 1 and 2	This transmittal concerns both Byron units in regards to the RAOC/CAOC bands, as well as the frequency of load follow maneuvers.

Introduction

The potential for piping acoustical response to affect the accuracy of AMAG ultrasonic flow measurement processes has been previously postulated and demonstrated at Byron Station. Braidwood Units 1 and 2 have similar geometrical properties and employ the same feedwater flow measurement techniques as do the Byron units. A series of dynamic pressure measurements was taken on Braidwood Units 1 and 2 on October 10, 2003 to facilitate determination of the extent to which the Braidwood AMAG flow instrumentation may be affected. The purpose of this document is to capture the results of the data reduction as well as provide some physical interpretation.

Data Description

Measurements were taken on the B and D feedwater lines in the steam tunnel and on the common header for both units. Four sets of data were taken for each location, at a frequency of 200 hz. Approximately 50000 data points were gathered for each set of data. The data was provided in terms of volts, with 10 volts being equivalent to 1250 psi. The data was reduced using the Mathcad software program in the following way: First the mean was calculated and 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. As a check of the transformation process, the inverse transform of each Fourier data set was taken and plotted along with the original data.

The processed data prior to Fourier reduction is plotted for each set. These plots represent the conversion of the provided voltages to pressures, followed by subtraction of the data set mean value. The plots are provided in Attachment A. Review of the data in this form provides two key observations. The first is that the Unit 1 B and D line pressure data shows significant discontinuities at irregular intervals, which is in sharp contrast to the U1 common header and all of the Unit 2 data. The pressure variations at the discontinuities are very large and are not physical, particularly since the common header data shows no evidence of pressure cycling consistent with the discontinuities in the B and D lines. The most likely source of this type of discontinuity would be loose or intermittent electrical connections in the test circuit. The remaining data minus the discontinuities appears to be reasonable and representative. Therefore for Unit 1, subsets of the data excluding the discontinuities will be used for the spectral analysis. The second point that can be observed, most clearly in the Unit 2 data, is that the common header pressure variations are significantly less than those in the individual lines, which suggests that the common header is generally less noisy.

Spectral Analysis

Attachment B contains the plots of Fourier coefficients and the Power Spectral Density for each data set (or selected portion thereof) for Unit 1. Attachment C contains the same information for the Unit 2 data. As noted above, the Mathcad program has been utilized to generate this information. The complex form of the FFT has been used since it eliminates the requirement to have data lengths equal to powers of 2. The normalization, based on using the capitalized form of the transform symbols, is based on 1/N, where N is the number of data points. The coefficient plots and power spectral density plots are provided with similar axis scales to allow some relative comparison.

Piping Resonance Analysis

The piping acoustic resonance frequencies can be predicted theoretically using established relationships. Based on experience of comparable evaluations of Byron feedwater lines, the most probable resonance will be based on the piping downstream of the feed regulating valves to the steam generator. The following relationship is based on a closed-open acoustic boundary condition and will be used to define the first five acoustic modes:

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

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

The speed of sound in the feedwater line is approximately 4200 fps. The lengths of the Unit 1B and D lines are approximately 589 feet and 356 feet respectively. The lengths of the Unit 2 B and D lines are approximately 598 feet and 356 feet respectively. The common header is approximately 323 feet long, based on Byron Unit 2 dimensions. This leads to the following frequencies being predicted:

mode	BW 1 Line B	BW1 Line D	BW 2 Line B	BW 2 Line D	BW 2 Common Hdr
1	1.783	2.815	1.756	2.966	3.25
2	5.348	8.445	5.268	8.898	9.75
3	8.913	14.075	8.779	14.831	16.25
4	12.479	19.705	12.291	20.763	22.75
5	16.044	25.335	15.803	26.695	29.26
6	19.610	30.965	19.314	32.627	35.76
7	23.175	36.595	22.826	38.559	42.3
8	26.740	42.225	26.338	44.492	48.8

Results

The plots of Fourier coefficients and Power Spectral Density were then reviewed and compared to the anticipated frequencies shown in the table above. The Unit 1 line B data suggests that the expected frequencies are in fact present in the signal, particularly through the first four modes. The PSDs support this conclusion. The Unit 1 line D data shows generally a significantly lower amount of acoustic response. The acoustic modes are there, but with less amplitude and less power associated with those amplitudes. The Unit 1 common header shows almost no significant acoustic frequency content at frequencies below 35 hz. A very prominent response exists at approximately 43 hz, which potentially correlates to the 7th mode frequency shown

above. This is not significant to the AMAG flow measurement process since frequencies above 25 hz are electronically damped.

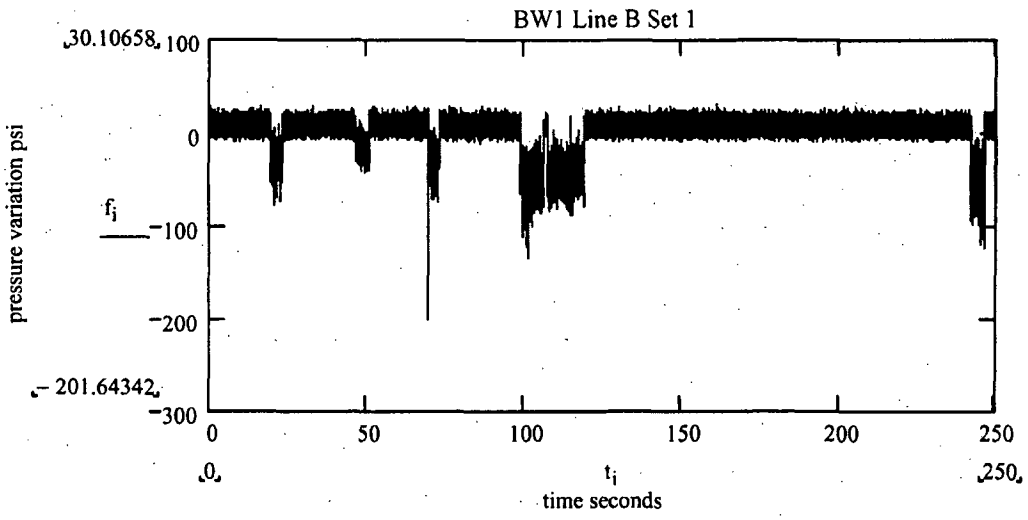
The Unit 2 data follows the same pattern as the Unit 1 data. The B line shows fairly significant response at the frequencies associated with acoustic response. The D line shows significantly reduced amplitude of response, but the characteristic modes are still discernible against the background data. The common header data shows very little response in the range of 5-25 hz, with a significant response occurring at approximately 47 hz. As with Unit 1, this response is large but will not affect AMAG for the reason noted.

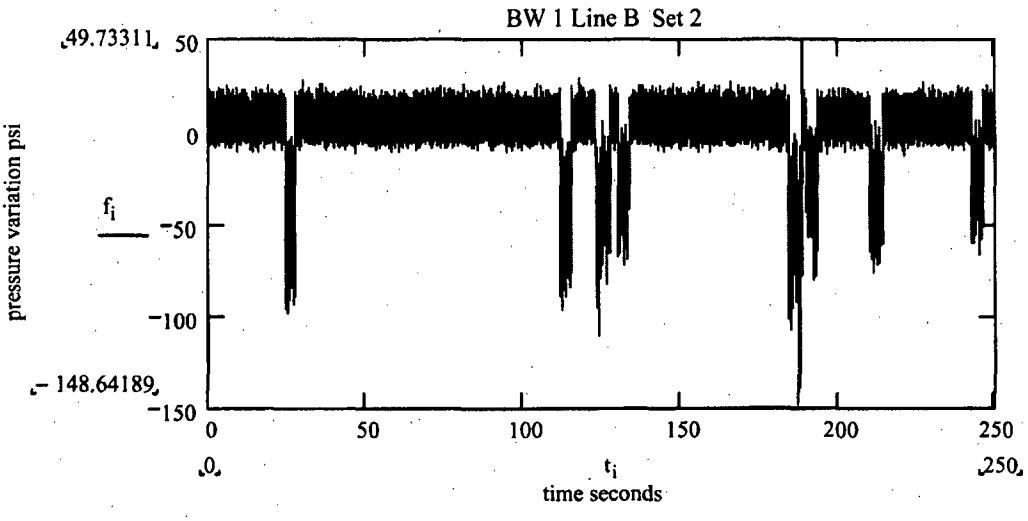
Conclusions

Dynamic pressure data has been collected from the Braidwood Unit 1 and 2 feedwater systems and a spectral analysis has been performed. A long line, a short line, and the common header for each unit were considered. The piping fundamental acoustic frequencies have been predicted for the lines and headers and a comparison to the FFT results was made. The results support that the long lines (B-lines) are more acoustically noisy than the short lines (D-lines), and that the common header is relatively absent of acoustic response, except at frequencies above those of concern. This is reasonable considering that there is little pressure drop occurring in the common header piping that would be capable of exciting acoustic response. The feed regulating valves, on the other hand, provide a large pressure drop and broadband noise signal that is potentially capable of exciting acoustic resonant behavior. The results obtained are consistent with this understanding.

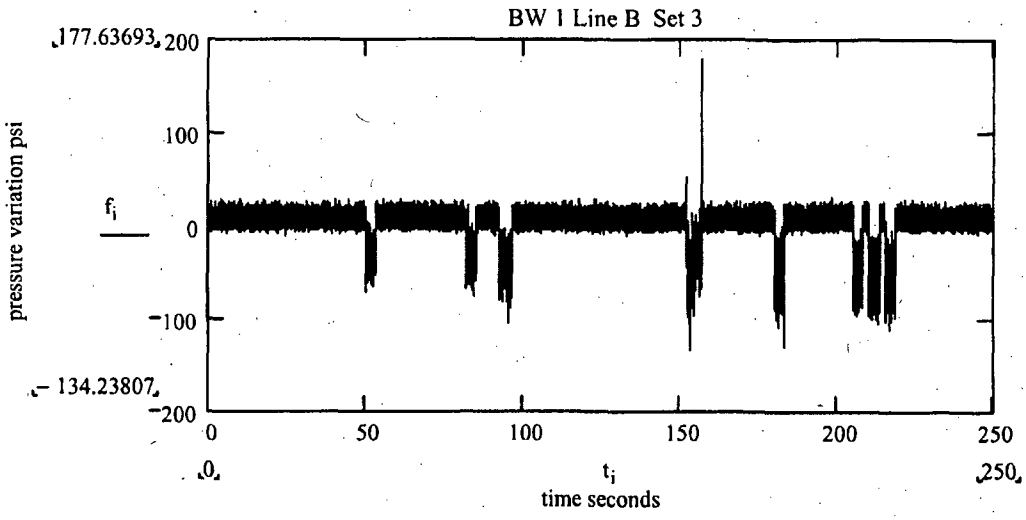
Attachment A, Base Data Prior to Fourier Reduction

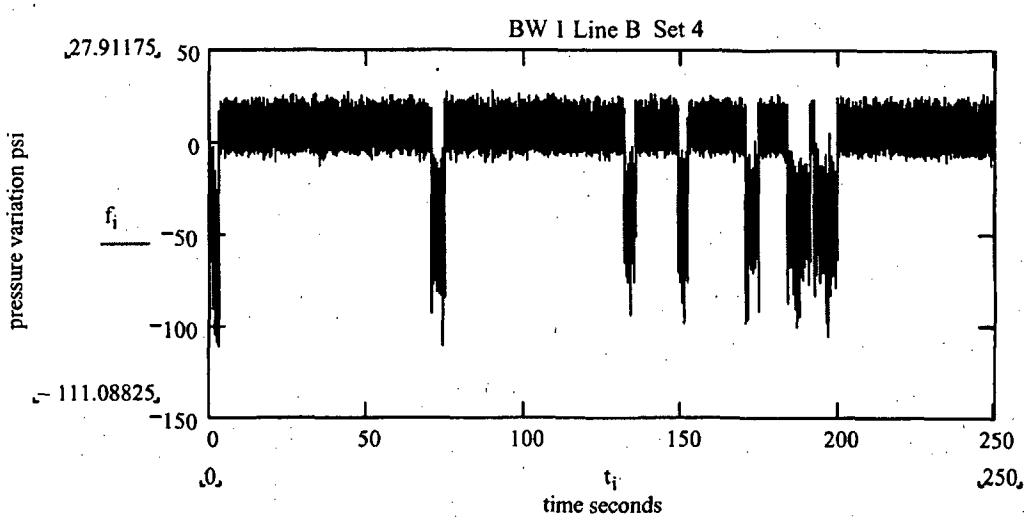
Braidwood Unit 1 Data



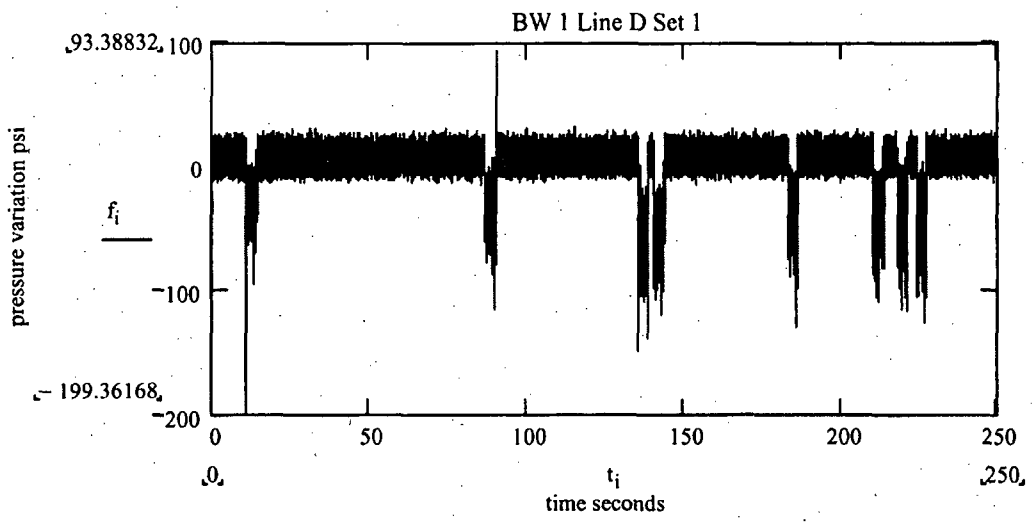


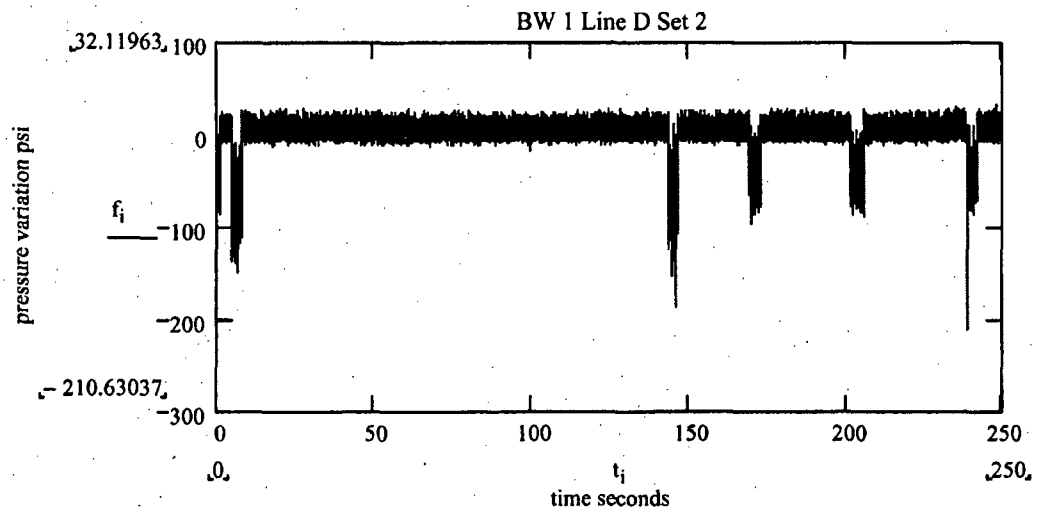
Attachment Q-7, Spectral Analysis of Brwd FW Piping (Pg 5 of 39)



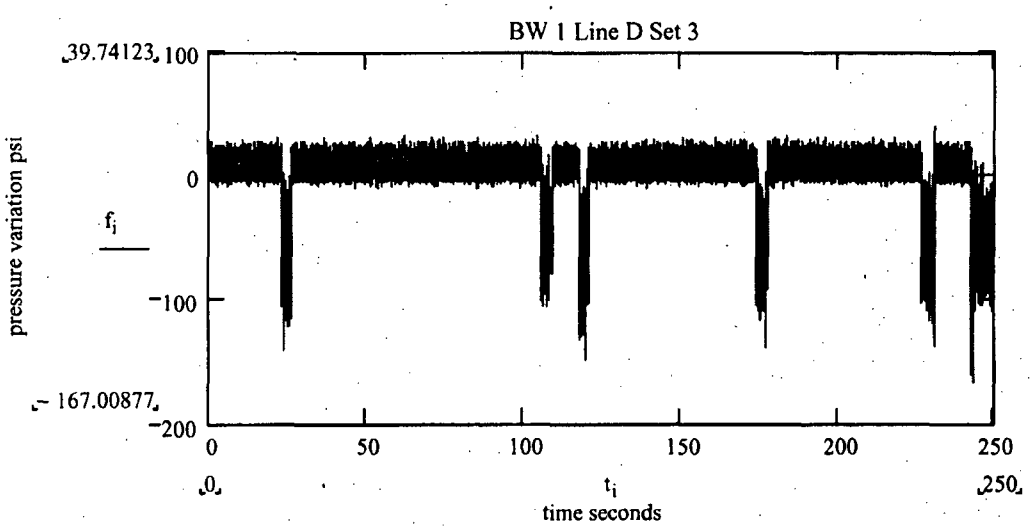


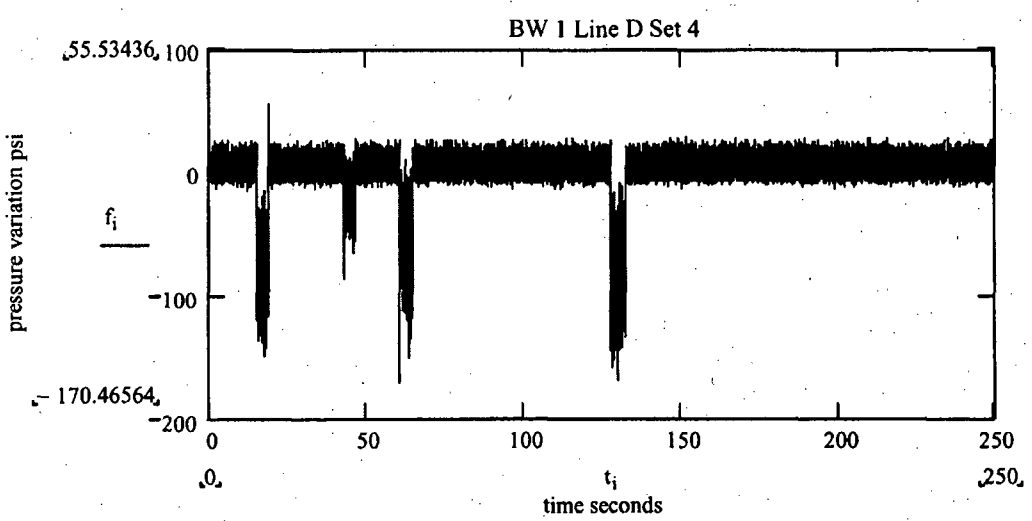
Attachment Q-7, Spectral Analysis of Brwd FW Piping (Pg 6 of 39)



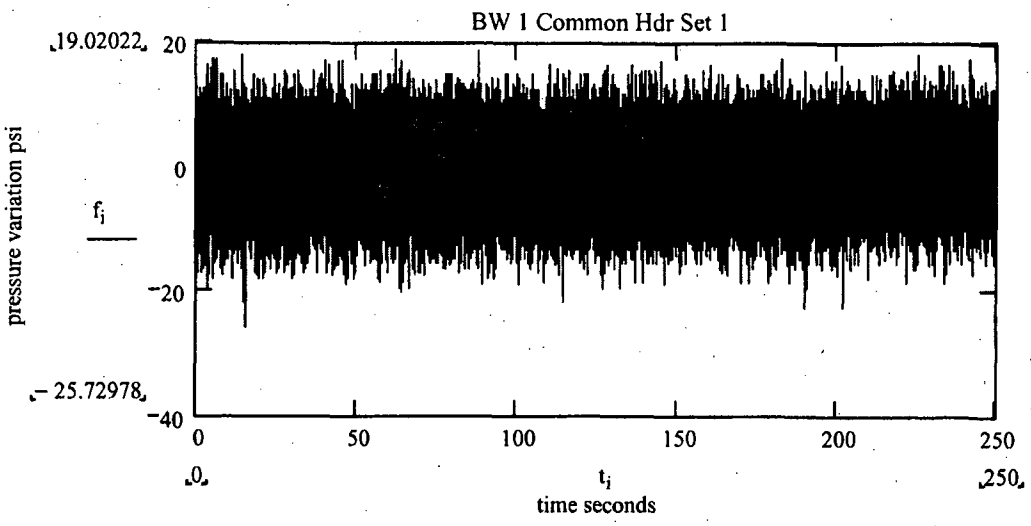


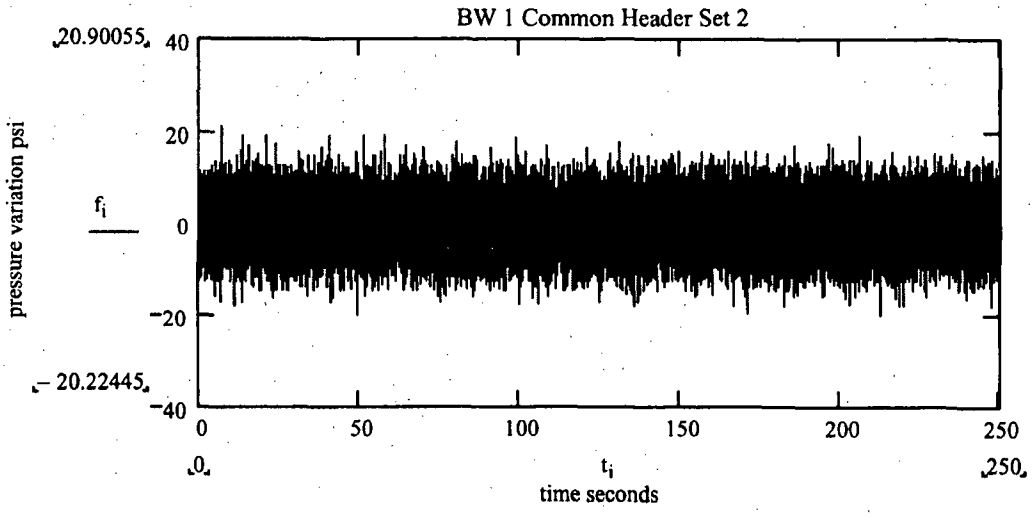
Attachment Q-7, Spectral Analysis of Brwd FW Piping (Pg 7 of 39)

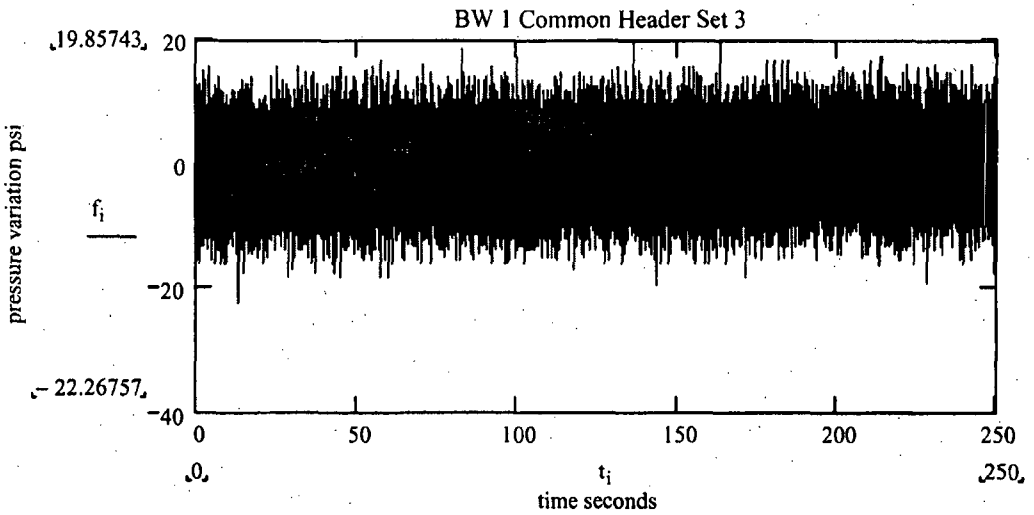


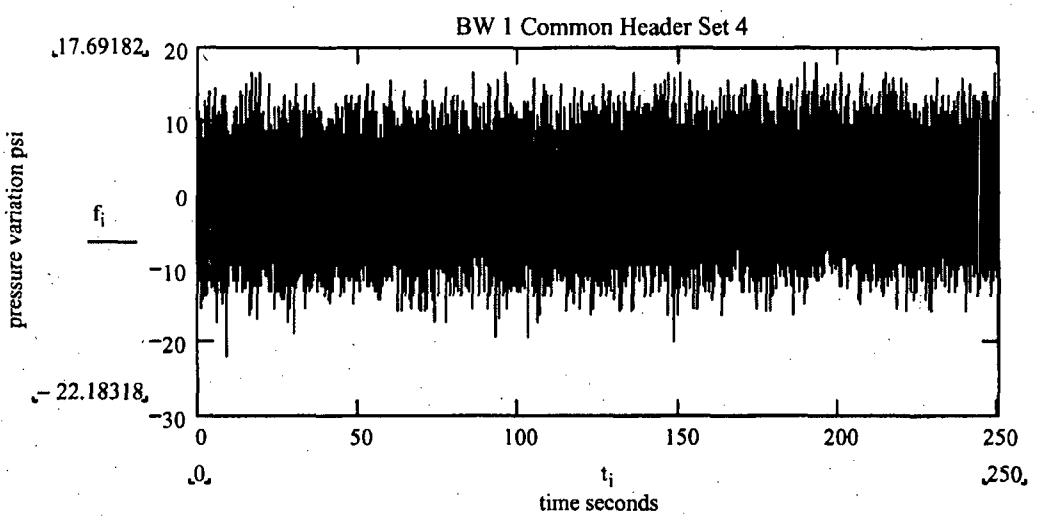


Attachment Q-7, Spectral Analysis of Brwd FW Piping (Pg 8 of 39)






BW 1 Common Header Set 3
19.85743
20
0
-20
-40
-22.26757
pressure variation psi
f_i
0
50
100
150
200
250
0
t_i
250
time seconds


BW 1 Common Header Set 4
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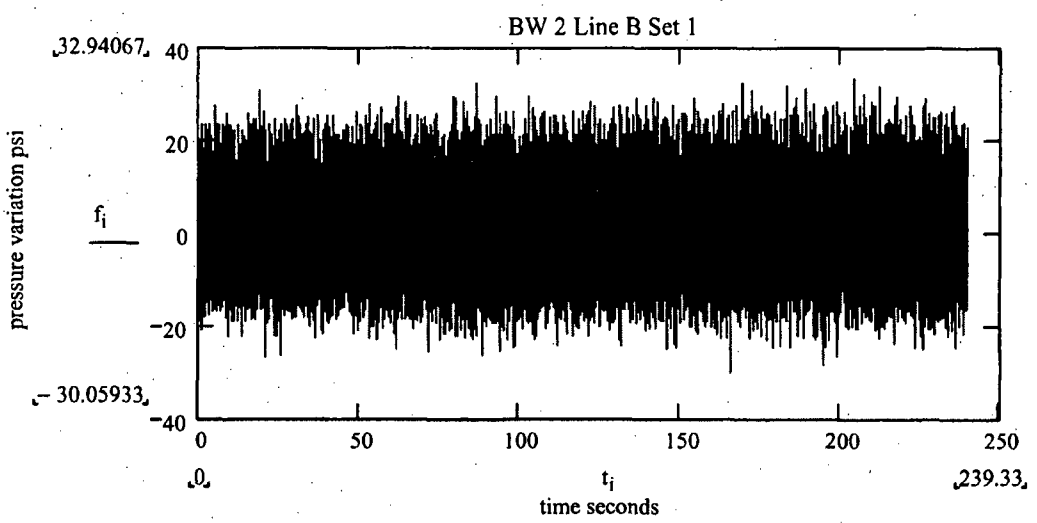
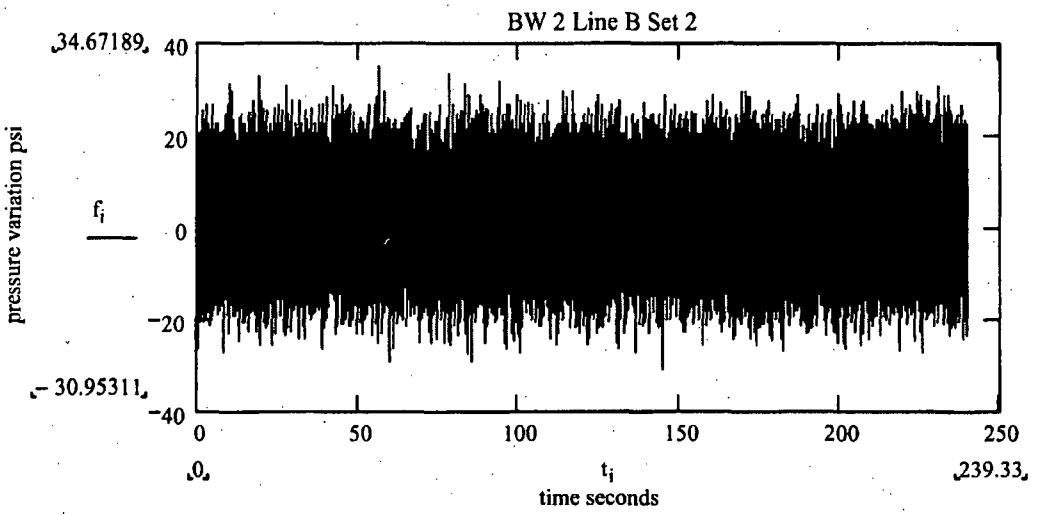
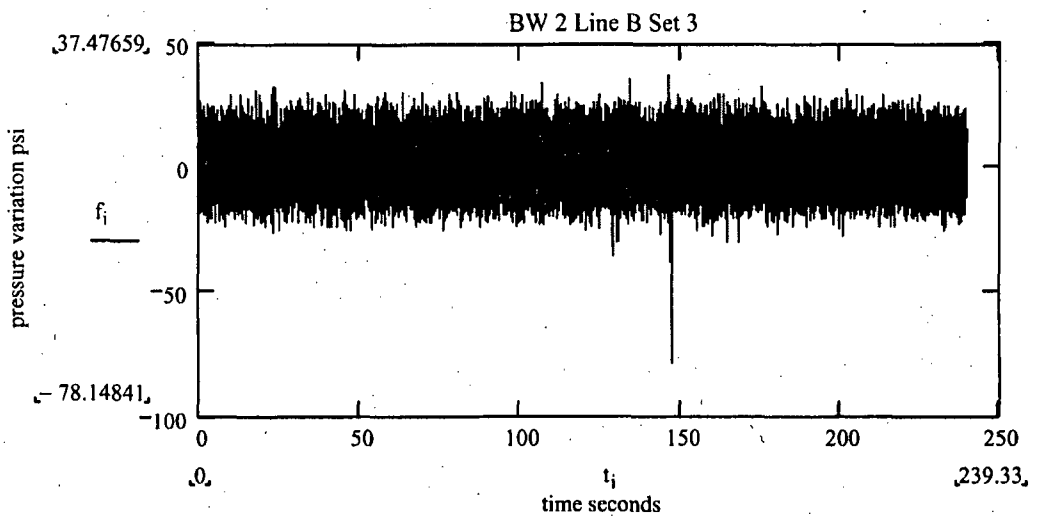
20
10
0
-10
-20
-30
-22.18318
pressure variation psi
f_i
0
50
100
150
200
250
0
t_i
250
time seconds

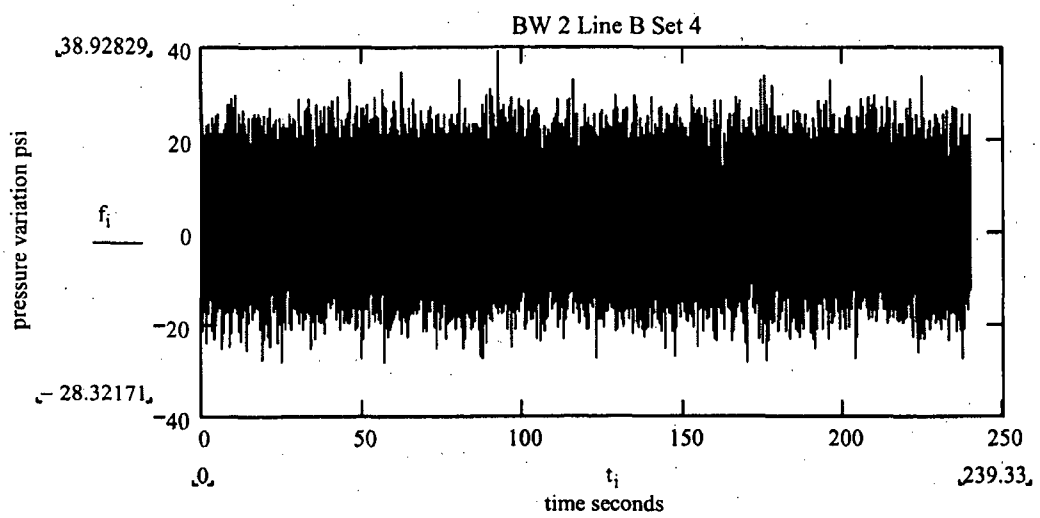
Braidwood Unit 2 Data



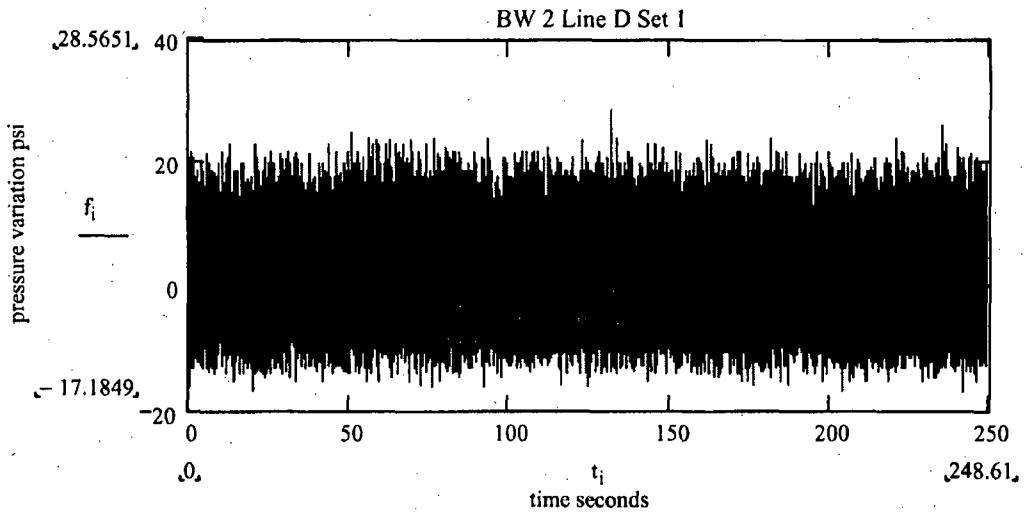


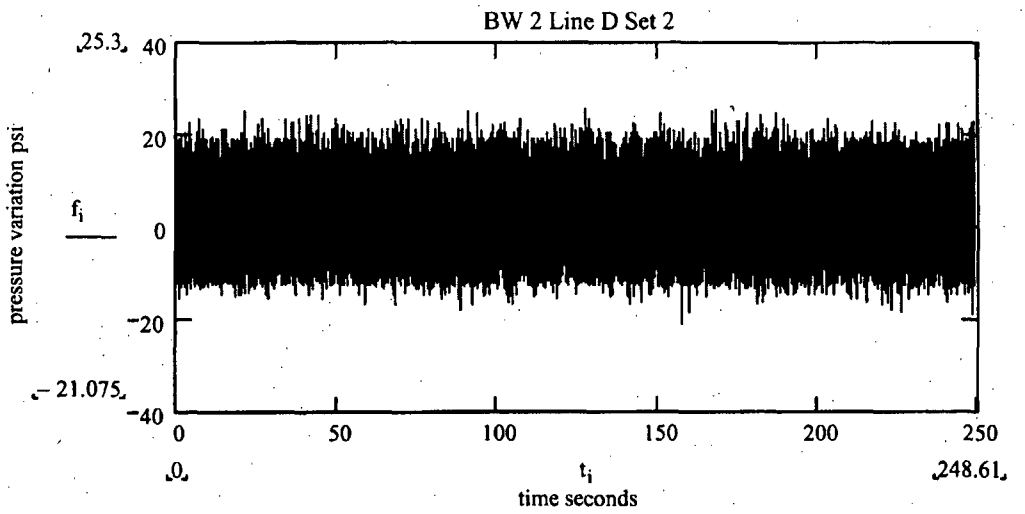
Attachment Q-7, Spectral Analysis of Brwd FW Piping (Pg 11 of 39)



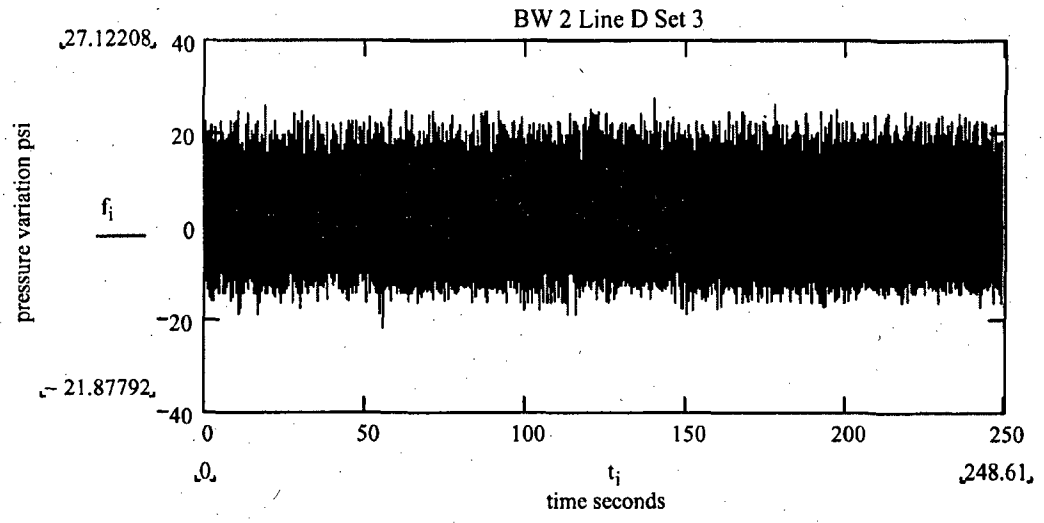


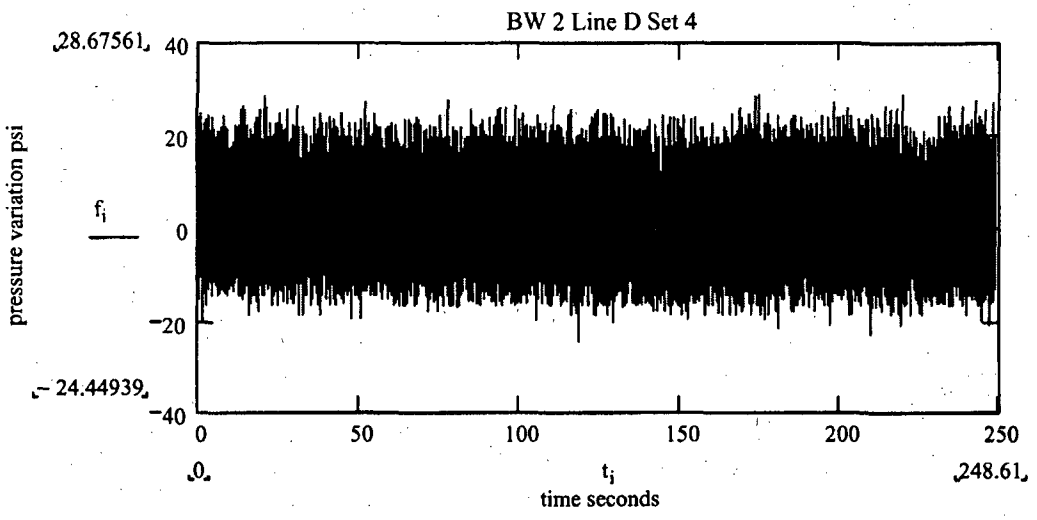
Attachment Q-7, Spectral Analysis of Brwd FW Piping (Pg 12 of 39)



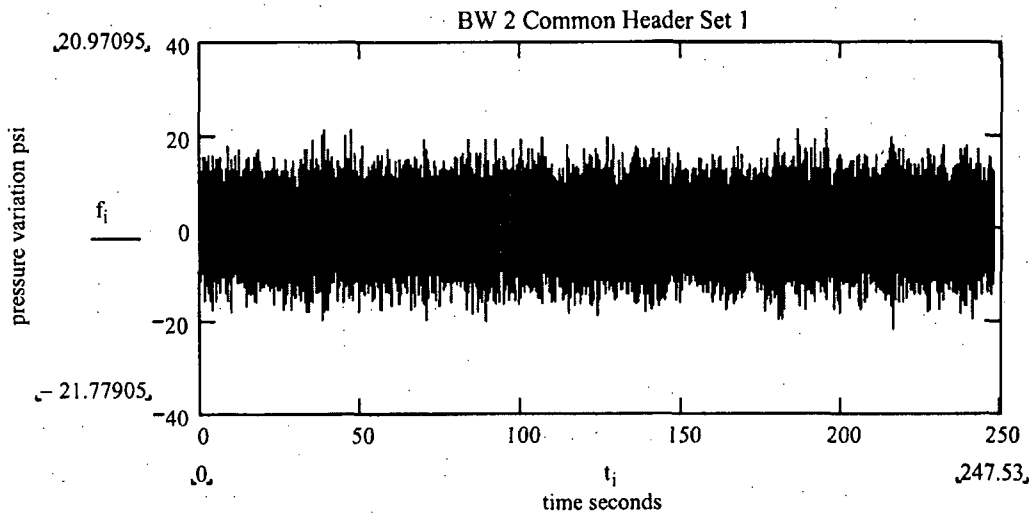


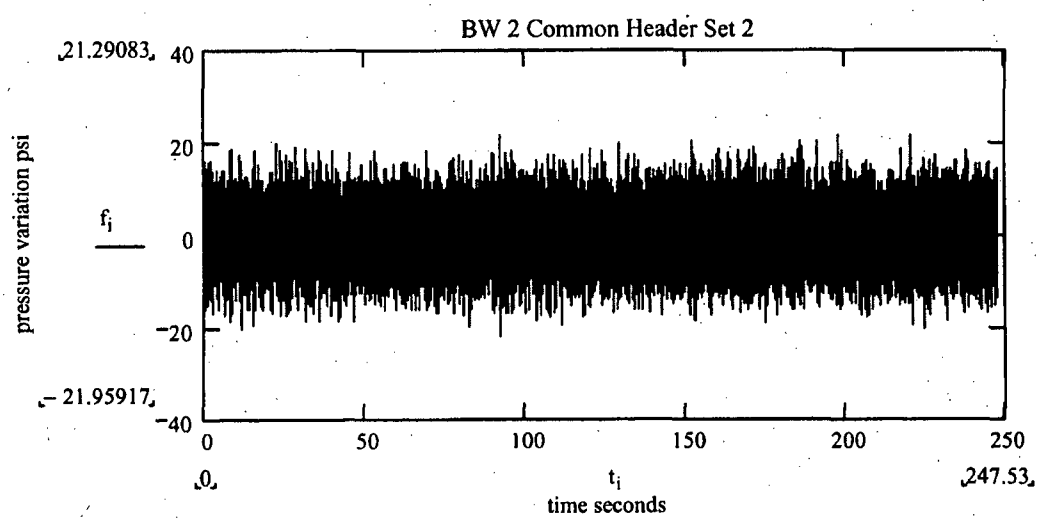
Attachment Q-7, Spectral Analysis of Brwd FW Piping (Pg 13 of 39)



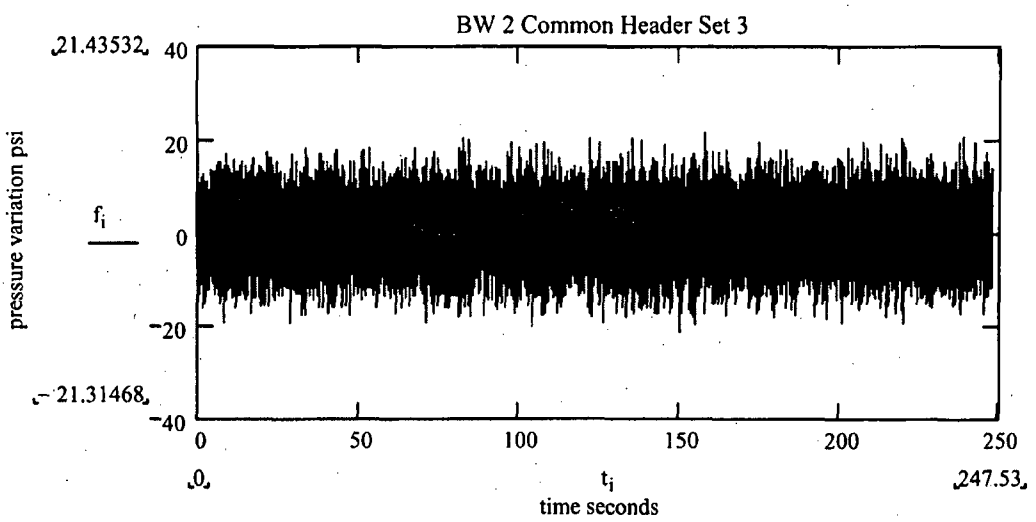


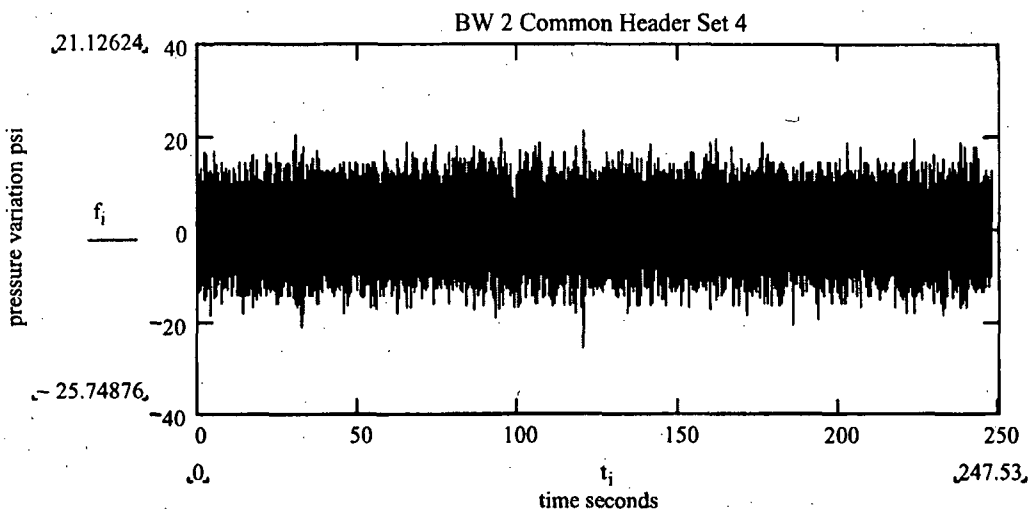
Attachment Q-7, Spectral Analysis of Brwd FW Piping (Pg 14 of 39)



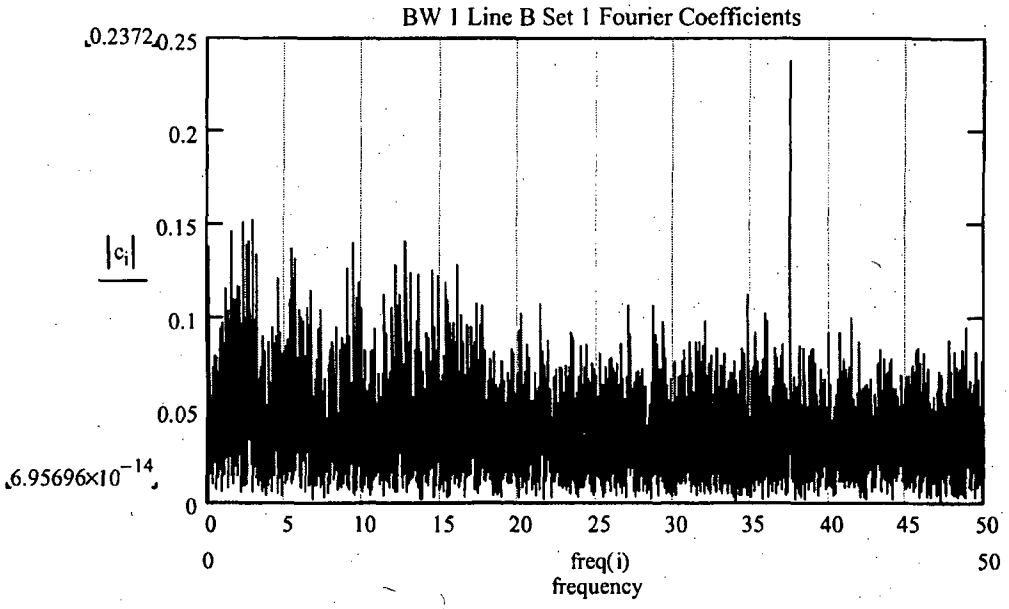


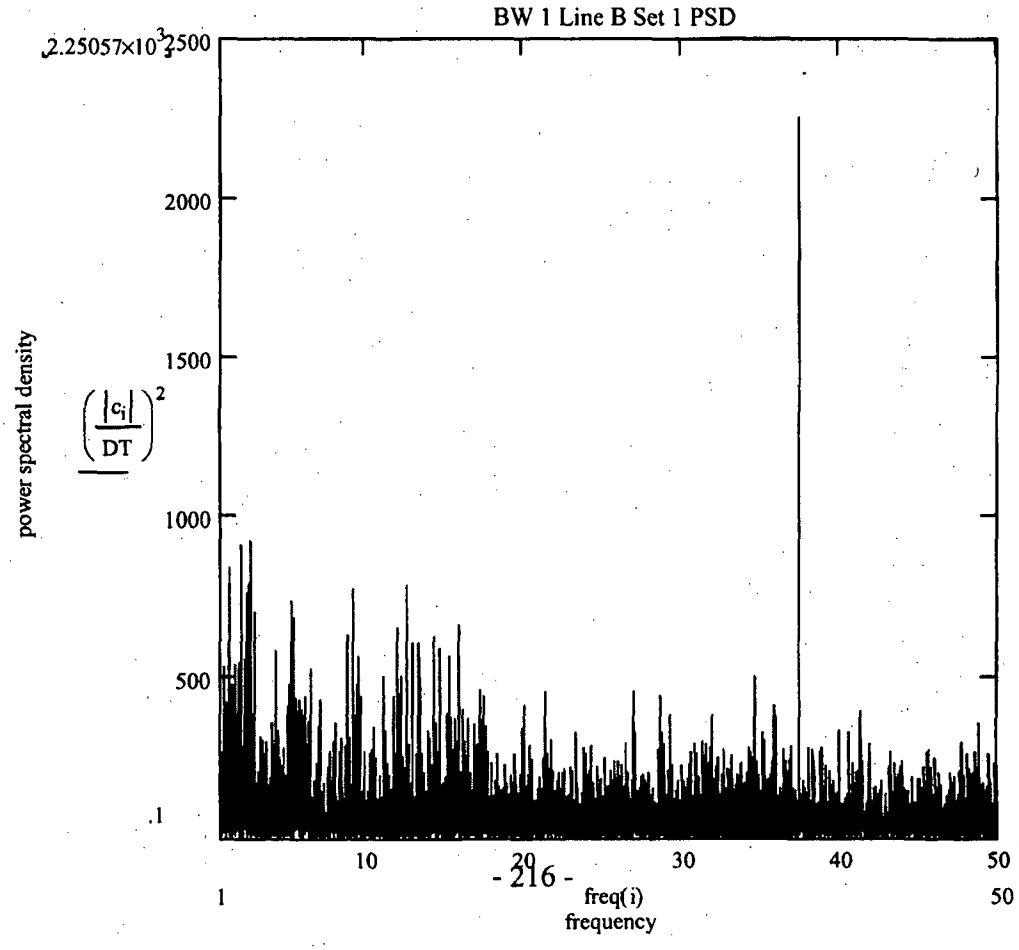
Attachment Q-7, Spectral Analysis of Brwd FW Piping (Pg 15 of 39)



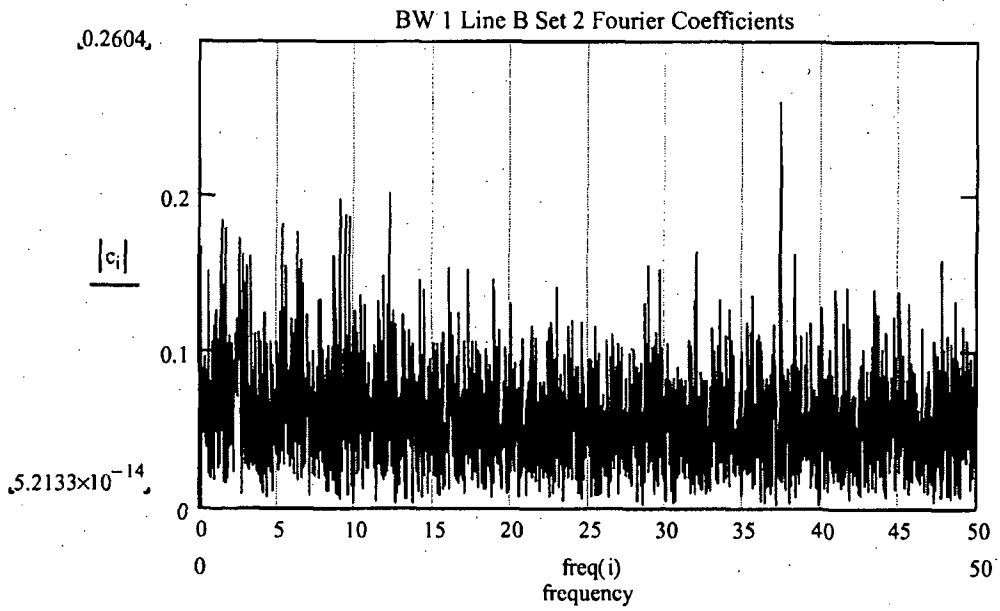


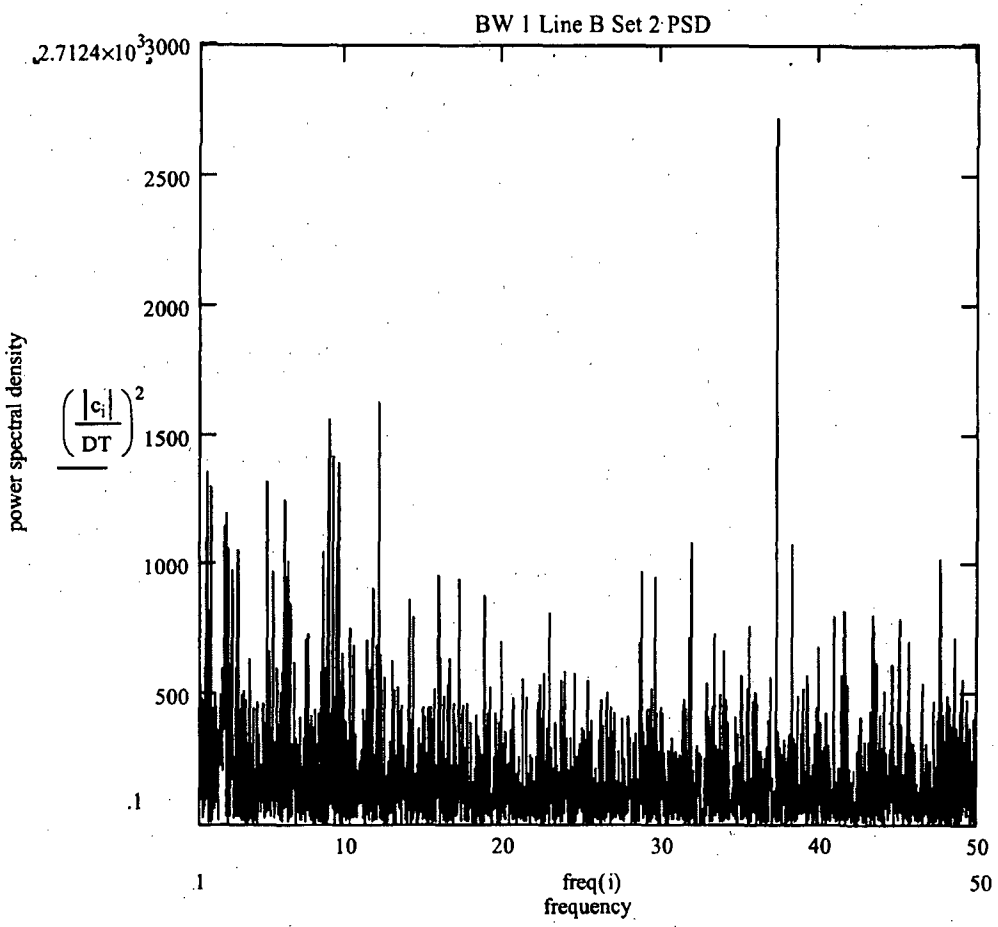
Attachment B Unit 1 Fourier Coefficients and Power Spectral Density Plots



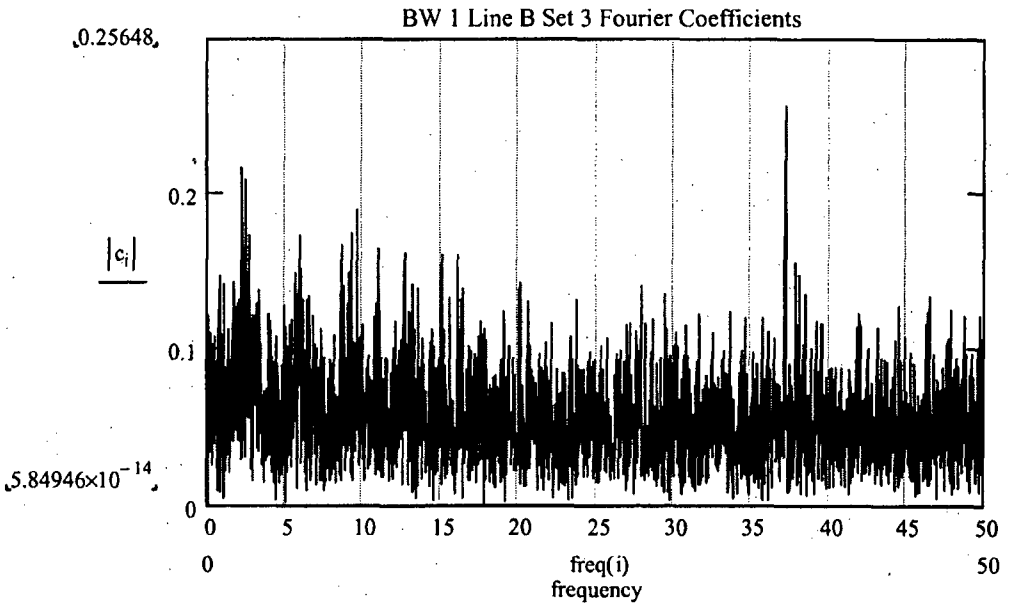


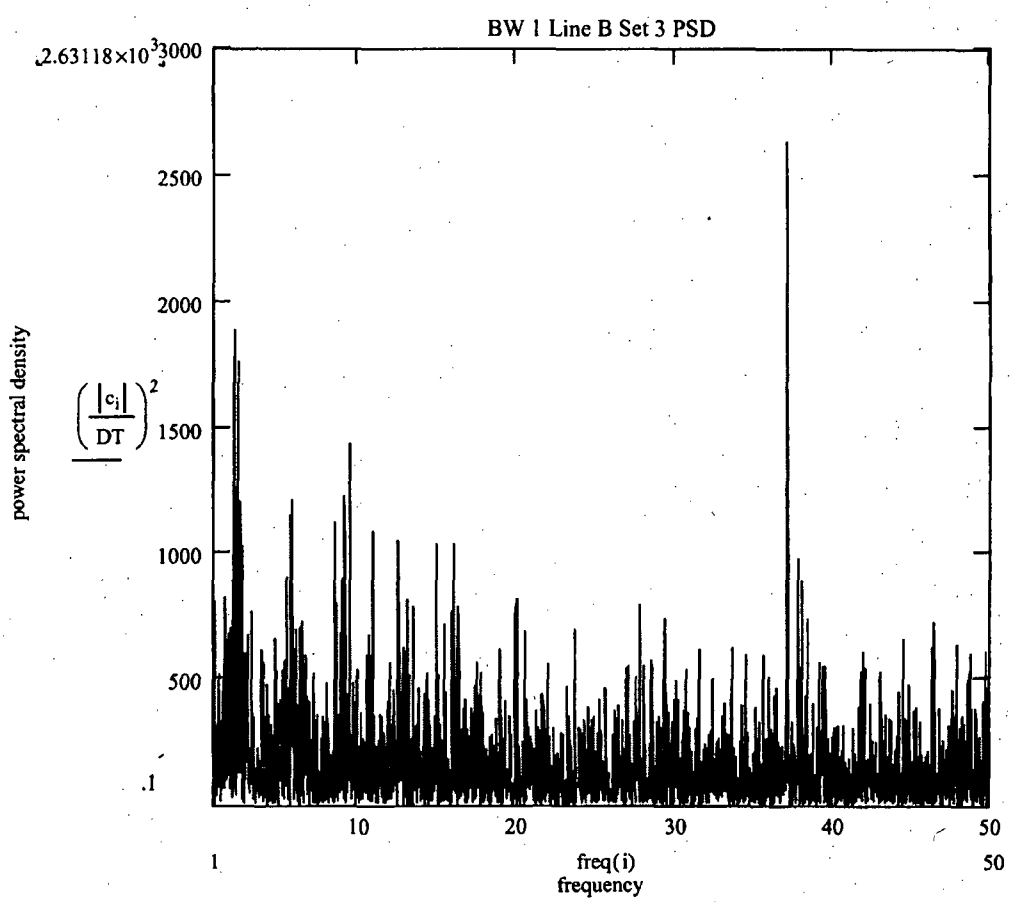
Attachment Q-7, Spectral Analysis of Brwd FW Piping (Pg 17 of 39)



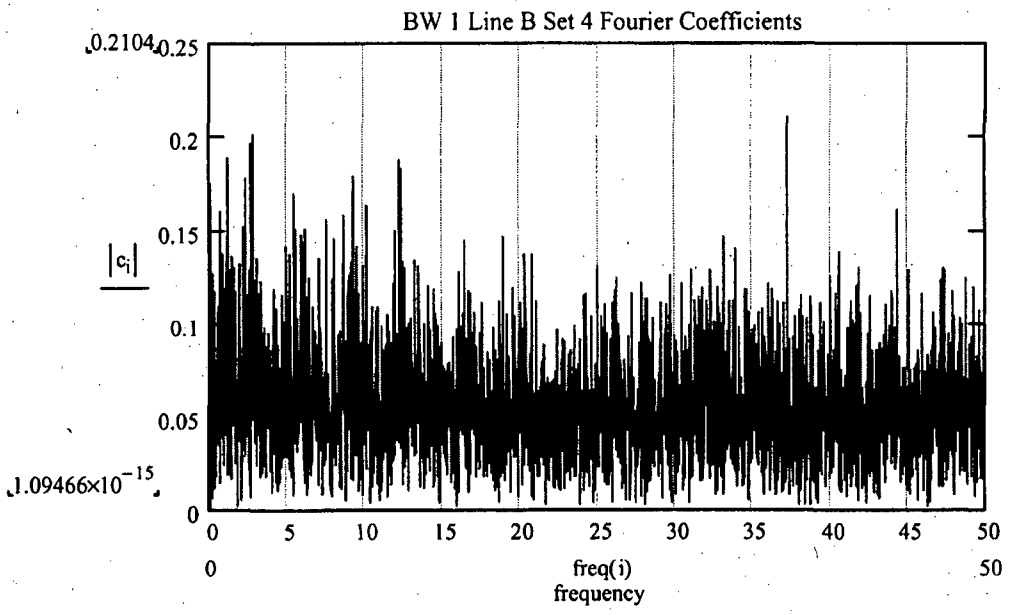


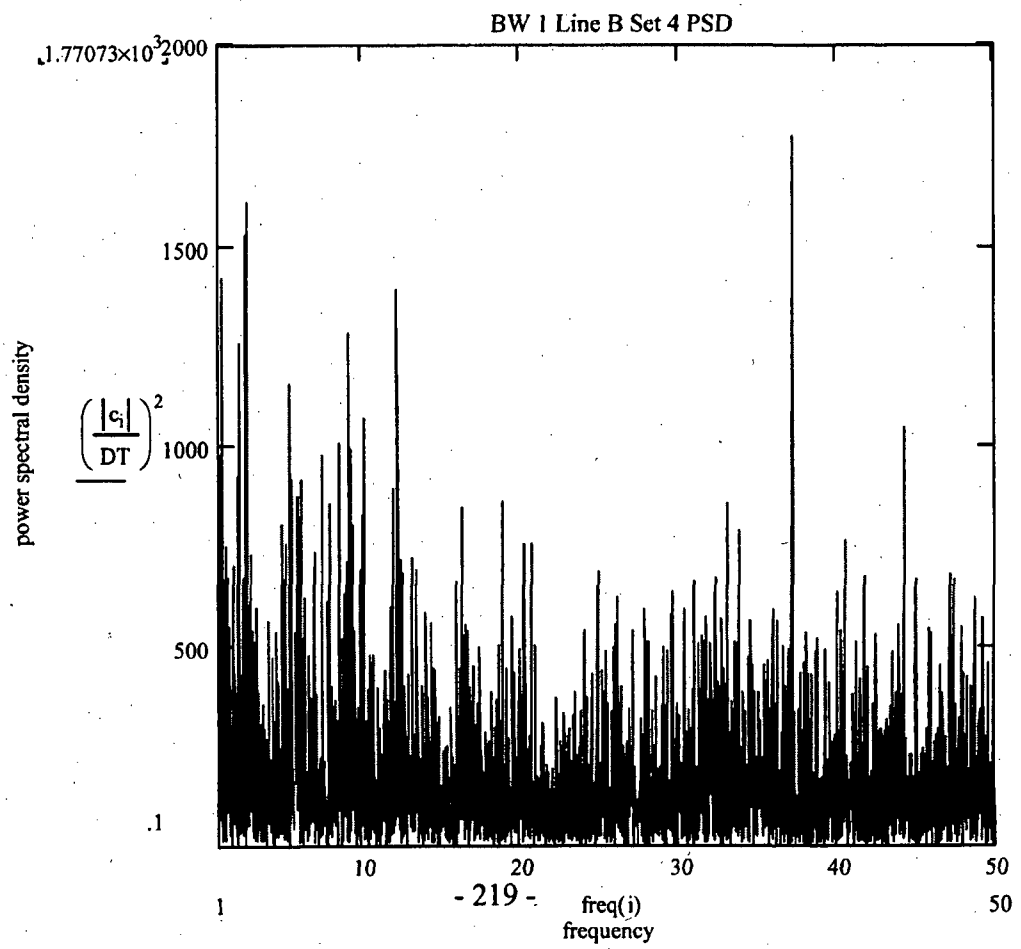
Attachment Q-7, Spectral Analysis of Brwd FW Piping (Pg 18 of 39)

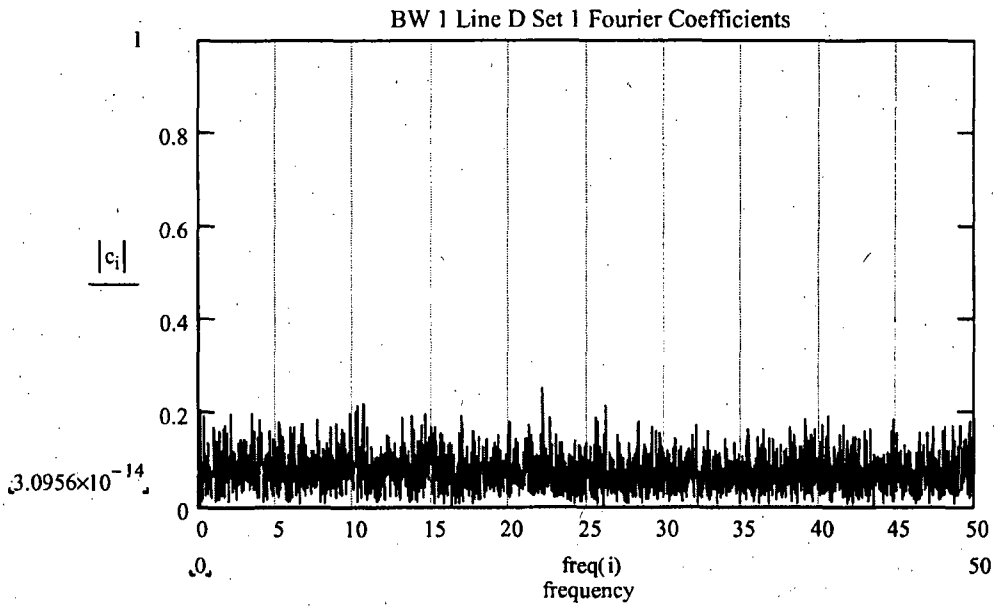


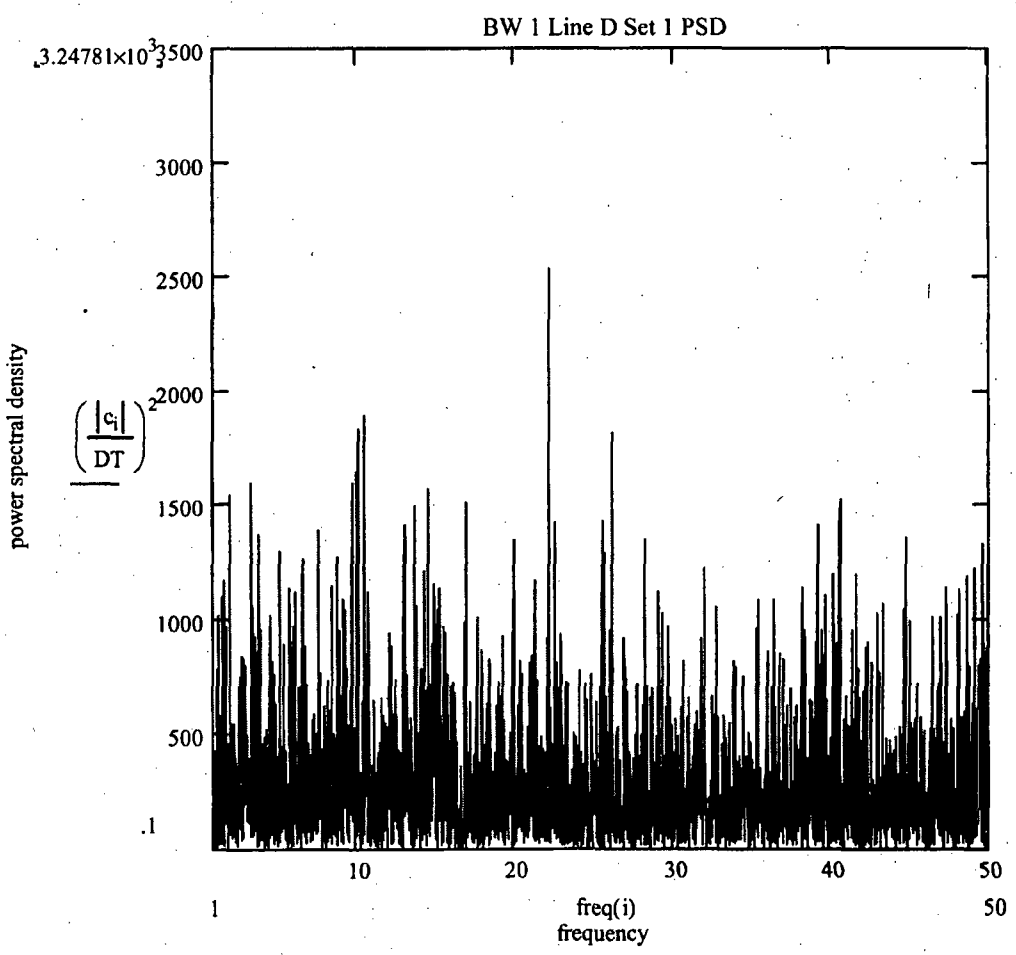


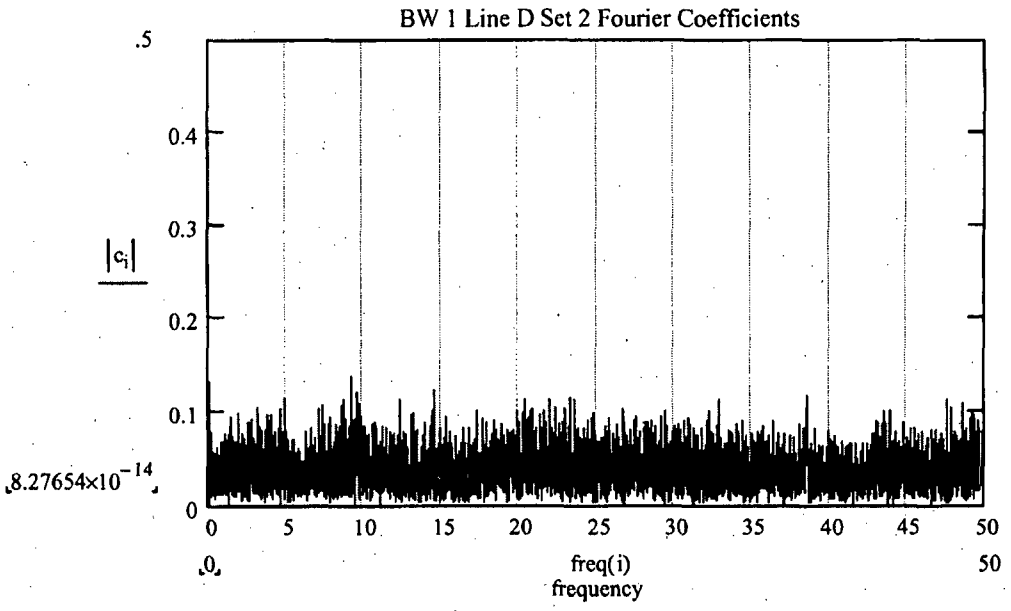
Attachment Q-7, Spectral Analysis of Brwd FW Piping (Pg 19 of 39)

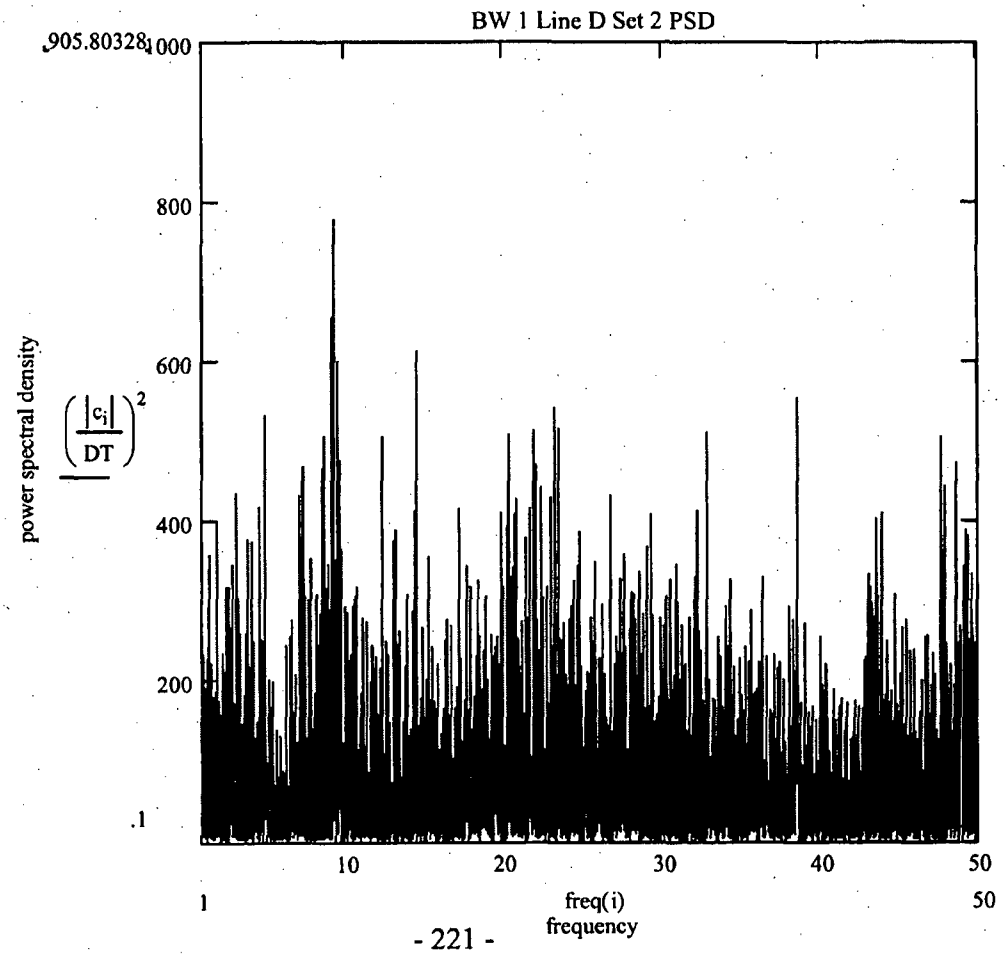


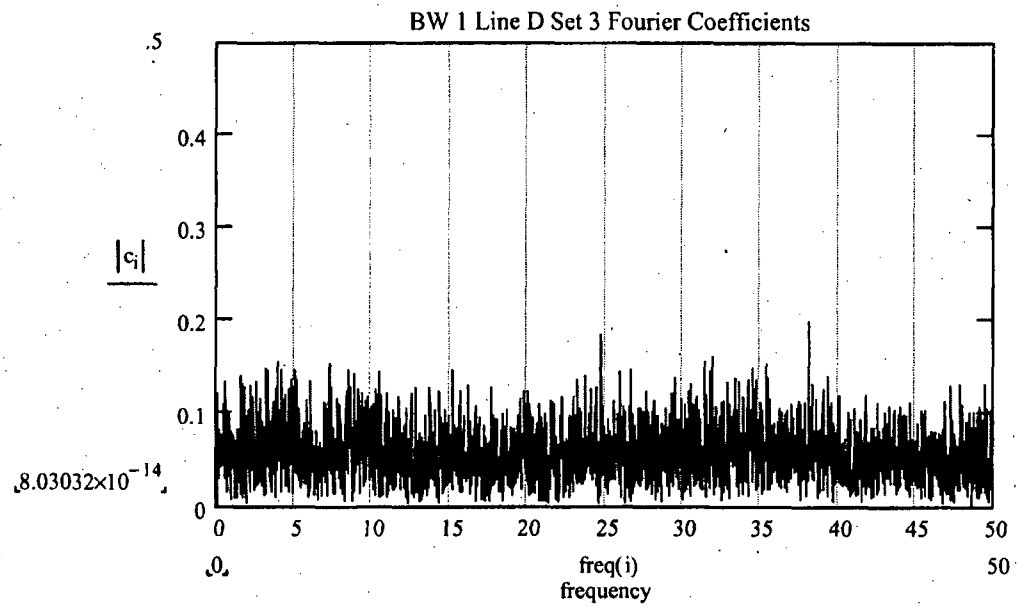


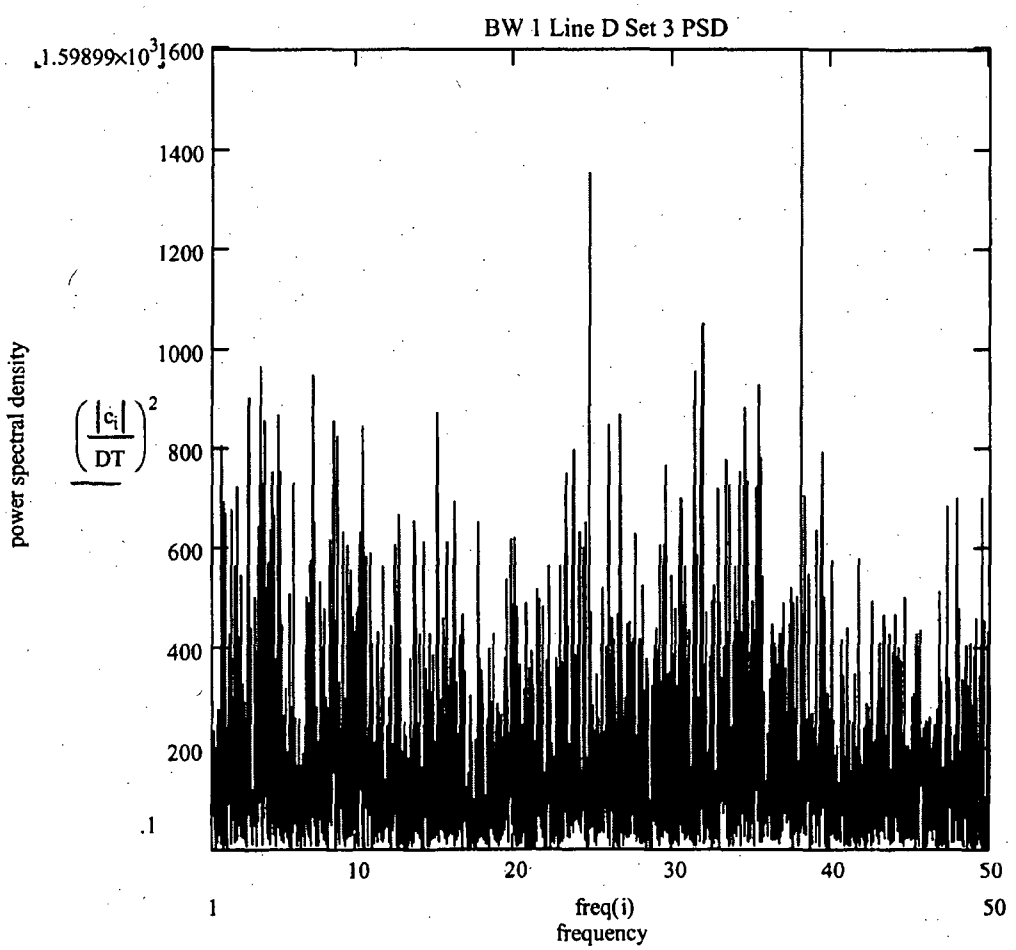

BW 1 Line D Set 1 Fourier Coefficients
1
0.8
0.6
0.4
0.2
0
$|c_i|$
3.0956×10^{-14}
0
5
10
15
20
25
30
35
40
45
50
0
freq(i)
frequency
50

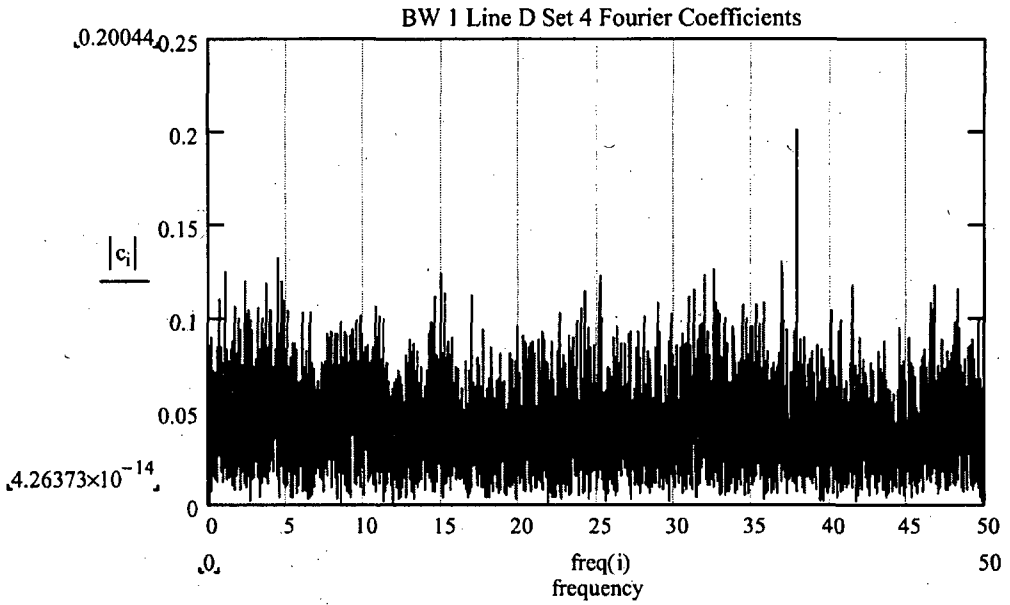

BW 1 Line D Set 1 PSD
3.24781×10^{3}
3500
3000
2500
2000
1500
1000
500
.1
power spectral density
$\left(\frac{|c_i|}{DT}\right)^2$
10
20
30
40
50
1
freq(i)
frequency
50

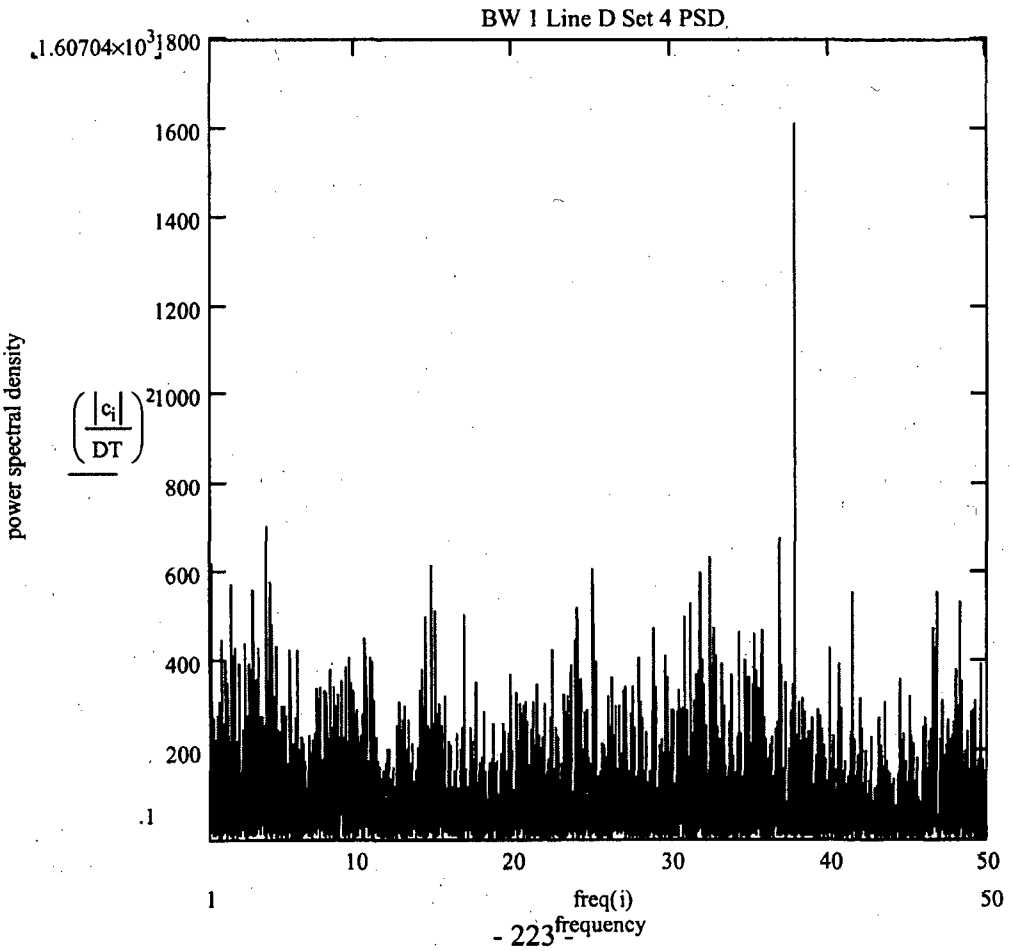

BW 1 Line D Set 2 Fourier Coefficients
.5
0.4
0.3
0.2
0.1
0
$|c_i|$
8.27654×10^-14
0
5
10
15
20
25
30
35
40
45
50
0
freq(i)
frequency
50

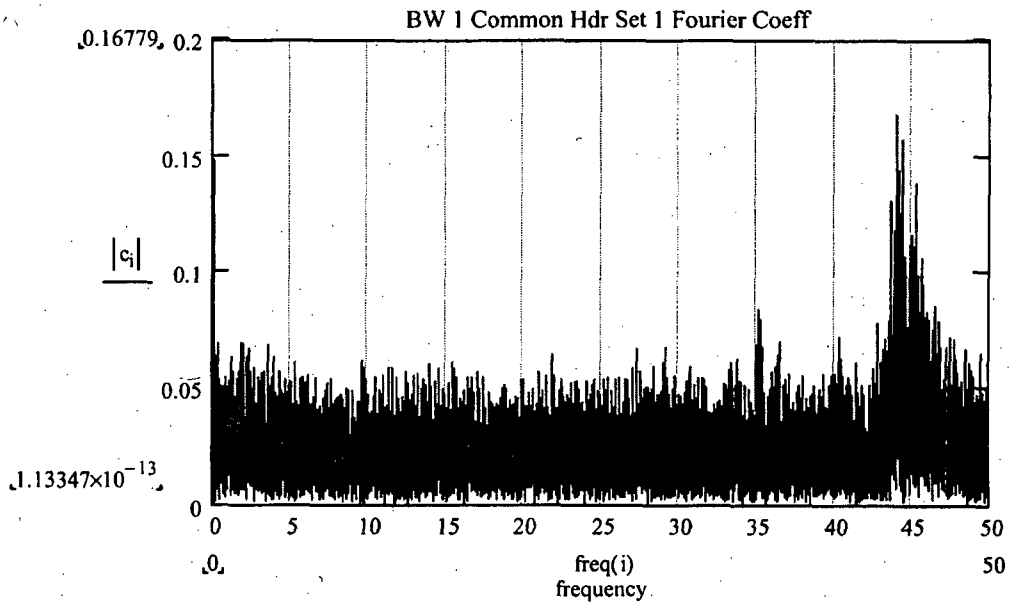

BW 1 Line D Set 2 PSD
905.80328
1000
800
600
400
200
.1
power spectral density
$\left(\frac{|c_i|}{DT}\right)^2$
10
20
30
40
50
1
freq(i)
frequency
50

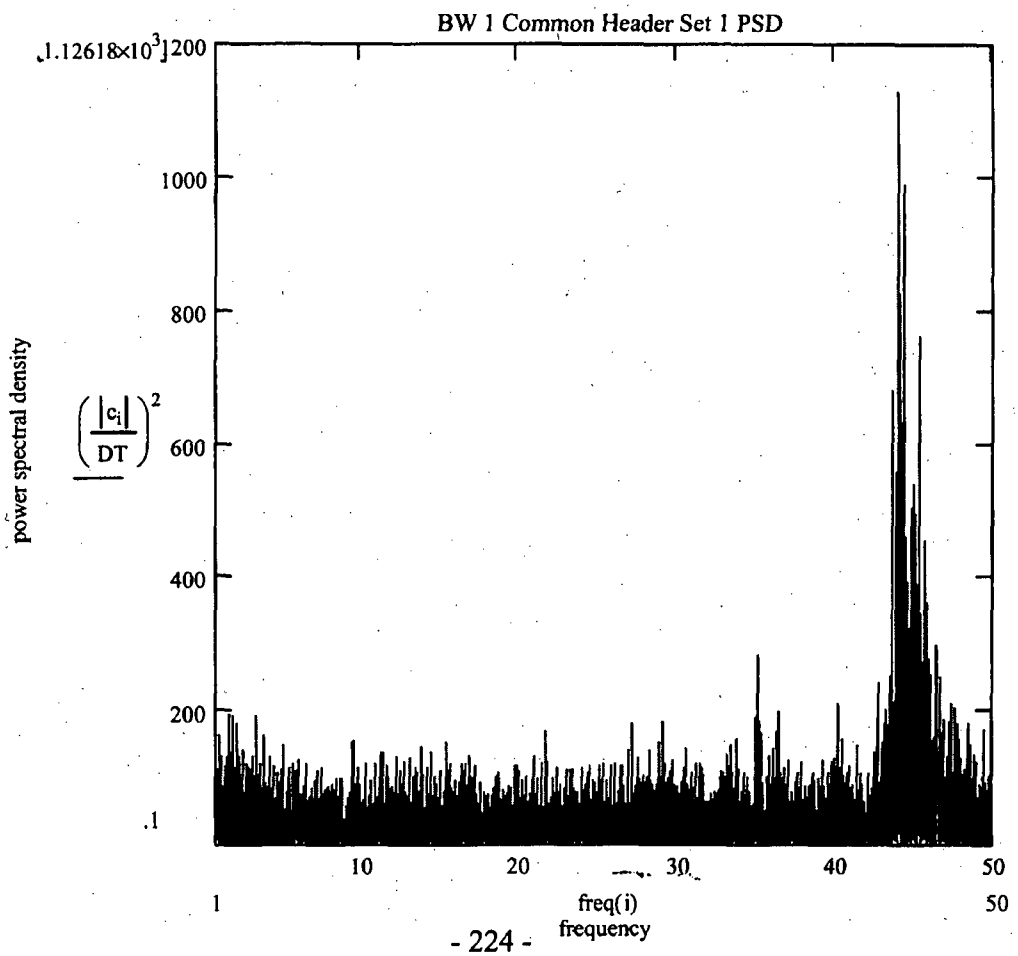

BW 1 Line D Set 3 Fourier Coefficients
.5
0.4
0.3
0.2
0.1
0
$|c_i|$
8.03032×10^-14
0
5
10
15
20
25
30
35
40
45
50
0
freq(i)
frequency
50

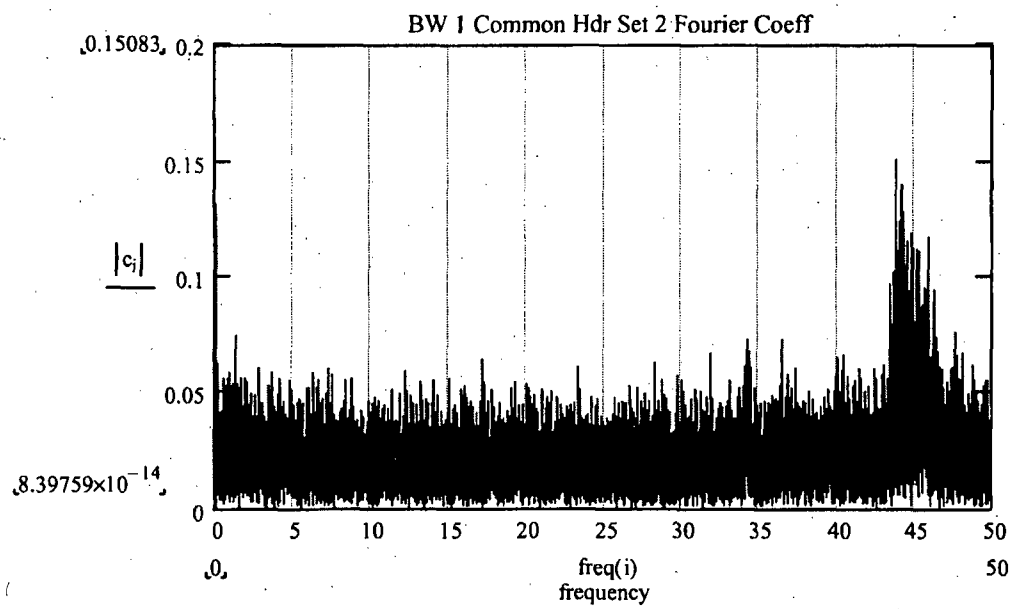

BW 1 Line D Set 3 PSD
1.59899×10^3
1600
1400
1200
1000
800
600
400
200
.1
power spectral density
$\left(\frac{|c_i|}{DT}\right)^2$
10
20
30
40
50
1
freq(i)
frequency
50

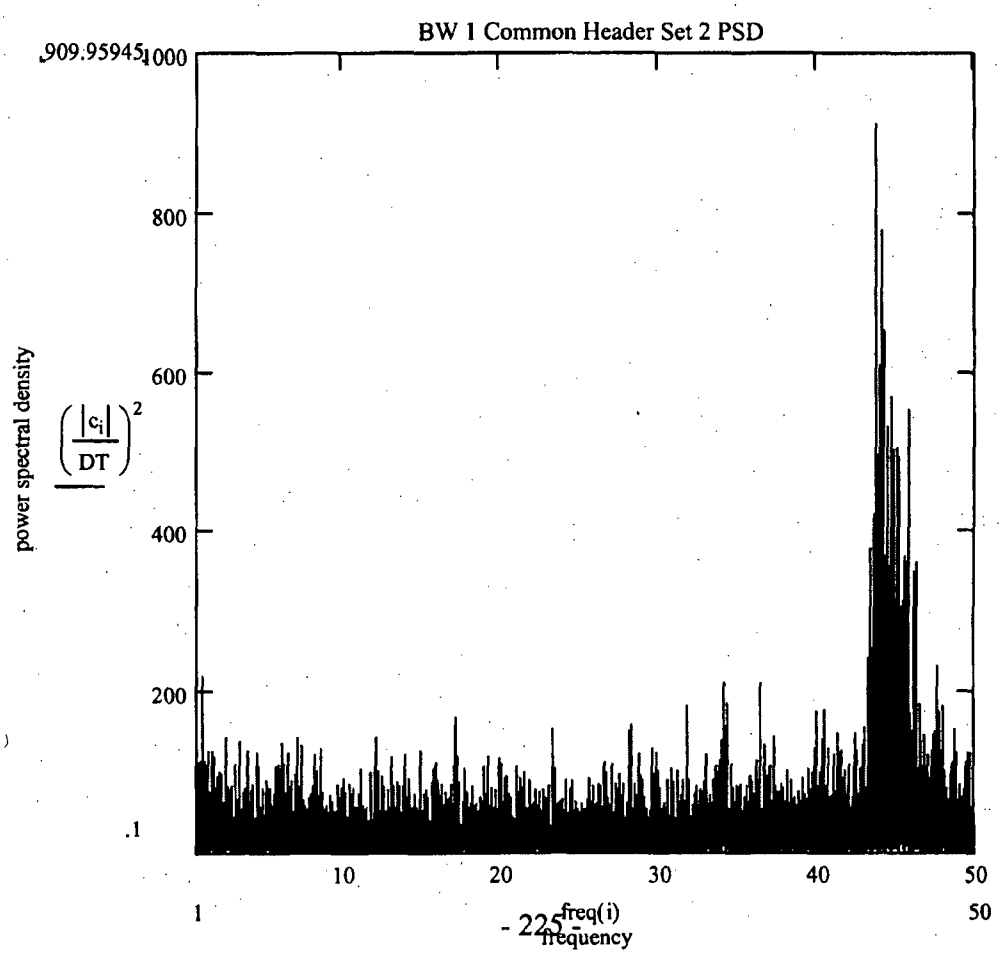

BW 1 Line D Set 4 Fourier Coefficients
0.20044
0.25
0.2
0.15
0.1
0.05
4.26373×10^-14
0
|c_i|
0
5
10
15
20
25
30
35
40
45
50
0
freq(i)
frequency
50

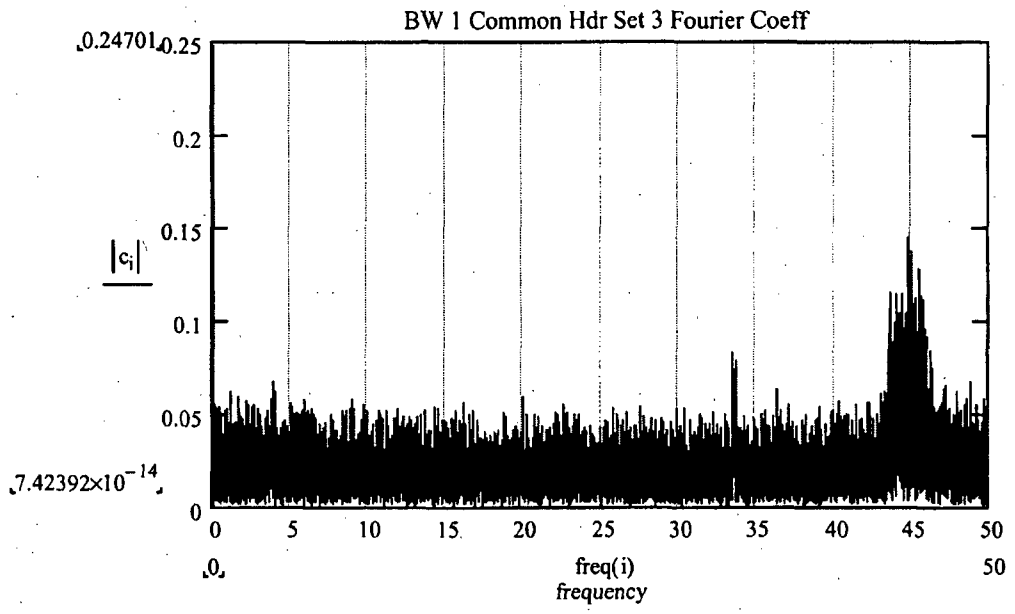

BW 1 Line D Set 4 PSD
1.60704×10^3
1800
1600
1400
1200
1000
800
600
400
200
.1
power spectral density
(|c_i| / DT)^2
10
20
30
40
50
1
freq(i)
frequency
50

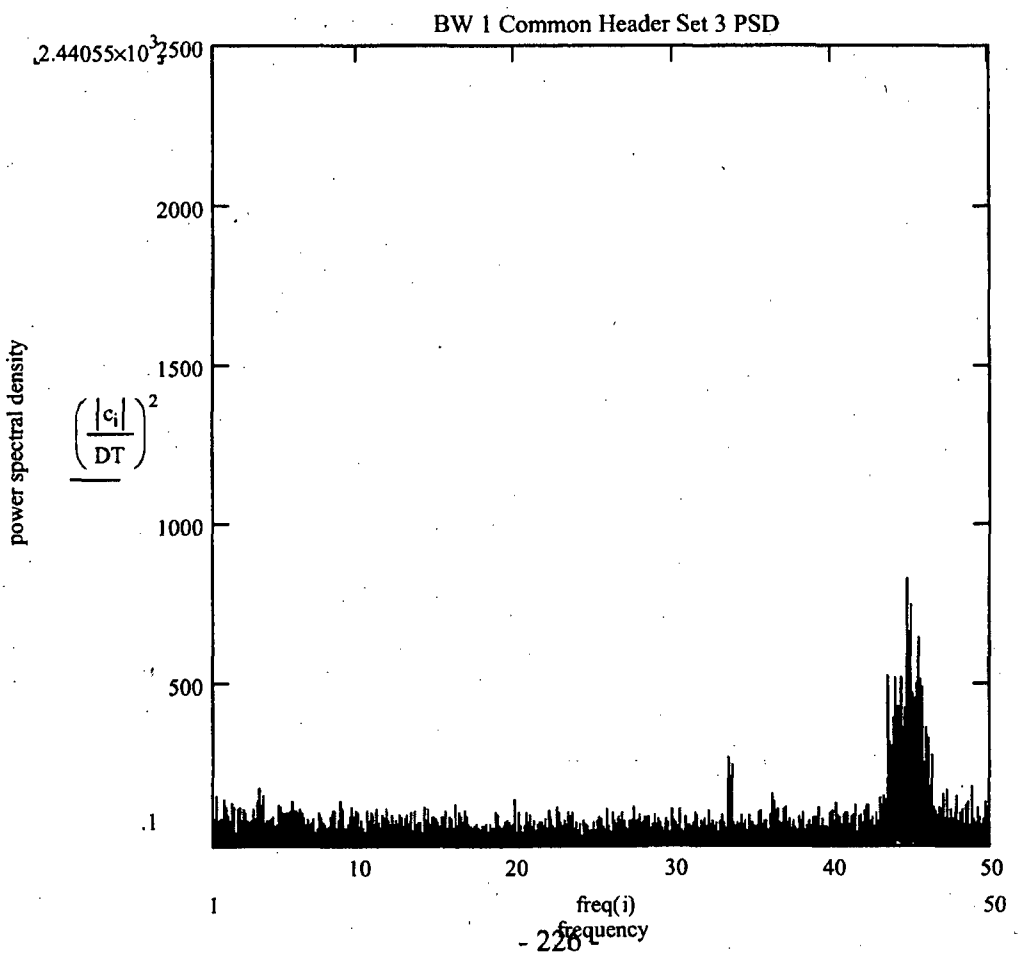

BW 1 Common Hdr Set 1 Fourier Coeff
0.16779
0.2
0.15
|c_i|
0.1
0.05
1.13347×10^-13
0
0
5
10
15
20
25
30
35
40
45
50
0
freq(i)
frequency
50

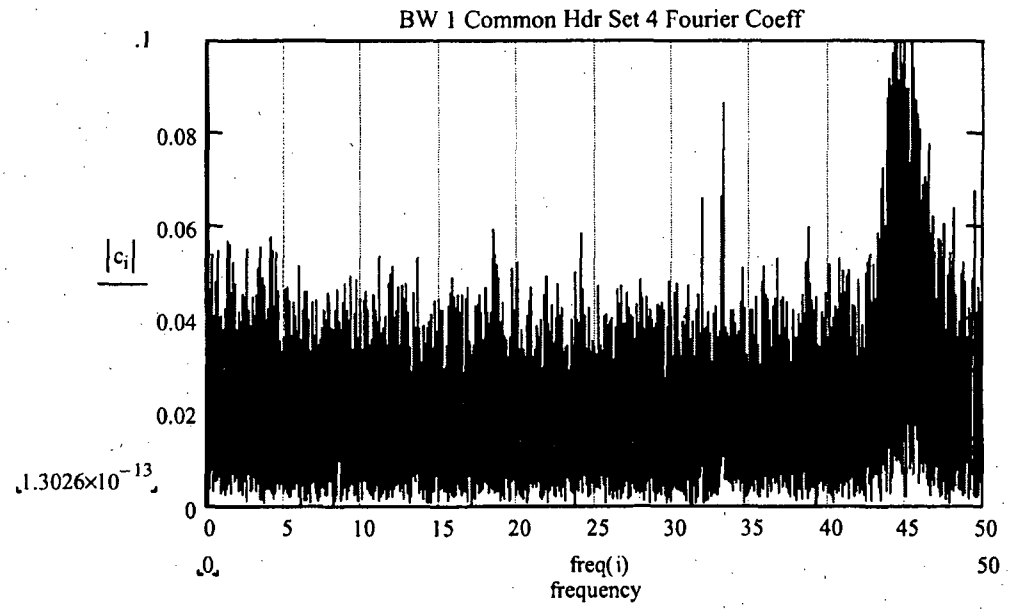

BW 1 Common Header Set 1 PSD
1.12618×10^3
200
1000
800
power spectral density
(|c_i| / DT)^2
600
400
200
1
10
20
30
40
50
1
freq(i)
frequency
50

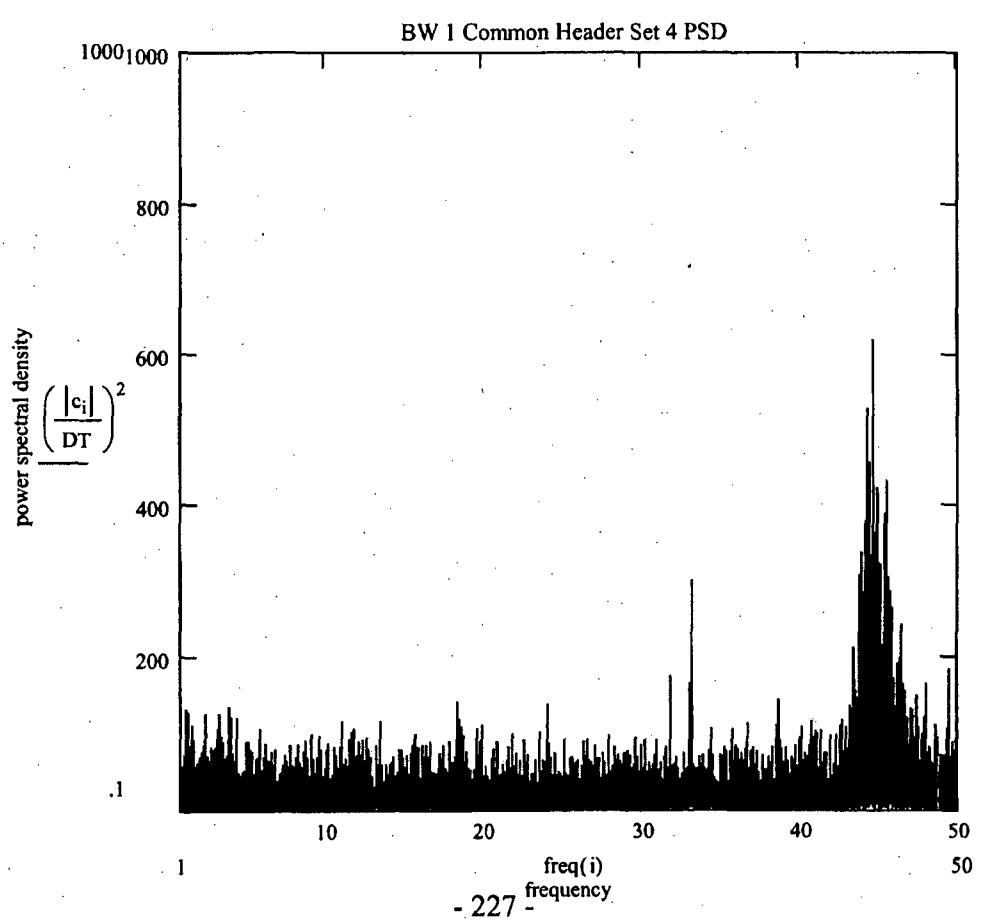

BW 1 Common Hdr Set 2 Fourier Coeff
0.15083
0.2
0.15
0.1
0.05
0
8.39759×10^-14
|c_i|
0
5
10
15
20
25
30
35
40
45
50
0
freq(i)
frequency
50


BW 1 Common Header Set 2 PSD
909.95945
1000
800
600
400
200
.1
power spectral density
(|c_i| / DT)^2
10
20
30
40
50
1
freq(i)
frequency
50

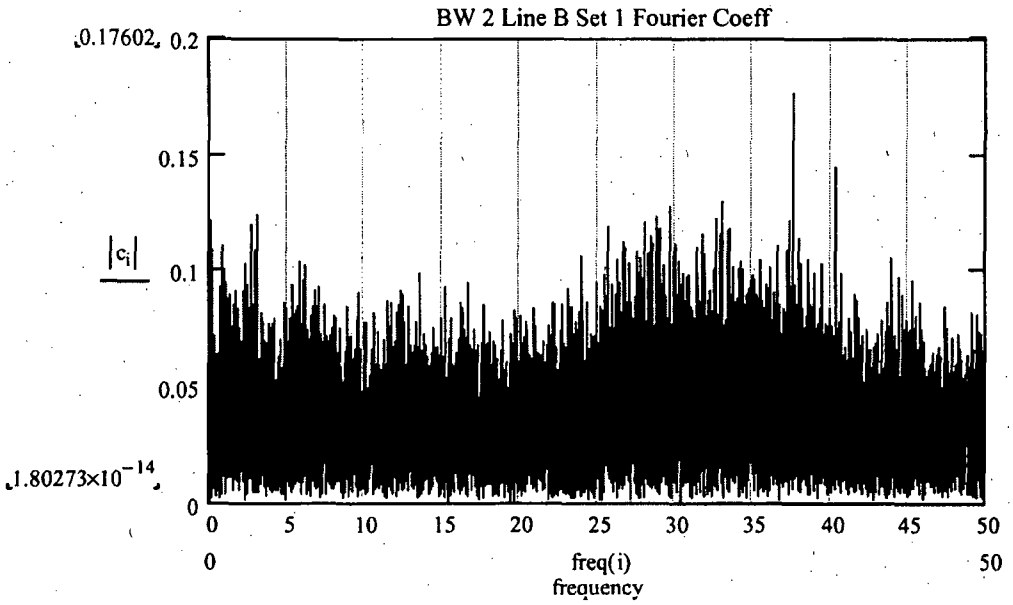

BW 1 Common Hdr Set 3 Fourier Coeff
0.24701
0.25
0.2
0.15
0.1
0.05
7.42392×10^-14
0
|c_i|
0
5
10
15
20
25
30
35
40
45
50
0
freq(i)
frequency
50

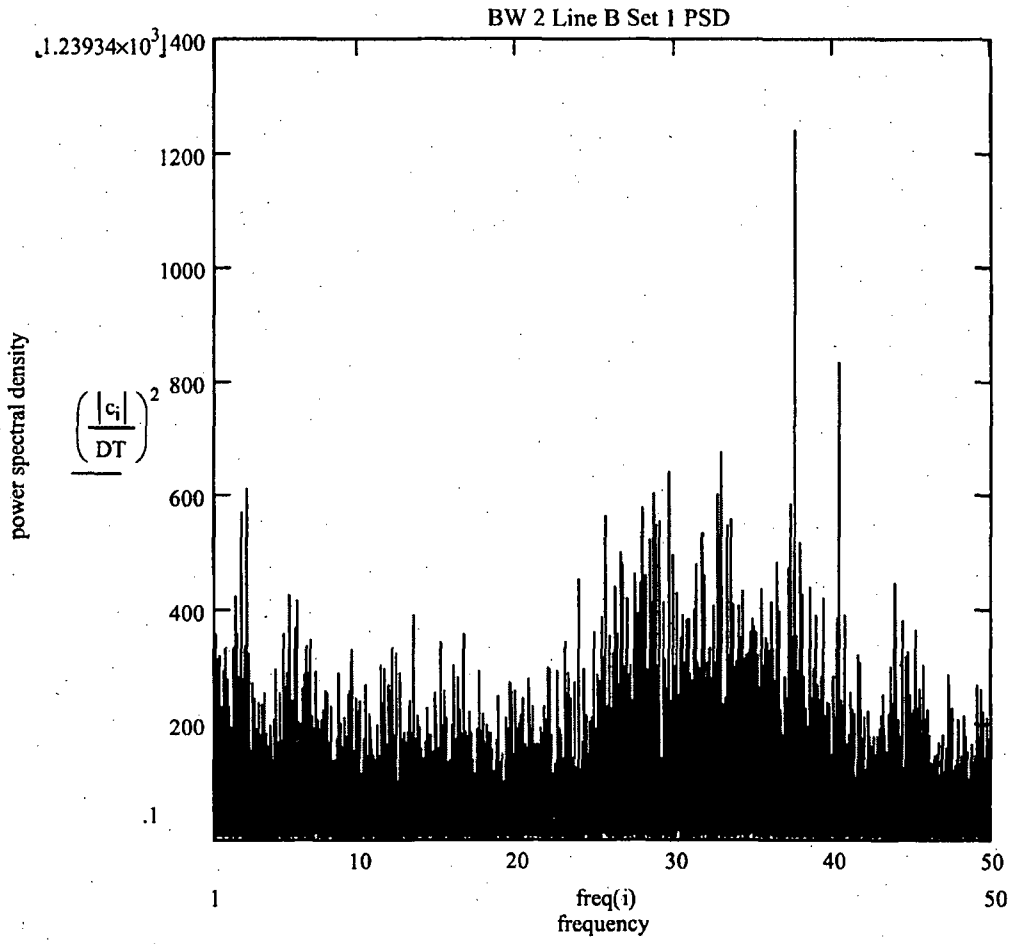

BW 1 Common Header Set 3 PSD
2.44055×10^3
2500
2000
1500
1000
500
1
power spectral density
(|c_i| / DT)^2
10
20
30
40
50
1
freq(i)
frequency
50


BW 1 Common Hdr Set 4 Fourier Coeff
.1
0.08
0.06
0.04
0.02
0
$|c_i|$
1.3026×10^{-13}
0
5
10
15
20
25
30
35
40
45
50
0
freq(i)
frequency
50

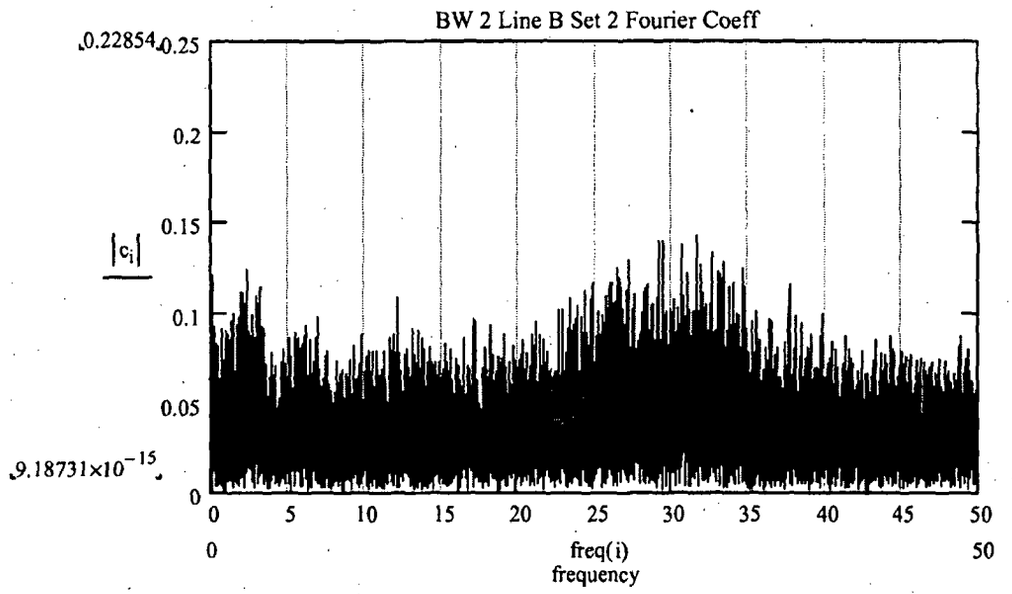

BW 1 Common Header Set 4 PSD
1000
1000
800
600
400
200
.1
power spectral density
$\left(\frac{|c_i|}{DT}\right)^2$
10
20
30
40
50
1
freq(i)
frequency
50

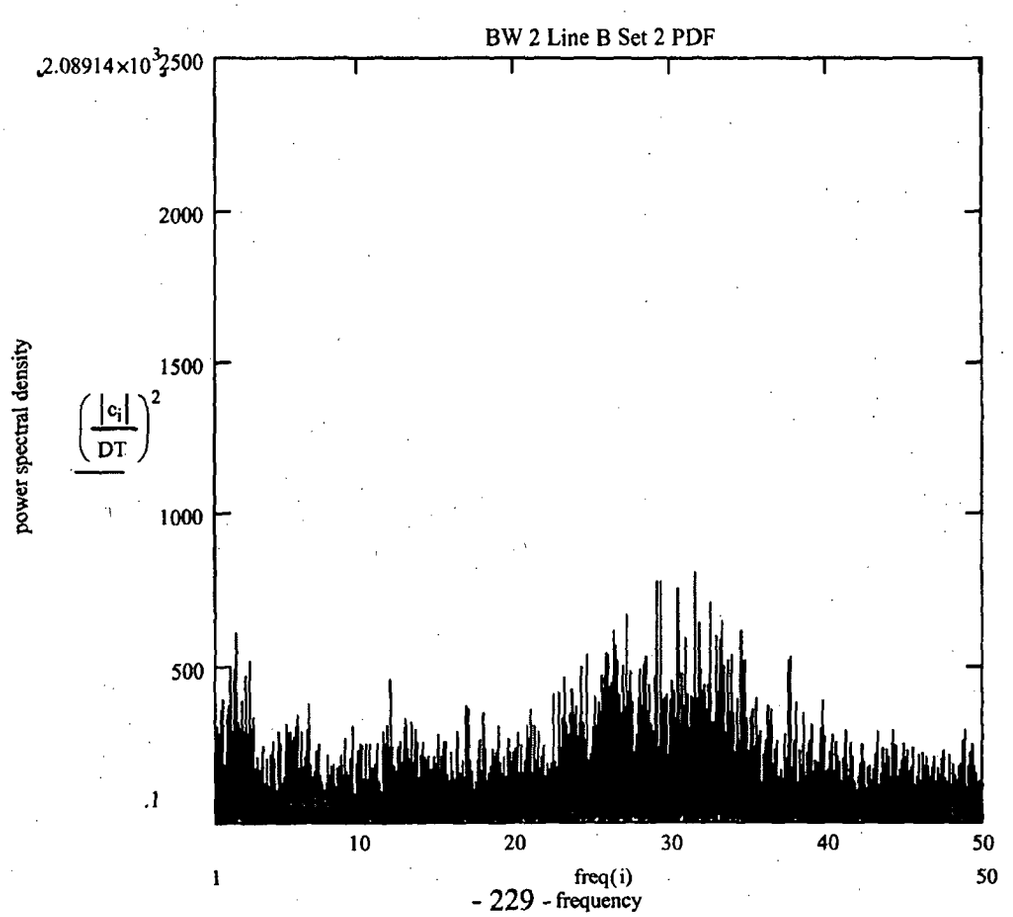
Attachment C Unit 2 Fourier Coefficients and Power Spectral Density Plots



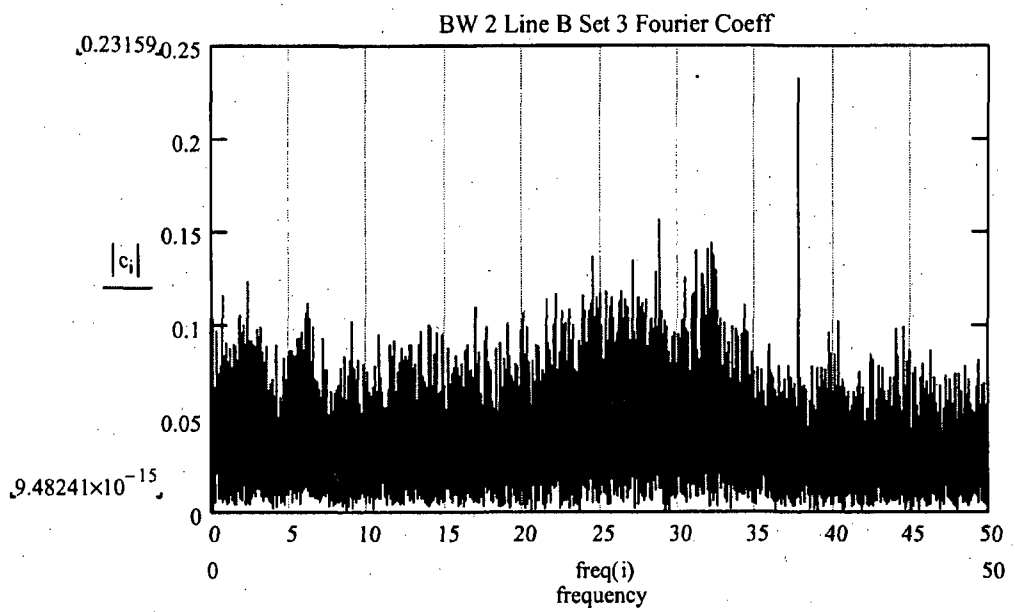


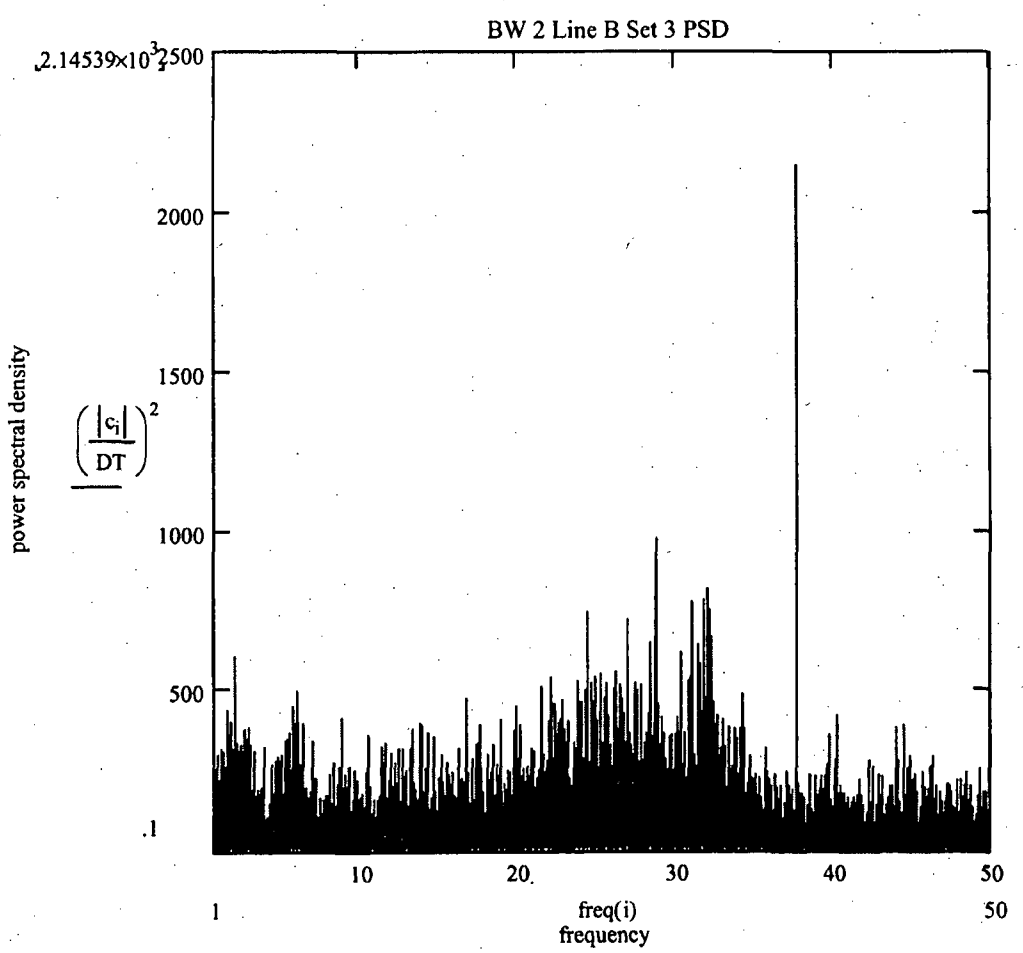
Attachment Q-7, Spectral Analysis of Brwd FW Piping (Pg 29 of 39)



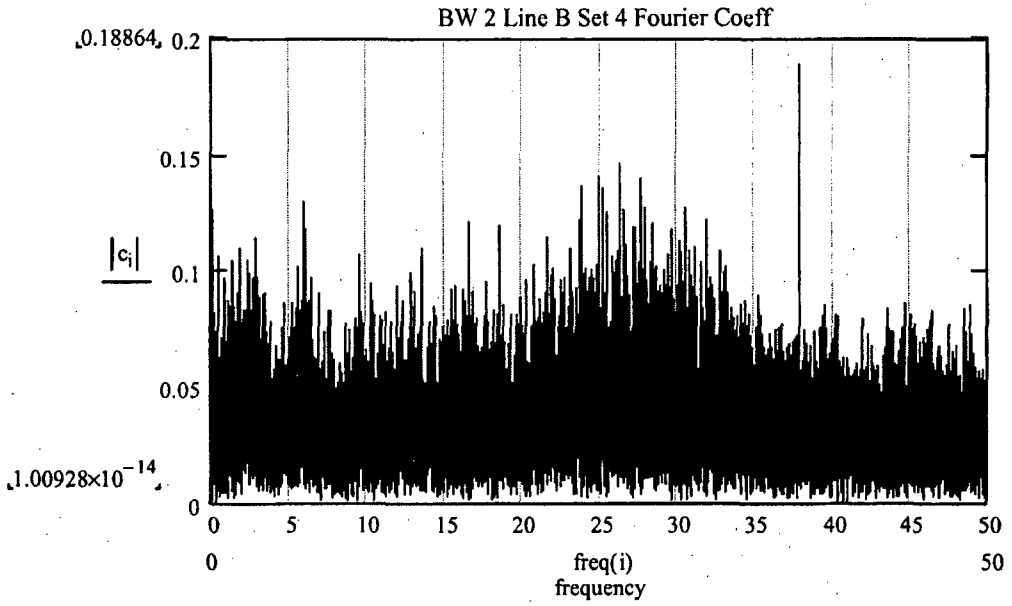


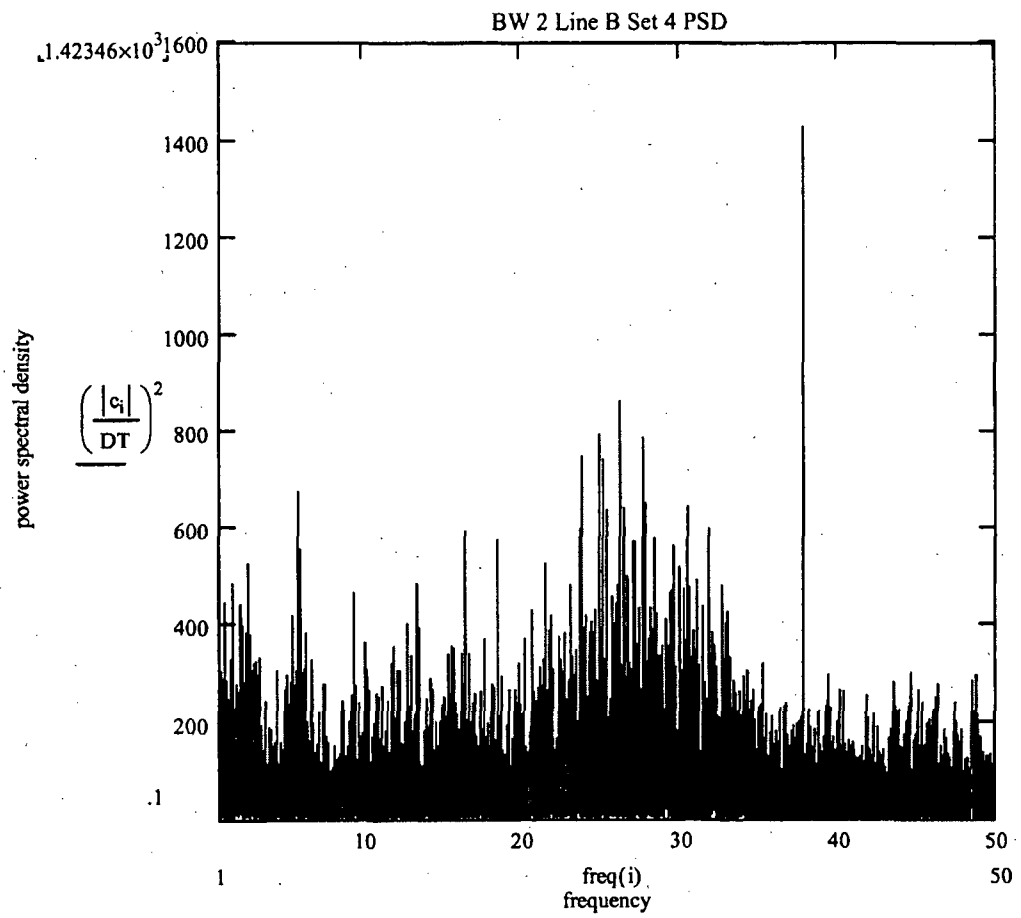
Attachment Q-7, Spectral Analysis of Brwd FW Piping (Pg 30 of 39)

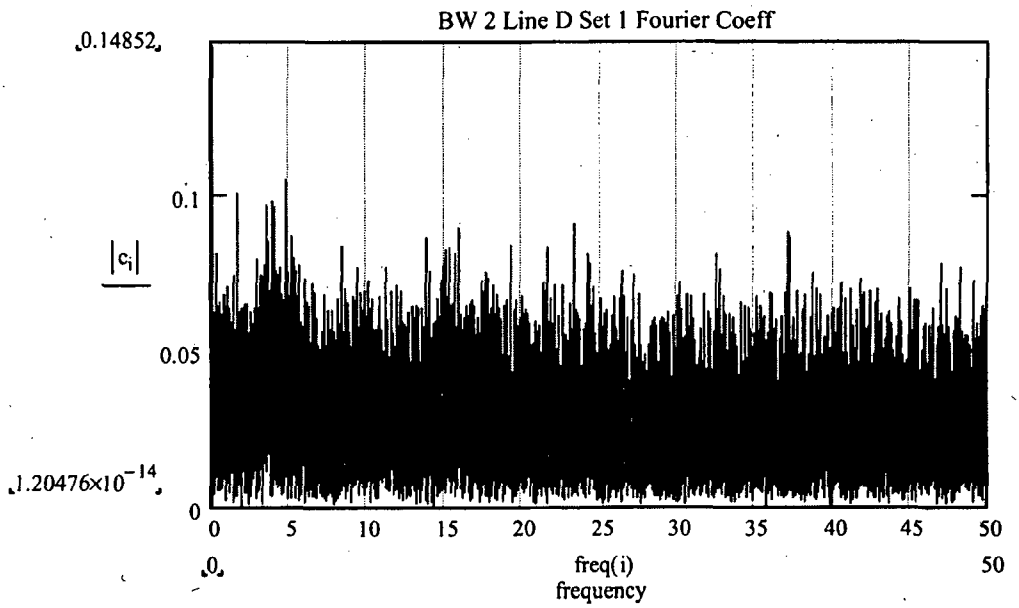


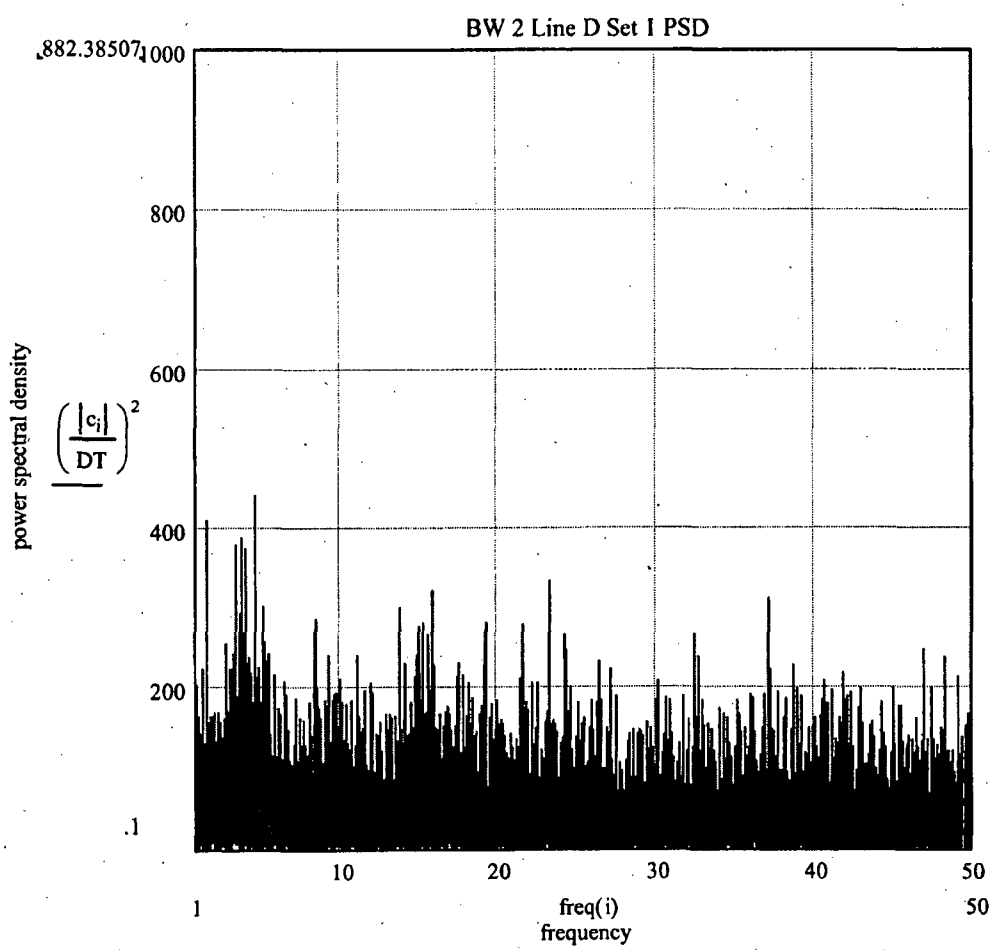


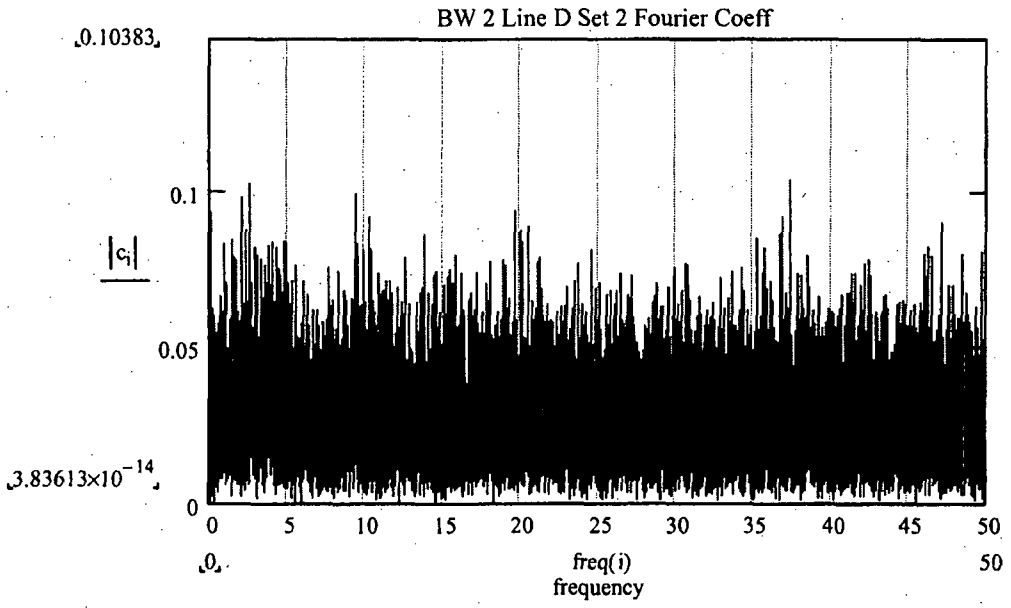
Attachment Q-7, Spectral Analysis of Brwd FW Piping (Pg 31 of 39)

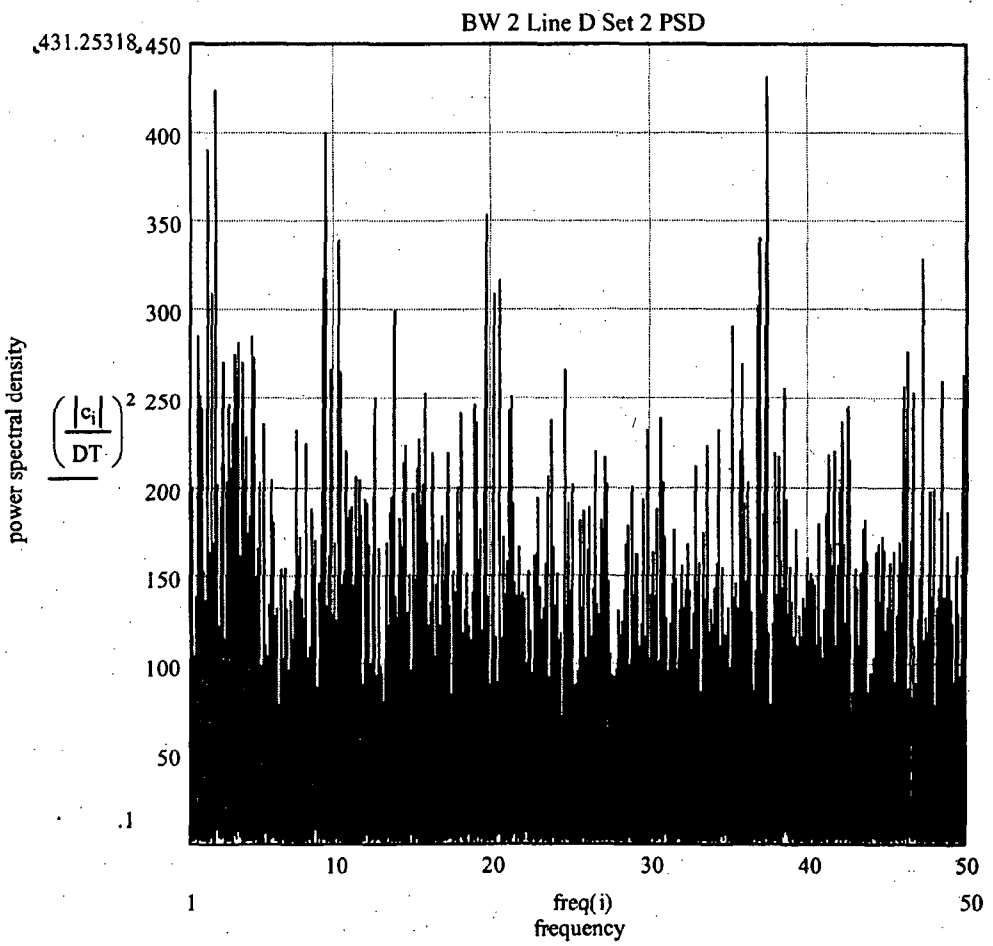


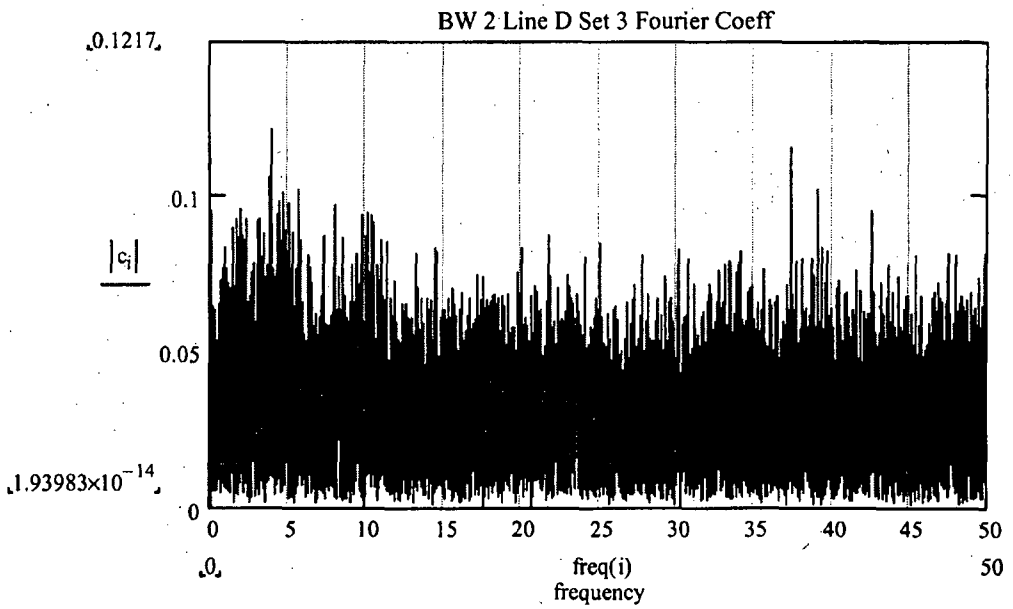


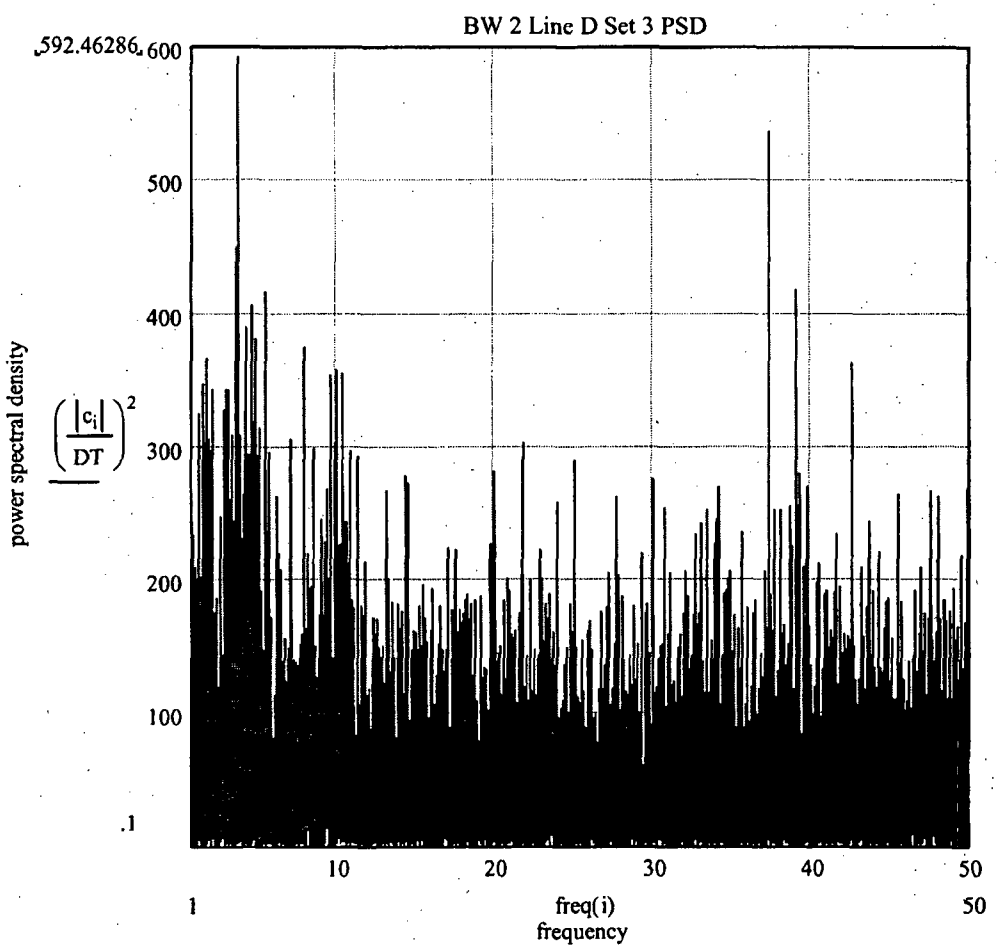

BW 2 Line D Set 1 Fourier Coeff
0.14852
0.1
$|c_i|$
0.05
1.20476×10^{-14}
0
0
5
10
15
20
25
30
35
40
45
50
0
freq(i)
frequency
50


BW 2 Line D Set 1 PSD
882.38507
1000
800
600
400
200
.1
power spectral density
$\left(\frac{|c_i|}{DT}\right)^2$
10
20
30
40
50
1
freq(i)
frequency
50

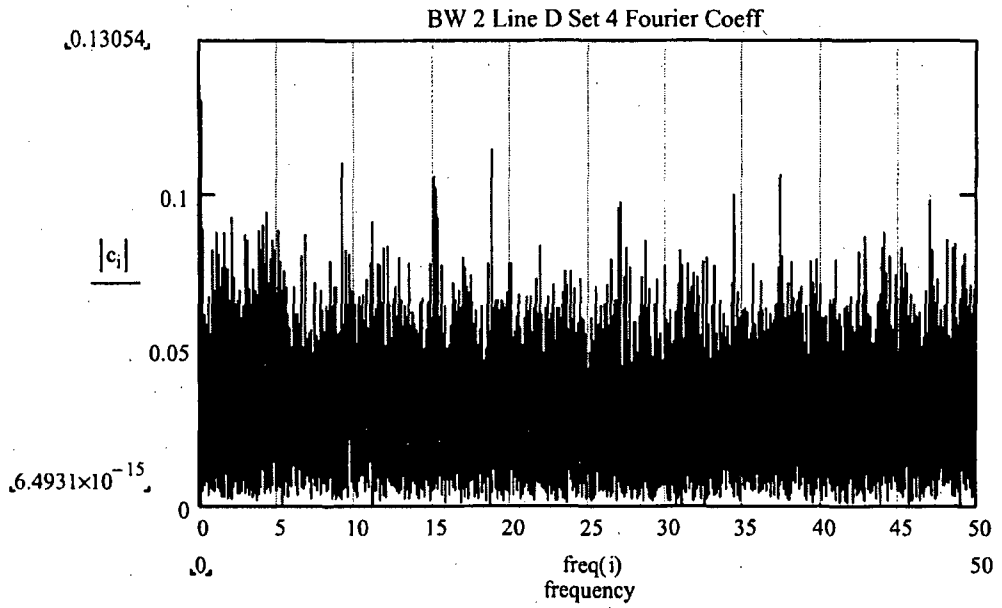

BW 2 Line D Set 2 Fourier Coeff
0.10383
0.1
$|c_i|$
0.05
3.83613×10^{-14}
0
0
5
10
15
20
25
30
35
40
45
50
0
freq(i)
frequency
50

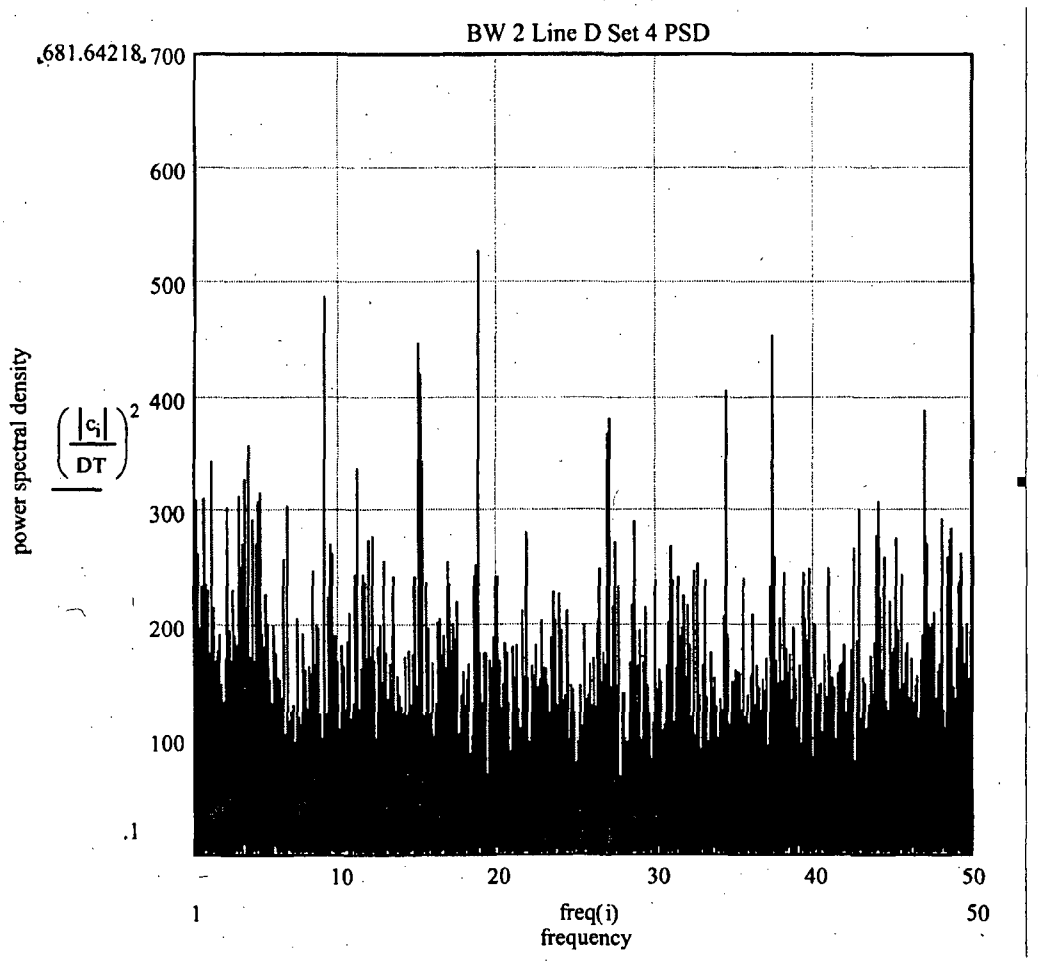

BW 2 Line D Set 2 PSD
431.25318
450
400
350
300
250
200
150
100
50
.1
power spectral density
$\left(\frac{|c_i|}{DT}\right)^2$
10
20
30
40
50
1
freq(i)
frequency
50


BW 2 Line D Set 3 Fourier Coeff
0.1217
0.1
$|c_i|$
0.05
1.93983×10^{-14}
0
0
5
10
15
20
25
30
35
40
45
50
0
freq(i)
frequency
50

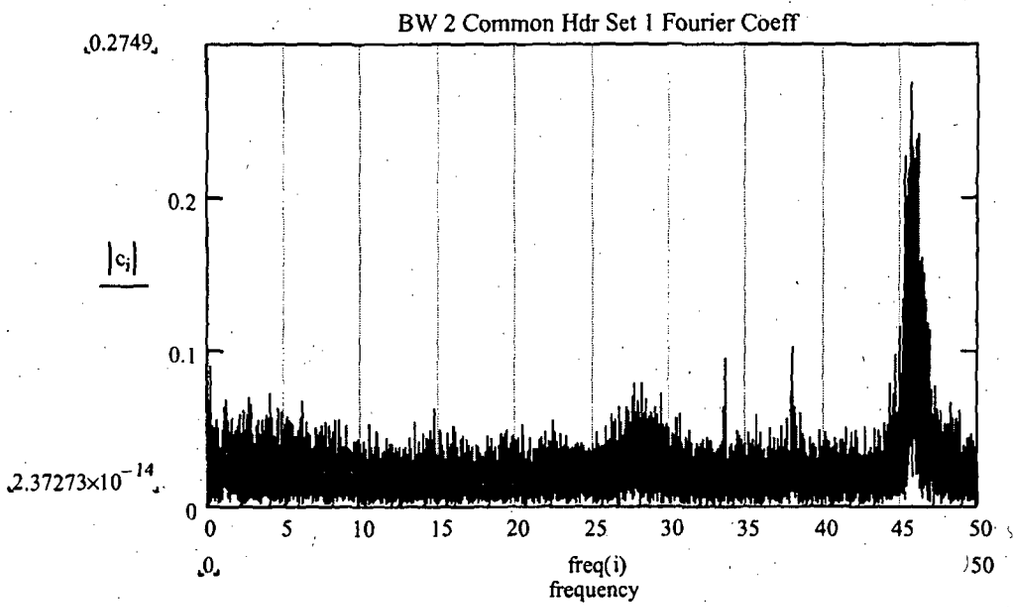

BW 2 Line D Set 3 PSD
592.46286
600
500
400
300
200
100
1
power spectral density
$\left(\frac{|c_i|}{DT}\right)^2$
10
20
30
40
50
1
freq(i)
frequency
50

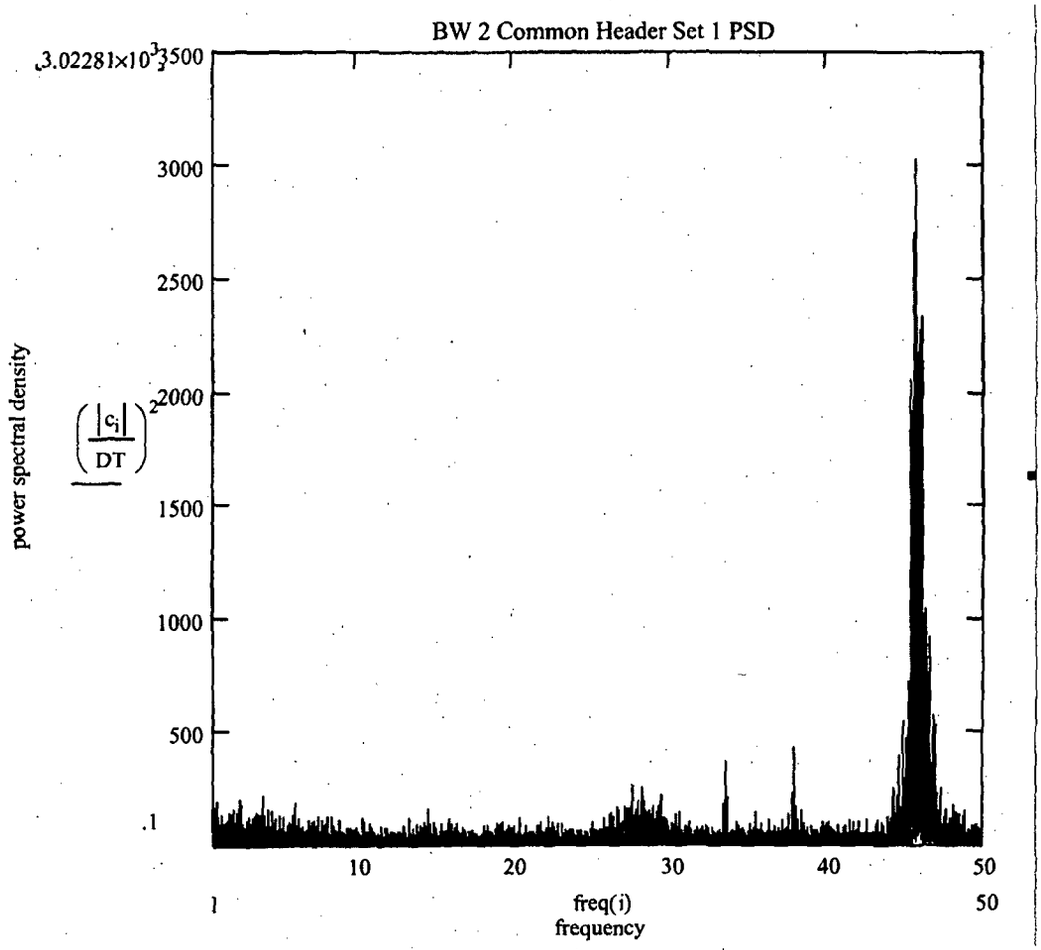
Attachment Q-7, Spectral Analysis of Brwd FW Piping (Pg 35 of 39)



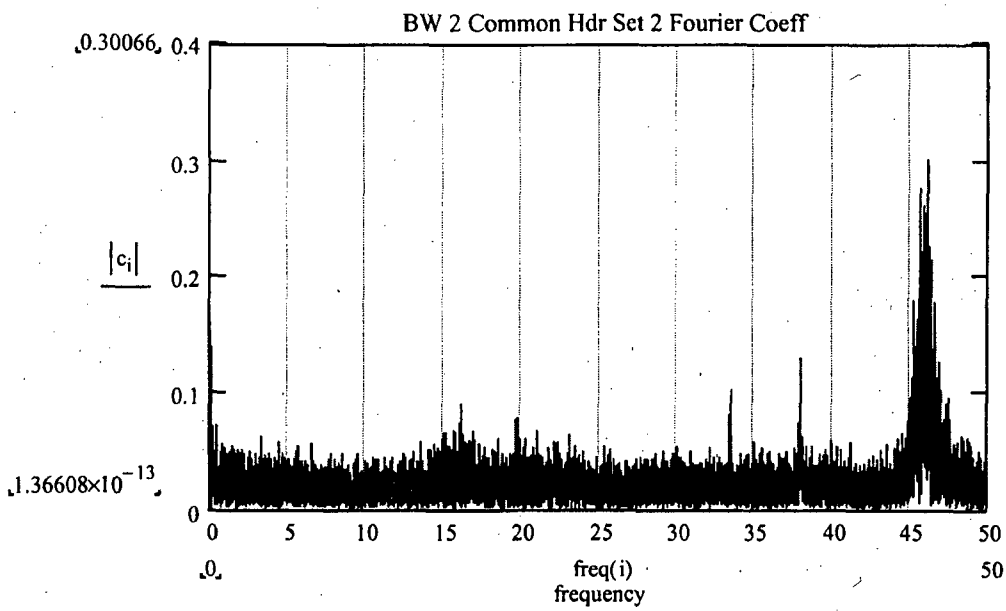


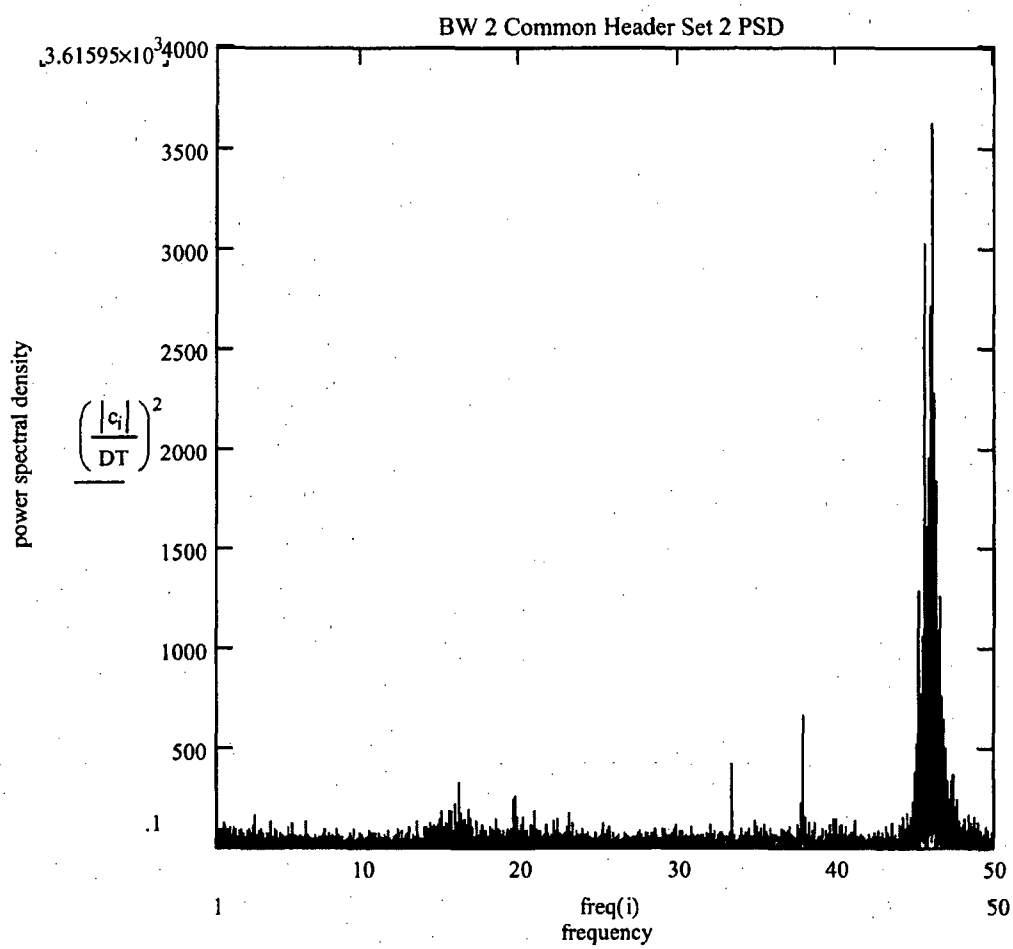
Attachment Q-7, Spectral Analysis of Brwd FW Piping (Pg 36 of 39)



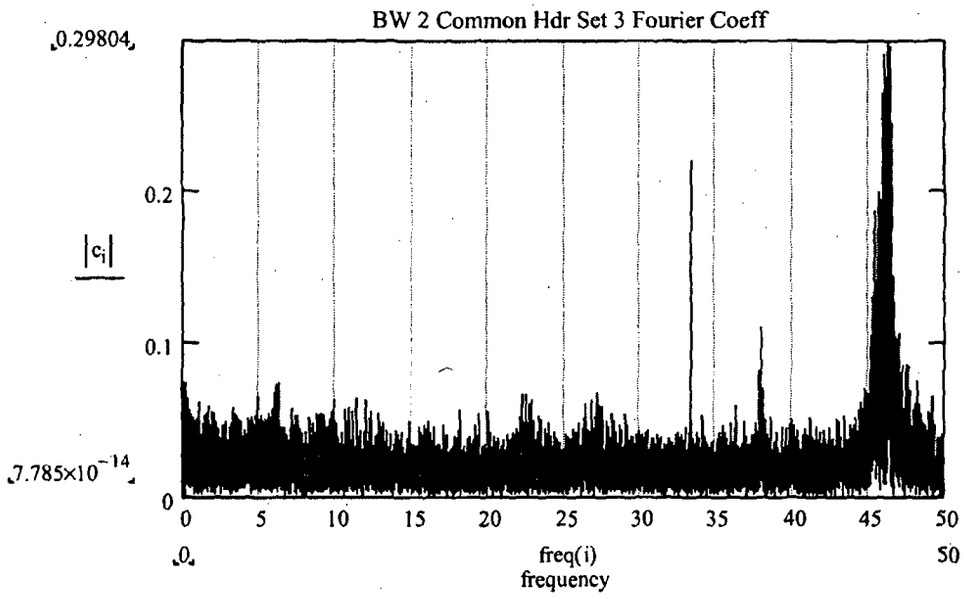


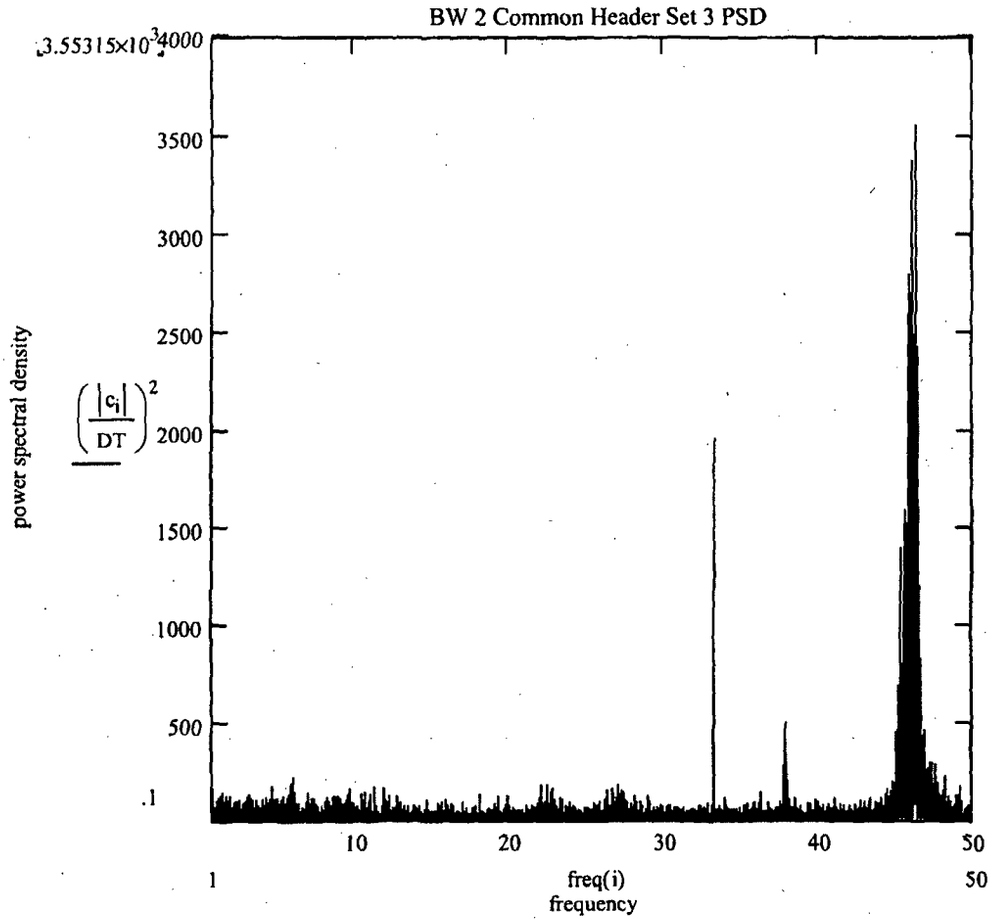
Attachment Q-7, Spectral Analysis of Brwd FW Piping (Pg 37 of 39)



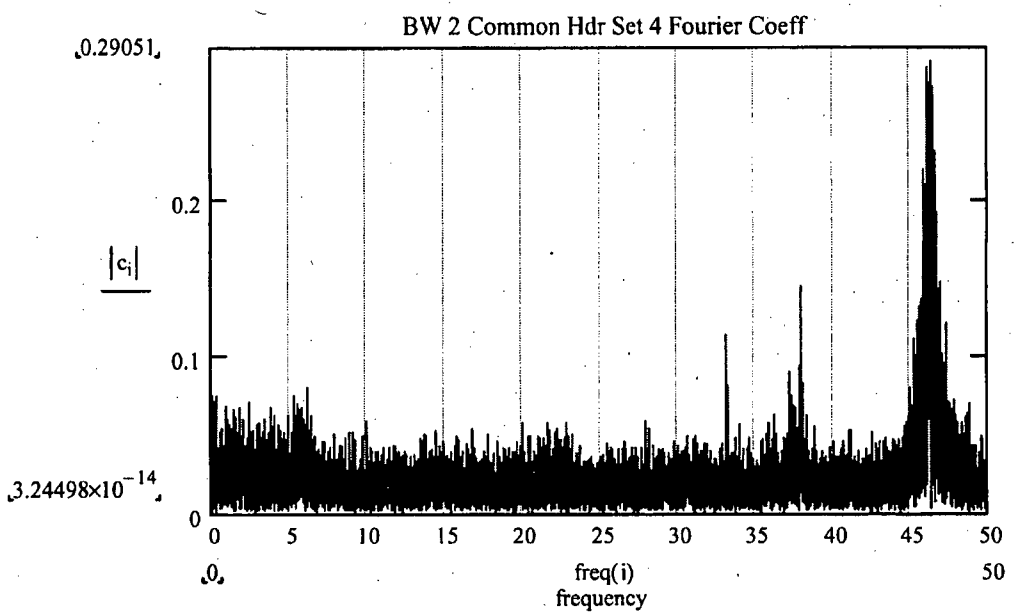


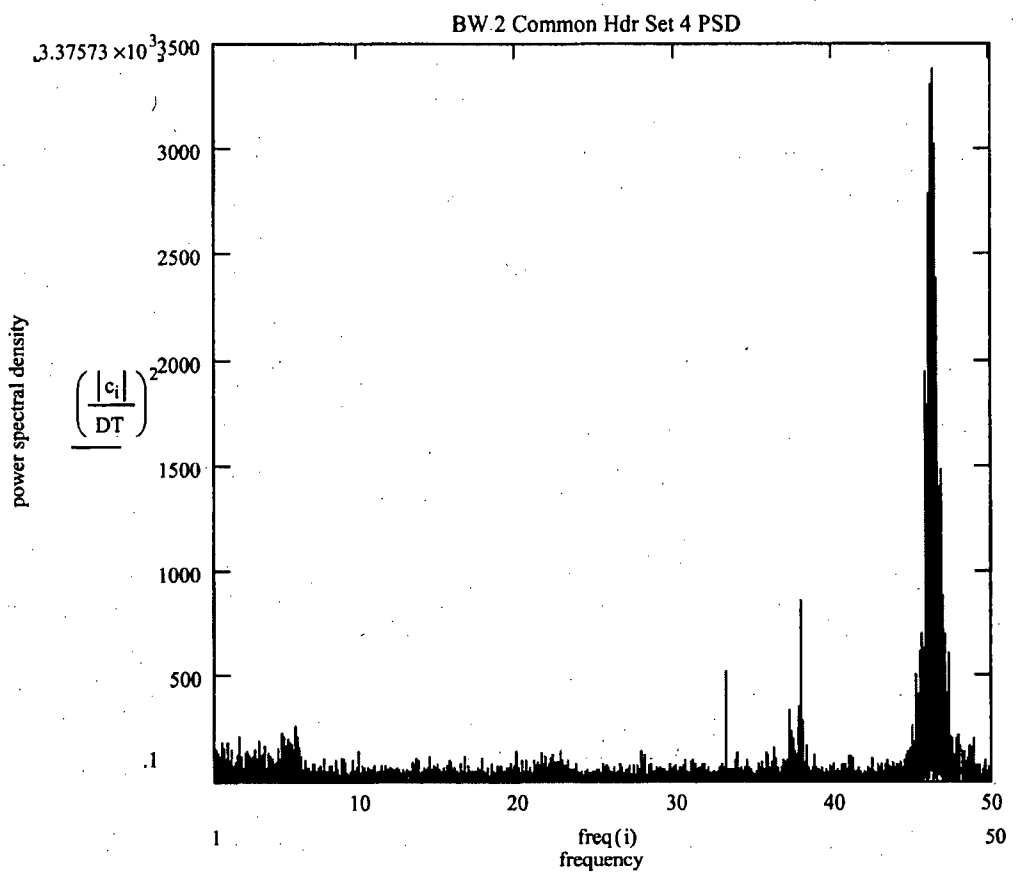
Attachment Q-7, Spectral Analysis of Brwd FW Piping (Pg 38 of 39)





Attachment Q-7, Spectral Analysis of Brwd FW Piping (Pg 39 of 39)





Introduction

The potential for piping acoustical response to affect the accuracy of AMAG ultrasonic flow measurement processes has been previously postulated and demonstrated at Byron Station Unit 2. Byron Unit 1 has similar geometrical properties and employs the same feedwater flow measurement techniques as does Byron 2. A series of dynamic pressure measurements was taken on Byron Unit 1 on November 24, 2003 to facilitate determination of the extent to which the Byron 1 AMAG flow instrumentation may be affected. The purpose of this document is to capture the results of the data reduction as well as provide some physical interpretation.

Data Description

Measurements were taken on the individual feedwater lines in the steam tunnel and on the common header for unit 2. Six sets of data were taken for each location, at a frequency of 200 Hz. Approximately 50000 data points were gathered for each set of data. The data was provided in terms of volts, with 10 volts being equivalent to 1250 psi. The data was reduced using the MathCAD software program in the following way: First the mean was calculated and 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. As a check of the transformation process, the inverse transform of each Fourier data set was taken and plotted along with the original data. These latter plots are not included.

The processed data prior to Fourier reduction was plotted for each set. These plots represent the conversion of the provided voltages to pressures, followed by subtraction of the data set mean value. Review of the data in this form provided two key observations. The first was that the Unit 1 line pressure data shows significant discontinuities at irregular intervals, which was in sharp contrast to the Unit 2 data. The pressure variations at the discontinuities are very large and are not physical, particularly since the common header data shows no evidence of pressure cycling consistent with the discontinuities in the lines. The most likely source of this type of discontinuity would be loose or intermittent electrical connections in the test circuit. The remaining data minus the discontinuities appears to be reasonable and representative. Therefore for Unit 1, subsets of the data excluding the discontinuities were used for the spectral analysis. The second point that was observed is that the common header pressure variations are significantly less than those in the individual lines, which suggests that the common header is generally less noisy. Both of these observations match with Braidwood, and the plots are not included here.

Spectral Analysis

Attachment A contains the plots of Fourier coefficients and Attachment B the Power Spectral Density for each data set (or selected portion thereof) for Unit 1. As noted above, the Mathcad program has been utilized to generate this information. The complex form of the FFT has been used since it eliminates the requirement to have data lengths equal to powers of 2. The normalization, based on using the capitalized form of the transform symbols, is based on 1/N, where N is the number of data points. The coefficient plots and power spectral density plots are provided with similar axis scales to allow some relative comparison.

Piping Resonance Analysis

The piping acoustic resonance frequencies can be predicted theoretically using established relationships. Based on experience of comparable evaluations of Byron feedwater lines, the most probable resonance will be based on the piping downstream of the feed regulating valves to the steam generator. The following relationship is based on a closed-open acoustic boundary condition and will be used to define the first eight acoustic modes:

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

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

The speed of sound in the feedwater line is approximately 4200 fps. The lengths of the Unit 1A and B lines are approximately 344 feet and 583 feet respectively. The lengths of the Unit 1 C and D lines are approximately 646 feet and 368 feet respectively. The common header is approximately 382 feet long, based on Byron Unit 1 dimensions. This leads to the following frequencies being predicted:

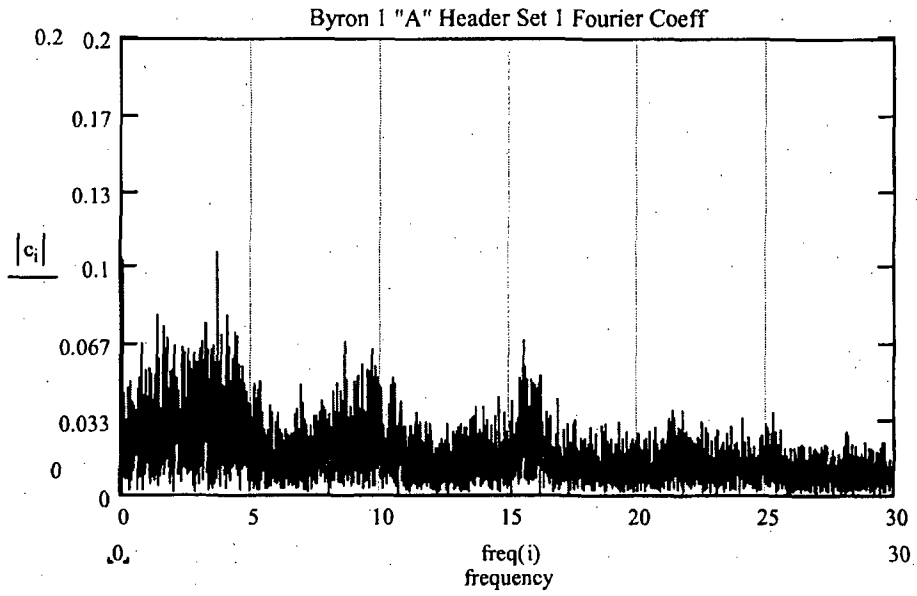
mode	BY 1 Line A	BY1 Line B	BY 1 Line C	BY 1 Line D	BY 1 Common Hdr
1	3.1	1.8	1.6	2.9	2.7
2	9.2	5.4	4.9	8.6	8.2
3	15.3	9.0	8.1	14. 3	13.7
4	21.4	12.6	11.4	20.0	19.2
5	27.5	16.2	14.6	25.7	24.7
6	33.6	19.8	17.9	31.4	30.2
7	39.7	23.4	21.1	37.1	35.7
8	45.8	27.0	24.4	42.8	41.2

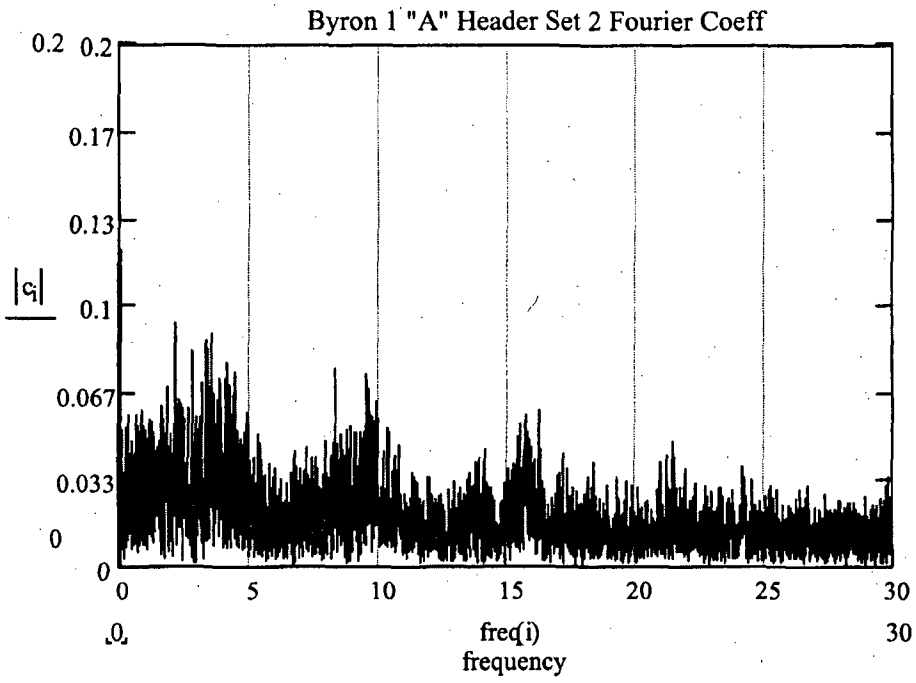
Results

The plots of Fourier coefficients and Power Spectral Density were then reviewed and compared to the anticipated frequencies shown in the table above. The Unit 1 line A data suggests that the expected frequencies are in fact present in the signal, particularly through the first three modes. 1D shows modes 2-4. 1C shows modes 1-5. 1D shows modes 2 and 3. The PSDs support these conclusions. The Unit 1 lines A and B data shows generally a significantly lower amount of acoustic response. The acoustic modes are there, but with less amplitude and less power associated with those amplitudes. The Unit 1 common header shows almost no significant acoustic frequency content at frequencies below 35 hz. No prominent responses exists greater than 35 Hz as at Braidwood.

Conclusions

Dynamic pressure data has been collected from the Byron Unit 1 feedwater system and a spectral analysis has been performed. All individual lines and the common header for Unit 1 were considered. The piping fundamental acoustic frequencies have been predicted for the lines and headers and a comparison to the FFT results was made. The results support that the long lines are more acoustically noisy than the short lines, and that the common header is relatively absent of acoustic response, except at frequencies above those of concern. This is reasonable considering that there is little pressure drop occurring in the common header piping that would be capable of exciting acoustic response. The feed regulating valves, on the other hand, provide a large pressure drop and broadband noise signal that is potentially capable of exciting acoustic resonant behavior. The results obtained are consistent with this understanding.


Byron 1 "A" Header Set 1 Fourier Coeff
0.2
0.2
0.17
0.13
|c_i|
0.1
0.067
0.033
0
0
0
5
10
15
20
25
30
.0
freq(i)
frequency
30


Byron 1 "A" Header Set 2 Fourier Coeff
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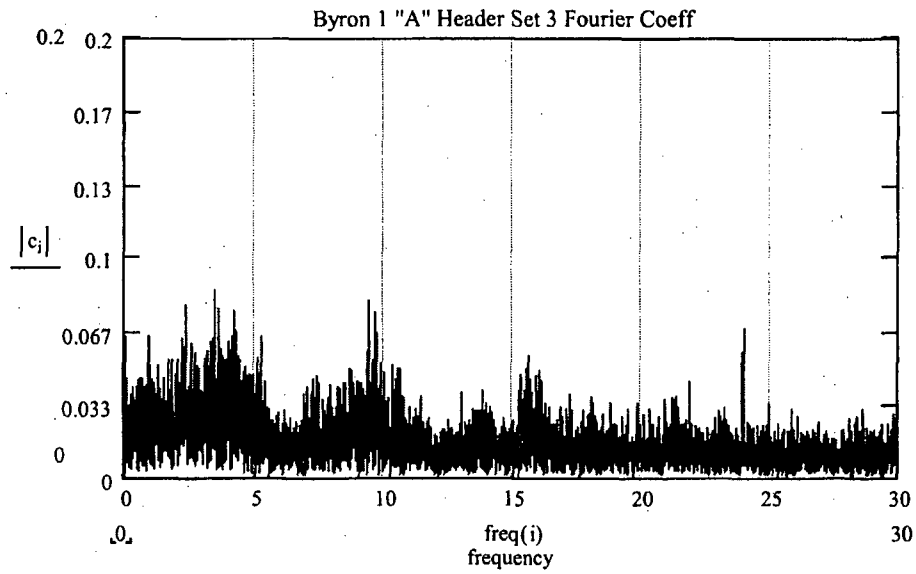
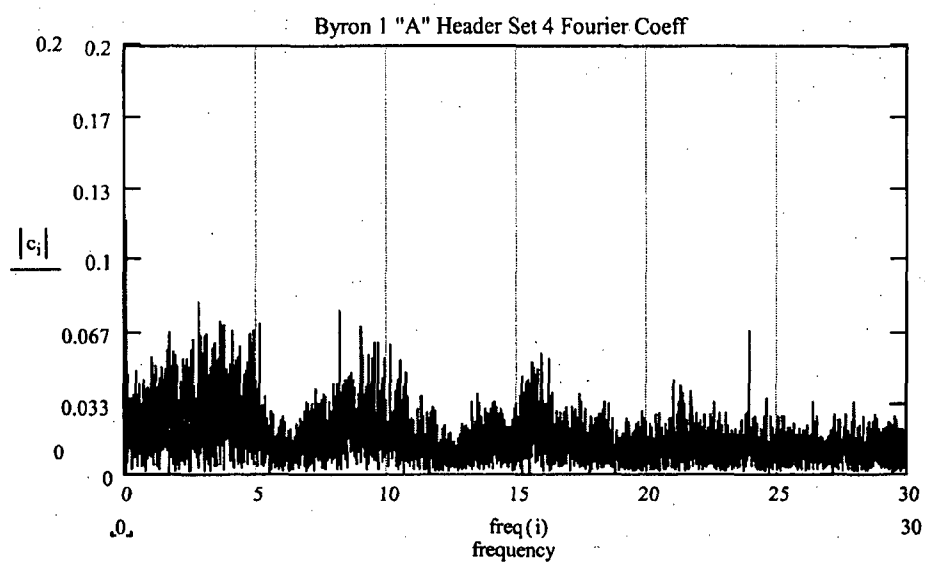
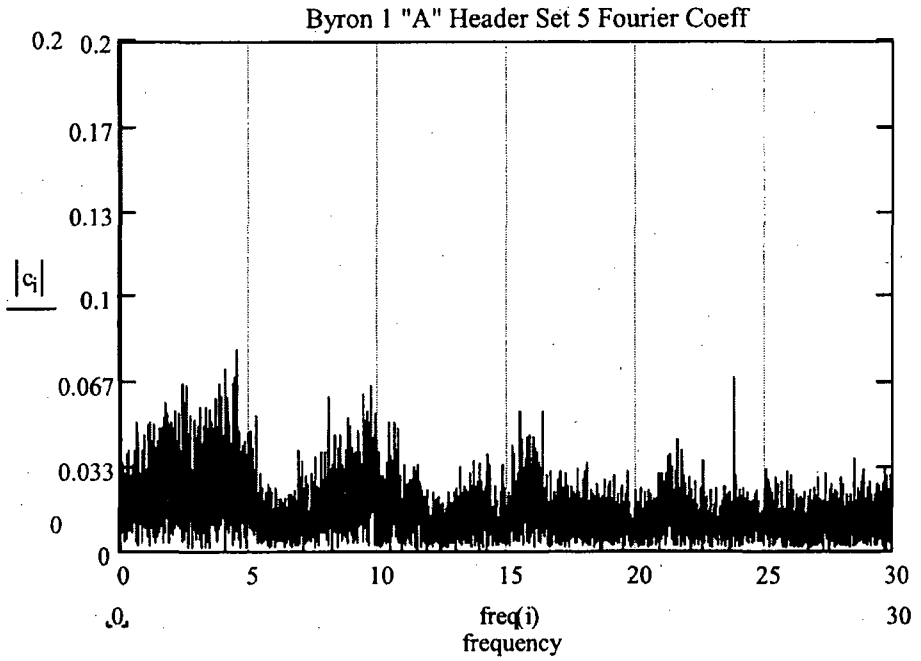
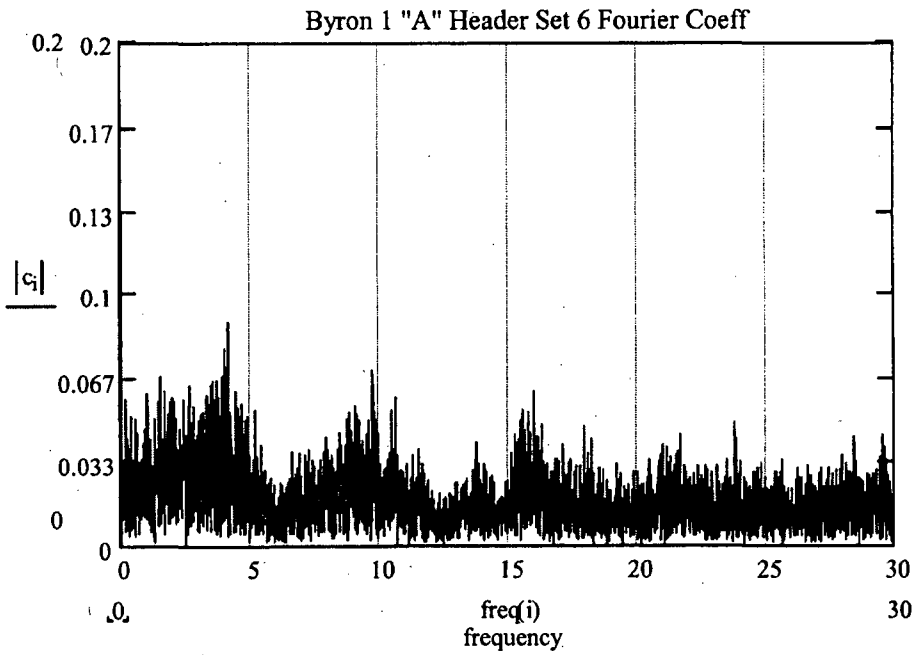
0.2
0.17
0.13
|c_i|
0.1
0.067
0.033
0
0
0
5
10
15
20
25
30
.0
freq(i)
frequency
30

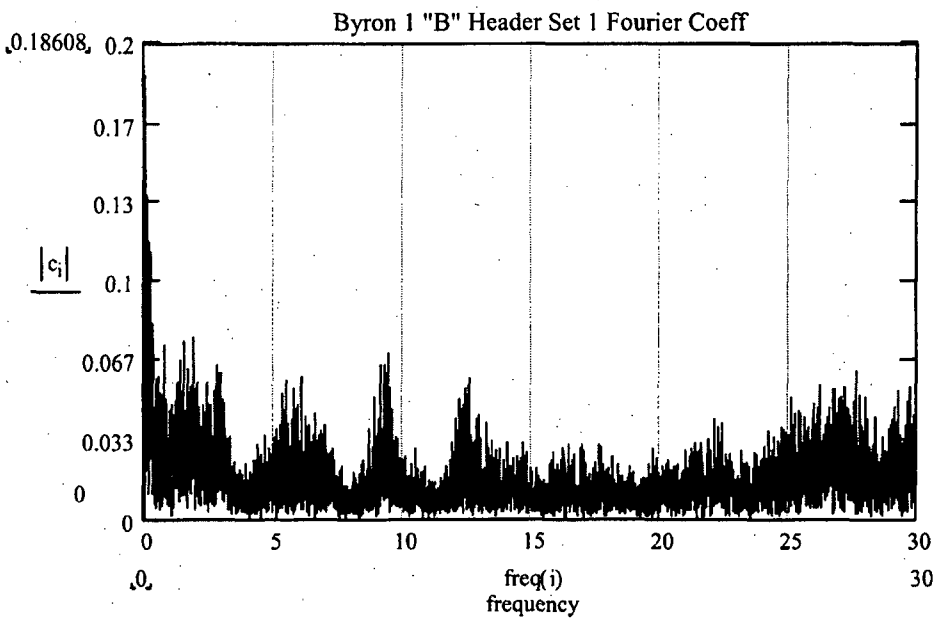
Attachment Q-8, Spectral Analysis of Byron 1 FW Piping (Pg 5 of 33)






Byron 1 "A" Header Set 5 Fourier Coeff
0.2
0.17
0.13
|c_i|
0.1
0.067
0.033
0
0
5
10
15
20
25
30
0
freq(i)
frequency
30


Byron 1 "A" Header Set 6 Fourier Coeff
0.2
0.17
0.13
|c_i|
0.1
0.067
0.033
0
0
5
10
15
20
25
30
0
freq(i)
frequency
30


Byron 1 "B" Header Set 1 Fourier Coeff
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0.17
0.13
|c_i|
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0.067
0.033
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0
0
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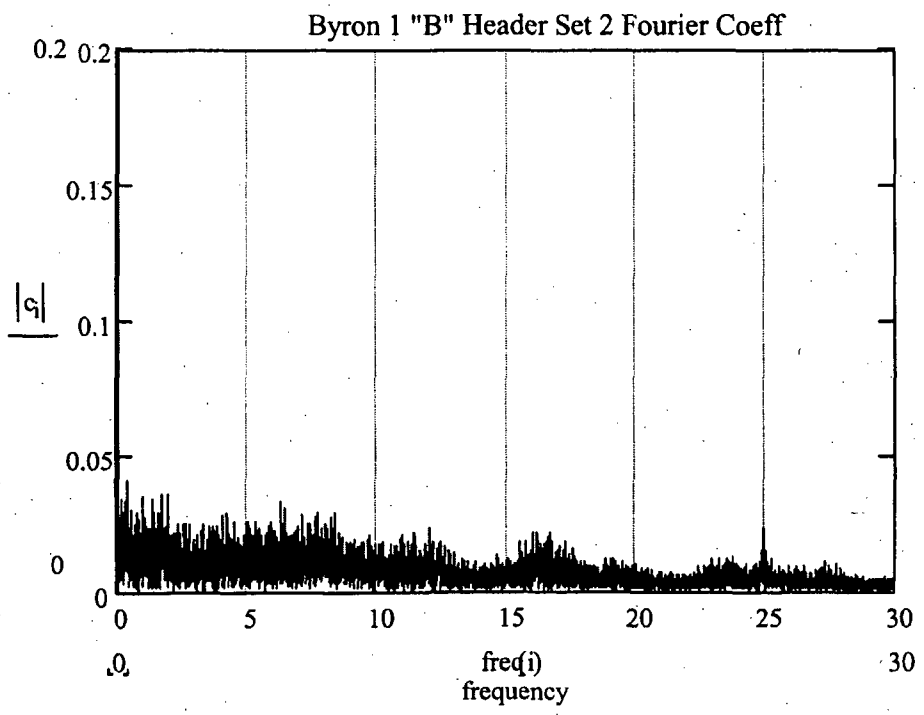
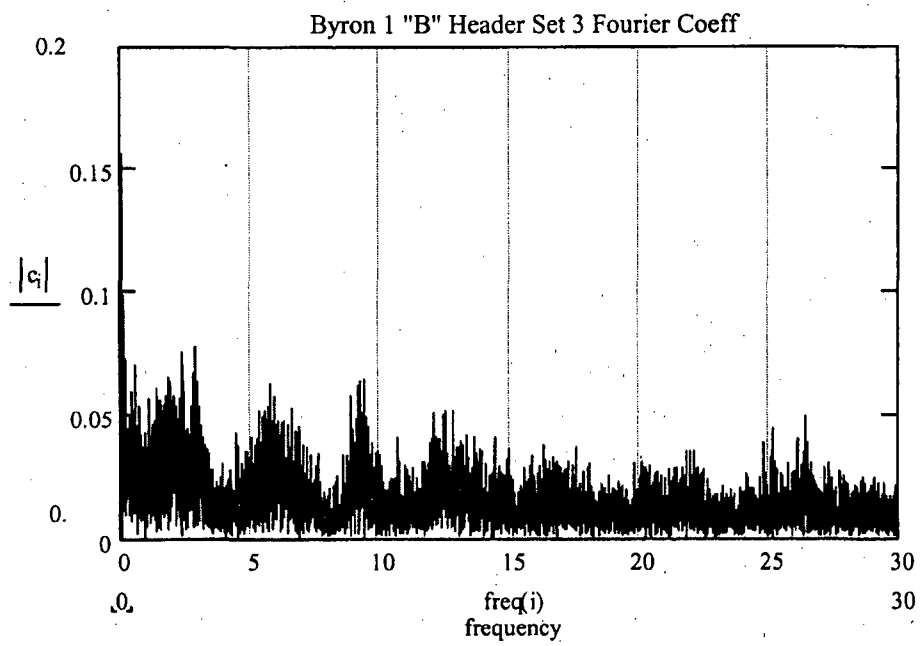
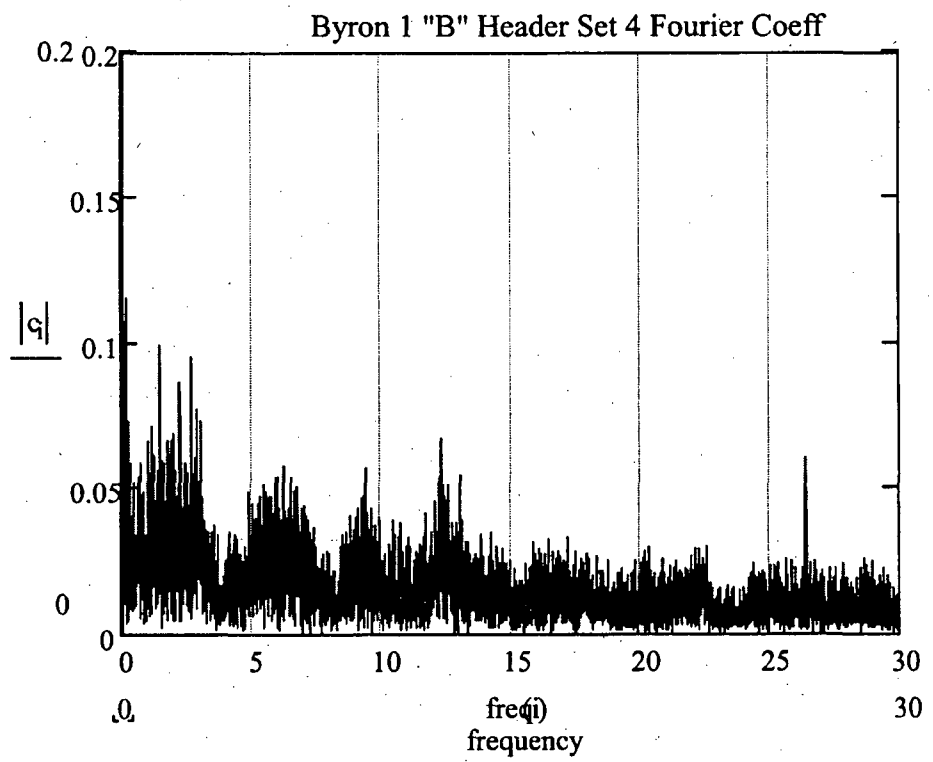
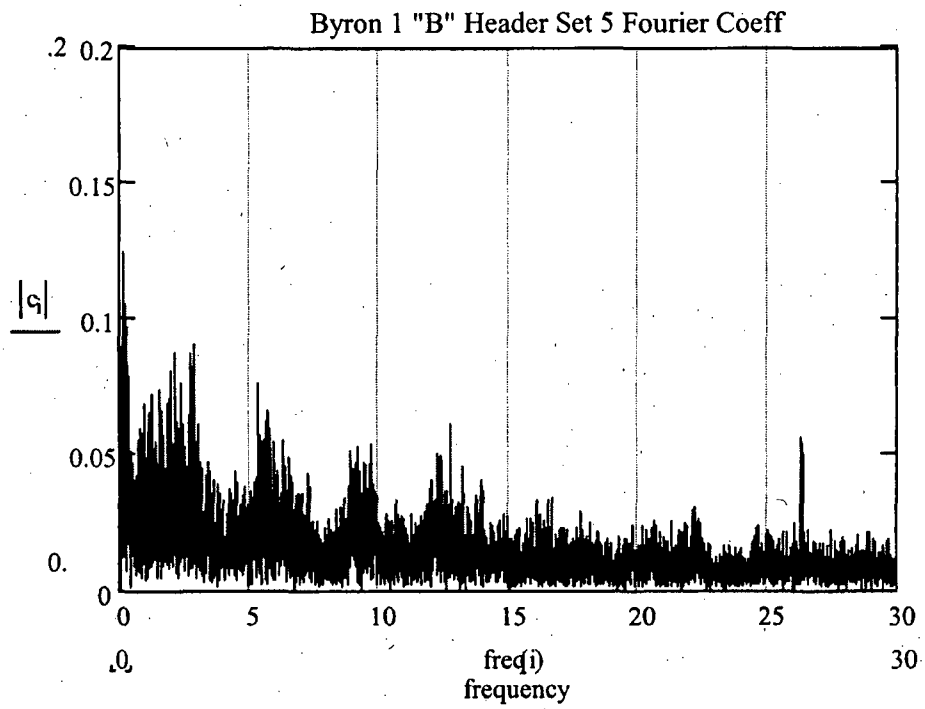
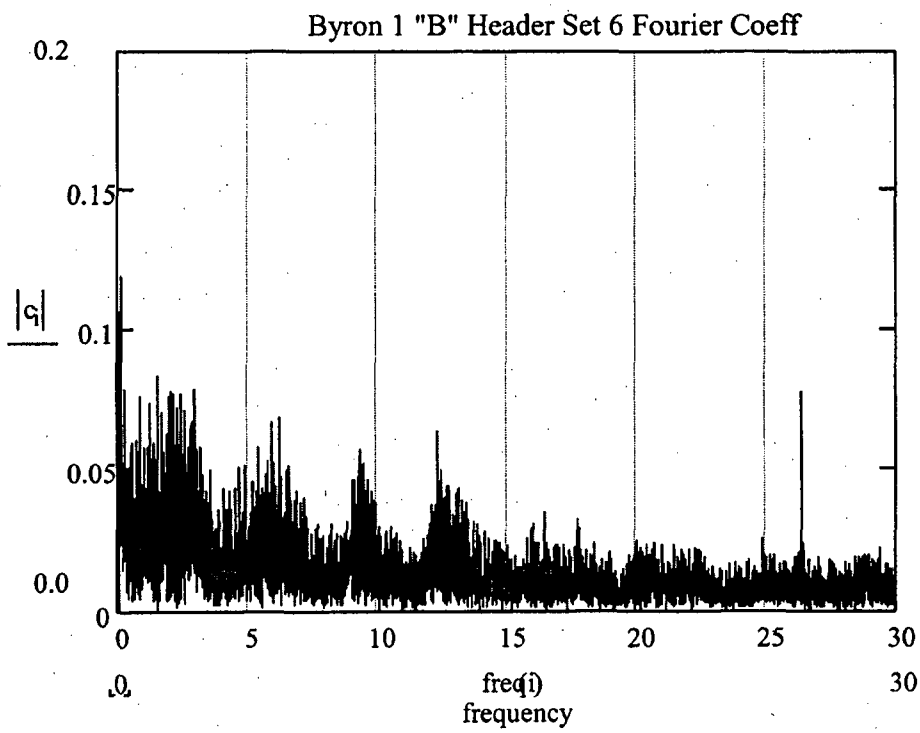
10
15
20
25
30
0
freq(i)
frequency
30


Byron 1 "B" Header Set 2 Fourier Coeff
0.2
0.2
0.15
|c_i|
0.1
0.05
0
0
0
5
10
15
20
25
30
0
freq(i)
frequency
30

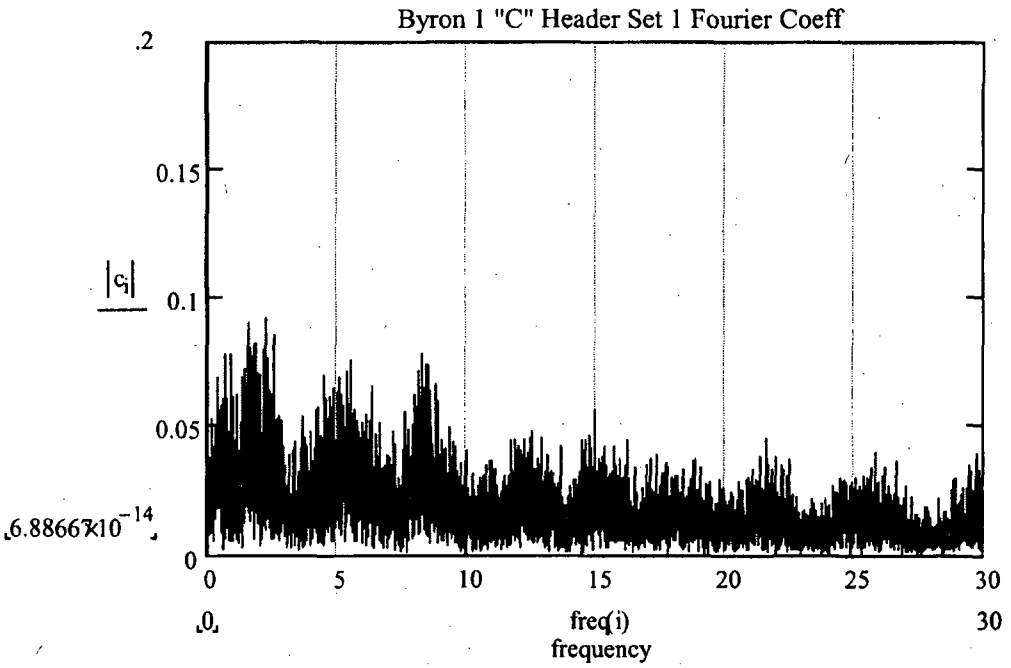

Byron 1 "B" Header Set 3 Fourier Coeff
0.2
0.15
|c_i|
0.1
0.05
0.
0
0
5
10
15
20
25
30
0
freq(i)
frequency
30

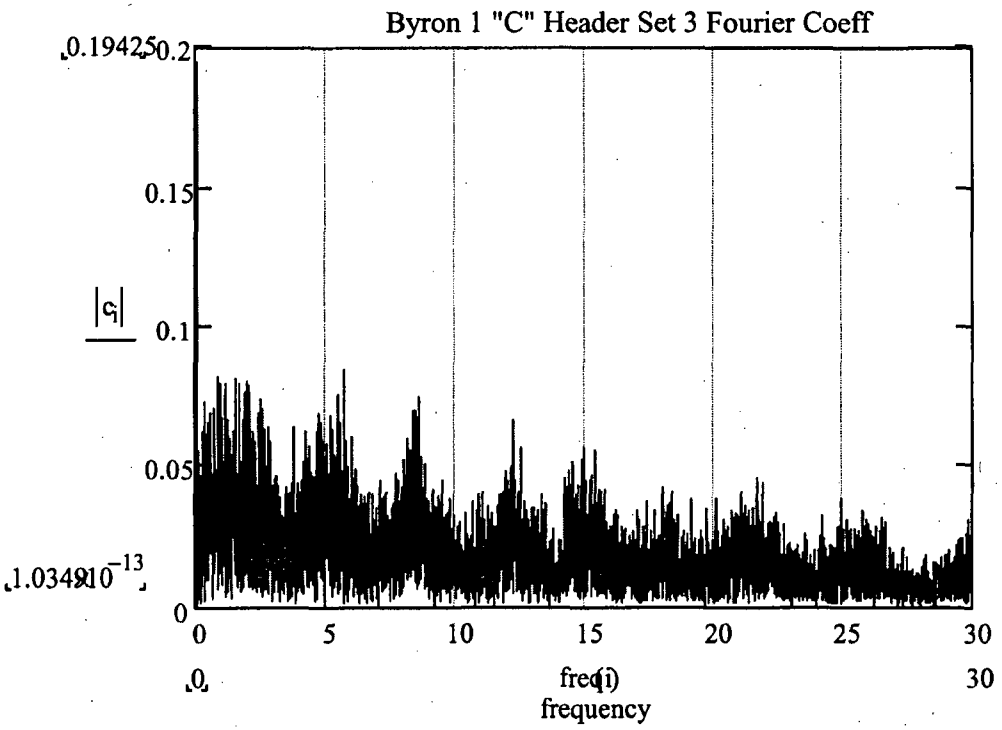

Byron 1 "B" Header Set 4 Fourier Coeff
0.2
0.2
0.15
|c_i|
0.1
0.05
0
0
0
5
10
15
20
25
30
0
freq(i)
frequency
30

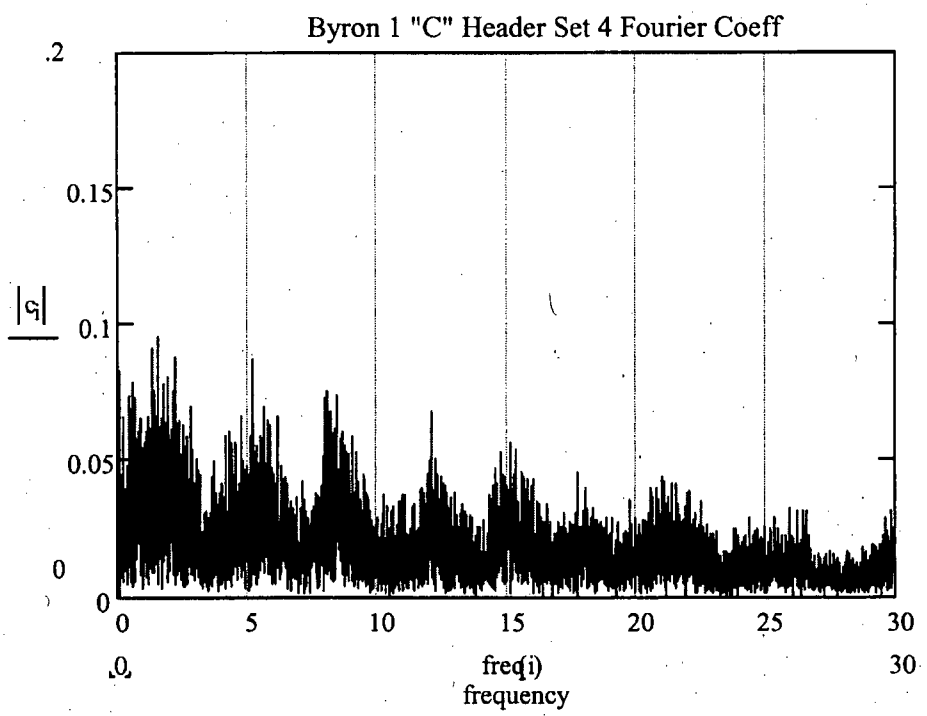

Byron 1 "B" Header Set 5 Fourier Coeff
.2
0.2
0.15
|q|
0.1
0.05
0.
0
0
5
10
15
20
25
30
.0
freq(i)
frequency
30

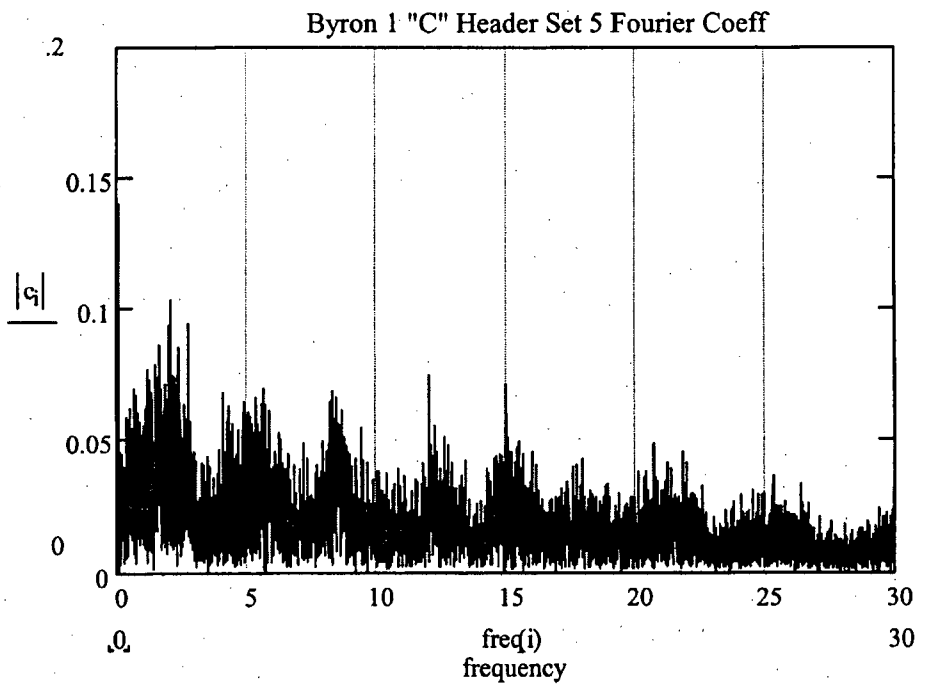

Byron 1 "B" Header Set 6 Fourier Coeff
0.2
0.15
|q|
0.1
0.05
0.0
0
0
5
10
15
20
25
30
.0
freq(i)
frequency
30

Attachment Q-8, Spectral Analysis of Byron 1 FW Piping (Pg 10 of 33)

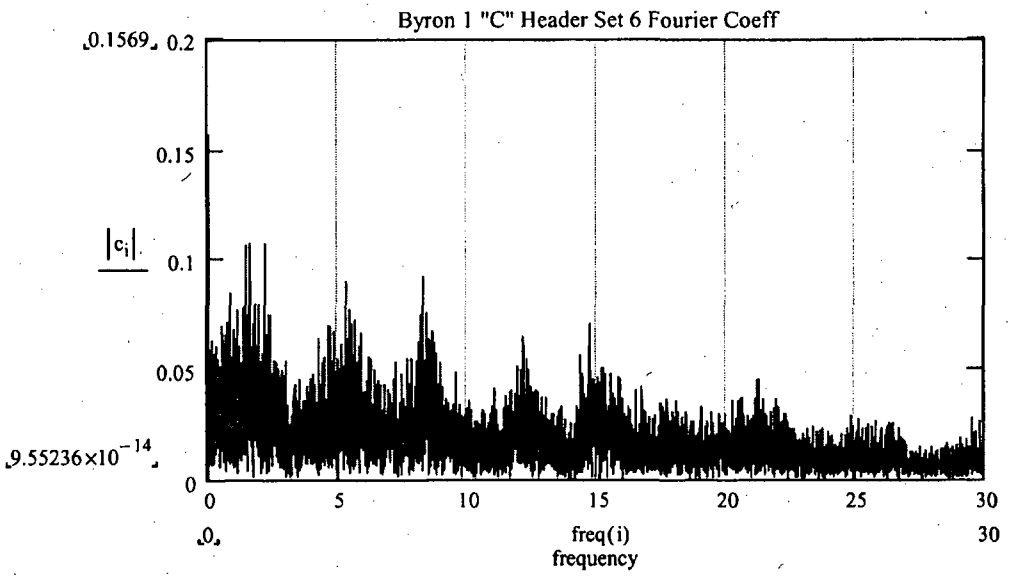




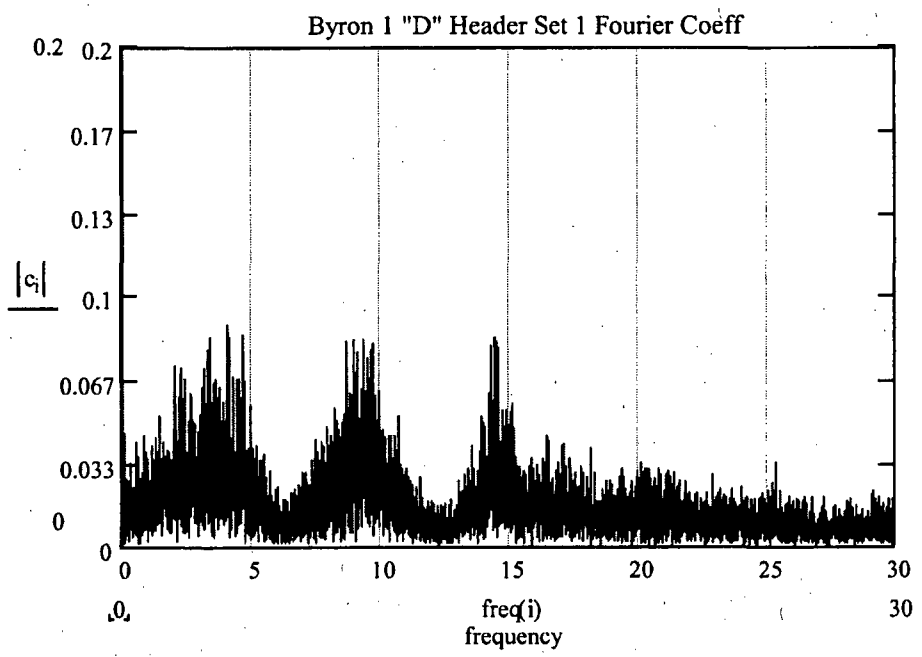

Byron 1 "C" Header Set 4 Fourier Coeff
.2
0.15
|c_i|
0.1
0.05
0
0
0
5
10
15
20
25
30
0
freq(i)
frequency
30

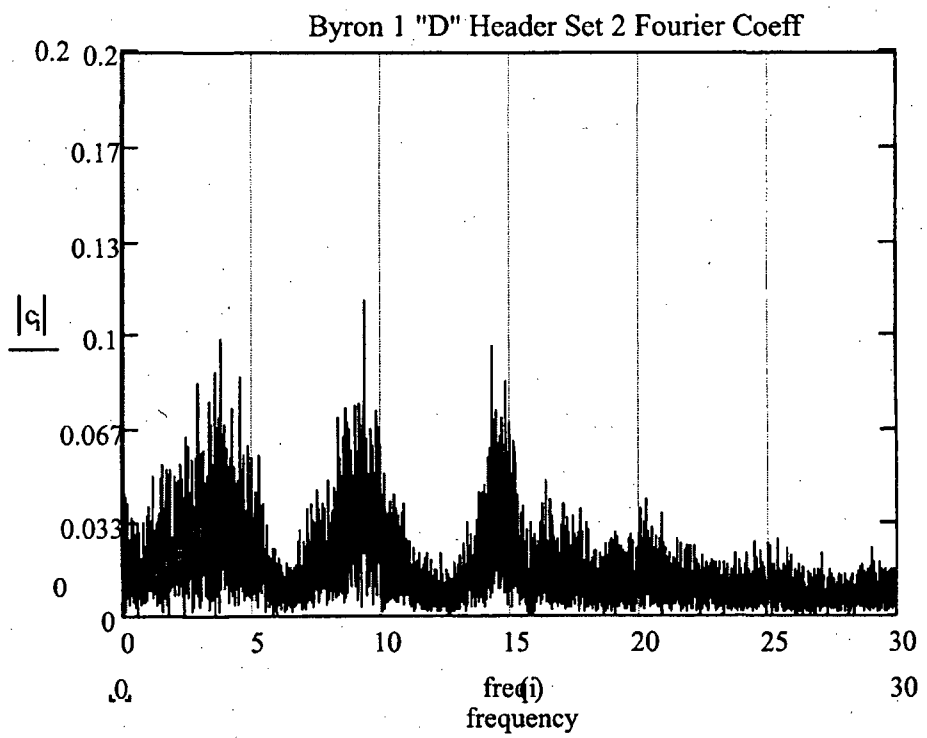

Byron 1 "C" Header Set 5 Fourier Coeff
.2
0.15
|c_i|
0.1
0.05
0
0
0
5
10
15
20
25
30
0
freq(i)
frequency
30

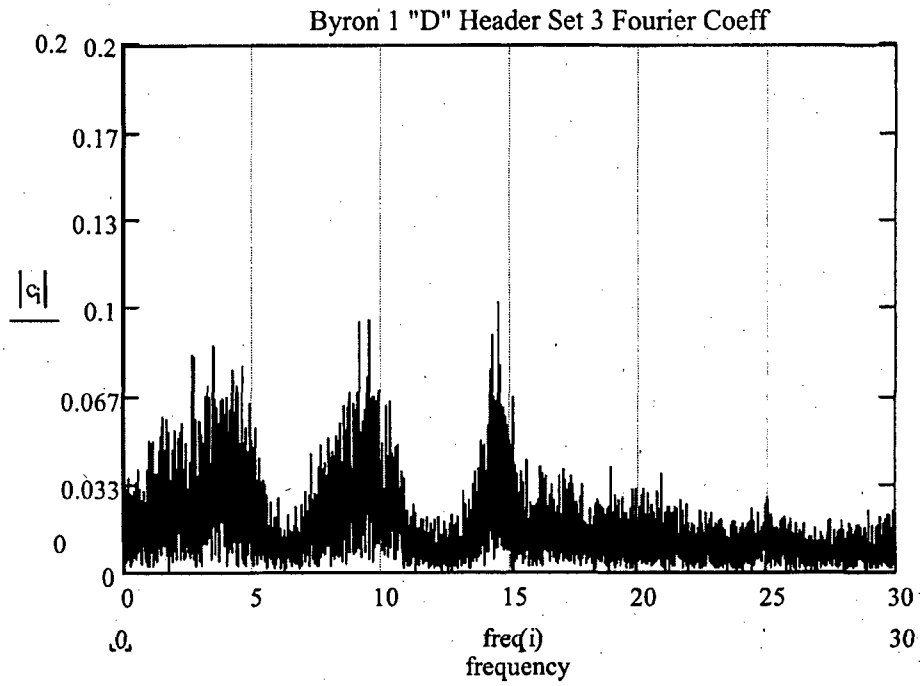
Attachment Q-8, Spectral Analysis of Byron 1 FW Piping (Pg 12 of 33)

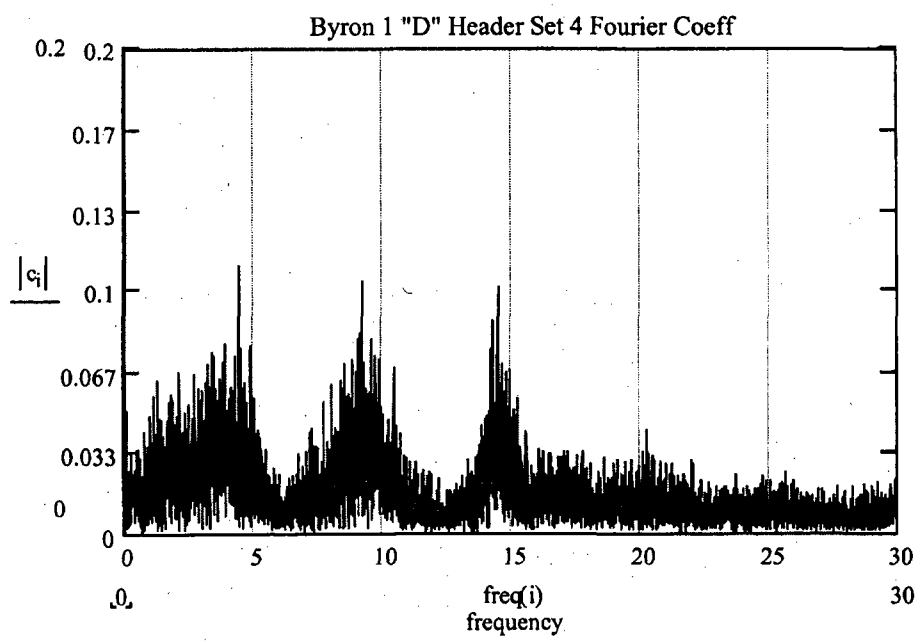


Attachment Q-8, Spectral Analysis of Byron 1 FW Piping (Pg 13 of 33)

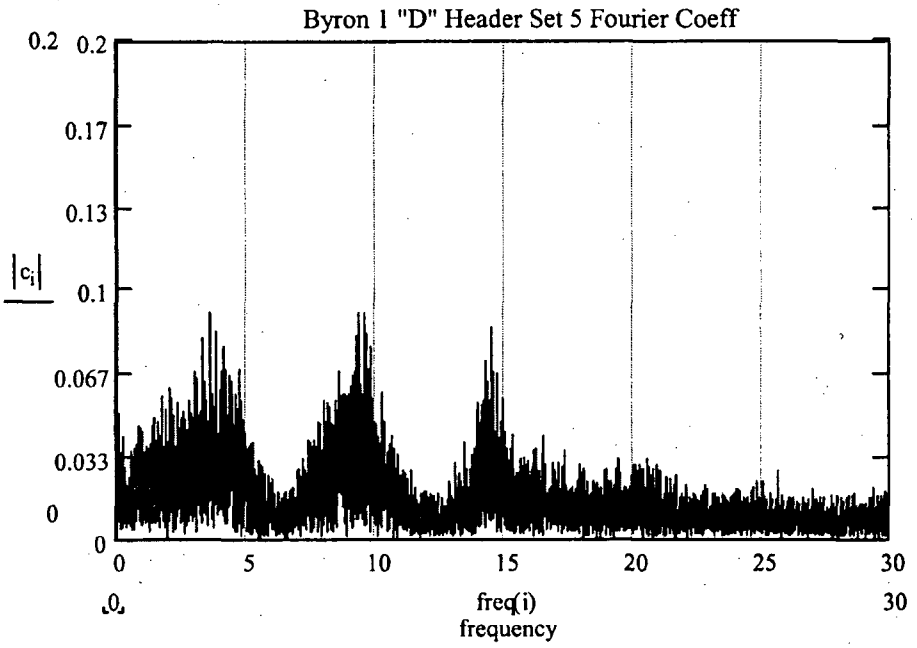


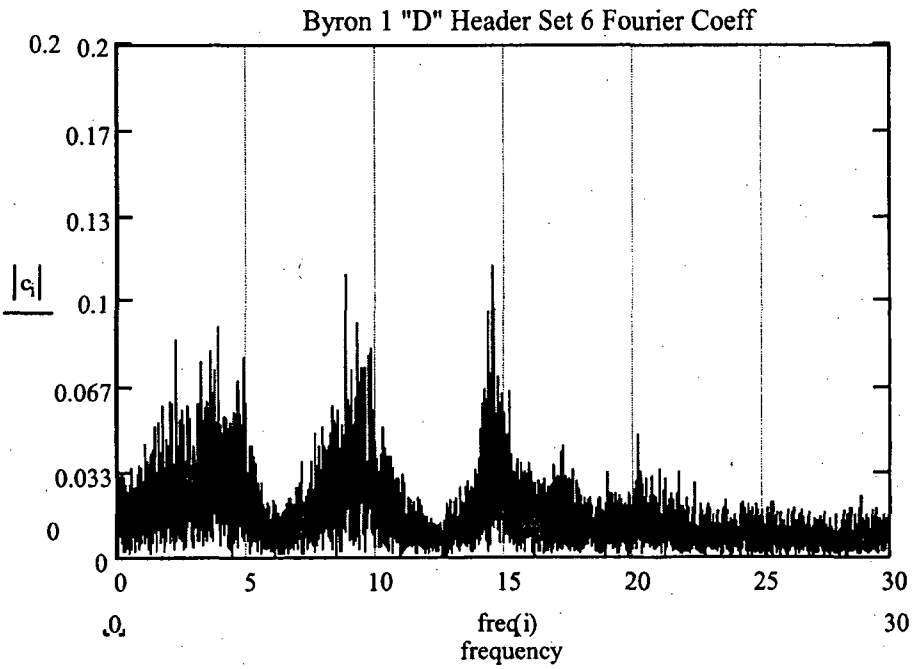


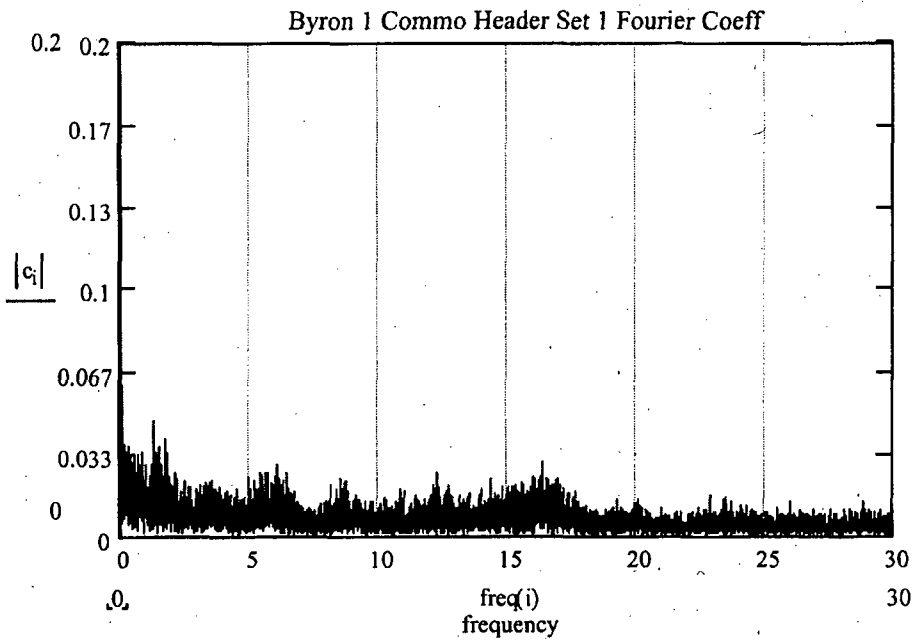

Byron 1 "D" Header Set 3 Fourier Coeff
0.2
0.2
0.17
0.13
|c_i|
0.1
0.067
0.033
0
0
0
5
10
15
20
25
30
0
freq(i)
frequency
30

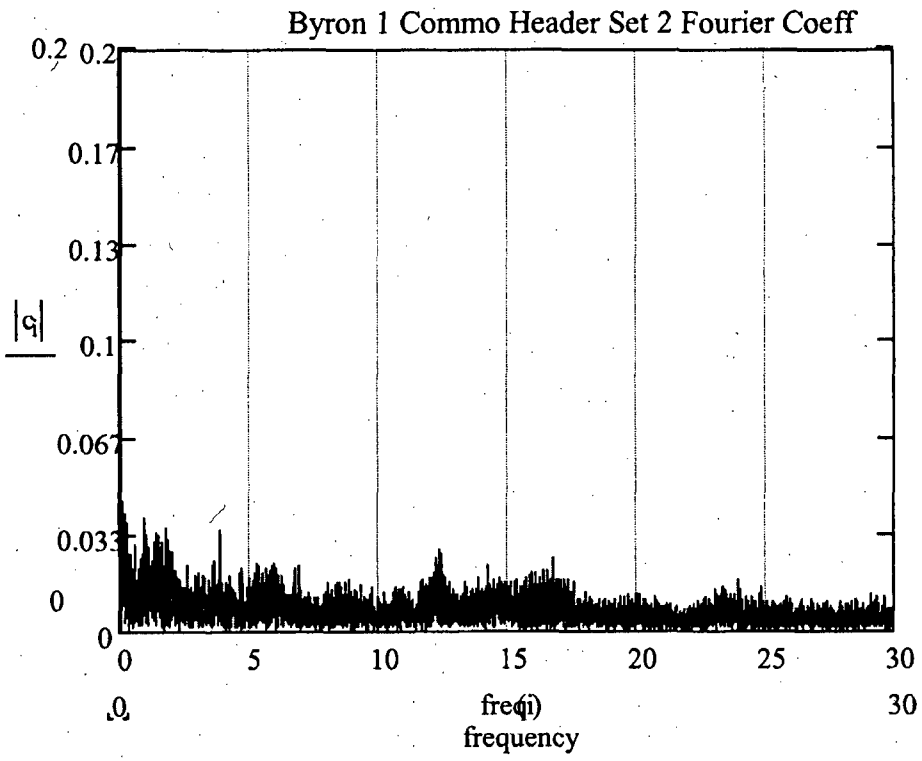

Byron 1 "D" Header Set 4 Fourier Coeff
0.2
0.2
0.17
0.13
|c_i|
0.1
0.067
0.033
0
0
0
5
10
15
20
25
30
0
freq(i)
frequency
30

Attachment Q-8, Spectral Analysis of Byron 1 FW Piping (Pg 15 of 33)

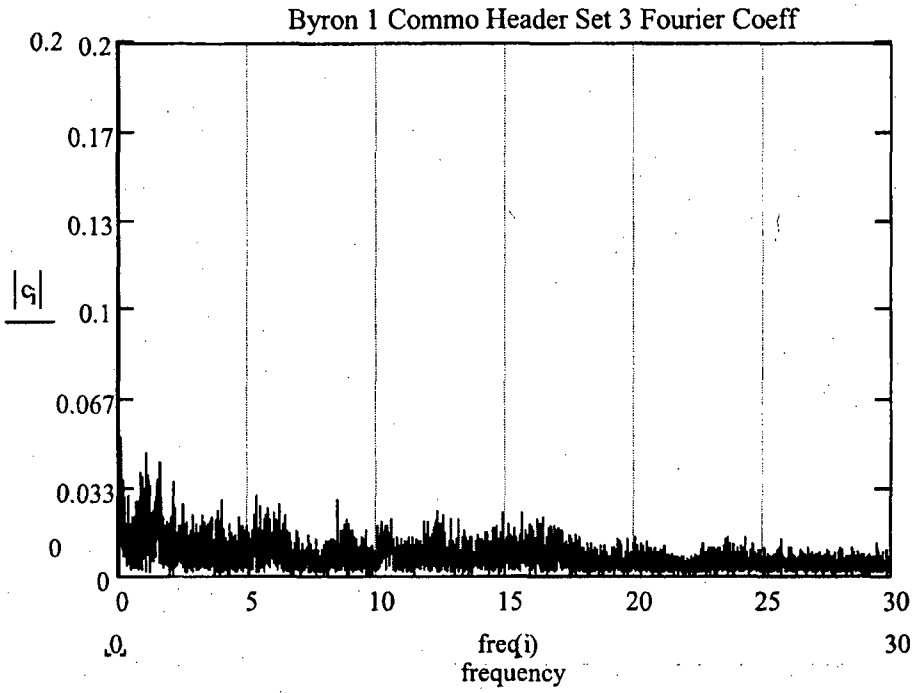


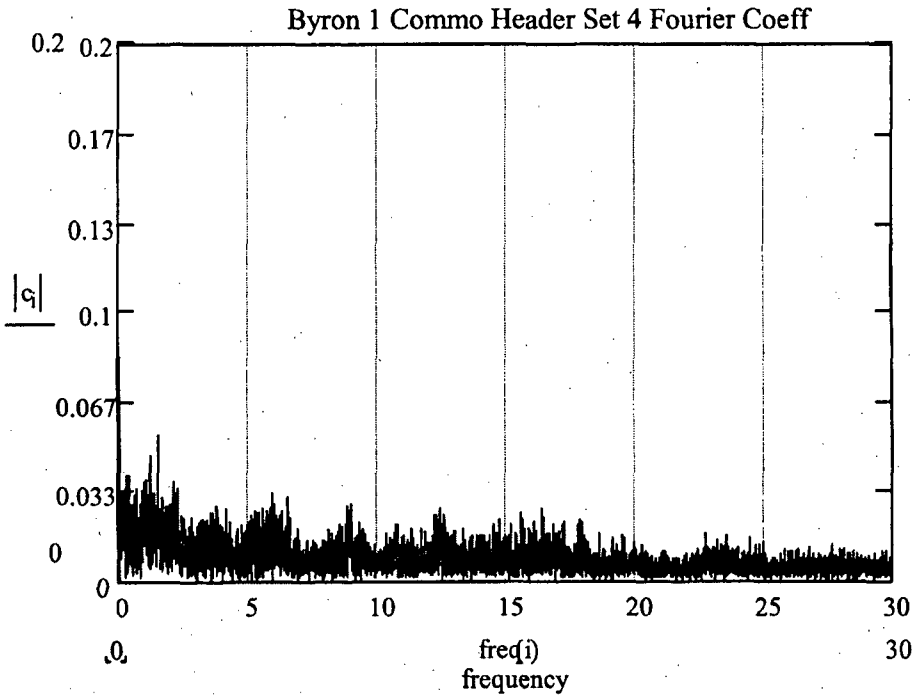



Byron 1 Commo Header Set 1 Fourier Coeff
0.2
0.17
0.13
|c_i|
0.1
0.067
0.033
0
0
5
10
15
20
25
30
0
freq(i)
frequency
30

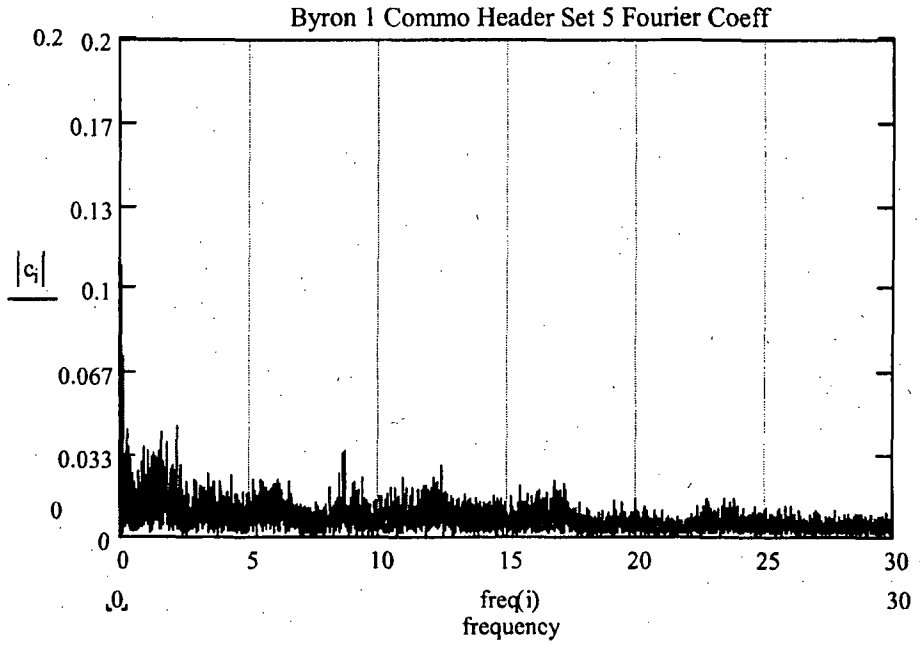

Byron 1 Commo Header Set 2 Fourier Coeff
0.2
0.17
0.13
|c_i|
0.1
0.067
0.033
0
0
5
10
15
20
25
30
0
freq(i)
frequency
30

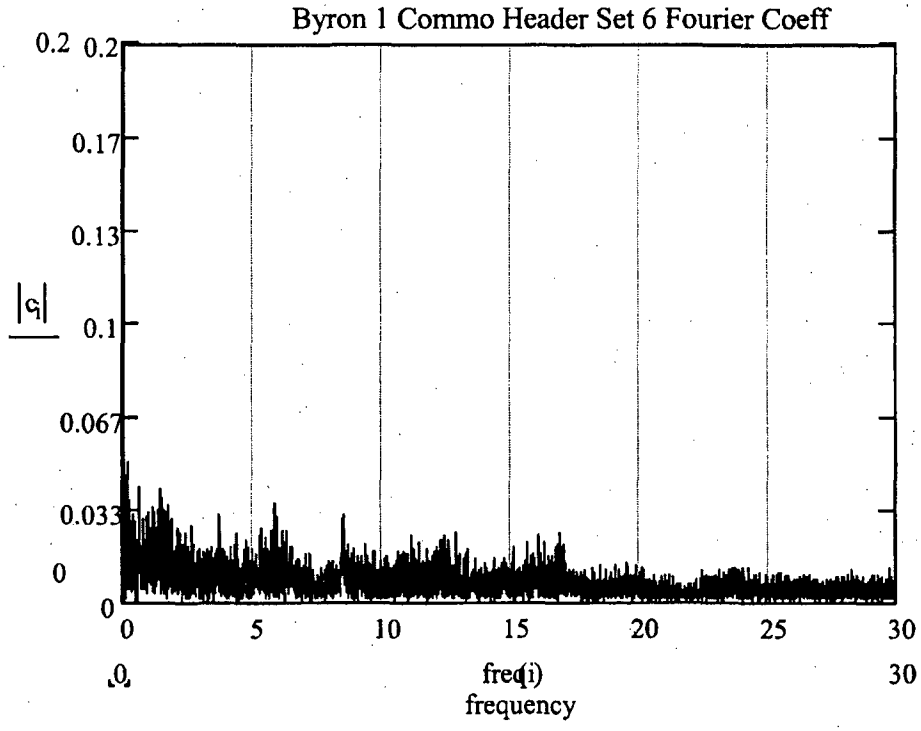
Attachment Q-8, Spectral Analysis of Byron 1 FW Piping (Pg 17 of 33)



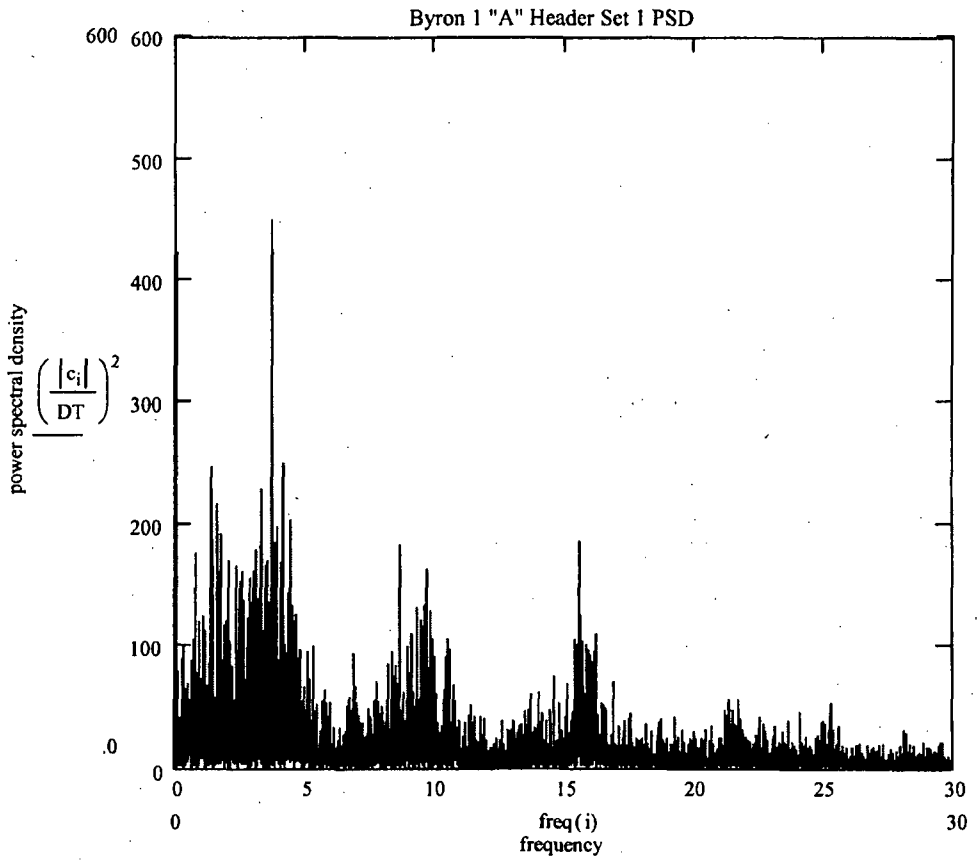


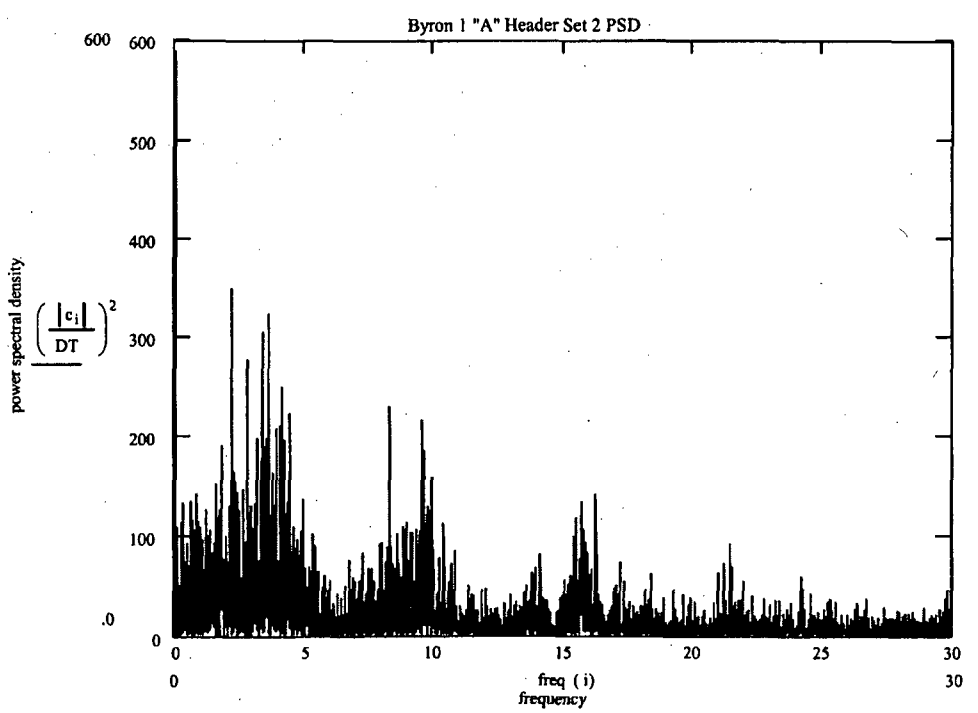
Attachment Q-8, Spectral Analysis of Byron 1 FW Piping (Pg 18 of 33)

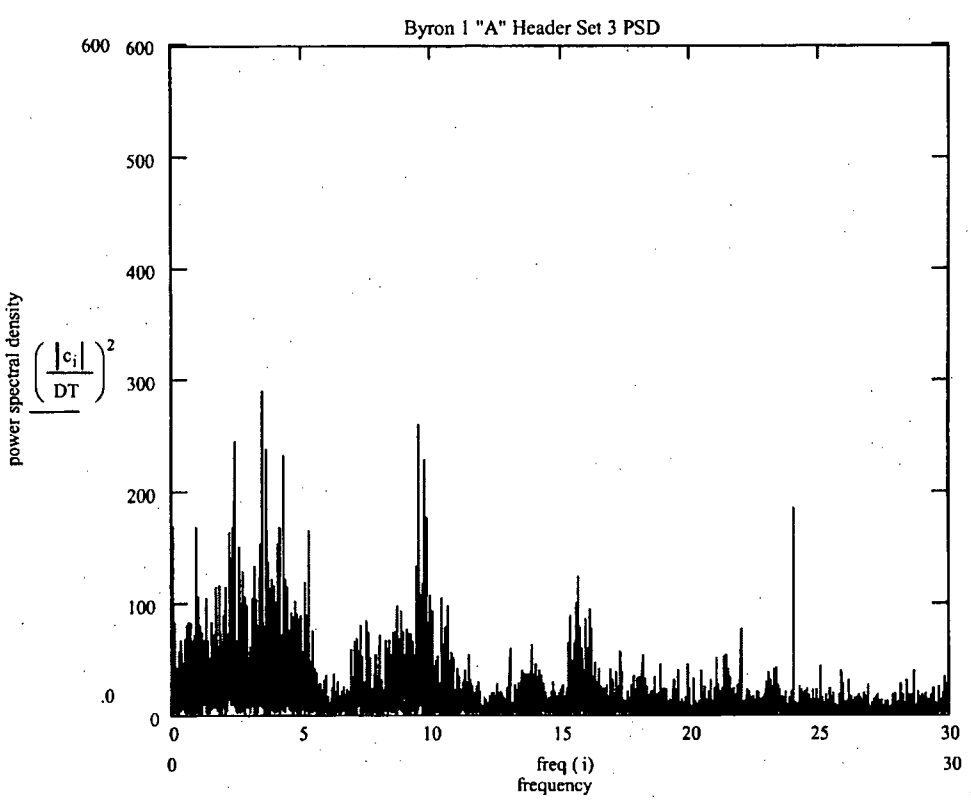




Attachment Q-8, Spectral Analysis of Byron 1 FW Piping (Pg 19 of 33)






Byron 1 "A" Header Set 3 PSD
power spectral density
$\left(\frac{|c_i|}{DT}\right)^2$
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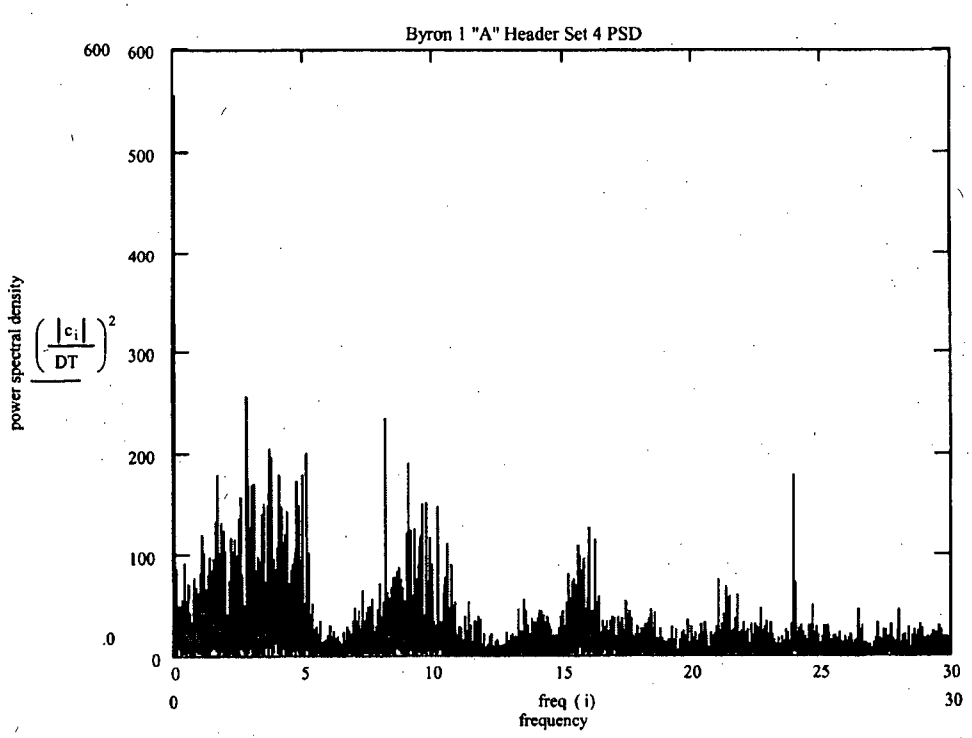
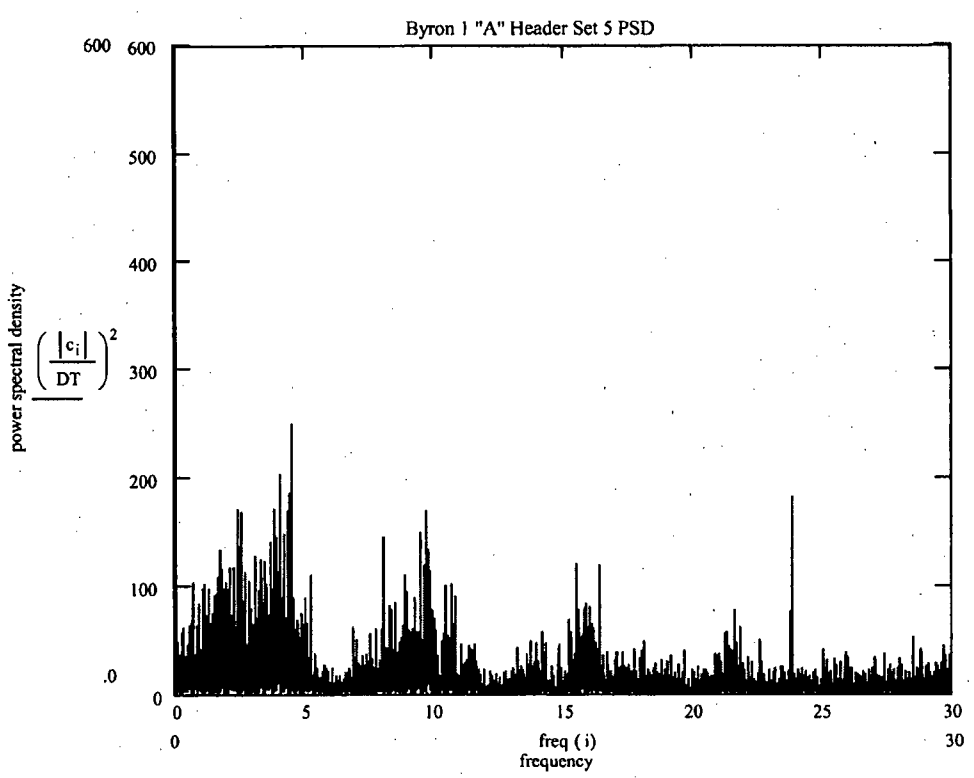
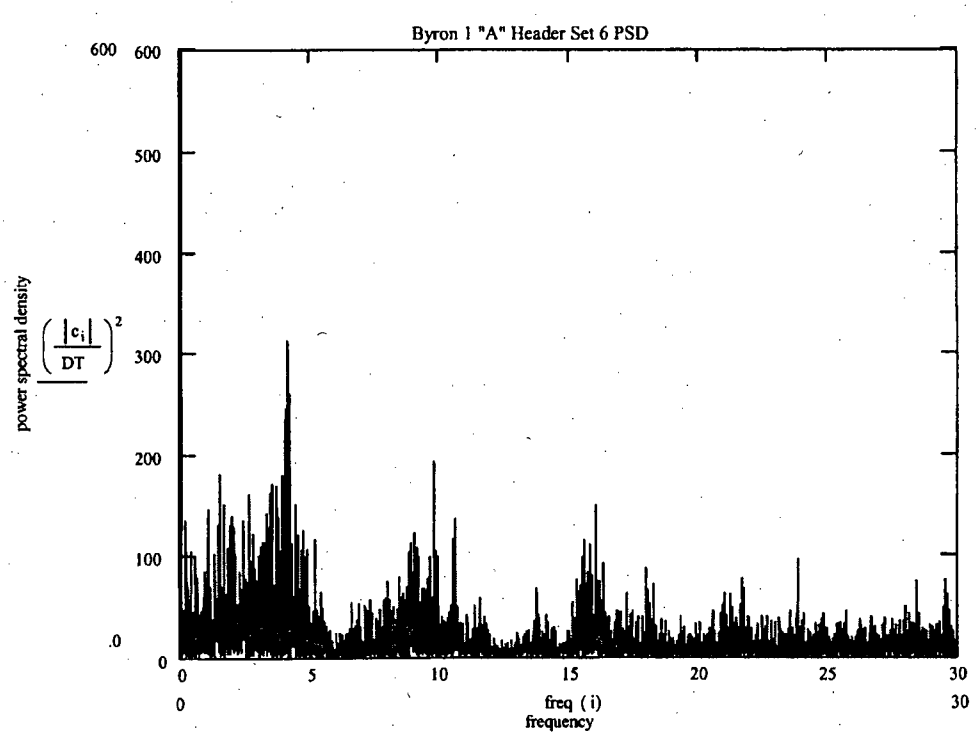
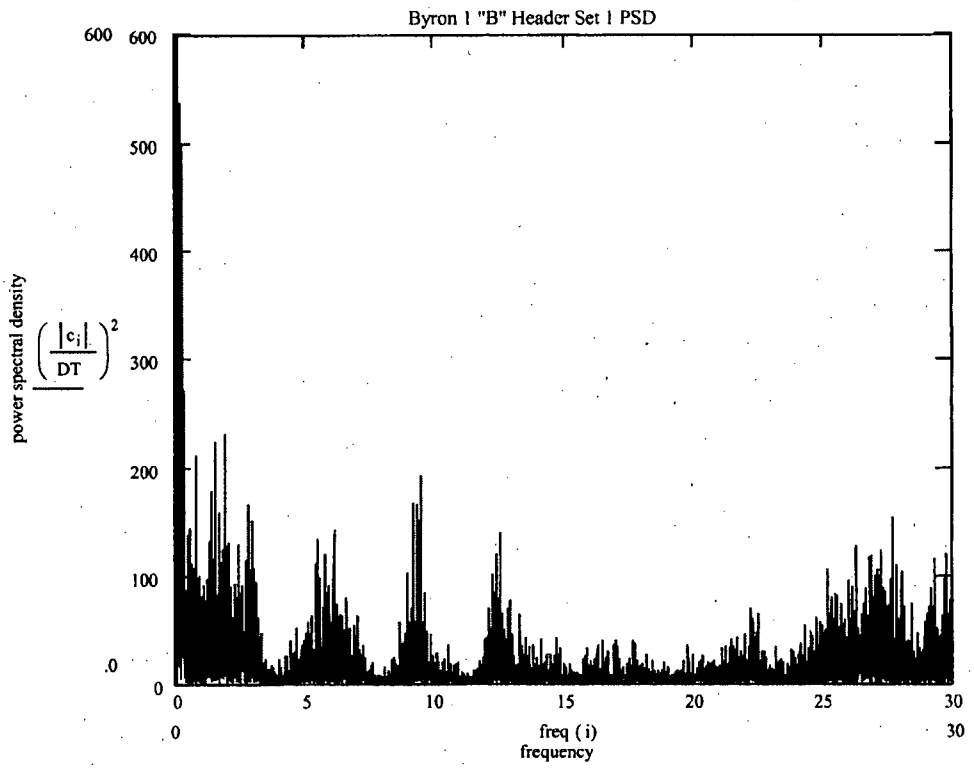
500
400
300
200
100
.0
0
0
5
10
15
20
25
30
0
freq (i)
frequency
30

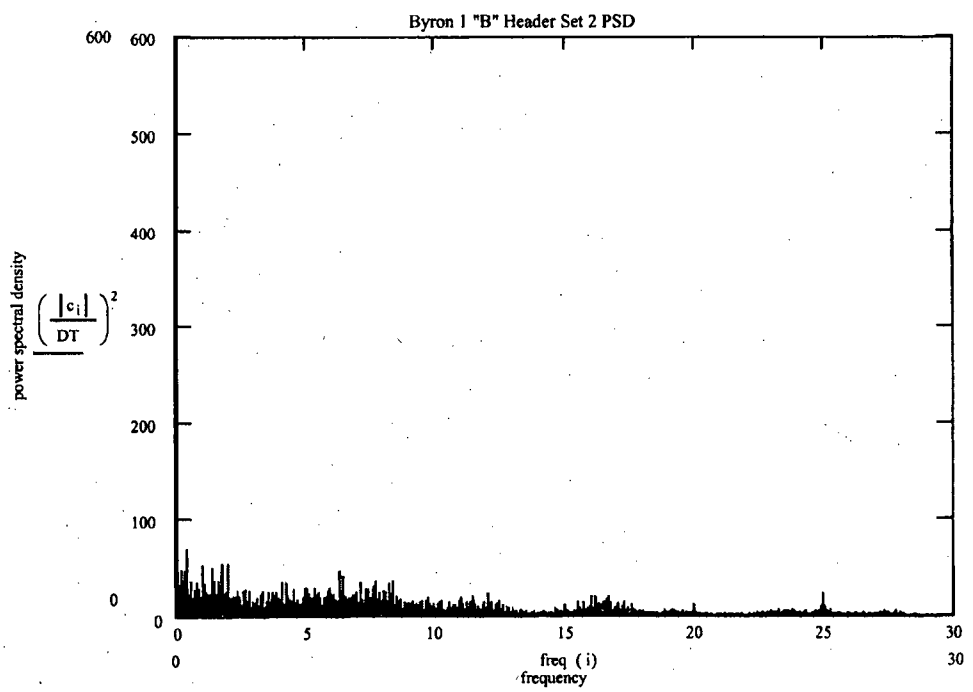

Byron 1 "A" Header Set 4 PSD
power spectral density
$\left(\frac{|c_i|}{DT}\right)^2$
600
500
400
300
200
100
.0
0
0
5
10
15
20
25
30
0
freq (i)
frequency
30

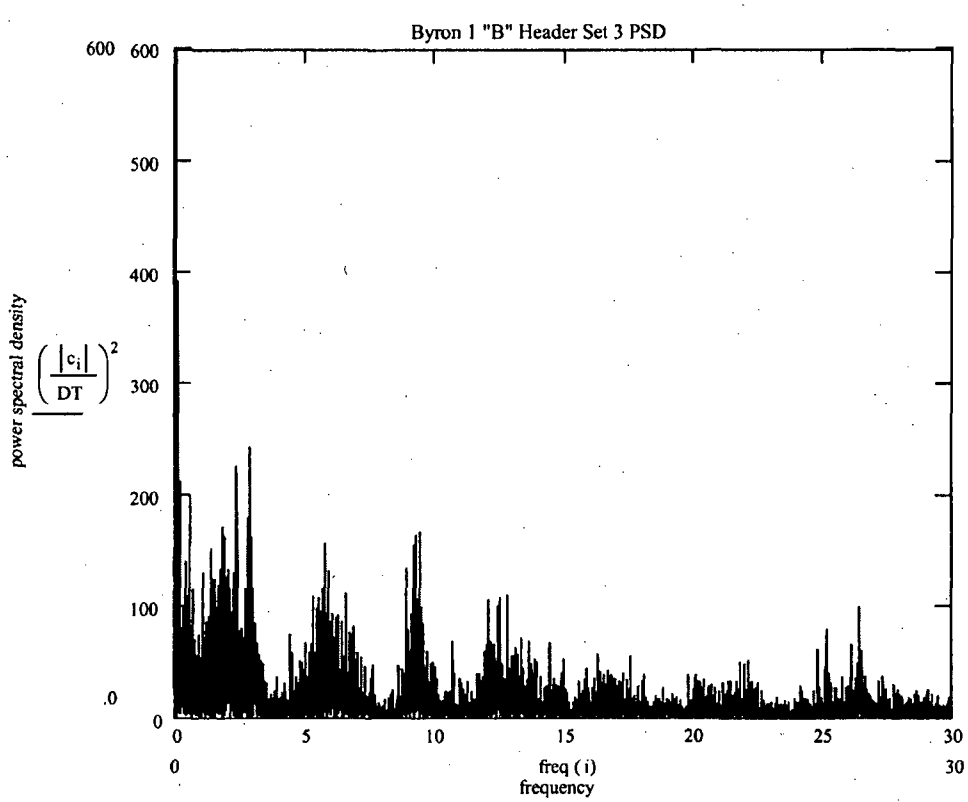

Byron 1 "A" Header Set 5 PSD
power spectral density
$\left(\frac{|c_i|}{DT}\right)^2$
600
500
400
300
200
100
.0
0
0
5
10
15
20
25
30
0
freq (i)
frequency
30

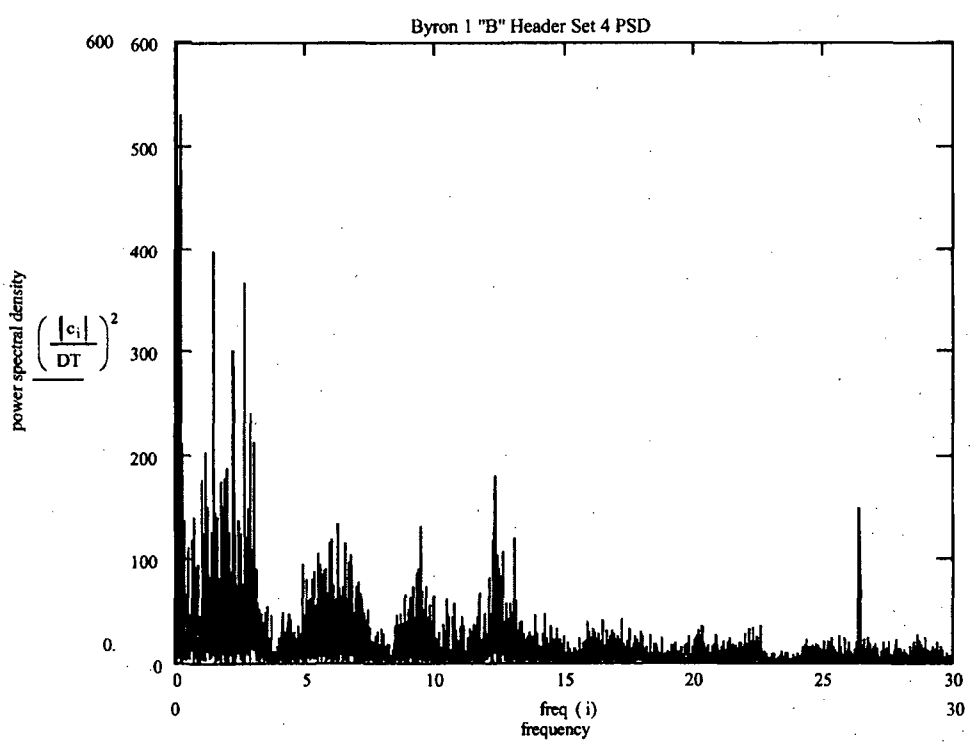

Byron 1 "A" Header Set 6 PSD
power spectral density
$\left(\frac{|c_i|}{DT}\right)^2$
600
500
400
300
200
100
.0
0
0
5
10
15
20
25
30
0
freq (i)
frequency
30

Attachment Q-8, Spectral Analysis of Byron 1 FW Piping (Pg 22 of 33)

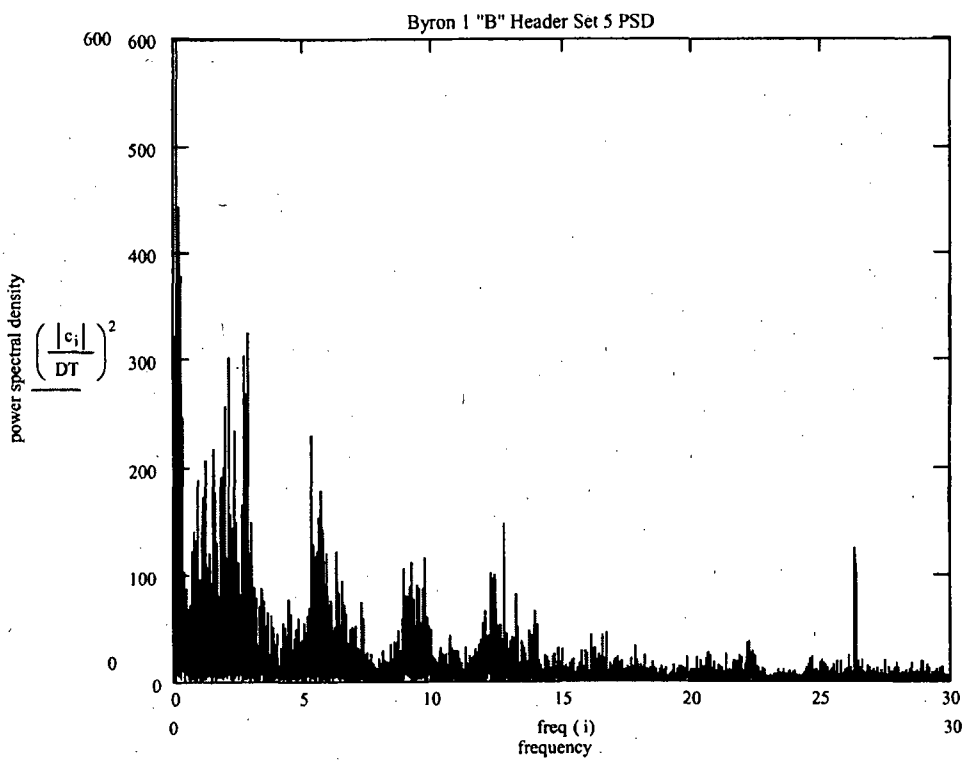


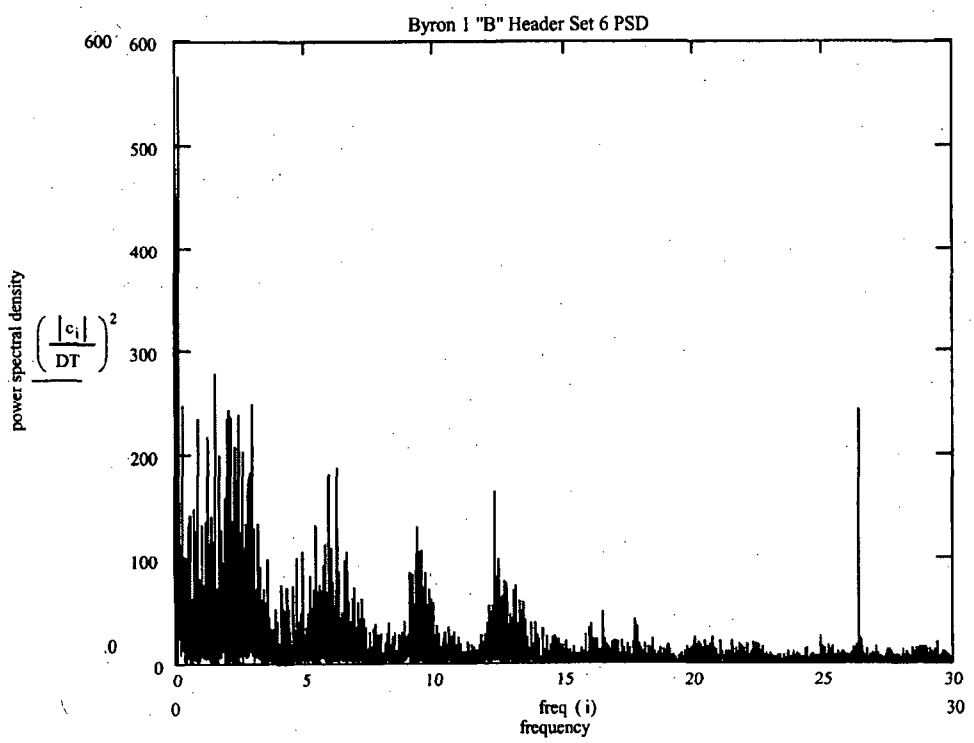


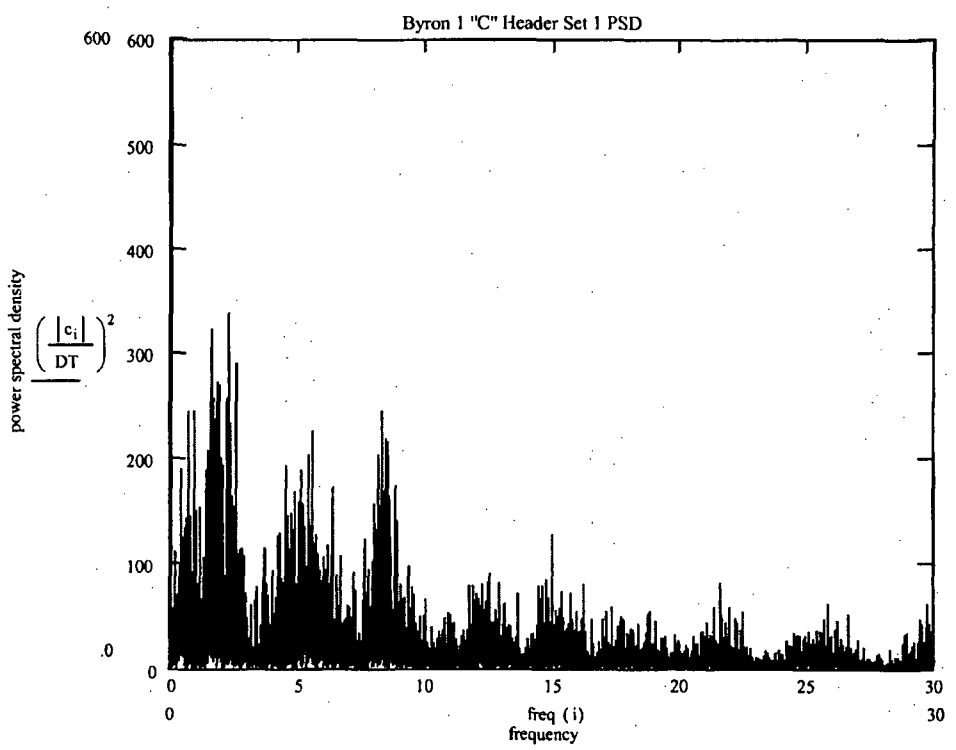

Byron 1 "B" Header Set 3 PSD
power spectral density
$\left(\frac{|c_i|}{DT}\right)^2$
600
500
400
300
200
100
.0
0
0
5
10
15
20
25
30
0
freq (i)
frequency
30

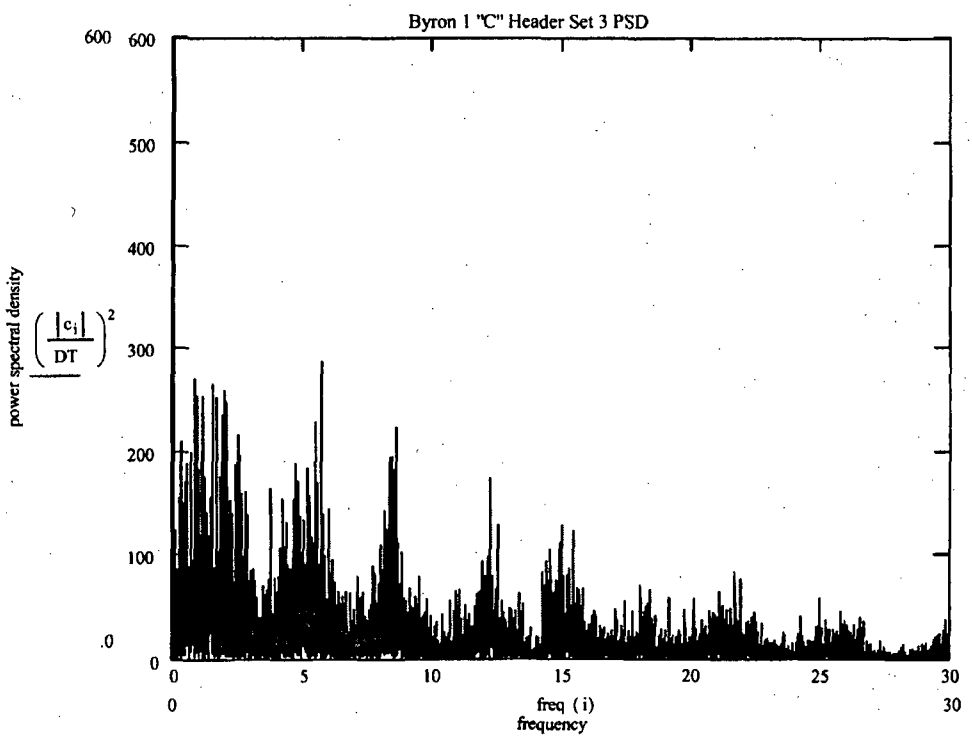

Byron 1 "B" Header Set 4 PSD
power spectral density
$\left(\frac{|c_i|}{DT}\right)^2$
600
500
400
300
200
100
0.
.0
0
5
10
15
20
25
30
0
freq (i)
frequency
30

Attachment Q-8, Spectral Analysis of Byron 1 FW Piping (Pg 24 of 33)

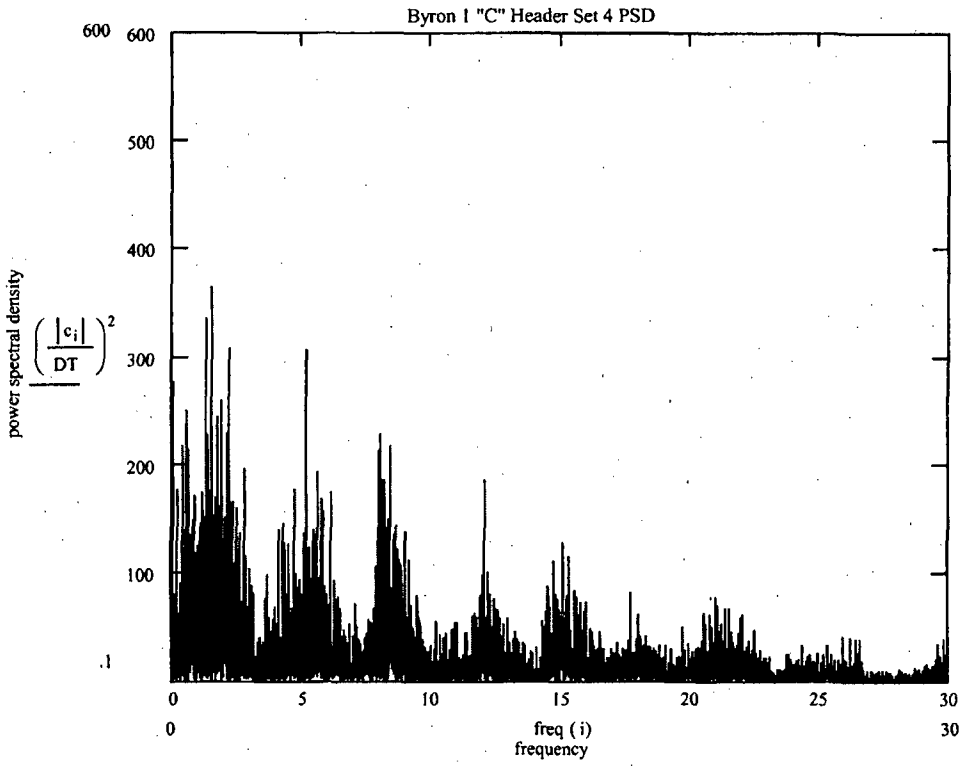


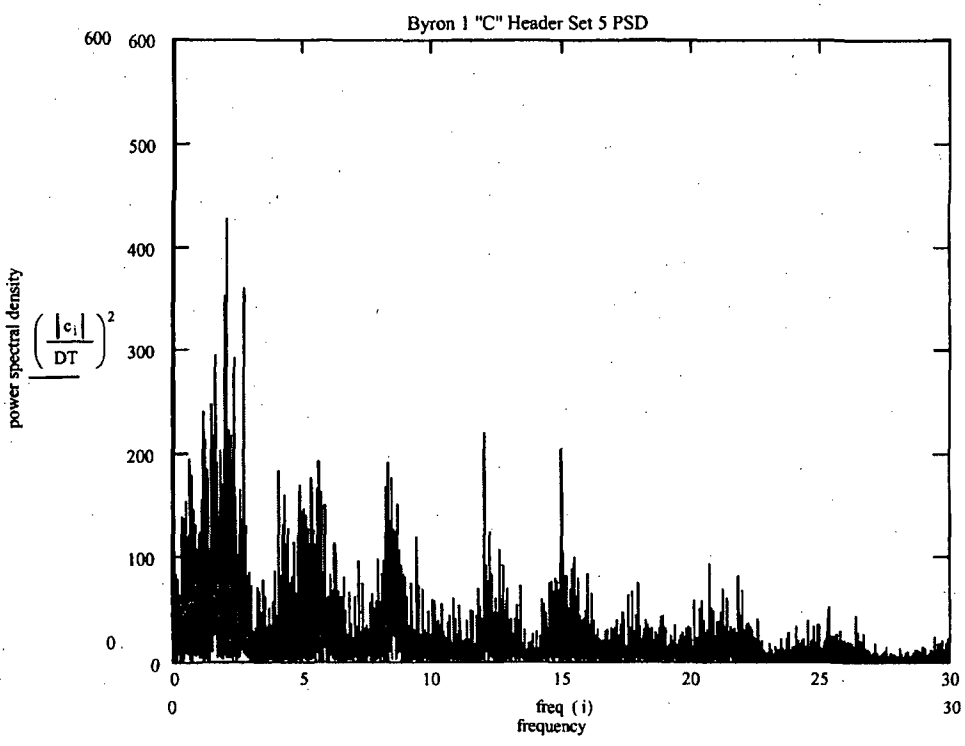



Byron 1 "C" Header Set 1 PSD
power spectral density
$\left(\frac{|c_i|}{DT}\right)^2$
600
500
400
300
200
100
.0
0
0
5
10
15
20
25
30
0
freq (i)
frequency
30

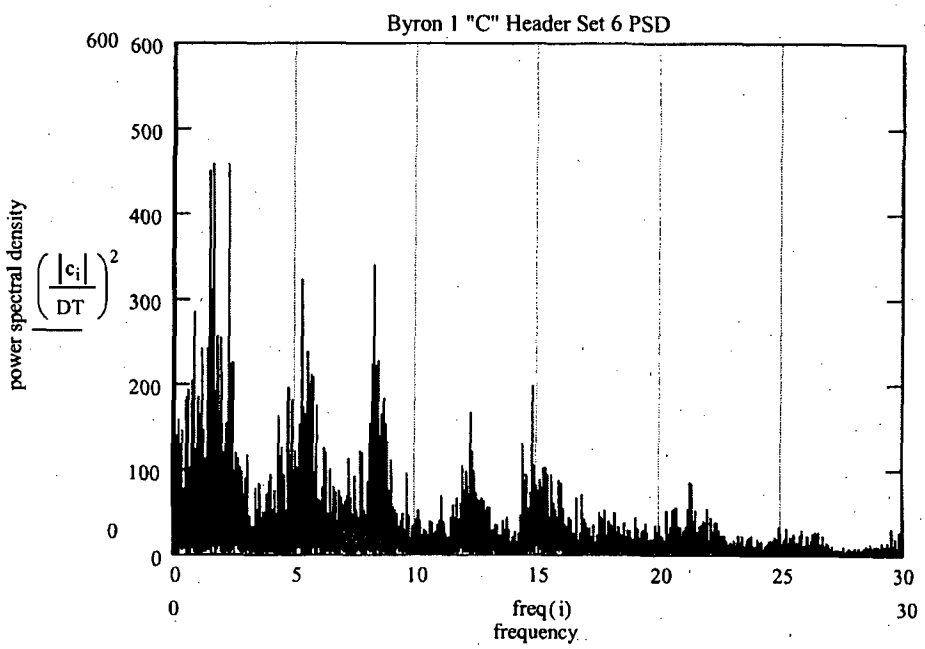

Byron 1 "C" Header Set 3 PSD
power spectral density
$\left(\frac{|c_i|}{DT}\right)^2$
600
500
400
300
200
100
.0
0
0
5
10
15
20
25
30
0
freq (i)
frequency
30

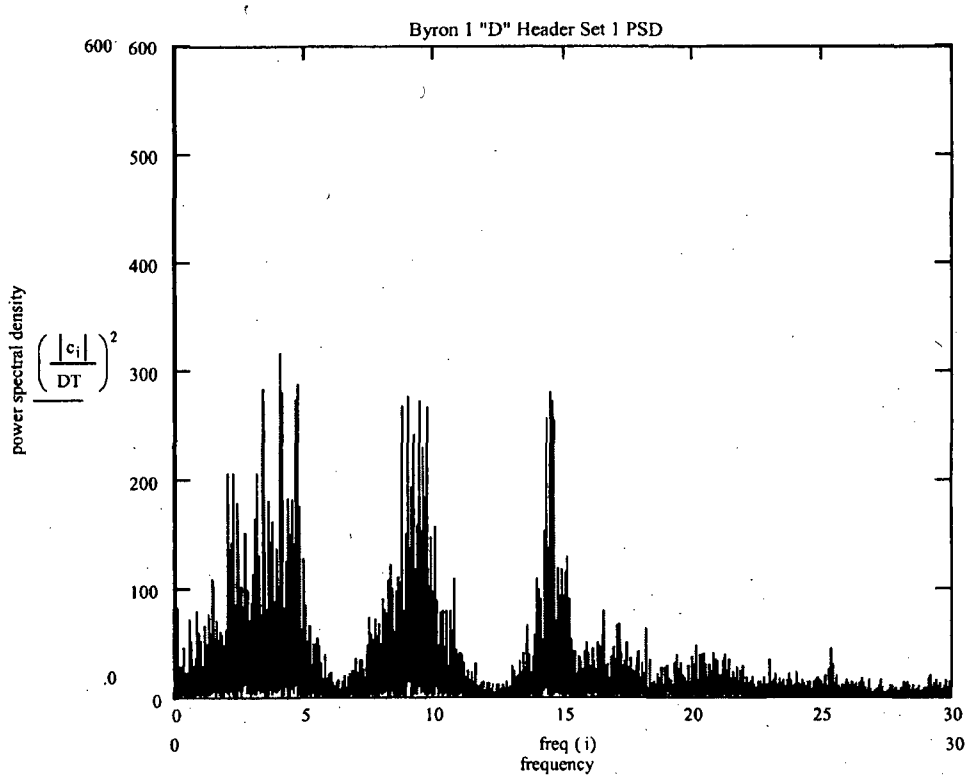
Attachment Q-8, Spectral Analysis of Byron 1 FW Piping (Pg 26 of 33)

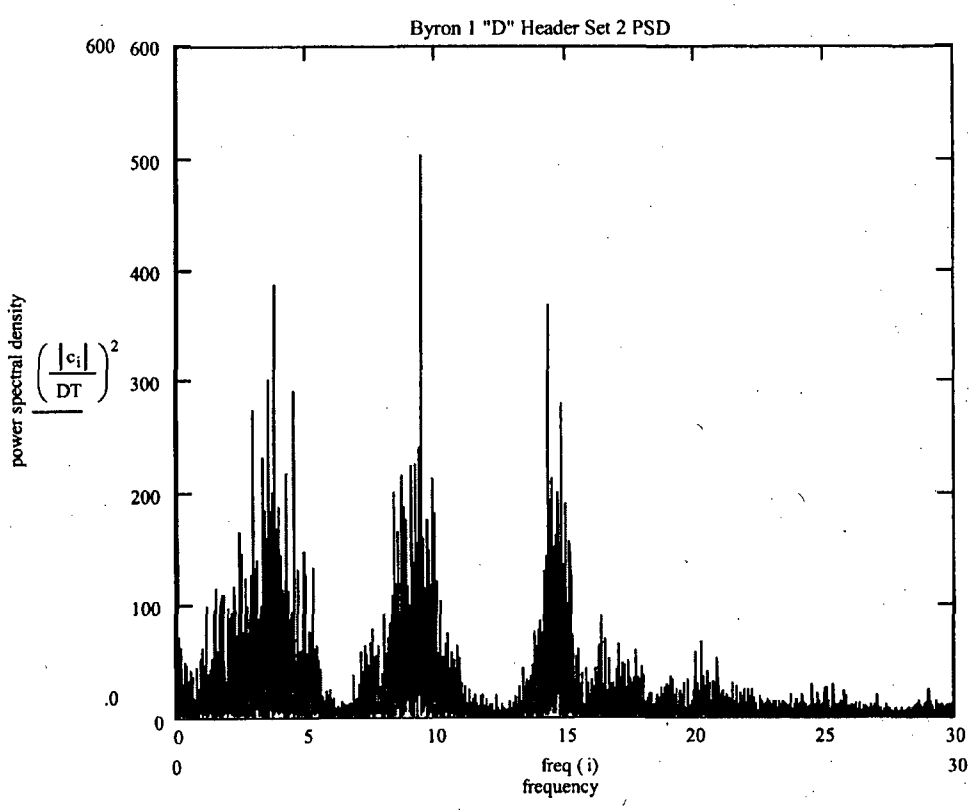


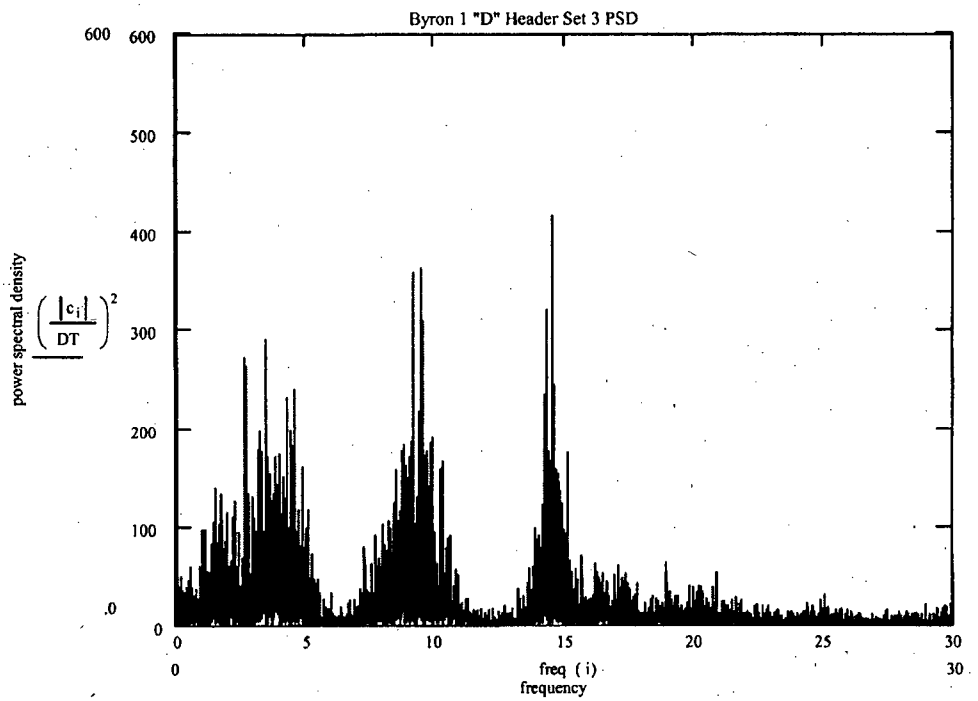


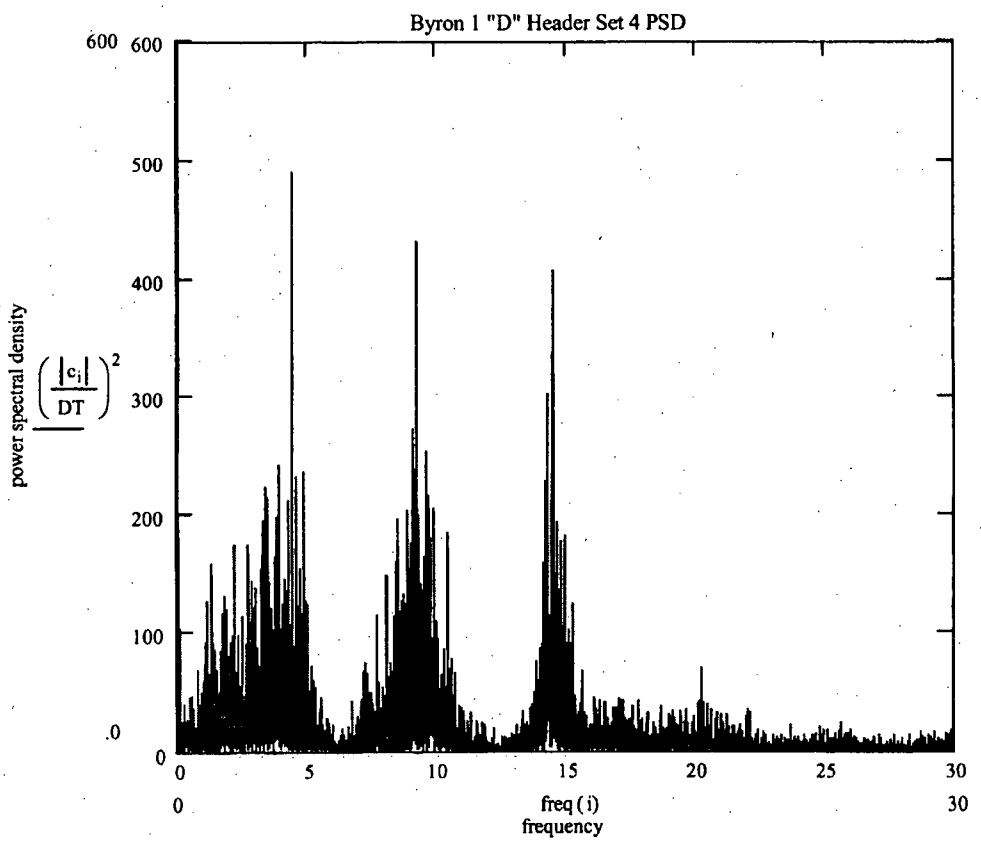
Attachment Q-8, Spectral Analysis of Byron 1 FW Piping (Pg 27 of 33)



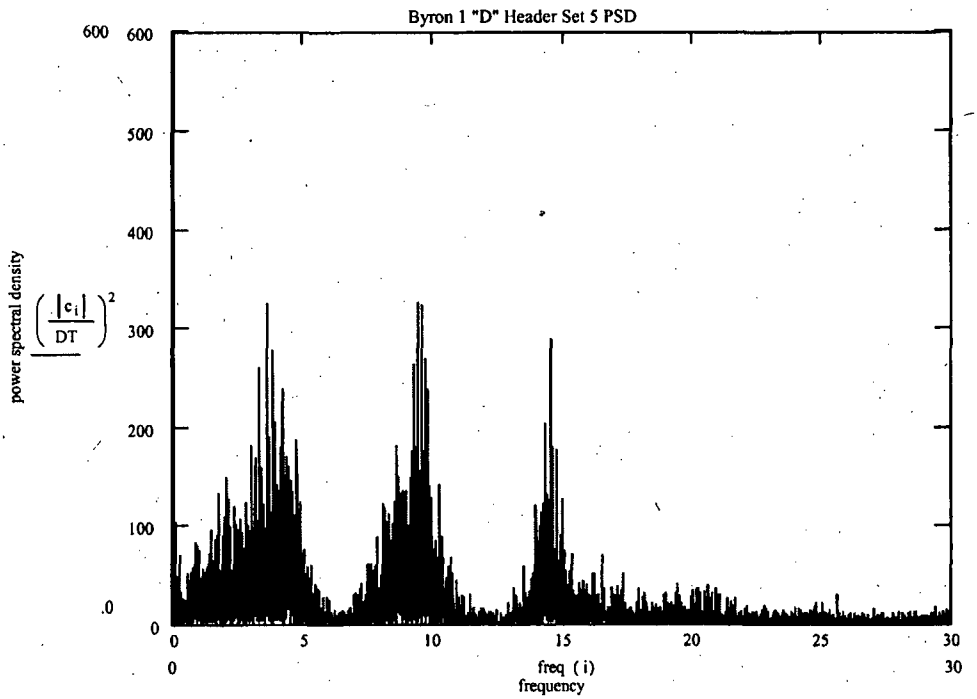

Byron 1 "D" Header Set 1 PSD
power spectral density
$\left(\frac{|c_i|}{DT}\right)^2$
600
500
400
300
200
100
.0
0
0
5
10
15
20
25
30
0
freq (i)
frequency
30

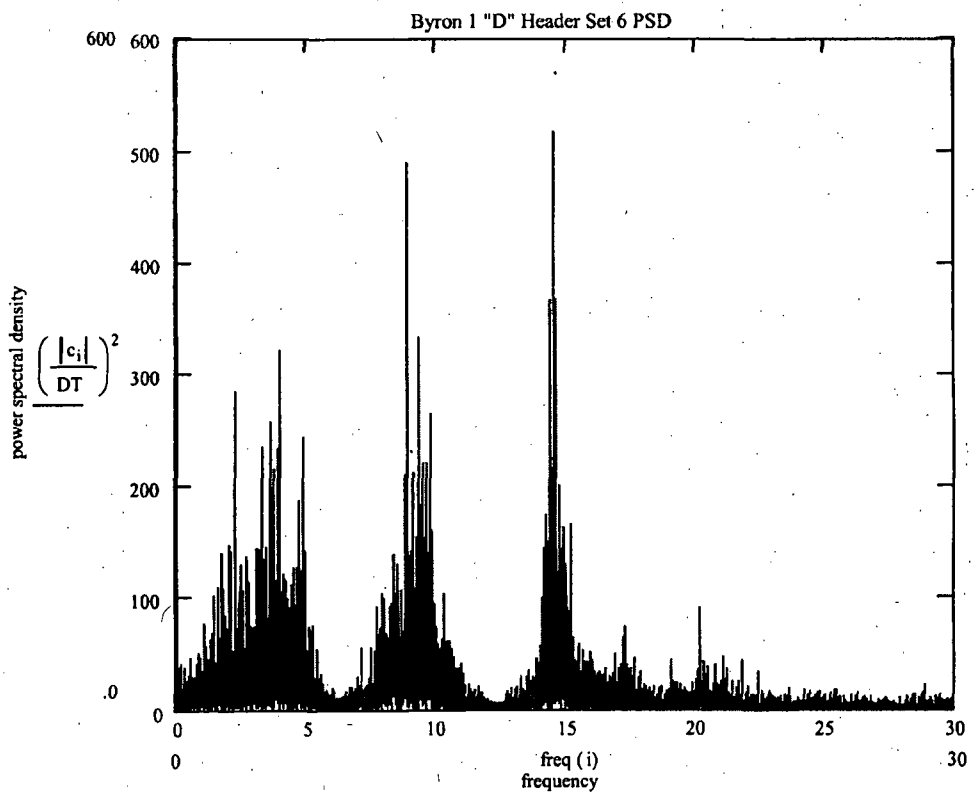

Byron 1 "D" Header Set 2 PSD
power spectral density
$\left(\frac{|c_i|}{DT}\right)^2$
600
500
400
300
200
100
.0
0
0
5
10
15
20
25
30
0
freq (i)
frequency
30


Byron 1 "D" Header Set 3 PSD
power spectral density
$\left(\frac{|c_i|}{DT}\right)^2$
600
500
400
300
200
100
.0
0
0
5
10
15
20
25
30
0
freq (i)
frequency
30

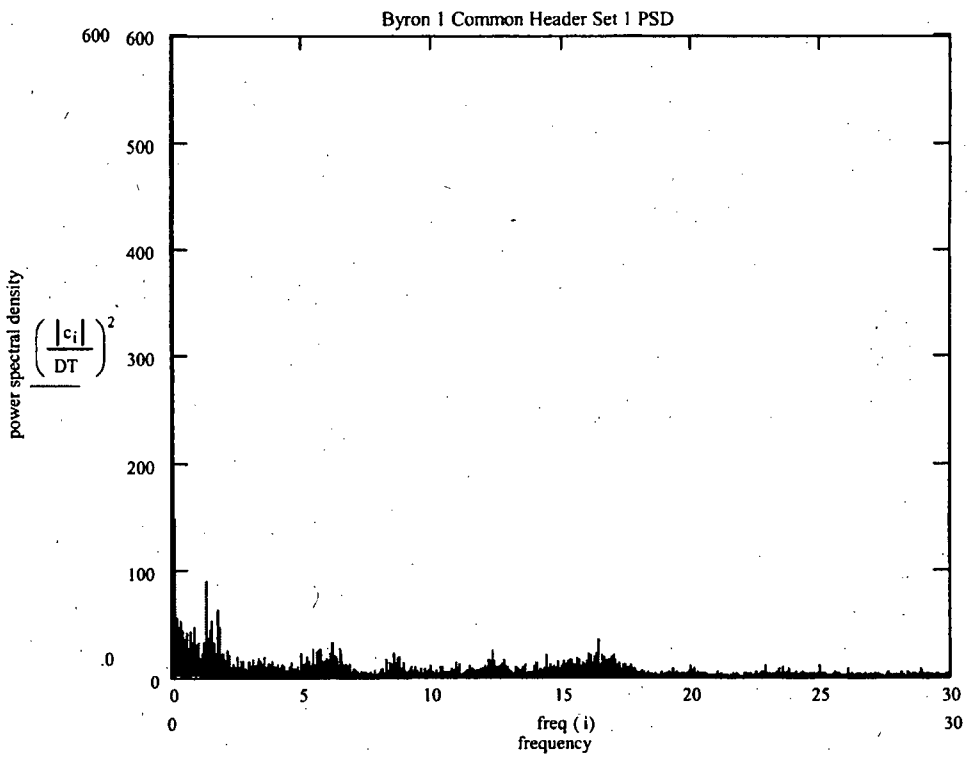

Byron 1 "D" Header Set 4 PSD
power spectral density
$\left(\frac{|c_i|}{DT}\right)^2$
600
500
400
300
200
100
.0
0
0
5
10
15
20
25
30
0
freq (i)
frequency
30

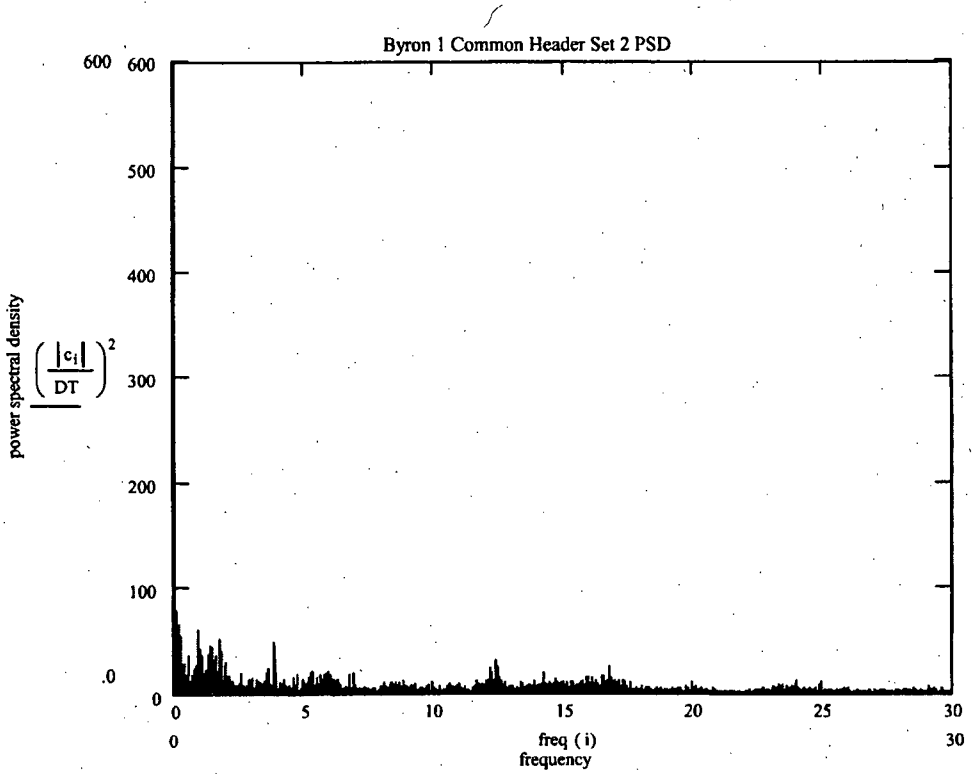
Attachment Q-8, Spectral Analysis of Byron 1 FW Piping (Pg 30 of 33)



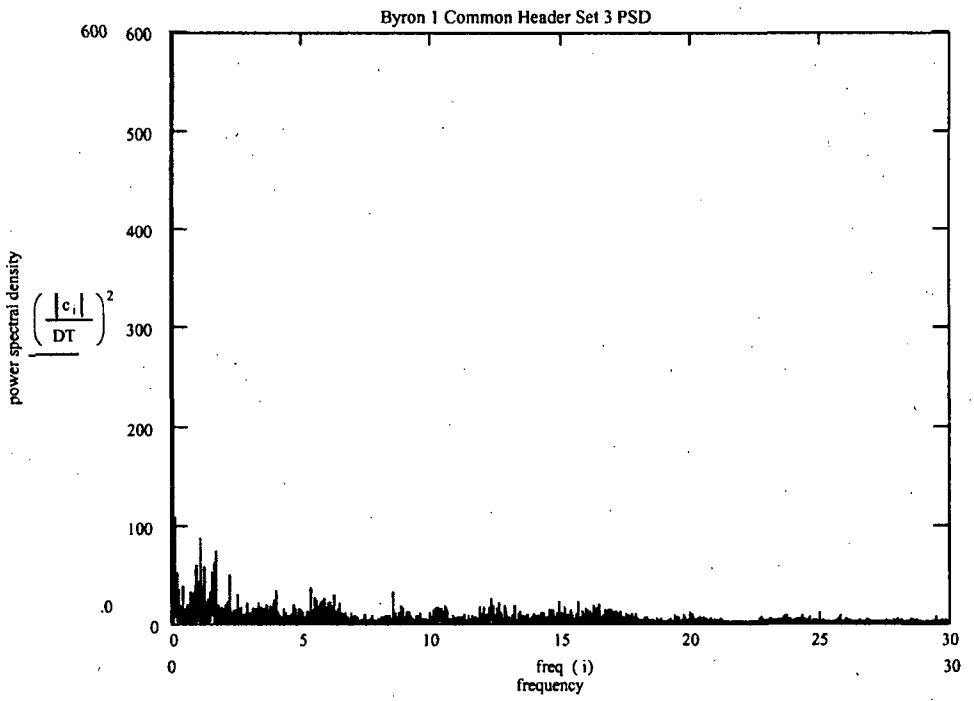


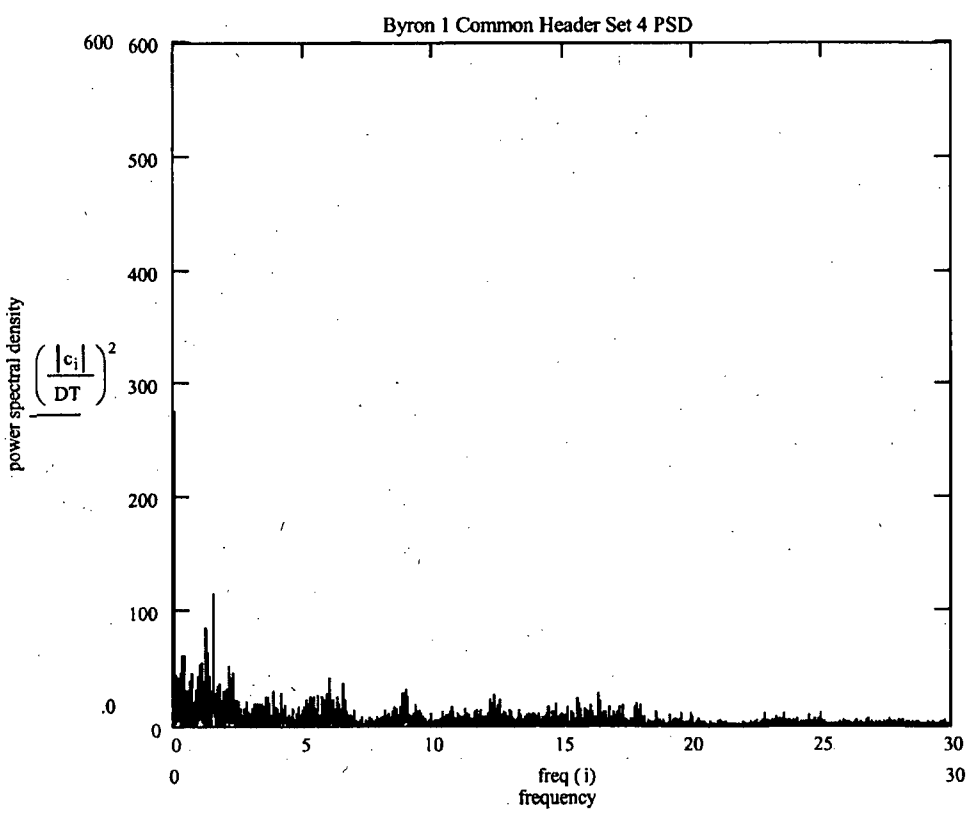
Attachment Q-8, Spectral Analysis of Byron 1 FW Piping (Pg 31 of 33)



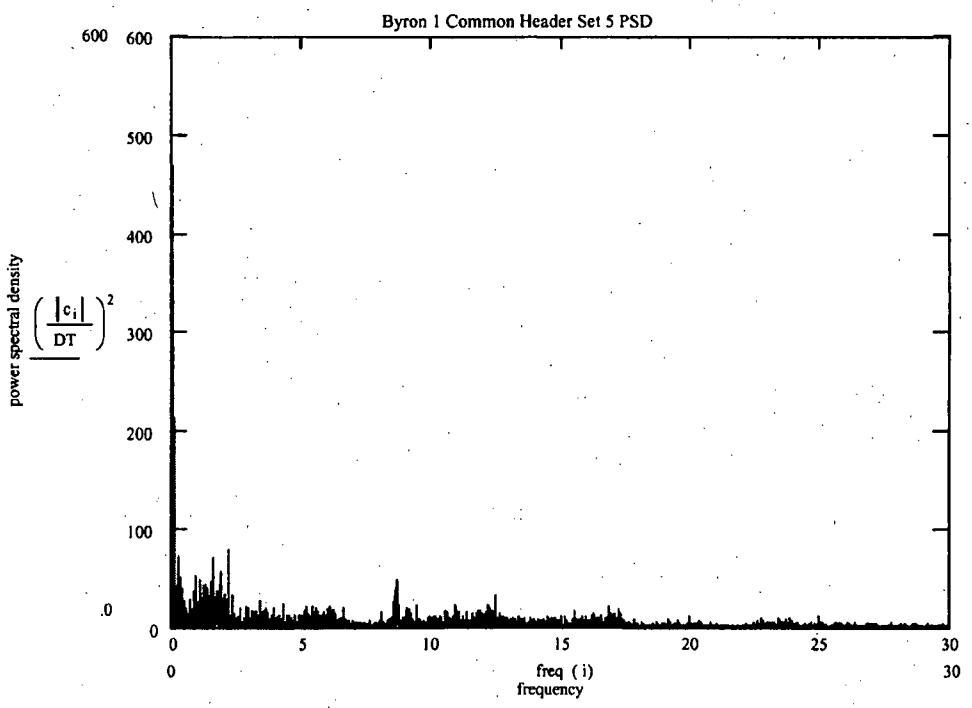


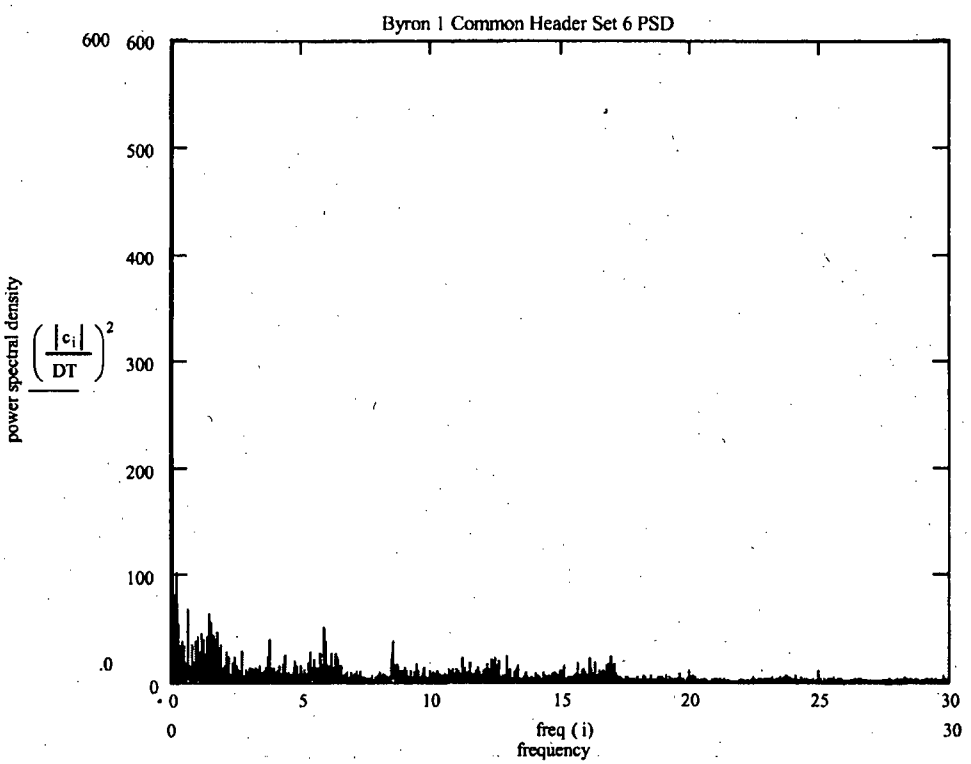
Attachment Q-8, Spectral Analysis of Byron 1 FW Piping (Pg 32 of 33)





Attachment Q-8, Spectral Analysis of Byron 1 FW Piping (Pg 33 of 33)





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Warrenville, IL 60555

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e-mail: hausercs@westinghouse.com

CAE-03-107
CCE-03-121

December 8, 2003

EXELON NUCLEAR
BYRON AND BRAIDWOOD NUCLEAR STATIONS
EXELON Frequency Spectrum Analysis Records

References:

1) TB-03-6, "CROSSFLOW Ultrasonic Flow Measurement System Signal Issues", September 5, 2003.
2) CAE-03-100, CCE-03-110, "CROSSFLOW Feedwater Flow Measurement Recommendations", November 11, 2003.
3) AMAG-INS-FS-013-01, "Frequency Spectrum Using DIAGNOSE Software", December 5, 2003.

Dear Mr. Printz:

Westinghouse Electric Company recently released the referenced Technical Bulletin, which included several future actions and commitments as well as recommendations for CROSSFLOW users. Since that time, Westinghouse and the Advanced Measurement and Analysis Group, Inc. (AMAG) have completed several of the referenced actions and would like to share the results below.

Following the discovery of signal contamination at Byron Unit 1, Westinghouse and AMAG launched a review of CROSSFLOW test activities and permanent installations performed to date. The following key criteria were used to determine the Extent of Condition and status of CROSSFLOW measurements for each utility customer.

1. Stability and variability of the correction factor during power changes.
   -Unexplained changes in Cf beyond established or alarmed limits need to be investigated.

2. Stability of CROSSFLOW performance (e.g., data rejection rate, standard deviation)
   -An unexplained increase in data rejection rate or standard deviation could be a precursor to the effects of signal contamination or to other physical changes to the system. This will ultimately result in an increase in Cf variability.

3. Continuous monitoring or an interface with the plant computer.
   -Utilities that utilize continuous monitoring or interface with the plant computer have continuous trending data available to capture potential changing conditions as an early warning.

4. Frequency Spectrum Analysis Records.
   -Original records that document the absence of contamination were available for many Crossflow installations. Through an interview process, it was verified that several units were tested although the frequency spectrum records were not retained. Several units, with no retained baseline records, were able to be promptly tested. As of this date, Westinghouse/AMAG have records for all Utilities currently using CROSSFLOW to adjust plant power.

Based on the above criteria, as applicable to the EXELON installations, the installations at Clinton, Dresden Units 2 and 3, LaSalle Units 1 and 2 and the common header locations at Braidwood 1 and 2 and Byron 1 and 2 are confirmed to be free from signal interference/contamination and can be used to provide future CROSSFLOW measurements. The baseline scans which were collected in accordance with Reference 3 are provided in the attachment to this letter for your records.

Additional recommendations regarding the CROSSFLOW equipment configuration for future measurements were provided in Reference 2.

Westinghouse will be issuing a Nuclear Safety Advisory Letter in early December that will include further guidance to the industry for monitoring for future potential signal contamination. AMAG is also developing new software to allow utilities to independently perform frequency spectrum analyses on demand. The additional guidance and new software will be presented and discussed at the upcoming CROSSFLOW Owners Meeting January 26-28, 2004 in San Antonio.

If you have any questions or would like further information, please call me at 412-374-4901.

Very truly yours,

WESTINGHOUSE ELECTRIC COMPANY

signed copy on file

C. S. Hauser
Nuclear Services Project Manager
Exelon Nuclear

Page 3 of 3
CCE-03-121
December 8, 2003

Cc: T. Eaton - Exelon
R. Doney – Westinghouse / Windsor
C. S. Hauser – Westinghouse / ECE 5-7
J. M. Bunecicky – Westinghouse / ECE 5-7
Project Letter File

Pages 276 through 307 redacted for the following reasons:
- -
Exemption 4

Attachment Q-11, Frequency Summary At Various Sound Speeds (Pg 1 of 6)

Byron 1	Byron 1				Byron 2					
3960 fps	A	B	C	D	A	B	C	D		Common header
S/G to Check	106	111	161	153	135	130	154	140		
Check to Venturi	131	338	358	101	124	334	359	100		
Venturi to FW Reg valve	107	133	125	113	108	130	102	115		
total length	344	583	646	368	368	595	616	356		
FW Heaters to common Bracket										
Common Bracket to FW Reg valve										
		Byron 1	Byron 2	Braidwood 1	Braidwood 2					
total length (30" after heaters)		382	382		323					
30" before heaters		132								
f=c*i/(4*L)	4	4	4	4	4	4	4	4		4
where L = total length	344	583	646	368	368	595	616	356		382
c=sound speed = 3960 fps	3960	3960	3960	3960	3960	3960	3960	3960		3960
i = 1, 3, 5, 7, 9										
BYRON	Unit 1				Unit 2					
MODE	Frequency								I	
1	2.878	1.698	1.533	2.690	2.690	1.664	1.607	2.781	1	2.592
2	8.634	5.094	4.598	8.071	8.071	4.992	4.821	8.343	3	7.775
3	14.390	8.491	7.663	13.451	13.451	8.319	8.036	13.904	5	12.958
4	20.145	11.887	10.728	18.832	18.832	11.647	11.250	19.466	7	18.141
5	25.901	15.283	13.793	24.212	24.212	14.975	14.464	25.028	9	23.325
6	[illegible]	18.679	16.858	[illegible]	[illegible]	18.303	17.679	30.590	11	[illegible]
7	[illegible]	22.075	19.923	[illegible]	[illegible]	21.630	20.893	36.152	13	[illegible]
8	[illegible]	25.472	22.988	[illegible]	[illegible]	24.958	24.107	[illegible]	15	[illegible]
9	[illegible]	[illegible]	26.053	[illegible]	[illegible]	28.286	27.321	47.275	17	[illegible]
10	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	30.536	52.837	19	[illegible]

Attachment Q-11, Frequency Summary At Various Sound Speeds (Pg 2 of 6)

Braidwood 1	Braidwood 1				Braidwood 2					
3960 fps	A	B	C	D	A	B	C	D		Common header
S/G to Check	121	119	161	148	135	122	152	136		
Check to Venturi	141	349	402	114	131	339	359	101		
Venturi to FW Reg valve	97	121	116	111	110	137	128	117		
total length	359	589	679	373	376	598	639	354		
f=c*i/(4*L)	4	4	4	4	4	4	4	4		4
where L = total length	359	589	679	373	376	598	639	354		323
c=sound speed = 3960 fps	3960	3960	3960	3960	3960	3960	3960	3960		3960
i = 1, 3, 5, 7, 9										
BRAIDWOOD	Unit 1				Unit 2					
MODE	Frequency								I	
1	2.758	1.681	1.458	2.654	2.633	1.656	1.549	2.797	1	3.065
2	8.273	5.042	4.374	7.962	7.899	4.967	4.648	8.390	3	9.195
3	13.788	8.404	7.290	13.271	13.165	8.278	7.746	13.983	5	15.325
4	19.304	11.766	10.206	18.579	18.431	11.589	10.845	19.576	7	21.455
5	24.819	15.127	13.122	23.887	23.697	14.900	13.944	25.169	9	27.585
6	[illegible]	18.489	16.038	29.196	28.963	18.211	17.042	30.763	11	[illegible]
7	[illegible]	21.851	18.954	[illegible]	[illegible]	21.522	20.141	36.356	13	[illegible]
8	[illegible]	25.212	21.870	[illegible]	[illegible]	24.833	23.239	41.949	15	[illegible]
9	[illegible]	28.574	24.786	[illegible]	[illegible]	28.144	26.338	47.542	17	[illegible]
10	[illegible]	[illegible]	27.703	[illegible]	[illegible]	31.455	29.437	53.136	19	[illegible]

Attachment Q-11, Frequency Summary At Various Sound Speeds (Pg 3 of 6)

Byron	Byron 1				Byron 2					
4600 fps	A	B	C	D	A	B	C	D		Common header
S/G to Check	106	111	161	153	135	130	154	140		
Check to Venturi	131	338	358	101	124	334	359	100		
Venturi to FW Reg valve	107	133	125	113	108	130	102	115		
total length	344	583	646	368	368	595	616	356		
FW Heaters to common Bracket										
Common Bracket to FW Reg valve										
		Byron 1	Byron 2	Braidwood 1	Braidwood 2					
total length (30" after heaters)		382	382		323					
30" before heaters		132								
f=c*i/(4*L)	4	4	4	4	4	4	4	4		4
where L = total length	344	583	646	368	368	595	616	356		382
c=sound speed = 4600 fps	4600	4600	4600	4600	4600	4600	4600	4600		4600
i = 1, 3, 5, 7, 9										
BYRON	Unit 1				Unit 2					
MODE	Frequency								I	
1	3.343	1.973	1.780	3.125	3.125	1.933	1.867	3.230	1	3.010
2	10.029	5.918	5.341	9.375	9.375	5.798	5.601	9.691	3	9.031
3	16.715	9.863	8.901	15.625	15.625	9.664	9.334	16.152	5	15.052
4	23.401	13.808	12.461	21.875	21.875	13.529	13.068	22.612	7	21.073
5	30.087	17.753	16.022	28.125	28.125	17.395	16.802	29.073	9	27.094
6	[illegible]	21.698	19.582	[illegible]	[illegible]	21.261	20.536	[illegible]	11	[illegible]
7	[illegible]	25.643	23.142	[illegible]	[illegible]	25.126	24.269	[illegible]	13	[illegible]
8	[illegible]	29.588	26.703	[illegible]	[illegible]	28.992	28.003	[illegible]	15	[illegible]
9	[illegible]	[illegible]	30.263	[illegible]	[illegible]	32.857	31.737	[illegible]	17	[illegible]
10	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	19	[illegible]

Attachment Q-11, Frequency Summary At Various Sound Speeds (Pg 4 of 6)

Braidwood	Braidwood 1				Braidwood 2					
4600 fps	A	B	C	D	A	B	C	D		Common header
S/G to Check	121	119	161	148	135	122	152	136		
Check to Venturi	141	349	402	114	131	339	359	101		
Venturi to FW Reg valve	97	121	116	111	110	137	128	117		
total length	359	589	679	373	376	598	639	354		
f=c*i/(4*L)	4	4	4	4	4	4	4	4		4
where L = total length	359	589	679	373	376	598	639	354		323
c=sound speed = 4600 fps	4600	4600	4600	4600	4600	4600	4600	4600		4600
i = 1, 3, 5, 7, 9										
BRAIDWOOD	Unit 1				Unit 2					
MODE	Frequency								I	
1	3.203	1.952	1.694	3.083	3.059	1.923	1.800	3.249	1	3.560
2	9.610	5.857	5.081	9.249	9.176	5.769	5.399	9.746	3	10.681
3	16.017	9.762	8.468	15.416	15.293	9.615	8.998	16.243	5	17.802
4	22.423	13.667	11.856	21.582	21.410	13.462	12.598	22.740	7	24.923
5	28.830	17.572	15.243	27.748	27.527	17.308	16.197	29.237	9	32.043
6	[illegible]	21.477	18.630	33.914	33.644	21.154	19.797	[illegible]	11	[illegible]
7	[illegible]	25.382	22.018	[illegible]	[illegible]	25.000	23.396	[illegible]	13	[illegible]
8	[illegible]	29.287	25.405	[illegible]	[illegible]	28.846	26.995	[illegible]	15	[illegible]
9	[illegible]	33.192	28.792	[illegible]	[illegible]	32.692	30.595	[illegible]	17	[illegible]
10	[illegible]	[illegible]	32.180	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	19	[illegible]

Attachment Q-11, Frequency Summary At Various Sound Speeds (Pg 5 of 6)

Byron 1	Byron 1				Byron 2					
4200 fps	A	B	C	D	A	B	C	D		Common header
S/G to Check	106	111	161	153	135	130	154	140		
Check to Venturi	131	338	358	101	124	334	359	100		
Venturi to FW Reg valve	107	133	125	113	108	130	102	115		
total length	344	583	646	368	368	595	616	356		
FW Heaters to common Bracket										
Common Bracket to FW Reg valve										
		Byron 1	Byron 2	Braidwood 1	Braidwood 2					
total length (30" after heaters)		382	382		323					
30" before heaters		132								
f=c*i/(4*L)	4	4	4	4	4	4	4	4		4
where L = total length	344	583	646	368	368	595	616	356		382
c=sound speed = 4200 fps	4200	4200	4200	4200	4200	4200	4200	4200		4200
i = 1, 3, 5, 7, 9										
BYRON	Unit 1				Unit 2					
MODE	Frequency								I	
1	3.052	1.801	1.625	2.853	2.853	1.765	1.705	2.949	1	2.749
2	9.157	5.403	4.876	8.560	8.560	5.294	5.114	8.848	3	8.246
3	15.262	9.005	8.127	14.266	14.266	8.824	8.523	14.747	5	13.743
4	21.366	12.607	11.378	19.973	19.973	12.353	11.932	20.646	7	19.241
5	27.471	16.209	14.628	25.679	25.679	15.882	15.341	26.545	9	24.738
6	[illegible]	19.811	17.879	[illegible]	[illegible]	19.412	18.750	[illegible]	11	30.236
7	[illegible]	23.413	21.130	[illegible]	[illegible]	22.941	22.159	[illegible]	13	[illegible]
8	[illegible]	27.015	24.381	[illegible]	[illegible]	26.471	25.568	[illegible]	15	[illegible]
9	[illegible]	[illegible]	27.632	[illegible]	[illegible]	30.000	28.977	[illegible]	17	[illegible]
10	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	19	[illegible]

Attachment Q-11, Frequency Summary At Various Sound Speeds (Pg 6 of 6)

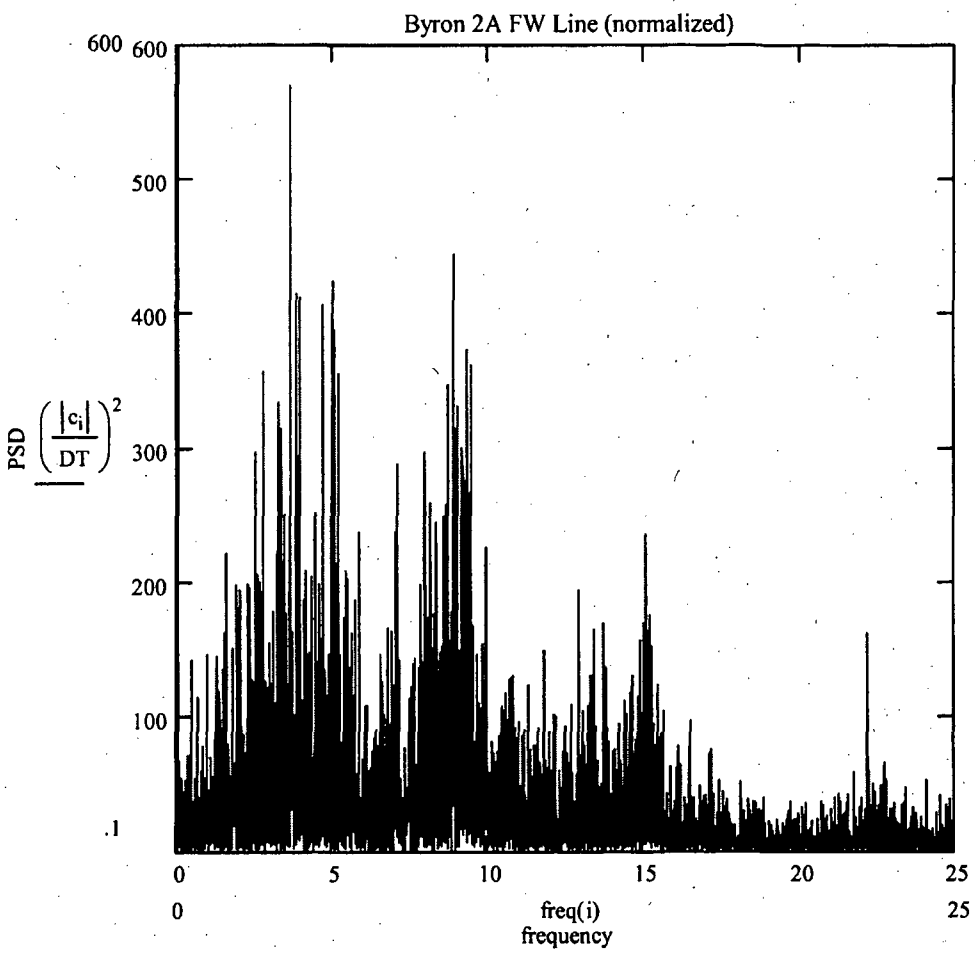
Braidwood	Braidwood 1				Braidwood 2					
4200 fps	A	B	C	D	A	B	C	D		Common header
S/G to Check	121	119	161	148	135	122	152	136		
Check to Venturi	141	349	402	114	131	339	359	101		
Venturi to FW Reg valve	97	121	116	111	110	137	128	117		
total length	359	589	679	373	376	598	639	354		
f=c*i/(4*L)	4	4	4	4	4	4	4	4		4
where L = total length	359	589	679	373	376	598	639	354		323
c=sound speed = 4200 fps	4200	4200	4200	4200	4200	4200	4200	4200		4200
i = 1, 3, 5, 7, 9										
BRAIDWOOD	Unit 1				Unit 2					
MODE	Frequency								I	
1	2.925	1.783	1.546	2.815	2.793	1.756	1.643	2.966	1	3.251
2	8.774	5.348	4.639	8.445	8.378	5.268	4.930	8.898	3	9.752
3	14.624	8.913	7.732	14.075	13.963	8.779	8.216	14.831	5	16.254
4	20.474	12.479	10.825	19.705	19.548	12.291	11.502	20.763	7	22.755
5	26.323	16.044	13.918	25.335	25.133	15.803	14.789	26.695	9	29.257
6	[illegible]	19.610	17.010	30.965	30.718	19.314	18.075	32.627	11	35.759
7	[illegible]	23.175	20.103	[illegible]	36.303	22.826	21.362	38.559	13	42.260
8	[illegible]	26.740	23.196	[illegible]	[illegible]	26.338	24.648	44.492	15	48.762
9	[illegible]	30.306	26.289	47.855	47.473	29.849	27.934	50.424	17	55.263
10	[illegible]	[illegible]	29.381	[illegible]	53.659	33.361	31.221	56.356	19	61.765

Attachment Q-12, White Paper On How Plant Acoustics Affect UFM (Pg 1 of 14)

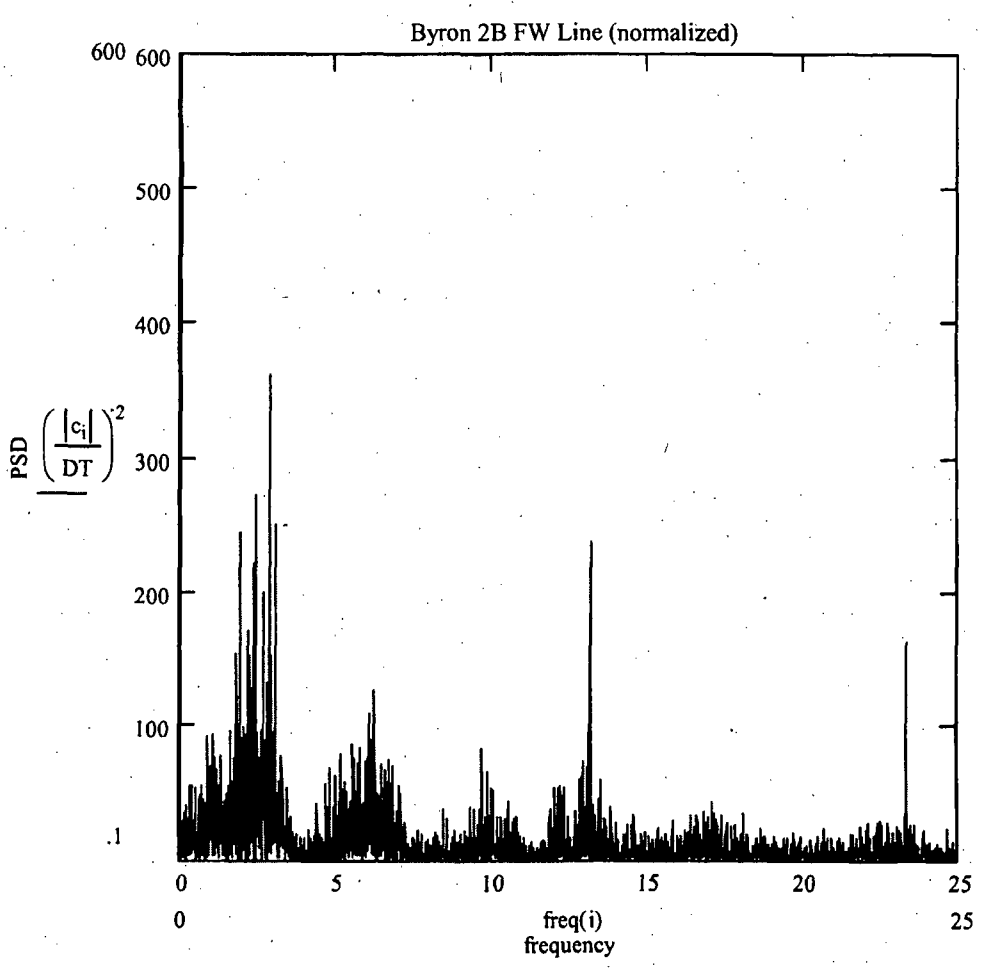
BYRON UNIT 2 REVISED MEASURED PRESSURE PSD AND CROSSFLOW DEMODULATED SIGNAL NORMALIZED FREQUENCY SPECTRUM PLOTS

The following plots were prepared to respond to comments with respect to the independent review of the AMAG Root Cause Report. Specifically, it was stated that the presentation in Appendix G of the report did not emphatically support the existence of acoustic frequency components that were directly comparable to the AMAG Diagnose software plots provided in Appendix L. The Power Spectral Density (PSD) plots included in Appendix G were in log format as well as normalized, while the comparable plots in Appendix L were in non-normalized linear format. Therefore the Appendix G plots have been regenerated employing a linear format. In addition, the collected demodulated signals were used to reconstruct the normalized frequency spectrum plots. To compare the frequency spectrum plots at the same range of frequency as the demodulated signal normalized frequency spectrum another set of power spectrum plots for collected pressure data were prepared and normalized based on the maximum measured pressure (maximum measured voltage). The current plots shows the correlation between the measured pressure (frequency and amplitude) to the observed periodic noise in Crossflow demodulated signal support the existence of acoustic frequency components that were directly comparable to the AMAG Diagnose software plots provided in Appendix L

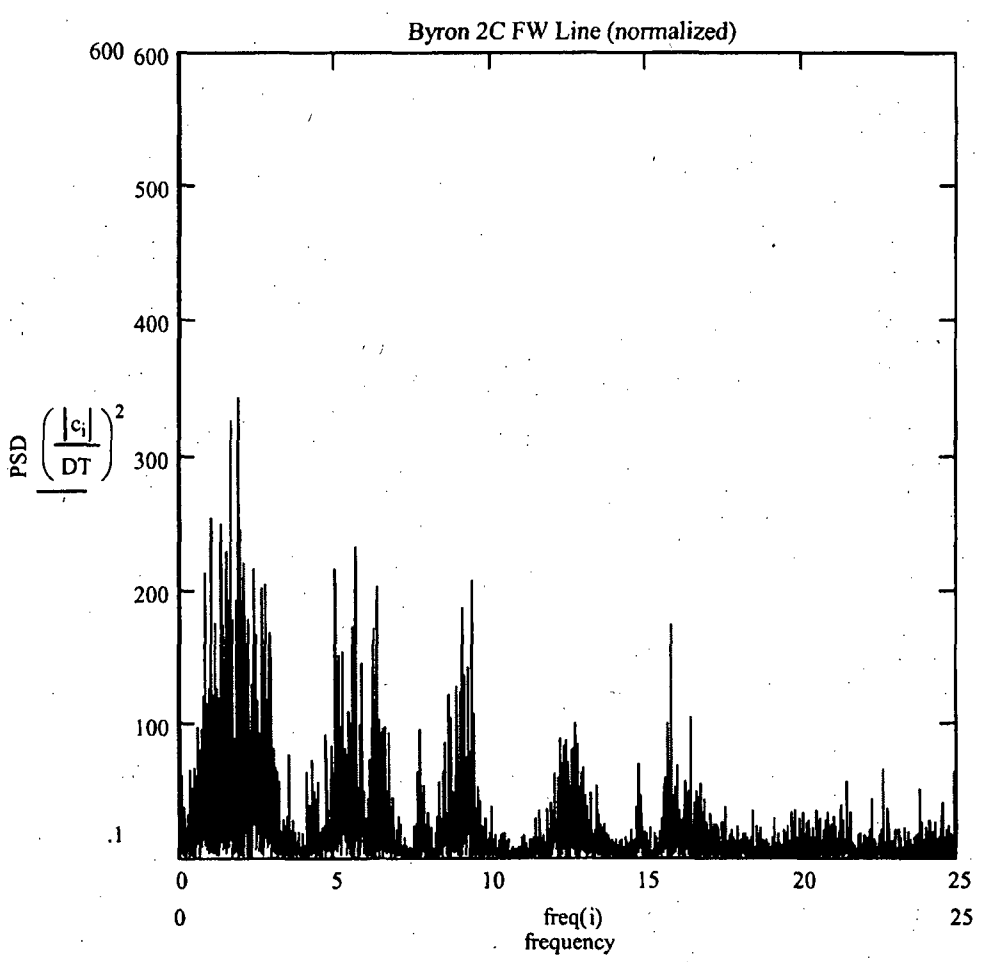
Attachment Q-12, White Paper On How Plant Acoustics Affect UFM (Pg 2 of 14)



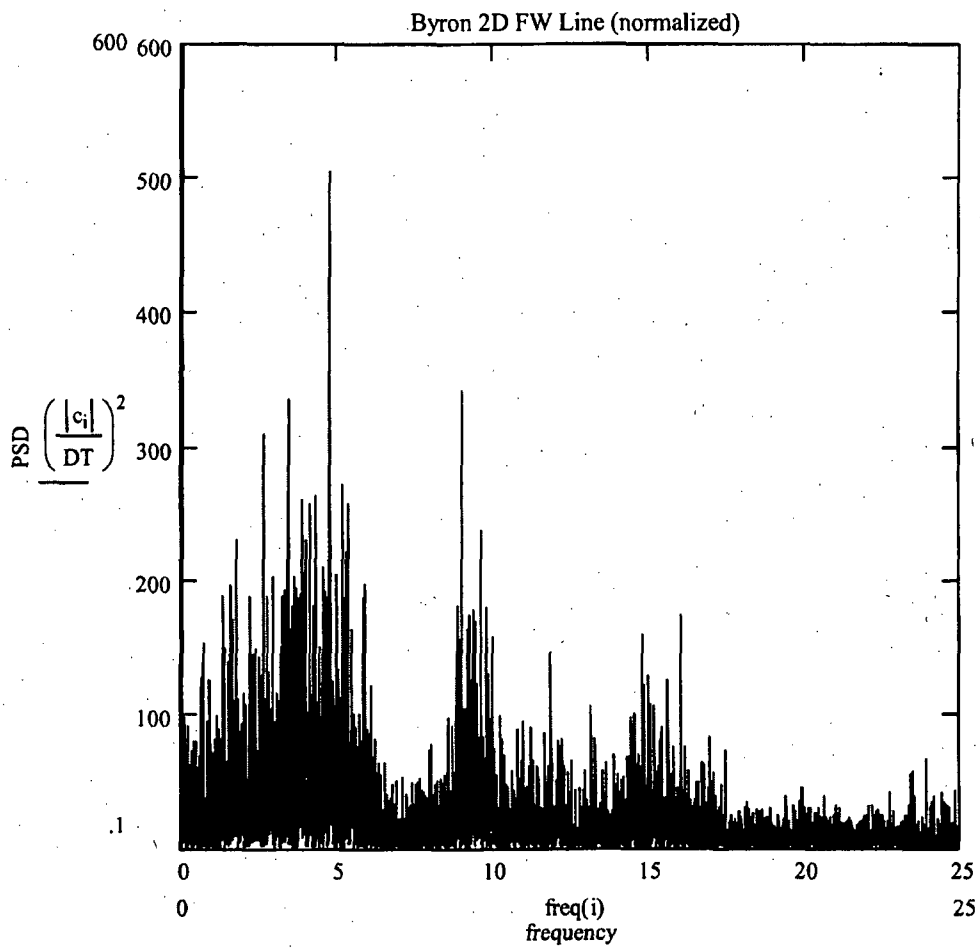
Attachment Q-12, White Paper On How Plant Acoustics Affect UFM (Pg 3 of 14)



Attachment Q-12, White Paper On How Plant Acoustics Affect UFM (Pg 4 of 14)

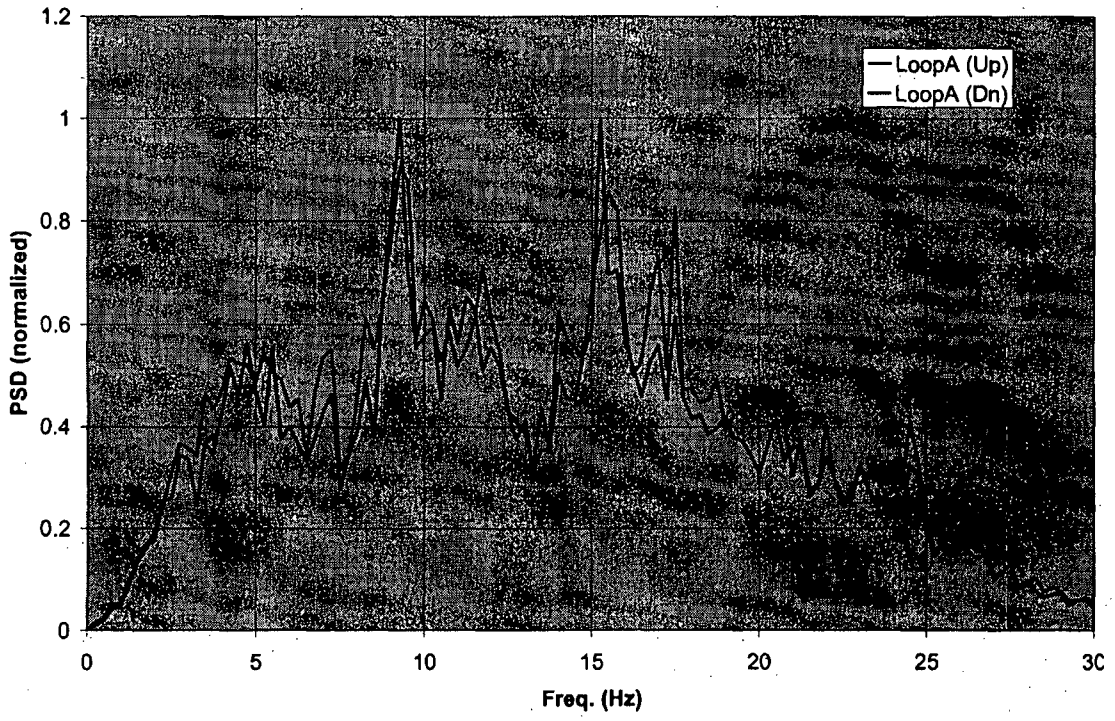


Attachment Q-12, White Paper On How Plant Acoustics Affect UFM (Pg 5 of 14)

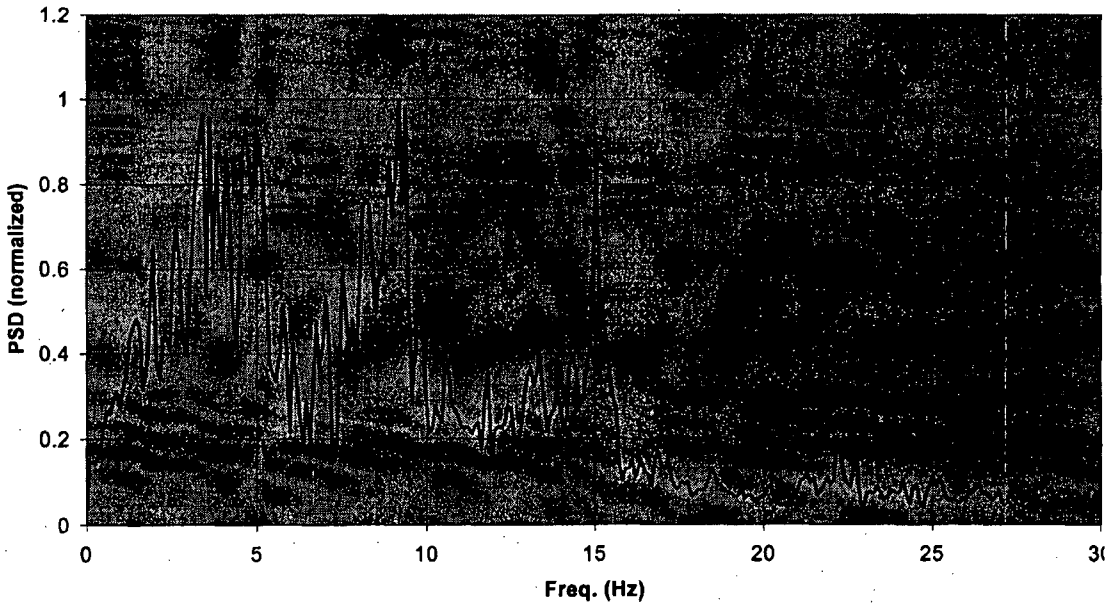


Attachment Q-12, White Paper On How Plant Acoustics Affect UFM (Pg 6 of 14)

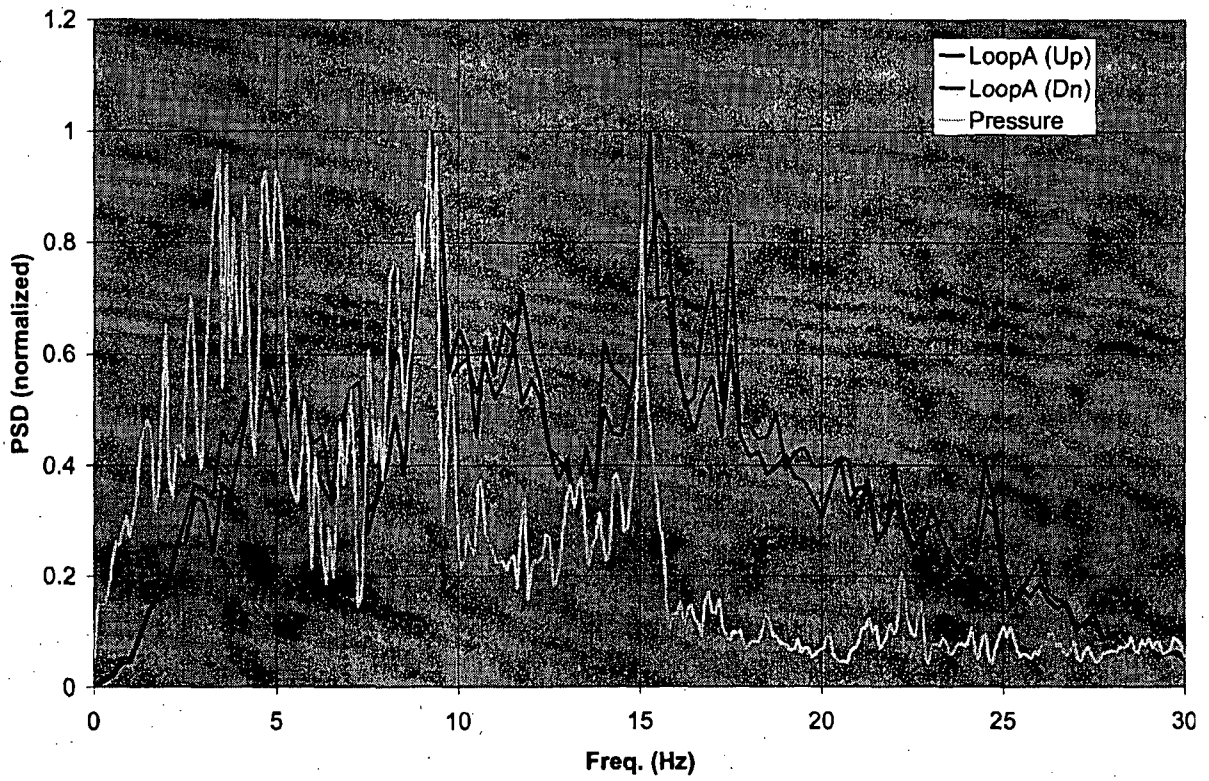
Byron Unit 2 Loop A



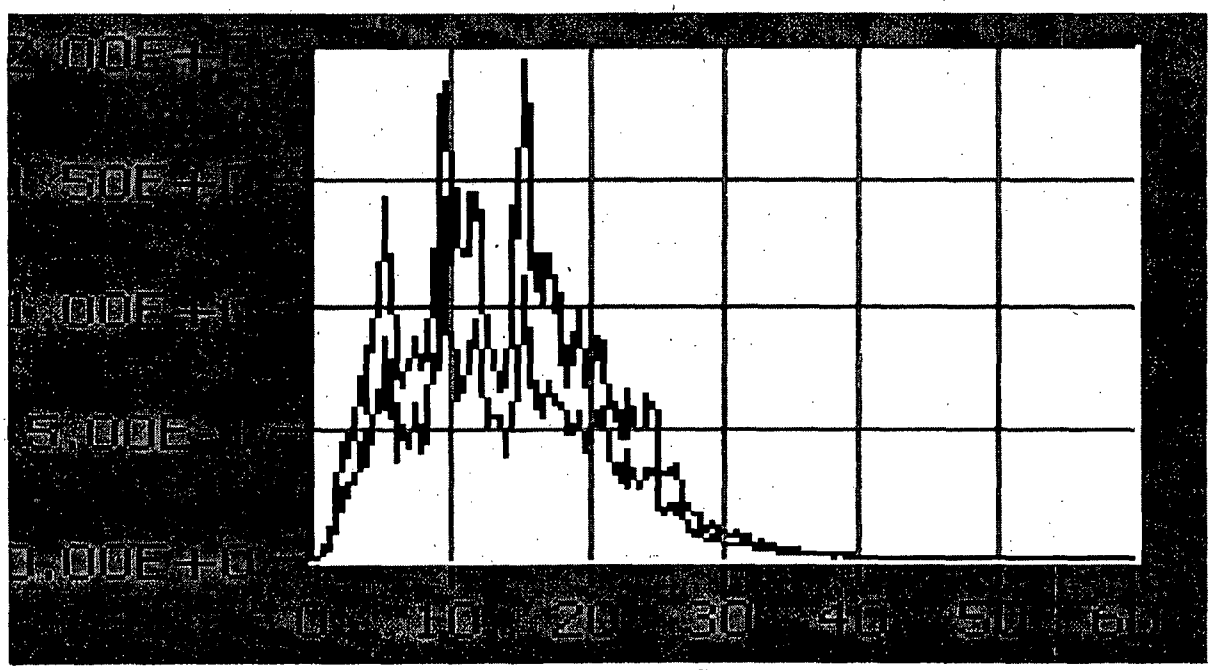
U2/LoopA Crossflow demodulated signal normalized PSD



U2/Loop A Measured pressure normalized PSD

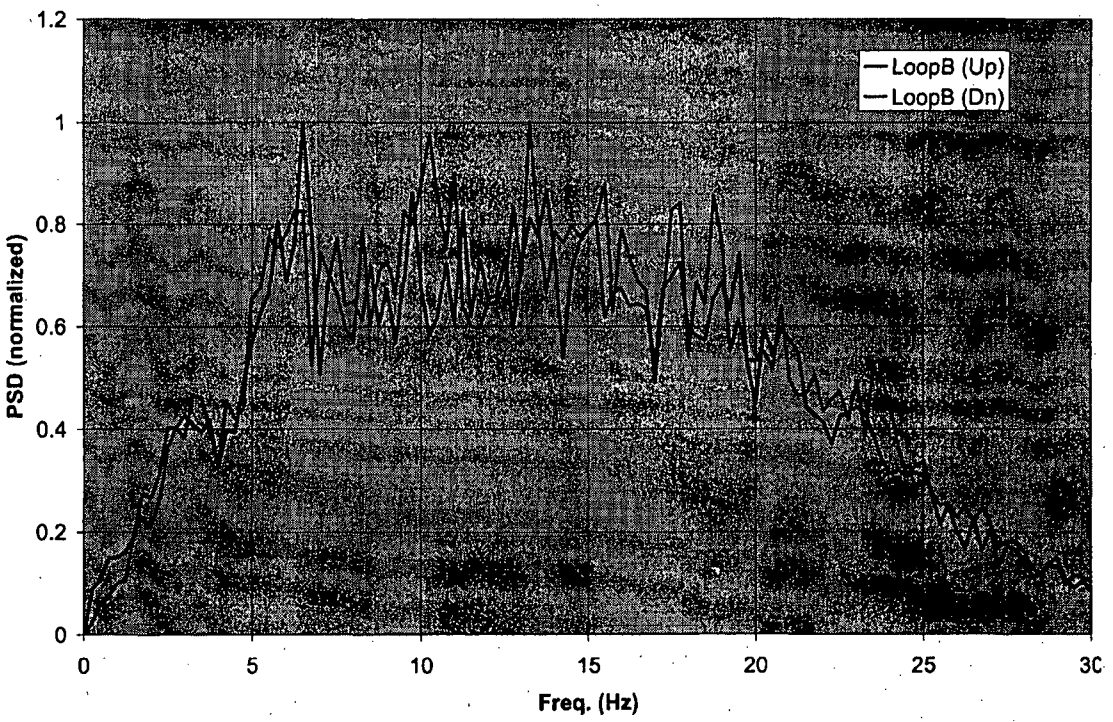


U2/Loop A Measured Pressure & Demodulated signal normalized PSDs

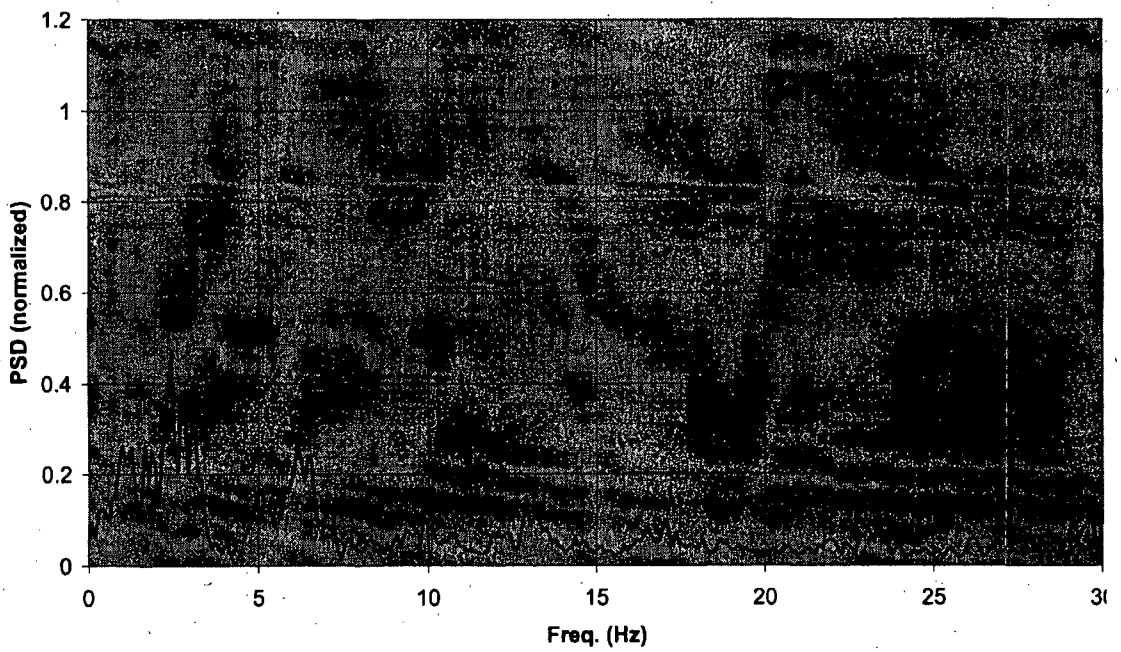


U2/Loop A Frequency Spectrum

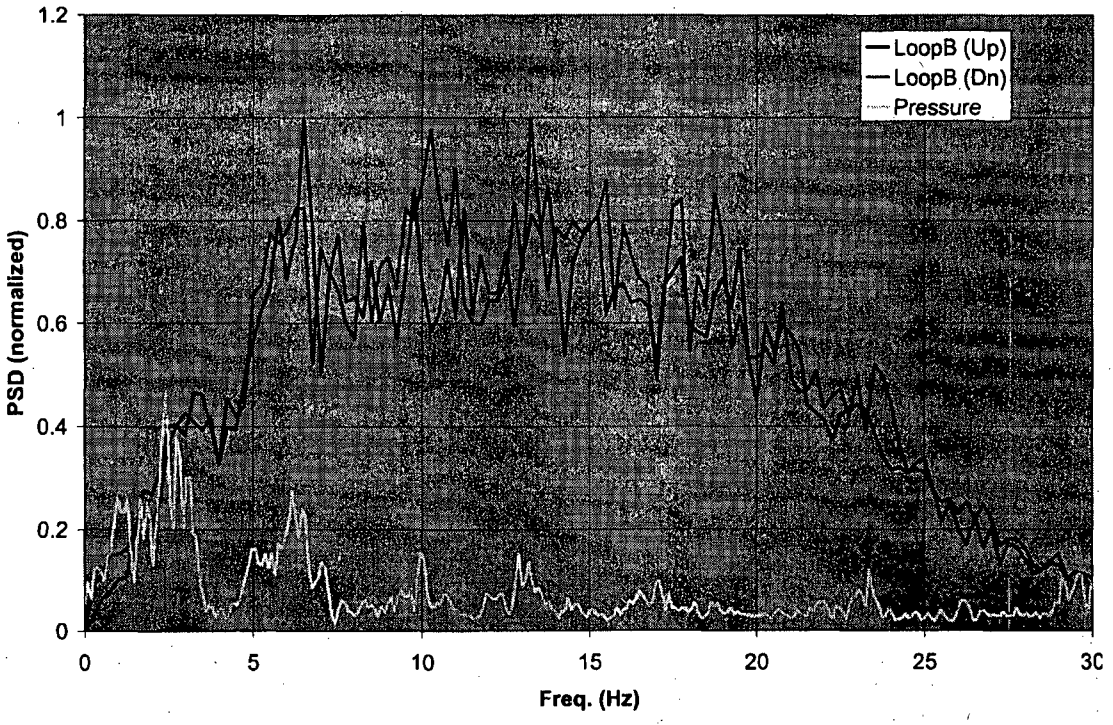
Byron Unit 2 Loop B



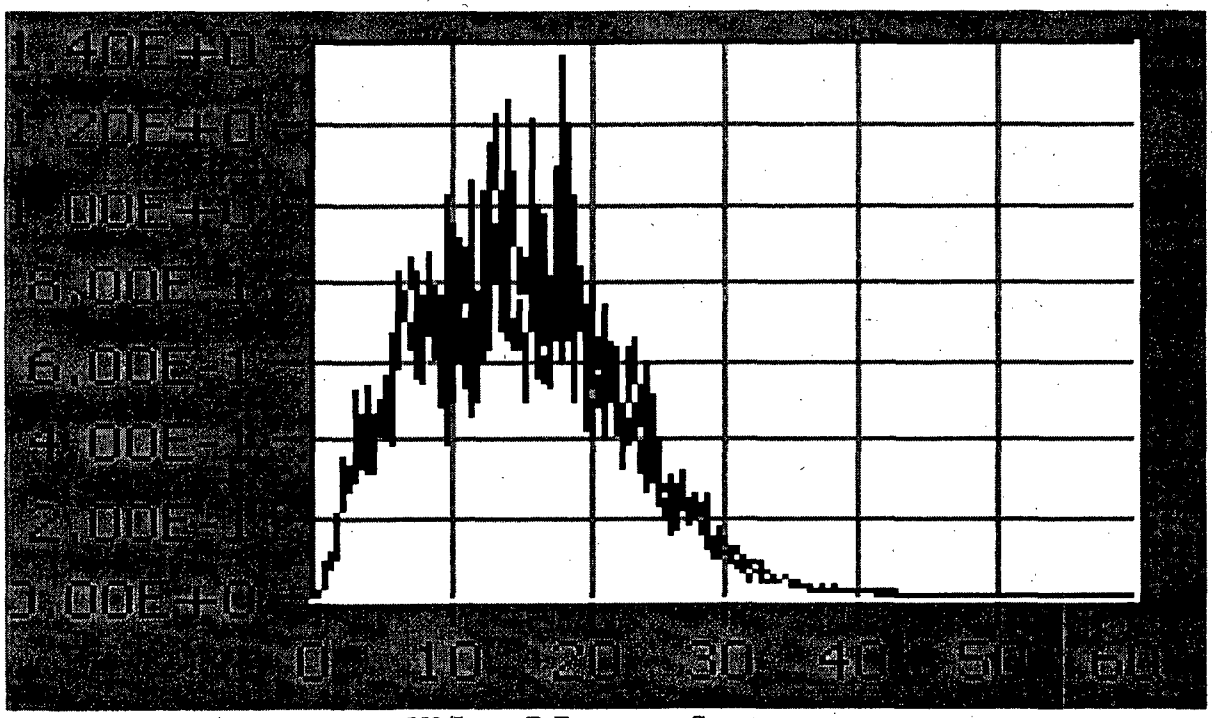
U2/LoopB Crossflow demodulated signal normalized PSD



U2/Loop B Measured pressure normalized PSD

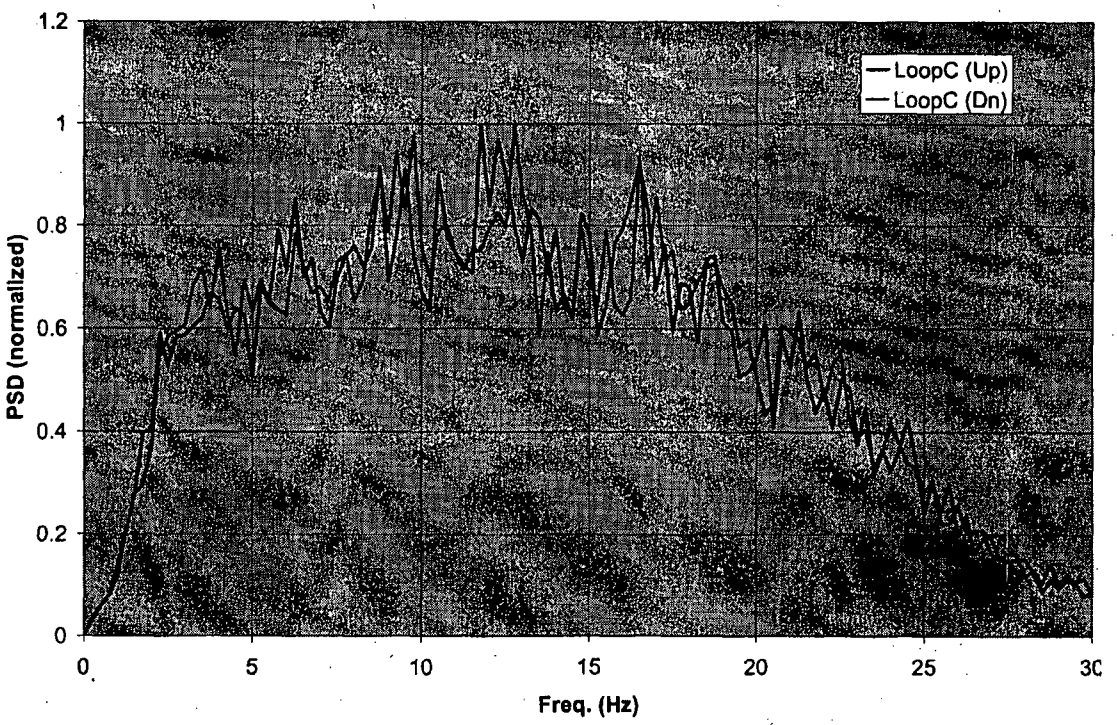


U2/Loop B Measured Pressure & Demodulated signal normalized PSDs

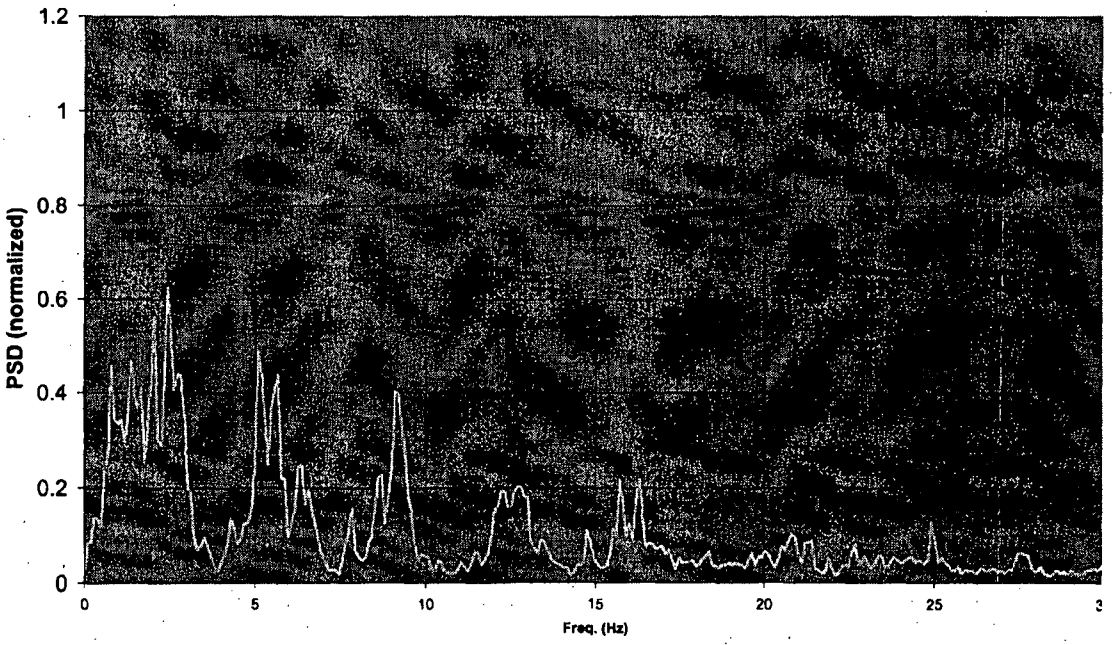


U2/Loop B Frequency Spectrum

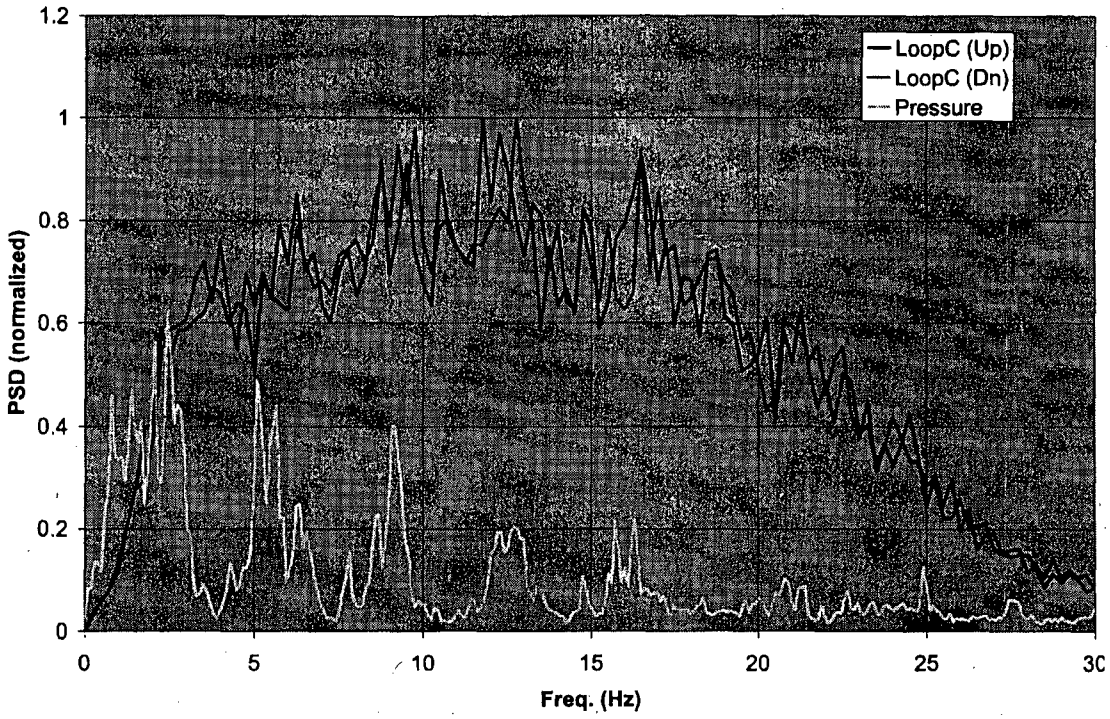
Byron Unit 2 Loop C



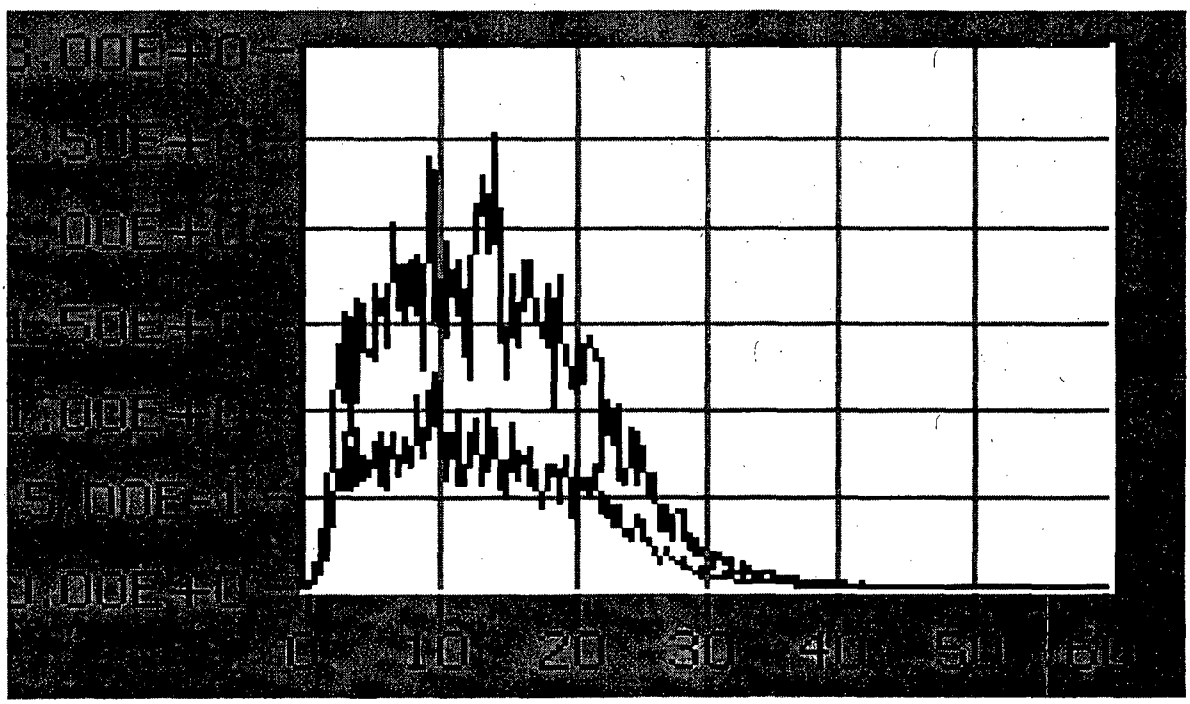
U2/LoopC Crossflow demodulated signal normalized PSD



U2/Loop C Measured pressure normalized PSD



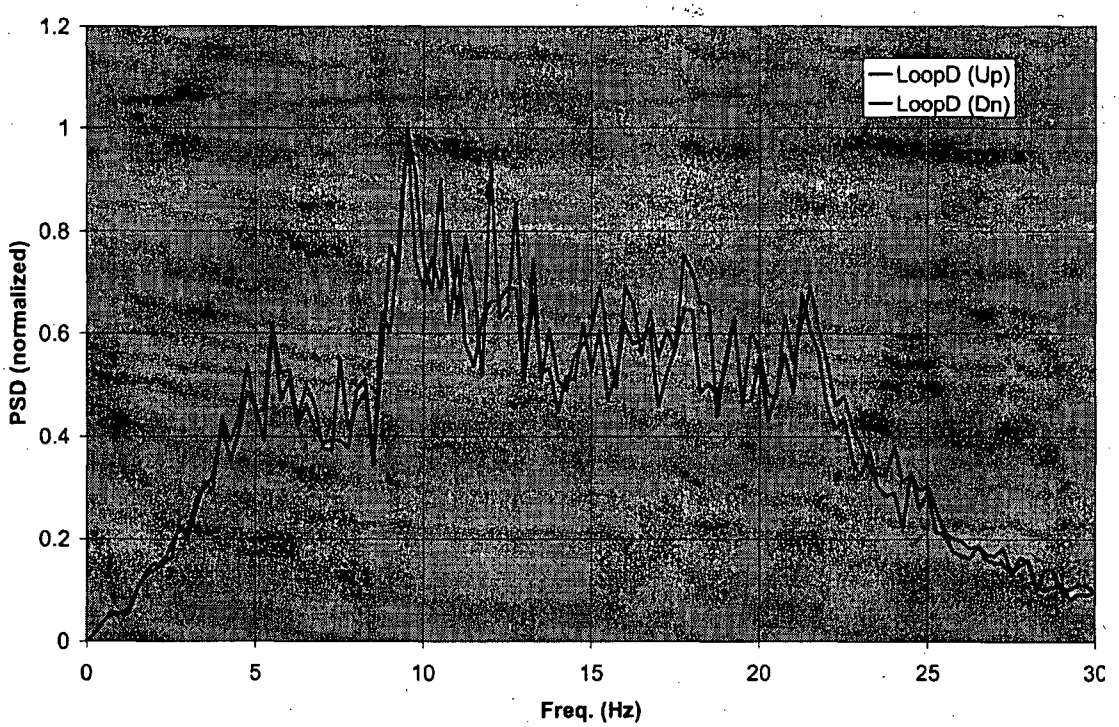
U2/Loop C Measured Pressure & Demodulated signal normalized PSDs



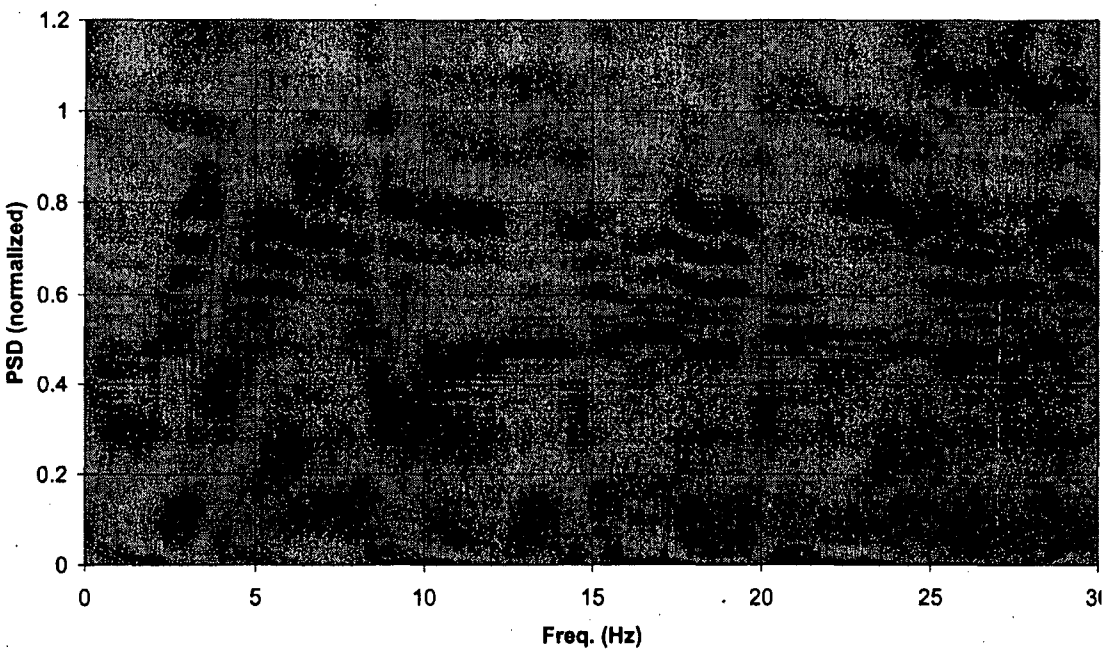
U2/Loop C Frequency Spectrum

Attachment Q-12, White Paper On How Plant Acoustics Affect UFM (Pg 12 of 14)

Byron Unit 2 Loop D

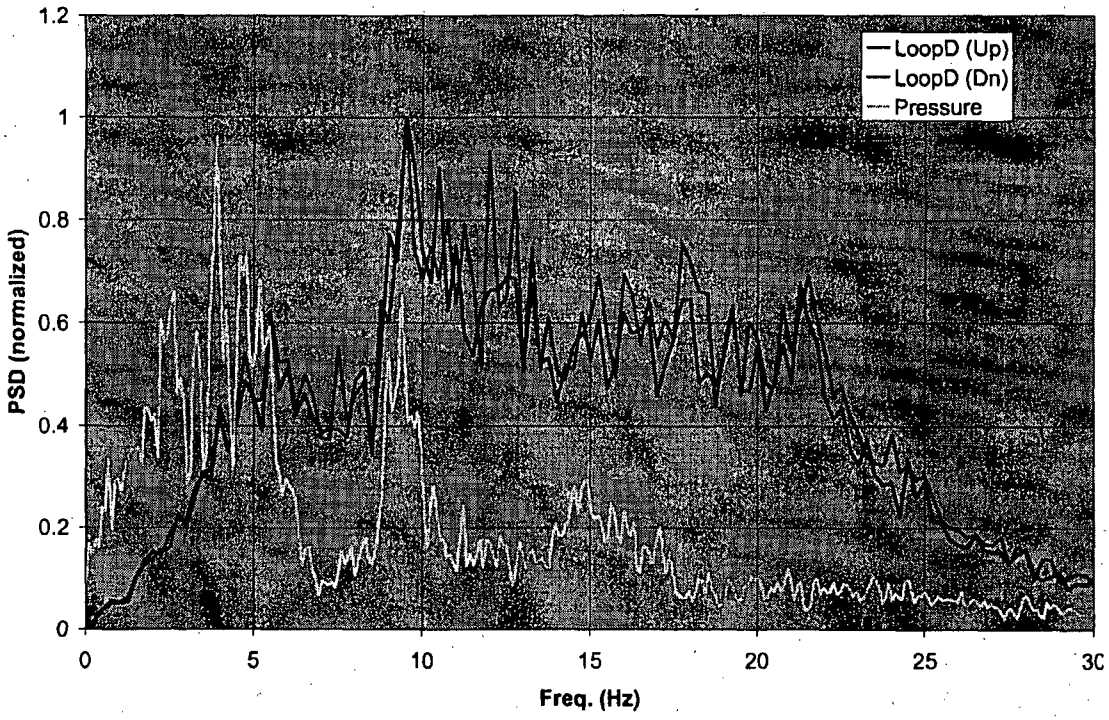


U2/LoopD Crossflow demodulated signal normalized PSD

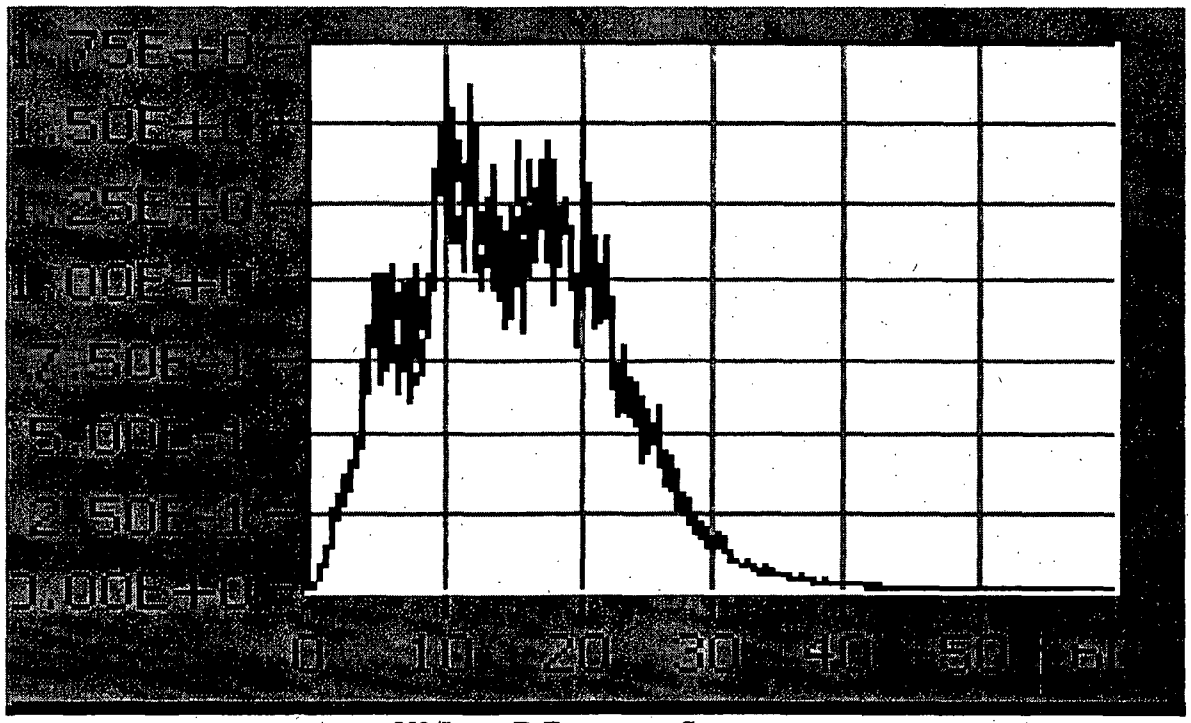


U2/Loop D Measured pressure normalized PSD

Attachment Q-12, White Paper On How Plant Acoustics Affect UFM (Pg 13 of14)



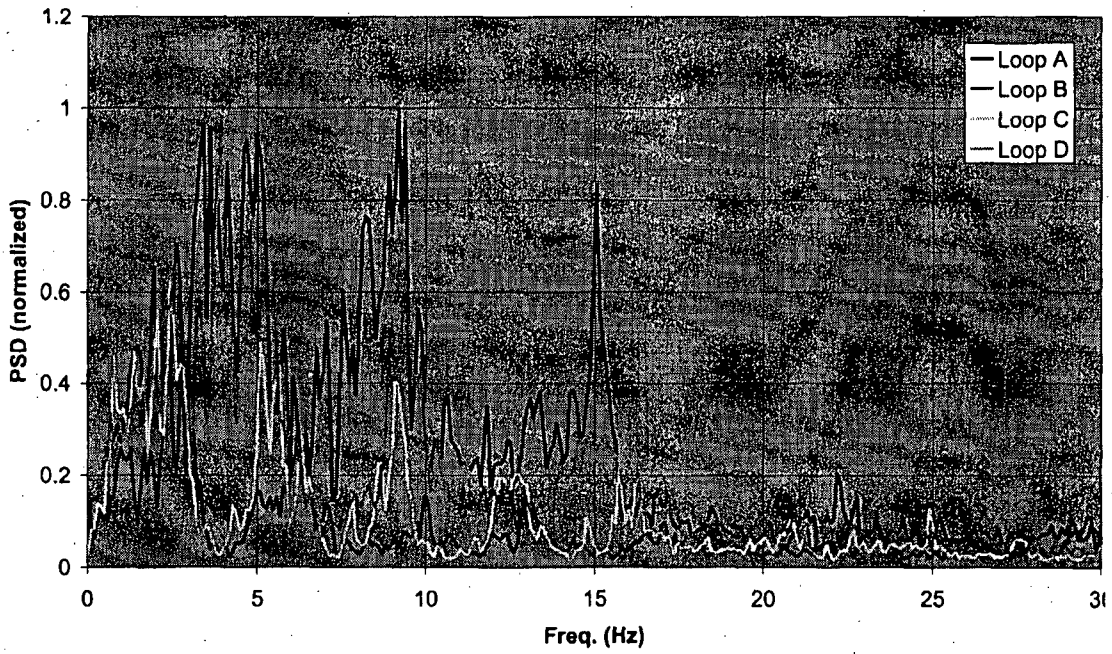
U2/Loop D Measured Pressure & Demodulated signal normalized PSDs



U2/Loop D Frequency Spectrum

Attachment Q-12, White Paper On How Plant Acoustics Affect UFM (Pg 14 of 14)

Byron Unit 2



U2/Loop A, B, C, and D Measured pressure normalized PSD

Attachment Q-13, Byron Updated Frequency Comparison

(Pg 1 of 2)

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		19.3	19.6	21.7						
5th frequency width		19.0-20.0	19.0-21.0	20.6-23.4						
6th frequency peak			22.4							
6th frequency width			21.7-22.8							

Natural piping frequency response theory @			4200 fps							
Unit	Byron 1					Byron 2				
Loop	A	B	C	D	Common	A	B	C	D	Common
1st frequency peak	3.1	1.8	1.6	2.9		2.9	1.8	1.7	2.949438	
1st frequency width										
2nd frequency peak	9.2	5.4	4.9	8.6		8.6	5.3	5.1	8.848315	
2nd frequency width										
3rd frequency peak	15.3	9.0	8.1	14.3		14.3	8.8	8.5	14.74719	
3rd frequency width										
4th frequency peak	21.4	12.6	11.4	20.0		20.0	12.4	11.9	20.64607	
4th frequency width										
5th frequency peak	27.5	16.2	14.6	25.7		25.7	15.9	15.3	26.54494	

Attachment Q-13, Byron Updated Frequency Comparison

(Pg 2 of 2)

In the below data, all Byron 1 data from 6 sets is summarized in "Set 1", based on observations of significant responses.

Piping Frequency data results	Set 1									
Unit	Byron 1					Byron 2				
Loop	A	B	C	D	Common	A	B	C	D	Common
1st frequency peak	3-4	2	2	3-4	1.358	3.5	2.5	2	3.5-4	
1st frequency width					noise					
2nd frequency peak	9-10	5.5-6	5	9-9.5	6.283	9	6.25	6	9	
2nd frequency width					noise					
3rd fre3quency peak	16	9	8.5	14-15	16.585	15	10	9	15-16	
3rd frequency width					noise					
4th frequency peak	22	12	12	20-21		22.5	13.5	13.5	22.5	
4th frequency width										
5th frequency peak			15			N/O	N/O	16	N/O	
5th frequency width										
6th frequency peak			22							
6th frequency width										
7th frequency peak										
7th frequency width										
8th frequency peak										
8th frequency width										

Attachment Q-14, Braidwood Updated Frequency Comparison

(Pg 1 of 6)

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										

Attachment Q-14, Braidwood Updated Frequency Comparison

(Pg 2 of 6)

Natural piping frequency response theory (FWRV to SG)					c= 4200 fps					
Unit	Braidwood 1					Braidwood 2				
Loop	A	B	C	D	Common	A	B	C	D	Common
1st frequency peak	2.92	1.78	1.55	2.82	3.251	2.79	1.76	1.64	2.97	3.251
1st frequency width										
2nd frequency peak	8.77	5.35	4.64	8.45	9.752	8.38	5.27	4.93	8.90	9.752
2nd frequency width										
3rd frequency peak	14.62	8.91	7.73	14.08	16.254	13.96	8.78	8.22	14.83	16.254
3rd frequency width										
4th frequency peak	20.47	12.48	10.82	19.71	22.755	19.55	12.29	11.50	20.76	22.755
4th frequency width										
5th frequency peak	26.32	16.04	13.92	25.34	29.257	25.13	15.80	14.79	26.69	29.257
5th frequency width										
6th frequency peak		19.61		30.97	35.759		19.31		32.63	35.759
6th frequency width										
7th frequency peak		23.17		36.60	42.260		22.83		38.56	42.260
7th frequency width										
8th frequency peak		26.74		42.23	48.762		26.34		44.49	48.762
8th frequency width										

Attachment Q-14, Braidwood Updated Frequency Comparison

(Pg 4 of 6)

Piping Frequency data results	Set 2									
Unit	Braidwood 1					Braidwood 2				
Loop	A	B	C	D	Common	A	B	C	D	Common
1st frequency peak		1.78		4.11	0.46		1.4		1.44	15.56
1st frequency width		0-2.8		0-4.67	0-2.57		0.75-2.57		.94-2.15	13.55-16.82
2nd frequency peak		5.56		8.5	5.61		6.17		4.07	19.16
2nd frequency width		4.9 - 5.8		5.6-11.21	4.9-7.1		3.97-7.24		2.15-6.08	18.93-20.33
3rd frequency peak		8.3		13.93	16.82		11.45		8.65	
3rd frequency width		7.94-9.48		11.21-15.42	14.02-20.09		7.24-15.19		6.08-12.62	
4th frequency peak		12.01		16.63			20.65		15.14	
4th frequency width		10.75-12.15		15.42-19.16			19.86-21.73		12.62-18.22	
5th frequency peak		15.42		21.4			24.3		19.07	
5th frequency width		14.48-17.52		19.16-23.36			22.20-24.4		18.22-21.96	
6th frequency peak		18.45		28.97			26.87		24.3	
6th frequency width		17.8-20.09		26.40-31.54			24.53-27.57		21.96-27.10	
7th frequency peak		22.43							30.37	
7th frequency width		21.72-27.10							27.10-30.84	
8th frequency peak										
8th frequency width										
					none significant					

Attachment Q-14, Braidwood Updated Frequency Comparison

(Pg 5 of 6)

Piping Frequency data results		Set 3								
Unit	Braidwood 1					Braidwood 2				
Loop	A	B	C	D	Common	A	B	C	D	Common
1st frequency peak		1.45		3.04	None		1.45		0.94	None
1st frequency width		0.7-2.34		2.06-5.60			0-2.80		.56-1.87	
2nd frequency peak		4.91		7.71			5.23		2.8	
2nd frequency width		3.27 - 7.47		6.07-8.88			3.50-6.78		1.87-6.54	
3rd frequency peak		8.79		14.39			8.13		9.35	
3rd frequency width		7.94-9.35		12.62-16.36			6.78-10.28		6.54-11.68	
4th frequency peak		10.23		19.39			12.62		13.79	
4th frequency width		9.81-10.37		18.69-19.63			10.28-13.55		11.68-15.89	
5th frequency peak		11.92		24.3			16.03		16.94	
5th frequency width		11.21-13.79		21.96-24.76			15.42-17.29		15.89-18.69	
6th frequency peak		15.51		31.54			21.59		21.26	
6th frequency width		13.79-17.76		28.04-31.78			20.56-22.99		18.69-24.3	
7th frequency peak		19.67		35.28			23.83		24.77	
7th frequency width		17.76-22.20		32.24-35.51			22.99-25.61		24.3-26.64	
8th frequency peak		23.36					28.5		27.48	
8th frequency width		22.2-25.70					27.57-28.97		26.64-28.27	

Attachment Q-14, Braidwood Updated Frequency Comparison

(Pg 6 of 6)

Piping Frequency data results		Set 4								
Unit	Braidwood 1					Braidwood 2				
Loop	A	B	C	D	Common	A	B	C	D	Common
1st frequency peak		1.87		3.5	None		1.87		0.94	1.64
1st frequency width		1.17-2.8		2.10-5.61			.93-2.80		.47-1.87	.94-1.87
2nd frequency peak		4.67		9.91			5.14		3.36	2.8
2nd frequency width		4.2 - 5.7		6.54-10.75			4.21-6.08		1.87-5.05	1.87-3.74
3rd frequency peak		8.5		14.11			8.64		8.27	5.14
3rd frequency width		7.71-10.51		13.08-15.42			7.24-10.89		7.94-9.35	3.74-6.08
4th frequency peak		15.65		19.25			12.85		10.37	
4th frequency width		14.95-16.82		17.28-22.43			10.89-13.08		9.81-13.08	
5th frequency peak		18.36		24.67			15.89		14.49	
5th frequency width		17.52-21.03		22.43-25.23			13.08-16.82		13.08-15.42	
6th frequency peak		24.58		31.54			21.12		18.22	
6th frequency width		21.72-27.10		27.57-34.11			19.86-21.73		17.76-20.09	
7th frequency peak				37.47			25.79		21.5	
7th frequency width				36.45-39.72			21.73-28.27		20.09-24.77	
8th frequency peak				41.36			30.21		26.64	
8th frequency width				41.12-42.99			28.27-32.1		24.77-27.57	27.57

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, Rev 1
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**
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	

__Signature on file_____
Root Cause Investigator / Date

_Signature on file_____
Department Head / Date

__Signature on file_____
Sponsor Manager / Date