Penspen Integrity
Units 7-8
St. Peter's Wharf
Newcastle upon Tyne
NE6 1TZ
United Kingdom

Telephone: +44 (0)191 238 2200
Fax: +44 (0)191 275 9786
Email: integrity.ncl@penspen.com
Website: www.penspenintegrity.com

When is Corrosion Not Corrosion? A Decade of MFL Pipeline Inspection.

Paul Tims, TotalFinaElf Exploration Norge AS, Stavanger, Norway

Owen Wilson, Andrew Palmer and Associates, Aberdeen, UK

Abstract

TotalFinaElf Exploration UK (TFEEUK), as the technical operator of the twin 32" Frigg gas export pipelines between the Frigg field and the St. Fergus gas terminal regularly inspect the pipelines with intelligent pigs to demonstrate their integrity.

Inspections of one of these pipelines found several significant defects that appeared to grow over time, to the point where the pressure at which the pipeline could safely be operated required to be reduced.

To restore the pressure-retaining capability of the pipeline to its design level, a section of pipeline was replaced and a sample containing the pressure-limiting defects was recovered to the surface. A physical survey of the corroded pipe joints discovered that the reported "corrosion" was not present but found instead a layer of ferrous debris adhered to the pipe wall. The interpretation of the debris as corrosion highlights the limitations of using an inferred inspection technique in an environment where no complementary inspection is practicable.

TFEEUK continue to regularly inspect these pipelines using intelligent pigs to demonstrate their integrity.

Introduction

During a routine survey in 1990 of one of the Frigg to St Fergus 32" Gas Export pipelines operated by TotalFinaElf Exploration UK (TFEEUK), a Magnetic Flux Leakage (MFL) inspection tool detected several significant defects. The results and the subsequent analysis and investigation instigated a programme of regular inspection that continued until 1999. On the strength of worsening results, the pipeline's Maximum Allowable Operating Pressure (MAOP) was down-rated twice in the same period.

The opportunity to bring the most severely corroded pipe joints to the surface presented itself when the worst corroded section of pipeline was bypassed in 2001. A physical survey of the corroded pipe joints discovered that the reported "corrosion" was not present but found instead, a layer of ferrous debris adhered to the pipe wall.

This paper discusses:

- The results and implications of the inspections.
- The work performed to demonstrate the continued safe operation of the pipeline.
- The results of a physical survey of the pressure-limiting "corrosion" defects.
- The possible origins of the ferrous debris layer.
- Work that has been done to assess the effect of the debris on the behaviour of MFL signals.

Inspection Results

The first inspection of the line, conducted in 1990, highlighted general corrosion of a low level, with 14[1] significant defects with peak metal loss depth ranging from 20% to 48% wall thickness. Throughout the four successive inspections in 1992, 1996, 1997 and 1999, the number of defects increased, and the worst features became progressively deeper.

A summary of the inspection results is presented in Table 1 in Appendix A. The numbers of defects are solely indicative as several of the inspections only reported on selected sections the pipeline rather than the full length. Furthermore, over the 10 year period, detection and reporting thresholds improved considerably resulting in defects being reported that may have been present earlier, but that were either below the detection or reporting thresholds. This is clearly evident in results of the 1996 and 1999 inspections – the only inspections to report on the entire length of the pipeline. The 1996 inspection reported a total of 7863 features, whereas the 1999 inspection reported 43918 features. The distribution of corrosion features (including the worst defects) over a section of the pipeline is shown in Appendix D. Worth noting is the approximate symmetry of the corrosion features around an axis running along the 6 o'clock position in the pipeline. Such corrosion patterns are not uncommon in pipelines and are normally a function of corrosion occurring at a water/product interface, the position of which varies with the vertical profile of the line.

[1] The 1990 inspection was only of the upstream (Northern) half of the pipeline – some 185 km. The downstream (Southern) half of the pipeline – approximately 175 km in length – was inspected in 1991. 20 significant defects with peak metal loss ranging from 10% to 25% of wall thickness were reported in this section of the line.

Table 1 also shows that, apart from the first inspection in 1990, the depth of the deepest feature appeared to increase steadily over time. When the data is reanalysed using a consistent analysis and sizing model, however, the depth is of the deepest feature is much more consistent over time.

The worst features were, however, consistently detected over the period. One of the significant characteristics of the worst features was their general stability in terms of location and shape. The evolution of the dimensions of the worst feature over time is shown in Table 2 in Appendix A. The effects of the different analysis and sizing models can clearly be seen on the data presented in Table 2 – when analysed using the model in use at the time of each original inspection, the defect dimensions (principally length and depth) are seen to increase steadily over the 10 year period. When analysed using a consistent model (in this case, the model in use at the time of the 1997 inspection), the defect dimensions are much more consistent, particularly with respect to depth, although the defect length still clearly increases over the period from 1990 to 1996.

The evolution of the magnetic signal of this defect can be seen in the series of diagrams in Appendix B. Two greyscale images of the more severe features are also presented in Appendix B. The images are broadly similar, but that from the 1999 inspection clearly shows several lower level features adjacent to the main line of features. These are represented graphically in Appendix C.

The worst defect was long and thin in shaped and situated in the 6 o'clock position. The analysis of the magnetic flux readings characterised the feature as an initially deep feature, with a step to a shallower plateau, on which further pitting corrosion was identified in the later surveys.

The other notable aspect of the corrosion was that the worst features were concentrated in a very small number of pipe joints. As time progressed, the 8 limiting features in terms of the pressure retaining capability of the entire pipeline were confined to 3 pipe joints distributed over an 8 km length of the pipeline. 6 out of the 8 pressure limiting features were contained within the same pipe joint.

Corrosion Mechanism

This highly localised corrosion led to an investigation of the steel properties of particular pipe joints. The pipeline was constructed with pipe joints from four different manufacturers, so there was speculation that one type of steel was more susceptible to the corrosion being experienced. When the corrosion was cross-referenced with the different steels, there seemed to be a strong correlation between the more severe corrosion and one of these manufacturers.

The production over time was also investigated to establish whether there were any production upsets that might have introduced a corrosion mechanism into the otherwise apparently innocuous dry gas environment of the pipeline. It turned out that wet condensate had, in the past, been batched in the pipeline, and that the corrosion inhibition of these batches may not have been efficient. Furthermore, a wet buckle had occurred during the installation of the pipeline in the mid-1970's around the location of the worst corrosion. It was suspected that this may have increased the propensity for linepipe corrosion in this area.

The combination of the potentially susceptible steel and a corrosion mechanism gave a plausible explanation of the corrosion being reported.

Down-rating

The survey results in 1997 caused the most significant problem in terms of the integrity of the pipeline. The worst features failed the Line Pipe Corrosion Group Sponsored Project (LCGSP)[2] defect assessment criteria (subsequently to become DnV RP F101), so a Finite Element Analysis (FEA) study was performed on the worst feature and the surrounding features to demonstrate the residual pressure retaining capability of the pipeline.

The FEA study considered five combinations of potentially interacting defects contained in the worst affected pipe joint. The study also investigated the effects of the inspection tool measurement tolerances on the predicted defect failure pressures. The analyses determined the predicted failure pressures for the various defect combinations and showed that, although interaction between the defects was predicted to occur, the effects on failure pressure were small – less than a 2% reduction over the predicted failure pressure of the single worst defect. A Von Mises stress distribution for one of the defect combinations analysed is shown in Appendix E.

The failure pressures predicted by the FEA study showed that the depth of the worst feature recorded was beyond the limit of what could be demonstrated to be acceptable with the design MAOP. The step was therefore taken to down-rate the pipeline by 20 bar from 148.9 barg to 128 barg.

The focus of the 1999 survey was to ensure that the corrosion had arrested (the practice of batching wet inhibitor was stopped before the 1997 survey, however as the growth mechanism was a hypothesis further inspection was required to test it) and the pipeline could

[2] Total Oil Marine, the Operator of the pipeline at the time, was a member of the LCGSP.

continue to be operated safely at the down-rated pressure. To ensure repeatability, the same inspection tool was used as the 1997 survey, with the same sensor array and electronic package. When the inspection reports were delivered, however, a further 3% reduction in the wall thickness of the worst feature was reported (from 48% of wall thickness to 51% of wall thickness, as shown in Tables 1 and 2 of Appendix A).

After much discussion with the inspection contractor it was discovered that the analytical process for interpreting the magnetic flux measurements from the sensor had, in fact, been upgraded in the time between the two surveys as this was felt to give a more accurate interpretation of the measurements. The question of whether the feature had physically deepened therefore remained.

To answer this question, the 1999 results were re-interpreted with the 1997 analytical model, and the results reported the same defect depth as was previously reported with the 1997 data (as shown in Tables 1 and 2 of Appendix A). This gave confidence that the feature had not grown. Given, however, that the 1999 analytical process was considered more accurate than the 1997 model, the decision was made to re-analyse the fitness-for-purpose of the reported defects using the 1999 feature dimensions. This resulted in the down-rating of the pipeline by a further 5 bar to 123 barg. The results from 1997 and 1999 for the worst defects, and the re-interpreted results from 1999 are shown in Appendix C.

Bypass and Pipe Joint Cut-out

In 2001, the installation of a new section of pipeline to be tied in to the existing pipeline presented the opportunity to by-pass the worst areas of corrosion and restore the MAOP of the pipeline to its design level – itself an important consideration in maximising the throughput capacity for new gas.

In order to accurately determine the position of the corrosion in the pipeline, it was necessary to establish a common reference between the internal and external reference system (the tolerances of internal and external survey systems mean that common points must be used for accurate cross-referencing between different survey types). Powerful magnets were therefore installed on the exterior of the pipeline, using an ROV installed clamping system before the 1999 inspection.

Locations for the magnets were chosen bounding the worst area of corrosion to be bypassed, also attempting not to hide significant features under the magnets themselves. The positioning of the magnets and an overall view of the reported corrosion can be seen in Appendix D. These magnets were used as reference points for the bypass tie-in, and were also used to locate the pipe joints for cutting out and recovery to the surface.

An important part of the identification of the pipe joints to cut out was the correlation of the pigging weld record and the lay record data. This exercise was done using known construction features that were detailed in the lay record and also detectable by the inspection tool. The magnets could not be used for this purpose, because it was not possible to accurately establish which pipe joints the magnets had been mounted on. The drawback with the construction references was that they were so far apart, and also far from the reported corrosion.

The most useful data recorded in the pigging and lay records turned out to be the pipe joint lengths. The variation in the lengths of the pipe joints was recorded during the construction of the pipeline and was also quite accurately reported in the pigging record. The comparison of these lengths proved, therefore, to be the basis for the final adjustments for the correlation of the data. An example of the correlation around the cut points can be seen in Appendix F. Another feature of the construction that proved useful was the fact that some of the 12m long pipes were made up of two shorter lengths. These "jointer" pipes showed up well in the pigging record as an extra weld.

As both the magnets and corrosion were detected by the 1999 internal inspection, calculating the physical distance from the magnet to the cut points to a high degree of accuracy and certainty was therefore possible. These distances were translated onto the as-found magnet and pipeline positions, and tracked across the seabed. Two pipe joints, one containing the worst corrosion features, were then cut out of the bypassed section of pipeline with a diamond-wire saw and brought to the surface.

Investigation of Physical Corrosion

The recovered pipe joints were transported to the yard, and an investigation of the internal surface conducted. The original weld number paint markings from construction could still be seen on the external weight coat, and these corresponded to the expected weld numbers, confirming that the correct pipe joints had been recovered.

Both pipe joints were examined internally, their size allowing good access for visual inspection. The pipe joint that contained the worst "corrosion" was found not to contain any corrosion features, but instead a layer of apparently rusty material was seen to be deposited on the bottom of the pipeline centred around the 5 – 5.30 o'clock position for a length of approximately 10 m (starting and ending approximately 1 m inward of the ends of the pipe joint). Two white, calcareous deposit lines were visible around the 3 o'clock and 9 o'clock running along the length of the pipe (these were later identified as Magnesium Hydroxide). These appeared to be some form of interface mark (essentially a "tide mark"), and confirmed the original orientation of the joints in the pipeline. The adjacent pipe joint contained no debris layer or apparent corrosion.

The layer of rusty material formed a near-solid "sheet" varying in thickness typically around 10 mm, but up to 20 mm, and up to 220 mm wide (thinner at the upstream end than the downstream end). This "crust" was hard, brittle, and could be kicked off the pipe wall in chunks although it was surprisingly resilient to impact and abrasion. After removal from the pipe and exposure to the atmosphere for a few weeks, the crust would crumble, presumably as binding agents evaporated. No significant corrosion was evident under the debris layer. The volume of material contained in the debris crust was estimated at between 5 and 10 litres.

On close examination the material forming the crust was found to be made of tightly packed, tiny spherical metallic balls, typically around 1 mm in diameter, relatively consistent in size and apparently bound together by corrosion products. When sectioned and examined under a microscope, some of the spheres exhibited cracks and some were hollow. X-ray diffraction and spectroscopy analyses were performed on samples from various parts of the debris layer. The analyses identified Iron, Carbon and Silicon elements in the metallic spheres. The corrosion product was found to comprise mostly of oxides of iron. Traces of Calcium, Aluminium and Magnesium were also identified.

Photographs of the defect crust in-situ, removed from the pipe, and sectioned and magnified are shown in Appendix G.

As noted above, the debris crust was surprisingly resilient to impact and abrasion. That the layer had apparently been present in the pipeline for many years is worthy of note - many heavy duty cleaning pigs, some fitted with powerful magnets had been run down the pipeline over its lifetime. Furthermore, several MFL intelligent pigs were also run down the pipeline. Experience with these tools suggests that they are amongst the most efficient cleaning tools available due their weight, brushes and powerful magnets.

If a layer of hard debris such as was found in the pipeline had been suspected at any stage during operation, pin-wheel type pigs could have been run to try and remove it. Given the nature of the gas flow through the pipeline and the results of the cleaning pigging, however, there was never any reason to suspect that such debris might be present.

It should be noted that the presence of the debris layer in the recovered pipe joint does not, on its own, invalidate the internal corrosion reported elsewhere in the line by the inspection tool.

Possible Sources of the Debris

Several potential sources have been identified for the debris crust found in the pipeline:

- Product from flame cutting.
- Weld spatter from burn-through of the weld root during construction.
- Iron grit blast.

The significant quantity of material found deposited in the pipe length suggests that flame cutting was unlikely – whilst occasional welds may have been cut out, the volume of material suggests a more frequent event.

Weld spatter is a possible source of the material, but it is not considered credible that so much material could come from only the welds at either end of the pipe joint.

Spent grit blast material from part of the construction process is certainly a possible cause. The detail of the fabrication and construction procedures used during the preparation of the linepipe at the mill and coating yard, and then during construction on the lay-barge have not been investigated, but it is certainly conceivable that shot-blasting was carried at some point, either as a standard operation, or, for example, as part of a frequent repair process.

What is likely is that small amounts of material, however they arrived in the pipeline, have been collected and transported along the pipeline by early pigging operations, perhaps during pre-commissioning activities. This material has then been deposited and smeared along the pipe wall. Corrosion within the layer, the drying effects of the gas flow, and further pigging runs combined to compress and bind the layer into the hard crust that was found.

The above explanations are neither conclusive nor mutually exclusive.

Metallic Crust Laboratory Simulation

The inspection contractor who performed the surveys of the pipeline instigated an investigation into the effects of the debris crust on MFL signals.

Samples of the debris crust were broken down, mixed with glue and spread on coupon of test steel. The density of the glue/debris mix was kept consistent with that of the original debris crust.

Magnetic flux data was collected from the test coupon using a system that simulated the way in which the inspection tool gathers data. The bare test coupon, containing two artificial defects, was mapped first. The glue/debris mix was then used to fill in one of the defects and the survey repeated. The surveys were further repeated with glue/debris layers of gradually increasing thickness, from 2 mm to 10 mm, over a general area, including one of the defects.

The results of the work demonstrated that, as expected, the presence of the metallic debris layer had a significant effect on the MFL signals. Any defects under the layer became much less distinct as the thickness of the debris layer increased (a 10 mm thick layer could cause a change in predicted defect depth of as much as 40%).

The effects of variations in the debris layer were not investigated. It is believed that local variations in thickness, density and potentially other properties could produce MFL signals that could be falsely interpreted as a pipe wall defect. Features such as a rough edge to the debris crust, or a missing chunk of crust are quite conceivable and their effects on MFL signals need to be investigated. TFEEUK are pursuing this in conjunction with the inspection contractor.

Conclusion

The use of MFL technology has been demonstrated to give misleading results in this circumstance. What this highlights is the fact that the technology is an inferred inspection technique, measuring magnetic flux signals that can be misinterpreted. In certain cases, it therefore introduces an element of doubt or risk when using this technology if it is being solely relied on to determine the integrity of a pipeline.

Where uncertainty exists, and it is possible and practicable, a complementary inspection method should be employed. For land pipelines, this usually takes the form of an excavation and external inspection method such as ultrasonic tools. In the case of a subsea pipeline, whilst possible, an external inspection is, due to the environment, significantly more hazardous and normally very costly and may therefore not be desirable or practicable.

A complementary internal inspection with an ultrasonic tool would have been possible, although again, may not always be practicable in a gas pipeline due to the requirement to run the tool in a slug of liquid. There is also a suspicion that, given the granular nature of the debris crust, the ultrasonic signal would have been attenuated to the point of non-return, resulting in further uncertainty. The only other internal inspection technique that may have highlighted the true nature of the crust is a visual inspection. This technology is becoming available for longer pipelines with the development of digital storage devices.

Having said that, the results seemed at the time very conclusive, and all the evidence corroborated the assumption of corrosion, so it seemed unnecessary to pursue any complementary inspection. There was no reason to suspect the presence of the debris layer, and no precedent in either TotalFinaElf operating experience or that of the inspection contractor that raised any suspicions as to the real nature of the reported features. The main lessons learned from this is to be vigilant of any assumptions, to explore all possibilities, and to bare in mind it may be cost effective to perform complementary inspections in certain circumstances.

Magnetic Flux Leakage remains a valid inspection technique that produces generally accurate, reliable and repeatable results in the majority of circumstances. TotalFinaElf, both in the UK and Worldwide continue to employ MFL inspection tools from all the major inspection contractors to assist in ensuring the integrity of their assets, including the pipeline discussed in this paper.

Appendix A – Summary of Inspection Findings

	Year				
	1990[1]	**1992**[2]	**1996**[3]	**1997**[5]	**1999**[6]
No. of Features > 60% WT	0	0	0	0	0
No. of Features > 40% WT	4	3	4	5	14
No. of Features > 20% WT	14	319	184	195	242
No. of Features < 20% WT	N/A	3572	7680	4568	43676
Total Number of Features	14	3891	7864	4764	43918
Originally Reported Depth of Worst Feature (% WT)	48%	42%	43%[4]	48%	51%
Revised Depth of Worst Feature (%WT)[7]	47%	46%	46%	48%	48%

Table 1 – Summary of Inspection Data

Notes:
1. The 1990 inspection only covered the upstream (Northern) half of the pipeline – some 185 km.
2. The 1992 inspection only reported on a 10 km section containing the worst defects. This was located between PK 304 and PK 314 (46 km to 56 km downstream of launch).
3. The 1996 inspection reported on the whole 364 km pipeline length.
4. A defect with a depth of 53% wall thickness was reported in a thick-walled length of the pipeline. The depth noted in Table 1 is the deepest defect reported in the main section of the pipeline.
5. The 1997 inspection reported on 7 selected areas. Of the 4764 features reported, 1994 were categorised as of manufacturing origin.
6. The 1999 inspection reported on the whole 364 km pipeline length. Of the 43918 features reported, 12395 were categorised as of manufacturing origin.
7. The previous inspection data was reanalysed in 1997 using the same analysis and sizing models. The 1999 data was also reanalysed using the 1997 sizing models.

Inspection Data	Analysis Model	Axial Length (mm)	Circumferential Width (mm)	Depth (% WT)
1990	1990	18	65	38
1990	*1997*	*156*	*56*	*47*
1992	1992	15	63	42
1992	*1997*	*180*	*51*	*46*
1996	1996	250	65	44
1996	*1997*	*260*	*51*	*46*
1997	*1997*	*260*	*50*	*48*
1999	1999	260	50	51
1999	*1997*	*260*	*50*	*48*

Table 2 – Dimensions of Worst Defect

Note : Data in italics is all analysed using the 1997 data analysis and sizing model.

Appendix B – Magnetic Signals for the Worst Defects

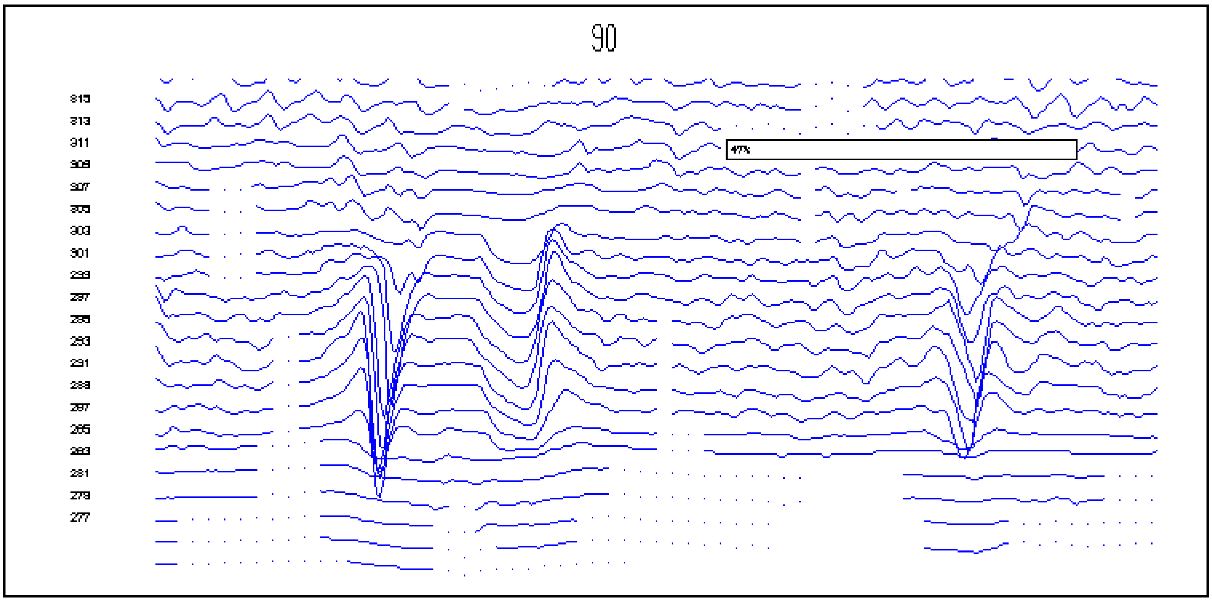

Figure B1 – Magnetic Flux Leakage Signal, Worst Defects, 1990

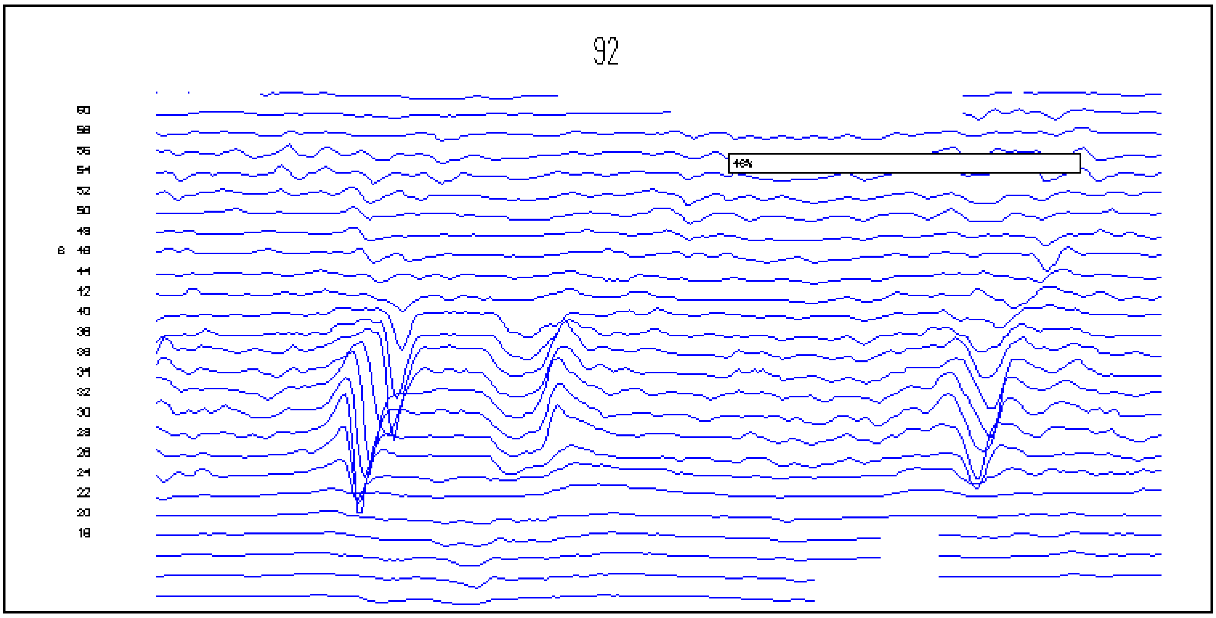

Figure B2 – Magnetic Flux Leakage Signal, Worst Defects,1992

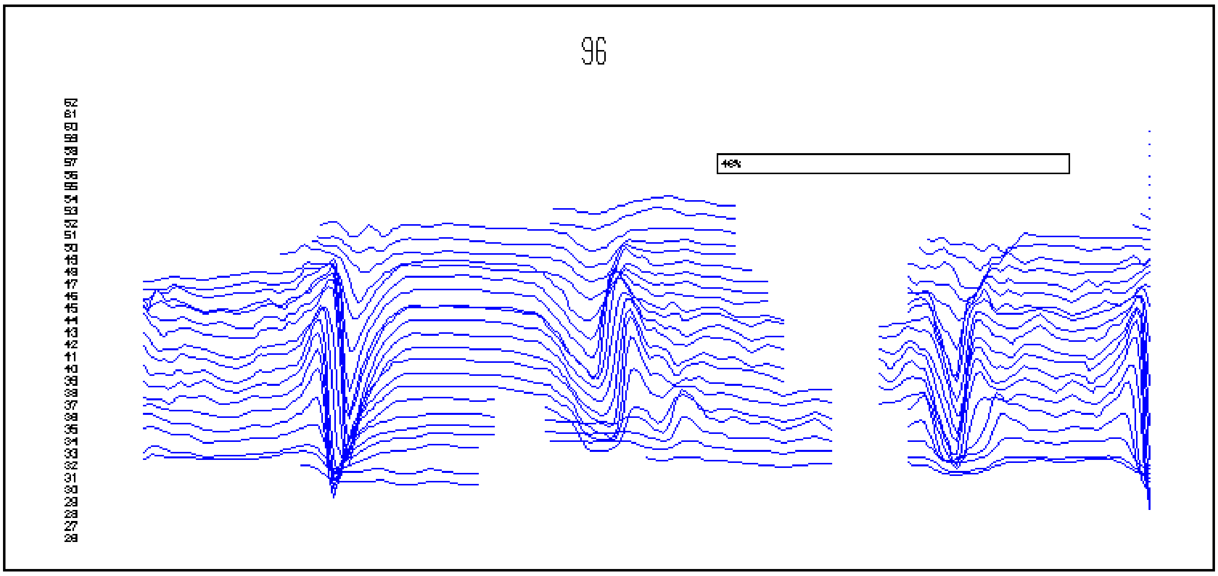

Figure B3 – Magnetic Flux Leakage Signal, Worst Defects,1996

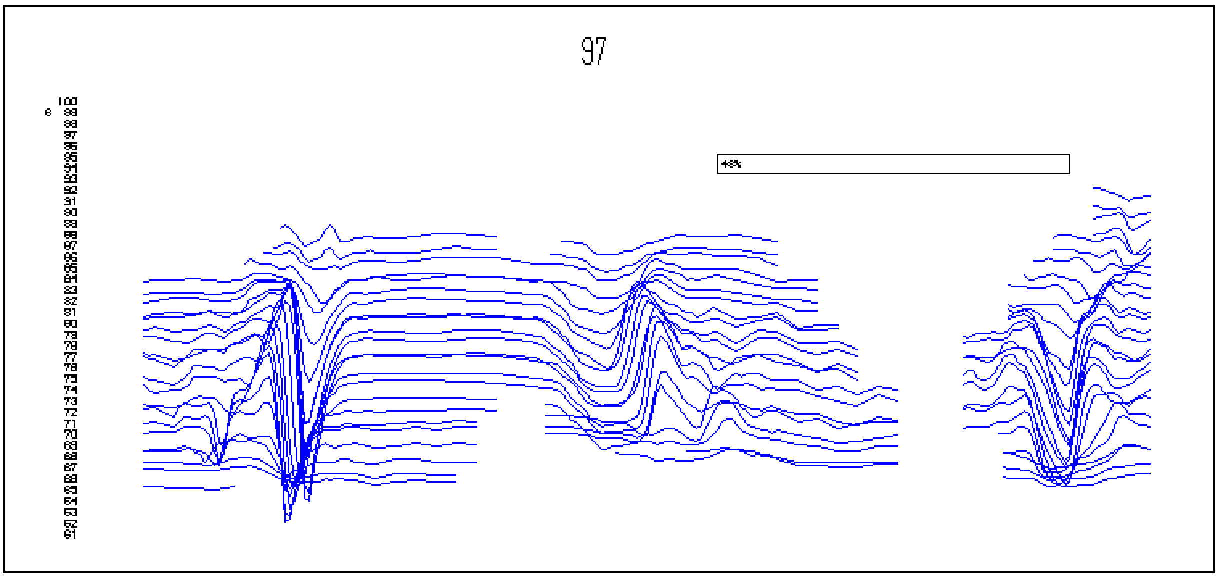

Figure B4 – Magnetic Flux Leakage Signal, Worst Defects,1997

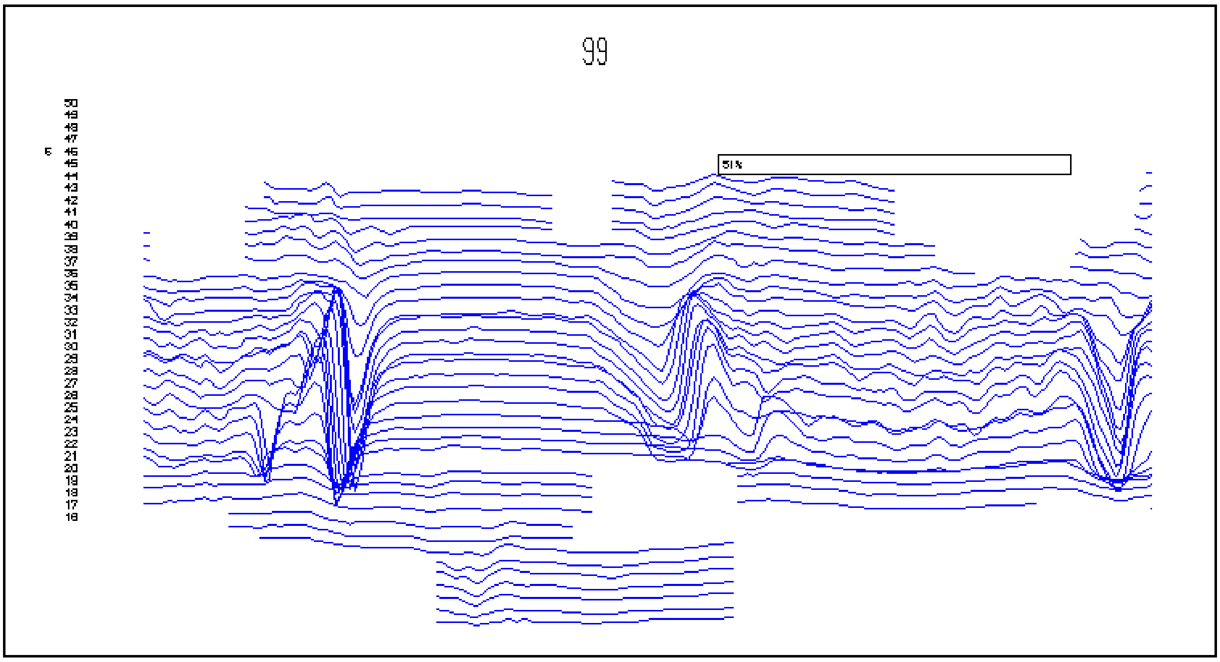

Figure B5 – Magnetic Flux Leakage Signal, Worst Defects,1999

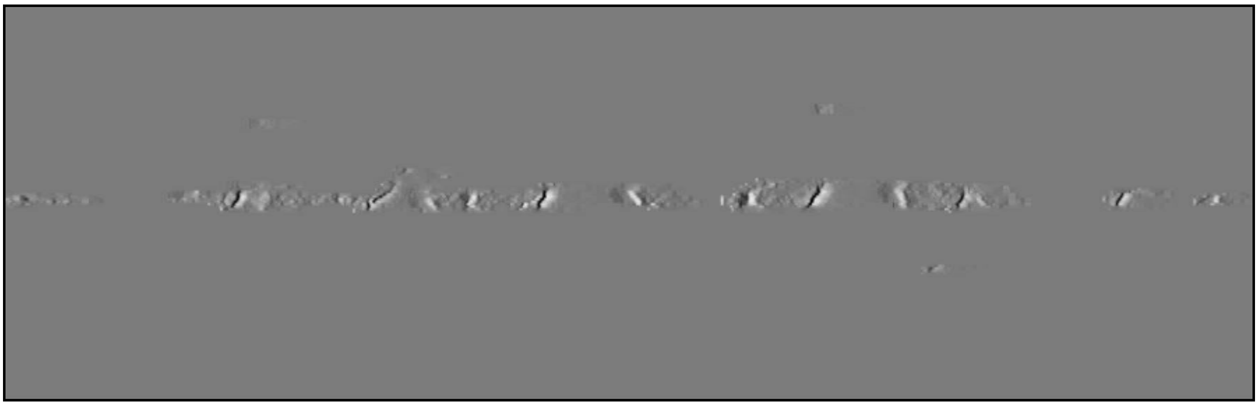

Figure B6 – Greyscale MFL Signal, Worst Defects,1997

Figure B7 – Greyscale MFL Signal, Worst Defects,1999

Note: The approximate dimensions of the greyscale plots is 4.0 m (axial length) x 0.8 m circumferential length

Appendix C – Inspection Results, Worst Corrosion

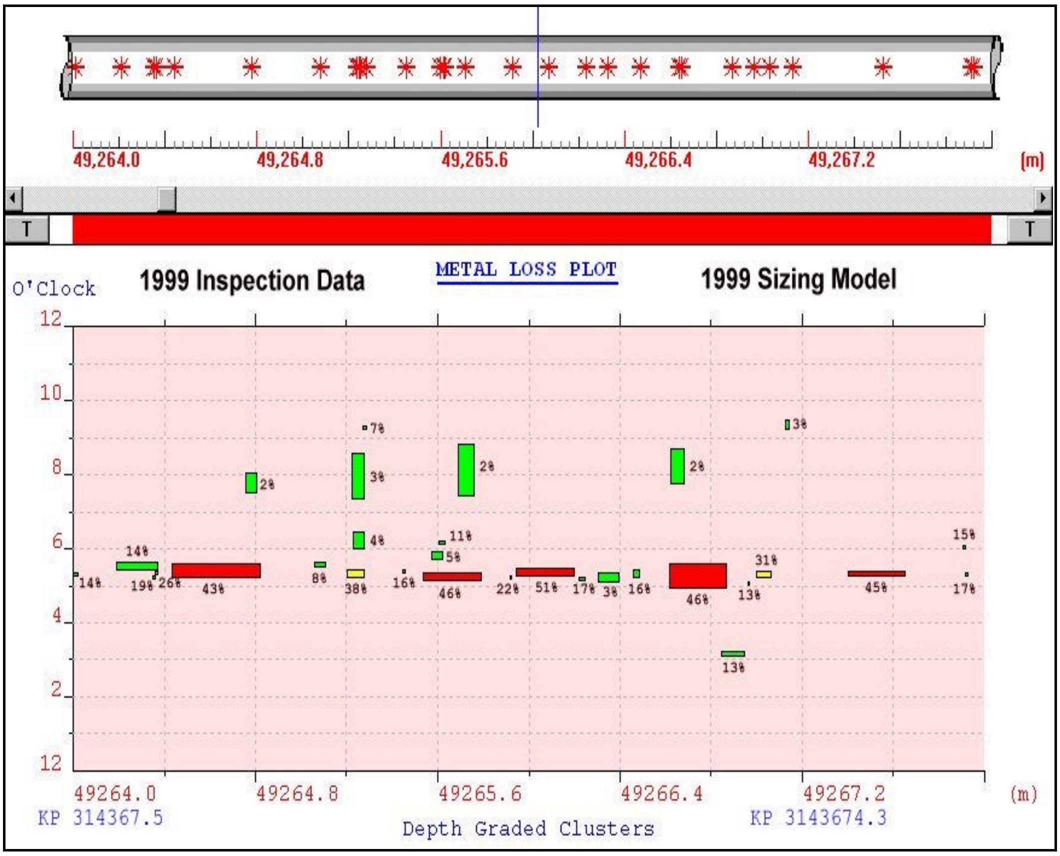

Figure C1 – 1999 Inspection Data, Assessed Using 1999 Sizing Model

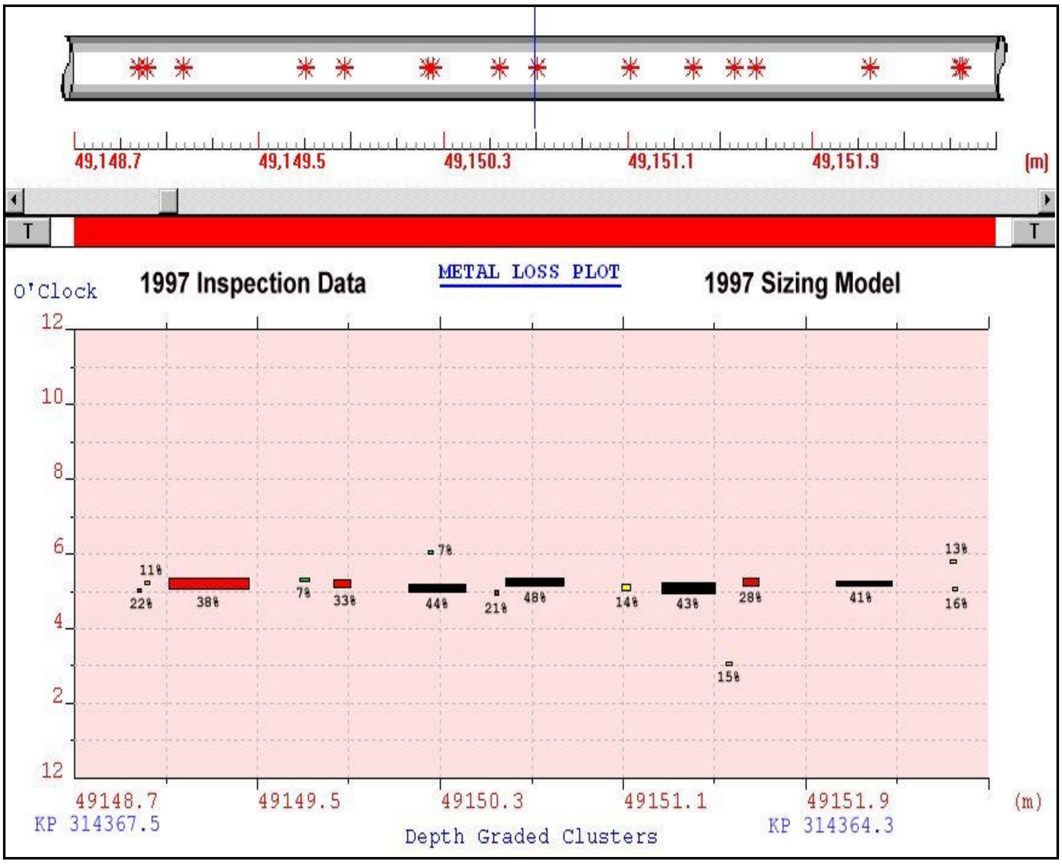

Figure C2 – 1997 Inspection Data, Assessed Using 1997 Sizing Model

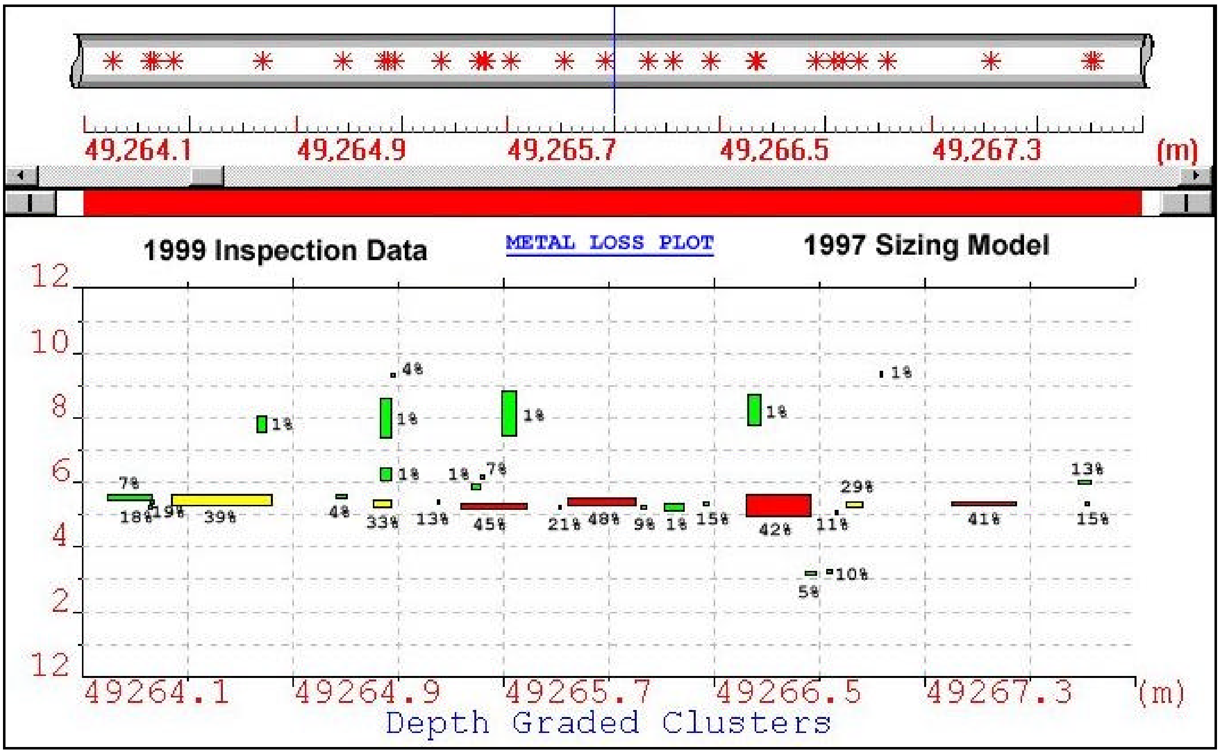

Figure C3 – 1999 Inspection Data, Re-assessed Using 1997 Sizing Model

Appendix D – FEA Study, Von Mises Stress Distribution

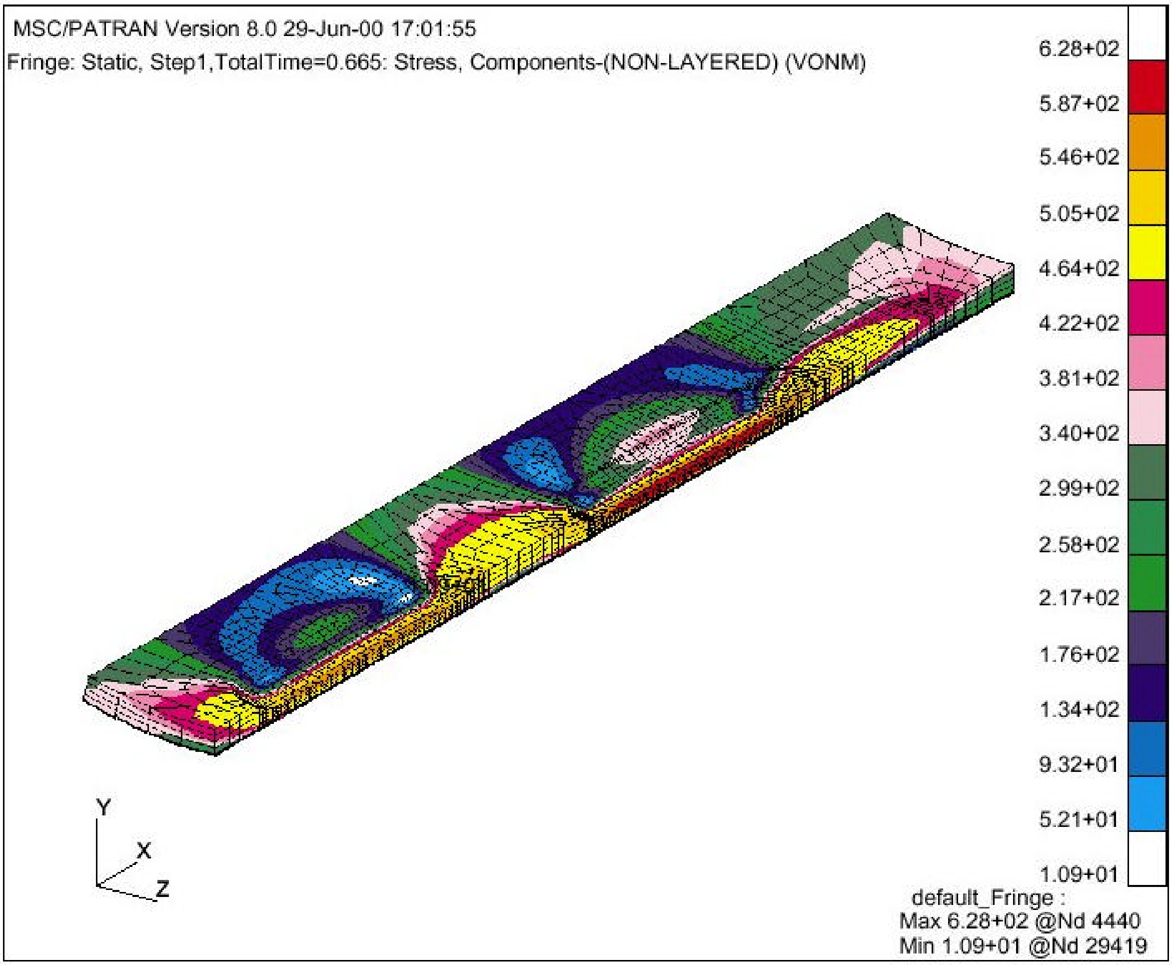

Figure D1 – Von Mises Stress Distribution for Worst Defect Combination

Appendix E – Magnet Locations and General Corrosion Plot

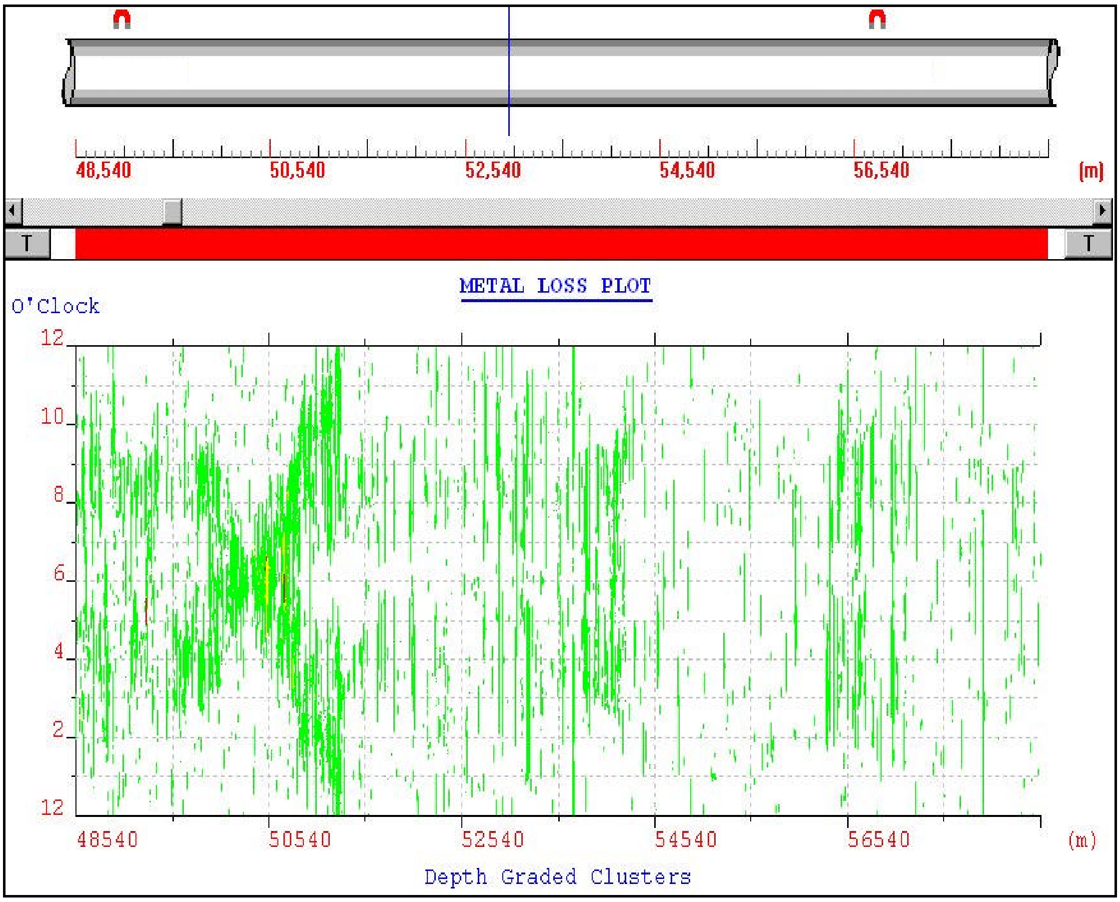

Figure E1 – General Corrosion Plot and Magnet Positions for Section of Pipeline

Appendix F – Correlation Between Pigging and Lay Records

Weld No	Piece No	Plate No	Length (m)	Anode/BA	Weld No	Pig Dist
	B0247711	44680	12.28344	None		12.3
41220					A 1915	
	B0246136	241406	12.31392	**MAGNET**		12.3
41230					A 1916	
	B0244830	243170	12.10056	None		12.1
41240					A 1917	
	B0247381	42798	12.16152	BA		12.2
41250					A 1918	
	B0248600	43614	12.31392	None		12.3
41260					A 1919	3.8
41270	B0200236	236200	12.58824	None		8.8
41280					A 1920	
	B0247376	41382	11.7348	None		11.7
41290					A 1921	
	B0248011	41358	12.31392	None		12.3
41300					A 1922	
	B0248286	42288	12.31392	None		12.3
41310					A 1923	
	B0245279	242378	11.85672	None		11.9
41320					A 1924	
	B0246016	241678	11.5824	Anode		11.6
41330					A 1925	
	B0245870	242866	12.00912	None		12.0
41340					A 1926	
	B0248259	43492	12.192	None		12.2
41350					A 1927	
	B0247734	47734	12.31392	None		12.3
41360					A 1928	
	B0244879	243420	12.28344	None		12.3
41370					A 1929	
	B0247509	42296	11.8872	None		11.9
41380					A 1930	
	B0248831	43302	11.91768	None		11.9
41390					A 1931	
	B0245817	243830	12.28344	BA		12.3
41400					A 1932	
	B0246838	243426	11.94816	None		12.0
41410	**CUT POINT**				A 1933	
	B0244745	243476	12.31392	None		12.3
41420	**CUT POINT**				A 1934	
	B0247423	41952	11.70432	None		11.7
41430	**CUT POINT**				A 1935	
	B0248636	43512	12.31392	None		12.3
41440					A 1936	
	B0249059	41384	11.82624	None		11.8
41450					A 1937	
	B0247680	41360	12.31392	None		12.3

Appendix G – Debris Crust Photographs

Figure G1 – Debris Crust in the Bottom of the Pipe

Figure G2 – Debris Crust in the Bottom of the Pipe

Figure G3 – Sample of Debris Crust Removed from the Pipe

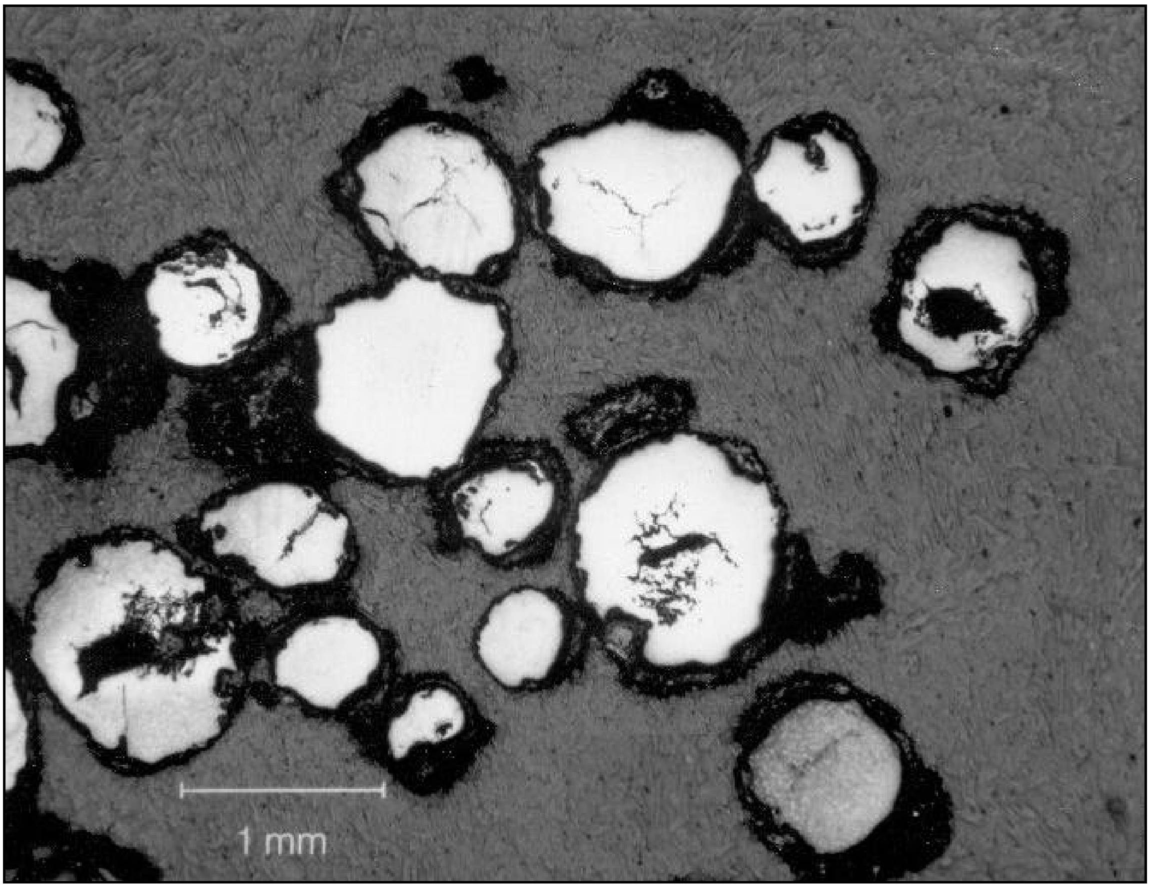

Figure G4 – Microscopic Close-Up of Sectioned Debris Material