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Internal Repair of Pipelines
12-Month Technical Progress Report

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Note: SI is an abbreviation for "Le Systeme International d'Unites."

ABSTRACT

The two broad categories of deposited weld metal repair and fiber-reinforced composite liner repair technologies were reviewed for potential application for internal repair of gas transmission pipelines. Both are used to some extent for other applications and could be further developed for internal, local, structural repair of gas transmission pipelines. Preliminary test programs were developed for both deposited weld metal repair and for fiber-reinforced composite liner repair.

Evaluation trials have been conducted using a modified fiber-reinforced composite liner provided by RolaTube and pipe sections without liners. All pipe section specimens failed in areas of simulated damage. Pipe sections containing fiber-reinforced composite liners failed at pressures marginally greater than the pipe sections without liners. The next step is to evaluate a liner material with a modulus of elasticity approximately 95% of the modulus of elasticity for steel.

Preliminary welding parameters were developed for deposited weld metal repair in preparation of the receipt of Pacific Gas & Electric's internal pipeline welding repair system (that was designed specifically for 559 mm (22 in.) diameter pipe) and the receipt of 559 mm (22 in.) pipe sections from Panhandle Eastern. The next steps are to transfer welding parameters to the PG&E system and to pressure test repaired pipe sections to failure.

A survey of pipeline operators was conducted to better understand the needs and performance requirements of the natural gas transmission industry regarding internal repair. Completed surveys contained the following principal conclusions:

- Use of internal weld repair is most attractive for river crossings, under other bodies of water, in difficult soil conditions, under highways, under congested intersections, and under railway crossings.
- Internal pipe repair offers a strong potential advantage to the high cost of horizontal direct drilling (HDD) when a new bore must be created to solve a leak or other problem.
- Typical travel distances can be divided into three distinct groups: up to 305 m (1,000 ft.); between 305 m and 610 m (1,000 ft. and 2,000 ft.); and beyond 914 m (3,000 ft.). All three groups require pig-based systems. A despooled umbilical system would suffice for the first two groups which represents 81% of survey respondents. The third group would require an onboard self-contained power unit for propulsion and welding/liner repair energy needs.
- Pipe diameter sizes range from 50.8 mm (2 in.) through 1,219.2 mm (48 in.). The most common size range for 80% to 90% of operators surveyed is 508 mm to 762 mm (20 in. to 30 in.), with 95% using 558.8 mm (22 in.) pipe.

An evaluation of potential repair methods clearly indicates that the project should continue to focus on the development of a repair process involving the use of GMAW welding and on the development of a repair process involving the use of fiber-reinforced composite liners.

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1.0 - INTRODUCTION

Repair methods that can be applied from the inside of a gas transmission pipeline (i.e., trenchless methods) are an attractive alternative to conventional repair methods since the need to excavate the pipeline is precluded. This is particularly true for pipelines in environmentally sensitive and highly populated areas. Several repair methods that are commonly applied from the outside of the pipeline are, in theory, directly applicable from the inside. However, issues must be addressed such as development of the required equipment to perform repairs remotely and the mobilization of said equipment through the pipeline to areas that need to be repaired. Also, several additional repair methods that are commonly applied to other types of pipelines (gas distribution lines, water lines, etc.) have potential applicability but require further development to meet the requirements for repair of gas transmission pipelines.

Gas transmission pipeline repair by direct deposition of weld metal, or weld deposition repair, is a proven technology that can be applied directly to the area of wall loss (e.g., external repair of external wall loss - Figure 1) or to the side opposite to the wall loss (e.g., external repair of internal wall loss – Figure 2).

Figure 1 - Installation of a Full-Encirclement Repair Sleeve

Figure 2 - External Weld Deposition Repair of Internal Wall Loss in 90 Degree Elbow

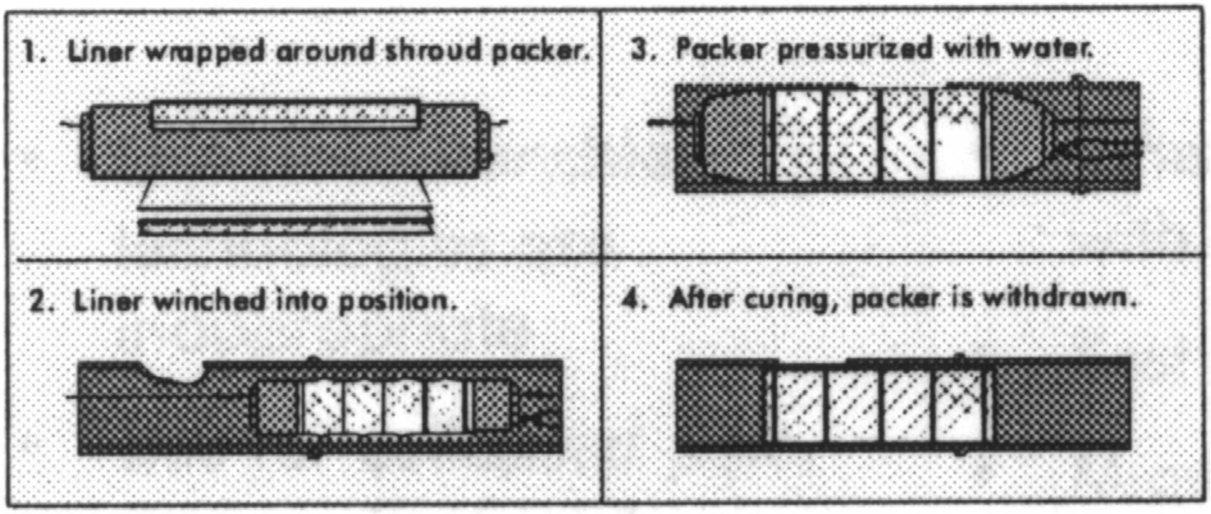
There are no apparent technical limitations to applying this repair method to the inside of an out-of-service pipeline. It is direct, relatively inexpensive to apply, and requires no additional materials beyond welding consumables. However, application of this repair method to the inside of an in-service pipeline would require that welding be performed in a hyperbaric environment. Deposited weld metal repairs are also used to repair circumferentially oriented planar defects (e.g., intergranular stress corrosion cracks adjacent to girth welds) in the nuclear power industry. Remote welding has been developed primarily by needs in the nuclear power industry, though working devices have been built for other applications, including repair of gas transmission pipelines. An example is shown in Figure 3.

Figure 3 - Osaka Gas System for Remote Robotic Internal Repair of Root Weld Defects in Gas Transmission Pipelines

Fiber-reinforced composite repairs are becoming widely used as an alternative to the installation of welded, full-encirclement sleeves for repair of gas transmission pipelines. These repairs typically consist of glass fibers in a polymer matrix material bonded to the pipe using an adhesive. Adhesive filler is applied to the defect prior to installation to allow load transfer to the composite material. The primary advantage of these repair products over welded, full-encirclement sleeves is the fact that welding is precluded. An illustration of the most commonly-used of the fiber-reinforced composite devices, Clock Spring®, is shown in Figure 4.

Figure 4 - Clock Spring® Fiber-Reinforced Composite Device for Pipeline Repair

A variety of liners are commonly used for repair of other types of pipelines (gas distribution lines, sewers, water mains, etc.). Of these, the three that are potentially applicable to internal repair of gas transmission pipelines are sectional liners, cured-in-place liners, and fold-and-formed liners. Sectional liners are typically 0.9 to 4.6 m (3 to15 ft.) in length and are installed only in areas that require repairs. Cured-in-place liners and fold-and-formed liners are typically applied to an entire pipeline segment. Cured-in-place liners are installed using the inversion process, while fold-and-formed liners are pulled into place and then inverted so that they fit tightly against the inside of the pipe. The installation of a sectional liner is illustrated in Figure 5.



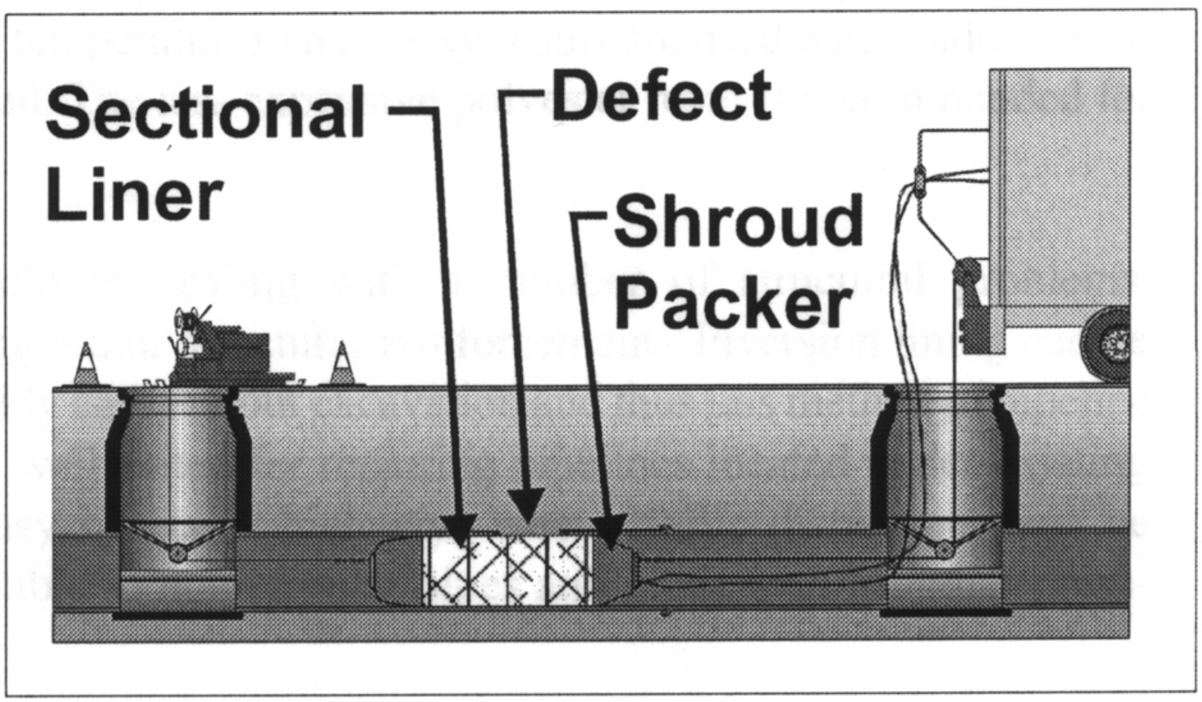


Figure 5 - Installation of a Sectional Liner in Low-Pressure Pipeline

2.0 - EXECUTIVE SUMMARY

The two broad categories of deposited weld metal repair and fiber-reinforced composite liner repair technologies were reviewed for potential application for internal repair of gas transmission pipelines. Both are used to some extent for other applications and could be further developed for internal, local, structural repair of gas transmission pipelines. Both of these repair technologies can easily be applied out-of-service and both require excavation prior to repair.

The most frequent cause for repair of gas transmission pipelines was identified as external, corrosion-caused loss of wall thickness. The most commonly used in-service method for repair is externally welding on a full-encirclement steel sleeve. Weld deposition repair is also a proven technology that can be applied directly to the area of wall loss. There are no apparent limitations to applying this repair technology to the outside of an out-of-service pipeline. Repairing the inside of an in-service pipeline would require that welding be conducted in a hyperbaric environment, which would require extensive research to develop.

Fiber-reinforced composite liner repairs are becoming widely used to repair pipeline in- and out-of-service as an alternative to welding. Three liners that are potentially applicable to internal repair of pipelines are sectional liners, cured-in-place liners, and fold-and-formed liners. External corrosion can also be repaired by applying adhesive to the defect and wrapping a fiber-reinforced composite liner material around the outside diameter of the pipeline.

Preliminary test programs were developed for both deposited weld metal repairs and for fiber-reinforced composite liner repair. Areas of damage were artificially introduced into pipe sections using methods previously developed at EWI. RolaTube developed a modified version of their fiber-reinforced composite with nine plies of glass-polypropylene in the form of overlapping pre-pregnated tapes of unidirectional glass and polymer. These liners were inserted into two of four damaged pipe sections. All four damaged pipe sections were then hydrostatically pressurized until rupture. The two pipes with liners failed at pressures only marginally greater than the pipes with no liner. It was determined that the liner material was more elastic than the steel pipe and therefore not able to carry its share of the load.

Further analysis of the postmortem results indicates that a fiber-reinforced composite liner material with a modulus of elasticity on the order of 95% of that for steel should suffice for effective reinforcement of steel pipelines, thus allowing the liner to carry its share of the load without putting the interface between the liner and the steel pipe in tension. RolaTube is redesigning the liner material using carbon/polypropylene, which has a much higher modulus of elasticity than glass/polypropylene. RolaTube experienced difficulties consolidating the initial supply of carbon/polypropylene composite material inside the test sections that they received. They have identified an alternative supplier and are presently awaiting delivery of materials.

The deposited weld metal repair test program was initiated and welding parameters were successfully developed for internal circumferential and patch type repairs. A Bortech welding head with an analog controller was used to develop the first welding parameters. The Bortech system exhibited some limited maneuverability. The next phase of welding procedure development trials are planned with a Magnatech digital controller that PG&E has recently obtained. The Magnatech set-up is anticipated to be more agile thus allowing greater refinement of welding parameters.

A survey of pipeline operators was conducted to better understand the needs and performance requirements of the natural gas transmission industry regarding internal repair. A total of fifty-six surveys were distributed. Twenty completed surveys were returned, representing a 36% response rate, which is considered very good given the fact that tailored surveys are known in the marketing industry to seldom attract more than a 10% response rate.

The twenty survey responses produced the following principal conclusions:

- Use of internal weld repair is most attractive for river crossings, under other bodies of water (e.g., lakes and swamps) in difficult soil conditions, under highways, under congested intersections, and under railway crossings. All these areas tend to be very difficult and very costly if, and where, conventional excavated repairs may be currently used.
- Internal pipe repair offers a strong potential advantage to the high cost of horizontal direct drilling (HDD) when a new bore must be created to solve a leak or other problem in a water/river crossing.
- Typical travel distances can be divided into three distinct groups: up to 305 m (1,000 ft.); between 305 m and 610 m (1,000 ft. and 2,000 ft.); and beyond 914 m (3,000 ft.). All three groups require pig-based systems. A despooled umbilical system would suffice for the first two groups which represents 81% of survey respondents. The third group would require an onboard self-contained power unit for propulsion and welding/liner repair energy needs.
- Pipe diameter sizes range from 50.8 mm (2 in.) through 1,219.2 mm (48 in.). The most common size range for 80% to 90% of operators surveyed is 508 mm to 762 mm (20 in. to 30 in.), with 95% using 558.8 mm (22 in.) pipe.

Once pipe samples with the redesigned liner material are received from RolaTube, further development of the fiber-reinforced composite liners will consist of repeating the experimental program conducted to date. Following this, provided that the redesigned fiber-reinforced composite liner material is effective at restoring the pressure containing capabilities of the pipes, an experimental program involving larger diameter pipe, e.g., 508 mm (20 in.), will be undertaken. If the redesigned liner material is not effective at restoring the pressure containing capabilities of the pipes, additional finite element analysis (FEA) will be carried out to determine the improved physical properties for the fiber-reinforced composite liner material.

3.0 - EXPERIMENTAL

To date, experimental work to evaluate potential repair methods has concentrated on fiber-reinforced liners and the development of preliminary weld deposition parameters. The survey part of the project did not involve an experimental procedure or equipment in the conventional sense. This section describes all experimental methods used during this reporting period.

3.1 - Fiber-Reinforced Liners

In the previous reporting period, Task 2.0 research activities resulted in the discovery of several potentially useful commercial fiber-reinforced composite liner products that are directly applicable to internal repair. The initial test program focused on a modified Wellstream-Haliburton/RolaTube product, which was a bi-stable reeled composite material used to make strong, lightweight, composite pipes and pipe linings (Figure 6). When unreeled, it changes shape from a flat strip to an overlapping circular pipe liner that is pulled into position. Following deployment, the longitudinal seam was welded with an adhesive that was activated and cured by induction heating. One example of this product is 100 mm (4 in.) diameter by 2.5 mm (0.10 in.) thick and is said to have a 5.9 MPa (870 psi) short-term burst pressure.

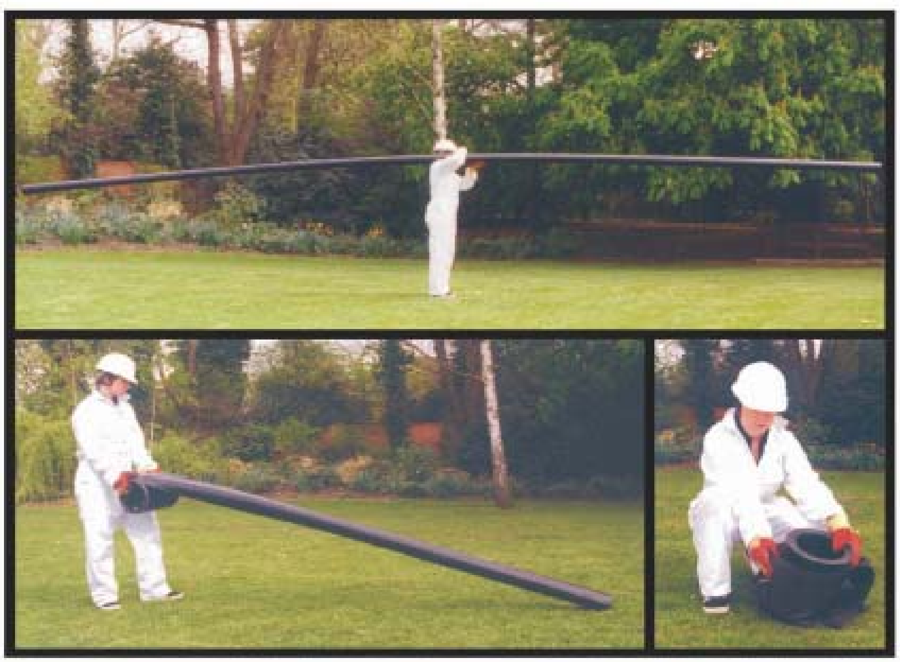


Figure 6- RolaTube Bi-Stable Reeled Composite Material

For the initial trials in the previous reporting period, RolaTube developed a modified version of the bi-stable reeled composite product which uses -nine plies of a glass-polypropylene material in the form of overlapping, pre-pregnated tapes of unidirectional glass and polymer. Glass-high density polyethylene (HDPE) material was also considered. The glass-polypropylene material was selected after problems bonding the glass-HDPE material to steel were encountered. Heat and pressure were used to consolidate the plies glass-polypropylene material into a liner (Figure 7). The resulting wall thickness of the liner is 2.85 mm (0.11 in.).

Figure 7 - Lay-Up and Forming of Fiber-Reinforced Composite Liner

A supply of 114.3 mm outside diameter (OD) x 4 mm wall thickness (4.5 in. OD × 0.156 in. wall) API 5L Grade B pipe material was procured and cut into four sections approximately 1.2 m (4 ft.) long. After the inside surface was degreased, lengths of lining were installed into two of the pipe sections (Figure 8).

Figure 8 - Insertion of Liner into 114.3 mm (4.5 in.) Diameter Pipe

The installation process consisted of inserting a silicon rubber bag inside the liner (Figure 9) and locating the liner inside the pipe. The silicon bag was then inflated to press the liner against the pipe wall.

Figure 9 - Silicon Rubber Bag Inserted into Liner

For these experiments, the entire pipe sections were then heated to 200°C (392°F) in an oven (Figure 10) to fuse the liner to the pipe wall.

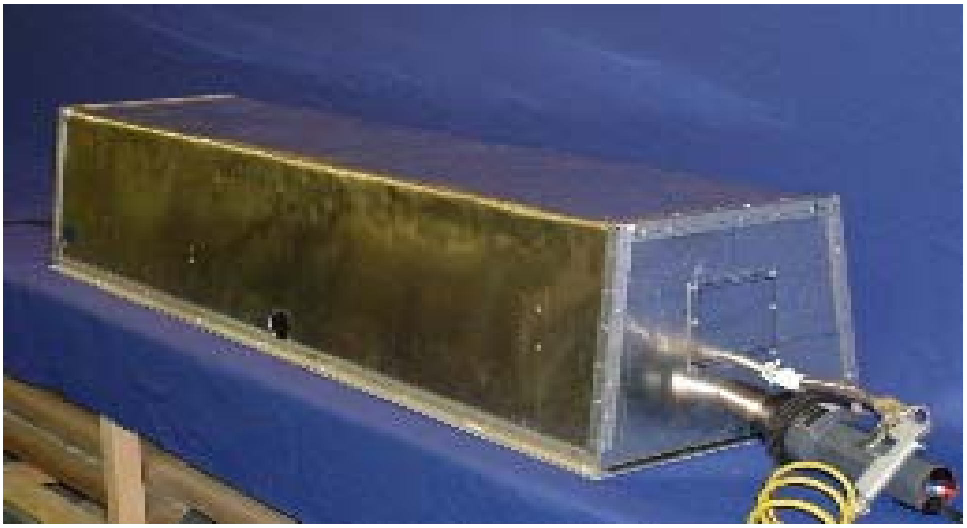


Figure 10 - Oven Used to Heat Pipe and Liner to 200°C (392°F)

Possible choices for liner installation in the field include infra-red (IR) heaters on an expansion pig or a silicon bag inflated using hot air. An installed liner is shown in Figure 11.

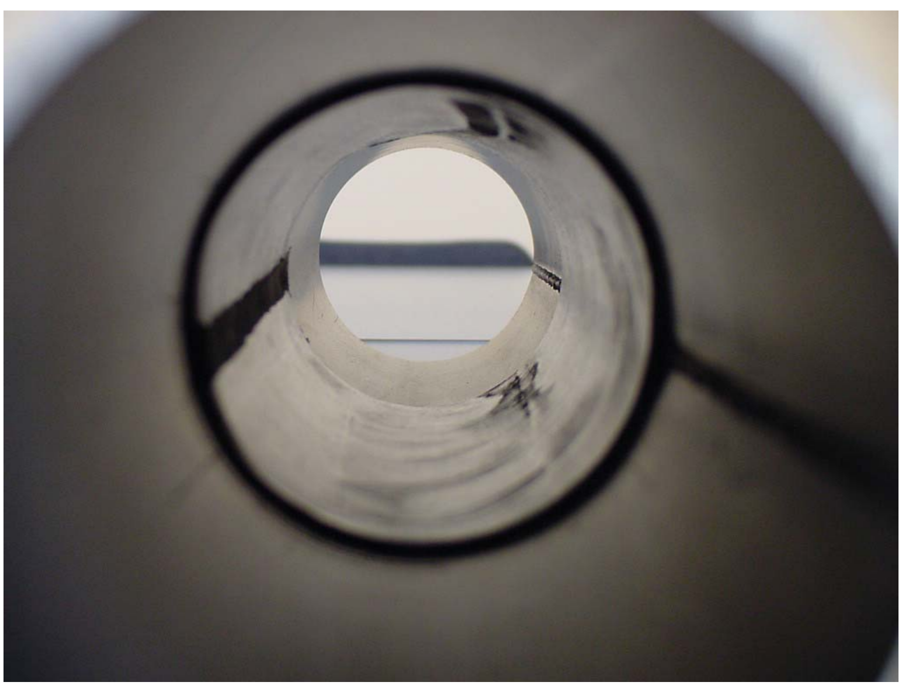


Figure 11 - Liner Inserted into Center of 114.3 mm (4.5 in.) Diameter Pipe

Using the RSTRENG software[1], dimensions of simulated general corrosion and a deep, isolated corrosion pit both with a 30% reduction in burst pressure were calculated then introduced into pipe sections with a milling machine. Using a ball end mill, long shallow damage representative of general corrosion (Figure 12) was introduced into one pipe section lined with fiber-reinforced composite liner and one without.

Figure 12 - Long, Shallow Simulated Corrosion Damage

Using an end mill with rounded corners, short, deep damage representative of a deep isolated corrosion pit (Figure 13) was introduced into the second pair of pipe sections; one lined, one not lined.

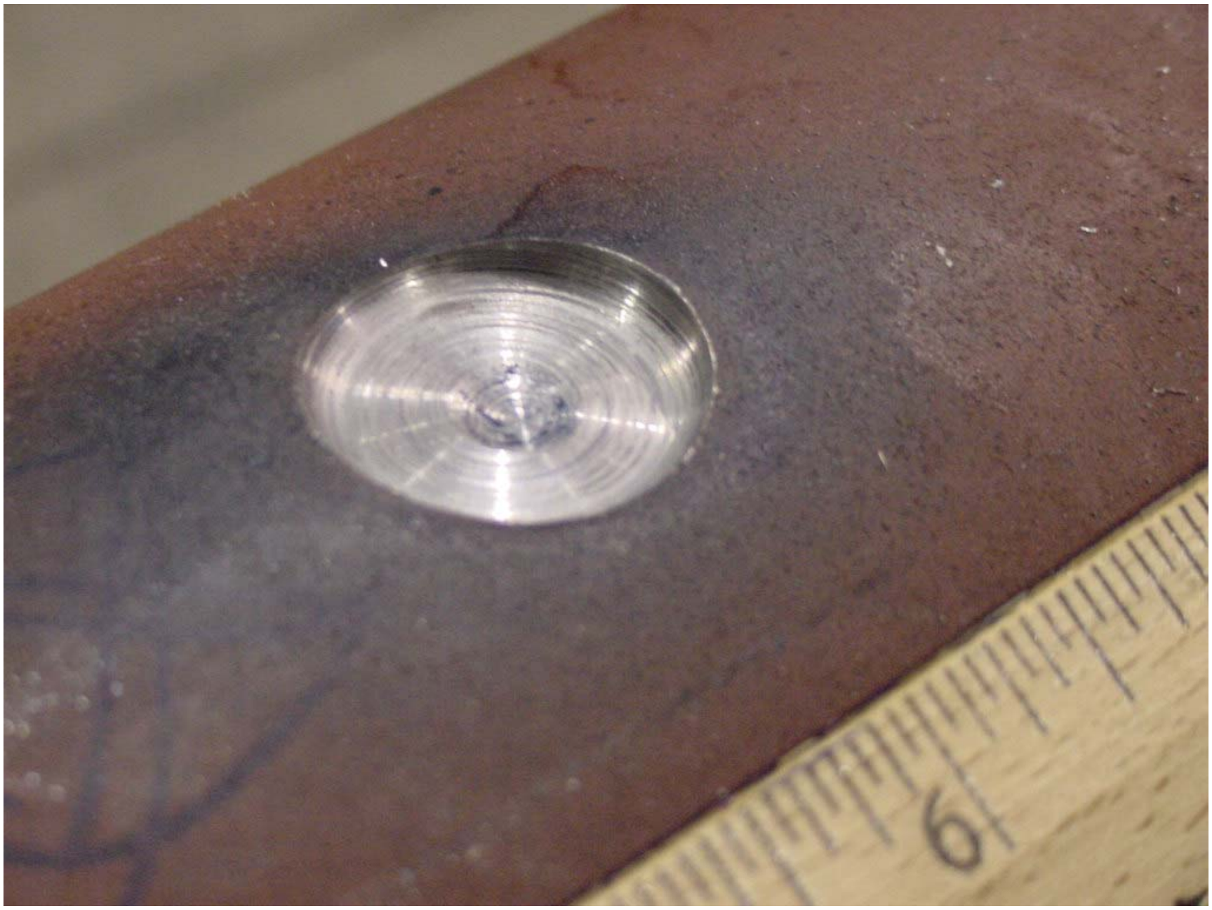


Figure 13 - Short, Deep Simulated Corrosion Damage

End caps were then welded to all four of the pipe sections (Figure 14).

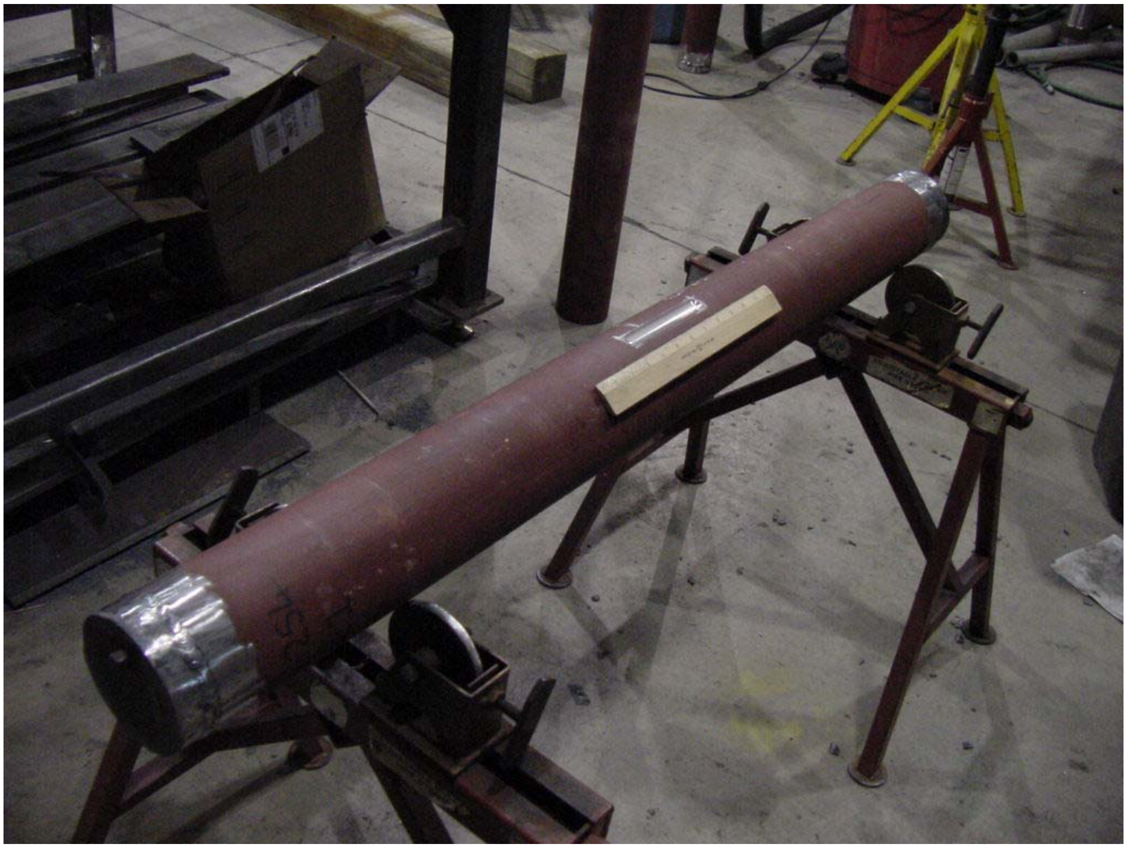


Figure 14 - 114.3 mm (4.5 in.) Diameter Pipe with End Caps Welded and Simulated Corrosion Damage Introduced

Following the installation of end caps, all four pipe sections were hydrostatically pressurized to failure.

3.2 - Weld Deposition Repair Trials

Test work is planned to evaluate different pipeline repair conditions, such as soil and coating type. Baseline welding procedures were needed to support these evaluations. Several welding systems were evaluated for internal weld deposition using GMAW and used to develop some baseline welding procedures. These evaluations were focused on determining whether or not the systems could make a good internal weld deposit. The pipe axis was fixed in the 5G horizontal position (Figure 15). As welding progressed around the inside diameter, welding position transitioned between flat, vertical, and overhead. The types of envisioned repairs were ring deposits to perhaps reinforce a defective weld, spiral deposits to repair an entire pipeline section, and patches to repair local corrosion damage. Weld deposit motion for the former two types would best be achieved using orbital type welding procedures where welding clocks around the circumference. The patch repair could be accomplished using deposit motion that was either orbital or axial. Motion also required the use of torch weaving, a technique that improves out-of-position weld pool shape. This is common in vertical-up welding to provide an intermediate shelf on which to progressively build the weld pool deposit. The effects of deposit motion on productivity and quality also needed to be evaluated for this application. With the different welding systems, the preferred metal transfer mode for GMAW was short-circuit transfer. This mode assures drop transfer in all welding positions. Open arc droplet transfer that is provided by spray, pulse spray, and globular transfer are not suitable for spiral overhead welding where gravity promotes spatter instead of metal transfer.

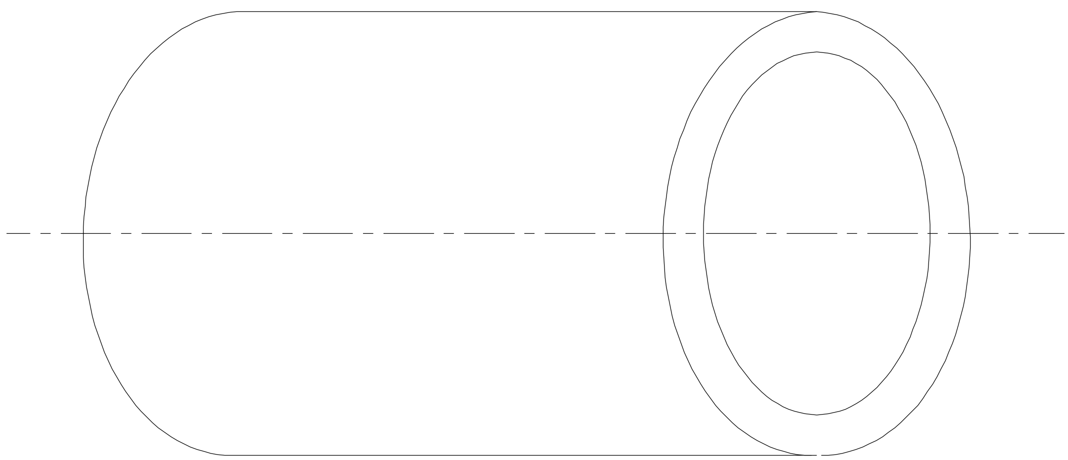


Figure 15 - Pipe in the 5G Horizontal and Fixed Position

The following welding systems were evaluated for internal repair of pipelines:

- Internal bore cladding system (Bortech)
- 6-Axis robot capable of complex motion control (OTC Daihen)
- Orbital welding tractor configured for inside welding (Magnatech Pipeliner)

Each system had motion control limitations and individually would not be appropriate candidates for an internal repair welding system. The internal bore cladding system manufactured by Bortech (Figure 16 and Figure 17) was designed for spiral cladding the inside of pipe that is preferable in the vertical position.

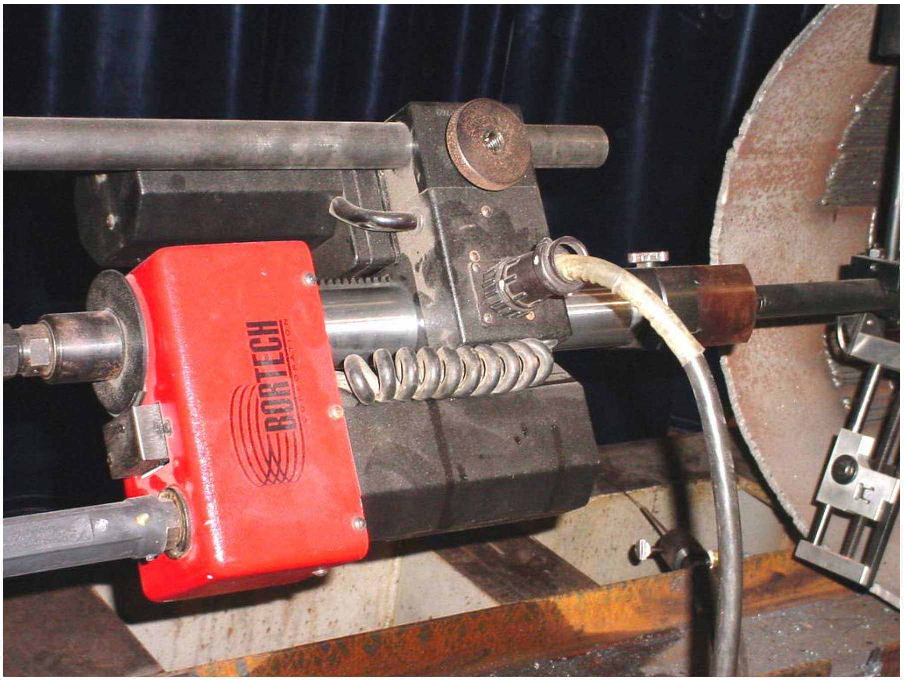


Figure 16 - Bortech Motion Mechanism for Continuous Spiral Deposition

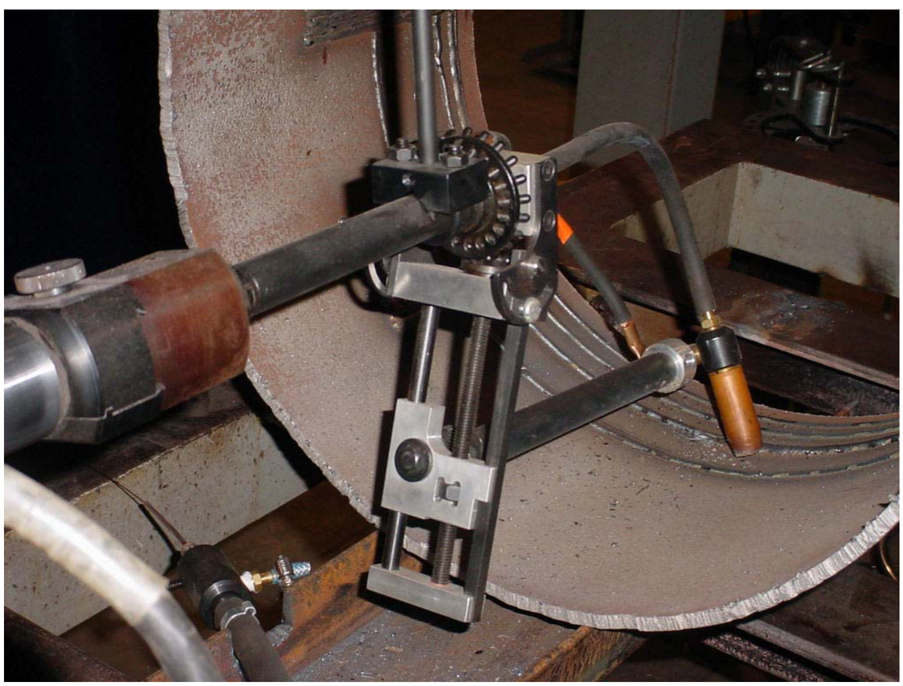


Figure 17 - Bortech Torch and Torch Height Control

The Bortech system has simple controls for operating constant voltage (CV) power supplies (Figure 18). This includes the ability to set wire feed speed, voltage, step size for the spiral motion, and rotation speed (travel speed). The system is very affordable as it uses simple motors for motion. When positioned inside a horizontal pipe, it was discovered that the rotation drive suffered from significant backlash. Conversations with the supplier led to the purchase and installation of a counterbalance weight that was used to balance the weight of the opposing torch.

Figure 18 - Bortech Controller

Preliminary weld trials with the Bortech system had marginal results. Only stringer beads were successfully deposited using short-circuit transfer in the spiral clad mode. Travel speeds of 3.81 to 4.45 meters per minute (mpm) (150 to 175 ipm) were used with an 0.89 mm (0.035 in.) diameter ER70S-6 filler metal (i.e., electrode). With stringer beads, the deposition rate was low since only narrow beads could be deposited. The bead shape suffered the most in the overhead position when starting downhill. Weaving was required to improve weld bead profile thus allowing higher deposition rates and improved fusion. The off-the-shelf system did not permit oscillation, but could if adapted with modern controls. In principle this type of mechanism would be suitable for an internal repair system. Here, anti-backlash servo-motors and gears, and programmable controls would be required with an improved system. Similarly, an additional motor drive that permits control of torch and work angle would also be required to cope with all the possible repair scenarios to optimize bead shape.

Based on the results experienced with the Bortech system, it was decided to develop preliminary welding procedures using a robotic GMAW system. A 6-axis coordinated motion robot (Figure 19) permitted the application of weave beads for spiral cladding or stringer beads in either direction. An observed limitation was the fact that the system did not have a welding torch current commutater to permit continuous spiral welding.

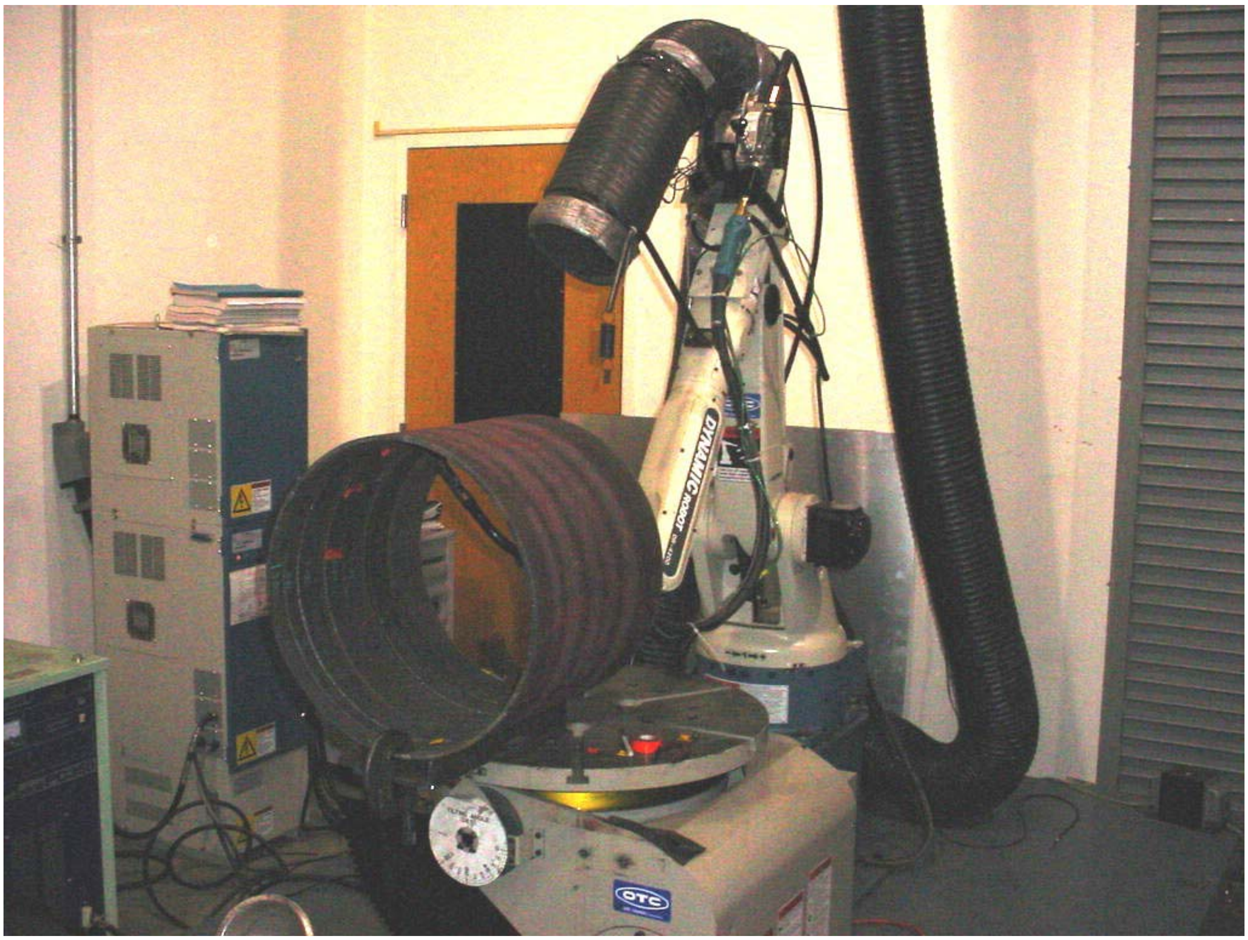


Figure 19 - OTC Robot Set-Up for Internal Welding

The standard robot welding torch (Figure 20) could only be used for half a revolution, then it had to be unwound to complete the remainder of each deposit ring. This limitation was acceptable for parameter development since the focus was the welding parameters not high duty cycle welding. The robot was interfaced to an advanced short-circuit power supply, the Kobelco PC-350.

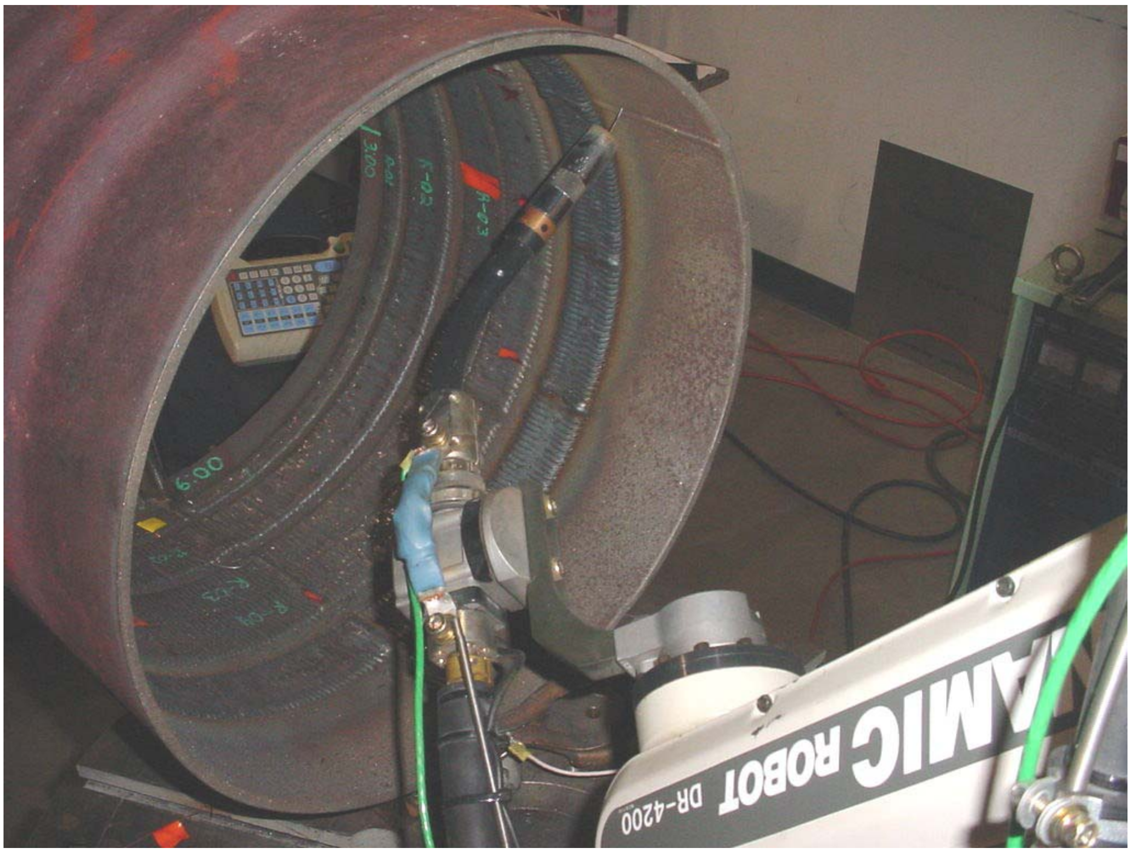


Figure 20 - OTC Robot Arm and Torch

The Kobelco PC-350 power supply (Figure 21) uses fuzzy logic pulse waveforms to minimize spatter during metal transfer and permits the application of variable polarity waveforms. Variable polarity combines the rapid, low heat input, melting of negatively charged electrode with the metal transfer stability of electrode positive. Until 1988, all commercial GMAW systems used positively charged electrodes for constant voltage and pulse power supplies. The PC-350 is more advanced than standard variable polarity power supplies, since it uses a fuzzy logic short-circuit anticipation control. On comparable applications that require low heat input, the PC-350 has shown productivity improvements compared to standard short-circuit. This power supply is equipped with waveform algorithms pre-programmed for steel using either 100% Carbon Dioxide shielding gas or an Argon - Carbon Dioxide shielding gas mixture for both

0.8mm (0.035-in) or 1.2mm (0.045 in) diameter electrodes. The waveform was simply modified by changing the electrode negative ratio on the pendant. Arc length and heat input is changed by an arc length knob on the pendant which varies the pre-programmed pulse frequency.

Figure 21 - Kobelco PC-350 Variable Polarity Fuzzy Logic Power Supply

The OTC robot welding system was used to develop preliminary repair welding procedures with the intent that they would be transferred to a different system for pipeline repair demonstrations. A range of orbital (ring motion) weave parameters were developed to establish an operating window, deposit quality, and deposition rate. Preliminary tests were also performed to evaluate bead overlap and tie-in parameters that would be required to make high quality repairs. All the welding tests were performed with a 95% Argon - 5% Carbon Dioxide shielding gas mixture using an 0.89 mm (0.035 in.) diameter ER70S-6 electrode.

Several years ago, PG&E purchased a welding tractor (Figure 22) from Magnatech for internal weld repair procedure development. This system was sent to EWI for this project so it could be used for pipeline repair testing and demonstrations, since this equipment is portable where the robot welding system is not portable.

Figure 22 - Magnatech ID Welding Tractor Capable of Spiral & Ring Motion with Oscillation

The Magnatech welding tractor has orbital motion with controls (Figure 23) for torch oscillation. The system is limited to a finite number of revolutions that can be made before cables need to be unwound. The controls are analog and do not have high accuracy, however, they are sufficient for preliminary parameter development and demonstration welding. Programmable controls would be required for an internal repair welding system using a Magnatech tractor. In addition, numerous mechanical changes would be required to accommodate a range of pipeline diameter sizes.

Figure 23 - Magnatech Control Pendant Showing Control Parameters

The Magnatech tractor was interfaced to a Panasonic AE 350 power supply (Figure 24). This power supply provides pulse waveforms and can be operated in a short-circuit mode where artifical intelligence is used to minimize spatter. The current pulsing and short circuiting helps lower heat input and improve deposition rate in out-of-position welds. Pre-programmed current waveforms are provided by algorithms for steel electrodes, and many other materials.

Figure 24 - Panasonic AE 350 Power Supply with Pulse Short-Circuit Metal Transfer Control

PG&E bought this system specifically for repair welding of 559 mm (22 in.) diameter pipe. For this project, 559 mm (22 in.) diameter pipe was provided by Panhandle Eastern so this system could be used for pipeline tests and demonstrations. At the time of this progress report, no welding has been performed with this system. The 559 mm (22 in.) diameter pipe supplied by

Panhandle Eastern was made in the 1930s and has an asphalt coating. Approximately 12.19 m (40 feet) was provided by this company for the project.

During the next reporting period, dirt box tests will be performed on this pipe using the Magnatech system. The effects of soil type and welding procedure on this type of coating will also be evaluated with these tests.

3.3 - Survey Development

The survey (Appendix A) was sent to a wide range of gas transmission companies, both member companies of the Pipeline Research Council International (PRCI), and also to other companies within the industry (Appendix B). The list of contacts was built up from the PRCI Materials Committee Roster, a list of other gas companies from the http://www.ferc./gov/gas companies/pipelines web site, and a web-based list of gas company executives, in addition to personal contacts within the industry. An extensive series of phone calls were made to establish the most appropriate person or persons at each company to whom to send the survey, and to establish whether a central point of contact (POC) or multiple recipients was preferred. In most cases, the appropriate staff member at parent companies with several pipeline subsidiaries preferred to be a central POC, gathering this and sending the feedback to EWI through one survey for their company. Email addresses (Appendix D) were gathered for all the survey recipients such that the survey could be sent, completed, and returned, electronically.

4.0 - RESULTS AND DISCUSSION

This report describes the first twelve month's progress of a project sponsored by the U.S. Department of Energy (DOE) National Energy Technology Laboratory (NETL) to develop internal repair technology for gas transmission pipelines. In order to thoroughly investigate repair technology, this project brings together a combination of partners that have a proven track record in developing pipeline repair technology. The project team consists of Edison Welding Institute (EWI), a full-service provider of materials joining engineering services; Pacific Gas & Electric (PG&E), a pipeline company that has a current need for the technology; and the Pipeline Research Council International (PRCI), an international consortium of pipeline companies, to provide project oversight and direction. EWI is the lead organization performing this Award for NETL located in Morgantown, West Virginia.

Task 1.0 - Research Management Plan

During the previous reporting period, the team created a Research Management Plan(2). This document contains a work breakdown structure and supporting narrative that concisely summarizes the overall project. The plan is an integration of the technical and programmatic data into one document that details the technical objectives and technical approach for each task and subtask. The document also contains detailed schedules and planned expenditures for each task and all major milestones/decision points. During this reporting period, the plan was updated to reflect schedule changes. As mutually decided by NETL and EWI, during the next reporting period, the plan will be updated to accommodate a 6-month no cost extension required to obtain new fiber-reinforced composite liner material for evaluation.

Task 2.0 - Technology Status Assessment

During the previous reporting period, a Technology Status Report(3) was produced that presents the status of existing pipeline repair technology that can be applied to the inside of a gas transmission pipeline. This report describes the current state-of-the-art technologies that are being developed, including the positive and negative aspects of each technology. This task is complete.

Task 3.0 - Review Operators Experience and Repair Needs

During the previous reporting period a total of fifty-six pipeline operator companies were surveyed to determine the specific geographic locations and special situations where internal repair would be the preferred repair method for gas transmission pipelines. A total of twenty completed surveys were returned, representing a 36% response rate, which is considered very good given the fact that tailored surveys are known in the marketing industry to seldom attract more than a 10% response rate. This task is complete.

Subtask 3.1 - Repair Needs and Performance Requirements

The pipeline operators experience and repair needs survey was divided into the following parts:

- Currently-Used Repair Methods
- Use/Potential Use of Internal Repair
- Need for In-Service Internal Repair
- Applicable Types of Damage
- Operational and Performance Requirements for Internal Repairs

The survey primarily focused on pipeline operating companies (gas transmission) that are members of the Pipeline Research Council International (Appendix B). The survey was also sent to other pipeline operating companies (Appendix C). A detailed list of contact information for surveyed individuals can be found in Appendix D.

Following receipt of completed surveys, follow-up telephone calls were made to further identify the range of pipeline sizes, materials and coating types in most common use and the types of pipeline damage and remediation/upgrades (to more stringent code requirements) that are most frequently encountered. The pipeline companies were also asked to define specific operational and performance requirements for internal repairs, including post repair inspection and future pipeline inspection (i.e. pigging). Additionally, the survey determined operating requirements such as the minimum and maximum distance a repair system needs to be able to travel inside a pipe to facilitate internal repair and potential obstructions such as elbows, bends, branches, and taps that may limit access.

Companies that offer in-line inspection services were also surveyed to determine the maximum geometric variations associated with internal repairs (particularly internal build-up, liner thickness, etc.) that can be tolerated by current and next generation in-line inspection vehicles (a.k.a. smart pigs).

As mentioned in the previous reporting period, if the results of the survey had indicated that operators have a strong preference for the development of internal repair methods that can be applied while the pipeline remains in-service, a separate series of experiments would have been planned to investigate the effect of methane in the welding environment on the integrity of completed welds.

During any arc welding operation, the material being welded is exposed to temperatures that range from ambient to well above the melting temperature 1,536°C (2,736°F). When steel at high temperature is exposed to a hydrocarbon gas (such as methane), carburization can occur. When steel at temperatures above 1,130ºC (2,066ºF) is exposed to methane, eutectic iron can form as the result of diffusion of carbon from the methane into the steel. In previous work at EWI,[(4)] in which welds were made on the outside of thin-wall pipe containing pressurized methane gas (Figure 25, Figure 26, and Figure 27), carburization and the formation of thin layer of eutectic iron occurred (Figure 28 and Figure 29).

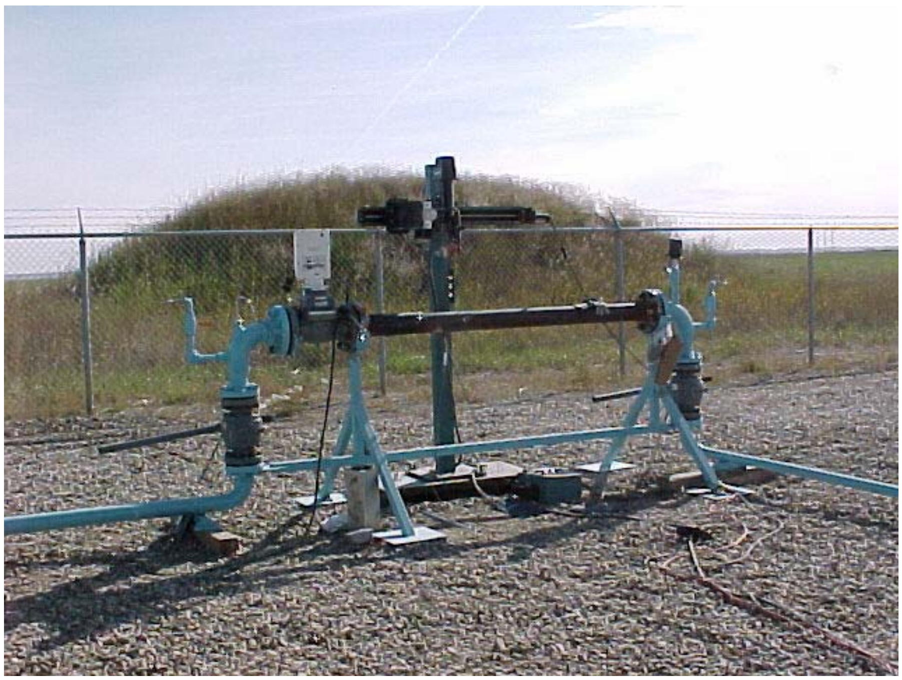


Figure 25 - Experimental Set-Up for Welding onto Thin-Wall Pipe containing Pressurized Methane Gas

Figure 26 - External Appearance of Welds Made on 3.2 mm (0.125 in.) Thick Pipe with Methane Gas at 4.5 mPa (650 psi) and 6.1 m/sec (19.9 ft/sec) Flow Rate

Figure 27 - Internal Appearance of Welds Shown in Figure 26

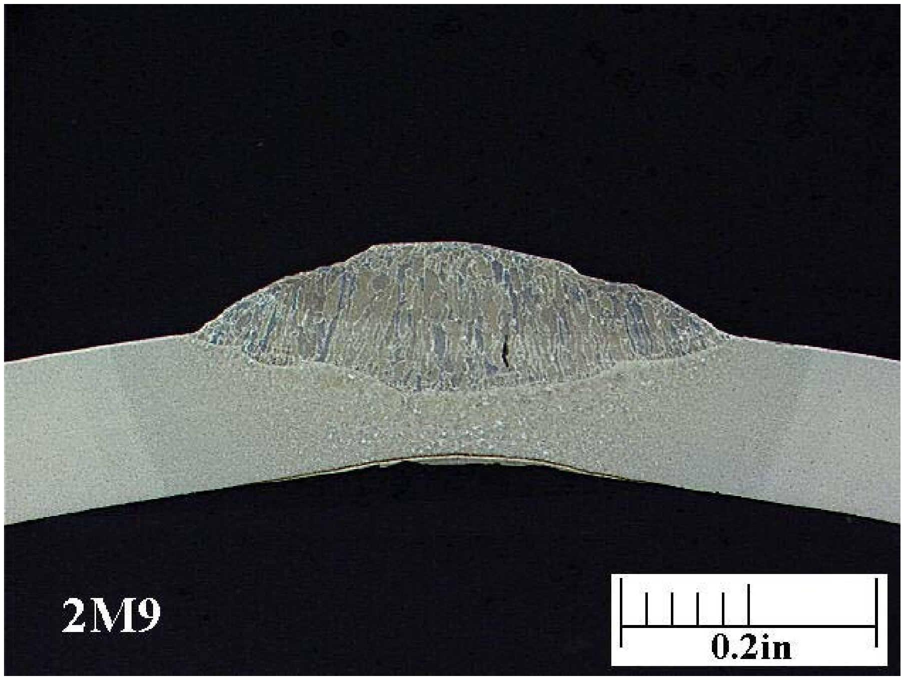


Figure 28 - Metallographic Section through Weld 2M9 (middle weld shown in Figure 26 and Figure 27)

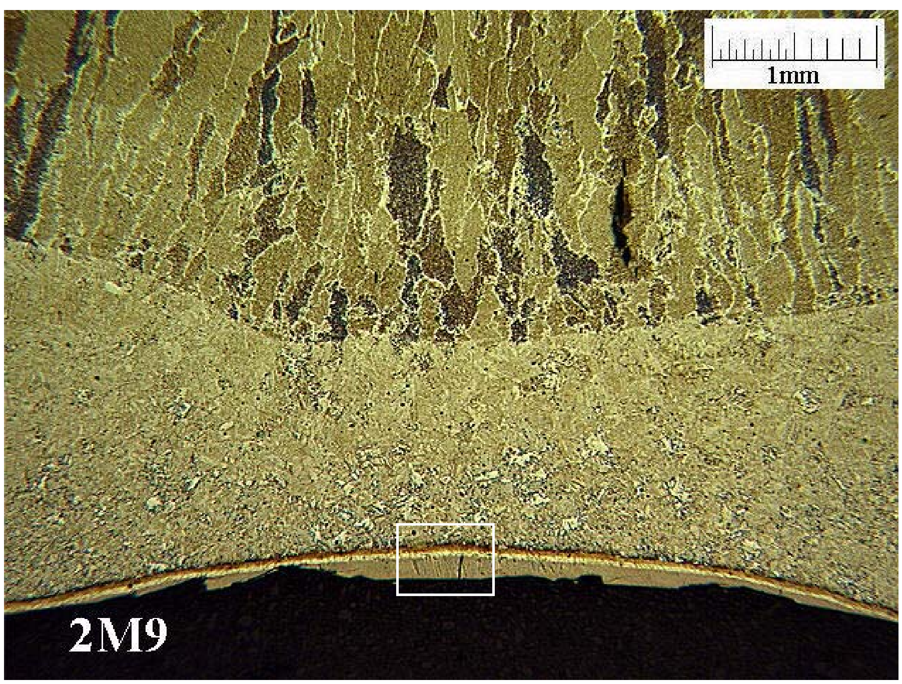


Figure 29 - Eutectic Iron Layer at Inside Surface of Metallographic Section through Weld 2M9

This phenomenon was previously reported by Battelle during experiments with liquid propane.[5] There were also small cracks associated with the eutectic iron layer (Figure 30), which were attributed to the limited ductility of eutectic iron. This subtask is complete.

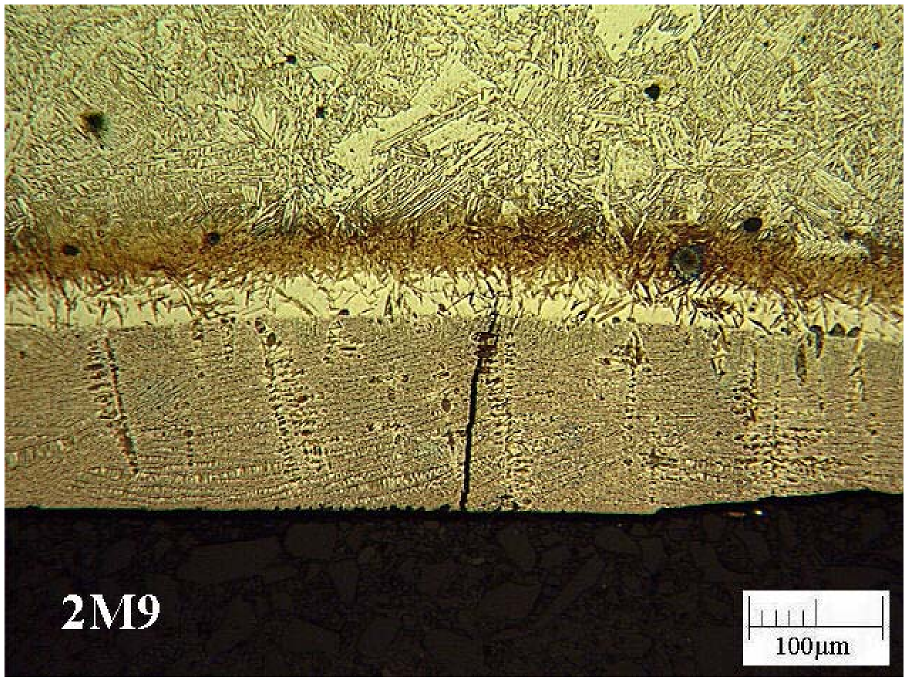


Figure 30 - Cracks in Eutectic Iron Layer of Metallographic Section Shown in Figure 29

Subtask 3.2 - Target Specifications for an Internal Pipeline Repair System

During this reporting period, the results of the survey were collected/analyzed and the target specifications for an internal Pipeline Repair System were identified.

General Specifications:

- The most frequently cited potential application would be for out-of-service use under river crossings, lakes, swamps, highways, high population density areas, and railway crossings.
- Use of internal repair as a temporary repair is of limited interest and is only attractive in seasonal climates where excavation and permanent repair would occur during the summer months.

- The repair system should have the ability to effect permanent internal repairs within the range of 508 mm to 762 mm (20 in. to 30 in.) diameter pipe as identified by 90% of survey respondents (559 mm (22 in.) diameter is the most commonly used size).

Deployment Distance Specifications:

- One excavation should be required to insert internal repair device into the pipe. From this insertion point, the repair device should travel in each direction from the excavation.
    - 81% of all respondents would be served by a pig-based system (with despooled umbilicals) capable of traveling 610 m (2,000 ft.) which would suffice for all highway and river crossings. A river crossing of up to 1,219 m (4,000 ft.) could be accessed from an insertion point on either side of the river.

Inspection Specifications:

- The repaired pipeline must be inspectable by pigging after repair per DOT code 49 CFR 192.150[6] which states, "each new transmission line and each line section of a transmission line where the line pipe, valve, fitting, or other line component is replaced must be designed to accommodate the passage of instrumented inspection devices."
- Repairs made by the system must be inspectable via nondestructive evaluation (NDE) pigging, preferably radiographic testing (RT), with ultrasonic testing (UT) as an acceptable alternative. Inspection requirements should meet those specified in the following codes:
    - ASME B31.8
    - ASME B31.4
    - CSA Z662
    - DOT Part 192 NDE

Coatings Specifications:

- Repairs must not compromise cathodic protection effectiveness after completion.
- Preservation of pipeline coating integrity must meet DOT 192/195 requirements

Geometric Specifications:

- System must be capable of effecting circumferential and/or patch type repairs.
- System must be capable of negotiating bends in the range of 1.5D maximum to 6D minimum (3D is the most common).
- Repair reinforcement, or protrusion into the pipeline, should not exceed 1% to 2% of the inside diameter, e.g., 1.5 mm (0.06 in.) for a 914 mm (36 in.) diameter pipe.

This subtask is complete. Information identified in this subtask will be used to complete Subtask 6.3 Functional Specification of an Innovative Internal Pipeline Repair System.

Subtask 3.3 - Summary of Industry Needs for Internal Pipeline Repair

During the previous reporting period EWI completed and submitted the Task 3.0 Review of Operators Experience and Repair Needs (41633R25.pdf) to NETL ADD Document Control in Pittsburgh, PA. This subtask is complete and there are no planned activities for next reporting period. The results of the survey follows.

Survey Responses

The following survey responses are summarized in categories that correspond to the sections and questions asked in the survey itself. The questions are repeated (and presented in bold type to distinguish them) within each section to avoid the need to continually refer to Appendix A. In most instances, the data collected is presented in the form of a bar chart for easy interpretation.

Most respondents answered all the survey questions, but this was not always the case. As such, in many cases there were twenty responses to a particular question, in others there were less, and in some cases, such as the types of coatings used on pipelines, there were many more, since most companies have used several coating types over the years.

Part 1 – Currently-Used Repair Methods

1. **Describe the corrective actions your company has taken due to degradation (corrosion, cracking, etc.) of transmission pipelines, especially repair or replacement actions.**

   Figure 31 summarizes the responses received. The most common type of repair is a welded external steel sleeve which was mentioned fourteen times, followed closely by "cut-out and replace" which was listed thirteen times. ClockSpring®, grind-out repairs, and composite wraps were all mentioned eight times.

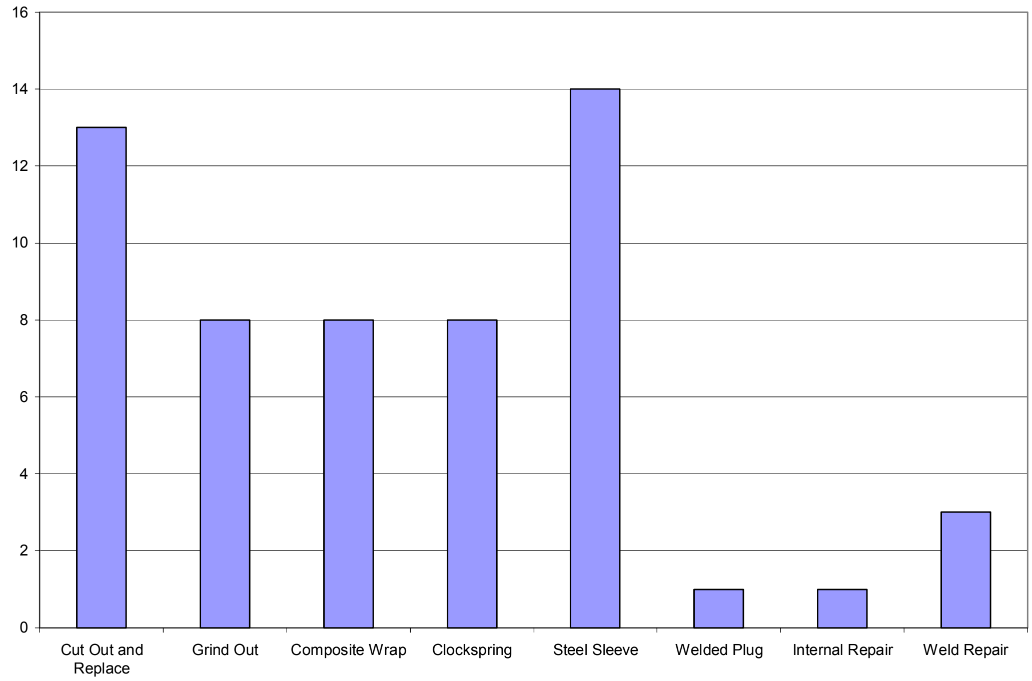


Figure 31 - Currently Used Repair Methods

One response summarized the company's perspective in the following fashion: cut-out and replace cylinder (seldom), full encirclement steel sleeves (most common), direct deposition of weld metal (seldom, but frequency may increase), grinding to remove gouges (common), and welding a plugged fitting like a Threadolet over the damage.

After the degradation is detected by whatever means, repair protocols are used. For general corrosion these include steel sleeves or composite sleeves. For stress corrosion cracking (SCC), gouges, and sharp corrosion profiles, grinding is often used. Typically gouges are ground until the cold worked material has been removed and are sleeved where necessary. For cracks, much of the time these are cut out, however, there are times that cracks are ground out using in-house protocols. Repair of dents is carried out with steel reinforcement sleeves. All respondents indicated that excavations and repairs involve the replacement of the existing coating with liquid applied epoxy coating.

One reply indicated that the first step was evaluation to ASME B31G. For repairs needed in lines that can be taken out of service, the solution is to either replace the damaged section as a "cylinder" or attach a sleeve. In the past, sleeves were exclusively steel, as technology has evolved, fiberglass wraps have been used. For low pressure lines leak clamps rated up to 6.89MPa (1,000 psi) are used where appropriate.

In the case of internal corrosion, on-stream cleaning, chemical treatment, in-situ coating and in-situ polyethylene (PE) sleeve repairs have been applied. Recently, an internal repair approach of a 914 m (3,000 ft.) long, 607 mm (24 in.) diameter, river crossing was considered (http://www.unisert.com) using an internal fiberglass sleeve supported by a grouted annulus. Ultimately, a new HDD river crossing option was selected because of loss of cover in the river bottom.

Another respondent stated that a variety of repair methods are used, with the selection of the method dependent on several factors including class location, type of damage, operating pressure, and operational considerations.

Corrosion is repairable by a variety of repair methods dependent upon the conditions. Options include band clamp, mechanical sleeve, weld-on sleeve, ClockSpring®, and replacement. External repair methods used by one company include sleeves (reinforcing, pressure containment), grinding (cracks) and pipe replacement. Another company indicated that they normally use ClockSpring® to re-enforce external corrosion areas, whereas cracks that exceed code limitations require an automatic cut-out (which is the last option to consider). Yet another company uses external repair techniques that include a simple blast and recoat, grind and recoat, ClockSpring® repair, welded sleeve repair or pipe replacement.

2. Have you used methods other than external sleeving or pipe replacement to repair different types of degradation?

The responses to this question were split 50% "no" and 50% "yes." The "yes" responses typically gave examples which are summarized as follows:

- Grinding is used to remove gouges (common), cracks, SCC, and sharp anomalies.
- Plugs are fitted and welded over the damage, e.g. a Threadolet.
- Composite wraps are used.
- ClockSpring® is used.
- Direct deposition welding has been used to repair wall loss
- “Encapsulating” a malfunctioning or defective area has been used.
- Taps have been used for small defects.
- Leak clamps have also been used.

Seven of the responses mentioned grinding of one type of defect or another and was the most common other type of repair. Three examples of different types of welding solution were cited, of which only one involved direct deposition of weld metal on the outside of the pipe.

4. **What criteria (including ease of pipe access) affect choice of the specific repair method to be used?**

The compiled answers to this question are represented in Figure 32 and show twelve responses, of which cost and the availability of the repair method were those most frequently cited. The next important consideration is the position of the defect, and whether the line had to be out-of-service as the next most frequently mentioned criteria.

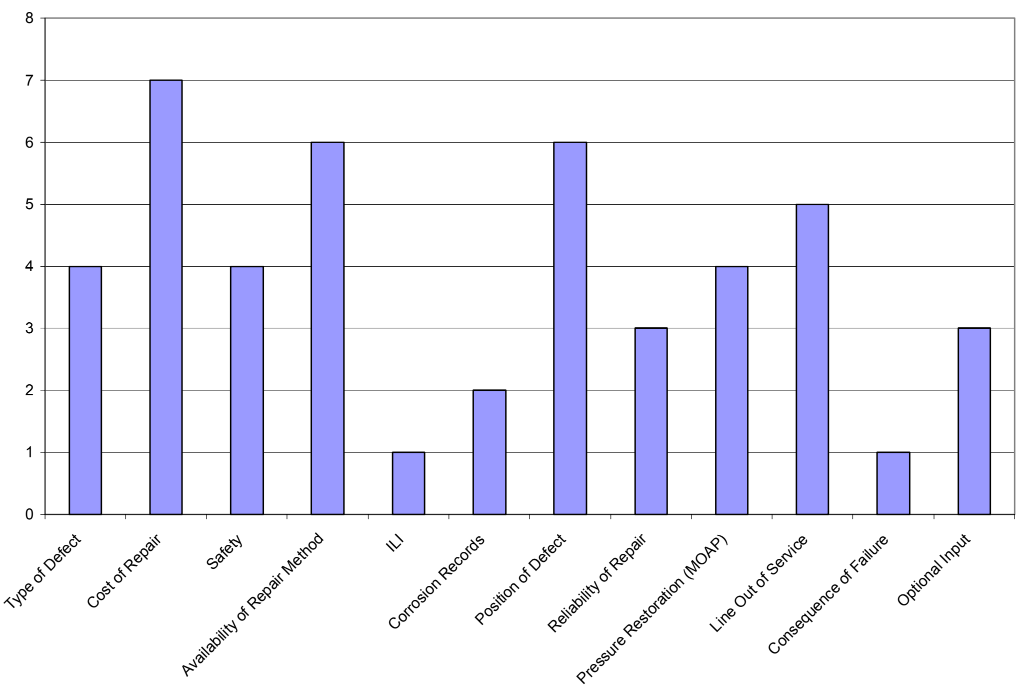


Figure 32 - Criteria Affecting Choice of Repair Method

One respondent summarized the evaluated criteria as follows:

- Consequence of failure
- Position of defect (on bend, weld, top/bottom, etc.)
- Impact of a pressure restriction
- Cost of repair
- Type of defect

- Availability of repair method, crews, expertise, etc.

Another response listed the following criteria:

- Maximum allowable operating pressure (MAOP) and possible future increases
- Maximum operating pressure (MOP) at time of repair
- Pipeline specified minimum yield strength (SMYS)
- Downstream demand
- Ability to remove the pipeline from service
- Cost
- Projected life of the pipeline

The size of flaw (surface area), the ability to shut in and replace the damaged section, the ratio of estimated failure pressure to MAOP, and the ability to stop additional degradation (in the case of internal corrosion) were stated as important criteria by another respondent.

Other responses follow:

- Must make repairs without taking the line out of service since it is not looped.
- Need to have the line out-of-service or at less pressure during repair work
- Can the pipeline be taken out-of-service, gas loss?
- Leak history
- Corrosion records
- ILI (in-line inspection) logs
- Cost (access, out-of-service time, mobilization time, etc.)
- Reliability (how reliable is the repair method to fix the problem, permanent repair, temp. repair)
- Safety issues
- Operator qualification
- Type and depth
- Material properties and type of pipes, e.g. electric resistance welded (ERW), seamless, etc.
- Coating

- Location (proximity to housing or public facilities)
- Operational timing (ability to take line out-of-service, i.e. impacts to customers and system)
- Type or severity of defect, access to site, time constraints in regards to length of line outage or restriction, soil conditions (e.g. swamp, rock, etc.), environmental issues (wetlands, streams, etc.).
- Pressure, Department of Transportation (DOT) status (we operate many rural gathering lines), contents of line, risk to public
- Location, pipe condition, operating pressure/SMYS, pipe geometry (e.g. straight, over-bend, sag, etc.)

5. **Comments pertaining to currently used repair methods.**

Not unexpectedly, comments ranged from:

- Most of our line has easy access
- The use of sleeves for the repair of external flaws has been satisfactory to date
- Most existing methods have been effective
- The ClockSpring® has been a very useful repair method in the last few years
- Many are very difficult in swamp or underwater locations

Cut-out repair is considered the last resort due to flow disruption and overall cost. External faults are more readily repaired using sleeves than internal anomalies. Internal damage requiring repair in bends equate to a pipe replacement. The threshold for pipe replacement versus repair decreases once the first replacement in a section is justified.

Live repair methods require a reduction in operating pressure. Normally the excavation trench requires tight sheeting and shoring, a certified welder, and qualified maintenance welding procedure with low hydrogen procedures (e.g. E7018 low hydrogen electrodes).

Part 2 – Use/Potential Use of Internal Repair

1. **Has your company attempted repair of a transmission line from inside the pipe?**

Of the nineteen responses to this question, only one was "yes." Another company indicated that they considered the use of the PG&E tool for weld repair on the internal diameter, but the expense was said to be large and the diameter range was limited. Other companies raised the question of how to ensure the quality of the repair.

If so, describe the repair(s)

Plastic tight liners were used and for lower pressure lines (less than 100 psig MAOP) slip lined plastic liners have been used. Both of these methods require the line to be out of service when repair is made.

2. **There are many factors that affect the decision to repair or replace pipe. What circumstances would favor performing a repair from inside the pipe using only one or two excavations rather than excavating the entire length of pipe?**

Figure 33 shows the primary factor for choice of an internal repair method is road and river crossings. Confidence in repair method, presence of numerous but localized areas of damage, inability to excavate large areas because of environmental permitting issues, economics/cost and availability of a proven, industry (and regulator) accepted internal method were also factors mentioned.

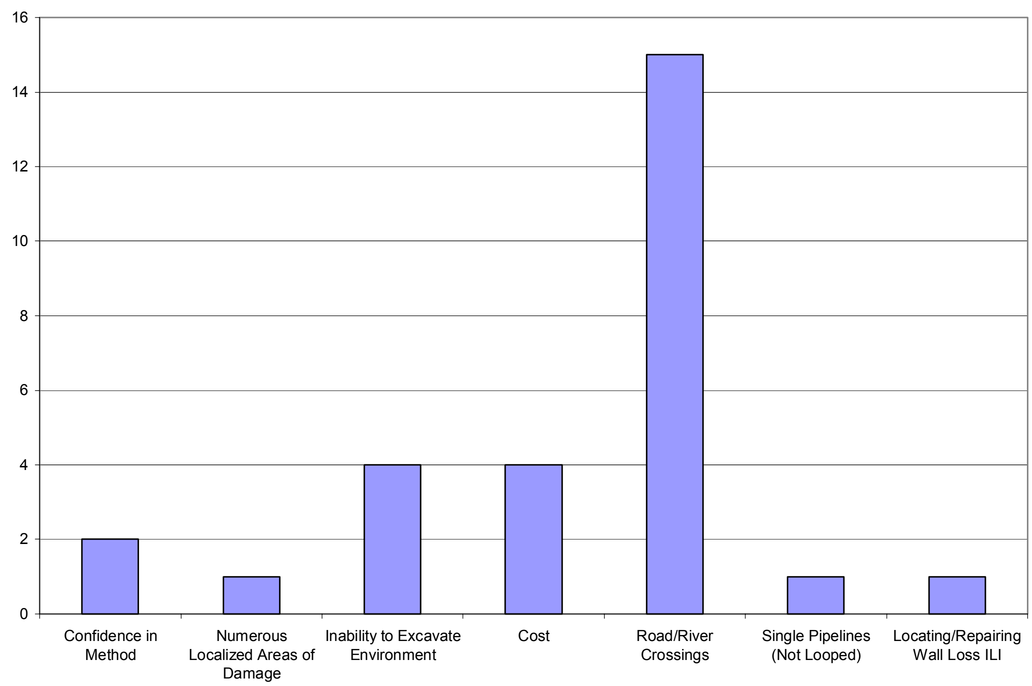


Figure 33 - Decision Factors for Internal Pipe Repair

Specific comments follow:

- Depending on the depth of burial and the presence of over-bends, sag bends or side-bends or road/river crossings etc., then an internal repair may be much more preferable than cutting out the piece of affected pipe. Single barrel pipelines (versus looped lines) are more difficult to remove from service (customer interruption).
- Factors, such as, class location, environmentally sensitive areas, in crossings, under waterways or rugged terrain would be some of the major factors influencing this decision; an anomaly found inside a casing might be (a factor), under a road, irrigation canal, or railroad tracks; difficult to excavate locations (e.g. rocky conditions, caliche soils, etc.); and cost would be another factor influencing the decision. This potential technology would also be useful for locating and repairing internal wall loss identified by ILI inspections without excavation of the entire pipeline and numerous cuts to the line.
- Property damages, contractor costs, inaccessible right-of-way, lack of temporary workspace, road, railroad, and stream crossings sometimes must be replaced just because indicated damage cannot be directly measured highway crossings, railroad crossings, and heavy traffic intersections.
- Highly congested areas that impact risk to other pipelines or utilities and proximity to structures.
- Possibly a pipeline under water or a permanent structure where the pipeline is not easily accessible
- Where the pipe repair is located under a road or body of water where access is limited.
- Pipelines that are under paved areas, or in narrow or confined rights-of-way where space is limited. Crossings at roads, railroads, lakes, and rivers, and water cover, such as, marsh or swamp.
- If the cost of an internal repair plus the outage restriction was less than the cost of an external repair. For example, if the defect was in the middle of a major water crossing or swamp which would normally require ice road construction for access.
    - High traffic areas
    - Federal, state, city or county roadway restoration requirements
    - Environmental concerns
    - Railway crossings

3. If the technology were available to perform a repair from the inside, would your company consider using the technology?

One "no" response was received. The other seventeen responses were "yes" and some were qualified with additional comments as follows:

- We would want to review testing and possibly witness a demonstration
- Only if proven
- If cost is reasonable
- Particularly if DOT compatible
- Depending on the site-specific conditions

One response indicated that the company transports non-corrosive natural gas, so the probability of an internal flaw is highly unlikely. While this may be true for many companies in terms of internal corrosion, it misses the point that the internal repair can be used for repair of external damage.

If so, for what application(s) – e.g., specific geographic locations and special situations?

Figure 34 summarizes the answers to this question. River crossings and populated areas with highway crossings were most frequently cited. Use for repair of flaws found by pigging, included internal or external corrosion pitting, gouges, seam or weld flaws (if detectable by pigging).

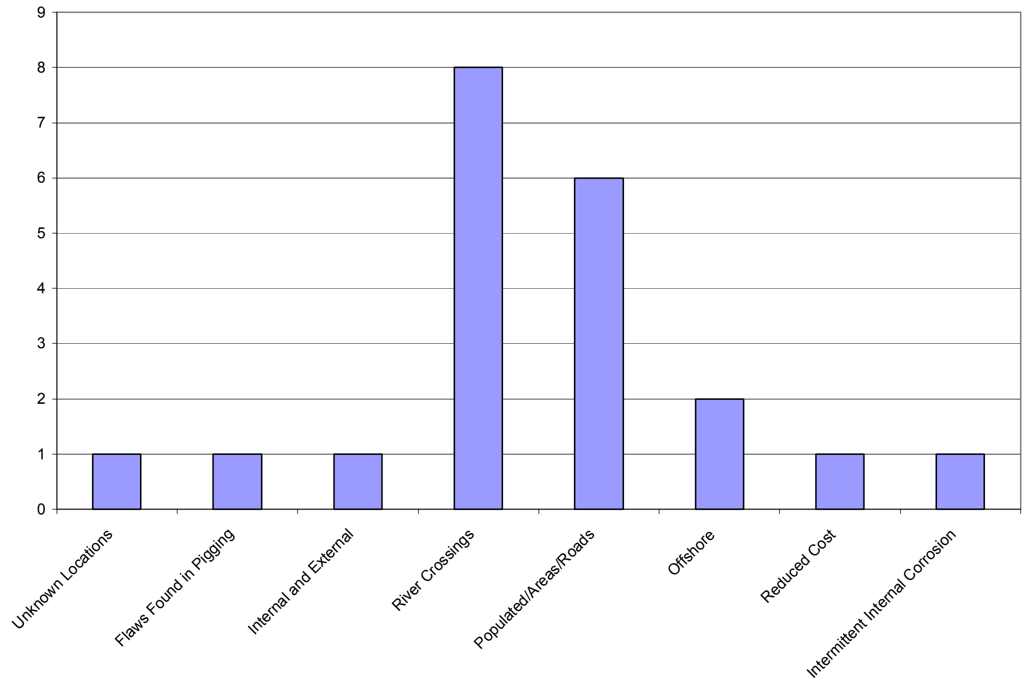


Figure 34 - Specific Geographic Locations and Special Situations

Seven responses mentioned river crossings and this was the most common response to this question. Others cited pipelines that are under paved areas, or in narrow or confined rights-of-way where space is limited, crossings at roads, railroads, lakes, swamp areas, and difficult access due to physical barriers inherent to high population density and congested areas (e.g., numerous utilities, building, streets, etc.).

One response mentioned concerns regarding the use of internal repair on a direction bored crossing of a freeway, because of unknown future cathodic protection (CP) effectiveness after welding.

Another response referred to applications where it is not cost effective to repair or replace the pipe conventionally, provided the internal repair is an equivalent repair. Probably the best application in this case would be offshore.

4. **At least one excavation will be required to insert the internal repair device into the pipe. From this excavation, the repair device could travel in each direction from the excavation. About how far from the insertion point should the repair device be able to travel?**

Answers ranged from 15 m (50 ft.) to 113 km (70 miles); the latter for offshore operation, with most answers being in the 305 m to 915 m (1,000 ft. to 3,000 ft.) range. The array of responses is summarized in Figure 35, showing that there are discrete lengths of 305 m (1,000 ft.) and 610 m (2,000 ft.) "umbilicals" (or travel distances) for certain categories of repairs or related requirements. The typical travel distances required are divided into three groups; up to 305 m (1,000 ft.); between 305 m to 610 m (1,000 ft. and 2,000 ft.); and beyond 915 m (3,000 ft.), and are indicated by the dotted lines in Figure 35. In concept, all these systems would be pig-based. Systems with despooled umbilicals could be considered for the first two groups, while the last group would be better served with a self propelled system with self-contained onboard power and welding system.

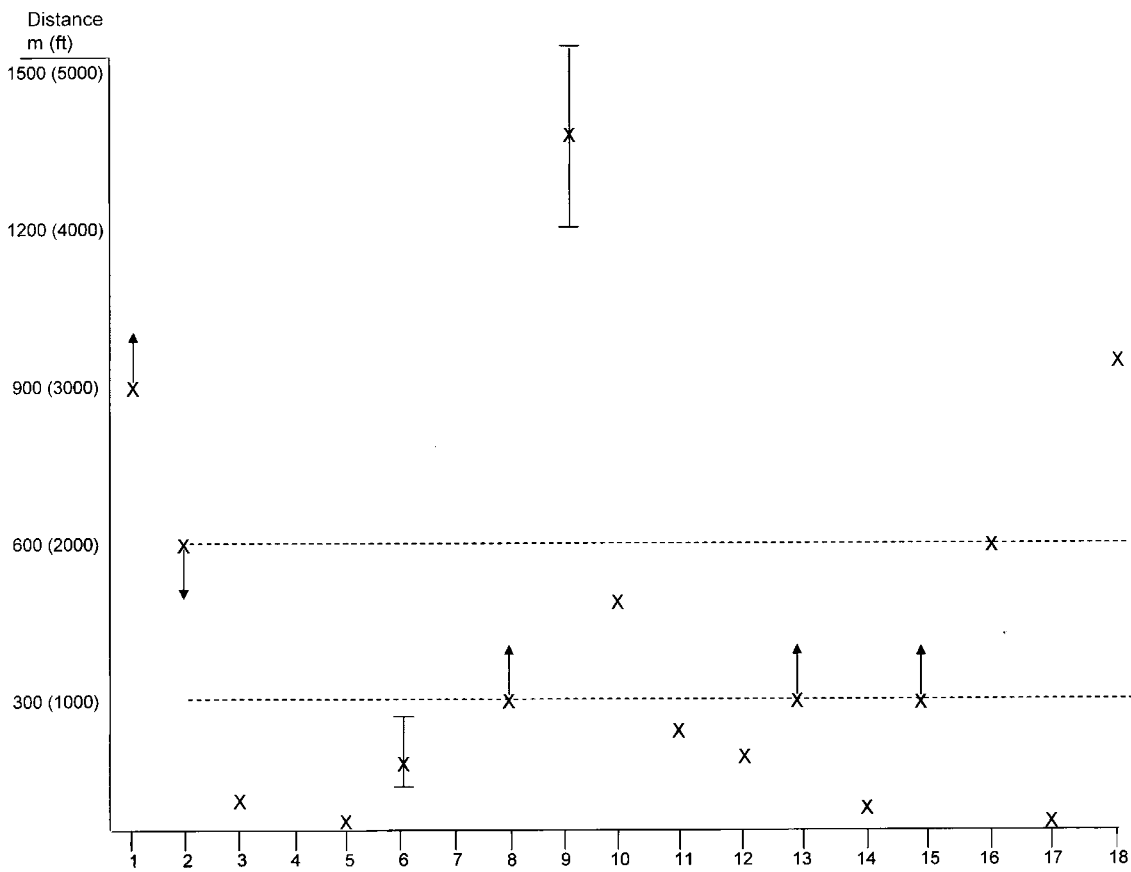


Figure 35 - Distance Repair System Required to Travel Down Pipe

152 m (500 ft.) appears to be adequate to cross most interstate highway crossings and 610 m (2,000 ft.) for all river crossings. A major river crossing would require the device to travel up to 610 m (2,000 ft.). In one case it was stated that the longest section of pipe which is not accessible (directional bore) is approximately 1,219 m (4,000 ft.), so

the need would be to access the pipe a distance of approximately 610 m (2,000 ft.) from either end.

Longer distances, probably from 915 m (3,000 ft.) to several miles or more would require the technology to travel in a similar way as an inspection pig. Realistically, such a system would have to be based on an onboard propulsion device using gas line pressure as the motive force. A self-contained, inverter-based welding power source and welding system would also be required.

In what range of pipe diameters should the repair device be capable of operation?

A wide range of pipe sizes were cited, both within a particular company, and between various companies. The results are summarized in Figure 36 show that pipe size range requirements run from 51 mm (2 in.) through 1,219 mm (48 in.) diameter. The common size range for 80% to 90% of operators surveyed is 508 mm to 762 mm (20 in. to 30 in.) diameter, with 95% using 559 mm (22 in.) diameter pipe.

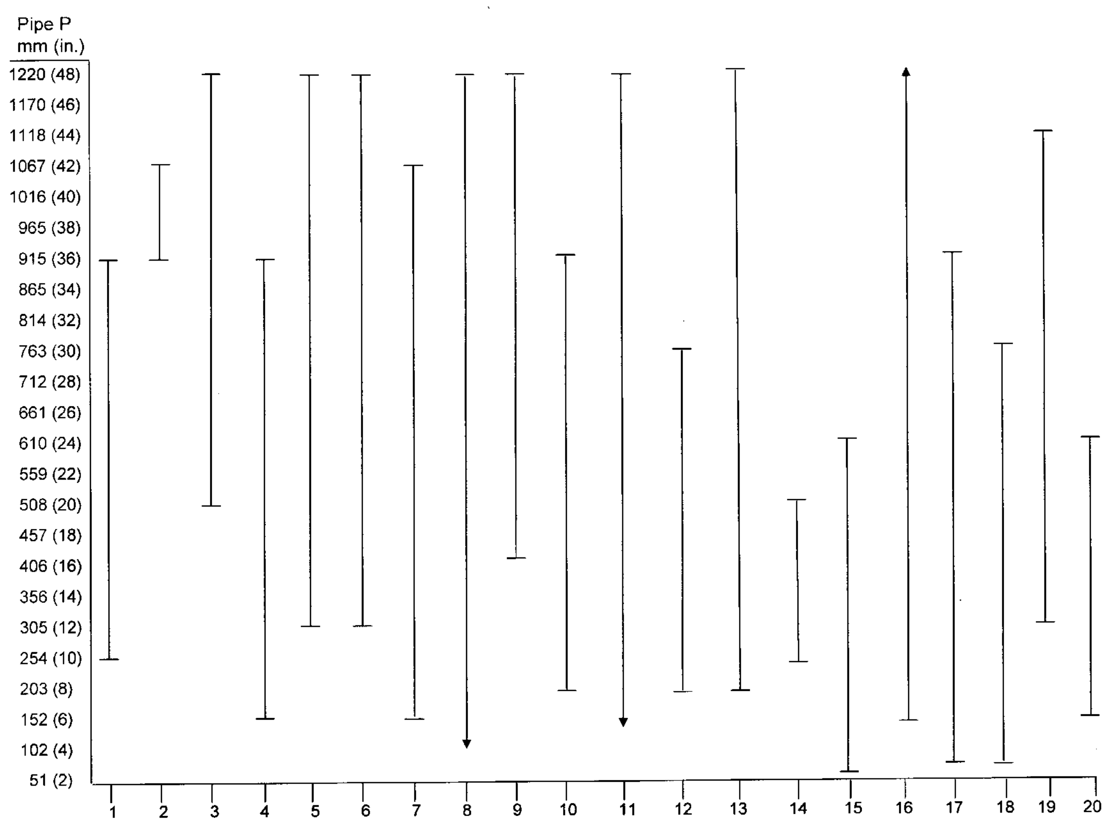


Figure 36 - Range of Pipe Diameters Used

5. **What potential obstructions such as elbows, bends, branches, and taps should the repair system be able to negotiate?**

   The answers to this question were quite varied and are summarized in Figure 37. Pipe bends of various radii were most commonly mentioned including 1.5 times the diameter (1.5D), 3 times the diameter (3D), and 6 times the diameter (6D), with 3D pipe bends being the most commonly used. Elbows were mentioned in three responses. It is interesting to note that the answer "all" was given four times.

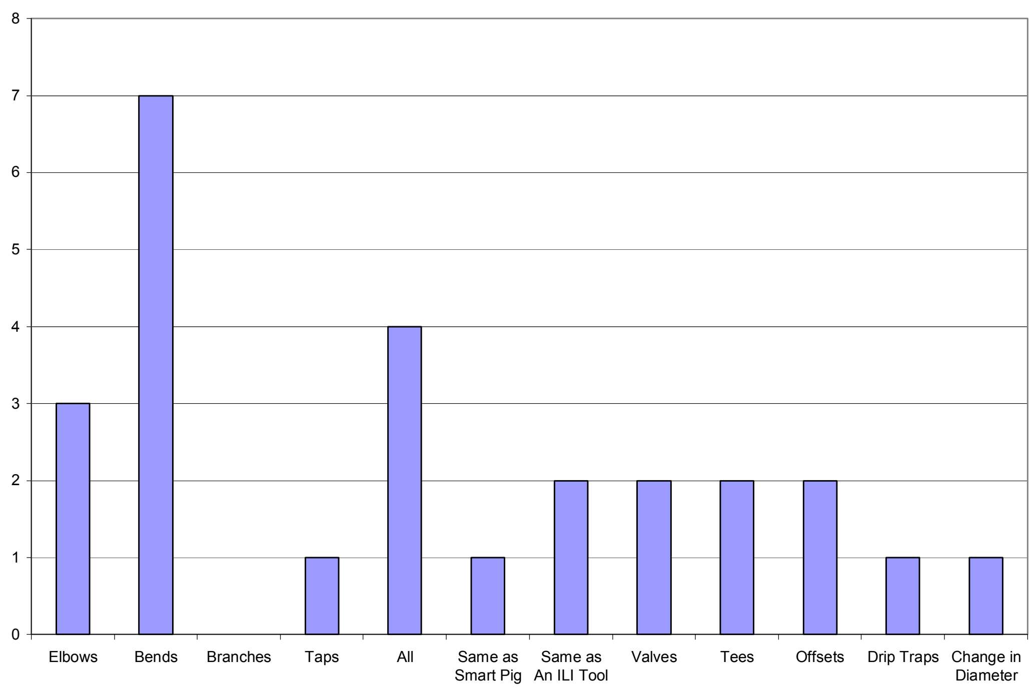


Figure 37 - Potential Obstructions to be Negotiated

6. **For the situations described in Question #3, at what approximate cost would an internal repair method become competitive with existing repair options?**

   Statements and cost figures varied widely from $25,000 to $1,000,000 depending on the perspective of the survey respondent and the terrain that their pipeline systems crossed (see Figure 38).

- Case by case basis
- $1,000/0.3 m ($1,000/ft.) is the benchmark for internal repair as this is the cost for HDD
- Road crossing/HDD cost is $50,000 to $1,000,000 depending on pipe size & distance
- $25,000 per repair site
- $30,000 - $60,000 per repair site
- $50,000 - $70,000 per repair site
- $200,000 per repair site
- Permanent repair less up to $1,000,000
- Twice the cost of conventional repair
- Half the cost of conventional repair

Figure 38 - Cost Comparative Breakpoint for Internal Repair

One reply indicated that internal repair probably would not be competitive with external repair/replacement except in river crossings. Anything cheaper than a new HDD and tie-in would be economical in that case.

One company indicated that the cost is related directly to the amount of time the pipeline would be out of service. For major river/road crossings the technology would be competing with HDD @ $1,000/0.3 m ($1,000/ft.). On land, if one can dig up the area and cut out the affected piece of pipe faster than repairing it, then this is what companies would do since the cost of the pipe and a couple of field welds is inconsequential compared with the cost of having the pipeline out of service. The potential cost option could be the reconstruction of a river crossing or other directionally bored crossing.

One respondent indicated that pipe repairs without external access are typically expensive, thus limiting the types of repairs to critical service lines. Repair costs, if the repair can be quickly mobilized (i.e. leaking system) and be confidently applied, can approach $1,000,000. Therefore the repair would have to serve as a permanent repair.

Another company noted that existing external methods are relatively inexpensive. Repairs required in an area that is inaccessible to current external repair methods can be very expensive and vary by the pipe size, length, and situation. The advantage will be to repair multiple locations or hard to reach locations with minimal excavation. Quite reasonably, several respondents answered that this would have to be examined on a case-by-case basis.

Yet another response indicated that an internal repair tool would be valuable where the pipe is inaccessible. Replacing a road crossing/directional bore could range from $50,000 to $1,000,000 depending on the size of pipe/distance. Other quantitative replies were within the wide range of about $30,000 to $60,000 per repair site in one case; for repairs other than in crossings, about $25,000 per site total including excavation, recoating and backfill; and another reply mentioned about $200,000, while a another response indicated that an internal repair would have to be 50% to 75% of the cost for a conventional repair/replacement to be competitive.

7. **Have new regulatory requirements created a need to improve the fitness for service of existing transmission lines via localized repair or removal of conditions that are acceptable under previous criteria?**

Responses to this question were varied, with six "no" responses and nine "yes" responses. Specific remarks are listed below:

- Not in Canada – new requirements only change documentation effort.
- Regulations will require companies to prove the fitness for purpose of their pipelines rather than improve. There maybe circumstances with HCA's where repairs are now required.
- Some, but I see this as having little impact on the use of this technology. The newly proposed pipeline integrity regulation will make us more aware more quickly to the extent of repair required.
- Under the current Texas Railroad Commission Integrity Rule, and the pending DOT integrity rule, operators are in-line inspecting more pipe than has been done in the past. More repairs may be necessary as a result of more inspections.
- Upcoming inspection requirements may result in the discovery of defects requiring repairs that would not otherwise have been discovered. Increased cost of excavation restoration has been imposed by various municipalities.

8. **What is the estimated number of repairs per year which could potentially be performed by internal repair in your company for the reasons discussed in Questions #3 and #7?**

Responses varied from "none," through "1 repair in 5 years," and in one case "10-75 repairs per site." These answers are summarized in Figure 39, which shows that answers from "1 repair in 5 years," up to "5 repairs per year" were by far the most common response. This indicates a limited expected requirement for such a system, particularly based on expected relative cost to purchase and operate. This supports the suggestion that pigging operators would be the best source to supply and operate such equipment on a contracted basis.

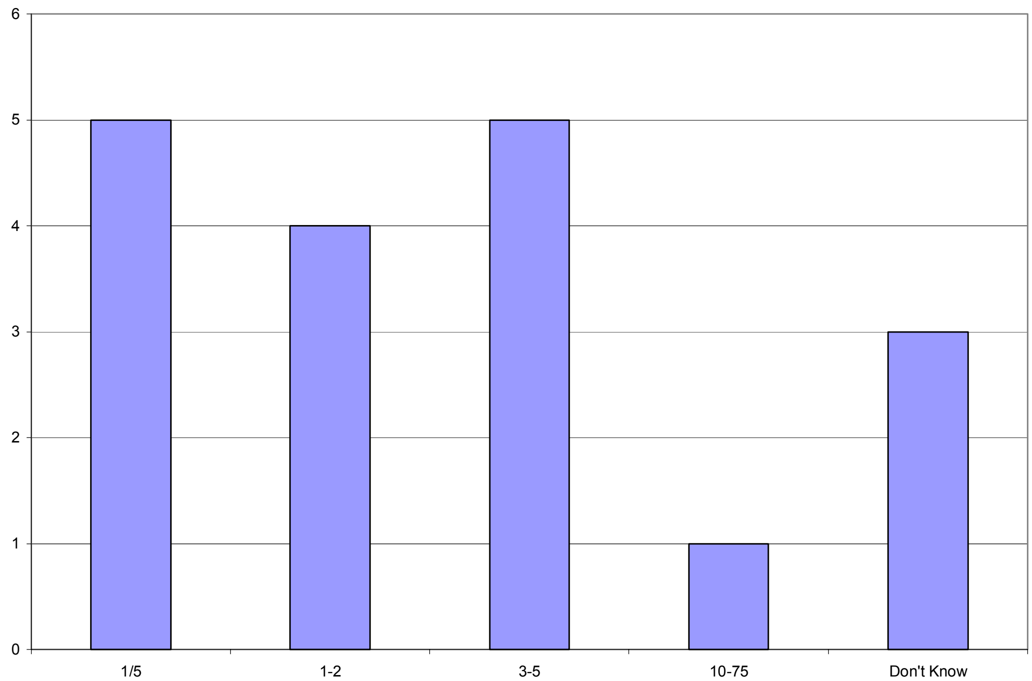


Figure 39 - Estimated Number of Internal Repairs Required Per Year

9. **Comments pertaining to the use/potential use of internal repair.**

Significant individual responses follow:

- Internal methods would be hard to accept as it would be difficult for QA/QC and direct inspection.
- It would have to provide a permanent repair and be piggable to be worthwhile.
- Reinforcing weld joints internally for the in-service pipelines built using welding process, which produced joints with incomplete penetration and lack of fusions.
- Any internal repair sites would have to still be capable of passing an ILI tool and be visible to that tool.
- Internal repair could not impede the ability to pig lines and still be a viable option.
- The major concern would be not to obstruct subsequent ability to assess the pipeline's integrity through internal inspection schemes.
- It is a good to have, whenever necessary.
- A method of inspection of the repaired area may need to be devised.

- It would seem that internal repair methods would have minimal use unless long distances need repaired in congested locations.
- Offshore or underwater (e.g. river crossings, swamps, etc.) offer best economics.
- It would be a valuable tool to have; however, I see no advantage to the process for pipe which is accessible. The only value would be where pipe is inaccessible in a road/stream.
- The use of an internal repair would probably be driven by the discovery of unacceptable corrosion in an inaccessible location. We are currently unaware of this situation in our system.

Part 3 – Need for In-Service Internal Repair

1. **How important is the ability to perform a repair from the inside the pipe while the pipeline remains in service?**

   The majority of survey respondents considered the ability for the pipeline to remain in service while the repair was conducted to be very important (Figure 40), especially if their system was not looped. Companies with looped pipeline systems presumably account for the respondents that considered this to be only somewhat important.

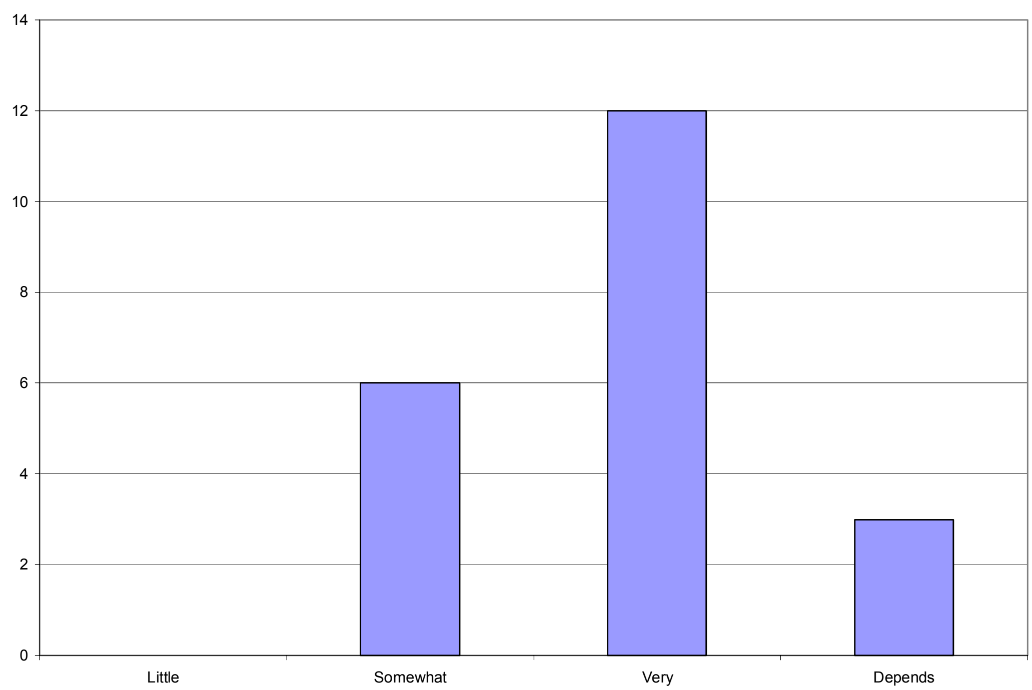


Figure 40 - Importance of Repair While Pipeline Remains In-Service

Significant individual responses:

- If the pipeline could remain in service the probability of using the tool would be very greatly increased.
- The ability to keep a pipeline in service during repair work would be an important factor when considering internal repair as a possible option.
- Very important for the economics of a large diameter transmission line. Keeping the line in-service is a distinct advantage over cut-out.
- For us it would be important because we are not looped.
- Because this may compete with external sleeving, I think that this is real important.
- This repair method would save gas that would normally be lost and would allow service to be uninterrupted. It is very important.
- Minimizing business disruptions to key customers is important. This ability would make such a repair method very important.
- For those pipelines where service cannot be interrupted and where welding is impractical, it is very important.

2. **Would internal repair remain attractive if it was necessary to completely shut down the pipeline (depressurized and evacuated) during the repair?**

   The answers summarized in Figure 41 include six "yes" and three "no," with a variety of other responses in between.

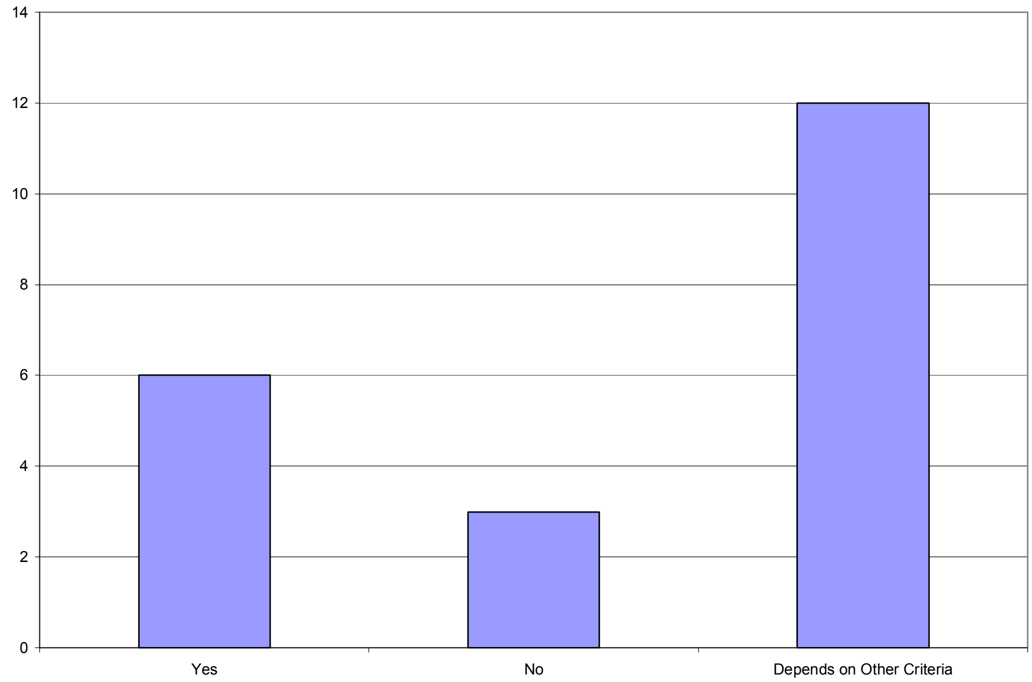


Figure 41 - Still Attractive if Pipeline Must be Shut Down (Depressurized and Evacuated)

Twelve respondents collectively indicated that this depends on a number of other criteria. It would remain attractive if:

- It could eliminate the need to build an ice road in the swamp or dam and flume a river
- in highly congested areas it could be attractive
- Could be where it is too hard to get to the defect location directly like under a river, lake, for offshore and underwater.
- For offshore environments, shut-in is possible, blow-down probably an extra $100k minimum dependant upon gas prices.
- To depressurize and evacuate the gas adds cost that would affect how attractive this type of repair would be.

Depressurized but not evacuated?

Responses are presented in Figure 42: there were eight "yes" responses and two "no" responses.

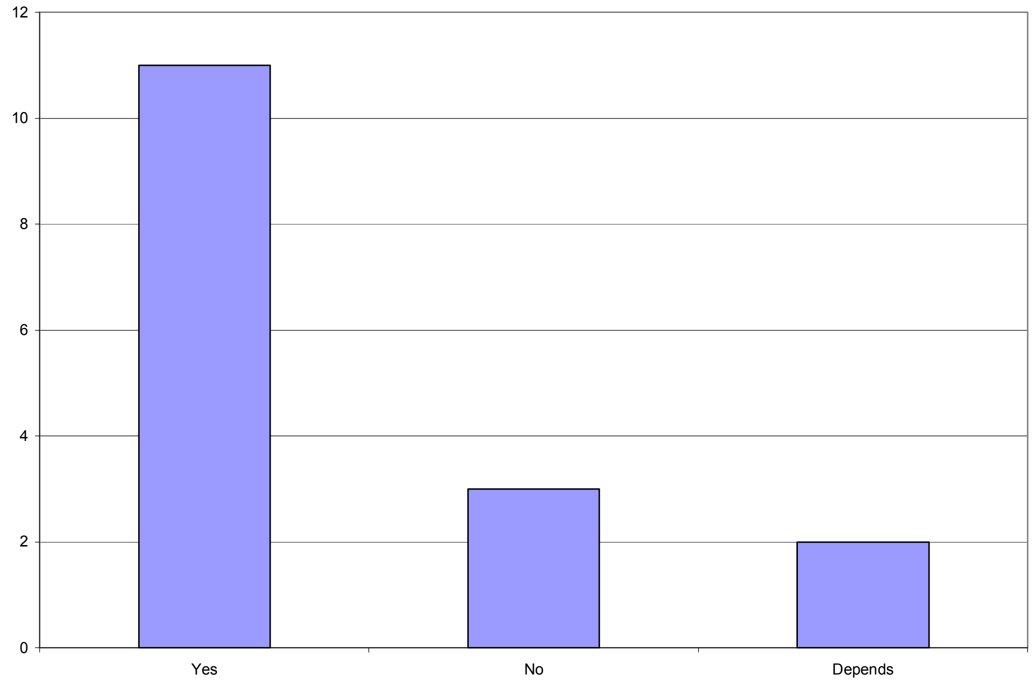


Figure 42 - Still Attractive if Pipeline Must be Depressurized but Not Evacuated

Individual responses:

- Depressurized but still flowing is better.
- Depressurized and not flowing is poor; usually the cost of excavation is minor compared to the outage.
- It is typically not possible to depressurize without a blow down and would not be as attractive.
- There could still possibly be applications but would then be much more a function of the cost of the internal repair versus the cost of external repair or replacement.

Out-of-service (no flow), but remain pressurized?

Responses are summarized in : there were eleven "yes" responses and two "no" responses. If the pipeline must be out-of-service, the amount of pressure remaining and whether or not it is evacuated are probably far lesser considerations.

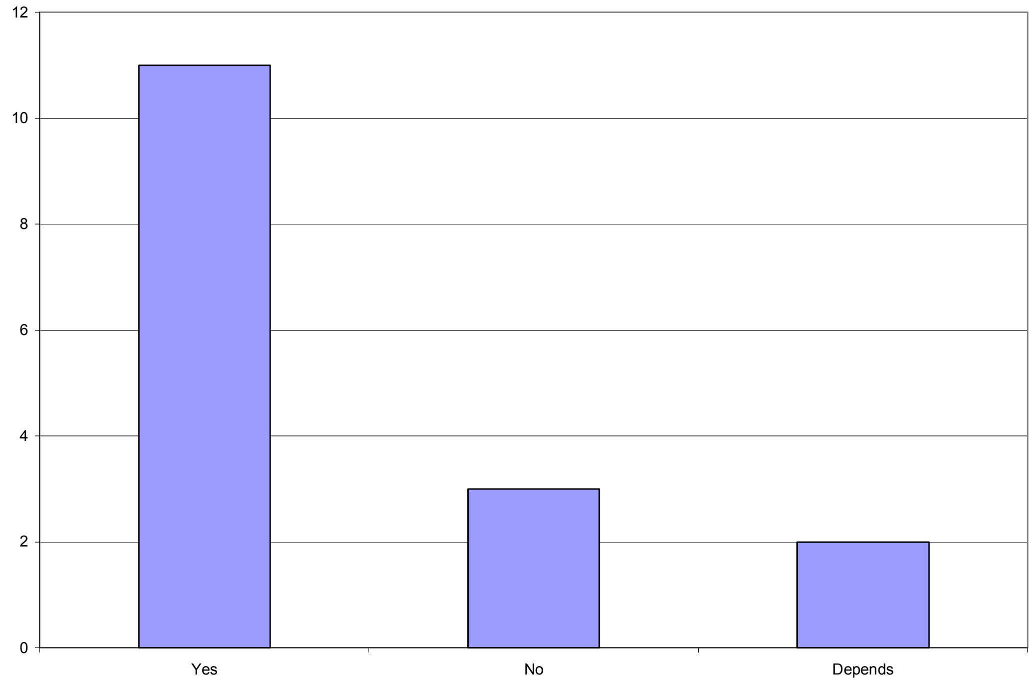


Figure 43 - Still Attractive if Pipeline Must be Out of Service but Pressurized?

Specific responses:

- This is more attractive than the previous two.
- It would be an attractive repair technology under these conditions.
- Leaving the line pressurized would reduce the gas lost, and reduce the potential cost of the repair.

3. Comments pertaining to the need for in-service internal repair.

One response commented that hopefully internal repair would only be required for operators who transport wet or corrosive products. This comment refers to their lack of internal corrosion damage, but also indicates a lack of understanding that the internal repair could be used to repair external corrosion damage. An internal repair appears to be attractive if it reduces the potential for gas lost from blowing down a pipeline, and reduces cost, and/or reduces out-of-service time. Obviously, as the price of gas increases each of the above options will have more impact.

Part 4 – Applicable Types of Damage

1. **What types of external coatings would be found on transmission lines owned by your company?**

   A wide variety of coatings were cited ranging from none (bare steel pipe) through a wide range of bitumastic, coal tar, wax; plastic and composite tapes and wraps; to POWERCRETE® and concrete. The number of responses indicating the use of each coating type is summarized in Figure 44. The top three coating types mentioned were fusion bonded epoxy (FBE), coal tar, and concrete/POWERCRETE®.

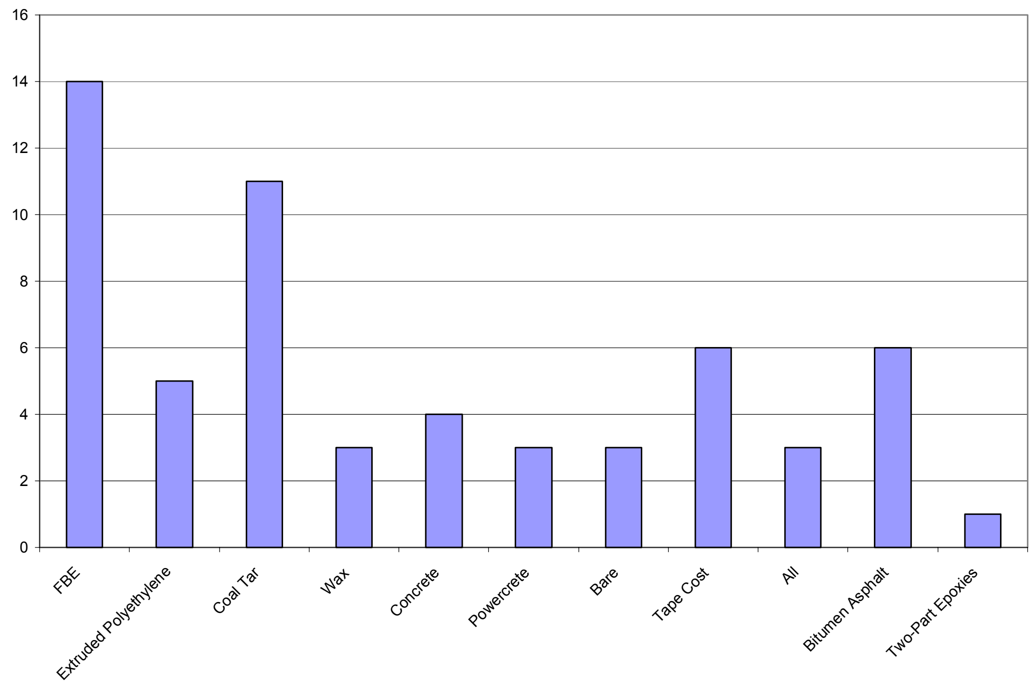


Figure 44 - External Coatings Used

2. **If a repair involving welding from the inside was performed, how important is it to preserve the integrity of the coating?**

   The ten responses are summarized in Figure 45. There were ten responses to this question. One company indicated a level of importance of "important," six companies listed the level as "very important," and three indicated a level of "critical/essential." Five respondents commented that preserving the coating integrity was not very important, as the CP system was considered capable of taking care of local degradation in these instances.

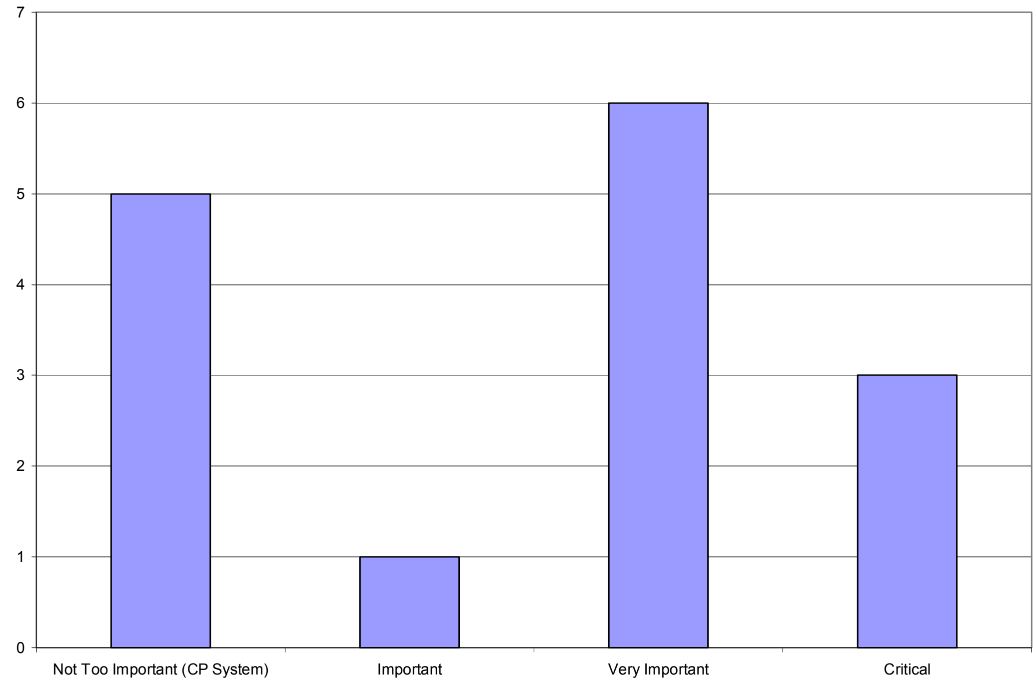


Figure 45 - Maintenance on Coating Integrity

Individual responses:

- It is of utmost importance.
- If the existing coating cannot be maintained, then additional excavations will be necessary and the coating repaired.
- It is very important for large damaged areas since access to site to repair the coating may be difficult.
- It is necessary to try to preserve as much coating as possible since the repair may be applied to an area of external corrosion and we would not be able to assess the root cause of the corrosion or know if it is mitigated.
- An offshore pipeline operator suggested that perhaps considering attaching an anode if necessary, but then again, reasonable access would be required. In offshore applications, a small amount of coating damage is not too much of a problem.

3. **Is your cathodic protection system capable of compensating for relatively small breaches in the coating?**

The results here are shown in Figure 46. All respondents said that the CP system is capable of compensating for relatively small breaches in the coating: there were thirteen "yes" responses and five qualified "yes" responses.

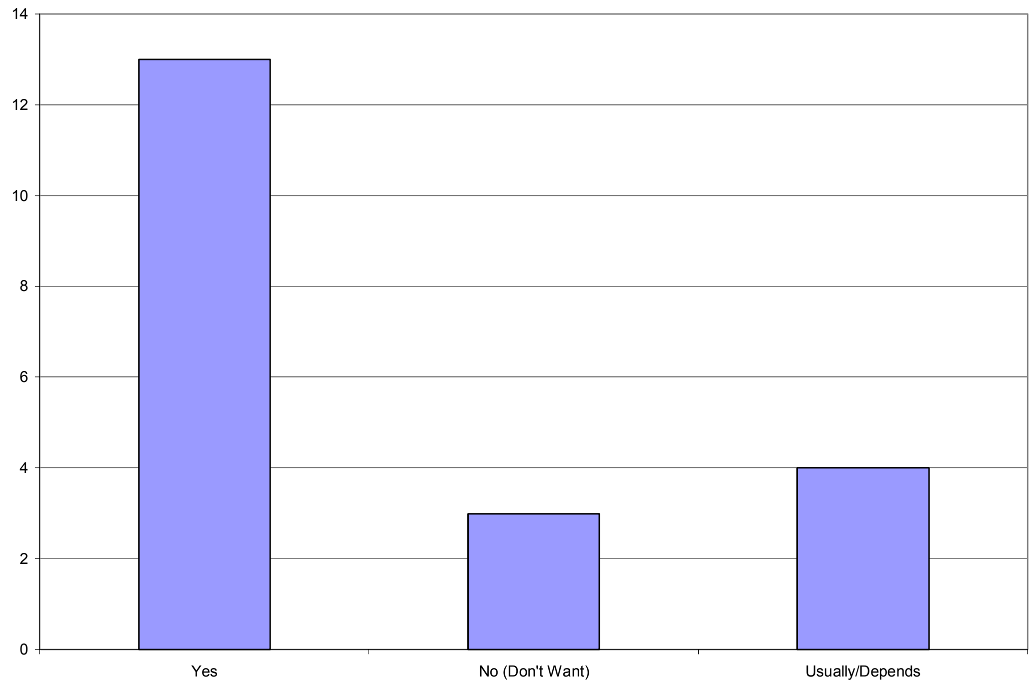


Figure 46 - Is CP System Capable of Compensating for Small Coating Breaches

Comments received:

- Preservation of external coating must be a major consideration.
- Not for disbonded coating.
- It would not meet DOT code requirements under 192/195.
- We do not want any breaches or holidays in their coatings. Coating damage would reduce the attractiveness of this repair system.

One company stated that the CP system can normally compensate, but that one would have to consider that if you had an external corrosion anomaly at the repair site, you may repair it and still have an active external corrosion site. The internal repair would have to be fully pressure containing. Also, if the weld damages good coating, and there is some localized issues with CP protection, that may set-up an active corrosion site at the weld sites (especially if damaged coating is left disbonded and shielded from CP).

4. **Comments pertaining to applicable types of damage.**

   The following three comments were received:

   - I would not want to trade a known likelihood of external coating damage in order to permit an internal repair.
   - I do not think the industry or the regulators would accept a repair method that damages the coating and leaves it in worse shape than originally found
   - If the coating is damaged and CP shielding occurs, then problems would be great. It may be possible to install a Magnesium (Mg) anode at the repair location to spot protect damage to the coating.

Part 5 – Operational and Performance Requirements for Internal Repairs

1. **Two general categories of repairs are being considered, (1) using weld metal to restore a surface and (2) installing an internal sleeve, either metallic or nonmetallic, to provide structural reinforcement of leak tightness. Is it important that the line remain inspectable by pigging after repair?**

   The responses are summarized in Figure 47, which shows the unanimous response was "yes."

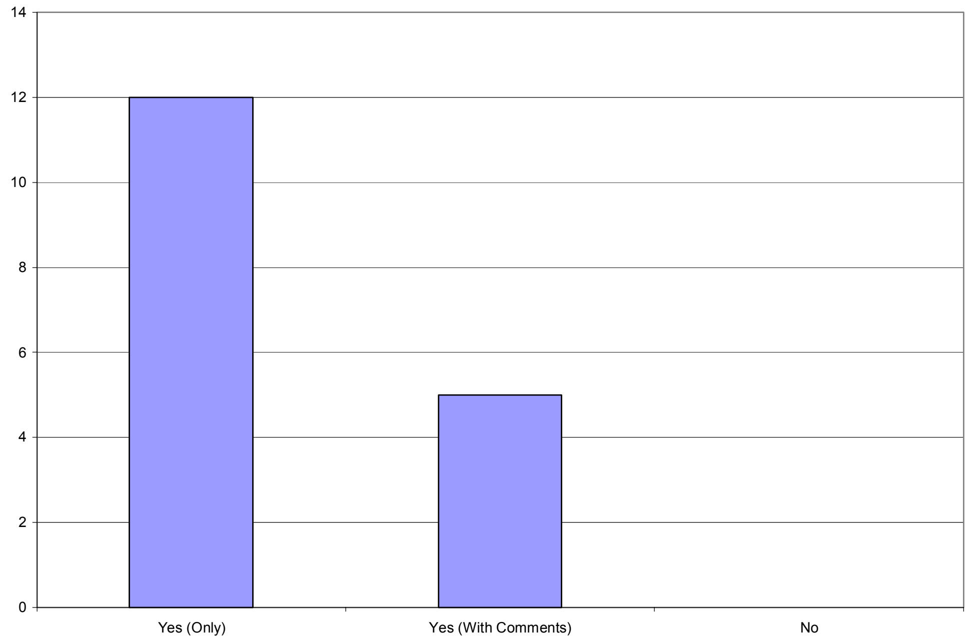


Figure 47 - Inspectable by Pigging

The five "yes" responses contained the following comments:

- Maybe not for a temporary repair. One scenario that comes to mind is in the mountains where there is too much snow to access. A temporary repair could be made and not worry about ILI restriction. Would perform cut-out in the summer.
- Yes, if original line was piggable.
- DOT code 49 CFR 192.150 states that all new lines, or line repaired, will be able to accommodate the passage of an ILI device. Additionally, with the new integrity management rules requiring regular pigging of pipelines, any internal repair would have to allow the passage of a pig.
- Under existing DOT codes it would seem that being able to inspect the line is required. New pipeline integrity regulations may allow for alternative methods.
- For some lines, being “smart- piggable” after repair would be mandatory.

About how far could the repair protrude into the pipe before it would interfere with pigging?

The responses are summarized in Figure 48. Six responses gave a range in the region of 5% to 10% of nominal pipe diameter. Even for relatively small diameter pipe this amount of protrusion could be quite large.

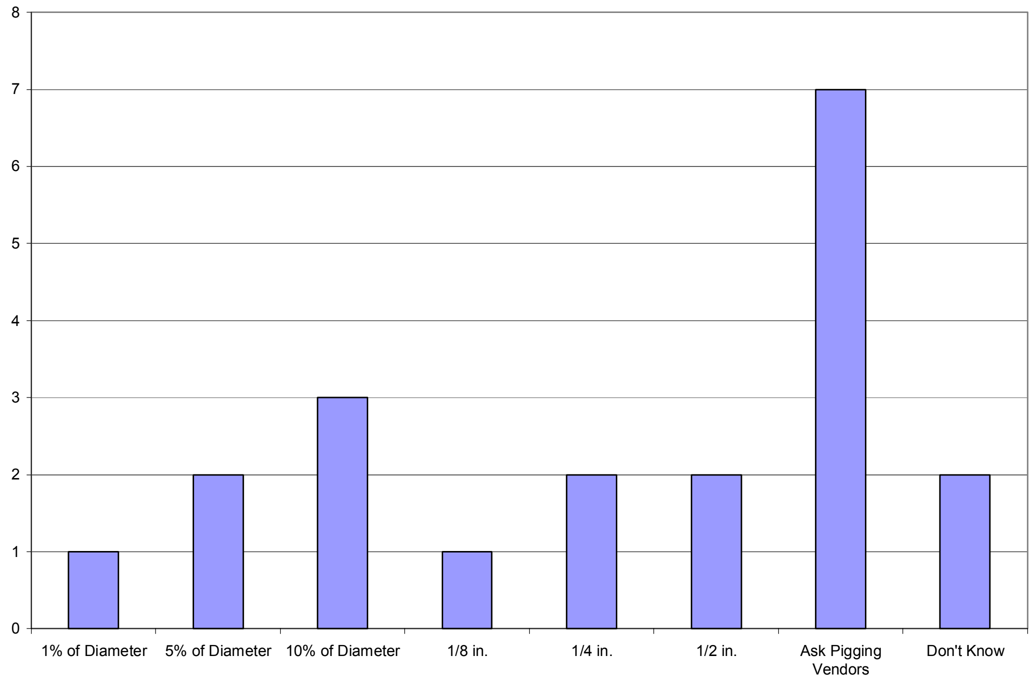


Figure 48 - How Far Could the Repair Protrude Into Pipe Before Interference

Seeking guidance from pigging vendors was suggested by seven of the responses. An amount of 1% of diameter was considered a good number as a rule of thumb in one case. In another, about 1.5 mm (0.6 in.) for a 914 mm (36 in.) pipe (2% of diameter) was mentioned. Several responses mentioned that the type of pig is an important consideration when considering an answer to this question. A "smart pig" was said to be able to accommodate a 10% reduction in diameter.

One response stated that the acceptable protrusion varies depending on the type of pig, pipe size, geometry, and longitudinal length of the restriction. Another response stated that this is dependent upon the type of pigging utilized (e.g., traditional versus smart).

2. **What NDE would your utility require for a repair to an existing longitudinal or circumferential weld?**

Thirteen survey respondents included radiographic testing (RT) or indicated that only radiographic inspection was used or allowed; five indicated that ultrasonic testing (UT) is also permitted; and two responses indicated that magnetic particle inspection (MPI) is also allowed (see Figure 49).

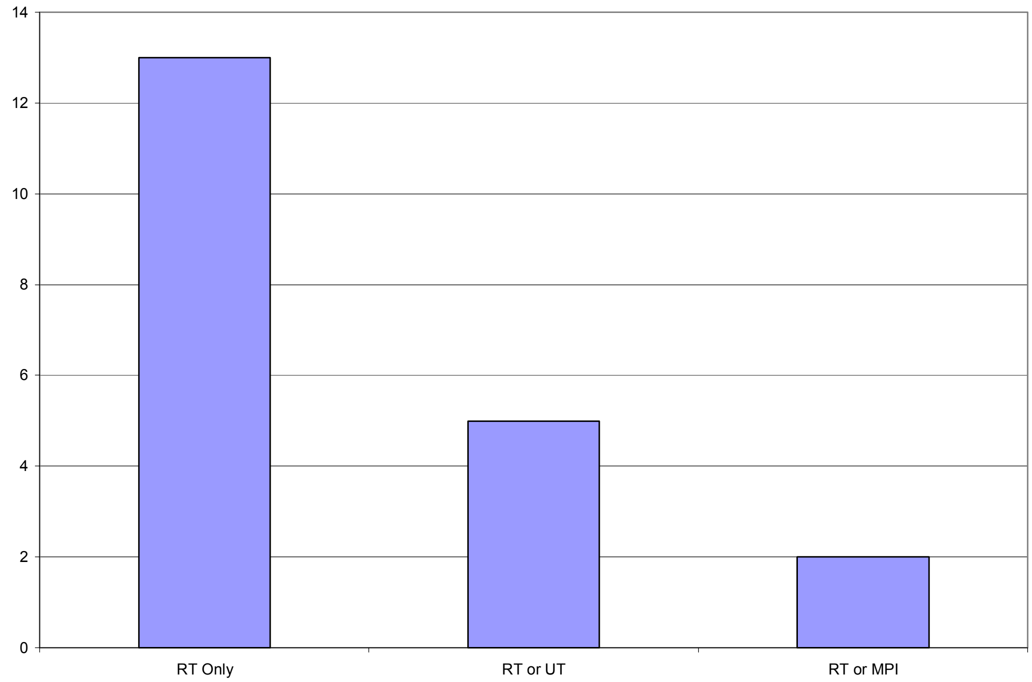


Figure 49 - NDE Required for Repair to an Existing Weld

UT or RT acceptability is judged to code acceptance criteria; specifically ASME B31.8 or B31.4, and CSA Z662 codes were mentioned. In one case it was noted that all welds below 40% SMYS are repaired with a reinforcement sleeve/canopy or removed from the system. In another, it was stated that inspection must comply with Part 192 NDE requirements.

What NDE would your utility require for a welded repair to base metal (e.g. corrosion pitting)?

Figure 50 summarizes the NDE requirements for weld repair to base metal: seven responses include or only use/allow RT, three responses include UT as an acceptable alternative to RT, and three responses include MPI. UT or RT acceptability to code acceptance criteria ASME B31.8 or ASME B31.4 were also mentioned. In one case, it was noted that, at a minimum, all weld repairs are visually inspected and soap tested. Another response indicated that all welds must meet the acceptability standards of the currently referenced edition of the API 1104.

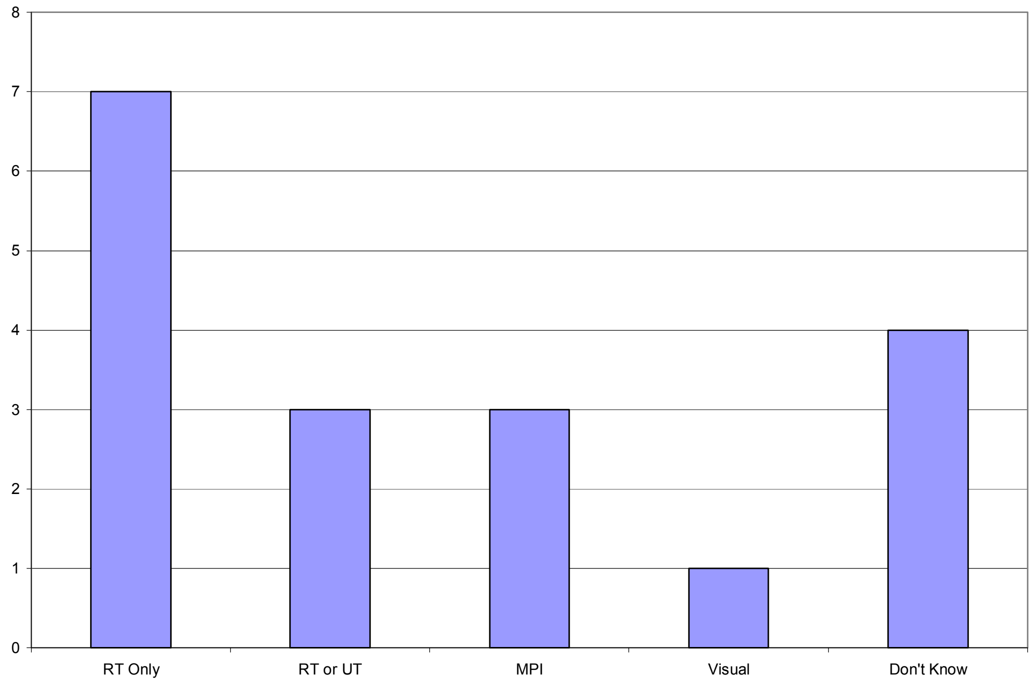


Figure 50 - NDE Required for Base Metal Repair

Could a visual or magnetic particle examination be substituted for radiography in these special circumstances?

The answers to the question were evenly distributed. There were three "yes" only responses, three qualified "yes" answers, three "MPI not visual," three "maybe," three "no," and three "don't know."

Specific comments:

- On fillet welds to the base metal, yes. For the long seam repair, probably not.
- Below 40% SMYS repairs utilizing pre-qualified components with a manufacturer established MAOP require both a visual and a soap test.
- I am not sure how the MPI would be done remotely, but it would have value.

3. **Would the use of internal repair be attractive even if it were considered a temporary repair?**

The answers to this question were mixed, as summarized in Figure 51: eight were "no" responses, three were "yes" only, and eight were qualified "yes" responses.

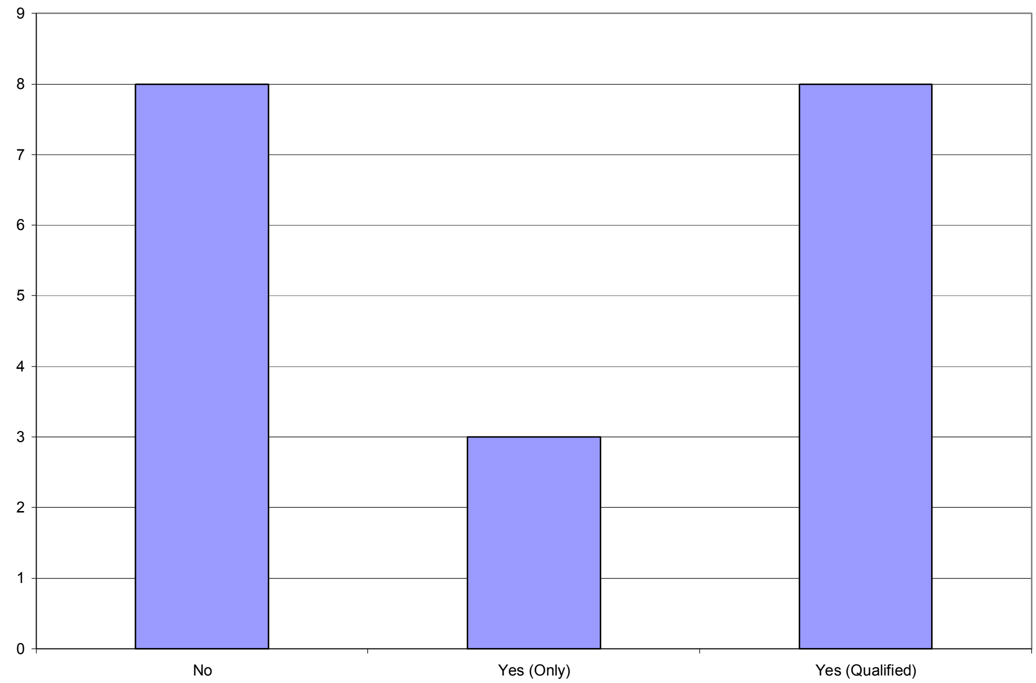


Figure 51 - Would Internal Repair be Attractive Even as a Temporary Repair?

Individual comments:

- In some circumstances, especially in seasonal climates (Canada, mountains, muskeg).
- Yes, if it could be done at relatively low cost (competing with an external sleeve, which is permanent) and with little to no interruption in service.
- Only if the cost was very low.
- If we were using this as a repair, we would rather have a permanent solution.
- Only in a very limited number of cases.
- It could be to allow for scheduling repairs and avoid a shut down during critical times.

- Yes – if it could be accomplished without purging the pipeline.
- Possibly, dependent upon the situation.

4. **Comments pertaining to operational and performance requirements for internal repairs.**

   Specific responses:

   - Repairs would need to be as good as the original pipe; one wouldn't want to create local corrosion cells if the weld filler metal was more/less active than the base metal. This would only be attractive if shutdown is not required and no excavation is required to find the defect.
   - The internal repair should provide for a smooth internal surface. The weld repair would not leave an area subject to long term cracking. CP would not be compromised. Repair will not interfere with future inspections.

Part 6 - General Comments

Please provide any general comments that you may have. For example, comments on an acceptable range of commercial pricing for such a system would be useful (as distinct from a repair cost in Question#6 of Part 2).

Individual responses follow:

- This would not be a piece of equipment that our company would use often enough to justify us owning it. The most effective management of this system may be through a smart pigging company that could offer this as a follow-on service after inspection.
- The internal repair should return pipe to its original serviceability and safety factor. Pricing would determine selection if the repair was appropriate and proven for the type of defect. The costs are going to be weighed against the cost of excavation and the need to purge the line. Quite often, corrosion damage and even some dents can be repaired with steel sleeves using hot tap procedures so the pipeline does not have to be shut down. In swamp conditions, excavation is very expensive due to special equipment and the need to construct isolation dams to keep out the water and use pumps to dry the hole. Of course, offshore repairs require divers and habitats. The internal repair method would have the best economics for underwater repair locations. Some urban areas may have the same type of economics.

- Having an internal welding tool option would be very advantageous for a given situation. That situation is a totally inaccessible location such as a directional bore. For a busy intersection or street alignment where the pipeline can be accessed by conventional method at a high cost, accessing the pipeline externally would be preferred. The repair method would have to be approved by DOT prior to being used.
- The cost depends mainly on the requirements of the repair as in pipe size, length, customer outages, etc. I would say that it has to be considerably less then the standard repair methods to make the new repair method accepted by industry. Because it is internal and the integrity of the repair has to be assessed through some form of NDE, the actual repair strength will be hard to sell.

Task 4.0 - Evaluation of Potential Repair Methods

This task will evaluate potential repair processes to assess their feasibility and suitability for internal pipeline repair. The results from the evaluation will be used to complete Task 5.0. Consideration will be given to each method's applicability to planar or metal loss damage types and their suitability for in-service repair. During the previous reporting period, the Task 2.0 - Technology Status Assessment was used to identify the broad categories of deposited weld metal and fiber-reinforced composite repair technologies that are potentially applicable to gas transmission pipelines from the inside; both were investigated in the preliminary experiments in the Task 4.0 evaluation.

Subtask 4.1 - Identify Potential Repair Methods

To capture the results of Subtask 4.1 activities, a Matrix of Potential Repair Methods (M9) was created to compare and contrast the collective knowledge of, and interest in, specific repair methods that should be emphasized in the experimental portion of this project.

The five major feasibility categories defined for the Matrix:

- Technical Feasibility
- Inspectability
- Technical Feasibility of the Process while the Pipeline is In-Service
- Cost
- Industry Experience with the Repair Method

Each feasibility category was then subdivided into capabilities or characteristics to rank. Each capability/characteristic was assigned a unique weight factor to distinguish its importance in the overall repair process feasibility. Weight factors were based on the quantity of survey responses associated with the feasibility capability/characteristic, with the sum of all weight factors being 100%.

For each potential repair process, individual feasibility capabilities were rated on a scale from (-1) to (5) as defined in Table 1.

Rating	Definition of Rating
-1	Unacceptable
0	Unknown Potential - High Risk
1	Marginal Potential - High Risk
2	Development Required - High Risk
3	Development Required - Low Risk
4	Acceptable - No Risk
5	Ideal - No Risk

Table 1- Key to Ratings in Potential Repair Process Matrices (Table 2 - Table 4)

Each rating was then multiplied by its unique weight factor to arrive at the weighted score for the individual feasibility capability. Five feasibility characteristics were determined to be "show stoppers," given the fact that an unacceptable rating for these capabilities would negate repair process feasibility.

The five show stoppers were identified as:

- Ability to Perform the Process Out-of-Position
- Technical Feasibility of the Process Itself
- Ability of the Process to Match the Strength of the Base Material
- Technical Feasibility of Performing the Process In-Service
- Material Cost

The rating of each show stopper was multiplied by 25 to produce the corresponding weighted score.

The Matrix of Potential Repair Methods is subdivided into three technology specific tables: Potential Welding Repair Methods (Table 2), Potential Liner Repair Methods (Table 3), and Potential Surfacing Repair Methods (Table 4).

Feasibility Category	Weight Factor	Capability or Characteristic to Rank	Welding Processes											
			GTAW		GMAW		FCAW		SAW		Laser		Explosive	
			Rating	Weighted Score	Rating	Weighted Score	Rating	Weighted Score	Rating	Weighted Score	Rating	Weighted Score	Rating	Weighted Score
Technical		Out-of-Position Applicability	2	50	3	75	3	75	-1	-25	2	50	1	25
		Process Technical Feasibility	2	50	3	75	-1	-25	-1	-25	0	0	-1	-25
	5%	Process Robustness	2	10	3	15	2	10	0	0	2	10	1	5
	10%	Repair Permanence	2	20	3	30	2	20	0	0	2	20	1	10
	10%	Process Deployment Risk	2	20	5	50	-1	-10	0	0	1	10	-1	-10
	5%	Remote Operation Feasibility	2	10	3	15	-1	-5	0	0	1	5	0	0
		Ability to Match Strength of Pipe Material	3	75	4	100	4	100	0	0	3	75	3	75
	1%	Ability to Match Pipe Corrosion Resistance	3	3	4	4	4	4	0	0	4	4	3	3
	1%	Ability to Effect Patch Repair	2	2	3	3	-1	-1	0	0	2	2	-1	-1
	5%	Ability to Effect Circumferential Repair	2	10	3	15	-1	-5	0	0	2	10	1	5
	10%	Ability to Negotiate 3D Bends	3	30	3	30	3	30	3	30	0	0	0	0
	5%	Metallurgical Bond	5	25	5	25	5	25	5	25	5	25	2	10
	1%	Mechanical Bond	5	5	5	5	5	5	5	5	5	5	2	2
Inspectability	5%	Ability to Inspect via Pigging	5	25	5	25	-1	-5	0	0	5	25	0	0
	5%	Radiographic Flaw Detectability	5	25	5	25	5	25	5	25	5	25	-1	-5
In-Service	7%	Low Power Required (Process Efficiency)	4	28	4	28	4	28	1	7	-1	-7	-1	-7
	5%	Pipeline Depressurized, But Not Evacuated	2	10	2	10	2	10	0	0	0	0	0	0
	5%	Pipeline Pressurized	0	0	0	0	0	0	0	0	0	0	-1	-5
		Technical Feasibility	2	50	2	50	-1	-25	0	0	0	0	2	50
Cost	5%	Process Development	1	5	3	15	0	0	0	0	1	5	0	0
	10%	Process Application	1	10	4	40	0	0	0	0	0	0	0	0
		Material	2	50	4	100	4	100	0	0	1	25	0	0
History	5%	Industry Experience with Process	0	0	4	20	4	20	0	0	0	0	2	10
	100%			513		755		376		42		289		142

Table 2 - Potential Welding Repair Methods

Feasibility Category	Weight Factor	Capability or Characteristic to Rank	Liner Processes									
			Fiber-Reinforced Composite		Steel Coil		Shape Memory Alloy		Reeled Composite		Solid Expandable Tubulars	
			Rating	Weighted Score	Rating	Weighted Score	Rating	Weighted Score	Rating	Weighted Score	Rating	Weighted Score
Technical		Out-of-Position Applicability	2	50	3	75	3	75	2	50	3	75
		Process Technical Feasibility	2	50	3	75	3	75	2	50	2	50
	5%	Process Robustness	1	5	2	10	2	10	1	5	2	10
	10%	Repair Permanence	2	20	3	30	3	30	1	10	2	20
	10%	Process Deployment Risk	2	20	0	0	0	0	1	10	2	20
	5%	Remote Operation Feasibility	2	10	1	5	0	0	1	5	2	10
		Ability to Match Strength of Pipe Material	2	50	1	25	1	25	-1	-25	2	50
	1%	Ability to Match Pipe Corrosion Resistance	3	3	2	2	2	2	2	2	2	2
	1%	Ability to Effect Patch Repair	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1
	5%	Ability to Effect Circumferential Repair	3	15	2	10	2	10	2	10	2	10
	10%	Ability to Negotiate 3D Bends	3	30	0	0	0	0	1	10	-1	-10
	5%	Metallurgical Bond	0	0	-1	-5	-1	-5	-1	-5	-1	-5
	1%	Mechanical Bond	2	2	0	0	1	1	1	1	2	2
Inspectability	5%	Ability to Inspect via Pigging	2	10	0	0	2	10	0	0	2	10
	5%	Radiographic Flaw Detectability	-1	-5	0	0	0	0	-1	-5	0	0
In-Service	7%	Low Power Required (Process Efficiency)	3	21	3	21	3	21	3	21	2	14
	5%	Pipeline Depressurized, But Not Evacuated	3	15	2	10	2	10	3	15	2	10
	5%	Pipeline Pressurized	3	15	2	10	2	10	3	15	1	5
		Technical Feasibility	3	75	2	50	2	50	3	75	2	50
Cost	5%	Process Development	3	15	2	10	1	5	3	15	2	10
	10%	Process Application	3	30	3	30	2	20	3	30	1	10
		Material	2	50	3	75	-1	-25	3	75	-1	-25
History	5%	Industry Experience with Process	3	15	3	15	-1	-5	3	15	0	0
	100%			495		447		318		378		317

Table 3 - Potential Liner Repair Methods

Feasibility Category	Weight Factor	Capability or Characteristic to Rank	Surfacing Processes							
			Electroless Nickel		Thermal Spray		Carburization		Explosive	
			Rating	Weighted Score	Rating	Weighted Score	Rating	Weighted Score	Rating	Weighted Score
Technical		Out-of-Position Applicability	1	25	0	0	0	0	1	25
		Process Technical Feasibility	1	25	1	25	-1	-25	0	0
	5%	Process Robustness	0	0	1	5	0	0	2	10
	10%	Repair Permanence	0	0	1	10	0	0	2	20
	10%	Process Deployment Risk	0	0	0	0	0	0	0	0
	5%	Remote Operation Feasibility	0	0	0	0	0	0	0	0
		Ability to Match Strength of Pipe Material	0	0	-1	-25	0	0	2	50
	1%	Ability to Match Pipe Corrosion Resistance	1	1	2	2	0	0	3	3
	1%	Ability to Effect Patch Repair	0	0	2	2	0	0	0	0
	5%	Ability to Effect Circumferential Repair	0	0	2	10	0	0	2	10
	10%	Ability to Negotiate 3D Bends	0	0	0	0	0	0	0	0
	5%	Metallurgical Bond	2	10	-1	-5	0	0	2	10
	1%	Mechanical Bond	2	2	2	2	0	0	1	1
Inspectability	5%	Ability to Inspect via Pigging	0	0	0	0	0	0	1	5
	5%	Radiographic Flaw Detectability	2	10	2	10	0	0	2	10
In-Service	7%	Low Power Required (Process Efficiency)	0	0	0	0	0	0	0	0
	5%	Pipeline Depressurized, But Not Evacuated	0	0	0	0	0	0	-1	-5
	5%	Pipeline Pressurized	0	0	0	0	0	0	-1	-5
		Technical Feasibility	3	75	1	25	0	0	-1	-25
Cost	5%	Process Development	0	0	0	0	0	0	0	0
	10%	Process Application	0	0	0	0	0	0	0	0
		Material	0	0	0	0	0	0	0	0
History	5%	Industry Experience with Process	-1	-5	1	5	0	0	0	0
	100%			143		66		-25		109

Table 4 - Potential Surfacing Repair Methods

Figure 52 is a bar chart that contains the total weighted scores for each potential repair technology. It is apparent that, of the three broad categories of repair (welding, liners, and surfacing), repair methods that involve welding are generally the most feasible. Of the various welding processes, GMAW is the preferred method. The primary factors that make GMAW the most feasible are process technical feasibility and robustness, and industry familiarity with the process. The second most feasible of the three broad categories is repair methods that involve internal liners. Of these, fiber-reinforced composite liners are the most promising. The primary factors that make fiber-reinforced composite liners the most feasible are the ability to match the strength of the pipe material and negotiate bends, and their corrosion resistance. The advantage of using a fiber-reinforced composite liner is somewhat offset by its material cost which is anticipated to be comparatively higher than that of a steel coil liner.

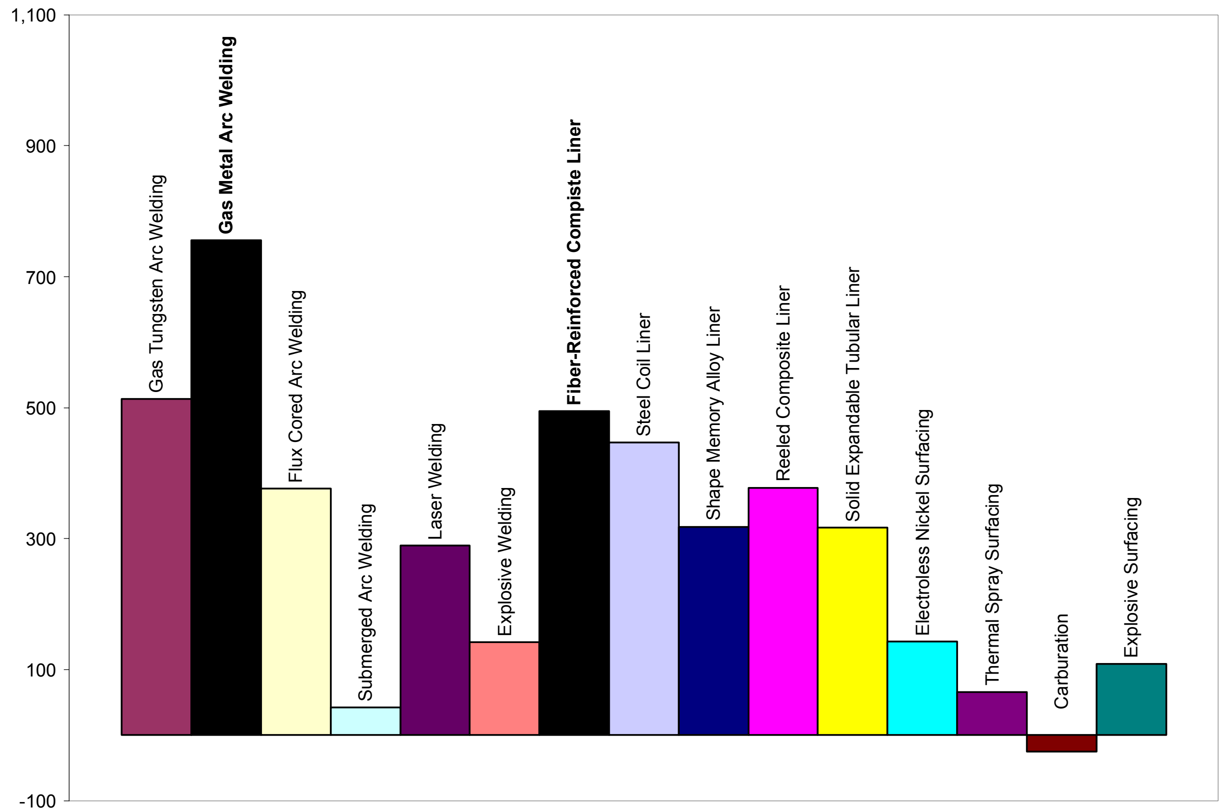


Figure 52 - Weighted Scores of Potential Repair Methods

Based on the results of this evaluation of potential repair methods, the experimental portion of the project will continue to focus on the development of a repair process that involves the use of GMAW welding and on the development of a repair process that involves the use of fiber-reinforced composite liners, unless directed to do otherwise by National Energy Technology

Laboratory (NETL). If, during the course of the experimental portion of the project, one of these repair methods proves to be less feasible than anticipated, it will be dropped in favor of the other. This subtask is complete.

Subtask 4.2 - Develop Internal Repair Test Program

During the previous and current reporting periods, all of the experimental work pertaining to the evaluation of potential repair methods was focused on fiber-reinforced composite repairs. During this reporting period, preliminary welding parameters were developed. Further development of welding parameters was delayed pending receipt of the PG&E internal welding system and pending receipt of 559 mm (22 in.) diameter pipe material from Panhandle Eastern for which the PG&E system was specifically designed.

Deposited Weld Metal Repairs

During the previous reporting period, a preliminary test program for deposited weld metal repairs was developed. This test program initially focused on developing GMAW parameters necessary to complete an internal circumferential weld deposition repair.

Arc welding processes offer a viable repair method that can be applied from the inside of a gas transmission pipeline. There are several arc welding processes that can be operated remotely. Based on the survey and assessment of candidate arc welding processes conducted during this reporting period, the GMAW process was the most likely choice for this application. It offers a good combination of simplicity, high productivity, robustness, and quality that are required for this welding repair application. Arc welding processes are routinely used to externally repair pipelines. However, repair from the inside offers new challenges for process control since welding will need to be performed remotely. In addition, since the intent is to leave the pipeline in the ground, there are several variables that will affect the welding process and quality. Soil conditions have the potential to influence heat removal during welding thereby altering the fusion characteristics, welding cooling rate, and mechanical properties. The effects of welding on the external coating used to protect against corrosion will need to be evaluated to assure future pipeline integrity. Finally, if welding was performed in-service, the pressure and flow rate of the gas will have a strong effect on the equipment design of the welding process. New process equipment technology will be required to shield the welding process from methane contamination and cope with higher gas pressures. A significant deliverable will be the development of an equipment specification defining all the functional requirements for an internal repair welding system.

During this reporting period, preliminary welding procedures were developed using the 6-axis robot. The objective of these tests was to establish deposit layer parameters that could be used to make ring, spiral or patch repairs. Since the objective for these repairs is to reinforce the wall thickness, the bead shape criteria was to make flat deposits. If a large area needed repaired, multiple weld beads would be tied to each other. Here, bead overlap parameters need to be developed to optimize the uniformity of the entire repair deposit area. In many ways, the parameters that were developed are similar to cladding procedures. The ideal weld bead shape would have uniform thickness across the weld section except near the weld toes which should taper smoothly into the base material (Figure 53). Smooth toes promote good tie-ins with subsequent weld beads. The fusion boundary should be uniform and free from defects.

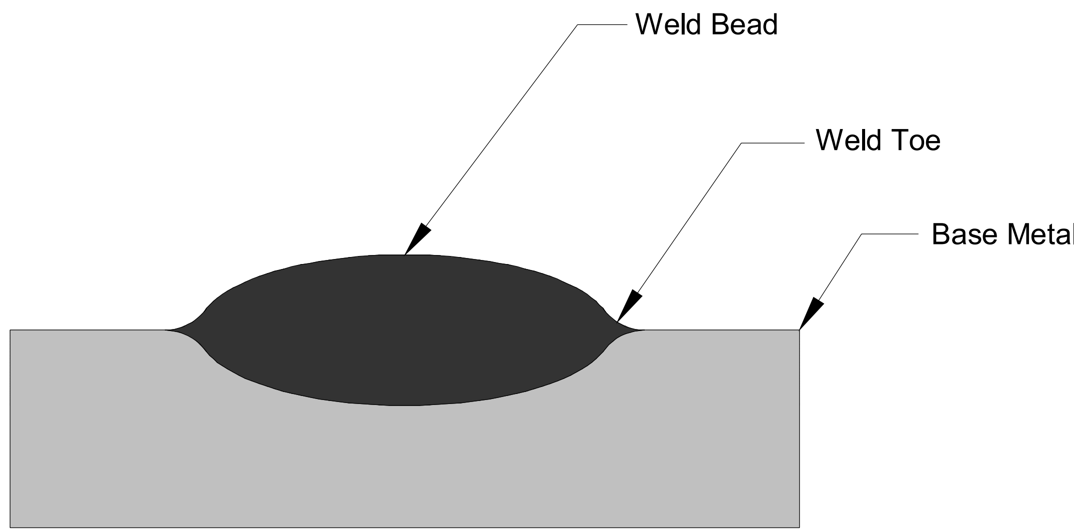


Figure 53 - Weld Bead Shape Diagram

Using the robot welding system, ring welding procedures using weaving were developed for several bead widths (Figure 54). This figure shows the location were the first half of the ring was stopped and the second half was started in the overhead position. This was not an ideal stop-start location but was required with the robot to manage the welding cables. If start-stops were required to complete a repair, it would be preferred to have them positioned at a different location around the circumference, ideally in the flat position. Tie-in parameters will need to be optimized for each possible starting position once preferred bead shape weaving parameters are selected. A true orbital bore welding machine, like the Bortech, would have a current and shielding gas commutation system to provide infinite rotations without cable problems thereby minimizing stop-starts.

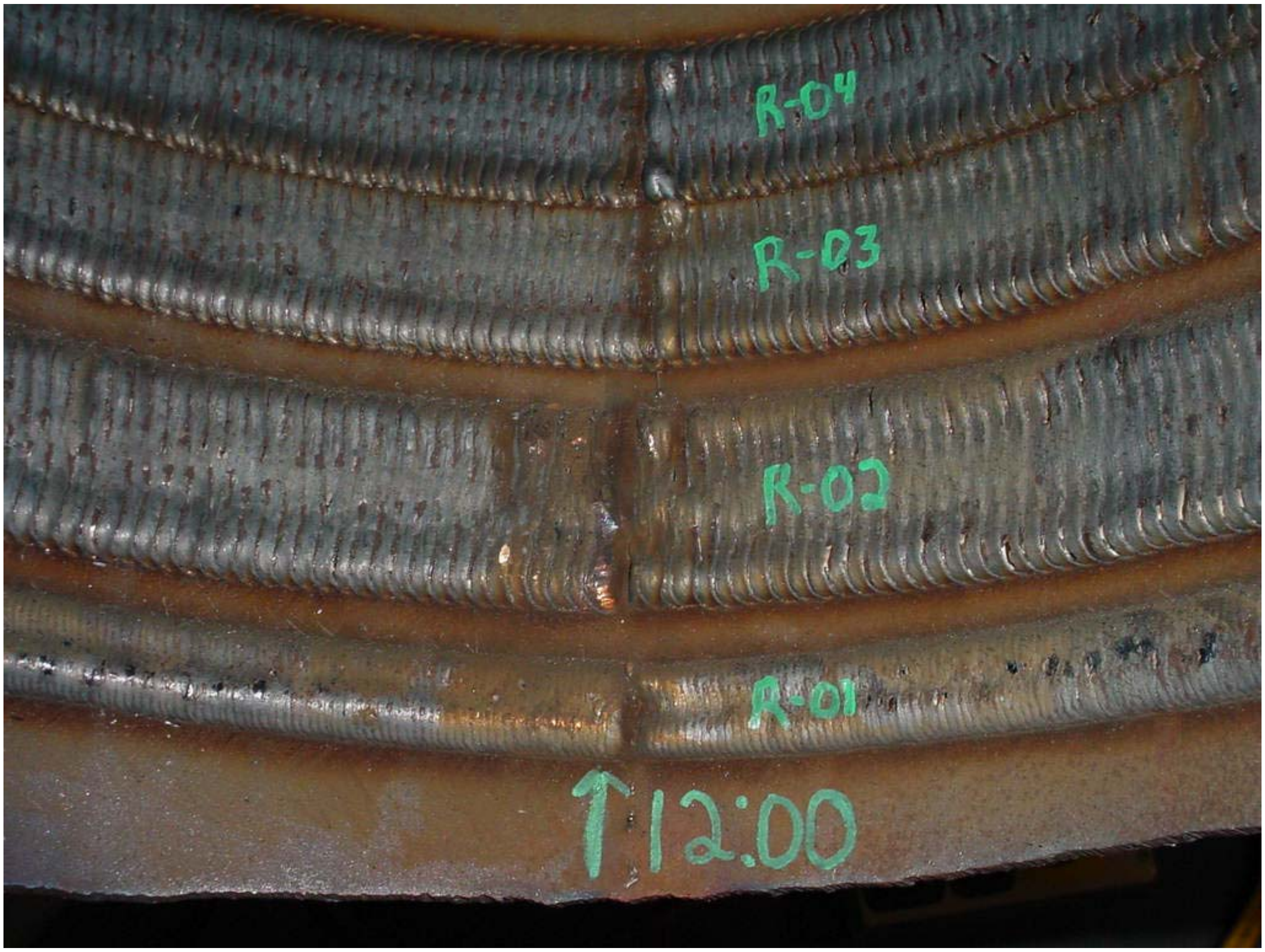


Figure 54 - Tests R-01 through R-04 at 12:00 (Note the Poor Tie-Ins for R-01 through R-03)

When welding is initiated, the pipe is near room temperature. The weld bead profile at the start (Figure 55 and Figure 56) slowly changes as a steady-state temperatures are built in the material based on the heat input of each welding procedure. In general, most weld starts appeared more convex based on the low starting material temperature.

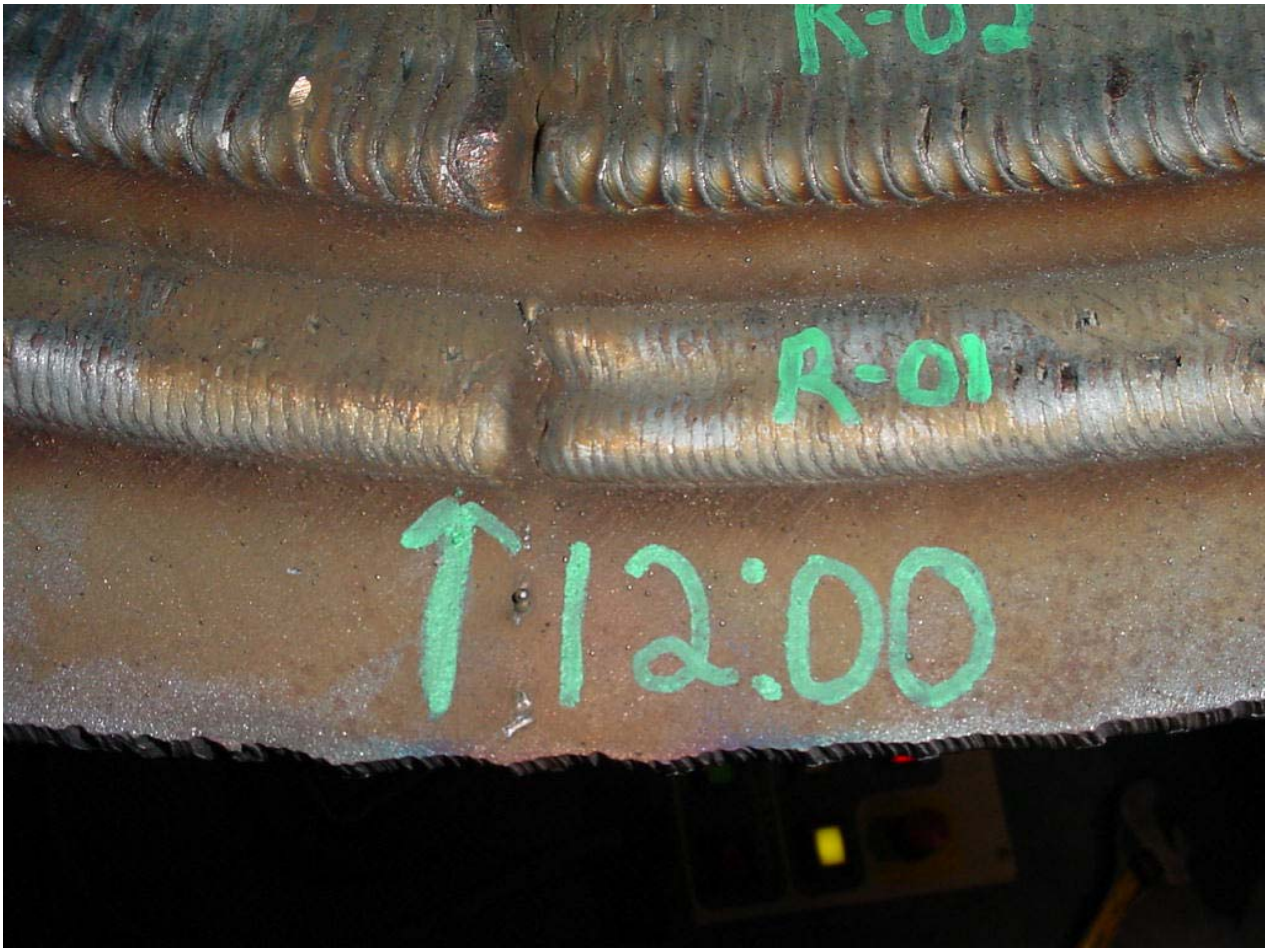


Figure 55 - Test R-01 at 12:00 Showing Poor Stop-Start Tie-In

Figure 56 - Tests R-03 and R-04 at 12:00 Showing Better Stop-Start Overlap. (Note that test R-04 was overlapped on test R-03 to provide a larger deposit layer.)

The preferred welding parameters were based on optimizing the bead shape in the steady state (Figure 57). For internal repair of pipelines, a programmable weld controller could be used to use higher welding heat input at the weld start. This would provide better weld bead start quality. Once welding the start parameters could be ramped in the steady-state parameters to provide uniform bead shape.

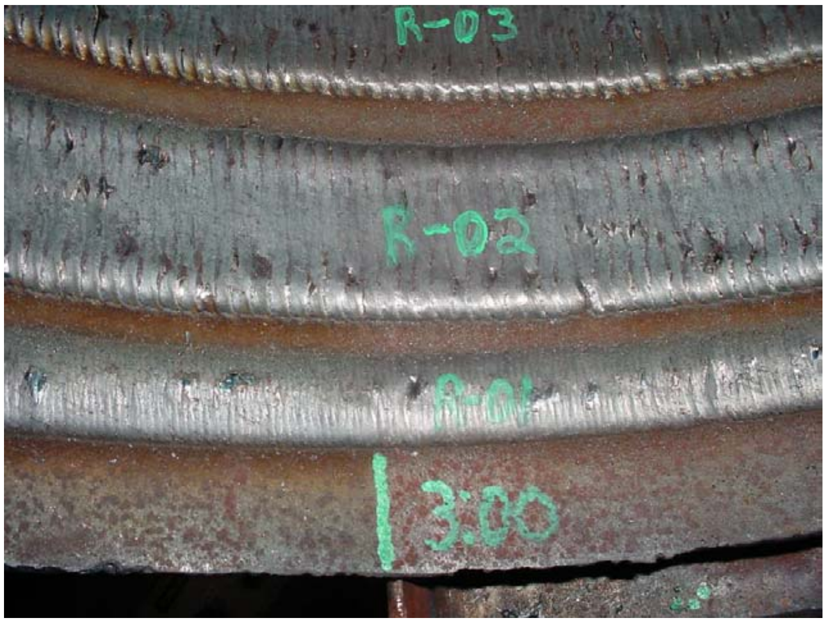


Figure 57 - Tests R-01 and R-02 at 3:00 Showing Steady-State Bead Shape

Table 5 contains the welding parameters for the weave bead procedures used. Wire feed speeds varied from 5.08 to 6.35 mpm (200 to 250 ipm). This was better than preliminary tests with the Bortech system which were at 4.45 mpm (175 ipm) and resulted in stringer beads that had a ropy appearance.

Weld No.	Specimen No.	Wire Feed Speed mpm (ipm)	Voltage (Trim)	Travel Speed mmpm (ipm)	Weave Amplitude mm/side (in/side)	Weave Frequency (Hz)	Dwell Time (seconds)	Comment
1	R-01	5.08 (200)	0	76.2 (3)	9.9 (0.39)	0.6	0.6	Good for a narrow repair.
2		5.08 (200)	0	127 (5)	25.4 (1.00)	0.6	0.2	Too fast. Zig-zag pattern results.
3	R-02	6.43 (253)	-4	25.4 (1)	25.4 (1.00)	0.1	0.6	• Bad at overhead position • Turned voltage to -4 • Dwell is not needed
4	R-03	6.43 (253)	-4	25.4 (1)	25.4 (1.00)	0.1	0.0	6 mm (0.25 in.) overlap at overhead position to tie two welds together - porosity resulted.
5	R-04	6.43 (253)	-4	25.4 (1)	25.4 (1.00)	0.1	0.0	• 6 mm (0.25 in.) overlap at overhead and flat positions. • Centerline is 22 mm (0.88 in.) from previous weld edge (3 mm (0.125 in.) circumferential overlap). • Good circumferential tie on uphill side. • Poor circumferential tie on downhill side. • Need more wire feed speed due to bad fusion on downhill side
6	R-05	7.62 (300)	-4	25.4 (1)	25.4 (1.00)	0.1	0.0	• 6 mm (0.25 in.) overlap at every 30 degrees. • See Table 6 for tie-in quality at each position

Table 5 - Welding Parameters for Specimens R-01 through R-05

Table 6 contains the tie-in quality at each clock position for specimen R-05.

Position (clock)	Tie In Quality (poor/OK/good)
12:00	Poor
1:00	Poor
2:00	Poor
3:00	Poor
4:00	OK
5:00	Good
6:00	Good
7:00	Robot problem
8:00	Good
9:00	Good
10:00	Good
11:00	OK

Table 6 - Tie-In Quality at Each Clock Position for R-05

To further improve starting bead shape some additional tests were performed using 7.62 mpm (300 ipm) wire feed speed (Figure 58). These tests were used by the technician to study the precise location for starting on a stop and to evaluate gravity effects. As shown by these tests, the use of higher wire feed speeds which produce higher heat input can be used to improve start bead shape. No additional procedures were developed with the 6-axis robot.

12:00 – Too Much Overlap

1:00 – Too Much Overlap

2:00 – Slightly Better

3:00 – Some Convexity

4:00 – Okay

5:00 – Good

6:00 – Good

7:00 – Bad Appearance Due Robot Program Error

8:00 – Good

9:00 – Good

10:00 – Good

11:00 – Okay

Figure 58 - Tie-In Tests Using Parameters R-05 Every 30 Degrees Around One Ring Deposit

During the next reporting period, successful welding procedures will be transferred to the Magnatech system which will be used for pipe tests and demonstrations. Additional procedures will need to be developed once the test plan is created for evaluating internal repair using weld deposition.

Fiber-Reinforced Liners

During this reporting period, a preliminary test program of small-scale experiments for fiber-reinforced composite repairs was developed and initiated in order to take advantage of existing tooling for the RolaTube product.

Following the installation of end caps, all four pipe sections were hydrostatically pressurized to failure. All four pipe sections failed in the areas of simulated corrosion damage. The two pipes with long shallow damage representative of general corrosion resulted in ruptures (Figure 59 and Figure 60) and the two pipes with short, deep damage representative of a deep isolated corrosion pit developed leaks (Figure 61 and Figure 62). The hydrostatic testing results are shown in Table 7.

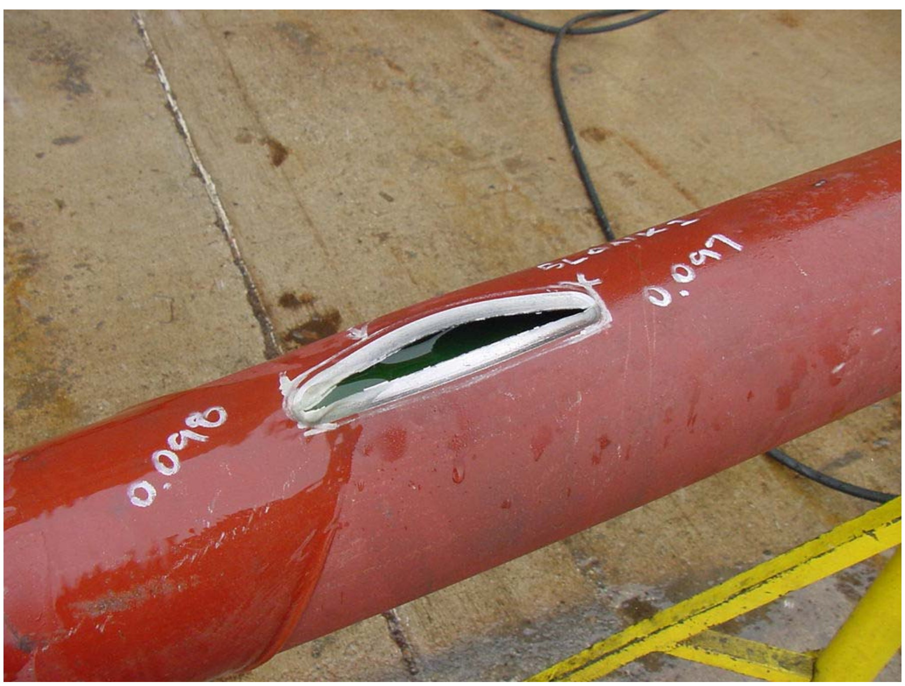


Figure 59 - Pipe Section with Long, Shallow Simulated Corrosion Damage – Without Liner – Following Hydrostatic Pressure Test

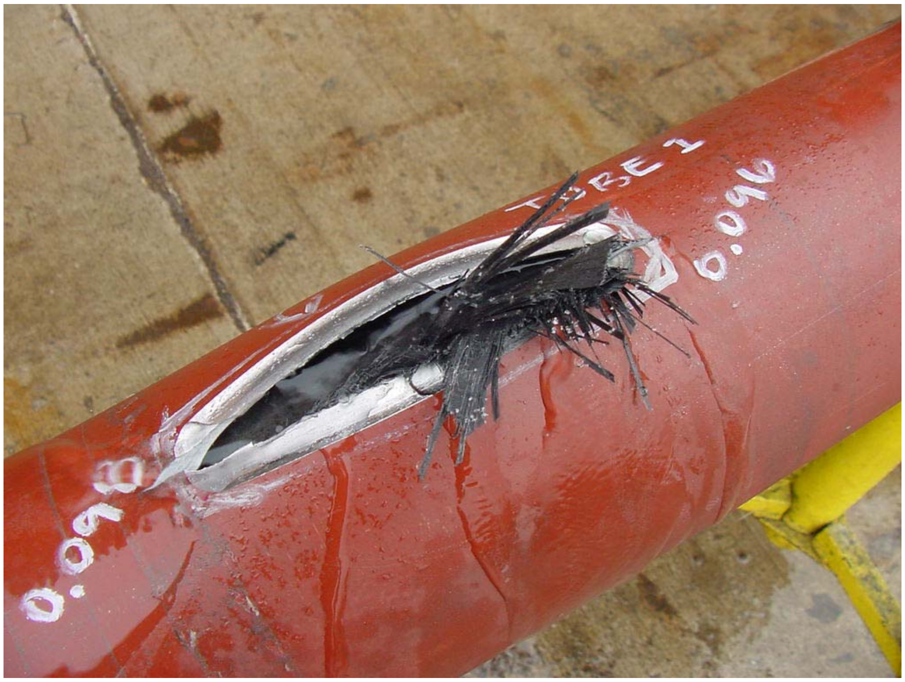


Figure 60 - Pipe Section with Long, Shallow Simulated Corrosion Damage – With Liner – Following Hydrostatic Pressure Test

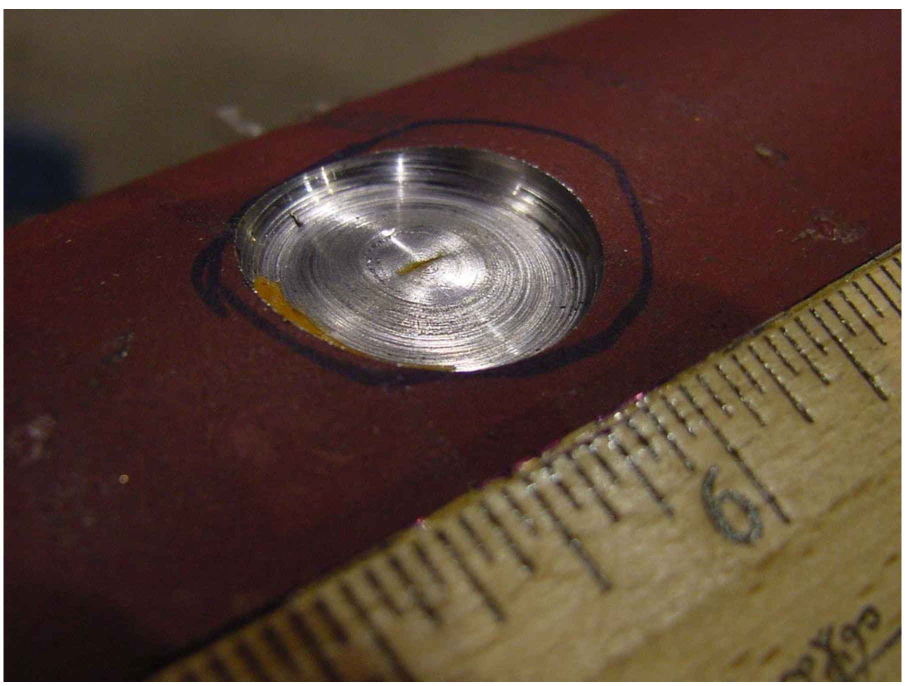


Figure 61 - Pipe Section with Short, Deep Simulated Corrosion Damage – Without Liner – Following Hydrostatic Pressure Test

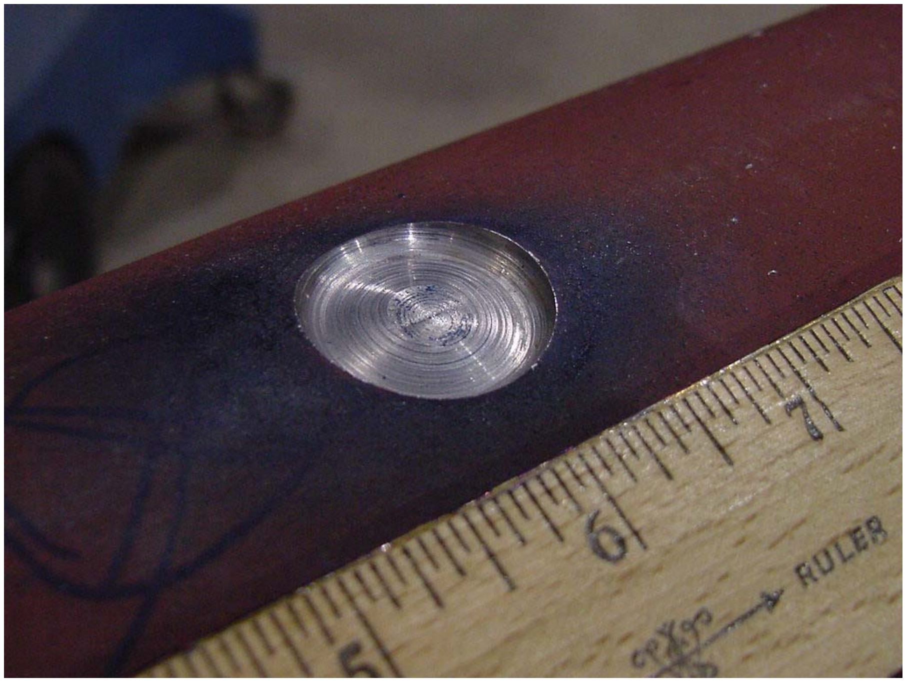


Figure 62 - Pipe Section with Short, Deep Simulated Corrosion Damage – With Liner – Following Hydrostatic Pressure Test

Simulated Corrosion Damage	Liner	Hydrostatic Failure Pressure MPa (psi)	Failure Mode/Location
Long, Shallow	No	23.6 (3,431)	Rupture in simulated corrosion damage
	Yes	23.9 (3,472)	Rupture in simulated corrosion damage
Short, Deep	No	25.8 (3,750)	Leak in simulated corrosion damage
	Yes	27.7 (4,031)	Leak in simulated corrosion damage

Table 7 - Hydrostatic Pressure Testing Results

The failure pressures for the pipes with the liners were only marginally greater than the pipes without the liners (i.e., 23.9 vs. 23.6 MPa (3,472 vs. 3,431 psi) for the pipe samples containing long shallow damage and 27.7 vs. 25.8 MPa (4,031 vs. 3,750 psi) for the pipe samples containing short, deep damage), indicating that the liners were generally ineffective at restoring the pressure containing capabilities of the pipes.

A postmortem analysis of the first four hydrostatic burst tests in pipe sections with simulated corrosion was conducted. So as not to damage the liner, water jet cutting was used to section the pipe sample containing the round-bottom longitudinal slot with the liner installed. The results indicate that the liner did rupture (Figure 63 and Figure 64), indicating that disbonding was not an issue.

Figure 63 - Water-Jet Cut Section through Pipe Sample Containing Round-Bottom Longitudinal Slot with Liner Installed

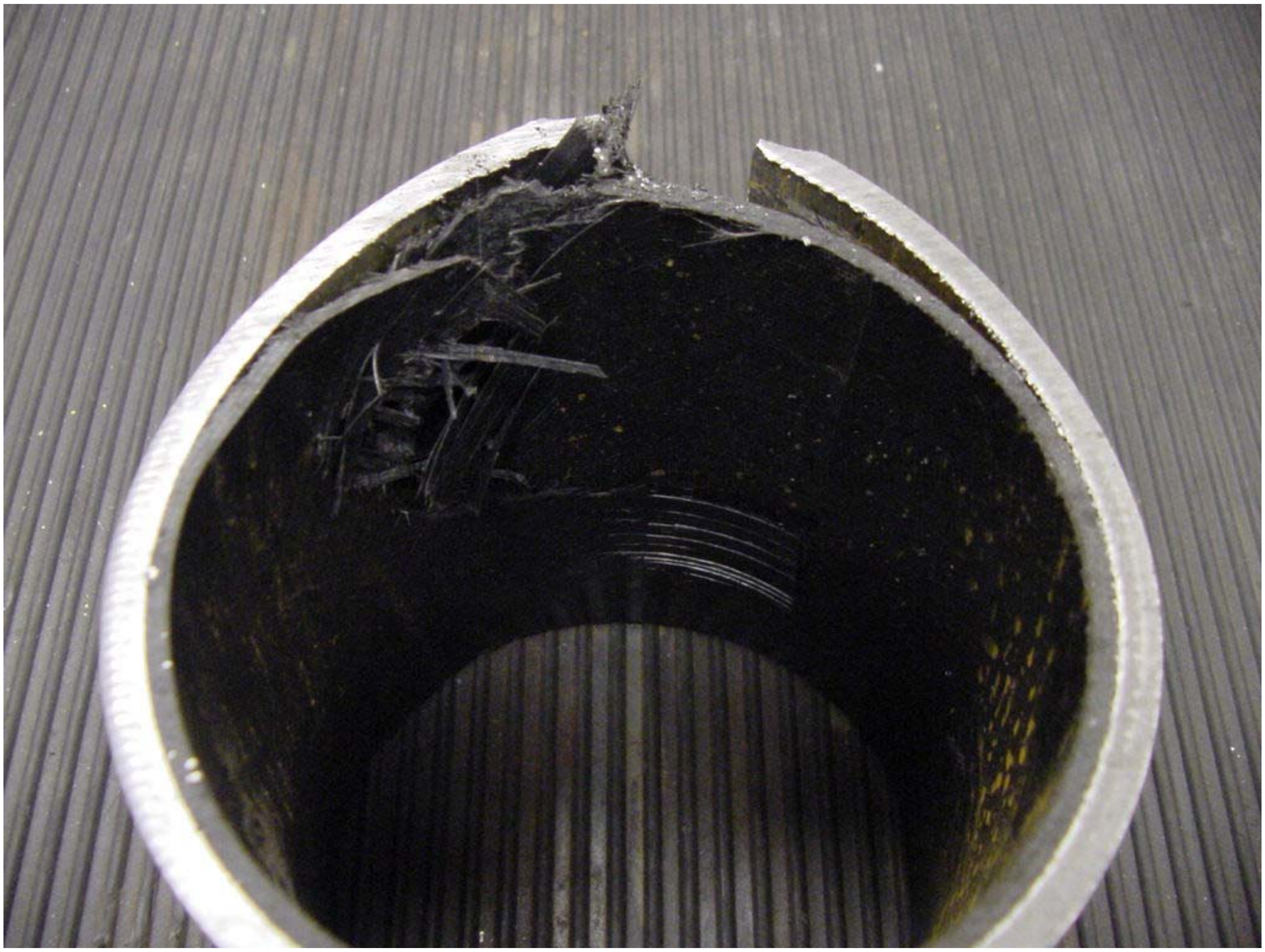


Figure 64 - Pipe Sample Containing Round-Bottom Longitudinal Slot Showing Rupture of Liner Material

Postmortem test results also indicate that the difference in modulus of elasticity between the steel and the liner material prevents the liner from carrying its share of the load. The modulus of elasticity for steel is approximately 206.8 GPa (30 x 10^6 psi). Tensile testing was carried out to determine the modulus of elasticity for the glass/polypropylene liner material that was used (Table 8 and Figure 65). The mean value for the modulus of elasticity for the liner material was measured to be approximately 15.2 GPa (2.2 x 10^6 psi). Because the liner material has a significantly lower modulus of elasticity than the steel pipe, as pressure in the lined pipe increases, the stiffness of the steel prevents the composite liner material from experiencing enough strain to share any significant portion of the load.

	Stress at Break MPa (ksi)	Strain at Break (%)	1% Secant Modulus MPa (ksi)
Trial 1	486.6 (70.58)	4.34	15,123.4 (2,193.394)
Trial 2	557.6 (80.88)	4.21	17,166.7 (2,489.741)
Trial 3	492.0 (71.36)	5.21	17,316.5 (2,511.472)
Trial 4	371.5 (53.89)	5.02	14,103.5 (2,045.482)
Trial 5	460.9 (66.85)	4.56	14,347.9 (2,080.924)
Trial 6	154.7 (22.45)	4.51	15,191.0 (2,203.205)
Mean	420.6 (61.00)	4.64	15,541.5 (2,254.036)
S. D.	143.4 (20.81)	0.39	1,384.3 (200.776)
C. V.	235.1 (34.11)	8.45	61.4 (8.907)
Minimum	154.7 (22.45)	4.21	14,103.5 (2,045.482)
Maximum	557.6 (80.88)	5.21	17,316.5 (2,511.472)
Range	402.8 (58.43)	1.00	3,213.0 (465.990)

Table 8 - Tensile Testing Results for Glass/Polypropylene Liner Material

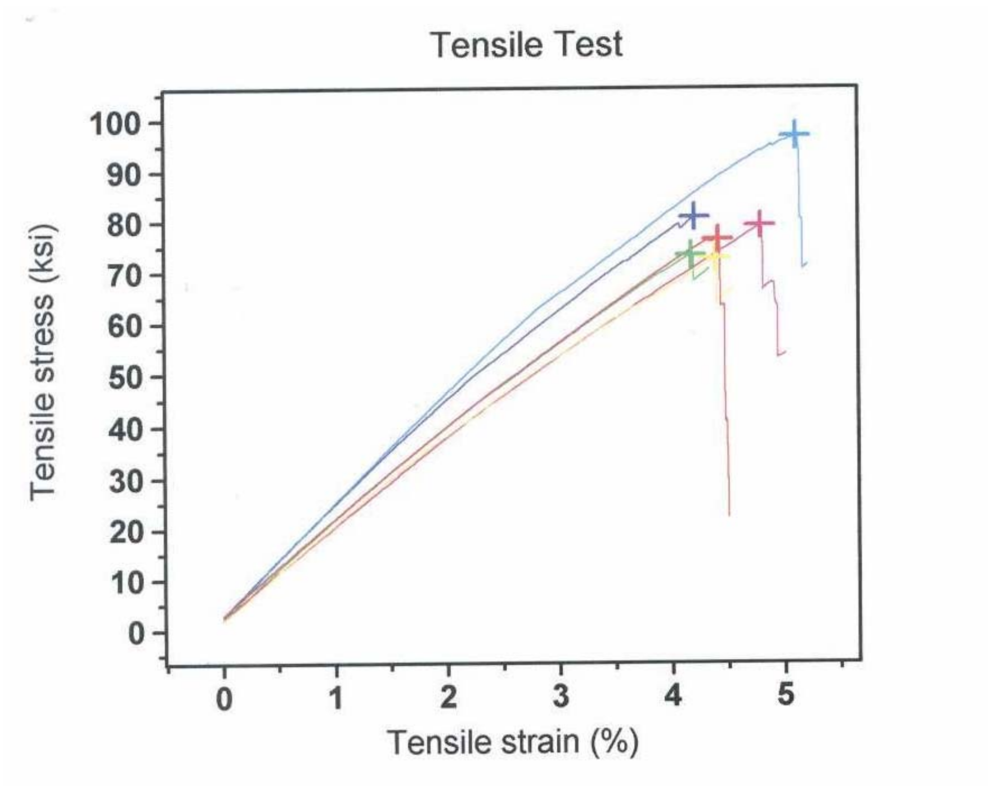


Figure 65 - Tensile Testing Results for Glass/Polypropylene Liner Material

It is anticipated that a liner material with a modulus of elasticity on the order of 95% of that for steel will be required for effective reinforcement of steel pipelines that have been weakened by wall loss defects (e.g., by eternal corrosion). A liner material with a modulus of elasticity that is just less than that of steel (i.e., on the order of 95%) would allow the liner to carry its share of the load without putting the interface between the liner and the steel pipe in tension. If the modulus of elasticity for the liner material were greater than that of the steel pipe, as pressure in the pipe increases, the stiffness of the liner would prevent it from expanding with the steel pipe, putting the weak adhesively-bonded interface in tension. If the adhesive layer between the pipe and the sleeve were to be broken, this would allow pressure into the annular space between the pipe and liner, allowing the pressure to act upon the defect-weakened area and rendering the liner useless.

Carbon fiber-based composite materials have a much higher modulus of elasticity than glass-based composite materials. The modulus of elasticity for commercial grade raw carbon fiber material is in the 206.8 GPa (30 x 10^6 psi) range, but this is reduced significantly when a matrix material is introduced. High grade raw carbon fiber materials have a modulus of elasticity that is in the 344.7 to 413.7 GPa (50 to 60 x 10^6 psi) range; however, these high grade raw carbon fiber materials are expensive and scarce. None-the-less, it may be possible to design a liner material that, when the matrix material is introduced, has a modulus of elasticity on the order of 95 % of that for steel.

The cost of a liner composed of high grade raw carbon fiber material will be high. The results of the survey of pipeline operators suggests that such a repair may still be useful in spite of the high cost for river crossings, under other bodies of water (e.g., lakes and swamps), in difficult soil conditions, under highways, under congested intersections, and under railway crossings.

RolaTube agreed to redesign the liner with a modulus of elasticity closer to that of steel using carbon/polypropylene as opposed to glass/polypropylene. RolaTube experienced difficulties consolidating the initial supply of carbon/polypropylene composite material that they received inside the test sections. The problem appears to be associated with the quality of the raw materials, which results in bridging and failure to properly consolidate. RolaTube recently identified an alternative supplier and is presently awaiting delivery of materials. In the mean time, a parallel search for a suitable carbon fiber material was initiated at EWI.

Once pipe samples with the redesigned liner material are received from RolaTube, the experimental program described above will be repeated. Following this, provided that the redesigned line material is effective at restoring the pressure containing capabilities of the pipes, an experimental program involving larger diameter pipe (e.g., 508 mm (20 in.)) will be undertaken. If the redesigned line material is not effective at restoring the pressure containing capabilities of the pipes, additional finite element analyses will be carried out to determine the required properties of the liner material.

Subtask 4.3 - Simulation and Analysis of Potential Repair Methods

In previous work for PRCI[7], finite element analysis (FEA) was performed to simulate external weld deposition repair of internal wall loss. To supplement this work, plans were made for additional FEA to simulate internal weld deposition repair of external wall loss.

During the last reporting period, and prior to the initial trials for fiber-reinforced composite repairs, RolaTube conducted FEA to determine the required properties of the liner material. Again, postmortem analysis of the pipe section damage indicates that the difference in modulus of elasticity between the steel and the original liner material prevents the liner from carrying its share of the load.

During the next reporting period, RolaTube will carry out FEA to predict the performance of a liner material that has a modulus of elasticity on the order of 95% of that for steel. If the redesigned liner material is not effective at restoring the pressure containing capabilities of the pipes, additional FEA will be carried out to determine the required properties of another liner material.

Subtask 4.4 - Internal Repair Evaluation Trials

During previous and current reporting period, all of the evaluation trials pertaining to the evaluation of potential repair methods focused on fiber-reinforced composite liner repairs.

During the next reporting period, weld deposition repairs will be made on the 559 mm (22 in.) diameter pipe that was acquired from Panhandle Eastern will be sectioned. Areas of damage will be artificially introduced into pipe sections using methods previously stated in the experimental section describing the manufacture of simulated damage on pipe sections used for fiber-reinforced liner evaluation. The artificially introduced damage will then be repaired using the GMAW process applied from the inside of the pipe. These development trials will be carried out under conditions that simulate application to the inside of a buried pipeline. It is envisioned that a soil box set-up will be fabricated and used to simulate these conditions, so that the effect of welding and soil conditions on pipeline coating integrity can also be evaluated. All significant data pertinent to weld deposition repair will be recorded during these evaluation trials.

During the next reporting period, once pipe samples with the redesigned liner material are received from RolaTube, the experimental program described above will be repeated and repaired pipe sections hydrostatically pressure tested until failure. All significant data pertinent to fiber-reinforced liner repair will be recorded during these evaluation trials.

Subtask 4.5 - Review and Evaluation of Internal Pipeline Repair Technologies Report

During this reporting period and the previous reporting period, experimental work was conducted to produce data for this report.

During the next reporting period, EWI will produce the Task 4.0 - Evaluation of Potential Repair Methods draft report containing a detailed analysis of the development trial results. The report will include a matrix listing capabilities and/or limitations of each repair method, and recommendations of potential repair methods that should be included in the next phase of the project.

Task 5.0 - Optimize and Validate Internal Repair Methods

Task 4.0 is prerequisite to Task 5.0, therefore, no activity occurred during this reporting period. There is no activity planned for this task in the next reporting period.

Task 6.0 - Develop Functional Specification

During this reporting period, preliminary system specifications were created for Subtask 3.2 - Define Target Specifications for an Internal Pipeline Repair System based on the data contained in the Subtask 3.3 - Summary of Industry Needs for Internal Pipeline Repair Report. During this reporting period, there was no activity on this task. During the next 18 months, development work will be initiated on the functional specification.

Task 7.0 - Demonstration of Repair Technology

During this reporting period there was no activity conducted for this task, as development is scheduled to begin in November of 2004.

5.0 - CONCLUSIONS

The most common cause for repair of gas transmission pipelines is external, corrosion-caused loss of wall thickness[8]. To prevent an area of corrosion damage from causing a pipeline to rupture, the area containing the corrosion damage must be reinforced. Other pipeline defects that commonly require repair include internal corrosion, original construction flaws, service induced cracking, and mechanical damage.

Defects oriented in the longitudinal direction have a tendency to fail from hoop stress (pressure loading) and must be reinforced in the circumferential direction. Defects oriented in the circumferential direction have a tendency to fail from axial stresses (e.g., pipeline settlement) and must be reinforced in the longitudinal direction. Full-encirclement steel repair sleeves resist hoop stress and, if the ends are welded to the pipeline, can also resist axial stresses.

Technology Status Assessment

The Task 2.0 - Technology Status Assessment indicates that the most commonly used method for repair of gas transmission pipelines is the full-encirclement steel repair sleeve. This and other repair methods commonly applied from the outside of the pipeline are typically executed with the pipeline in-service. While in-service application would be desirable for internal repair, many of the repair methods that are applicable to the inside of the pipeline require that the pipeline be taken out-of-service. Extensive high risk research and development would be required to make these repair processes suitable for in-service natural gas pipeline application. Most of the repair methods that are commonly applied to the inside of other types of pipelines, which typically operate at low pressure, are done so to only restore leak tightness. These repair methods would also require extensive research and development in order for them to have the ability to restore the strength of a gas transmission pipeline. Given the budget and time restraints of this program, efforts will remain focused on evaluating internal repair technologies for application while the pipeline is out-of-service.

Survey of Industry Needs for Internal Pipeline Repair

The twenty responses to the operator needs survey produced the following principal conclusions:

1. Use of internal weld repair is most attractive for river crossings, under other bodies of water such as lakes and swamps, in difficult soil conditions, under highways and in congested intersections, and under railway crossings. All these areas tend to be very difficult and very costly, if, and where conventional excavated repairs may be currently used.

2. Internal pipe repair offers a strong potential advantage to the high cost of HDD when a new bore must be created to solve a leak or other problem in a water/river crossing.
3. Typical travel distances can be divided into three distinct groups: up to 305 m (1,000 ft.); between 305 m and 610 m (1,000 ft. and 2,000 ft.); and beyond 914 m (3,000 ft.). All three groups require pig-based systems. A despooled umbilical system would suffice for the first two groups which represents 81% of survey respondents. The third group would require an onboard self-contained power unit for propulsion and welding/liner repair energy needs.
4. Pipe diameter sizes range from 50.8 mm (2 in.) through 1,219.2 mm (48 in.). The most common size range for 80% to 90% of operators surveyed is 508 mm to 762 mm (20 in. to 30 in.), with 95% using 558.8 mm (22 in.) pipe.
5. Based on the frequency of expected use by many operators, the issue of acceptable system cost for a deployable solution could best be tackled through selling such technology as an additional service through existing "smart pig" vendors/operators.
6. There has been almost no use of internal repair to date and the concept is currently fairly alien to pipeline operators. Even the potential for internal repair of external damage using such a system needs further promotion/education within the industry as a whole.
7. Most operators were open to the economic potential an internal repair system may offer in terms of reducing interruption to product flow, particularly if they did not have looped lines.
8. The top three items of concern for selecting a repair method were cost, availability of the repair method (time/cost), and the position of the defect(s).
9. A wide range of pipe coatings were cited as being deployed in the field. The top three mentioned were FBE, coal tar, and concrete/POWERCRETE®.
10. The majority of operators considered the ability for the pipeline to remain in service while the repair was conducted to be very important.
11. RT is by far the most accepted method for pipeline NDE. UT was the second most common process cited.

To summarize, the important characteristics of a useful internal pipeline repair system would include the ability to operate at a long range from the pipe entry point, the agility to transverse bends and miters, and the ability to effect a permanent repair that is subsequently inspectable via pigging.

Potential Repair Methods

Figure 52 - Weighted Scores of Potential Repair Methods is a bar chart that contains the total weighted scores for each potential repair technology that was considered. It is apparent that, of

the three broad categories of repair (welding, liners, and surfacing), repair methods that involve welding are generally the most feasible. Of the various welding processes, GMAW is the preferred method. The primary factors that make GMAW the most feasible are process technical feasibility and robustness, and industry familiarity with the process. The second most feasible of the three broad categories is repair methods that involve internal liners. Of these, fiber-reinforced composite liners are the most promising. The primary factors that make fiber-reinforced composite liners the most feasible are the ability to match the strength of the pipe material and negotiate bends, and their corrosion resistance. The advantage of using a fiber-reinforced composite liner is somewhat offset by its material cost which is anticipated to be comparatively higher than that of a steel coil liner.

The experimental portion of the program should continue to focus on the development of a GMAW welding repair process and on the development of a fiber-reinforced composite liner repair process. If, during the course of the experimental portion of the project, one of these repair methods proves to be less feasible than anticipated, it will be dropped in favor of the other.

Evaluation of Repair Methods

GMAW and fiber-reinforced composite liner repair technologies will be evaluated by this program. Both are used to some extent for other applications and could be further developed for internal, local, structural repair of gas transmission pipelines.

Deposited Weld Metal Repairs

Arc welding processes offer a viable repair method that can be applied from the inside of a gas transmission pipeline. There are several arc welding processes that can be operated remotely. Based on the survey and assessment of candidate arc welding processes, the GMAW process was the most likely choice for this application. It offers a good combination of simplicity, high productivity, robustness, and quality that are required for this welding repair application. Arc welding processes are routinely used to externally repair pipelines. However, repair from the inside offers new challenges for process control since welding will need to be performed remotely. In addition, since the intent is to leave the pipeline in the ground, there are several variables that will affect the welding process and quality. Soil conditions have the potential to influence heat removal during welding thereby altering the fusion characteristics, welding cooling rate, and mechanical properties. The effects of welding on the external coating used to protect against corrosion will need to be evaluated to assure future pipeline coating integrity. Finally, if welding was performed in-service, the pressure and flow rate of the gas will have a strong effect on the equipment design of the welding process. New process equipment technology will be required to shield the welding process from methane contamination and cope with higher gas pressures. A significant deliverable will be the development of an equipment specification defining all the functional requirements for an internal repair welding system.

Weld deposition accomplishments during this reporting period:

- Welding equipment has been acquired and set-up that can be used for internal repair of pipe tests and demonstrations.
- Sound weld beads were made in all positions using preliminary parameters that use weaving.
- Programmable controls will be required to optimize bead shape and deposition pattern.

In addition to the previously stated characteristics of a useful internal pipeline repair system, a successful internal welding repair system would include a machining capability to prepare the weld joint, a grinding system for cleaning and preparation, and a high deposition robust welding process. Although many of these features are incorporated in the existing pigging systems, there is no single system that possesses all the required characteristics. Further work is required to develop a system with all of these features.

Fiber-Reinforced Liners

Further development of fiber-reinforced composite repairs/liners with sufficient strength is required prior to application to internal, local structural repair of gas transmission pipelines. Ideally, these products would combine the strength of currently used external repair products or composite reinforced line pipe (CRLP) with the installation process currently used for liners in other types of pipelines. Adhesion of the liner to the pipe surface, which is important for structural reinforcement but not restoration of leak tightness, also needs to be addressed. The required thickness of a repair for structural reinforcement and the potentially adverse effect on internal inspection and flow restriction is another issue to be addressed.

To date, the failure pressures for the pipe sections with fiber-reinforced composite liners were only marginally greater than for pipe sections without liners, indicating that the first liners tested were generally ineffective at restoring the pressure containing capabilities of the pipes. Once pipe samples with the redesigned liner material are received from RolaTube, the test program described in the experimental section will be repeated. If the redesigned line material is not effective at restoring the pressure containing capabilities of the pipes, additional FEA will be carried out to determine the required properties of an alternate liner material. Once the optimum fiber-reinforced composite material/process is identified, necessary features for delivery via pigging system can be developed.

6.0 - REFERENCES

(1) Kiefner, J. F. and Vieth, P. H., "A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe" Final Report to A.G.A. Pipeline Corrosion Supervisory Committee, Project PR-3-805, Battelle, Columbus, OH, December 1989.

(2) Gordon, J. R., Bruce, W. A., and Porter, N. C., “Internal Repair of Pipelines – Research Management Plan,” Report to National Energy Technology Laboratory, U.S. Department of Energy, DOE Award No.: DE-FC26-02NT41633, Edison Welding Institute, October 2002.

(3) Gordon, J. R., Bruce, W. A., Sullivan, M., and Neary, C. M., “Internal Repair of Pipelines – Technology Status Assessment,” Report to National Energy Technology Laboratory, U.S. Department of Energy, DOE Award No.: DE-FC26-02NT41633, Edison Welding Institute and Pacific Gas & Electric, November 2002.

(4) Bruce, W. A., “Welding onto In-Service Thin Wall Pipelines,” Final Report for EWI Project No. 41732CAP to PRC International, Contract No PR-185-9908, July 2000.

(5) Kiefner, J. F., Barnes, C. R., Gertler, R. C., Fischer, R. D., and Mishler, H. W., “Experimental Verification of Hot Tap Welding Thermal Analysis. Final Report - Phase II - Volume 2, Liquid Propane Experiments,” Repair and Hot Tap Welding Group, Battelle Columbus Laboratories, May 1983.

(6) Research & Special Programs Administration, U.S. Department of Transportation. "§192.150 Passage of internal inspection devices," DOT 49 CFR Part 192 - Transportation of Natural & Other Gas by Pipeline: Minimum Safety Standards, July 1998.

(7) Wang, Y.-Y., and Bruce, W. A., “Examination of External Weld Deposition Repair for Internal Wall Loss,” Final Report for EWI Project No. 07723CAP to PRC International, Contract No PR-185-9633, March 1998.

(8) Eiber, R. J., Bubenik, T. A., and Leis, B. N., "Pipeline Failure Mechanisms and Characteristics of the Resulting Defects," Eighth Symposium on Line Pipe Research, Paper No. 7 (Houston, TX: American Gas Association, 1993).

7.0 - BIBLIOGRAPHY

Bruce, W. A., “Welding onto In-Service Thin Wall Pipelines,” Final Report for EWI Project No. 41732CAP to PRC International, Contract No PR-185-9908, July 2000. This report discusses special welding difficulties and the extra care required to ensure safe operating procedures and sound welds due to repairs and modifications to in-service, thin walled pipelines.

Eiber, R. J., Bubenik, T. A., and Leis, B. N., "Pipeline Failure Mechanisms and Characteristics of the Resulting Defects," Eighth Symposium on Line Pipe Research, Paper No. 7 (Houston, TX: American Gas Association, 1993). This report discusses four broad categories of pipeline failure mechanisms: outside forces, environmentally induced defects, manufacturing/materials defects, and operator error or miscellaneous defects.

Gordon, J. R., Bruce, W. A., and Porter, N. C., “Internal Repair of Pipelines – Research Management Plan,” Report to National Energy Technology Laboratory, U.S. Department of Energy, DOE Award No.: DE-FC26-02NT41633, Edison Welding Institute, October 2002. This plan contains a concise summary of the technical objectives and approach for each task. The document also contain detailed schedules and planned expenditures for each task and all major milestones and decision points for the two year project duration.

Gordon, J. R., Bruce, W. A., Sullivan, M., and Neary, C. M., “Internal Repair of Pipelines – Technology Status Assessment,” Report to National Energy Technology Laboratory, U.S. Department of Energy, DOE Award No.: DE-FC26-02NT41633, Edison Welding Institute and Pacific Gas & Electric, November 2002. This report presents the status of existing pipeline repair technology that can be applied to the inside of gas transmission pipelines, and includes results from a comprehensive computerized literature search, together with information obtained from discussions with companies that are currently developing or evaluating novel pipeline repair methods.

Kiefner, J. F., Barnes, C. R., Gertler, R. C., Fischer, R. D., and Mishler, H. W., “Experimental Verification of Hot Tap Welding Thermal Analysis. Final Report - Phase II - Volume 2, Liquid Propane Experiments,” Repair and Hot Tap Welding Group, Battelle Columbus Laboratories, May 1983. This report documents the verification of two thermal analysis models of hot tap welding on pressurized pipelines. With velocity input modified as shown, the models are capable of predicting maximum temperatures in the pipe wall especially at the inside surface and critical cooling rates in the heat-affected zones within the range of heat inputs that are practical for shielded metal arc welding.

Research & Special Programs Administration, U.S. Department of Transportation. "§192.150 Passage of internal inspection devices." *DOT 49 CFR Part 192 - Transportation of Natural & Other Gas by Pipeline: Minimum Safety Standards*. Amdt. 192-72, 59 FR 17281, Apr 12, 1994, as amended by Amdt. 192-85, 63 FR 37502, July 13, 1998. This code describes minimum safety requirements for pipeline facilities and the transportation of gas, including pipeline facilities and the transportation of gas within the limits of the outer continental shelf as that term is defined in the Outer Continental Shelf Lands Act (43 U.S.C. 1331).

Kiefner, J. F. and Vieth, P. H., "A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe" Final Report to A.G.A. Pipeline Corrosion Supervisory Committee, Project PR-3-805, Battelle, Columbus, OH, December 1989. This report documents a modified criterion for evaluating the corrosion level of a pipeline based on pipeline stress calculations (available as a PC program) as a less conservative alternative to ANSI / ASME B31G.

Wang, Y.-Y., and Bruce, W. A., "Examination of External Weld Deposition Repair for Internal Wall Loss," Final Report for EWI Project No. 07723CAP to PRC International, Contract No PR-185-9633, March 1998. This report discusses the deposition of weld metal on the external surface of straight sections of pipe, field bends, tees and elbows as a potentially useful method for in-service repair of internal wall loss.

8.0 - LIST OF ACRONYMS

ANSI	American National Standards Institute
API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
CAE	Computer Aided Engineering
CP	Cathodic Protection
CRLP	Composite Reinforced Line Pipe
CSA	Canadian Standards Association
CV	Constant Voltage
DOE	Department of Energy
DOT	Department of Transportation
ERW	Electric Resistance Welded
EWI	Edison Welding Institute
FBE	Fusion Bonded Epoxy
FEA	Finite Element Analysis
FRCP	Fiber-Reinforced Composite Pipe
Glass-HDPE	Glass-High Density Polyethylene
GMAW	Gas Metal Arc Welding
HDD	Horizontal Direct Drilling
HDPE	High Density Polyethylene
ILI	In-Line Inspection
IR	Infra-Red
MAOP	Maximum Allowable Operating Pressure
MOP	Maximum Operating Pressure
MPI	Magnetic Particle Inspection
NDE	Nondestructive Examination
NETL	National Energy Technology Laboratory
OD	Outside Diameter
PC	Personal Computer
PE	Polyethylene
PG&E	Pacific Gas & Electric Co.
PRCI	Pipeline Research Council International
QA	Quality Assurance
QC	Quality Control
RT	Radiographic Testing
SCC	Stress Corrosion Cracking
SMYS	Specified Minimum Yield Strength
UT	Ultrasonic Testing

9.0 - APPENDICES

Appendix A

Industry Survey with Cover Letter

April 11, 2003

<<<FIELD 1>>>

EWI Project No. 46211GTH, "Internal Repair of Pipelines"

Dear <<<FIELD 2>>>:

Enclosed is a survey of operator experience and industry needs pertaining to internal repair of pipelines. EWI is conducting this survey as part of a project being funded by the National Energy Technology Laboratory. The objectives of this project are to evaluate, develop, demonstrate, and validate internal repair methods for pipelines.

Please complete this survey at your earliest convenience.[1] Your participation is greatly appreciated. If you have questions or require additional information, please contact me at 614-688-5059 or bill_bruce@ewi.org

Sincerely,

William A. Bruce, P.E.
Principal Engineer
Materials section

Enclosure

[1] A copy of this survey was also sent to <<<FIELD 3>>> at your company. You may want to coordinate your response.

April 11, 2003
EWI Project No. 46211GTH

Internal Repair of Pipelines Survey of Operator Experience and Industry Needs

conducted for:

National Energy Technology Laboratory
Morgantown, WV

Project No. 46211GTH

on

Internal Repair of Pipelines – Survey of Operator Experience and Industry Needs

for

National Energy Technology Laboratory
Morgantown, WV

April 11, 2003

EWI
1250 Arthur E. Adams Drive
Columbus, OH 43221

Internal Repair of Pipelines – Survey of Operator Experience and Industry Needs

1.0 Introduction

A repair method that can be applied from the inside of a gas transmission pipeline (i.e., a trenchless repair) is an attractive alternative to conventional repair methods since the need to excavate the pipeline is precluded. This is particularly true for pipelines in environmentally sensitive and highly populated areas. Several repair methods that are commonly applied from the outside of the pipeline are, in theory, directly applicable from the inside. However, issues such as development of the required equipment to perform repairs remotely and mobilization of equipment through the pipeline to areas that require repair need to be addressed. Several additional repair methods that are commonly applied to other types of pipelines (gas distribution lines, water lines, etc.) also have potential applicability for internal repair of gas transmission pipelines. Many of these require further development to meet the requirements for repair of gas transmission pipelines. The objectives of a project being funded by the National Energy Technology Laboratory are to evaluate, develop, demonstrate, and validate internal repair methods for pipelines; develop a functional specification for an internal pipeline repair system; and prepare a recommended practice for internal repair of pipelines. One of the initial tasks of this project involves conducting a survey to determine the repair needs and performance requirements for internal pipeline repairs. The purpose of this survey is to better understand the needs of the natural gas transmission industry regarding internal repair.

2.0 Instructions

Please respond as completely as possible to as many questions as possible. Space is also provided for any comments that you may have.

3.0 Survey

Part 1 – Currently-Used Repair Methods

1. Has your company experienced degradation (corrosion, cracking, etc) of a transmission line?

   If so, has your company replaced or repaired pipe because of degradation?

2. What specific repair methods would typically be used to repair different types of degradation?

Comments pertaining to currently-used repair methods –

Part 2 – Use/Potential Use of Internal Repair

1. Has your company attempted repair of a transmission line from inside the pipe?

   If so, describe the repair(s)

2. There are many factors that affect the decision to repair or replace pipe. What circumstances would favor performing a repair from inside the pipe using only one or two excavations rather than excavating the entire length of pipe?

3. If the technology were available to perform a repair from the inside, would your company consider using the technology?

   If so, for what application(s) – e.g., specific geographic locations and special situations?

4. At least one excavation will be required to insert the internal repair device into the pipe. From this excavation, the repair device could be travel in each direction from the excavation. About how far from the insertion point should the repair device be able to travel?

   What range of pipe diameters should the repair device be capable of operation in?

5. What potential obstructions such as elbows, bends, branches, and taps should the repair system be able to negotiate?

Comments pertaining to the use/potential use of internal repair –

Part 3 – Need for In-Service Internal Repair

1. How important is the ability to perform a repair from the inside the pipe while the pipeline remains in service?

2. Would internal repair remain attractive if it was necessary to completely shut down the pipeline (depressurized and evacuated) during the repair?

   Depressurized but not evacuated?

Out of service (no flow) but remain pressurized?

Comments pertaining to the need for in-service internal repair –

Part 4 – Applicable Types of Damage

1. What types of external coatings would be found on transmission lines owned by your company?

2. If a repair involving welding from the inside was performed, how important is it to preserve the integrity of the coating?

   Is your cathodic protection system capable of compensating for relatively small breaches in the coating?

Comments pertaining to applicable types of damage –

Part 5 – Operational and Performance requirements for Internal Repairs

1. Two general categories of repairs are being considered, (1) using weld metal to restore a surface and (2) installing an internal sleeve, either metallic or nonmetallic, to provide structural reinforcement of leak tightness. Is it important that the line remain inspectable by pigging after repair?

   About how far could the repair protrude into the pipe before it would interfere with pigging?

2. What NDE would your utility require for a repair to an existing longitudinal or circumferential weld?

   Could a visual or magnetic particle examination be substituted for radiography in these special circumstances?

What NDE would your utility require for a welded repair to base metal (e.g. corrosion pitting)?

3. Would the use of internal repair be attractive even if it were considered a temporary repair

Comments pertaining to operational and performance requirements for internal repairs –

Part 6 - General Comments

Please provide any general comments that you may have.

Appendix B

Members of the Pipeline Research Council International

Members of the Pipeline Research Council International

Advantica Technologies Ltd
BP
Buckeye Pipe Line Company
Chevron Texaco Pipeline Company
CMS Panhandle Companies
Colonial Pipeline Company
Columbia Gas Transmission Co.
ConocoPhillips
Consumers Energy
Dominion Transmission
Duke Energy Gas Transmission
El Paso Corporation
Enbridge Pipelines
Enron Transportation Services Corp.
Explorer Pipeline Company
ExxonMobil Pipeline Company
Foothills Pipe Lines Ltd
Gassco A.S. (Norway)
Gasum Oy (Finland)
Gaz de France
Gulf South Pipeline
Marathon Ashland Pipe Line LLC
N.V. Nederlandse Gasunie/Gastransport Services (The Netherlands)
National Fuel Gas Supply Corporation
Saudi Aramco
Sempra Energy Utilities/Southern California Gas Company
Shell Pipeline Company LP
Southern Natural Gas Company
TEPPCO
TransCanada PipeLines Limited
Transco (UK)
TransGas
Williams Gas Pipeline

Appendix C

List of Natural Gas Pipeline Operating Companies
(from http://www.ferc.gov/gas/pipecomp.htm)

List of Natural Gas Pipeline Operating Companies

Algonquin Gas Transmission Company
Algonquin LNG, Inc.
ANR Pipeline Company
ANR Storage Company
Black Marlin Pipeline Company
Blue Lake Gas Storage Company
Canyon Creek Compression Company
Carnegie Interstate Pipeline Company
Chandeleur Pipe Line Company
Colorado Interstate Gas Company
Columbia Gas Transmission Corporation
Columbia Gulf Transmission Company
Cove Point LNG Limited Partnership
Crossroads Pipeline Company
Discovery Gas Transmission LLC
Dominion Transmission Inc.
Dynegy Midstream Pipeline, Inc.
East Tennessee Natural Gas Company
Egan Hub Partners, L.P.
El Paso Natural Gas Company
Equitrans, Inc.
Florida Gas Transmission Company
Gas Transport, Inc.
Granite State Gas Transmission, Inc.
Great Lakes Gas Transmission Limited Partnership
Gulf South Pipeline
Gulf States Transmission Corporation
High Island Offshore System
Iroquois Gas Transmission System, L.P.
Kansas Pipeline Company
Kentucky West Virginia Gas Company
Kern River Gas Transmission Company
KM Interstate Gas Transmission Co.
KN Wattenberg Transmission
Maritimes & Northeast Pipeline L.L.C.
Michigan Gas Storage Company
Midwestern Gas Transmission Company
MIGC, Inc.
Mississippi River Transmission Corporation
Mojave Pipeline Company
National Fuel Gas Supply Corporation
Natural Gas Pipeline Company of America
Nora Transmission Company
Northern Border Pipeline Company
Northern Natural Gas Company
Northwest Pipeline Corporation

OkTex Pipeline Company
Overthrust Pipeline Company
Ozark Gas Transmission System
Paiute Pipeline Company
Panhandle Eastern Pipe Line Company
Petal Gas Storage Company
PG&E Gas Transmission-Northwest Corporation
Questar Pipeline Company
Reliant Energy Gas Transmission Company
Sabine Pipe Line Company
Sea Robin Pipeline Company
Shell Offshore Pipelines
South Georgia Natural Gas Company
Southern Natural Gas Company
Southwest Gas Storage Company
Steuben Gas Storage Company
TCP Gathering Co.
Tennessee Gas Pipeline Company
Texas Eastern Transmission Corporation
Texas Gas Transmission Corporation
Total Peaking LLC
Trailblazer Pipeline Company
TransColorado Gas Transmission Company
Transcontinental Gas Pipe Line Corporation
Transwestern Pipeline Company
Trunkline Gas Company
Trunkline LNG Company
Tuscarora Gas Transmission Company
U-T Offshore System
Vector Pipeline
Venice Gathering System, L.L.C.
Viking Gas Transmission Company
Williams Gas Pipelines Central, Inc.
Williston Basin Interstate Pipeline Company
Wyoming Interstate Company, Ltd.
Young Gas Storage Company, Ltd.

Appendix D

Lists of Surveyed PRCI Member & Other Gas Transmission Companies
Including Contact Name, Email, and Telephone Contact Information

Members of the Pipeline Research Council International Email Contacts for Survey

(As of 7/9/03 Email of main POC {when determined} for multiple listings, or single listings on Materials Committee)

Organization	POC Email Address
Advantica Technologies Ltd	bob.andrews@advanticatech.com
BP	moskowln@bp.com, moredh@bp.com hammondj3@bp.com,
Buckeye Pipe Line Company	wshea@buckeye.com
Chevron Texaco Pipeline Company	GBKO@ChevronTexaco.com
CMS Panhandle Companies	smgallagher@cmsenergy.com
Colonial Pipeline Company	jgodfrey@colpipe.com
Columbia Gas Transmission Co.	jswatzel@nisource.com
ConocoPhillips	dave.ysebaert@conocophillips.com
Consumers Energy	rswelsh@cmsenergy.com
Dominion Transmission	brian_c_sheppard@dom.com
Duke Energy Gas Transmission	scrapp@duke-energy.com
El Paso Corporation	bennie.barnes@elpaso.com
Enbridge Pipelines	scott.ironside@enbridge.com
Enron Transportation Services Corp.	mcrump@enron.com
Explorer Pipeline Company	jwenzell@expl.com
ExxonMobil Pipeline Company	don.e.drake@exxonmobil.com
Foothills Pipe Lines Ltd	jack.beattie@foothillspipe.com
Gassco A.S. (Norway)	eh@gassco.no
Gasum Oy (Finland)	ilkka.taka-aho@gasum.fi
Gaz de France	gerard.jammes@gazdefrance.com
Gulf South Pipeline	scott.williams@gulfsouthpl.com
Marathon Ashland Pipe Line LLC	tlshaw@mapllc.com
N.V. Nederlandse Gasunie/Gastransport Services (The Netherlands)	w.sloterdijk@gasunie.nl
National Fuel Gas Supply Corporation	pustulkaj@natfuel.com
Saudi Aramco	shuler.cox@aramco.com
Sempra Energy Utilities/Southern California Gas Company	bamend@semprautilities.com
Shell Pipeline Company LP	janiemeyer@shellopus.com
Southern Natural Gas Company	george.benoit@elpaso.com
TEPPCO	lwmallett@teppco.com
TransCanada PipeLines Limited	david_dorling@transcanada.com
Transco (UK)	jeremy.bending@uktransco.com
TransGas	btorgunrud@transgas.com
Williams Gas Pipeline	Thomas.R.Odom@Williams.com

Members of the Pipeline Research Council International
Contact Names and Phone Numbers

(As of 7/9/03)

Organization	POC Name	Phone Number
Advantica Technologies Ltd	Bob Andrews	011 44 1509 282749
BP	John Hammond	011 44 1932 775909
BP	David Moore	907 564 4190
BP	Larry Moskowitz	281 366 2924
Buckeye Pipe Line Company	William Shea	610 254 4650
Chevron Texaco Pipeline Company	George Kohut	510 242 3245
CMS Panhandle Companies	Scott Gallagher	713 989 7444
Colonial Pipeline Company	John Godfrey	678 762 2217
Columbia Gas Transmission Co.	Jim Swatzel	304 357 2797
ConocoPhillips	Dave Ysebaert	281 293 2969
Consumers Energy	Robert Welsh	517 788 1928
Dominion Transmission	Brian Sheppard	304 627 3733
Duke Energy Gas Transmission	Steve Rapp	713 627 6394
El Paso Corporation	Bennie Barnes	719 520 4677
Enbridge Pipelines	Scott Ironside	780 420 5267
Enron Transportation Services Corp.	Michael Crump	713 345 1623
Explorer Pipeline Company	Jeff Wenzell	918 493 5140
ExxonMobil Pipeline Company	Don Drake	713 656 2288
Foothills Pipe Lines Ltd	Jack Beattie	403 294 4143
Gassco A.S. (Norway)	Egil Hurloe	011 47 52812500
Gasum Oy (Finland)	Ilkka Taka-Aho	011 358 20 44 78653
Gaz de France	Gerard Jammes	011 33 49 22 54 19
Gulf South Pipeline	Scott Williams	713 544 5220
Marathon Ashland Pipe Line LLC	Thomas Shaw	419 421 4002
N.V. Nederlandse Gasunie/Gastransport	Wytze Sloterdijk	011 31 50 521 2674
National Fuel Gas Supply Corporation	John Pustulka	716 857 7909
Saudi Aramco	Shuler Cox	011 966 3 874 6664
Sempra Energy Utilities/Southern Cal Gas	Bill Amend	213 244 5277
Shell Pipeline Company LP	John Niemeyer	713 241 1856
Southern Natural Gas Company	George Benoit	832 528 4244
TEPPCO	Leonard Mallett	713 759 3615
TransCanada PipeLines Limited	David Dorling	403 948 8147
Transco (UK)	Jeremy Bending	011 44 1689 881479
TransGas	Brian Torgunrud	306 777 9357
Williams Gas Pipeline	Thomas Odom	270 688 6964

Other Natural Gas Pipeline Operating Companies – Email Contacts

(As of 7/9/03)

Organization	Location	Email Address
Algonquin Gas Transmission Co.	Duke Energy	scrapp@duke-energy.com
Algonquin LNG, Inc.	Duke Energy	scrapp@duke-energy.com
Alliance Pipeline Ltd.		arti.bhatia@alliance-pipeline.com
ANR Pipeline Co.	El Paso	george.benoit@elpaso.com
ANR Storage Co.	El Paso	george.benoit@elpaso.com
Black Marlin Pipeline Co.	Williams	Thomas.R.Odom@Williams.com
Blue Lake Gas Storage Co.	El Paso	robert.white@elpaso.com
Canyon Creek Compression Co.	K. Morgan (KM)	mark_mayworn@kindermorgan.com
Carnegie Interstate Pipeline Co.	Equitrans	amurphy@eqt.com
Chandeleur Pipe Line Co.	ChevronTexaco	GBKO@ChevronTexaco.com
Colorado Interstate Gas Co.	El Paso	bennie.barnes@elpaso.com
Columbia Gas Transmission Corp.	Columbia	jswatzel@nisource.com
Columbia Gulf Transmission Co.	Columbia	jswatzel@nisource.com
Cove Point LNG, L.P.	Dominion	brian_c_sheppard@dom.com
Crossroads Pipeline Co.	Columbia	jswatzel@nisource.com
Discovery Gas Transmission LLC	Williams	Thomas.R.Odom@Williams.com
Dynegy Midstream Pipeline, Inc.		rich.a.mueller@dynegy.com
East Tennessee Natural Gas Co.	Duke Energy	scrapp@duke-energy.com
Egan Hub Partners, L.P.	Duke Energy	scrapp@duke-energy.com
El Paso Natural Gas Co.	El Paso	bennie.barnes@elpaso.com
El Paso Field Services	El Paso	pat.davis@elpaso.com
Energy East		spmartin@energyeast.com
EPGT Texas Pipeline, L.P.	El Paso	pat.davis@elpaso.com
Equitrans, Inc.		amurphy@eqt.com
Florida Gas Transmission Co.	Enron	mcrump@enron.com
Granite State Gas Transmission, Inc.	Columbia	jswatzel@nisource.com
Great Lakes Gas Transmission, L.P.		rgrondin@glgt.com
Gulf South Pipeline		scott.williams@gulfsouthpl.com
Gulf States Transmission Corp.	El Paso	george.benoit@elpaso.com
High Island Offshore System	El Paso	george.benoit@elpaso.com
Iroquois Gas Transmission System		ben_gross@iroquois.com
Kansas Pipeline Co.	Midcoast Energy Enbridge	scott.ironside@enbridge.com
Kentucky West Virginia Gas Co.	Equitrans	amurphy@eqt.com
Kern River Gas Transmission Co.	Williams	Thomas.R.Odom@Williams.com
Keyspan Energy		psheth@keyspanenergy.com
KM Interstate Gas Transmission Co.	KM	mark_mayworn@kindermorgan.com
KN Wattenberg Transmission	KM	mark_mayworn@kindermorgan.com
Maritimes & Northeast Pipeline L.L.C.	Duke Energy	scrapp@duke-energy.com
Michigan Gas Storage Co.	Consumers Energy	rswelsh@cmsenergy.com
Midwestern Gas Transmission Co.	Enron	mcrump@enron.com
MIGC, Inc.	Western Gas	jcurtis@westerngas.com

Organization	Location	Email Address
Mississippi River Transmission Corp.	CenterPoint Energy	scott.mundy@centerpointenergy.com
Mojave Pipeline Co.	El Paso	bennie.barnes@elpaso.com
National Fuel Gas Supply Corp.		pustulkaj@natfuel.com
Natural Gas Pipeline Co. of America	KM	mark_mayworn@kindermorgan.com
Nora Transmission Co.	Equitrans	amurphy@eqt.com
North Carolina Natural Gas	Carolina Power & Light	Theodore.hodges@cplc.com
Northern Border Pipeline Co.	Enron	mcrump@enron.com
Northern Natural Gas Co.	Midamerican Energy	paul.fuhrer@nngco.com
Northwest Pipeline Corp.	Williams	Thomas.R.Odom@Williams.com
Overthrust Pipeline Co.	Questar	ronji@questar.com
Oncor Gas		mrothba1@oncorgroup.com
Ozark Gas Transmission System		strawnlw@oge.com
Paiute Pipeline Co.	Southwest Gas	jerry.schmitz@swgas.com
Panhandle Eastern Pipe Line Co.	CMS	smgallagher@cmsenergy.com
Petal Gas Storage Co.	El Paso	bennie.barnes@elpaso.com
PG&E Gas Transmission-Northwest Corp.	PG&E	WJH7@pge.com
PG&E Gas Transmission-Northwest Corp.	PG&E	ADE1@pge.com
Questar Pipeline Co.	Questar	ronji@questar.com
Reliant Energy Gas Transmission Co.	CenterPoint Energy	scott.mundy@centerpointenergy.com
Sabine Pipe Line Co.	ChevronTexaco	GBKO@ChevronTexaco.com
Sea Robin Pipeline Co.	CMS	smgallagher@cmsenergy.com
Shell Offshore Pipelines	Shell	janiemeyer@shellopus.com
Southern Natural Gas Co.	El Paso	george.benoit@elpaso.com
Southwest Gas Corp.		jerry.Schmitz@swgas.com
Southwest Gas Storage Co.	CMS	smgallagher@cmsenergy.com
Steuben Gas Storage Co.	ANR/Arlington	george.benoit@elpaso.com
Tennessee Gas Pipeline Co.	El Paso	george.benoit@elpaso.com
Texas Eastern Transmission Corp.	Duke Energy	scrapp@duke-energy.com
Texas Gas Transmission Corp.	Williams	Thomas.R.Odom@Williams.com
Total Peaking LLC	Energy East	spmartin@energyeast.com
Trailblazer Pipeline Co.	KM	mark_mayworn@kindermorgan.com
TransColorado Gas Transmission Co.	KM	mark_mayworn@kindermorgan.com
Transcontinental Gas Pipe Line Corp.	Williams	Thomas.R.Odom@Williams.com
Transwestern Pipeline Co.	Enron	mcrump@enron.com
Trunkline Gas Co.	CMS	smgallagher@cmsenergy.com
Trunkline LNG Co.	CMS	smgallagher@cmsenergy.com
Tuscarora Gas Transmission Co.		lcherwenuk@tuscaroragas.com
TXU Gas/TXU Lone Star Pipeline	TXU Gas	mrothba1@oncorgroup.com
Vector Pipeline	Enbridge	scott.ironside@enbridge.com
Venice Gathering System, L.L.C.	Dynergy	rich.a.mueller@dynegy.com

Organization	Location	Email Address
Viking Gas Transmission Co.	Northern Border (Enron)	mcrump@enron.com
Williams Gas Pipelines Central, Inc.	Williams	Thomas.R.Odom@Williams.com
Williston Basin Interstate Pipeline Co.		keith.seifert@wbip.com
Wyoming Interstate Co., Ltd.	El Paso	bennie.barnes@elpaso.com
Young Gas Storage Co., Ltd.	El Paso	bennie.barnes@elpaso.com

Other Natural Gas Pipeline Operating Companies
Contact Names and Phone Numbers

(As of 7/9/03)

Organization	POC Name	Phone Number
Algonquin Gas Transmission Co.	Steve Rapp	713 627 6394
Algonquin LNG, Inc.	Steve Rapp	713 627 6394
Alliance Pipeline Ltd.	Arti Bhatia	403 517 7727
ANR Pipeline Co.	George Benoit	832 528 4244
ANR Storage Co.	George.Benoit	832 528 4244
Black Marlin Pipeline Co.	Thomas Odom	270 688 6964
Blue Lake Gas Storage Co.	Robert White	248 994 4046
Canyon Creek Compression Co. K. Morgan	Mark Mayworn	713 369 9347
Carnegie Interstate Pipeline Co.	Andy Murphy	412 231 4888
Chandeleur Pipe Line Co.	George Kohut	510 242 3245
Colorado Interstate Gas Co.	Bennie Barnes	719 520 4677
Columbia Gas Transmission Corp.	Jim Swatzel	304 357 2797
Columbia Gulf Transmission Co.	Jim Swatzel	304 357 2797
Cove Point LNG Limited Partnership	Brian Sheppard	304 627 3733
Crossroads Pipeline Co.	Jim Swatzel	304 357 2797
Discovery Gas Transmission LLC	Thomas Odom	270 688 6964
Dynegy Midstream Pipeline, Inc.	Rich Mueller	713 507 3992
East Tennessee Natural Gas Co.	Steve Rapp	713 627 6394
Egan Hub Partners, L.P.	Steve Rapp	713 627 6394
El Paso Field Services	Pat Davis	210 528 4244
El Paso Natural Gas Co.	Bennie Barnes	719 520 4677
Energy East	Scott Martin	607 347 2561
EPGT Texas Pipeline, L.P.	Pat Davis	210 528 4244
Equitrans, Inc.	Andy Murphy	412 231 4888
Florida Gas Transmission Co.	Michael Crump	713 345 1623
Granite State Gas Transmission, Inc.	Jim Swatzel	304 357 2797
Great Lakes Gas Transmission L.P.	Ryan Grondin	321 439 1777
Gulf South Pipeline	Scott Williams	713 544 5220
Gulf States Transmission Corp.	George Benoit	832 528 4244
High Island Offshore System	George.Benoit	832 528 4244
Iroquois Gas Transmission System, L.P.	Ben Gross	203 925 7257
Kansas Pipeline Company	Scott Ironside	780 420 5267
Kentucky West Virginia Gas Co.	Andy Murphy	412 231 4888
Kern River Gas Transmission Co.	Thomas Odom	270 688 6964
Keyspan Energy	Perry Sheth	516 545 3844
KM Interstate Gas Transmission Co.	Mark Mayworn	713 369 9347
KN Wattenberg Transmission	Mark Mayworn	713 369 9347
Maritimes & Northeast Pipeline L.L.C.	Steve Rapp	713 627 6394
Michigan Gas Storage Co.	Robert Welsh	517 788 1928
Midwestern Gas Transmission Co.	Michael Crump	713 345 1623
MIGC, Inc.	John Curtis	
Mississippi River Transmission Corp.	Scott Mundy	318 429 3943

Organization	POC Name	Phone Number
Mojave Pipeline Co.	Bennie Barnes	719 520 4677
National Fuel Gas Supply Corp.	John Pustulka	716 857 7909
Natural Gas Pipeline Co. of America	Mark Mayworn	713 369 9347
Nora Transmission Co.	Andy Murphy	412 231 4888
North Carolina Natural Gas	Ted Hodges	919 546 6369
Northern Border Pipeline Co.	Michael Crump	713 345 1623
Northern Natural Gas Co.	Paul Fuhrer	402 398 7733
Northwest Pipeline Corp.	Thomas Odom	270 688 6964
Oncor Gas	Mark Rothbauer	214 875 5574
Overthrust Pipeline Co.	Questar	ronji@questar.com
Ozark Gas Transmission System	Larry Strawn	405 557 5271
Paiute Pipeline Co.	Jerry Schmitz	702 365 2204
Panhandle Eastern Pipe Line Co.	Scott Gallagher	713 989 7444
Petal Gas Storage Co.	Bennie Barnes	719 520 4677
PG&E Gas Transmission-Northwest Corp.	Bill Harris	925 974 4030
PG&E Gas Transmission-Northwest Corp.	Alan Eastman	925 974 4312
Questar Pipeline Co.	Questar	ronji@questar.com
Reliant Energy Gas Transmission Co.	Scott Mundy	318 429 3943
Sabine Pipe Line Co.	George Kohut	510 242 3245
Sea Robin Pipeline Co.	Scott Gallagher	713 989 7444
Shell Offshore Pipelines	John Niemeyer	713 241 1856
Southern Natural Gas Co.	George Benoit	832 528 4244
Southwest Gas Corp.	Jerry Schmitz	702 365 2204
Southwest Gas Storage Co.	Scott Gallagher	713 989 7444
Steuben Gas Storage Co.	George Benoit	832 528 4244
Tennessee Gas Pipeline Co.	George Benoit	832 528 4244
Texas Eastern Transmission Corp.	Steve Rapp	713 627 6394
Texas Gas Transmission Corp.	Thomas Odom	270 688 6964
Total Peaking LLC	Scott Martin	607 347 2561
Trailblazer Pipeline Co.	Mark Mayworn	713 369 9347
TransColorado Gas Transmission Co.	Mark Mayworn	713 369 9347
Transcontinental Gas Pipe Line Corp.	Thomas Odom	270 688 6964
Transwestern Pipeline Co.	Michael Crump	713 345 1623
Trunkline Gas Co.	Scott Gallagher	713 989 7444
Trunkline LNG Co.	Scott Gallagher	713 989 7444
Tuscarora Gas Transmission Co.	Les Cherwenuk	775 834 3674
TXU Gas/TXU Lone Star Pipeline	Mark Rothbauer	214 875 5574
Vector Pipeline	Scott Ironside	780 420 5267
Venice Gathering System, L.L.C.	Rich Mueller	318 429 3943
Viking Gas Transmission Co.	Michael Crump	713 345 1623
Williams Gas Pipelines Central, Inc.	Thomas Odom	270 688 6964
Williston Basin Interstate Pipeline Co.	Keith Seifert	406 359 7223
Wyoming Interstate Company, Ltd.	Bennie Barnes	719 520 4677
Young Gas Storage Company, Ltd.	Bennie Barnes	719 520 4677