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INTERNAL CORROSION DIRECT ASSESSMENT OF GAS TRANSMISSION PIPELINES - METHODOLOGY

Final Report

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GRI DISCLAIMER

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DEDICATION

This report is dedicated to the memory of the late Phil Dusek who initiated and sustained the project activities.

GLOSSARY OF TERMS

Direct Assessment: a structured process for pipeline operators to assess the integrity of buried pipelines

Direct Examination: Physical examination of a pipeline surface. For internal corrosion, this requires entry to the pipe.

Electrolyte: A non-metallic substance (liquid or solid) that conducts electricity through movement of ions, thereby supporting corrosion.

Fluid: A substance that does not permanently resist distortion. Both liquids and gases are fluids.

Gas Storage System: Piping and related facilities to inject and recover natural gas in an underground formation. Recovered gas usually contains water carried from the storage structure.

Gathering System: Piping and related facilities to progressively commingle produced gas starting from individual wells to a trunk, common, or main line. Produced gas is unprocessed.

Indirect Examination: Use of tools to indirectly examine a pipeline. This includes monitoring (e.g., sampling, coupons/probes) and inspection methods (e.g., ultrasonics, radiography, in-line inspection).

Internal Corrosion Direct Assessment: An assessment methodology to determine if internal corrosion damage is likely or unlikely in a segment of pipe.

Liquid: A substance that tends to maintain a fixed volume but not a fixed shape.

Liquid Holdup: Accumulation of liquid (i.e., input liquid volume is greater than output liquid volume).

Multiphase Flow: Flow involving more than one phase. With respect to ICDA, it refers to natural gas and liquid water.

Superficial Gas Velocity: The volumetric flow rate of gas (at system temperature and pressure) multiplied by the cross-sectional area of the pipe.

Standard Cubic Feet and MMscf: Volume of gas under standard 1-atm and $60^{o}F$ conditions. MMscf is million standard cubic feet.

Tariff Quality Gas: Natural gas transported by an Interstate Gas Pipeline. Tariff requirements differ between companies, but usually include requirements for water, H_2S, total sulfur, CO_2, heating value, and temperature.

Transmission Pipeline: A pipeline used to transport tariff quality gas over large distances. With respect to ICDA, it includes specification of nominally dry gas (e.g., Water less than 7lb/MMscf).

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1 PROJECT SUMMARY

TITLE: Internal Corrosion Direct Assessment of Gas Transmission Pipelines

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REPORT PERIOD: January 2001 to April 2002

MISSION: 'Utilize existing technologies to develop an internal corrosion assessment methodology applied to gas transmission systems and determine its effectiveness.' This report covers methodology development only.

OBJECTIVE: 'Document and validate an assessment methodology to determine if internal corrosion is likely or unlikely to occur.' This report does not cover validation.

TECHNICAL PERSPECTIVE: Under normal operating conditions, gas transmission pipelines are not expected to internally corrode because an upstream gas dehydration treatment facility removes the water necessary for corrosion. The resulting gas is specified to be under-saturated with respect to water throughout the entire pipeline route. It is assumed that no other possibly corrosive liquids are carried over into the gas transmission pipeline.

Internal corrosion in gas transmission pipeline systems typically occurs when the upstream gas processing facility delivers product that does not meet quality specifications, since only then is it possible for liquid (i.e., 'free') water (and/or other possibly corrosive liquids) to enter the downstream transmission pipeline. Based on industry experience of gas plant operations, such deliveries and upsets have occurred, and in some cases have caused internal corrosion failures.

The success of an internal corrosion control program for gas transmission pipelines depends on 1) predicting susceptibility to internal corrosion under the full range of operating conditions, and 2) implementation of appropriate mitigation, monitoring, and inspection programs.

The first issue to consider in predicting internal corrosion susceptibility for a gas transmission pipeline is the possibility that the delivery of wet gas can occur in association with either of the following two scenarios:

- Occasional short-term upsets at the upstream processing facility, and/or
- Long-term, undetected delivery of gas that does not meet quality specifications.

Given either of the above two scenarios, the likelihood of corrosion occurring along a gas transmission pipeline depends on:

- The length of time that gas not meeting specifications is delivered,
- The gas composition, water chemistry, microbial activity, any other corrosive liquids associated with that gas, and
- The pipeline configuration and operating conditions resulting in local accumulation of water and/or other corrosive liquid.

Locating internally corroded pipe is difficult because the inside of the pipe is not easily accessible. Most existing detection methods require access to the inside of the pipe for either visual examination or inline inspection tools, and a large portion of pipelines does not allow inline inspection because of mechanical constraints. Inspection techniques such as radiography and ultrasonic transmission can measure wall thickness from the outside of the pipe, but excavation (and sometimes cleaning) of a buried pipe is required. Even then, only a small area of pipe can be inspected at a time. Therefore, a direct assessment of the likelihood of internal corrosion through knowledge of relevant pipeline physical and operating conditions enhances the safe operation of natural gas pipelines.

RESULTS: An internal corrosion assessment methodology applied to gas transmission systems was developed and is termed 'Internal Corrosion Direct Assessment' (ICDA).

TECHNICAL APPROACH: The basis behind ICDA is that detailed examination of locations along a pipeline where an electrolyte such as water would first accumulate provides information about the remaining length of pipe. The primary goal of the approach is to determine if internal corrosion is likely or unlikely to exist in a chosen length of pipe. If the locations along a length of pipe most likely to accumulate electrolyte have not corroded, then other locations less likely to accumulate electrolyte may be considered free from corrosion and not require further examination.

PROJECT IMPLICATIONS: The ICDA method can be used to focus the assessment of internal corrosion in pipelines and help ensure pipeline integrity. The method is applicable for gas transmission lines that normally carry dry gas but may suffer from short term upsets of wet gas or liquid water (or other electrolyte).

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2 INTRODUCTION

Direct Assessment (DA) is a structured process for pipeline operators to assess the threat to the integrity of buried pipelines.[1] One of several historical threats to pipeline integrity is internal corrosion as shown in Figure 1. Internal Corrosion Direct Assessment (ICDA) incorporates all existing methods of examination available to a pipeline operator and provides a methodology to best utilize those methods for specific applications. Direct examination of internal corrosion is impractical for most pipelines because it involves exposing the inside of a buried pipeline for physical measurements. Therefore, a suite of indirect examination tools in combination with a flow modeling approach is used to assess internal corrosion. Selection of tools depends on each application, and they are broadly categorized as 1) prediction of corrosivity, 2) corrosion monitoring, and 3) inspection or nondestructive examination (NDE). These three categories can also be described as 1) determining if corrosion will occur in the future, 2) finding on-going corrosion, and 3) measuring damage that has already occurred.

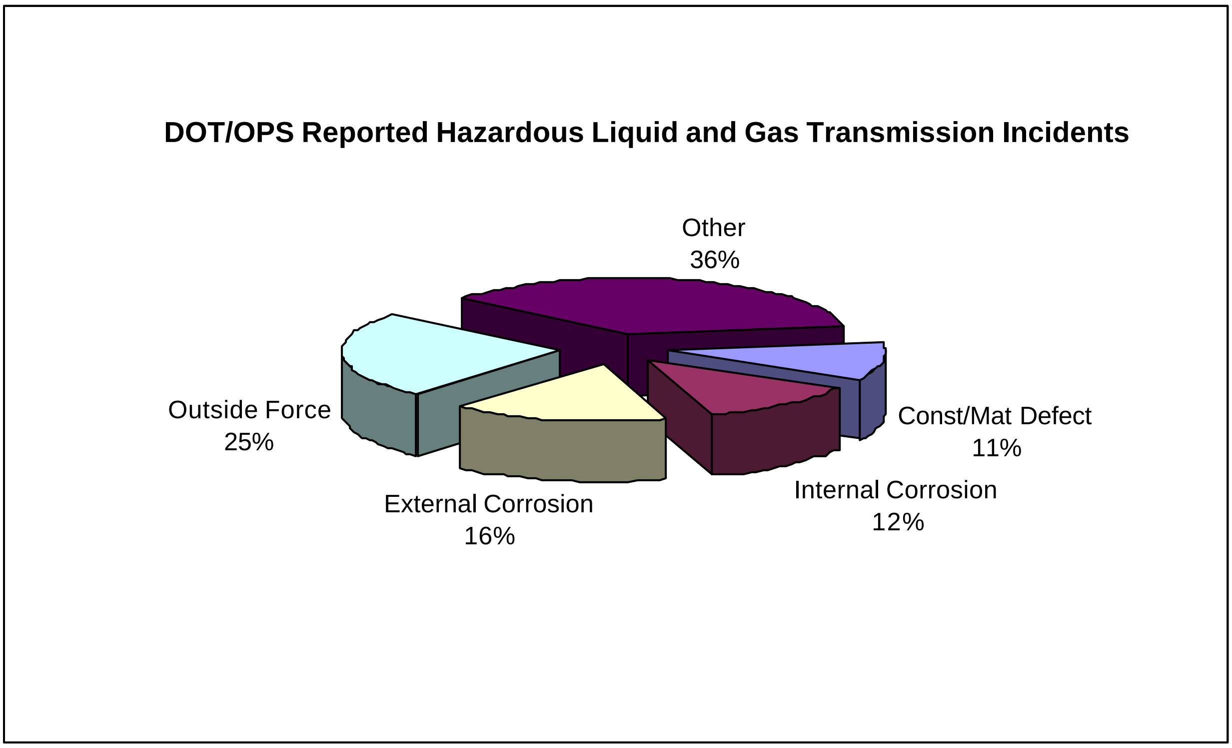

Figure 1. DOT/OPS year 2000 reported incidents.

2.1 Prediction of Corrosivity

The corrosivity of the environment inside a pipeline can be predicted based on gas composition, water chemistry, bacteria, and velocity effects. Without water or other electrolyte, no corrosion can occur. In addition, rate determining factors act interdependently, so any corrosion prediction that does not include them has limited accuracy and applicability.

2.1.1 Gas Composition

For gas transmission lines, the gases considered to affect corrosion are carbon dioxide (CO_2), hydrogen sulfide (H_2S), and sometimes oxygen (O_2). The amount of gas in a system is defined by its partial pressure, which is the product of the total system pressure and the mole fraction in the gas phase. For example, a system at 1000 psi containing 2% CO_2, has a CO_2 partial pressure of 20 psi.

The most common form of corrosion arises from the presence of CO_2 (sweet corrosion). Industry rules of thumb[2] for CO_2 corrosion are that 1) a partial pressure above 30 psi usually indicates corrosion; 2) a partial pressure between 3 and 30 psi may indication corrosion; and 3) a partial pressure below 3 psi generally is considered non-corrosive. The origins of these criteria appear to originate from experience (i.e., anecdotal evidence) rather than theoretical prediction or controlled experiments. An often used correlation for CO_2 corrosion is by DeWaard.[3]

Attack from H_2S, is referred to as sour corrosion. H_2S forms an acid when dissolved in water which can accelerate corrosion, but in some cases iron sulfide deposits may reduce corrosion. However, the protection by iron sulfide is unreliable and certain forms of iron sulfides are known to accelerate corrosion if electrolyte penetrates the corrosion product film. A related problem is sulfide stress cracking (SSC), which may occur at H_2S partial pressures of 0.05 psi or higher.[4]

Presence of as little as 100 ppm by volume of oxygen can increase the corrosion rate in the presence of CO_2 and H_2S. When O_2 is present along with H_2S, localized corrosion can occur, especially near the liquid-vapor interface. Oxygen increases the corrosion rate by increasing the corrosion potential. The corrosion rate is also dependent on the pH of the water and low rates are observed at pH values above about 6.

Gas quality specifications for gas concentration vary between companies, and waivers are often granted. The results of a 70 company survey are shown in Figure 2. This data is public domain information and thus easily available. Most of the survey information was gathered from electronic versions of tariffs available on the Federal Energy Regulatory Commission Bulletin Board Service (FERC BBS), while a few specific companies contributed information directly. It

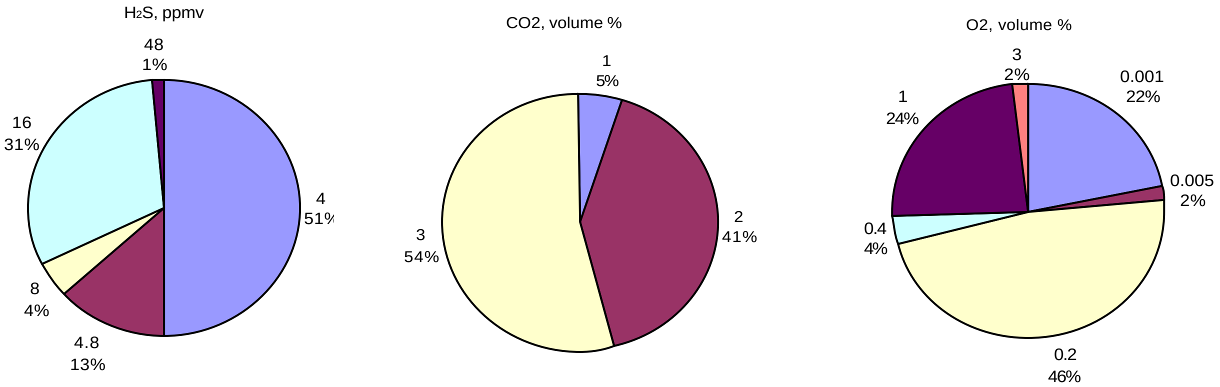

Figure 2. Gas quality specifications from survey of 70 companies.[1]

should be noted that even Tariff Quality gas may have sufficient contaminants for corrosion to occur. In addition, CO_2, H_2S, and O_2 act interdependently because their relative concentrations affect the character of corrosion products. Therefore, a complete assessment of how the gas composition affects corrosion requires consideration of all three gases and their relative concentrations.[5]

2.1.2 Water Chemistry

Water associated with natural gas is usually condensed from the gas phase or produced from a formation. Condensed water does not contain dissolved solids. Therefore, only dissolved gas needs to be considered (unless solids on the pipe wall are dissolved). Carbon dioxide dissolves in water and creates acidity.[6] The proton, bicarbonate ion, and undissociated carbonic acid molecule all serve as cathodic reactants for corrosion.[7]

$$CO_2 + H_2O \text{ ? } H_2CO_3 \text{ ? } HCO_3^- + H^+ \text{ ? } CO_3^{2-} + 2H^+$$

Hydrogen sulfide similarly dissolves in water affecting corrosivity by the following dissociation

$$H_2S \text{ ? } HS^- + H^+ \text{ ? } S^{2-} + 2H^+$$

Produced water typically contains significant dissolved solids including sodium, iron, manganese, barium, calcium, magnesium, chloride, bicarbonate, carbonate, and sulfate.[8] These species affect the deposit of solids on a pipe wall. In addition, bicarbonate and carbonate serve as pH buffers. Typical deposits are calcium and iron carbonates, barium and calcium sulfates, magnesium hydroxides and carbonates. Chloride (and other halogens) are particularly important because they can cause breakdown of protective films on metals resulting in localized corrosion.

2.1.3 Microbial Influence

Microorganisms (primarily bacteria, but may include fungi, algae, and protozoa) can influence corrosion of pipelines and is termed microbiologically influenced corrosion (MIC). Bacteria tend to form colonies of more than one type of microbe. These multi-membered colonies are also termed a community or consortium, and often form on the metal surfaces of pipelines and other associated equipment. Biofilms can also trap solids entrained in the gas stream forming deposits that may also influence corrosion. Due to the metabolic activities of microbial communities, the interface between the metal surface and the organisms may be physically and chemically altered. Microorganisms can form acids, alcohols, ammonia, carbon dioxide, hydrogen sulfide and other metabolic products capable of causing corrosion under appropriate conditions. Microbes can consume oxygen, concentrate corrosive anions (sulfates and chlorides) in pits or crevices and under deposits, break down passive surface films, and accelerate corrosive attack by a variety of mechanisms.[9]

2.1.3.1 Bacteria

Bacteria can live and reproduce in many different environments. For example, they can live in acidic (low pH), neutral, or alkaline (high pH) environments, and exist over a wide range of temperatures and pressures. Bacteria can be introduced into oil and gas systems through a variety of mechanisms: accidental ingress of produced water, proximity of storage fields, and inadequate removal of hydrotest water. While microorganisms are found in many pipeline systems, their presence does not necessarily cause accelerated corrosion.

Bacteria are simple one-celled organisms without true nuclei, and as a result are classified as among the simplest living organisms (prokaryotes). Bacteria consume nutrients from the environment, derive energy for life, and excrete waste products from these processes. There are many different types of bacteria with different preferences for nutrients, temperatures, pressures and environments. Bacteria can be classified based on their oxygen requirements. Aerobic bacteria require air or oxygen to live. Anaerobic bacteria require an environment without air or oxygen. The presence of air or oxygen can kill or inhibit the growth of some anaerobes. Obligate bacteria can only exist in one environment (either aerobic or anaerobic conditions, but not both).

The growth of facultative bacteria is not restricted, and these bacteria can live in either aerobic or anaerobic environments. There are additional terms that are used to describe bacteria that are not based on oxygen dependency. Bacteria that are attached to a surface are classified as sessile. Free-floating bacteria suspended in a fluid are classified as planktonic. Different types of bacteria can co-exist on a metal surface in the form of a interdependent consortium. The types of bacteria typically found in pipelines include:

- Sulfate reducing bacteria (SRB) - SRB reduce sulfate to sulfide as a source of energy. Most species of SRB contain the enzyme hydrogenase, which further catalyzes the reduction of sulfates by hydrogen. Since iron is generally used in SRB cell structure, an iron-rich environment often promotes their growth. Reduced sulfate reacts with available hydrogen and iron to form hydrogen sulfide and iron sulfide. SRB are strictly anaerobic, but may exist in oxygen-rich environments if oxygen scavengers (e.g., aerobes, facultative anaerobes, slime-forming bacteria) are present to create locally anaerobic conditions.
- Acid producing bacteria (APB) – As a result of their metabolism (i.e., breaking down of organic nutrients), APB can release aggressive metabolites such as organic acids, or, under certain specialized conditions, inorganic acids. In addition to acids, APB produce alcohols, hydrogen, carbon dioxide and other metabolites that can serve as nutrients for SRB and other similar organisms.
- Other Bacteria - Additional types of bacteria may be present in pipelines and associated facilities. Facultative anaerobes and slime-forming bacteria, among others, are of most relevance. These organisms are important because they provide food to other community members, sweep away rate-limiting or growth-inhibiting metabolites, and protect them through slime and/or deposit formation. These organisms can also scavenge any oxygen present, which can allow SRB and other strict anaerobes to exist

2.1.4 Velocity and Flow Effects

The effect of fluid velocity on corrosion has been extensively studied (e.g., NACE[10]). The majority of work has been to assess the effects of shear stress and mass transfer on corrosion rates. It should be noted that the effects of velocity are complex and depend on the metal and environment (e.g., Fontana[11]). Many systems have no dependence on flow, many systems have higher corrosion rates with increased flow (e.g., convection of cathodic reactants), some metals can passivate with increased flow, and protective films are affected by a complex combination of growth, dissolution, and disruption processes. The flow regime typically present in gas transmission lines and the resultant effect on corrosion are discuseed in section 4.2.

2.2 Corrosion Monitoring

Corrosivity can be detected by monitoring tools, but their utility is limited by the ability to locate them in either representative and/or the most susceptible locations along the pipeline. For gas transmission lines, installing a monitoring coupon or probe without consideration for the location of most susceptible corrosion has limited use. The commonly installed coupon at the end of a line (or at a riser) can be used to identify line-wide problems in a pipeline, but these tools are not effective for monitoring corrosion that may occur at isolated locations.

The simplest, oldest, and most widely used method to estimate corrosion is weight loss measurement of test coupons. A weighed sample coupon of the material under consideration is exposed to an environment and retrieved after a reasonable time interval. After removal of all deposits, the coupon is weighed again. The weight loss is then converted to a corrosion rate. The technique requires no complex equipment or procedures, merely an appropriately prepared coupon and a reliable means of removing corrosion product without disruption of the metal substrate. Most present analyses of exposed coupons include pit depth measurement and qualitative assessment of corrosion through comparison with visual (photograph) standards. This approach provides information about nonuniform corrosion or pitting. Advances have been made in extended analysis and interpretation of coupon data (e.g., Eckert[12]).

Electrical resistance (ER) probes operate on the same principle as weight loss coupons, except the metal loss is measured through decreased electronic resistance through a wire, foil, or other thin metal structure. The advantages are that the readings are continuous allowing rapid problem identification and the probe does not need to be retrieved (sensing is remote).

Electrochemical probes include linear polarization resistance (LPR) and electrical noise (EN). Electrochemical probes are useful for real-time measurement of corrosivity, but they must be located in an electrolyte to provide a reading. In addition, episodic hydrocarbon wetting can foul the probe. Their use in dry gas pipelines (or crude pipeline) is therefore limited. LPR probes measure polarization resistance of a steel sample, assume electrochemical parameters (i.e., Tafel slopes), and predict corrosion rate (e.g., French[13]). EN probes measure small spontaneous differences in current and potential between nominally identical coupons (e.g., Kearns [14]) to identify the onset of localized or uniform corrosion.

Another method to monitor corrosion is to collect samples of liquid, solids, or sludge from a pipeline. The presence of iron may indicate corrosion. For systems where iron may already exist, manganese can be used to detect pipe wall dissolution. One limitation to this technique is that it cannot be determined if a small acceptable amount of corrosion has occurred on a large area of pipe or if a high rate of corrosion has occurred over small areas.

It should be noted that it is possible to use NDE methods for corrosion monitoring. For example, permanently mounting an ultrasonic tool to a pipe wall allows the inspection tool to measure wall loss at that location continuously over time.

2.3 Inspection or NDE

Pipelines are most commonly inspected for corrosion using magnetic flux leakage (MFL) inline inspection pigs. However, a large portion of gas transmission pipelines has mechanical constraints preventing their use, and the tools cannot access some of the areas most susceptible to internal corrosion (e.g., drips and stub-ends). An inspection technique such as radiography and ultrasonic transmission can measure wall thickness from the outside of the pipe, but excavation of a buried pipe is required and only a small area of pipe can be inspected at a time. Other methods include ultrasonic transmission (UT) pigs and caliper pigs. Camera inspections are possible if the inside of the pipe is clean and can be accessed, but they are based on subjective interpretation of the inspection video. Camera inspection can detect the presence of corrosion products and possibly pitting; however, these results can not be quantified with respect to remaining wall thickness.

3 BACKGROUND

Under normal operating conditions, gas transmission pipelines are not expected to internally corrode because an upstream gas dehydration treatment facility removes the water necessary for corrosion. The resulting gas is specified to be under-saturated with respect to water throughout the entire pipeline route. It is assumed that no other possibly corrosive liquids are carried over into the gas transmission pipeline. Internal corrosion in gas transmission pipeline systems occurs when the upstream gas processing facility delivers product that does not meet quality specifications, since only then is it possible for liquid water (and/or other possibly corrosive liquids) to enter the downstream transmission pipeline. Such upsets have occurred and in some cases caused internal corrosion damage and failures (as was shown in Figure 1).

A search of publicly available information, including open literature, industry standards, and commercial models, showed that no previous work sufficiently addresses the issue of internal corrosion assessment in gas transmission pipelines. Much research has been performed on corrosion in wet gas systems such as gathering lines[15,16] including the use of multiphase flow modeling,[17,18,19] and commercial corrosion prediction models have incorporated this research. In addition, the scope of standards from organizations such as NACE International, ASTM, and API do not adequately cover internal corrosion specifically applied to gas transmission pipelines. It is hoped that the internal corrosion assessment methodology presented in this report will be evaluated, adopted, and evolved by these organizations. Commercial risk assessment software can also serve to disseminate assessment methodologies by incorporating the technology.

Internal corrosion has occurred in systems where the gas phase is saturated with water (e.g., gathering systems), and corrosion control programs generally exist to predict, monitor, mitigate, and inspect these systems. Corrosive liquids include condensed water from gas containing too much water vapor and liquid water that carries over from plant upsets. In addition, gas dehydration units usually use glycol (e.g., tri-ethylene glycol) which can contain water and support corrosion if introduced to a pipeline. Glycol can be introduced by mist carryover or by inadvertent upsets. The most effective method to prevent corrosion in gas transmission lines is to avoid introducing wet gas, liquid water, glycol, or other electrolytes to support corrosion. However, these inputs have historically occurred in gas transmission systems, so ICDA is intended to determine the corrosion related effects of these upsets.

Locating internally corroded pipe is difficult because the inside of the pipe is not easily accessible. Most existing detection methods require access to the inside of the pipe for either visual examination or inline inspection tools, and a large portion of gas transmission pipelines does not allow inline inspection because of mechanical constraints. Inspection techniques such as radiography and ultrasonic transmission can measure wall thickness from the outside of the pipe, but excavation (and sometimes cleaning) of a buried pipe is required. Even then, only a small area of pipe can be inspected at a time. Therefore, an assessment of the likelihood of internal corrosion through knowledge of relevant pipeline physical and operating conditions will enhance the safe operation of natural gas pipelines.

3.1 Liquid Water Upsets

One mechanism for liquid water to enter a pipeline is for it to be input as short, episodic carry-over of liquid water (and may be associated with saturated gas). Generally this liquid contains dissolved solids and is expected to evaporate in a nominally dry gas pipeline. Even if this water is treated with corrosion inhibitor, the remaining solids following evaporation are detrimental to corrosion control. Input of liquid water far upstream of a gas quality monitoring point often goes undetected. This is because the water evaporates and is diluted by a large volume of gas. However, corrosion might have occurred during the time that it accumulated following the input, and detrimental solids might have been left behind.

3.2 Wet Gas – Condensed Water

Another mechanism for liquid water to exist in a pipeline is to condense from wet gas. Water content in natural gas systems is commonly stated in pounds per million standard cubic feet (lb/MMscf). Another useful method of indicating water content is in terms of dew point, which is the temperature at which the gas becomes saturated with respect to water vapor. Water saturated (or wet) gas is the condition where water vapor is in equilibrium with liquid water; the partial pressure of water vapor in saturated gas equals the vapor pressure of the liquid water at the gas temperature. Since the partial pressure is proportional to the total pressure, and the vapor pressure is independent of total pressure, the dew point for a particular gas changes with operating pressure (i.e., the dew point temperature increases with pressure).

Typical gas quality contract specifications indicate water vapor content less than 7 lb/MMCF (112 g/m^3).[20] The results of a 70 company survey are shown in Figure 3. ASTM standard D1142-95[21] shows the relationship between water content (lb/MMscf), dew point (F), and pressure (psi). At 7 lb/MMscf (112 g/m^3) and 1000 psi (6.9 MPa) pressure, the dew point is 35 F (2 C).

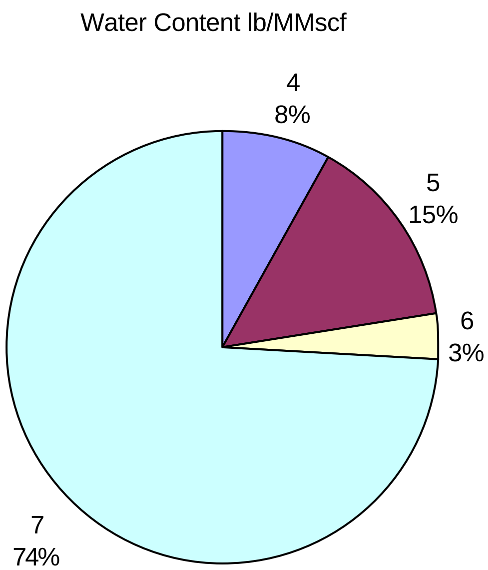

Figure 3. Water content specification from survey of 70 companies.[22]

Condensed water has low dissolved solids because they cannot be carried in the vapor phase. Subsequent evaporation of condensed water therefore leaves no solids on the pipe wall unless microbial activity has produced them. In addition, detrimental species such as chloride ions are not present. However, condensed water also has no carbonates, which serve as a pH buffer.

It should be considered that humid gas at temperatures above the dew point might also support corrosion if 1) the gas is close to the dew point or 2) hygroscopic or deliquescent solids exist in the pipeline. If salts were deposited during previous liquid water upsets, water may be absorbed by them and support corrosion in those locations. The graph shown in Figure 4 shows the relative humidity at which various salts will deliquesce (i.e., become liquid and support corrosion). Mixtures of solids may have different deliquescence points. Another factor is that the presence of solids or biofilms can slow the rate of evaporation because water becomes trapped in the solid matrix. Fortunately, the most likely locations for accumulation of solid materials can be predicted because they correlate with accumulation of liquid water.

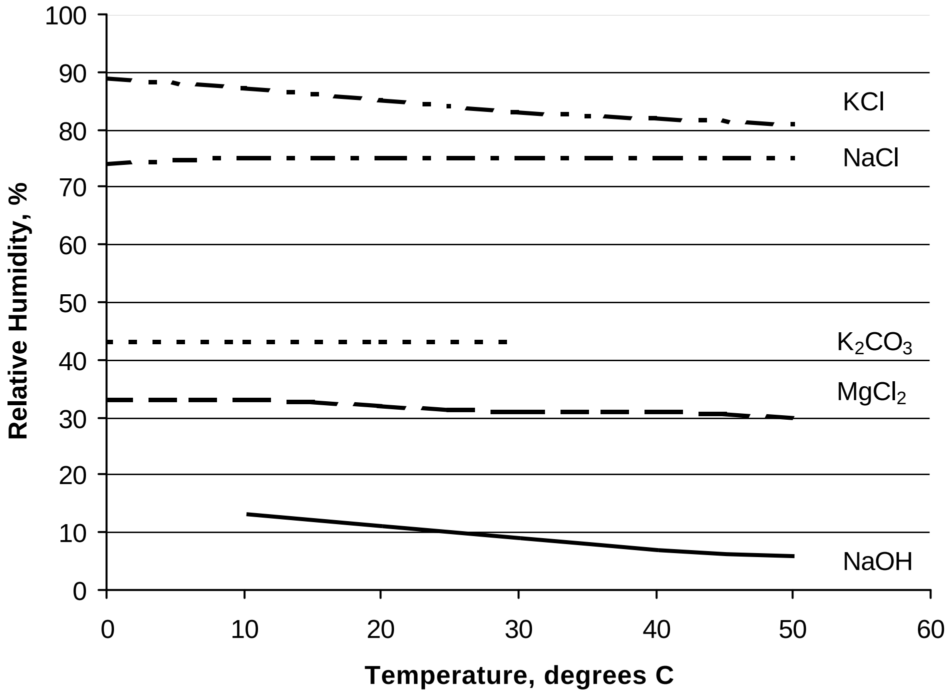

Figure 4. Deliquescence humidity for various salts after Greenspan.[23]

3.3 Glycol

In dry natural gas systems, glycol carry-over from a dehydration facility may lead to the formation of corrosive water/glycol mixtures.[24] A common method to remove water from natural gas is glycol dehydration.[25] Triethylene glycol (TEG) or Diethylene glycol (DEG) is used to absorb water in the gas stream. Countercurrent contacting of wet natural gas with TEG results in dry gas, but droplets of the wet glycol solution may be entrained in the gas stream and thus be carried over from the absorber into the pipeline. The glycol with absorbed water can then support corrosion. Glycol in a dry gas pipeline can be problematic because, unlike water, it will not evaporate under normally dry gas conditions. TEG has a vapor pressure less than 1 mm Hg at 100 C.[26]

3.4 Other Sources of Electrolyte

Other sources of electrolyte may exist in a pipeline that should be considered as part of an overall risk management and corrosion control program. However, the ICDA process does not specifically address sources such as remaining hydrotest water, corrosion inhibitor carriers, or methanol for hydrate control.

3.5 Use of Drips

Drips (also called drip legs or drip logs) are intended to remove free liquids from gas pipeline systems. A wide range exists in the use and design of drips,[27] with designs ranging from a short piece of pipe tied into the pipeline to configurations that are fully incorporated to the mainline. Many pipelines do not have any drips, and others have drips throughout a system. The reason for this wide range is that although drips are intended to remove liquids, they operate at full pressure and can corrode (and have ruptured). One factor influencing the effectiveness of drips is the inability to locate them where liquid is most likely to accumulate. This means that free liquid can exist in a pipeline, but the drip does not drain it because it is not at the same location as the accumulation. This problem is confirmed by the experience that liquids are pushed out of a pipe by cleaning tools (i.e., pigs) despite the existence of drips. It is also possible for a drip configuration to prevent pigs from being run. Although drips are often placed at low points in a pipeline system, selection of the proper location depends on the ability to quantitatively predict locations of liquid accumulation (e.g., by the ICDA approach).

4 ICDA METHOD

The basis behind ICDA for gas transmission lines is that detailed examination of locations along a pipeline where an electrolyte such as water first accumulates provides information about the remaining length of pipe. If the locations along a length of pipe most likely to accumulate electrolyte have not corroded, then other locations less likely to accumulate electrolyte may be considered free from corrosion and not require further examination. Simply stated:

Corrosion is most likely where water first accumulates

A flow diagram shown in Figure 5 illustrates the process. The first sub-algorithm in the process is to predict locations where electrolyte is likely to first accumulate. This task requires knowledge about the multiphase flow behavior in the pipe and is valid for lengths of pipe defined by potential inputs or outputs to the pipeline. The length of pipe to be considered by the ICDA process does not depend on distance. Rather, the ICDA applies to any length of pipe until a new input or output changes the potential for electrolyte entry or flow characteristics.

Development of ICDA was based on a set of pipeline characteristics that define the pipelines for which ICDA as described in this paper is appropriate. The first characteristic is that the transported gas is normally dry (e.g., <7 lb/MMCF (112 g/m^3)), and any short upsets of water eventually vaporize into the gas phase. This condition allows short-term upstream water accumulation, but downstream accumulation is not expected. Under this constraint, corrosion, if it exists, will occur at isolated locations along a pipeline. These pipelines are uninhibited, do not have internal coatings that provide corrosion protection, and are not frequently cleaned using a pig. The ranges of parameters for flow modeling include an anticipated majority of gas transmission lines and are not based on technical constraints. The bounds are: a maximum superficial gas velocity of 25 ft/s (7.6 m/s); pipe size from 4 to 48 inch (0.1 to 1.2 m) diameter; pressure from 500 to 1100 psi (3.4 to 7.6 MPa); and relatively constant temperature over pipe length (i.e., ambient soil temperature and up to 130 F (54 C) at compressor discharge).

It should be noted that electrolyte is necessary but insufficient for corrosion. Corrosion is possible only in the presence of an electrolyte, and the presence of corrosion damage indicates that electrolyte existed at that location. The absence of corrosion does not provide information about liquid accumulation because the factors listed in the introduction of this paper affect both the potential driving force for corrosion and the rate. For ICDA, liquid (i.e., ‘free’) water is considered to be the primary source of corrosive electrolyte, glycol and wet gas are considered secondary, and other sources (e.g., hydrotest water) are not considered. The ICDA user is encouraged to research historical data about a pipeline since upset conditions that influence internal corrosion can be brief and in some cases undetected.

Locations with the longest exposure times to accumulated water (or other electrolyte) will generally have the most severe corrosion damage, unless the pH is such that a protective film can form. This is because water that accumulates at more than one location in a pipeline will have similar composition and similar corrosion rate. Gas composition is uniform throughout the length of pipeline until gas input or output changes the composition. When water evaporates, it concentrates any dissolved solids, which tends to increase corrosivity. This condition tends to make the locations most likely to accumulate electrolyte the most corrosive. Microbial activity requires water, so it is expected to be most severe at water accumulation points.

The second sub-algorithm of Figure 5 is to perform a detailed examination on locations where the most likely electrolyte accumulation is predicted. This detailed examination includes all of the techniques described in the introduction of this report (i.e., prediction of corrosivity, corrosion monitoring, and inspection). For many pipelines it is expected that excavation and inspection by radiography or ultrasonic transmission will be required. It should be noted that once a site has been exposed, installation of a corrosion monitoring tool (e.g., coupon, probe, UT sensor) may allow an operator to increase inspection intervals and benefit from real-time monitoring in the locations most susceptible to corrosion. Corrosion monitoring tools installed at arbitrary locations (e.g., end of line) along a pipeline should not be expected to identify isolated corrosivity that occurs elsewhere in the pipeline. There may also be some applications where the most cost-effective approach is to run an in-line inspection tool for a portion of pipe, and use the results to assess the downstream internal corrosion where a pig cannot be run.

If the locations most susceptible to corrosion are determined to be free from damage, the integrity of a large portion of pipeline mileage can be assured, and resources can be focused on pipelines where corrosion is determined to be more likely. Of course, if corrosion is found, a potential integrity problem has been identified, and the method is also considered successful.

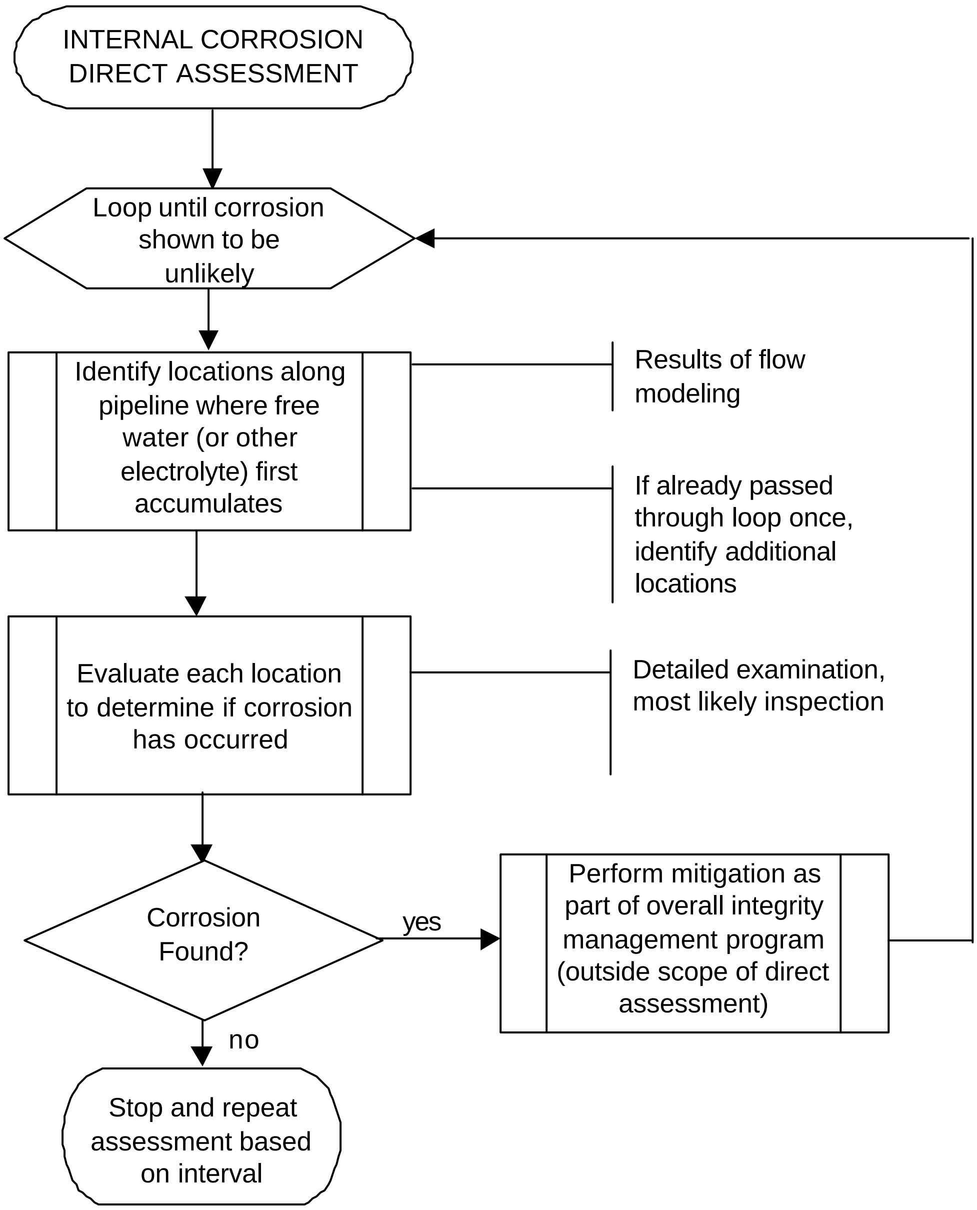

Figure 5. Flow diagram of ICDA for determined length of pipe. Also consider that other pipeline components (e.g., drips) may collect liquids.

4.1 ICDA in Overall Risk Management Process

ICDA is a method to assess the likelihood of corrosion in a given length of pipe within a transmission pipeline. The role of ICDA in an overall risk management process is shown in Figure 6. Activities such as corrosion mitigation or repair fall outside the scope of ICDA. However, the results of an internal corrosion assessment can be used together with estimated cost and consequence information to guide maintenance decisions such as repair or corrosion mitigation.

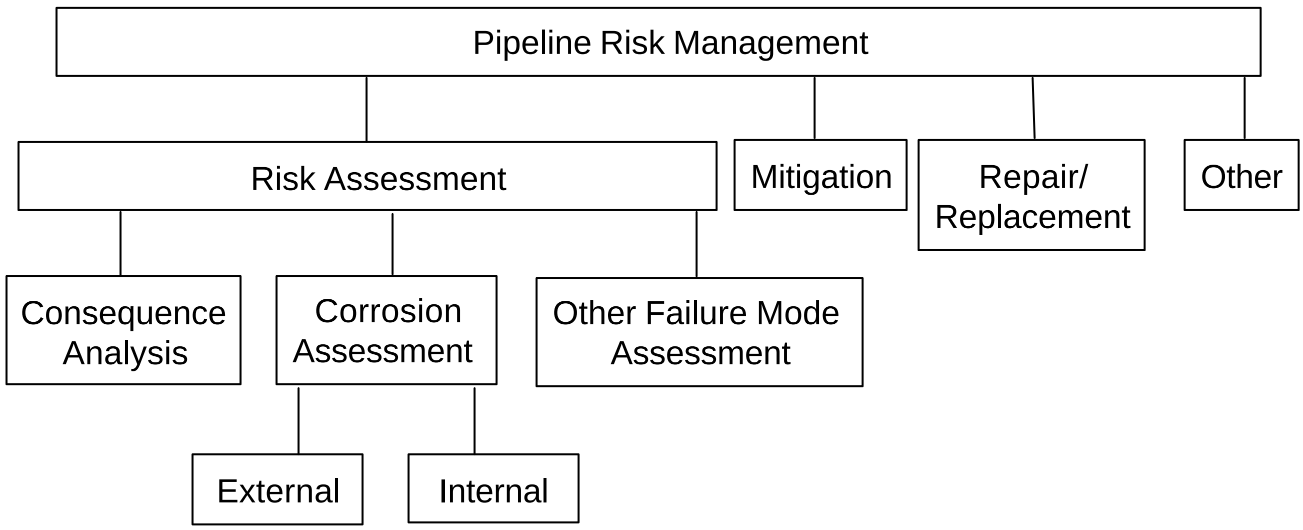

Figure 6. Role of ICDA in overall risk management process.

4.2 Use of Flow Modeling to Predict Liquid Accumulation Points

The ICDA method relies upon the ability to identify the locations most likely to accumulate electrolyte. These locations are predicted using the results of pipeline multi-phase flow modeling. OLGA-S was chosen to characterize the fluid flow behavior because it better extrapolates to field conditions than other available simulation models and is generally considered to be the state-of-the-art method for prediction of liquid hold-up.[28,29] This flow modeling method, in contrast to correlative methods, applies mechanistic analysis to the relevant multiphase flow regime. In addition, the model has been validated through large-scale laboratory results and comparisons to field data over a period of almost twenty years.[29,30,31] The field validation of the program was carried out through the OLGA Verification and Improvement Program (OVIP), a research program sponsored by more than 10 oil companies, in which both new simulations and previous correlative methods were compared to field data. For wet gas systems, liquid holdup was found to strongly depend on gas velocity and the angle of inclination. At low rates, the liquid holdup can increase by a factor of 100 or more as the inclination angle changes a fraction of a degree. Other models,[32] which are correlation based, do not predict this behavior.

For gas-liquid flow, five basic flow regimes have been identified, but only two are considered relevant to gas transmission pipelines. An example flow map following the approach of Taitel[33] is shown in Figure 7. Smooth stratified, wavy stratified, intermittent (slug and plug), annular with dispersed liquid, and dispersed bubble are possible in gas-liquid flow. In gas transmission pipelines, the volume of liquid phase (and therefore superficial liquid velocity) is assumed to be small because normal operating conditions are single phase gas, and free liquids exist in small volumes during episodic upsets. Intermittent flow (i.e., slugging) occurs when liquid rates are increased, and dispersed bubble flow requires a large continuous liquid phase.

Annular flow requires sufficient liquid to cover the pipe wall, but even a small amount of dispersed liquid can be entrained in the gas phase. Therefore, stratified (i.e., film) and dispersed liquid (i.e., droplet) flow regimes are relevant to gas transmission pipelines. As can be seen from the generic Figure 7, stratified flow occurs over a wide range of gas velocities whenever liquid superficial velocity (liquid flow rate divided by pipe cross sectional area) is low. This is the prevalent condition occurring in gas transmission lines.

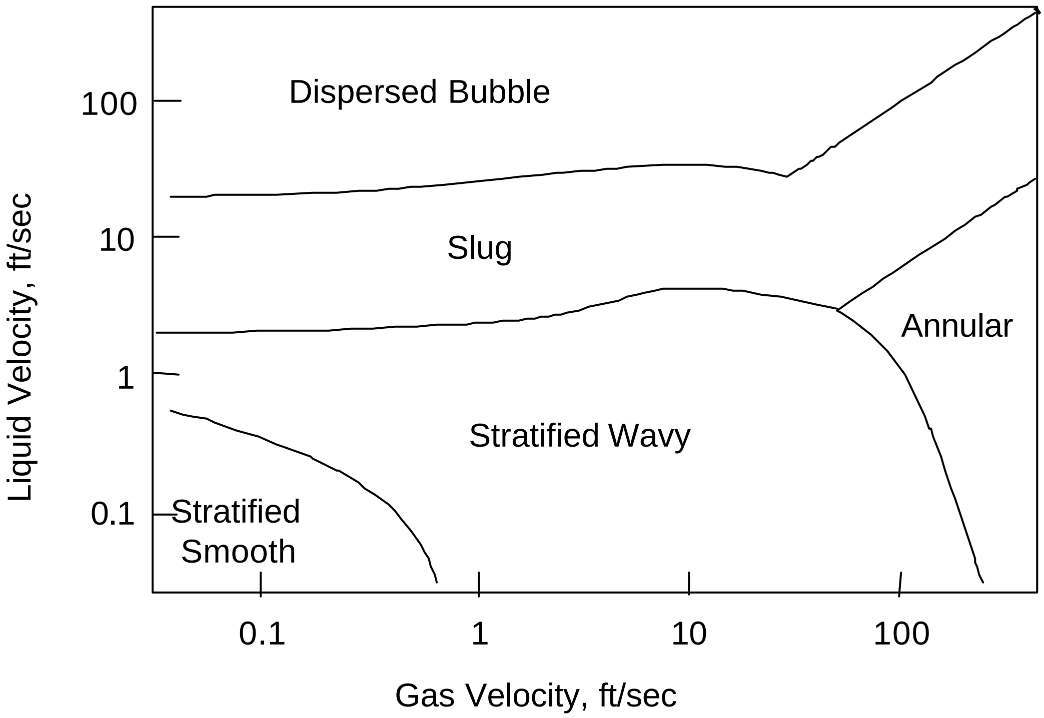

Figure 7. Example flow regime map for 24-inch I.D. horizontal pipe after Taitel.[33]

Stratified film flow is considered the primary liquid water transport mechanism, and any liquid droplets entrained in the gas are expected to evaporate because gas transmission pipelines carry nominally dry gas most of the time. Droplets have high surface area to volume ratio, the water is directly exposed to the gas phase, and the velocity of the gas near the droplet is high. All these three factors will lead to rapid evaporation of water droplets in the gas phase. Film flow in comparison has less favorable evaporative mass transfer characteristics. Liquid on the bottom of a pipe has less surface area to volume than when dispersed as bubbles, the gas velocity at the surface of the liquid is lower, and it is possible that a less volatile liquid covers the water inhibiting evaporation.

Film flow along a pipe is driven by the forces of shear stress imposed by the moving gas and gravity determined by pipe inclination. Three conditions are shown in Figure 8. A downhill pipe does not accumulate water because both gas flow and gravity move liquid downstream. A horizontal pipe does not accumulate water if the gas is moving because the effect of gravity is zero. However, an uphill pipe creates a condition where gravity and shear stress oppose each other. Holdup occurs when the downstream force of gravity is larger than the shear stress effect.

The balance between gravity (causing liquid to drain backwards) and shear stress between gas and liquid (causing liquid to be carried forward) defines the critical angle for liquid accumulation. The effect of pipe wall roughness (e.g., solids to increase or drag reducing coatings) is not considered significant because the shear stress at this location is small. Inclinations greater than critical will accumulate water, and inclinations less than critical will allow water to be carried downstream until a critical inclination is reached (or the water is evaporated). For a given inclination, water inventory increases when gas velocity falls below a critical threshold. For the low liquid loading encountered in gas transmission lines, this increase is quite dramatic. Characteristically, liquid holdup fractions will jump from less than one per cent to several tens of percent over a gas velocity decrease of less than 5 percent[34]. Water accumulates preferentially in first inclination exceeding a critical threshold, and continuous water input without evaporation will eventually load all critical inclinations with water so that large water input to a line will fill the first critical inclination point and carry over to the next critical inclination.

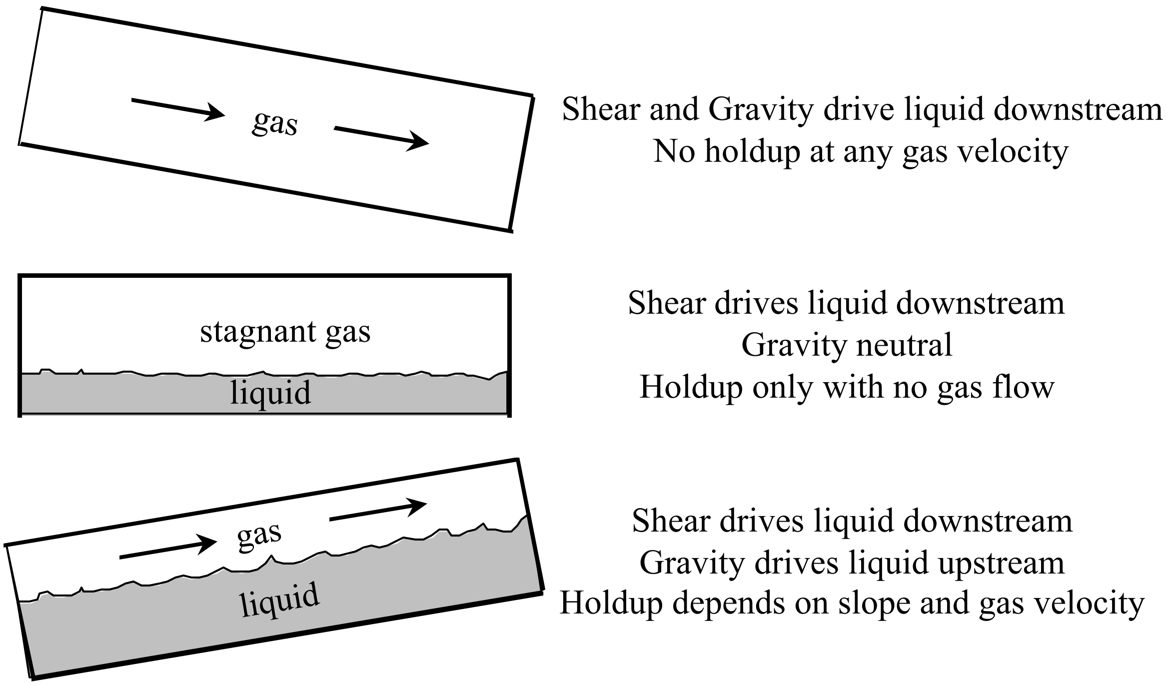

Figure 8. Shear stress balances gravity to determine liquid holdup.

4.3 Results of Flow Modeling

A series of multiphase flow simulations were run to determine the effects of pressure, temperature, gas velocity, and pipe diameter on critical angle for water accumulation. The bounds for this parametric study were pipeline operating pressure of 500 to 1100 psi (3.4 to 7.6 Mpa), temperature of 60 to 130 F (16 to 54 C), less than 25 ft/s (7.6 m/s) superficial gas velocity, and 4 to 48 (0.51 to 1.2 m) pipe diameter. Plots of critical inclination versus flow velocity illustrate the results of flow modeling. The results of predicting critical angles for 20-inch (0.51 m) pipe at 900 psi (6.2 MPa) and 60 F (16 C) are shown in Figure 9. At large angles of inclination and low gas velocities, water accumulates in the pipe. At low angles and high gas velocities, water carries through the pipe further downstream until it reaches an inclination of critical angle or evaporates.

Figure 10 shows the effect of pressure on critical angle for water accumulation. Higher pressures result in water being more easily carried downstream. For a given gas velocity, the critical angle necessary to hold up water increases with pressure. Conversely, a given inclination on a pipeline will hold up water at lower velocities as the pressure is increased.

Figure 11 shows the effects of both pipe diameter and temperature. At larger pipe diameters, liquid accumulates at lower critical angles given the same gas velocity. At higher temperatures, liquid accumulates at lower critical angles given the same gas velocity, but this effect is relatively small. The 130 F (54 C) upper temperature bound represents a typical compressor station outlet temperature, which decays according to[35]

$$\frac{T - T_{ground}}{T_{discharge} - T_{ground}} = \exp(-ax) \tag{1}$$

where T is temperature, alpha is a proportionality constant, and x is distance down the pipeline.

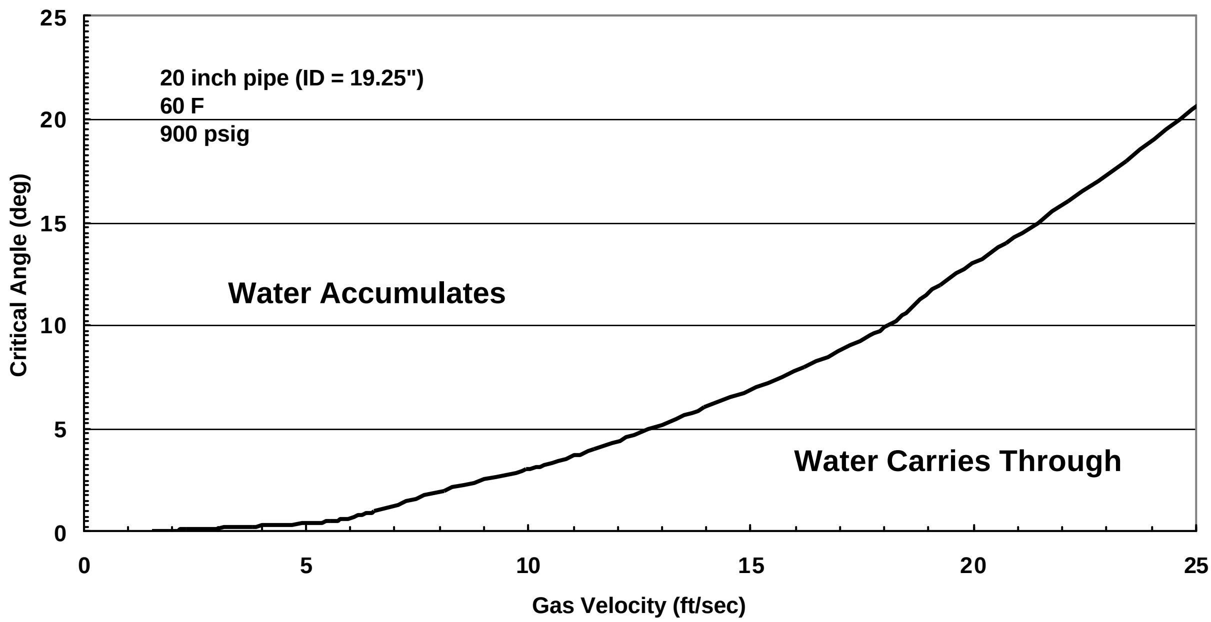

Figure 9. Critical angles for water accumulation. For large angles and small velocities, water accumulates. For small angles and large velocities, water carries through.

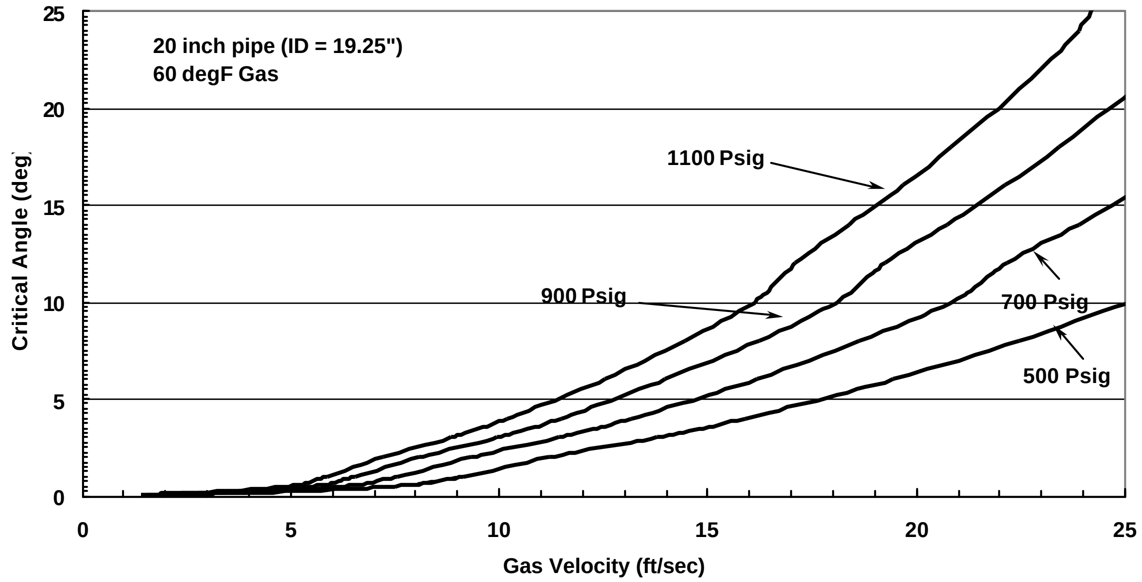

Figure 10. Critical Angles for water accumulation calculated by multiphase flow modeling.

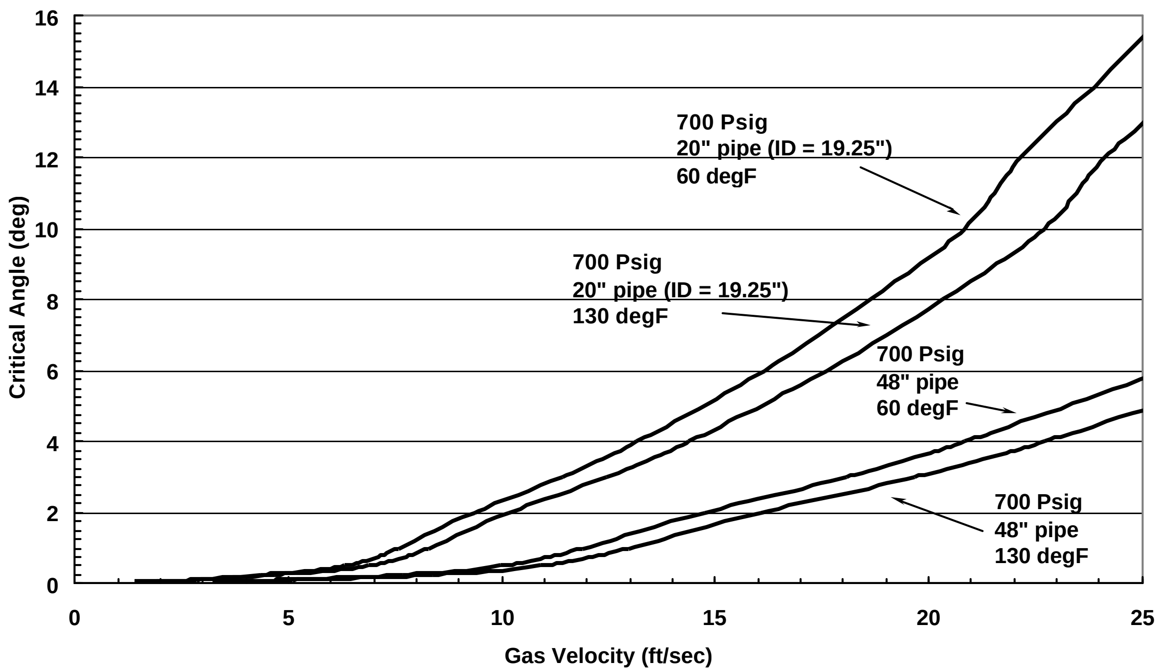

Figure 11. Critical angles for water accumulation calculated by multiphase flow modeling. Plot illustrates effect of temperature and pipe diameter.

To combine the results of simulations in an expression, a modified Froude number, F, similar to Taitel and Dukler[33] is proposed here (which represents a ratio of gravitational force to inertial stress per unit area acting on a fluid)

$$F = \frac{\rho_l - \rho_g}{\rho_g} * \frac{g * d_{id}}{V_g^2} * \sin(\theta) \tag{2}$$

where ρ is density, g is gravity, V is superficial velocity, and θ is angle of inclination.

The results of model runs were input to the Froude number and are plotted in Figure 12. At angles less than 0.5 degrees, F is 0.33 with a standard deviation of 0.07. At angles greater than 2, F is 0.56 with a 0.02 standard deviation. The angles between 0.5 and 2 degrees are believed to be associated with laminar to turbulent transition. F is linearly interpolated in the transition zone.

The Froude number serves to simplify calculations, and an Excel™ spreadsheet was prepared so that the user can input temperature, pipe diameter, pressure, and liquid density. Two screen captures of the spreadsheet using gas velocity and gas throughput are shown in Figure 13 and Figure 14 . User inputs are pipe size, pressure, and temperature. On a second worksheet in the workbook, the liquid density can be adjusted, and a compressibility factor, Z, used to calculate gas density given by

$$Z = \frac{PV}{nRT} \tag{3}$$

where P is pressure, V is volume, n is moles, R is the gas constant, and T is temperature. For the range of gas conditions, a default value of 0.83 is used for compressibility based on the output of simulations. This value is consistent with literature values.[36,37]

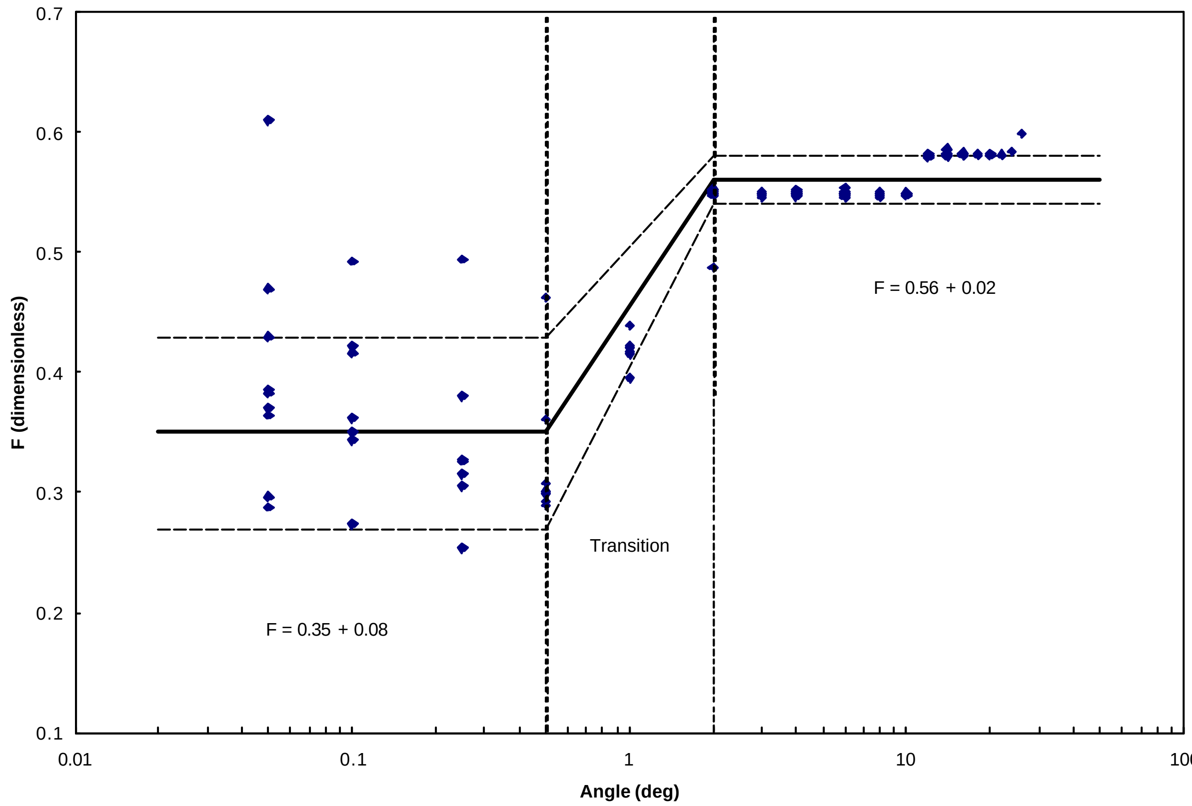

Figure 12. F factor versus critical angle for water accumulation. Average values ± standard deviation.

4.4 Utilizing the Results of Flow Modeling

Flow modeling results are used to predict the locations at which water begins to accumulate if it is input to the pipeline. Water accumulates on uphill sections of pipe. This is because the shear stress and gravity forces are balanced at this point. For a short dip associated with a feature (e.g., road crossing), water accumulation will occur on the short uphill segment and therefore indicates a narrow section of pipe to examine and/or inspect. The condition where a large up-slope exists such as would be found where a pipeline rises up a hill or mountain together with uncertainty or variation in gas velocity makes identification of the liquid accumulation location within the section of pipe more difficult.

Inclination is usually given in degrees or radians and defined as change in elevation. The sine of the inclination gives change in elevation over a distance of pipe:

$$\sin(q) \approx \frac{\Delta(\text{elevation})}{\Delta(\text{distance})} \tag{4}$$

An example pipeline elevation profile is shown in Figure 15 together with the resulting inclination profile calculated by

$$q = \arcsin\left(\frac{\Delta(\text{elevation})}{\Delta(\text{distance})}\right) \tag{5}$$

The angles of inclination are compared to the critical angle for water accumulation predicted by the flow modeling. The first inclination angle greater than the critical angle for accumulation is the location where water will first accumulate. This location is therefore most likely to suffer corrosion as compared to the remaining length of pipe.

Input items in red to calculate the critical angle for water holdup:

Pipe Size I.D., Inches	Pressure, psi	Temperature, F
22	**1000**	**60**

***Based on detailed modeling results within the range of 4 to 48 inch I.D., 500 to 1100 psi, 60 to 120F, and 0 to 25 ft/s gas velocity**

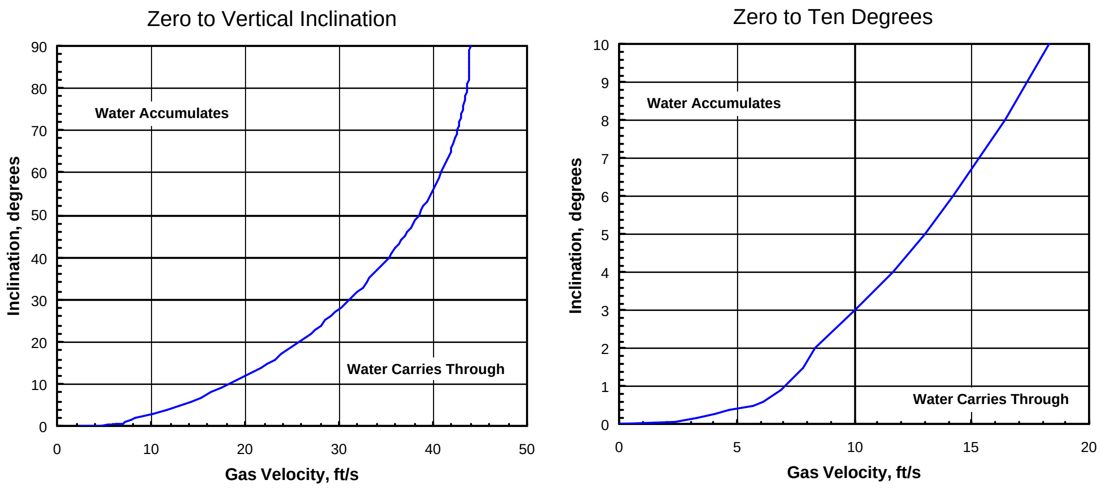

Figure 13. Screen Capture of Excel™ spreadsheet that utilizes a Froude number, F, to predict critical inclinations for water accumulation versus gas velocity.

Items to calculate the critical angle for water holdup input on Main Sheet:

Pipe Size I.D., Inches	Pressure, psi	Temperature, F
22	**1000**	**60**

***Based on detailed modeling results within the range of 4 to 48 inch I.D., 500 to 1100 psi, 60 to 120F, and 0 to 25 ft/s gas velocity**

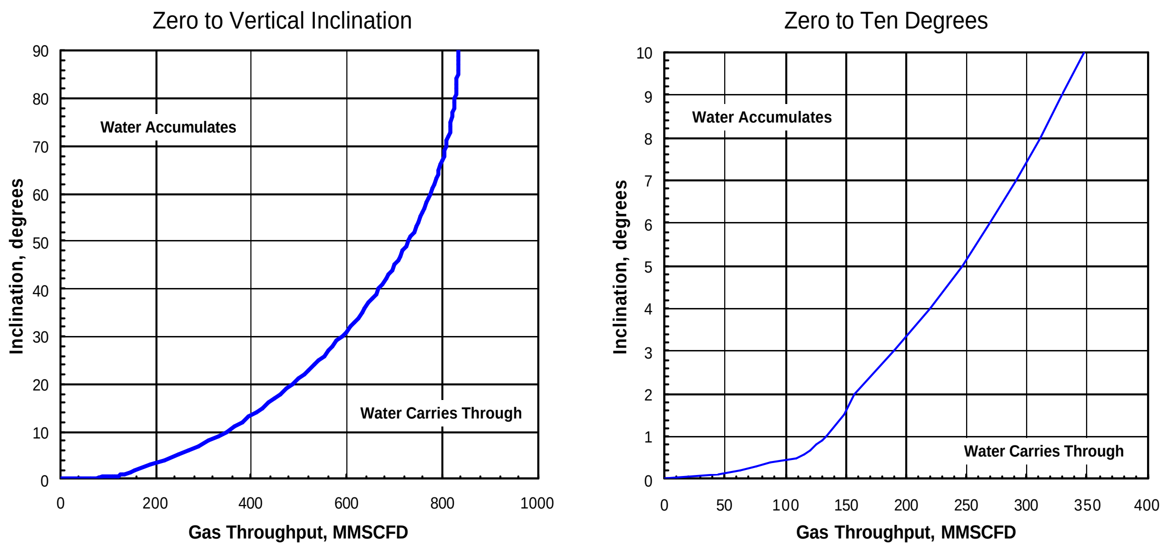

Figure 14. Screen Capture of Excel™ spreadsheet that utilizes a Froude number, F, to predict critical inclinations for water accumulation versus gas throughput.

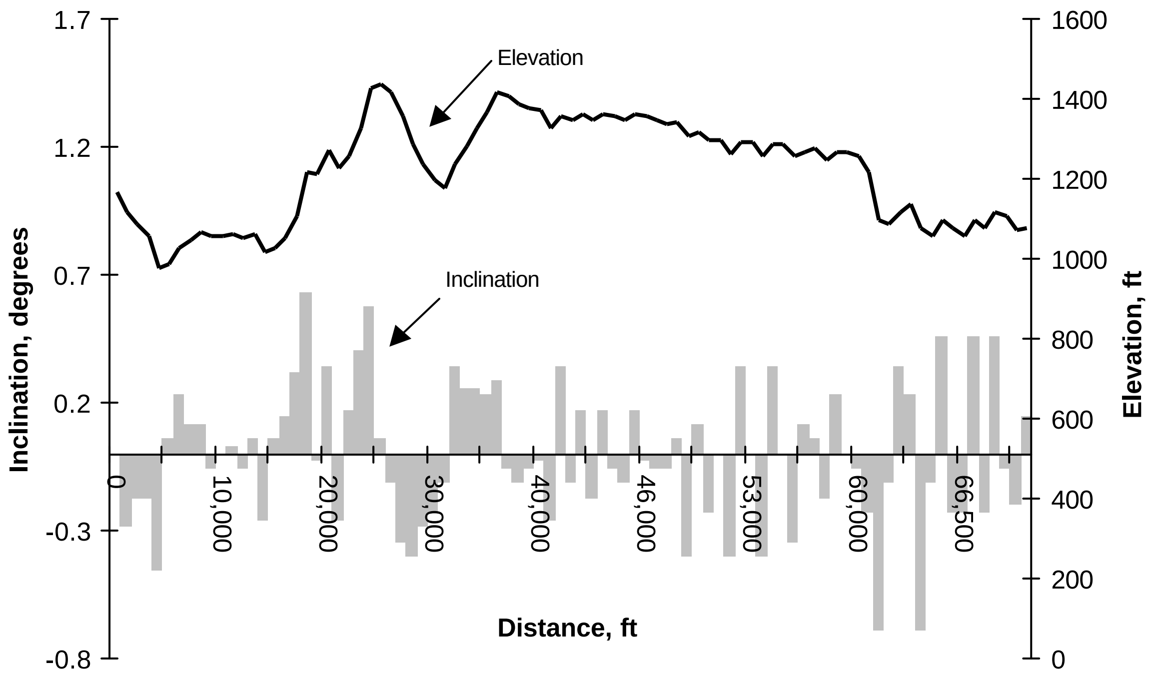

Figure 15. Example of pipeline elevation profile and calculated inclination.

4.5 Procedure for choosing detailed examination/inspection locations

Comparison of critical angles and actual inclinations yields locations for detailed examination/inspection. This paper discusses the selection of individual locations along a pipeline, and industry experience over time will help determine the number of redundant locations to select for sufficient confidence to identify internal corrosion. In the near term, it may be useful to select multiple redundant sites; this number may change as more experience is gained.

For pipelines operated at constant gas velocities, the first inclination with greater than the critical angle represents the location where water first accumulates. All upstream inclinations with lower angles are not expected to accumulate water and therefore are not likely to corrode. All downstream locations would either not be exposed to water (since it accumulated upstream and evaporated), or they would be exposed only after the upstream location has filled with liquid and subsequently carried over. In this case, the upstream location would have a longer exposure period and therefore is expected to suffer the most severe corrosion. For the case of a pipeline where all inclinations are less than critical angle, the angle of highest inclination is chosen to represent the pipeline length of interest.

Most pipelines have experienced a range of gas velocity from zero to a maximum, which complicates the procedure. Critically large inclinations will trap water at any velocity up to a maximum, but upstream locations with lower angles of inclination may trap water at velocities less than the maximum. Because of this, examination of inclinations above the critical angle can be used to assess the integrity of downstream pipe, but the integrity of upstream pipe remains unknown. If information exists about the period of time a pipeline has experienced velocity ranges, engineering judgement can be used to determine if short velocity changes are significant.

The procedure for the ICDA approach (considering a range of gas velocities) is shown in the flow diagram of Figure 16:

- Find the first pipe inclination greater than the largest critical angle determined by the range of operating conditions and the flow modeling results. If all inclinations have angle larger than critical, choose the angle of greatest inclination along the pipeline length.
- Perform detailed examination/inspection of the target location(s). If no corrosion is found, it is concluded that downstream corrosion is unlikely. However, if a range of velocity (or other relevant parameter) exists so the critical angle for accumulation may be smaller at certain times, upstream integrity cannot be determined by examination of a downstream inclination.
- Perform detailed examination/inspection on the location(s) with highest inclination upstream of the initial location(s). This will provide integrity information on the pipe downstream of the intermediate inclination point(s) and the first inclination with angle higher than the maximum critical angle.
- Along with choosing locations having inclinations above critical angle, any fixture that can trap water (e.g., drip, valve, stub-end) serves as an examination point. Upstream water traps can accumulate water (or other electrolyte) before it reaches an inclination greater than critical angle; these fixtures should therefore be examined, but they do not replace examination of the pipe because the rate of accumulation depends on the geometry of the fixture. Ideally, water that accumulates at a location with inclination greater than critical angle will evaporate before filling and carrying over to the next location. However, a scenario can be envisioned where a short upset with large liquid volume fills an accumulation point and carries over to a fixture that traps the water. This condition is acceptable if the

water evaporation rate is similar because the upstream accumulation point will be exposed to the water for a longer period of time (and therefore suffer more corrosion). However, if the trap geometry restricts evaporation, it is possible for corrosion to be more severe inside of the downstream trap. Therefore, traps of similar design directly downstream of a pipe inclination with angle greater than critical should be examined.

4.6 Data Requirements for ICDA Method

Most of the data required to use the ICDA method is commonly available to pipeline operators and is shown in Table 1. The exception is elevation profile of the pipeline, which must be known to predict the locations of electrolyte hold-up. The United States Geological Survey (USGS) has generated topographical maps that were made available to commercial software developers. Many of the software packages include major transmission pipelines on the maps, and for those pipelines not shown, they can be located by Geographical Information System (GIS) position. To estimate pipeline elevation by surface topography, constant depth of cover must be assumed. While this may be a reasonable approximation, this uncertainty should be considered when selecting the hold-up locations. In addition, all features affecting elevation (and not necessarily related to surface topography) must be identified separately (e.g., river crossings, drips, road crossing, expansion joints, etc.). If high accuracy is required, onsite pipe depth measurements and portable global positioning system (GPS) units can be use to accurately determine pipe elevation profile and location.

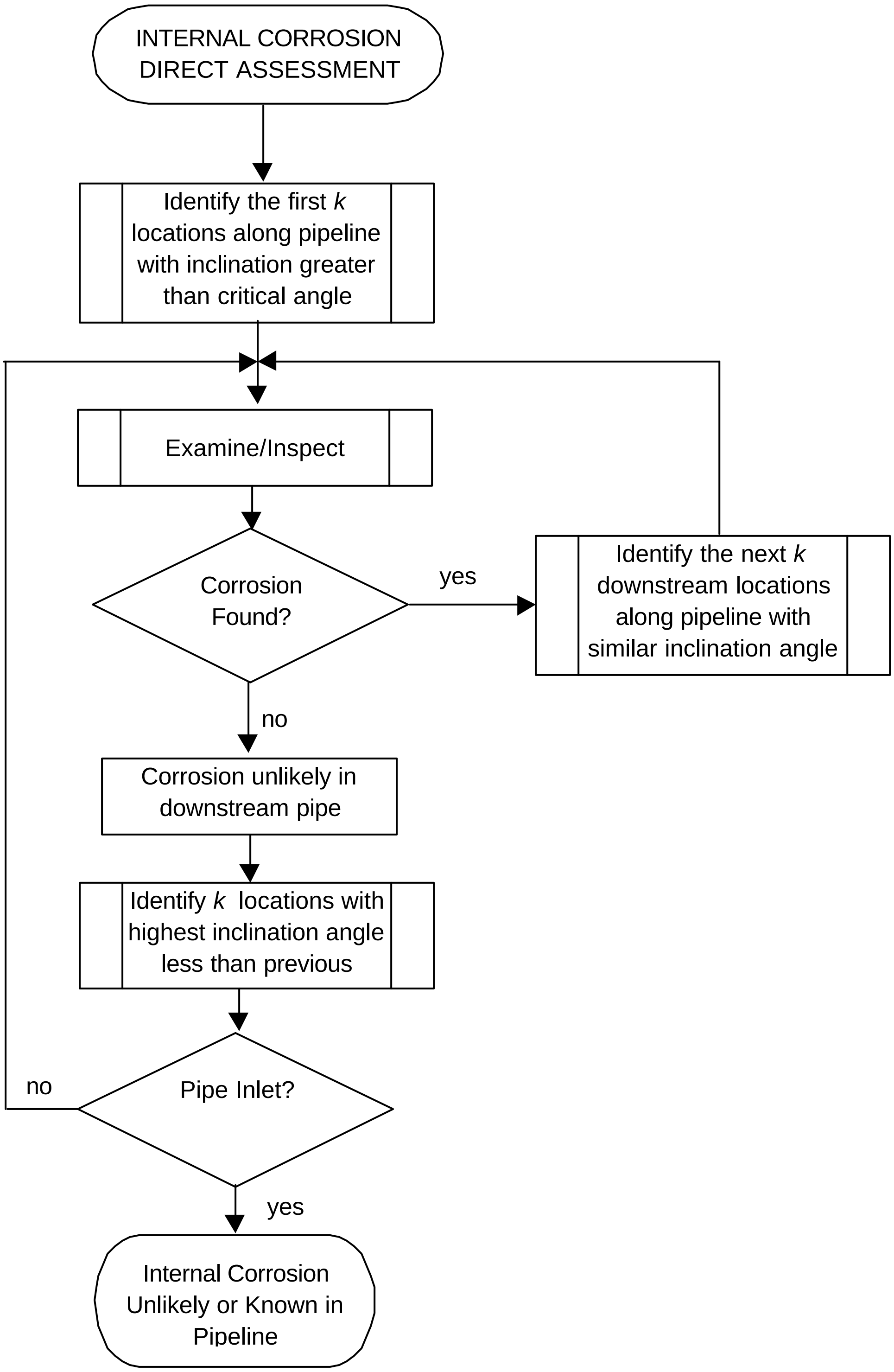

Figure 16. Flow diagram of ICDA Procedure. The number represented by 'k' will be adjusted based on validation of the procedure and future experience.

Table 1. Data Required to Use ICDA Methodology

CATEGORY	**COMMENTS**
Operating History	**Essential**: change in direction, service, removed taps, etc.
Defined Length	**Essential**: length between inputs/outputs
Elevation	**Essential**: topography (pipeline location + USGS data), assume constant depth of cover
Features w/ Inclination	**Essential**: roads, rivers, drains, etc.
Diameter	**Essential**: ID (or OD/wall thickness)
Pressure	**Essential**: normal operating range
Flow Rates	**Essential**: normal operating range
Temperature	**Essential**: conservatively assume ambient
Water Dewpoint	**Essential**: assume <7 lb/MMSCF
Type of Inputs/Outputs	**Essential**: need to at least know all locations
Upsets	**Informational**: nature, intermittent or chronic?
Type of Dehydration	**Informational**: rules out glycol input
Hydrotest Frequency	**Informational**: presence of water
Location of Leaks/Failures	**Informational**: supports ICDA
Other IC Data	**Informational**: supports ICDA

5 SUMMARY AND CONCLUSIONS

An internal corrosion assessment methodology applied to gas transmission systems was developed and is termed 'Internal Corrosion Direct Assessment' (ICDA). The ICDA method can be used to enhance the assessment of internal corrosion in pipelines and ensure pipeline integrity. The method is applicable for gas transmission lines that normally carry dry gas but may suffer from short term upsets of wet gas or liquid water (or other electrolyte).

The basis behind ICDA for gas transmission lines is that detailed examination of locations along a pipeline where an electrolyte such as water first accumulates provides information about the remaining length of pipe. If the locations along a length of pipe most likely to accumulate electrolyte have not corroded, then other locations less likely to accumulate electrolyte are considered free from corrosion and do not require further examination. Simply stated, corrosion is most likely where water first accumulates.

Many pipeline operators utilize risk management plans to prioritize areas of internal corrosion risk and take effective mitigative measures. This includes identifying areas where internal corrosion (or corrosivity) exists, and conversely where internal corrosion is unlikely. The direct assessment methodology assesses risk from internal corrosion and incorporates all existing methods of examination available to a pipeline operator. ICDA uses flow modeling results and provides a framework to best utilize those methods.

Strengths of the ICDA approach include that: 1) inspection (or other examination) of pipe outside of a high consequence area (HCA) can be used to ensure integrity inside a HCA; 2) the approach is simple and straightforward using mature technologies; 3) it can be run by on-staff corrosion engineers; 4) it can be used to optimize existing inspections (or any other existing assessment tool) by targeting locations of likely corrosion more accurately; and 5) it can optimize selection of corrosion monitoring tool location.

Weaknesses of the ICDA approach include that: 1) operator familiarity and diligence is required (much like other assessment methods), 2) the approach applies to dry gas lines with episodic upsets (and other additional requirements), and 3) it requires complementary tools for pipelines with extensive damage.

5.1 Validation

To determine the uncertainty from use of ICDA and validate the method, comparison with laboratory and field data is planned.

5.2 Future Improvements

The ICDA process was developed for transmission pipelines carrying nominally dry gas, and follow-on work should be performed to cover wet gas systems such as those found in gas storage and gathering systems. Storage/Gathering systems differ from transmission systems in that they tend to use smaller diameter pipe, carry gas saturated with water, have conventional corrosion monitoring and mitigation programs, and have many potential corrosion locations throughout a pipe length. Priority was placed on transmission systems because

- A method was proposed for dry gas systems to quickly assure IC integrity of large portion of buried pipe.

- Transmission lines are more likely traverse HCA's
- Maintenance/inspection operations or shutdown have greater economic/service impacts on transmission systems. Since each transmission line tends to carry more gas, a service interruption has greater consequences than a smaller pipeline, which may even have a parallel line.

The ICDA method development was not simultaneously applied to wet gas systems so that the effort could focus resources on single problem, and lessons learned from transmission systems could be applied to gathering and storage.

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