https://doi.org/10.37878/2708-0080/2020-5.041

INFLUENCE OF THE CORROSION AND ENSURING INTEGRITY THE FLUIDS TRANSPORT PIPELINES, ON BASED OF THE ROUTINE DIAGNOSIS



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Pipelines represent a very important part of the energy infrastructure. They ensure an economical, safe and continuous transport of fluids, in generally of oil crudes and natural gases. As time goes, pipelines of transporting oil and natural gas (more, buried and high-pressure pipeline) are subjected to loads and environmental effects which may cause them to become degraded with. Pipelines may suffer degradation from a variety of causes, as: corrosion, mechanical damage, stress cracking etc. As pipelines age and the degradation mechanisms become more problematic, it is recognised that the integrity of those pipelines must be proactively managed. All pipeline operators are well aware of this, and at this problem. Evident, the prudent operators have active programs, - timely intervention programs to assure continuing pipeline transporting fluids -, more, to mitigate deterioration and to repair defective pipes. Another important aspect is forecasting corrosion over a period of time in order to predict the possibility of pipeline failure (in other words, defect rate versus time to failure). A variety of techniques are used depending on the nature of the pipeline and the perceived problems. Some of the basic techniques are described in this article.

KEY WORDS: *oil, natural gas, pipeline, pressure, stress, inspection, defect, corrosion, cracking, maintenance.*

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ВЛИЯНИЕ КОРРОЗИИ И ОБЕСПЕЧЕНИЕ ЦЕЛОСТНОСТИ ТРАНСПОРТНЫХ ТРУБОПРОВОДОВ ЖИДКОСТЕЙ НА ОСНОВЕ РЕГУЛЯРНОЙ ДИАГНОСТИКИ

Трубопроводы представляют собой очень важную часть энергетической инфраструктуры. Они обеспечивают экономичную, безопасную и непрерывную транспортировку жидкостей, в основном сырой нефти и природного газа. Со временем трубопроводы для транспортировки нефти и природного газа (более того, подземные трубопроводы и трубопроводы высокого давления) подвергаются нагрузкам и воздействию окружающей среды, которые могут привести к их ухудшению. Трубопроводы могут подвергаться деградации по разным причинам, в том числе: коррозия, механическое повреждение, растрескивание под напряжением и т. д. По мере старения трубопроводов и возрастания проблем с механизмами деградации признается, что целостность этих трубопроводов должна контролироваться заранее. Все операторы трубопроводов хорошо осведомлены об этом и об этой проблеме. Очевидно, у осмотрительных операторов есть активные программы - программы своевременного вмешательства для обеспечения непрерывной транспортировки жидкостей по трубопроводу - более того, для уменьшения разрушения и ремонта дефектных труб. Другим важным аспектом является прогнозирование коррозии в течение определенного периода времени, чтобы предсказать возможность отказа трубопровода (другими словами, процент дефектов в зависимости от времени до отказа). В зависимости от характера трубопровода и предполагаемых проблем используются различные методы. Некоторые из основных техник описаны в этой статье.

КЛЮЧЕВЫЕ СЛОВА: *нефть, природный газ, трубопровод, давление, напряжение, проверка, дефект, коррозия, растрескивание, техническое обслуживание.*

КОРРОЗИЯНЫҢ ӘСЕРІ ЖӘНЕ ТҰРАҚТЫ ДИАГНОСТИКА НЕГІЗІНДЕ СҰЙЫҚТАРДЫ ТАСЫМАЛДАЙТЫН ҚҰБЫРЛАР ТҰТАСТЫҒЫН ҚАМТАМАСЫЗ ЕТУ

Құбырлар энергетикалық инфрақұрылымның маңызды бөлігін құрайды. Олар сұйықтықтардың үнемді, қауіпсіз және үздіксіз тасымалдануын, негізінен мұнай шикізаты мен табиғи газдарды қамтамасыз етеді. Уақыт өте келе мұнай мен табиғи газды тасымалдайтын құбырларға (көбірек, жерленген және жоғары қысымды құбыр) жүктер мен қоршаған ортаның әсері әсер етуі мүмкін, бұл олардың тозуына әкелуі мүмкін. Құбырлар әр түрлі себептермен тозуы мүмкін, мысалы: коррозия, механикалық зақымдану, кернеудің крекингі және т.с.с. Құбырлардың қартаюы және деградация механизмдері күрделене бастаған кезде, бұл құбырлардың тұтастығын белсенді басқару қажет. Мұнай құбырларының барлық операторлары мұны және проблеманы жақсы біледі. Ақылды операторлардың белсенді бағдарламалары бар, яғни сұйықтықты тасымалдайтын құбыр желісінің жалғасуын қамтамасыз ету үшін уақтылы араласу бағдарламалары бар, сонымен қатар, тозуды азайту және ақаулы құбырларды жөндеу. Тағы бір маңызды аспект - бұл құбырдың істен шығу мүмкіндігін болжау үшін коррозияны белгілі бір уақыт ішінде болжау (басқаша айтқанда, ақаулардың жылдамдыққа қатысты). Құбырдың сипатына және қабылданған мәселелерге байланысты әр түрлі техникалар қолданылады. Кейбір негізгі техникалар осы мақалада сипатталған.

ТҮЙІН СӨЗДЕР: *мұнай, табиғи газ, құбыр, қысым, стресс, тексеру, ақау, коррозия, крекинг, техникалық қызмет көрсету.*

1. INTRODUCTION

Pipelines may suffer degradation from a variety of causes, including corrosion, mechanical damage, fatigue, and stress corrosion cracking. The appropriate remedies for these problems are well known but other than the routine patrolling of the rights-of-way and monitoring of cathodic-protection potentials and rectifier currents, such remedies are too expensive to be applied on a regular or routine basis. By that we mean that most operators cannot afford to routinely and periodically utilize inline inspection and/or hydrostatic testing to revalidate their pipelines. Usually, these techniques are invoked when some special circumstances exist. The special circumstances may be the existence of excessive amounts of low pipe-to-soil potential readings, the occurrence of leaks or ruptures, or just an intuitive feeling that it is time to check the condition of a pipeline. Alternatively, as we are finding, more and more operators are coming to depend on more sophisticated models to determine when intervention is needed. The types of models we have used are described.

2. FAILURE PRESSURE VERSUS DEFECT SIZE

Pipeline integrity is usually defined in terms of pressure-carrying capacity. For a given diameter, wall thickness, and grade of material, one can expect that a sound piece of line pipe will be able to sustain an internal pressure level of at least 100% of its *specified minimum yield strength* (SMYS). And, that pressure level can readily be calculated by means of the *Peter Barlow*[2] *formula* - an equation which calculates the relationship of internal pressure to allowable stress, nominal thickness and diameter of pipe.

$$P = \frac{(2\ st)}{(OD\ x\ SF)}$$

where:

P is fluid pressure (psig);
s - material strength (psig);
t - pipe wall thickness (in);
OD - pipe outside diameter (in);
SF - safety factor (psig).

For example [1], if one has a 16 inch O.D. by 0.250 inch wall thickness API 5L X52[3] line pipeline, the pressure level corresponding to 100% of SMYS is 1,625 psig[4] (~ 112 bar). For comparison, the 72% of SMYS maximum operating pressure level is 1,170 psig (~ 81 bar). Thus, one has the expectation that a new piece of this particular pipe has a safety margin against failure of 1,625/1,170 or 1.39. In fact, if it is free of defects, it will have a failure pressure of at least 1,938 psig (~ 133 bar). The latter is based upon research conducted by the pipeline research Committee of the American Gas Association. Realistically, not all pipe is defect free, otherwise there would never be pre-service hydrostatic test breaks. But, after a preservice test to a pressure level of 90 to 100%

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[2]Peter Barlow (1776-1862), an English mathematician.
[3]API 5L X52 line pipe is most common and is used for the transportation of oil, gas, and water.
[4]1psig = 0.0689475728 bar

of SMYS, one can expect a pipeline to perform satisfactorily at an operating stress level up to 72% of SMYS, that is, until or unless it becomes degraded in service by corrosion, mechanical damage, fatigue, or stress-corrosion cracking. Thanks to extensive research by the previously mentioned Pipeline Research Committee of A.G.A., an experimentally validated model exists for calculating the effects of a longitudinally oriented part-through-the-wall defect on the pressure carrying capacity of the pipe. For any given piece of pipe, the model can be used to generate the relationships between failure pressure and flaw size. For our example, the 16 in O.D. by 0.250 in wall thickness X52 material, the relationships for selected depths of flaws are shown in *Figure 1*. Each of the nine parallel curves represent the failure-pressure versus flaw-length relationship for a particular depth (d) to wall thickness (t) ratio. The curve which cuts across the others is the dividing line between leaks and ruptures.

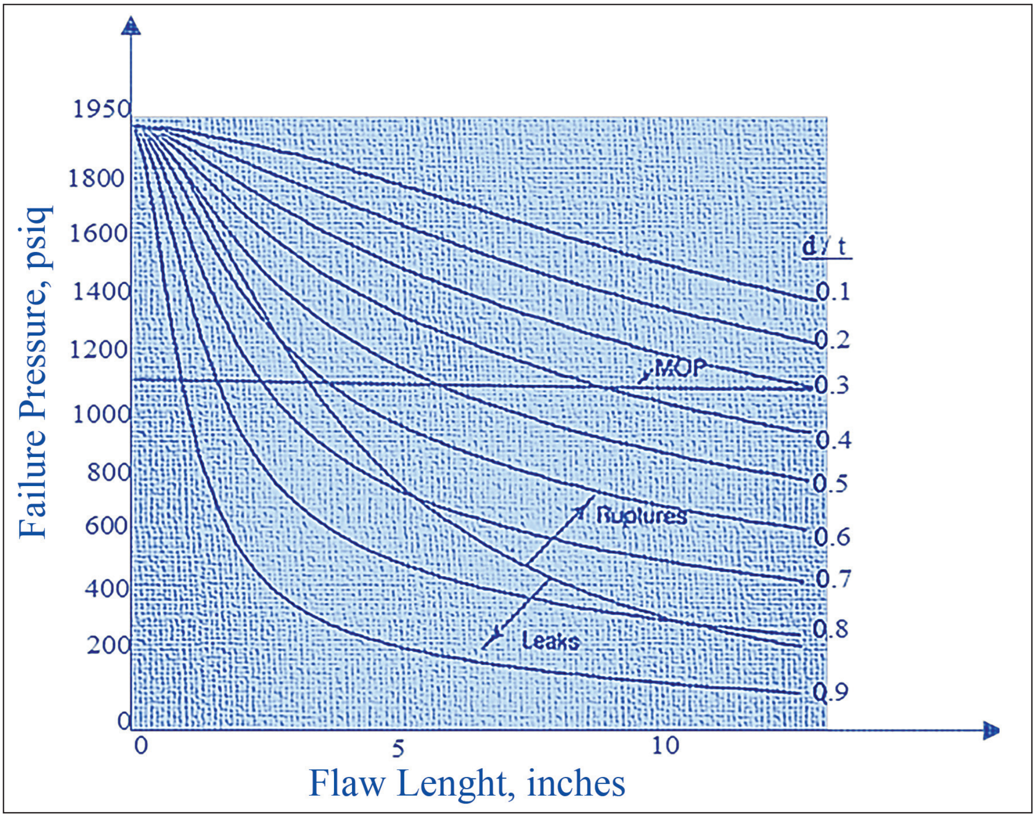


Fig. 1 – **Failure pressure versus flaw size for a material of normal toughness**

Defects with failure at pressures above and to the right of this curve will fail as ruptures whereas those which have failure pressures below and to the left of this curve will fail as leaks. A horizontal line is drawn on *Figure 1* to represent the maximum operating pressure (MOP) of this pipe material, 1,170 psig, corresponding to a hoop stress level of 72% of SMYS. All flaws with length and d/t combinations which lie below this line will fail at pressure levels below the MOP.

All flaws which lie above this line could exist in the pipeline in service. For example, the curve representing a d/t of 0.5 crosses the line at a flaw length of 5.8 in. Flaws of that length which are more than half way through the wall will fail at the MOP; flaws of that length which are less than half way through will not.

The family of curves shown in *Figure 1* is quite useful in the kinds of models we use to determine the time-dependent degradation of a pipeline. Two features of the curves should be kept in mind as the discussion proceeds. First, these curves represent failure pressures that are achievable with steadily increasing pressure over a relatively short period of time (minutes).

Because of the phenomenon of time-dependent growth, it is possible to observe failures at pressure levels of 5 to 10% lower than these curves predict if pressure levels 5 to 10% below the predicted levels are held long enough. Secondly, these curves are affected by the ductile-fracture toughness of the material. The curves shown in *Figure 1* are characteristic of a steel line-pipe material.

The set of curves shown in *Figure 2* was generated for a hypothetical material of the same pipe geometry. Note that for a given defect size the material of optimum toughness has a higher failure pressure.

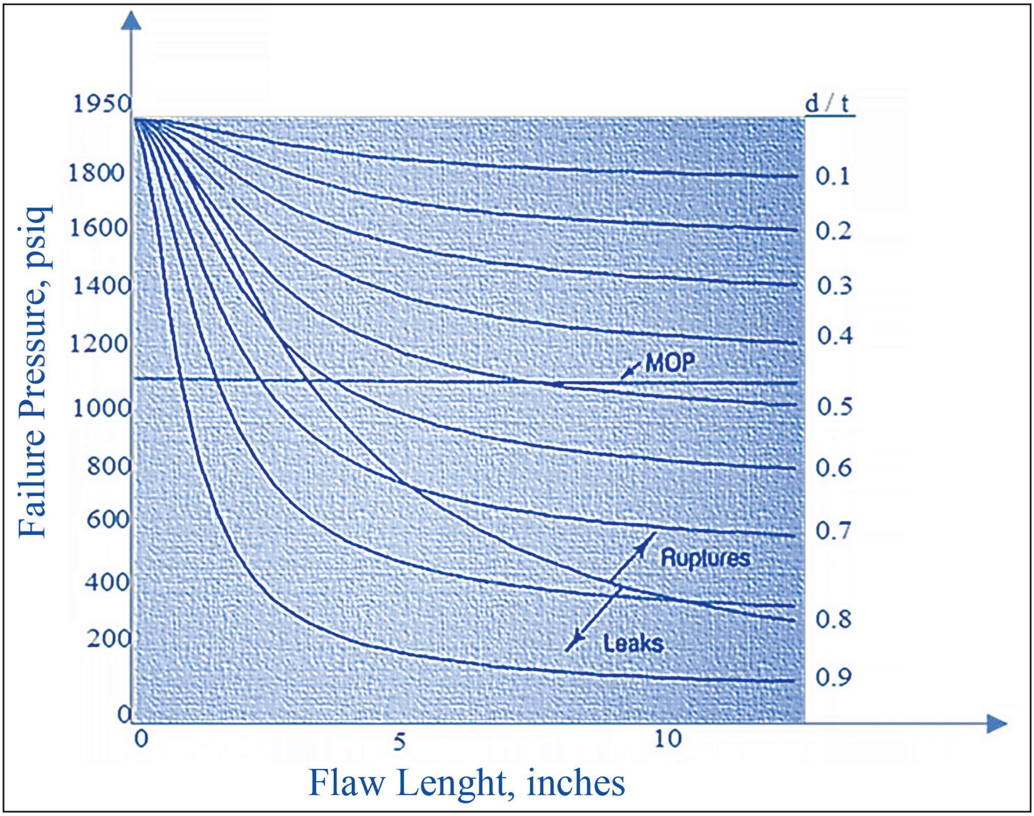


Fig. 2 – **Failure pressure versus flaw size for a material of optimum toughness or for blunt defects**

To illustrate, it is recalled from *Figure 1* that a 5.8 inch long flaw half way through the wall fails at 1,170 psig. In contrast, the same 5.8 in long flaw with a d/t of 0.5 in the very tough material has a failure pressure of 1,210 psig (~ 83 bar). It is noted that blunt flaws such as corrosion-caused metal loss tend to behave as illustrated in *Figure 2* rather than *Figure 1* regardless of the toughness of the material. This is because the material in a corrosion pit is strained over a large "gage length" unlike the situation of a crack-like flaw. For the latter, toughness becomes a very important parameter.

Representing the other extreme, *Figure 3* presents the failure-pressure-versus-flaw-size relationship for a very low toughness material such as the ERW bond line in an older, low-frequency welded material. Even though the diameter, thickness, and grade are the same as that represented in *Figures 1 and 2*, the critical flaw sizes are much smaller.

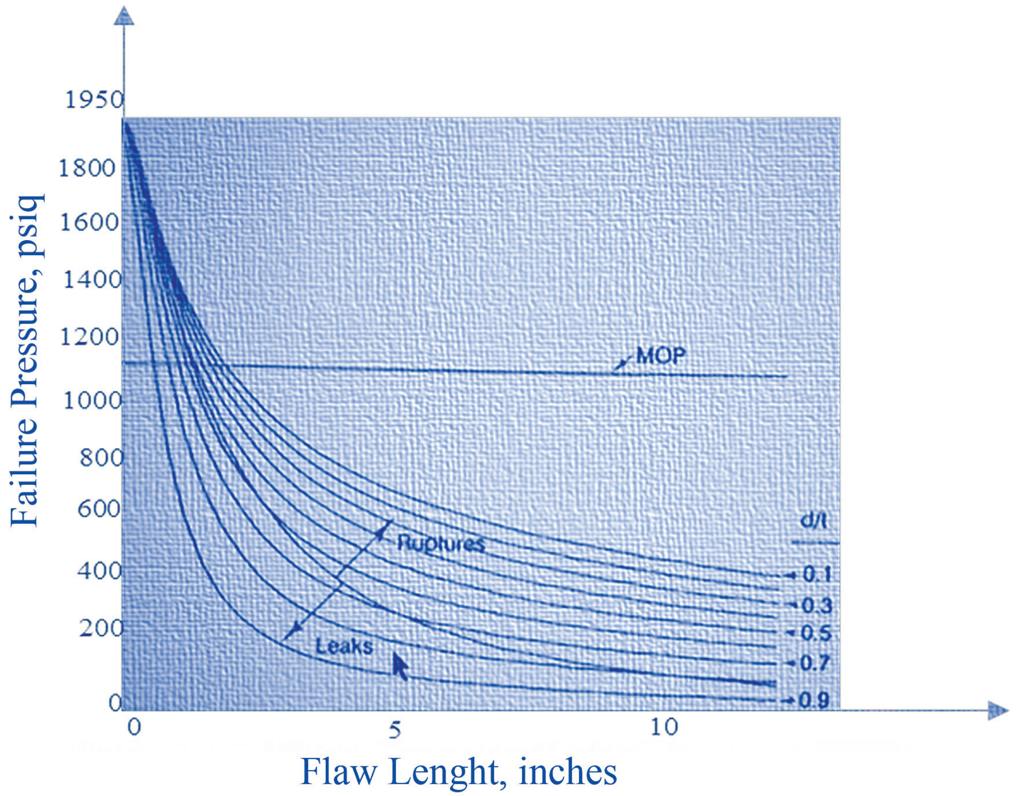


Fig. 3 – **Failure pressure versus flaw size for a material of low toughness**

With respect to in-line inspection, most pipeline are aware that the conventional magnetic-flux leakage tools are reasonably capable of sorting metal-loss anomalies into categories by depth of light, moderate, and severe. Lights generally are those with depths of less than 30% of the wall thickness (d/t < 0.3). Moderate are those with depths of 30 to 50% through the wall thickness (d/t = 0.3 to d/t = 0.5). Severe have depths greater than 50% of the wall thickness (d/t > 0.5). Recalling that the behavior of blunt metal loss flaw is best represented by the optimum toughness relationships of *Figure 2*, one can see in

Figure 4 (based on Figure 2) how in-line inspection data can be interpreted in terms of the effects on pressure-carrying capacity. The top cross-hatched area corresponds to light; the lower crosshatched area corresponds to moderate, and the unshaded area corresponds to severe. Note that for long flaws, the failure pressures corresponding to moderates become low enough to intersect the MOP level. This illustrates the need to excavate and examine moderates in a program of conventional in-line inspection. With the use of the more expensive, high-resolution in-line inspection tools, it is possible to define flaw length and, hence, to avoid many excavations.

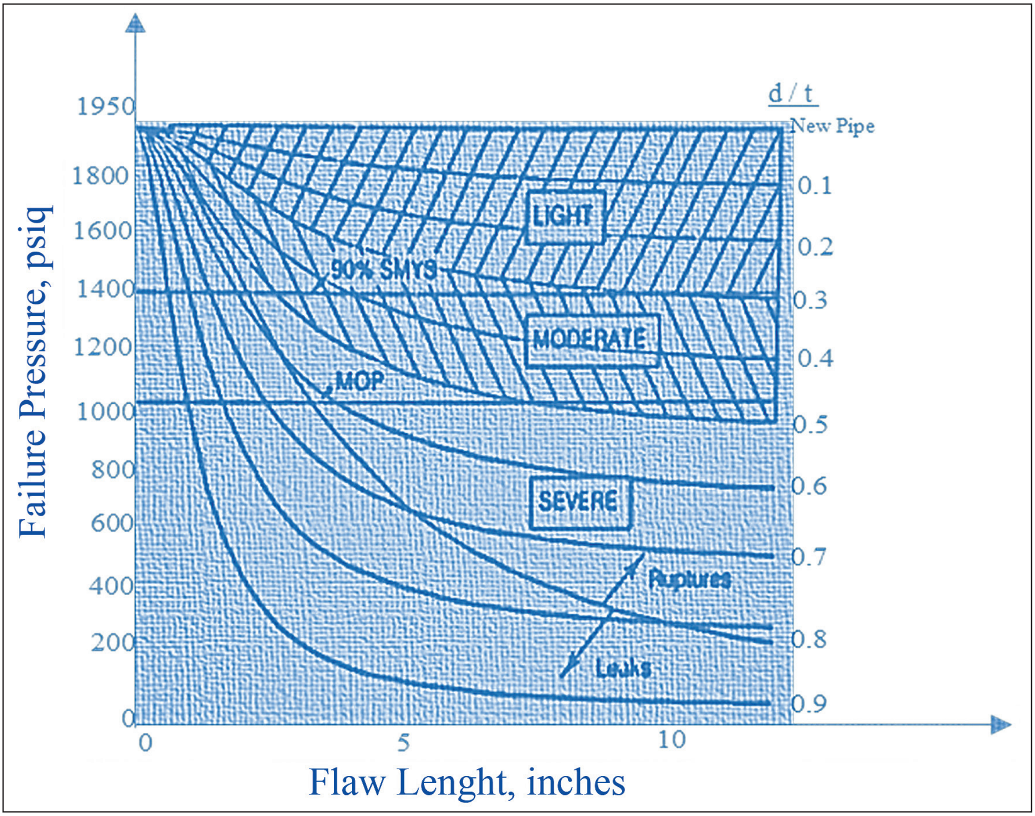


Fig. 4 – **Sizes of flaws located by in-line inspection (corrosion)**

Figure 4 provides an important conceptual comparison between in-line inspection and hydrostatic testing. With the aid of this figure, one can see where each has its advantages and disadvantages. The hydrostatic test represented by the 90% SMYS line provides a demonstration of the immediate pressure-carrying capacity up to a pressure level of 1,400 psig (~96 bar). The use of conventional magnetic-flux tools cannot provide this kind of assurance unless all severe and moderate anomalies are excavated, leaving only the lights. However, the hydrostatic test does not locate any of the anomalies that do not fail. Hence, very deep pits can survive the test and develop leaks shortly thereafter (as illustrated by the amount of unshaded area-severe anomalies-lying above the horizontal line at 1,400 psig). At least with in-line inspection, one can locate and remove or repair the anomalies (especially the deep ones). After having removed or repaired all moderates and severe, one can have a high degree of confidence that the pipeline will not fail or leak for a long time as the result of corrosion-caused metal loss. The same cannot be said after a hydrostatic test. Very short but deep pits could have survived the test and may become leaks (not ruptures) within a short time after the test.

3. RELATIONSHIP BETWEEN DESIGN PRESSURE AND WALL THICKNESS

The equation that ralates design pressure to wall thickness to can be derived by performing a force balance ao a pipe segment under a specified design pressure, as shown in *Figure 5*.

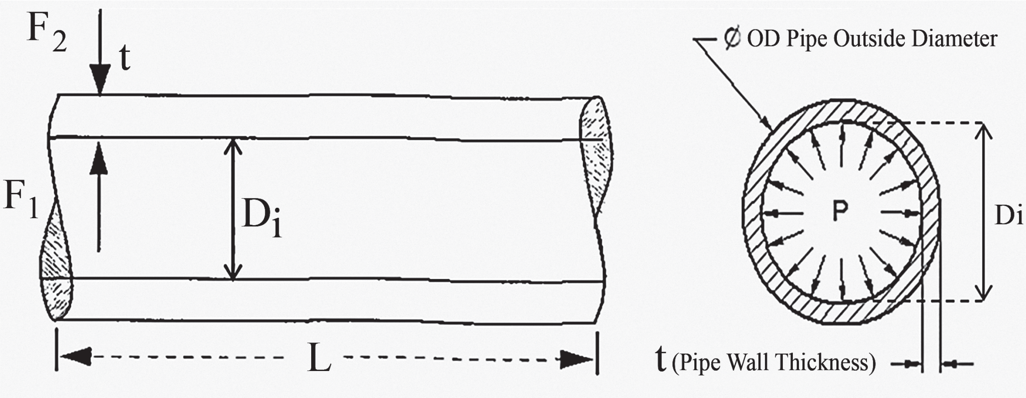


Fig. 5 – **Representation of forces acting on a segment of pipeline**

Force F_1 that is exerted on the pipe wall due to the design pressure is:

$$F_1 = \pi\,(OD)\,L\,P_{design} \tag{2}$$

Force F_2 is the pipeline specified minimum yield strength over the specified thickness

$$F_2 = s\,[\pi\,(OD)\,L - \pi\,D_i\,L] \tag{3}$$

how:

$$OD = D_i + 2t \tag{4}$$

then relationship (3) is written:

$$F_2 = s\,[\pi\,(di + 2t)\,L - \pi\,D_i\,L] \tag{5}$$

after simplifications

$$F_2 = 2\pi\,s\,t\,L \tag{6}$$

to balance the forces $F_1 = F_2$ or

$$\pi\,(OD)\,L\,P_{design} = 2\pi\,s\,t\,L \tag{7}$$

and according to the relation (1), P_{design} is written:

$$P_{design} = \frac{(2\,s\,t)}{(OD)} \tag{8}$$

Thus, of the design pressure for a given wall thickness, considering all these safety factors, will then be determined by

$$P_{design} = \frac{(2\ s\ t)}{(OD\ )}\ F\ L\ J\ T \qquad (9)$$

where:
P_{design} is pipeline design pressure, (psig);
s - material strength or specified minimum yield strength of the pipe, (psig);
t - pipeline wall thickness, (in);
OD - pipeline outside diameter, (in);
Di - inside diameter of pipe, (in);
F - design factor, (F = 0.80);
L - location factor (L = 0.55 – 1.00);
J - joint factor (J = 0.60 – 1.00);
T - temperature correction factor or temperature derating factor (T = 0.87 – 1.00).

4. TYPICAL DEFECTS OF FLUIDS PIPELINE STRUCTURE

The investigations result on the incidents of pipeline leakage introduce the main cause of this incident is the degradation mechanisms on pipeline structure. The degradation mechanism of the pipeline is due to various factors such as mechanical damage, corrosion, cracking caused by the environmental and the original manufacturer defect.

In *Figure 6* are represented the typical defects of pipeline structure.

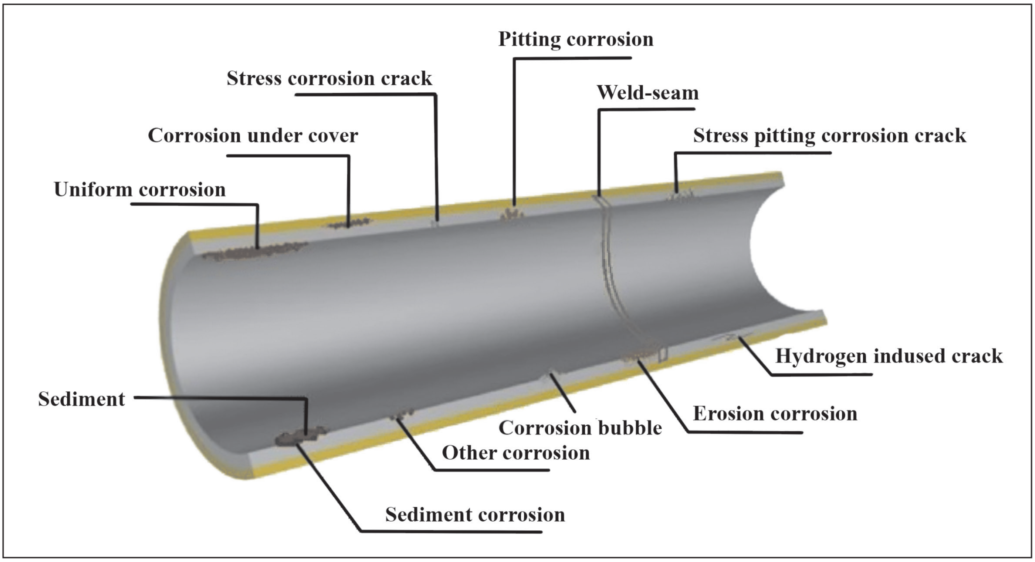


Fig. 6 – **Pipeline structure schematic of typical defects**

Evident, the continues assessment is require ensure the integrity of pipeline structure and to prevent the incident of gas and oil leakage. Many defects may result in lowering the security of the pipeline working, and eventually lead to leakage, even explosion accidents as mention.

So, it is of importance to develop the defect detection techniques for pipeline structures.

4.1. Location and dimensions of metal loss defects

To begin with, *Figure 7* shows an overview of a pipeline inspection operation and the identification of a pipeline defect [2], [3].

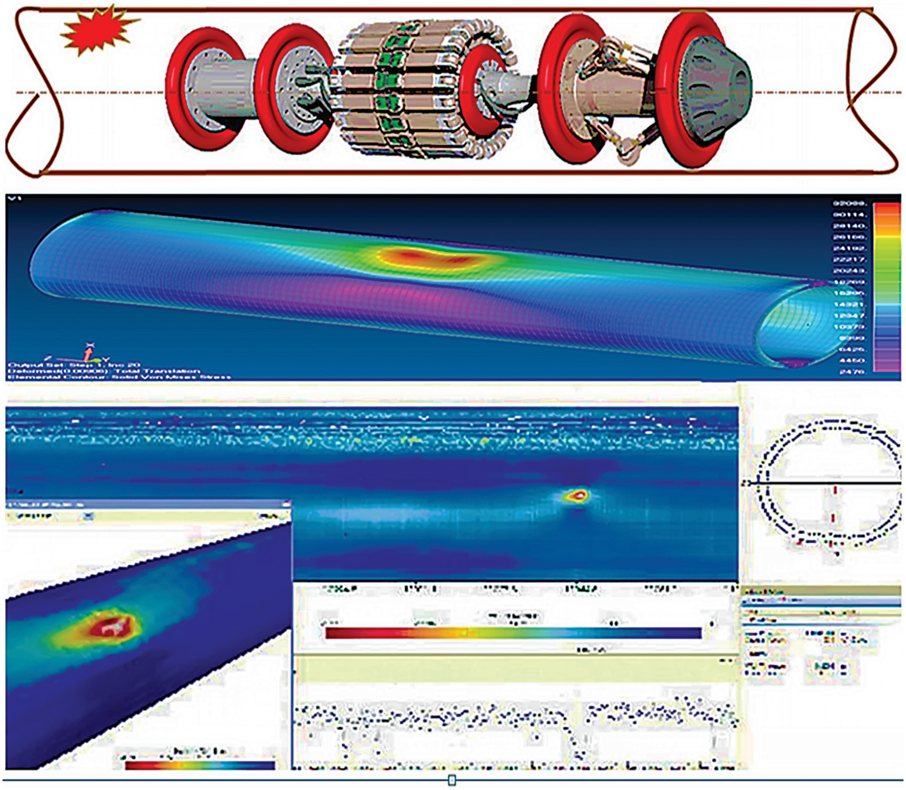
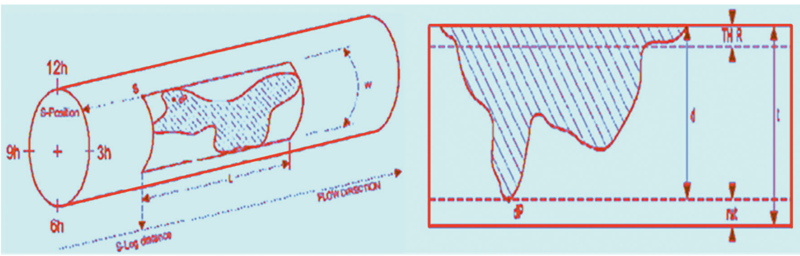


Fig. 7 – **The overview of a pipeline inspection operation and the identification of a pipeline defect [2]**

The location of a fault is given by the standard S-Log distance and S-Position on the clock as described in *Figure 8*. The lengths (L) of a metal loss defect are given by the projection of its length on the longitudinal axis of the pipe, and the width (W) of a metal loss defect is given by the projection of its width on the circumference of the pipe. [2]

The depth (d) of a metal loss defect is determined by the maximum wall loss (dP)



a) the location of a defect in the pipe *b) the depth of a metal loss defect*

Fig. 8 – **Location and dimensions of the defect with metal loss [2]**

The estimated burst pressure is calculated in relation to

$$P_{2,burst} = \frac{2\,s\,t}{OD}\,(SMYS + \frac{10{,}000}{145})[\,\frac{1-0.85\frac{d}{t}}{1-(0.85\frac{d}{t})\frac{1}{M2}}\,] \tag{10}$$

and according to the relation (8), $P_{2,burst}$ is written:

$$P_{2,burst} = (SMYS + \frac{10{,}000}{145})[\,\frac{1-0{,}85\frac{d}{t}}{1-(0{,}85\frac{d}{t})\frac{1}{M2}}\,] \tag{10}$$

Where M_2 is the factor Folias, and calculated:

$$or\ \frac{L_{Total}^2}{\mathrm{Dt}} \le 50$$

$$M_2 = \left(1 + \frac{1.255}{2} \times \frac{\mathrm{L_{Total}^2}}{\mathrm{Dt}} - \frac{0.0135}{4} \times \frac{\mathrm{L_{Total}^4}}{\mathrm{D^2t^2}}\right)^{1/2} \tag{11}$$

$$For\ \frac{L_{Total}^2}{\mathrm{Dt}} > 50 \tag{12}$$

$$M_2 = 0.032\,\frac{L_{Total}^2}{\mathrm{Dt}} + 3.3$$

where:
$P_{2,burst}$ is pipeline burst pressure, (psig);
s - material strength or specified minimum yield strength of the pipe, (psig);
t - pipeline wall thickness, (in);
d - maximum depth of the corroded surface (in);
OD or D - pipeline outside diameter, (in);
SMYS - Specified Minimum Yield Strength;
M_2 - the factor Folias [M2= f (LTotal. OD)];
L_{Total} - the axial extent of corrosion (in).;

As for *t* - pipeline wall thickness variations, they are picked up and reported by the corrosion tools, and while stable in nature, are nonetheless monitored and assessed from inspection to inspection, as shown in *Figure 8* [2].

Figure 9 shows all metal loss defects that exceed the reporting level (number of defects relative to pipe length) detected by intelligent tools.

Table provides an overview of the distribution of defects with metal loss by depth in%, detected by the tools intelligently and classified during the analysis.

In *Table* shows that a number of 45,800 indications of metal loss were reported, distributed along the entire length and circumference of the pipe. Most of these indications have been identified as light or medium metal losses, as follows:

• 4,960 (~10%) metal loss defects were classified as mild to moderate internal corrosion;

• 8,880 (~20%) metal loss defects were classified as mild to very severe external corrosion.

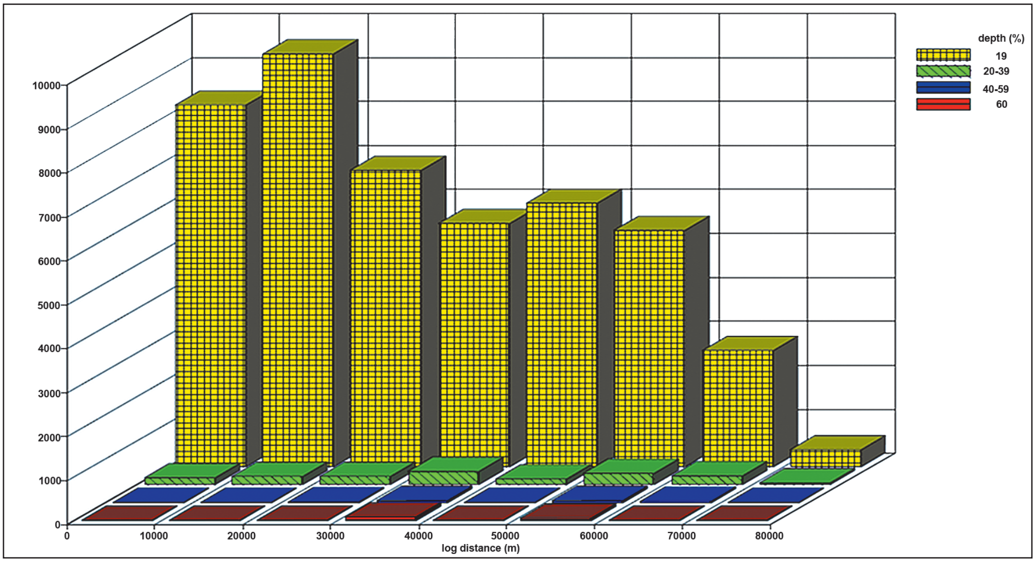


Fig. 9 – **Distribution of all defects with metal loss [2]**

Table – **Provides an overview of the distribution of defects with metal loss by depth in % [2]**

CORROSION DEFECTS:				
Depth of metal loss	**Total**	**Corrosion defects inside the wall**		
		Yes	Not	N/A
≥ 60%	149	1	152	no one
40–59%	171	2	175	no one
20–39%	955	50	978	no one
5–19%	12,970	4,907	7,575	no one
Total	**14,245**	**4,960**	**8,880**	**no one**
NON-CORROSION DEFECTS:				
Depth of metal loss	**Total**	**Non-Corrosion defects inside the wall**		
		Yes	Not	N/A
≥ 60%	8	5	no one	3
40–59%	70	20	1	10
20–39%	207	110	7	68
5–19%	31,270	13,705	18	17,971
Total	**31,555**	**13,840**	**26**	**18,052**
ALL DEFECTS WITH METAL LOSS				
Depth of metal loss	**All Defects**			
≥ 60%	157			
40–59%	242			
20–39%	1,162			
5–19%	44,240			
Total	**45,800**			

From this inspection of the metal loss it can be concluded that immediate remedial action is required for all corrosion defects, anomalies with calculated wall loss ≥ 50% and for anomalies with a reduction in inside diameter ≥ 6%.

In general, the detection and measurement of the pipe defect depends on the actual level of perturbations in the pipe material [2].

5. PIPELINE INTEGRITY MANAGEMENT SYSTEM (PIMS)

Usually, the primary concern of pipeline operators is to ensure continuous, safe and reliable operation while improving asset integrity and operational efficiency.

Integrity is the application of selected engineering and management disciplines to ensure that a pipeline performs in accordance with its appropriate and intended functions.

Operation is taking place amid increasing demand, higher energy costs, potential security threats, and both regulatory and environmental pressures.

The safety management system follows the well-known principles of the PDCA[5] cycle *(Figure 10)*.

Main elements:

• **Plan**

- Leadership, Policies;
- Organizational structure, rolls and responsibilities;
- Hazard identification and risk assessment;
- Regulatory requirements;

• **Do**

- Goals and targets;
- Operational control;
- Management of change;
- Training, competence and evaluation;

• **Check**

- Communication;
- Measurement and monitoring;
- Incident investigation system/reporting;

• **Act**

- Records, management activity;
- Management review and audits.

A more detailed breakdown of the subject is beyond the scope of this article; just some typical aspects are mentioned.

[5]The PDCA Cycle is a methodology used for continuous process improvement and problem solving in companies. This method is used to troubleshoot problems that are not easily viewed.
Generally, these problems have also undergone several failed attempts at solution.
Its purpose is to accelerate and perfect the activities of a company, by identifying the problems, their causes and possible solutions.

Fig. 10 – **PDCA cycle**

5.1. Risk-based maintenance

Risk-based maintenance (RBM) prioritizes maintenance resources toward pipeline that carry the most risk if they were to fail. It is a methodology for determining the most economical use of maintenance resources. This is done so that the maintenance effort a pipelines system is optimized to minimize any risk of a failure.

A risk-based maintenance strategy is based on two main phases:

1) Risk assessment;
2) Maintenance planning based on the risk.

The maintenance type and frequency are prioritized based on the risk of failure.

Pipelines that have a greater risk and consequence of failure are maintained and monitored more frequently.

Pipelines that carry a lower risk are subjected to less stringent maintenance programs.

Implementing a risk-based maintenance process means that the total risk of failure is minimized pipelines systems the facility in the most economical way. The monitoring and maintenance programs for high risk pipelines are typically condition-based maintenance programs (CBM).

Condition-based maintenance is a maintenance strategy that monitors the actual condition of an asset to decide what maintenance needs to be done. CBM dictates that maintenance should only be performed when certain indicators show signs of decreasing performance or upcoming failure. Checking a pipeline for these indicators may include non-invasive measurements, visual inspection, performance data and scheduled tests. Condition data can then be gathered at certain intervals (for example, pipe inspection with the intelligent pig), or continuously (systems SCADA). Condition-based maintenance can be applied to mission critical and non-mission critical pipelines.

Unlike in planned maintenance, where maintenance is performed based upon predefined scheduled intervals, condition-based maintenance is performed only after a decrease in the condition of the pipe wall thickness has been observed.

Compared with preventive maintenance, this increases the time between maintenance repairs, because maintenance is done on an as-needed basis.

CBM is calculated in relation to:

$$CBM = C_s + F_{sr} \tag{13}$$

where:

C_s is Cost Savings;

F_{sr} - Higher system reliability

Condition-based maintenance allows preventive and corrective actions to be scheduled at the optimal time, thus reducing the total cost of ownership.

Today, improvements in technology are making it easier to gather, store and analyze data for CBM.

In particular, CBM is highly effective where safety and reliability is the paramount concern as the oil and gas industry.

6. CONCLUSIONS

As an alternative to conventional bulk carriage, long distance pipeline transport is a proven technology that minimizes operating costs. Whether you are involved in the planning, building, or operation of pipelines, your products demand certified safety standards during design and installation.

The corrosion rate can be estimated by dividing the nominal wall thickness of the pipeline by the number of years between the time of the original installation and the time of the first leak. This involves assuming a constant rate of corrosion over the life of the pipeline.

For any pit that is not a leak, the corrosion rate will be less; it will be proportional to the d/t ratio of the pit. For our example pipeline (0.250 in wall thickness), if we assume that it first developed a leak after 25 years of service, its worst-case corrosion rate is 0.25/25 or 0.010 in/year. If we postulate that there is a pit on this pipeline that is 80 % through the wall, the corrosion rate for that pit is 0.8 x 0.01 = 0.008 in/year. With this kind of a corrosion-rate rationale, we can utilize a figure like Figure 2 to plan the revalidation of a corroded pipeline.

A key parameter for scheduling the revalidation of an externally or internally corroded pipeline is the worst-case corrosion rate or corrosion-caused metal loss. A pipeline operator’s corrosion control personnel may be able to estimate such a rate. Alternatively, one can obtain a reasonable estimate if prior corrosion leaks have occurred. Also, the hardest type of defect to deal with is stress corrosion cracking. With this type of cracking, the main problem is that no reliable model exists to define the crack growth rate. Furthermore, it is suspected that the rate is highly variable with changes in environmental conditions.

For the right application of diagnostics tools, which are the bases of the maintenance and rehabilitation works, there is an indispensable need for technical systems, such as

SCADA, within which reliable leak detection systems has a prominent role. Now the pipeline operators have such software tools that can effectively handle a wide range of functionalities in a single system (Pipeline Integrity Management System).

According to strict requirements, operators must be able to demonstrate and document the integrity of their pipelines at all times. A comprehensive integrated Pipeline Integrity Management System (PIMS) provides assessment of associated risks and implements measures to mitigate consequential failure. Regular technical monitoring to ensure smooth operation is also required throughout pipelines' complete lifecycle. So, A strong and reliable PIMS strategy ensures your social accountability commitments to public safety and environmental protection.

Therefore, operators of pipelines in the oil and gas and other high-hazard industries must be sure equipment and materials are fit for service and functioning according to the highest safety and production levels in order to stay compliant and profitable.

In consequently, this article presents to the reader some aspects related to the maintenance and safety operation of oil and gas transport pipelines.

ABBREVIATED TERMS

API	American Petroleum Institute
CBM	Condition-based maintenance
ILI	In-Line Inspection
IMP	Integrity Management Program
MOP	Maximum Operating Pressure
PIMS	Pipeline Integrity Management System
RBM	Risk-based maintenance
SCADA	Supervisory Control and Data Acquisition
SMYS	Specified Minimum Yield Strength

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