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SYNERGETIC EFFECT OF A DRAG REDUCER AND PIPELINE INTERNAL COATING ON CAPACITY ENHANCEMENT IN OIL AND GAS PIPELINES: A LITERATURE REVIEW

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Abstract

This article presents a review of investigations on the effect of drag-reducing agents and internal coatings to increase gas and liquid pipeline system capacity, and the correlation between the pipe internal surface roughness, pressure drop, and the maximum flow rate of gas through the pipeline. The enhancements in pipeline hydraulics are identified and used to estimate increase in pipeline capacity and subsequent savings in operating cost over a wide range of fluid and pipeline parameters. The economic benefits are presented as payback periods using discount cash flow techniques. Moreover, the aim of this study was to review published information on drag reducers and pipeline internal coating relevant to pipeline capacity enhancement.

Keywords*: Drag reducer, internal coating, operating expenditure, pipeline capacity, synergetic effect, surface roughness, flow improver.*

Introduction

To transport fluid through pipelines, energy must be applied to the fluid. This energy is lost due to friction as the fluid moves down the pipeline. Drag reduction technology can reduce the energy lost due to friction, or drag, by over 60% in most cases. When additional capacity is needed in a given oil and gas pipeline, the choices are simple:

- add pumping horsepower at select stations;
- add pump stations at select locations;
- add pipeline loops;
- use a drag reducer or flow improver.

Using the latter in a pipeline, you may have hit the jackpot. It's an answer that more and more pipelines are discovering every day [2].

Fluid flow in pipes depends on factors such as [3, 4]

- the length, internal diameter, internal roughness of the pipe;
- the viscosity, density and velocity of the fluid;
- changes in fluid temperature;
- the geometry of the pipeline, including bends, risers, valves and other fittings.

The pressure drop in a pipeline is due to internal friction. Internal coating reduces internal friction of the pipeline and thus reduces pressure drop. Due to decrease in pressure drop, flow automatically increases [3].

Economically, internal coatings have been proved to lower capital and operating expenditures over the long term. A study in the year 2000 by Nelson and Rob [5] confirmed that

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internal coatings were capable of lowering friction coefficients by 50% in carbon steel pipes [3]. Additional study by Rafael Zamorano on a 1200 km pipeline owned by Gas Atacama confirms huge savings of $2.4 million by using internal coatings [3, 6], (see Table 1). By internally coating a 250 km pipeline, Shell Global Solutions achieved cost savings of 5% and also moved to a smaller diameter pipeline [3, 7]. Institut Francais du Petrole of France, realized cost savings of 7-14% and 15-25% for a slightly corroded and extremely corroded pipeline respectively [3, 8, 9-10].

Table 1. Cost Savings using a Flow Efficiency Coating [3, 11]

Incremental compression service cost	With internal coating in Argentina	Bare pipe	Savings
Fuel gas (US$ millions)	6.5	8.9	2.4
Capital expenditure (CAPEX) (US$ millions)	17.7	26.6	8.9
Operating expenses (OPEX) (US$ millions)	18.1	27.2	9.1
Total cost (US$ millions)	42.3	62.7	20.4

For gas pipelines, based on practical test and experience, the application of internal coating can result in the following profits.

- Increase in throughput: the increase will be maintained for years, as has been experienced worldwide for many years. Generally, it is considered that a 1% enhancement in throughput warrants internal coating. For smoothing the internal profile so that gas or fluids flow more readily through the pipe, a thin film epoxy coating is applied of 1.5 – 3mils (37 – 75 microns) dry film thickness. Application is normally by spraying, following sound surface preparation. This system is essentially used for natural gas pipe insides.
- Cleaning of the transmission pipeline after laying becomes easy and faster. Also more rapid drying after hydrostatic testing
- Pipe length protected before pipe laying: no corrosion which would damage the smoothness, and create product contamination
- Paraffin and other deposition is lowered. This in turn increases gas flow
- Cheap pumping costs, which are maintained in service
- Maintenance: frequency of cleaning is substantially reduced
- A considerable decrease is achieved in the maintenance of coated lines, due to less frequent pigging being required, and due to easier cleaning. It was found that in running pigs, about half the pressure was required to move a pig through a coated line as compared to an uncoated line. Similarly, when lines were hydrostatically tested, as compared to an uncoated line. Similarly, when pipelines were hydrostatically tested it was possible to completely dry a 36-inch pipeline with as few as four pig runs. Frequency of pigging varies from pipeline to pipeline, but several major gas transmission companies have provided some data from their experience. This showed that with coated pipe, pigging was necessary only every 12 to 18 months. In uncoated pipe, pigging is normally required about 3 times a year.
- Product purity: no contamination from corrosion dust which might block, or damage, applications
- Helps pipe inspection: the light reflective internal coating displays lamination and other pipe defects.
- Reduction in friction

- Sound economics: In achieving the above advantages, the initial cost of the coating operation is recovered many times. Even if the diameter of the gas pipeline as installed is adequate for the immediate throughput requirements, internally coating is yet considered advisable in order to allow a margin for the in evitable increased future demand.

An economic higher compromise figure of 3mls (75 microns) dry film thickness is specified where the gas is mildly corrosive.

Because the effect of the condition of the pipe interior is dependent on the Reynolds number, the effect of internal coatings on the throughput of any water pipeline will be greatest for small diameter lines operating at high capacities. In terms of pressure, the effect of internal coatings will decrease pressure losses in any pipeline more dramatically, the smaller the pipeline and the greater the capacity.

Special linings are available which has been approved by relevant authorities for use with portable water pipelines. These coatings have been used in pipelines for portable water, and have also given good service in portable water tanks [12-13].

Reduced pumping cost

It is generally acknowledging that pumping costs in uncoated lines progressively increase with time. Parallel with the maintenance of through-put efficiency in coated lines, there is no increase in pumping time and costs.

Reduction in friction

Published data on loss of pressure in water lines clearly shows that internal coating is not only a vital requirement for protection and maintenance of the installation, but that the coating also has a direct effect on losses of pressure and energy.

Condition	**Absolute roughness (k_s (mm))**
New, bitumen coated	0.01 – 0.02
New, not bitumen coated	0.04 – 0.10
Bitumen, partially loosened	0.08 – 0.10
Light encrustation	0.10 – 0.20
Cleaned after extended use	0.10 – 0.20
Overall rusting	0.15 – 0.40
Chlorinated rubber coating	0.007
Two-component polyurethane	0.001

Judicial application of drag reducers in pipeline operations will:

- reduce capital expenditure – drag reducers can limit the requirement of additional pumping facilities or looped pipe segments; thereby reducing construction costs;
- increase flow rates with existing assets to capture additional throughput volume;
- maintain maximum allowable operating pressure (MAOP): allow continuous operation within the constraints of maximum allowable operating pressures without sacrificing capacity;
- bottlenecks in refinery operations are reduced by treating in-plant crude lines;
- recover lost throughput after maintenance turn-around;
- increase production of crude oil by lowering wellhead pressure;
- reduce expenses in energy and maintenance by eliminating pump stations or pump units;
- enhance operational flexibility;
- allow entrance into high pressure offshore pipelines;
- reduce demurrage costs with faster loading and unloading of tankers.

As a preliminary step, a literature review has been performed to establish the current state of knowledge in relevant areas.

Research problem

In most petroleum pipelines, the flow through the pipeline is turbulent. Turbulent flow is described as irregular, random movement of fluid particles in directions at right angles to the direction of the main flow. The flow is unstable. Turbulent eddies are produced at the pipe wall and move into the core of the pipe. More energy is needed to move fluid at a given average flow velocity in turbulent flow since not all of the energy is lost in the formation of eddy currents. A family of polymeric chemical additives known as drag reducers can decrease this turbulent energy loss. In general, the more turbulent the flow, the more effective the drag reducer becomes and subsequently, more efficient energy use can be achieved.

Internal coating is used to reduce surface roughness and accordingly internal friction. This will decrease the pressure drop between compressor stations, and consequently allows installing less power and consume less fuel. And hence the potential to lower CAPEX and OPEX respectively. Due to decrease in pressure drop, flow automatically increases.

Since the invention of internal coating in 1955 by Tennessee Gas pipeline company of United States of America (USA) and Drag reducers in 1946 by B. A. Toms, a British chemist in London, they have been used individually for capacity enhancement in pipelines. The core problem which this research intends to study is:

- how the combined (synergetic) use of a drag reducing agent and a pipeline internal coating increases liquid and gas pipeline capacity.

Internal coating: literature review

It has been well established, substantially increased "through-put" of product can be achieved in internally coated pipes. Internal coatings smoothen the pipe interior and in so doing reduce operational costs associated with pumping petroleum products.

The main aim of internally coating a pipeline, is to provide protection against corrosion and abrasion, reduce friction, reduces cost of scrubbers, strainers, "pigs", and other type of pipeline cleaning services. Also, internally coating a pipeline will provide product purity and prevent contamination from corrosive products, significantly reduce maintenance and labour costs, and protect the pipe interior against the buildup of deposits (calcareous or paraffin). For both liquid and gas pipelines the cost of internally coating the pipeline and use of flow improver can only be justified in most cases only on the basis of reduced operating cost.

In 1955, Tennessee Gas pipeline company of United States of America (USA) introduced the practice of internally coating pipelines [14]. This was followed by Transcontinental (Transco) Gas Pipeline Corporation in 1959 [15]. The first and broadest test to determine the increase in flow throughputs were carried out by Tennessee Gas Pipeline in 1958 [16-17] using a 10year old 24-inch diameter pipeline through the following three (3) test stages:

i. pipeline in its existing state;
ii. after cleaning;
iii. after internal coating.

The measured increase in capacity were of the order of 10% of which 4% was attributable to pipe cleaning. These test proved the ability of internal coating to increase throughput or pipeline capacity. A further test one year later on the same section of pipeline showed there to have been no apparent deterioration of the flow [18, 19]. Further subsequent tests have indicated no significant reduction in the capacity-confirm the very substantial savings obtained by internally coating. Furthermore, uncoated pipes require frequent cleaning, in contrast to internally coated pipe. These results have been closely paralleled by flow results obtained by many transmission companies since 1958.

Klohn (1959) has fully described the testing procedure for establishing this improved throughput. Reference must also be made to a publication by the American Gas Association (1965), [16]. This studies in detail the steady flow in gas pipelines, considering testing, measurement, behavior and computation. Inter alia, this also refers to internally coated lines. Taylor (1960) has stated that an increase of even only 2% in gas flow can justify the cost of internal coatings. The degree of smoothness of an internally coated pipe is inversely proportional to the friction resistance. The application of such thick films has been repeatedly shown to provide characteristics that are equal, or superior to those of new, clean pipes, and to regularly pigged pipelines.

The actual increase which can be achieved depends on the pipeline and flow characteristics. The usual range of increased throughput is 5-10% although as much as 25% has been reported for small pipeline diameters [19]. Since a potential increase of only 1% in pipeline capacity can justify the cost of internal coating, the measured increases give a significant economic incentive [20].

Early applications of internal coatings were mainly to water lines to ensure high purity or to gas lines where maximum increase in throughput were expected [21]. However, recently, internal coating has been applied to crude lines specifically to provide corrosion protection and also for improved hydraulics as well as reduced maintenance, and lower wax deposition [22]. 75% reduction in frequency of pigging and 25% reduction in wax deposition has been reported for some onshore pipelines [23]. Seedoriff reports calculations from data taken at the La Huerta pump and at the booster, comparing throughput before and after internally coating a 14-inch diameter plant water pipeline. The total distance of the pipeline was 49,750ft, with a difference in elevation of 40ft. before internal coating, the total friction head was 548.7ft of water and the pumping rate of 1750gpm. This compared after internal coating, with a pumping rate of 2200gpm, with a total friction head of 233.9ft of water. Calculations indicate that the cost of power only for pumping 1750gpm before internal coating for 8760 hours per year, totaled $367,330. The cost of pumping 2170gpm after internal coating for 8760hours per year totaled $350,463. That is a total calculated saving of $16,867 per year in pumping cost alone [12-29].

In an eight-mile 16-inch steel water pipeline, coupons were taken from the pipeline after some 11 years to check the internal coating for build-up of calcium carbonate. All the coupons indicated the pipeline to be in practically the same condition as it was when coated, and the C factor remained about 150.

Thirty-one miles of 10inch and 12 inch steel water supply pipelines. Prior to internally coating, this pipeline had been in service approximately eleven years. The C factor had dropped from approximately 150 to approximately 65, due to oxygenation barnacles and calcium carbonate build-up. After internally coating, the capacity of the pipeline almost doubled. In 1972, the pipeline was reported as still operating at a C factor approaching 150.

Twenty miles of 16-inch and 8-inch main steel water pipeline and gathering system. When last reported in 1972, this pipeline had been in continuous service since 1963 with no appreciable decrease in the C factor, and no corrosion or evidence of calcium carbonate build-up [12-29].

In another typical potable water pipeline, tuberculation had reduced the flow. Internal cleaning and internal coating increased the C factor from 75 to 147, and was maintained at this figure when rechecked after three (3) years.

Cast iron $1\frac{1}{2}$ mile, 6-inch pipeline operating at 100psi internally coated to improve flow efficiency. This pipeline was installed some three years earlier, but was never cleaned. Throughput had been cut by half, to 213g at 105psi. Examination four years after internal coating showed the internal coating to be in excellent condition with a flow of 535g at 65 psi.

In summary, it is concluded that internal coating of pipelines can give substantial increase in throughputs. These increase will depend on the pipeline, coating and flow characteristics. On the other hand, the associated theoretical analysis has yet to be developed for predicting such increases for any pipeline system [30].

Epoxy Pipe Coating

Two-pack epoxy type internal pipe coatings are used in the interior of pipe used in transmitting dehydrated natural gas, wet gas, crude oil, sour crude oil, salt water, drinking water, fresh water, petroleum products, and numerous chemicals [31-32]. Such specialized epoxy internal pipe coatings have now been available for a considerable number of years and because of field experience, can be applied in adequate film thickness, with the required resistance characteristics. Polyamide epoxy and solvent free epoxy are typical examples of epoxy internal pipe coatings.

Two main methods for applying internal coatings are spraying and in-situ coating.

Typical applications and case histories

Typical examples have been selected from experience to illustrate various pipelines conditions protection by internally coating and subsequent performance.

Petrochemical and refined product lines

Naphtha feedstock lines – subject to purging with sea water – still functioning satisfactorily some three years after coating [20].

Paraffin deposition

Buildup in crude oil pipelines is a well-known problem. Internal coatings have been applied to reduce build up. Examination in service does not always occur, and records are not always transmitted to the coating supplier. However, some case histories are available. For example, a 12-inch crude oil pipeline internally coated was opened at 5 and 10 years after coating – no paraffin deposition was observed. These observations confirm similar reports from various pipeline operators [20].

Coal slurry pipelines

Slurry pipelines offer a distinct advantage over other forms of transport such as lorry or railroad since they are buried and not visible. Within a year of two after the pipeline is constructed, the right-of-way is difficult to identify from the nearby terrain [12].

Slurry pipelines are reliable since they are not affected by severe weather, such as snow storms or very low ambient temperatures. Further, due to the degree of automation possible, they are relatively insensitive to labour disputes, and it is considered that the industry is seeing the start of a new generation of energy movers; that is, long distance high volume coal slurry pipelines. Internal protection against corrosion and erosion is a vital consideration in such projects [20].

Capsule transport

Since the 19th century, pneumatic capsule pipeline (PCP) has been used for transporting many products such as books, mail, printed telegraph messages, cash receipts, machine parts, blood samples (in hospitals).

The concept of container transportation has already been exploited at a building material quarry in Georgia: here a two kilometer pipeline transports gravel to the point of dispatch. Compressed air is used instead of water, and moves six wheeled containers with a total weight of 25 tons at a speed of 30km an hour. It was decided to extend the line further 50km to reach a plant manufacturing Ferro-concrete building elements [20, 33].

In the long term, capsuled systems have a number of advantages over lorries. They give no exhaust pollution, keep toxic substances away from the public, and offer less opportunity for theft. Once a pipeline is laid, its maintenance cost is small. Capsules would also appear to be a better method of transporting minerals to and from quarries than a straightforward conveying system.

Consideration of capsule pipelining clearly indicates that coatings will have an important role to play if this procedure reaches commercial acceptance. Firstly, internal lining of the pipeline will reduce friction and protect the steel from corrosion, and possible long term erosion effects. Secondly, external coating of any metal capsules will result in similar advantages. Thirdly, the pipe exterior will require long term protection, and this would, with advantage, be a tough and resilient coating. Fourthly, the capsule interiors will require protection [20].

Concrete pipes

Coatings for the internal and external coating of concrete and asbestos – cement pipes are also available. These can often extend the life and service conditions of such pipes.

Adhesion tests have been carried out to the interior of cement and asbestos-cement sewer pipes. A specific epoxy coal tar coating was selected for trial, applied to about 500 microns' dry film thickness.

Special testing indicated the absence of detectable pores in the coating. Adhesion test were carried out by tensile tests. Steel coupons were glued with an epoxy adhesive to the coating. After curing and ageing, the steel coupon was "pulled off" – determining the tensile strength.

The measured tensile stress was well in excess of 30 $kgfcm^{-2}$ – the results ranging on different concrete substrates from 38 – 60 $kgfcm^{-2}$, it was found that if the tensile stress measured is larger than about 30 $kgfcm^{-2}$, the results are determined by the tensile strength of the concrete itself, that is its tendency to fracture. The coating therefore had greater adhesion to the concrete substrates than their own cohesion integrity [20].

Theoretical Analysis

Analysis of natural gas pipelines

Friction Factor and Pipe Roughness

For steady state conditions, the Reynolds number (Re) for gases can be expressed as [34-39]:

$$Re = \frac{DV\rho}{\mu} \tag{1}$$

Where:
Re = Reynolds number;
D = pipeline diameter (m);
μ= fluid viscosity ($kgs^{-1}m^{-1}$);
V = fluid velocity (ms^{-1});
ρ = fluid density(kgm^{-3}).

Substituting for density (ρ), and velocity as flow rate/area, into Equation (1), we get:

$$Re = \frac{49.44QgP_b}{\mu DT_b} \tag{2}$$

Where:
Re = Reynolds number;
D = pipeline diameter (mm);
g = Gas specific gravity;

μ= fluid viscosity (Pa-S);
P_b = Base pressure (kPa);
Q = Gas flow rate ($m^3 day^{-1}$);
T_b = Base temperature (°K).

Colebrook, in the 1930's, proposed an equation which combined the smooth pipe law and the rough pipe law into a single equation.

$$\frac{1}{\sqrt{f}} = -2\log_{10}\left(\frac{e}{3.7D} + \frac{2.51}{Re\sqrt{f}}\right) \tag{3}$$

Equation (3) is effective for partially turbulent, transition and fully turbulent flow. The main difficulty in using it is that f appears on both sides, an iterative solution is required. Equation (3) forms the basis of all subsequent theoretical analysis [34-35, 36-39]. The variation of friction factor with surface roughness is by using the term transmission factor (F).

Flow and Pressure Drop

For steady state isothermal flow in horizontal gas pipelines, the basic equation derived from an energy balance over the length of the pipeline can be expressed as (general flow equation):

$$Q = 0.0011493E\left(\frac{T_b}{P_b}\right)\left(\frac{P_1^2 \_ P_2^2}{GTLZf}\right)^{0.5} D^{2..5} \tag{4}$$

where:
Q = gas flow rate, ($m^3.day^{-1}$)
f = darcy-weisbach friction factor
P_b = base pressure (kPa)
T_b = base temperature (°K)
P_1 = inlet pressure (kPa)
P_2 = outlet pressure (kPa)
G = gas specific gravity (air = 1.00)
T = average gas flowing temperature (°K)
L = pipe segment length (km)
Z = gas compressibility factor at the flowing temperature
D = pipe diameter (mm)
E = pipe efficiency factor

Equation (4) can be re-arranged if the relationship for the friction factor (*f*) is known. The following empirical correlations suitably modified are usually used in the analysis of natural gas pipelines [38, 40].

American Gas Association (AGA) equation

$$F = 4\log_{10}\left(\frac{3.7D}{e}\right) \tag{5}$$

The equivalent friction factor for AGA equation is, $f = \frac{4}{\left(4\log_{10}\left(\frac{3.7D}{e}\right)\right)^2}$

Weymouth

$$F = 11.18(D)^{1/6} \tag{6}$$

The equivalent friction factor for Weymouth equation is, $f = \frac{4}{\left(11.18\left(D^{\frac{1}{6}}\right)\right)^2}$

Panhandle "**A**"

$$F = 6.87Re^{0.07305} \tag{7}$$

The equivalent friction factor for Panhandle "A" equation is, $f = \frac{4}{(6.87Re^{0.07305})^2}$

Panhandle "B"

$$F = 16.49Re^{0.01961} \tag{8}$$

The equivalent friction factor for Panhandle "B" equation is, $f = \frac{4}{(16.49Re^{0.01961})^2}$

$$F = \frac{2}{\sqrt{f}} \tag{9}$$

$$\therefore f = \left(\frac{2}{F}\right)^2 = \frac{4}{(F^2)}$$

where:
f is the Darcy friction factor.
Substituting equations (5) to (8) individually into Equation (4) gives,

Weymouth equation

$$Q = 433.49E\left(\frac{T_b}{P_b}\right)\left(\frac{P_1^2 - P_2^2 - H_c}{GTLZ}\right)^{0.5} D^{8/3} \tag{10}$$

Panhandle "A"

$$Q = 0.0045965E\left(\frac{T_b}{P_b}\right)^{1.0788}\left(\frac{P_1^2 - P_2^2 - H_c}{G^{0.8538}TLZ}\right)^{0.5394} D^{2.6182} \tag{11}$$

Panhandle "B"

$$Q = 0.010019E\left(\frac{T_b}{P_b}\right)^{1.02}\left(\frac{P_1^2 - P_2^2 - H_c}{G^{0.961}TLZ}\right)^{0.51} D^{2.53} \tag{12}$$

where:
H_c = elevation correction (KPa^2)
Re = Reynolds number
All other parameters are as defined above.

Equation (10) is in USCS units (English units), and F is the transmission factor. Weymouth equation's original published form is presented in Equation (10) [38].

Modified Colebrook-White Equation

The transmission factor is calculated as:

$$\frac{1}{\sqrt{f}} = -2\log_{10}\left(\frac{e}{3.7D} + \frac{2.825}{Re\sqrt{f}}\right) \tag{13}$$

Where the variables in equation (5) to (13) are defined the same as in equation (4). The pipeline efficiency term 'E' is used to correlate measured and predicted data. For a new pipeline, a typical value of 'E' is 0.95 and is constant for a wide range of Reynolds number [34]. The effect of reduction in surface roughness on pipeline friction for AGA equation can be calculated directly from equation (5), depending on the flow regime. For Weymouth and Panhandle equations the effect of surface roughness can be estimated from equations (9), (10), and (11). This result in the following correlations [30].

AGA & Weymouth

$$\frac{Q_c}{Q_0} = (\frac{f_0}{f_c})^{0.5} \tag{14}$$

Panhandle "A"

$$\frac{Q_c}{Q_0} = (\frac{f_0}{f_c})^{0.5394} \tag{15}$$

Panhandle "B"

$$\frac{Q_c}{Q_0} = (\frac{f_0}{f_c})^{0.51} \tag{16}$$

Compression Analysis

For gas pipelines systems, the compression power can be calculated by:

$$P_w = \frac{k \cdot Z \cdot R \cdot T_1}{k-1} \times \left(\left(\frac{P_1}{P_2}\right)^{((k-1)/k)} - 1\right) \times Q_m \tag{17}$$

where:
P_w=Power (kW);
Z = gas compressibility factor (assuming Z=1);
P_1 = Pressure inlet compressor (kPa);
P_2 = Pressure outlet compressor (kPa);
Q_m=Compressor throughput (kg/s);
k= Gas isentropic (adiabatic) coefficient;
R = Universal gas constant, 8314/Molecular weight (J/(kg.K)).

The discharge temperature for an isentropic (adiabatic) compression can be calculated as:

$$T_2 = T_1 \times \left[\left(\frac{P_2}{P_1}\right)^{(\gamma-1)/\gamma}\right] \tag{18}$$

$$\gamma = \frac{C_p}{C_v} \tag{19}$$

where:

γ is the ratio of the specific heats (Cp/Cv) of the gas. This ratio is approximately 1.29 for natural gas. Air and a number of other gases have a value of k = 1.39 to 1.41 [41]. For air, k is 1.4.

Equation (17) together with pressure drop equations can be used to estimate the variation of compression power with pipe surface roughness. It is clear that for gas pipelines, unlike the liquid pipelines, the variation of compression requirements with surface roughness is a function of both friction factor (surface roughness) and pressure. Hence an explicit mathematical equation cannot be developed [30].

Reduction in Pipeline Diameter

For given flow conditions of pressure, flow rate, fluid properties and pipeline length, the friction factor (*f*) depends only on the pipeline diameter.

Exact relationship between *friction factor* and pipeline diameter will depend upon the correlation used to predict pressure drop [30].

AGA

$$\frac{D_c}{D_0} = (\frac{f_c}{f_0})^{0.2} \tag{20}$$

Panhandle 'A'

$$\frac{D_c}{D_0} = (\frac{f_c}{f_0})^{0.2059} \tag{21}$$

where:
subscript "c" denotes internally coated and "0" denotes uncoated.

Analysis of liquid pipelines

Flow and Pressure Drop

Mathematically, the Darcy Weisbach equation used to calculate the pressure drop across a pipe is:

$$\Delta P \ = \frac{f \times L \times V^2 \times \rho}{2 \times D} \tag{22}$$

where:
$\Delta P = \rho g h_l$ = pressure drop, (m or N-m/N);
h_l= frictional head loss, m;
G = acceleration due to gravity, m/s^2;
f = moody friction factor;
L = pipe length, m;
V = average velocity of fluid, m/s;
D = pipe diameter, m;
ρ = fluid density, kg/m^3.

According to Singh and Samdal (1987), for a given pipeline system, $flowrate, Q = V \times A$, therefore, the fluid velocity is directly proportional to the flowrate, Q, then for a given pipeline dimensions and fluid, equation (22) can be re-arranged to:

$$\Delta P \ \propto fQ^2 \tag{23}$$

and for a given flowrate, Q

$$\Delta P \ \propto f \tag{24}$$

And for a given pressure drop, ΔP

$$Q \ \propto 1/\sqrt{f} \tag{25}$$

The change in throughput for any combination of Reynolds number (Re) and surface roughness can be calculated by using equations (23), (24), and (25).

Pumping Power

To cause liquid to flow, work must be expended. The pump power output of a liquid pipeline system is calculated as:

$$P_w = HQ\rho/3.670 \times 10^5 \tag{26}$$

where:
P_w = pump power output (kW);
H = total dynamic head ($N.m.kg^{-1}$) (column of liquid);
Q = capacity ($m^3.h^{-1}$);
ρ= liquid density ($kg.m^{-3}$).

Combine equation (24) and (26) and rearrange, for a given flowrate (Q) to get:

$$P_{wc}/P_{w0} = f_c/f_0 \tag{27}$$

Reduction in Pipeline Diameter

For a liquid passing through a pipeline, a reduction in the diameter of the pipeline can compress the flowing fluid. It flows faster, which increases the flow rate. And if the diameter increases, then the flow rate reduces [30].

By substituting for V in terms of Q, Equation (22) can be re-arranged for a given flowrate (Q) and pressure drop (ΔP) and pipeline length (L).

$$f_c \propto D_c^5 \tag{28}$$

Or

$$\frac{D_c}{D_0} = (f_c/f_0)^{0.2} \tag{29}$$

Equation (29) can be used to determine the $\rho$with reduction in surface roughness [30].

Economic Analysis

The benefits of internal coating in terms of increased throughput and reduced pressure drop are used in this study to determine the economic benefits for applying internal coating using discount cash flow techniques [30].

The benefits of internally coating a pipeline can be expressed as

Operational

Reduced operating cost: The increase in flow and reduction in pressure drop due to internally coating a pipeline contributes for lesser power consumption. The same flow rate can be achieved at the expense of this power consumption to compress the gas. Moreover, it can also help in selection of smaller size compressor and ultimately reduces the cost at the design stage (see Table 1) [42].

Increased product throughput: Pressure drop in a pipeline is due to internal friction. Internal coating reduces internal friction of the pipeline and thus reduces pressure drop. Due to decrease in pressure drop, flow automatically increases [43].

Corrosion: internal coating can reduce internal corrosion of pipeline inner surface.

Design

Reduced steel costs associated with potential reduction in pipe diameter.

Internal Coatings provide smooth internal surface. The improved surface roughness creates laminar flow at the internal boundary. The laminar flow helps in achieving the maximum flow capacity in the pipeline as a reduction of friction at pipe surface thus reduction of diameter is achieved for same flow rate and ultimately cost saving in design phase.

The economic analysis is restricted to savings in operating cost resulting from lower pumping/compression requirements. Other operating cost such as pipeline pigging will be small compared to the fuel cost.

When considering future projects, top management will most likely call for the discounted-cash-flow rate of return and the payback period (PBP) [41]. The economic issues associated with capital investment in internal coating projects are studied in this section. In particular, the payback period (PBP), discounted cash flow techniques of net present value and internal rate of return are discussed in detail.

Payback period

PBP for an internal coating project, is the time required to earn back a sum invested in the project. The shorter the payback period, the more attractive the project becomes. The payback period can be calculated using Equation (30) as:

$$PBP = \frac{CC}{AS} \tag{30}$$

where:

PBP = Payback period (years);

CC = Capital cost of project or Initial investment ($);

AS = Annual net cost saving achieved or Annual cash flow ($).

Discount cash flow (DCF)

DCF is used to estimate the attractiveness of an investment opportunity.

Net present value

The sum of all the present values (PV) is known as the net present value (NPV). The higher the net present value, the more attractive the proposed project.

$$PV = S \times DF \tag{31}$$

where:

PV = present value of S in ‘n’ years’ time ($);

S = value of cash flow in ‘n’ years’ time ($);

DF = discount factor, $DF = (1 + IR/100)^{-n}$;

IR = interest rate (%);

N = number of periods (years).

Reduced pumping cost

According to Singh and Samdal (1987), With given values for cost of fuel, pump efficiency, gas turbine efficiency and the calorific value of gas, it can be shown that the value of fuel saved over the year is [30].

$$F_v = €0.489 Q_0 \Delta P_0 (1 - f_c/f_0) \tag{32}$$

And using discount cash flow techniques the payback period (PBP) is given by:

$$PBP = \log(11/(11 - \frac{C}{F_v}))/\log(1.1) \tag{33}$$

where:

F_v is annual fuel savings, C is pipe coating cost, P_1 is the inlet pressure, P_2 is the outlet pressure, P_w is power, Q is throughput, r is compression ratio, f is friction factor, and subscript ‘0’ represents uncoated and subscript ‘c’ represent internally coated [30].

Reduced compression costs

With given values for cost of fuel, compressor efficiency, gas turbine thermal efficiency, and the gas properties, the value of fuel saved over the year is given by [30]:

$$F_v = €1{,}617{,}958 Q_0 r_0^{0.26}\left(1 - (P_{1,c}/P_{1,0})^{0.26}\right) \tag{34}$$

According to Singh and Samdal (1987), the payback period (PBP) is given by equation (33).

In achieving the above advantages, the initial cost of the coating operation is recovered many times. Even if the diameter of the gas pipeline as installed is adequate for the immediate throughput requirements, internally coating is yet considered advisable in order to allow a margin for the in evitable increased future demand [30].

Drag Reducer

Flow improver/ drag reducing agent improve flow in pipelines. During fluid flow the portion of the fluid in contact with the wall is slower than the portion in the center. This leads to the formation of turbulent eddies which cause drag. A drag reducer suppresses the formation of turbulent eddies reducing the drag and subsequently the frictional pressure drop in the pipeline. Drag reduction in gas transmission pipelines could be by internal coating or by adding ammonia [44].

Drag reducers also known as flow improvers of the long chain polymer type have been known since 1946, when B. A. Toms, a British chemist in London, first undertook experiments. He found the drag reduction phenomenon while studying the characteristics of liquid solutions in turbulent flow.

The discovery didn’t get much attention until the 1960s and 1970s as several universities and companies conducted expensive experiments. Different polymers were studied and technical papers published.

The Trans-Alaska Oil Pipeline system (TAPS), operated by Alyeska Pipeline Service Co., began operation in the late 1970s and quickly found it necessary to increase its throughput in the 48-in. line. In July 1979, the TAPS pipeline began the first large scale commercial application of drag reducing additives. Initially, the additives increased flow by 100,000bbl day^{-1}. Today, the increase is 200,000bbl day^{-1}. Use of drag reducing additives made it possible for TAPS to avoid adding pumping stations at two locations. An example injection system is shown in Fig. 1.

Flow improver technology can reduce the energy lost due to friction or drag by more than 50% in most cases and increase flow rates by up to 100%. The effectiveness of a drag reducer depends largely on the properties of the fluid in the pipeline and the condition of the pipeline [2].

In 1956, the American Petroleum Institute studied the injection of a drag reduction agent (DRA) into a pipeline to reduce frictional resistance [45-50]. The basic structures of DRA molecule were proposed by Atlantic Richfield Company in the 1990s [49].

The additive is usually sold in either a 500-gallon portable tank, 5000-gallon tank containers or a 20,000-gallon railroad tank cars. Shipping and storage vessels must have a minimum working pressure of 40 psi.

Drag Reduction and Pipeline Capacity Enhancement

The usefulness of a drag reducer is generally expressed in terms of percentage drag reduction [2, 51]. For a given flow rate, the percentage drag reduction is calculated as

$$\%\,D.R = \frac{P-P_p}{P} \times 100 \tag{35}$$

Where

P = base pressure drop of the untreated fluid

Pp = pressure drop of the fluid containing drag-reducing polymer

D.R = Drag Reduction

Generally, Equation (36) is used to calculate the percentage throughput increase [2, 52].

$$Percent\ throughput\ increase = \left[\left(\frac{1}{1-\frac{\%D.R}{100}}\right)^{0.55} - 1\right] \times 100 \tag{36}$$

Where

% D.R = is the percentage drag reduction as defined in equation (35).

Assumption:

The pressure drop of both the treated and untreated fluid is proportional to flow rate raised to the 1.8 power [2].

Economics

The economics of using a flow improver additive depends on

- How much drag reduction or flow increase is needed?
- The characteristics of the crude oil / petroleum products being transported.
- The pipeline configuration.

Typically, the additive is most successful when the economics are in the range of 5e-25e/incremental barrel.

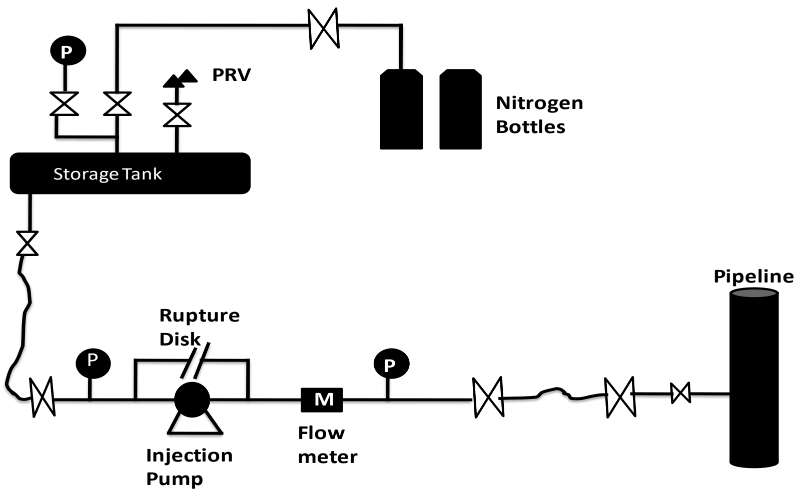

Fig. 1. Injection system for drag reducer [5]

Synergetic effect of a drag reducing agent and an internal coating

Theoretically, the synergetic effect of injecting a drag reducing agent in an internally coated pipeline, is the condition where the combined effect of pipeline internal coating and drag reducer on the pipe's capacity is bigger than the sum of the effects of each agent (i.e. internal coating, drag reducing agent) given alone [12], for example:

3 + 3 >> 6 (maybe 10 times or more)

Knowledge Gap

Research gaps identified are:

A study on the synergetic effect of internal coating and drag reducing additives for capacity enhancement in pipelines for both single phase and multi-phase flows.

Analysis of two-phase pipelines.

The subject of multi-phase flows is extensive and complex. There are numerous correlations available for calculating pressure drop in two-phase lines. Generally, all techniques require calculation of various parameters leading to the derivation of friction factor of the two-phase fluids. Then the pressure drop equation can be estimated. If the two-phase friction factor is a multiple of single phase factor, the effect of surface roughness can be determined. However, the derivation and description of each is yet to receive proper scholarly attention.

The flow through the pipeline must be turbulent for the drag reducing agent to work;

The drag reducing agent are usually effective up to more than 70% flow increase. For flow increase above 50% a combination of new pumps or loop sections together with additives may be required.

Drag reduction and internal coating studies on three-phase flows. This is also significant due to the existence of this flow regime in some oil and gas systems.

Conclusions

The review shows that synergetic use of internal coating and drag reducing agent can significantly reduce the pipe surface roughness resulting in lower friction factor, increased product throughput, and lower pipeline material and operating costs. For most applications, contractual supply and/or production considerations rules out the case for their application based on either increased product throughput or reduced pipeline costs. The economic analysis proposed is therefore based entirely on potential benefits from reduced operating costs.

Pipe friction factor decreases with decrease in surface roughness. The percentage reduction in friction factor increases with increase in Reynolds number and decrease in pipe diameter. The effect of pipe diameter on the reduction in the friction factor diminishes at high Reynolds numbers. The impact of Reynolds number is greatest between the range of $10^5 – 10^7$.

The benefit of reduced friction resulting from the application of a drag reducing agent or an internal coating depends on the surface roughness of the uncoated pipe.

For liquid systems the economic benefits are greater for smaller pipe diameters whereas for gas systems the benefits are greater for large pipe diameters. For a given conditions the benefits are greater for gas than liquid systems. The economics show that for both liquid and gas pipelines the cost of internally coating the pipeline or using a drag reducing agent can be justified in most cases on the basis of reduced operating cost. Payback periods, which are direct function of the fuel cost, are better for gas than liquid systems.

Pipelines today have a useful and interesting array of chemical products such as polymers, biopolymers and internal coatings to aid in moving difficult products and in getting more capacity from existing pipelines. The advantages have been outlined of internally coating pipelines and the use of drag reducers in pipelines carrying liquids, slurries and solids. Equally important in the future will be increasing demand for tough, resilient exterior coatings. With the benefits of internal coating and drag reducers in terms of increased pipeline capacity, reduced pressure drop, reduced operating cost, corrosion protection and reduced steel costs associated with potential reduction in pipe diameter, research on internal coating and drag reducers is expected to continue.

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