POLITECNICO DI TORINO

Department of Environment, Land and Infrastructure Engineering

Master of Science in Petroleum Engineering

MASTER THESIS

STUDY OF LIGHT CRUDE OIL

TRANSPORTATION

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JULY 2020

ACKNOWLEDGEMENTS

First of all, I would like to express my sincere gratitude to my supervisor Prof. Guido Sassi for his continuous support, supervision and guidance throughout the research. I am very grateful to him for providing me valuable support which I found very useful in writing my thesis. I really appreciate her guidance and patience to answer my questions.

I would also like to thank to all my respected professors in Petroleum Department, without their knowledge and guidance it was not even possible to accomplish this research. I am grateful for their cooperation during the period of my thesis.

Last but not the least; I would like to give my heartfelt thanks to my family and friends. This study would not be accomplished without their continued love, encouragement and appreciation.

DEDICATION

This thesis is dedicated to my Parents.
For their endless love,
Support and encouragement

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Abstract

The transportation of crude oil through pipeline is the most advanced form of transportation with major economic and environmental advantages. The transportation of crude oil depends on its rheological properties. The viscosity plays major role in transportation of crude oil. This study emphasis the relation between the kinematic viscosity and pressure loss where temperature of the surrounding remains constant. When crude oil flows through pipeline it experiences resistance to flow due to inter-molecular collision. Transportation of Light crude oil is relatively easier and simple than heavier crude oil but it becomes troublesome when the viscosity decreases to a point that induces high frictional resistance which results in greater pressure drop. The pressure drop in the pipeline not only decreases energy of the system but also alters the composition of crude oil due to the condensation of heavier components.

The viscosity of crude oil depends on the composition of crude oil. In this study the transportation of different fractions of light crude oil at low temperatures has been investigated and compared. The prediction of viscosity at low temperatures often does not provide coherent results. Therefore, in this study different viscosity models have been discussed and a suitable model has been applied to predict viscosity of crude oil fractions, whereas the model is also validated through experimental data. In crude oil the viscosity changes drastically with decrease in temperature resulting in high pressure drop, therefore it is important to keep the viscosity of crude oil below the alarming point to avoid high pressure drop. Different crude oil types exhibit different behavior with variation in the viscosity. In this study the trends of viscosity of different crude oil types are compared at different conditions and four viscosity reduction methods are suggested so that least pressure drop is induced. The crude oil fractions with higher boiling point exhibit relatively greater pressure loss due to variation in viscosity than the crude oil fractions with lower boiling point.

In this study various conditions and parameters are incorporated with given fluids to analyze their behavior. The flow parameters and crude oil composition are varied to study the extent of pressure loss. Methods for reduction in frictional losses are studied which includes dilution, heating, formation of emulsion and core annular flow. Relatively it is found that Core annular flow provide the most suitable condition in the given scenario.

1. Hydrocarbon Transportation:

1.1. Introduction

The major challenge in the oil industry is to transport the crude oil so that it is cost effective and as well as safe. On a greater scale, researchers believed that Oil transportation through pipelines is the most suitable mode of transportation as it is safe, quick and economical.

Oil is transported from wells to oil gathering system at oil fields and then to refinery and then to consumers. The consumers may be with in a country, with in continents or may be to one corner to another corner of the world. The well initially produces to surface through its natural potential because of the pressure difference created.

The fluid has some well head flowing pressure at surface that allows it to enter the pipelines and carry it to the main header, a pipeline with a bigger inner bore size, where different spur lines from different wells are gathered. At the well site the fluid may be initially treated for two phase or three phase separation through different vessels. In normal cases the main header pressure is lower than the spur lines pressure so that the fluid can enter the main header. The main line carries the fluid from different wells to a gathering system at field. The main headers can be designed in such a way that the wells having fluid with similar properties may be collected at same point. There can be one or more oil gathering points at gathering systems depending on fluid properties. The gathered fluid under goes pretreatment, where the water or gas is removed from crude oil in bulk.

In the thesis five different types of crude oils have been studied. The behavior of different crude oils with different flow parameters have been analyzed. The main purpose of the thesis is to study the relation between viscosity and pressure loss. As the crude oil is transported from one point to another, due to internal resistance to motion occur friction losses and the friction losses result in pressure drop. Nowadays, Transportation of crude occurs at long distances and requires pumping stations and various other facilities depending on the fluid properties and flow parameters. The viscosity of crude oil increase as the temperature decreases and higher the viscosity of crude oil higher is the friction loss. In this study the models of viscosity at low temperatures have been discussed and a suitable model is used to predict the viscosity of crude oil fractions at low temperature. The pressure loss analysis of different crude oil fraction travelled through the distance against the change in kinematic crude oil viscosity is carried out at a constant temperature of 8°C to study the behavior.

The study analysis the behavior of kinematic viscosity along the distance travelled and its effect on pressure loss. The study suggests several methods that alters the kinematic viscosity of crude oil fractions and decreases the pressure loss in the pipeline. The solutions include heating, Core annular flow, mixing with lighter crude oil fractions and addition of water to form emulsions. The purpose is to decrease the pressure loss and avoid plugging in pipelines for long distances for smooth supply of crude oil over a larger period of time.

1.2. Case Study:

In the mid-20th century in the area exploration phase were started after oil prospects had been found in limestone core sample. The field comprises of five main production areas in the eastern region of the Empty Quarter desert, along the Texas, USA. The field measures approximately 280km-long and up to 36km-wide.The main reservoirs of the field include the reservoir of the Jurassic-age mudstone formations, carbonate reservoir of oil and the carbonate evaporites reservoirs of the non-associated gas. Later the main reservoir, made of carbonate, holding immense amount of crude oil was drilled. Due to rigorous production activities and development the production increased over the years and accordingly later in the 20th year after it had been discovered, the annual oil production of the field exceeded above 5 million bbls/day. The field was estimated to contain 58.3 billion barrels of oil equivalent (bboe).

- As the surface of the field is so wide, a gathering system is required to collect the oil from wells and then transport to the main station. In the main station, the final treatment is applied before transporting it to the refinery.
- The ambient temperature of the field is low up to 4°C which reduces the temperature of crude that effects the movement of crude oil.
- There are 05 wells namely from PK#1 upto PK#5 a schematic picture is shown of such a system in Figure 1-1 which explains how the following assumptions are made.
- All the wells have different distance from the central gathering system which makes it complex to maintain a uniform pressure in the main header that carries crude oil to the gathering system.
- The major issue is that the composition and flow parameters of all the wells is different as there are 05 different zones through which crude oil is being produced.
- In order to transport the crude oil with minimum pressure losses it is important to apply different methodology for pressure losses reduction to each well according to its characteristics.
- Well Pk#1: Paraffin wax composition crude oil forming bulks of wax in pipeline causing restriction in crude oil flow causing hurdles in fluid flow. It is Heavy Black oil with very low GOR (negligible) and no water aquifer.
- Well Pk#2: Two phase oil and gas flow forming a slug flow that causes additional pressure loss in forms of pressure pulses and intermittent flow, disrupting a smooth supply of crude oil. It has no water aquifer.
- Well Pk#3: High viscosity fluid having high turbulent flow resulting in high friction loss resulting in Pressure loss. Well head Pressure is above bubble point with negligible water production, with active water aquifer but no water production.

- Well PK#4: Water production along with crude oil forming water in oil emulsion, The water having more density inhibits smooth oil flow as nature of water in oil emulsion causing pressure loss. It has small Water production with Active water aquifer.

- Well Pk#5: Low Well head flowing temperature, which with addition to low ambient Temperature reduces viscosity resulting in Pressure loss. Its Well head pressure is above bubble point, a shallow well, with Low well head flowing temperature and no water aquifer.

- Four methods to reduce friction losses is studied and applied to all 05 wells. Sensitivity analysis of all four methods is also carried out and in the end the comparison of the methodology is made in order to evaluate the pros and cons and evaluate the suitable method for each well.

WELL PARAMETERS

S#	Well	Pipe length (m)	Well Pressure (Bars)	Well Temp: °C	η (m2/s)	ρ (kg/m3)	Flow rate m3/d
1	PK#1	10000	28	20	2.98E-03	965.4	300
2	PK#2	2000	68	20	7.39E-06 1.22E-05	812.3 0.893	275 m3/d 0.2 (mmscf/d)
3	PK#3	20000	28	8	3.21E-04	941.2	200
4	PK#4	30000	24	8	7.19E-05	920.3	360
5	PK#5	20000	23	4	2.18E-05	861	300

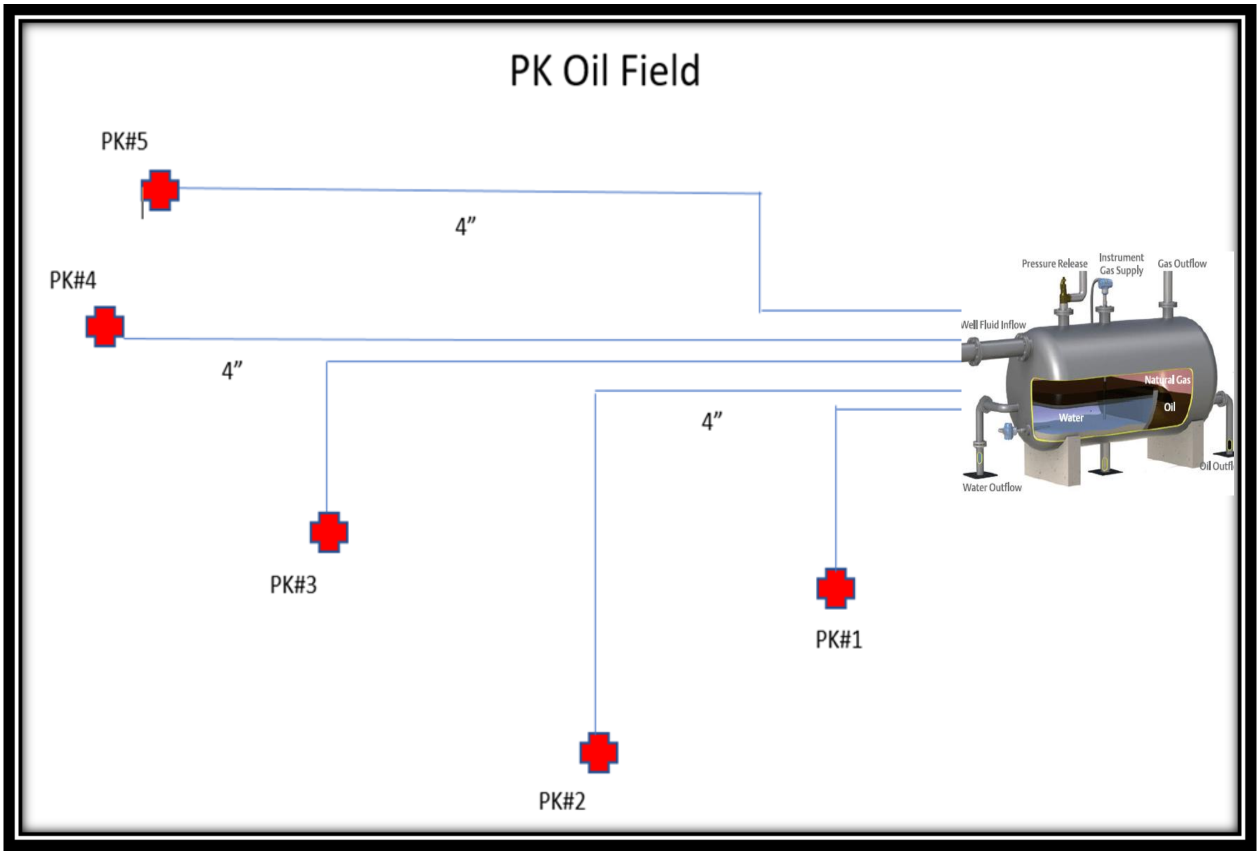

Figure 1-1 Schematic picture of a multi-level gathering System

1.3. History about different methods for Oil Transport in Field:

The invent of Gathering system is a part of Modern industry of oil and Gas. Crude oil is transported from well to a common point so that it can be initially treated and from there it is further sent to refineries for further processing. The flowline network and process facilities that transport and control the flow of oil or gas from the wells to a main storage facility, processing plant or shipping point. A gathering system includes pumps, headers, separators, emulsion treaters, tanks, regulators, compressors, dehydrators, valves and associated equipment. There are two types of gathering systems, radial and trunk line. The radial type brings all the flow lines to a central header, while the trunk-line type uses several remote headers to collect fluid. The latter is mainly used in large fields. The gathering system is also called the collecting system or gathering facility.

1.3.1. Pipelines

Byron D. Benson an oil producer started to invest in oil transportation in mid 1870s which took oil transportation from small distances to large commercial distances. Benson and his 9 other partners came together to form a company named as Tidewater Pipe Company, Limited. This was a foundation in building large gathering networks in an oil field prior sending to refineries for processing.

1.3.2. Oil Storage Tanks

North America petroleum fields in the late 1850s were introduced to new types of storage tanks. These were wooden or metal-riveted tanks, above ground vertically displaced, truncated cone shaped, and built of various sizes.

The smaller ones were called day tanks. Located in the proximity of the producing well, these were utilized for storing petroleum collected daily or weekly, depending by the yield of the well. Larger tanks generally built closer to transportation hubs, such as railways and river ports, stored oil as a stage in the transportation to refineries. In Ontario, where the geological conditions were favourable, it was possible to build semi-underground storage tanks made of horizontal rings of wood to resist lateral earth pressures and attendant earth slides. Daily tanks served to receive oil and water from one or more wells and to drain off water associated with petroleum production. In the 1860s tanks were built only out of wood, and during the early 1870s, the first riveted wrought iron[1] tanks were introduced both in the U.S. and Canada.

The oil was collected in storage tanks and then transported to refineries through rail and roads.

2. Rheology of fluids:

The fluid behavior and characteristics to flow are also important to consider as it also effects the parameters and the conditions. The fluids can be classified in two main rheological classes:[3]

- Newtonian fluids
- Non-Newtonian fluids.

2.1.Newtonian fluid

Sir Isaac Newton described the flow behavior of fluids with a simple linear relation which states that the relation between shear stress [m Pa] and shear rate [1/s] is directly proportional. This relationship is now known as Newton's Law of Viscosity, where the proportionality constant η is the viscosity of the fluid:

$$\mu = \tau / \gamma \qquad \textbf{(2-1)}$$

Where, τ is shear stress, μ is dynamic viscosity and γ is shear rate. Newtonian fluids are water, glycerin, approximating, also refined oil and gas.

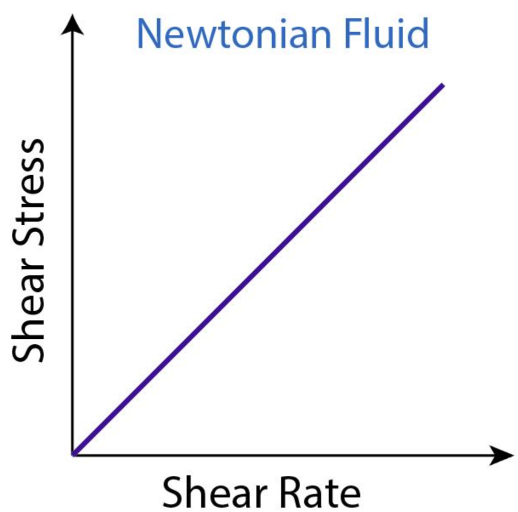

Figure 2-1 Newtonian fluid behavior Shear Stress vs Shear Strain

This model can be applied for most of the crude oils, especially at higher temperatures.

2.2.Non-Newtonian Fluid:

Those fluids, which do not follow the Newton law of viscosity, are called "non-Newtonian fluids", as they do not follow a direct proportionality between shear rate and shear stress. The shear stress changes as the shear rate changes; therefore, the ratio "shear stress/shear rate" is known as "apparent viscosity".

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The non-Newtonian fluids are classified in two main categories

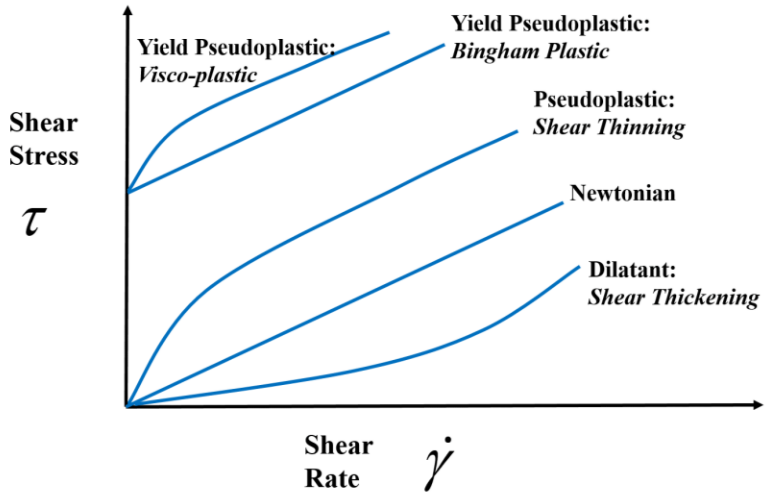

Figure 2-2 Non-Newtonian fluid behavior.

2.2.1. Time Independent non-Newtonian Fluids:

The viscosity of these fluids depends on time delay.

a) Bingham plastic fluids:

Bingham plastic fluids require an additional shear stress to flow, knows as "yield point". In the figure 3.2 The Bingham plastic fluids exhibit a straight line not passing through origin of plot. The flow is described through

$$\tau = YV + \mu_p * \gamma \qquad (2\text{-}2)$$

Where, μ_p is the slope of straight line, known as "plastic viscosity " and YV is initial shear stress, known as "yield point", required to flow .

b) Pseudo plastic fluids:

The viscosity of Pseudo plastic fluids decreases instantaneously on the application of shear stress, exhibiting a shear thinning behavior. The behavior of pseudo plastic fluids is represented by the following relation, known as "Power Law" or "Ostwald & De Waele model":

$$\tau = K\,(\gamma)\,n \qquad (2\text{-}3)$$

Where,

K=flow consistency index refers to viscosity.

n=flow behavior index When n<1, the fluid is called pseudo plastic

In the figure- 3.2 The pseudo plastic fluids are shown by a concave curve passing through the origin of the plot. The pseudo plastic Model is often applying to heavy crude oils.

c) Yield pseudo plastic fluids:

Yield pseudo plastic fluids have a yield point and apparent viscosity which have no linear relationship with the shear rate, as already observed for pseudo plastic fluids. In these fluids, the apparent viscosity decreases as the shear rate values increases. The Yield pseudo plastic fluids are represented by Herschel - Buckley model, expressed by this equation:

$$\tau = \tau o + K\,(\gamma\,)n \qquad (2\text{-}4)$$

d) Dilatant fluids:

The dilatant behavior does not apply to crude oil. It is opposite of the behavior of Pseudo plastic fluids. “Power Law” or “Ostwald & De Waele model” is also applied to these fluids, with the only difference power, n>1

$$\tau = K\,(\gamma)_n \qquad (2\text{-}5)$$

Where,

K=flow consistency index refers to viscosity.

n=flow behavior index When n>1, the fluid is called Dilatant Fluid.

In the figure- 3.2 The Dilatant fluids are shown by a convex curve passing through the origin of the plot.

2.2.2. Time Dependent non-Newtonian fluid:

The time dependent non-Newtonian fluids have different models than time independent non-Newtonian fluids, Because the apparent viscosity of the non-Newtonian time-dependent fluids depends on shear rates and the time the stress is acting on them.

a) Thixotropic fluids:

Thixotropy is a time dependent shear thinning property of the fluids, which on constant shear stress tend to become solids and on application of stress the viscosity decreases and it tends to flow. The heavy crude oils exhibits thixotropic property as in crude oils the long chained molecules start to precipitate and settle down forming crystals that on applying stress or stir get dissolved again.

b) Rheopectic fluids:

The Rheopectic fluids show opposite behavior to thixotropic fluids, they have a minimal viscosity at the start of the application of shear stress. As shear stress is increased over time the shear rate and viscosity increases to a maximum value with time. The molecular structures tend to form with the shear rate and after a certain maximum value of shear rate the molecular structures tend to break hence viscosity starts to decrease.

2.3. Flow profiles:

There are mainly two flow behaviors Laminar flow and Turbulent flow. Laminar flow is generally exhibited by heavier fluids and Turbulent flow is exhibited by lighter fluids.

2.3.1. Laminar flow:

The Laminar flow is the one in which the flow is in parallel layers without any eddies, current or swirls. In more simple form in the laminar flow the viscous forces are dominant then the inertial forces. Laminar flow pattern has Reynolds number under 2300.

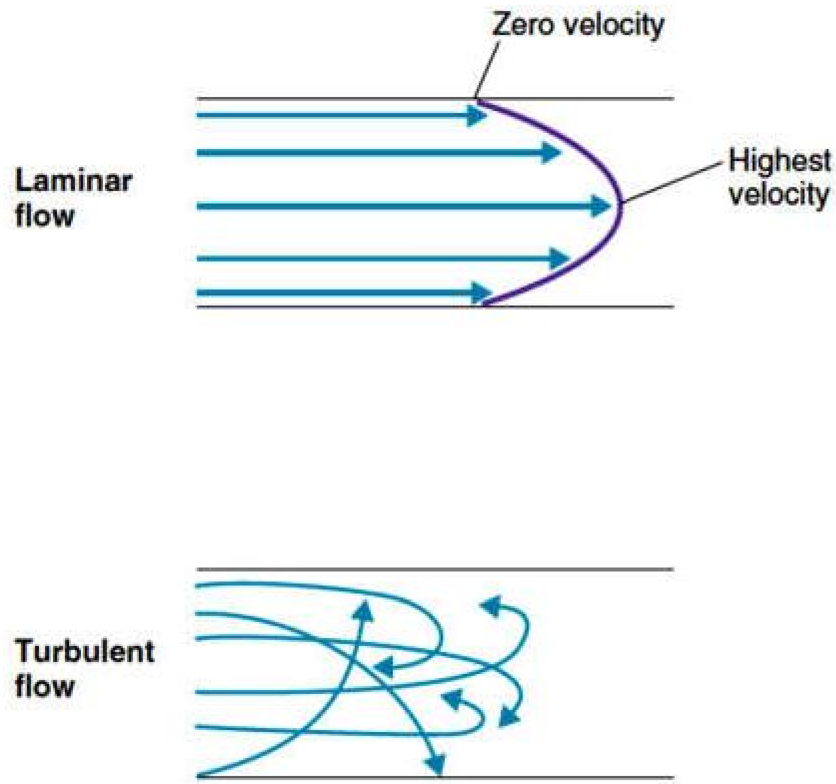

Figure 2-3 Laminar and turbulent flow patterns

2.3.2. Turbulent Flow:

The turbulent flow occurs in lighter fluids with high velocities, due to which there generates swirls and irregular flow patterns. Reynolds number higher than 2300 characterizes the turbulent flow. Reynolds decomposed this velocity of turbulent flow pattern into two separate parts, a constant and a varying part as:

$$\boldsymbol{u} = \bar{u} + \boldsymbol{u'} \qquad \textit{(2-6)}$$

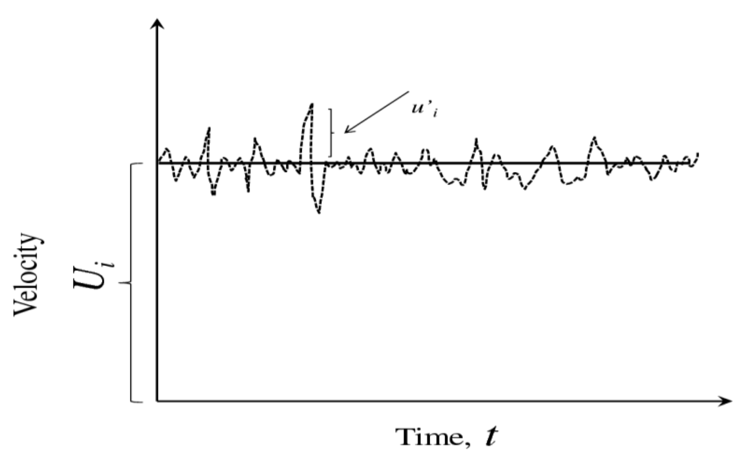

Figure 2-4 Turbulent Flow velocity

2.4.Reynolds Number

The dimensionless Reynolds number plays a prominent role in foreseeing the patterns in a fluid's behavior. The Reynolds number, referred to as Re, is used to determine whether the fluid flow is laminar or turbulent. It is one of the main controlling parameters in all viscous flows where a numerical model is selected according to pre-calculated Reynolds number.[6]

Although the Reynolds number comprises both static and kinematic properties of fluids, it is specified as a flow property since dynamic conditions are investigated. Technically speaking, the Reynolds number is the ratio of the inertial forces and the viscous forces. In practice, the Reynolds number is used to predict if the flow will be laminar or turbulent.

If the inertial forces, which resist a change in velocity of an object and are the cause of the fluid movement, are dominant, the flow is turbulent. Otherwise, if the viscous forces, defined as the resistance to flow, are dominant – the flow is laminar. The Reynolds number can be specified as below:

Re=inertial force/viscous force=fluid and flow properties/fluid properties

The dimensionless Reynolds number predicts whether the fluid flow would be laminar or turbulent referring to several properties such as velocity, length, viscosity, and also type of flow. It is expressed as the ratio of inertial forces to viscous forces and can be explained in terms of units and parameters respectively, as below:

$$Re=\rho VL/\mu=VL/v \qquad (2\text{-}7) \qquad [6]$$

Here μ is the dynamic viscosity of the fluid. The ratio $v= \mu/\rho$ is termed as kinematic viscosity. For circular tubes,, the transition from laminar to turbulent flow occurs over a range of Reynolds's numbers from approximately 2,300 to 4,000 regardless of nature of the fluid or the dimensions of the pipe or the average velocity. So below 2,300 is laminar and above 4,000 is turbulent.

2.5.Pressure drop:

In a cylindrical pipe of uniform diameter D, flowing full, the pressure loss due to viscous effects Δp is proportional to length L and can be characterized by the Darcy–Weisbach equation:

$$h_L=f\,\frac{L}{D}\frac{v^2}{2g} \qquad (2\text{-}8) \qquad [6]$$

where the pressure loss per unit length $\Delta p/L$ (SI units: Pa/m) is a function of:

D, the inner diameter of the pipe, m

L, length of pipe, m

g, acceleration due to gravity, (m/s^2)

$\langle v\rangle$, the mean flow velocity, (m/s);

f_D, the Darcy friction factor (also called flow coefficient λ).

2.6. Calculation of Friction factor:

Depending on flow regime the Friction factor value is calculated by using Moody Diagram for calculation of friction loss.

According to the Moody-diagram, the friction factor is a line on the log-log scale in the laminar territory. This suggests a simpler relationship than in the turbulent case, for laminar flow λ is calculated by:

$$\lambda = \frac{64}{Re} \qquad \textit{(2-9)}$$

As represented by a Straight Line Shown in Fig. for transient and turbulent Friction factor value depends on Pipe rigidity. Relative roughness is calculated which is pipe roughness divided by inner diameter. Literature suggest another approach for calculating friction factor

$$\frac{1}{\sqrt{f}} = -2\log_{10}\left(\frac{\varepsilon}{3.7} + \frac{2.51}{Re\sqrt{f}}\right) \; where; \; \varepsilon = \frac{100\mu m}{D}$$

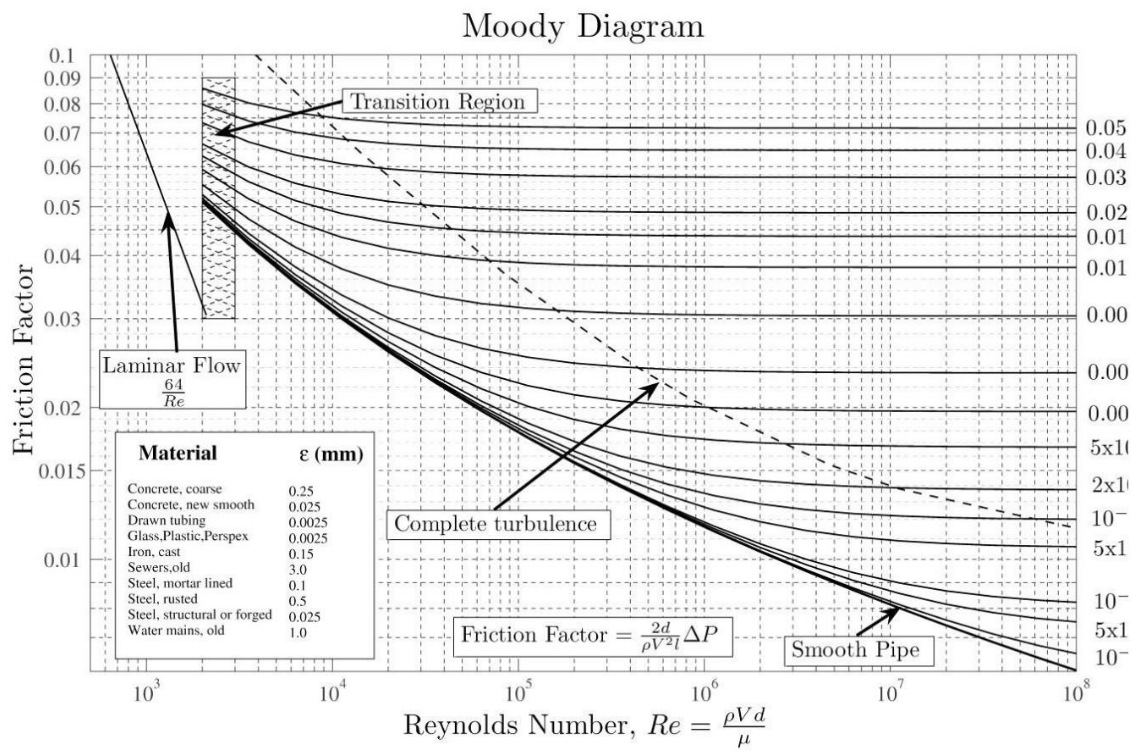

Figure 2-5 Moody Diagram for Friction Factor

2.7. Two Phase Pressure drop calculations:

In this study well Pk#2 is a two phase flow with oil and gas the calculations of Pressure drop for PK#2 are carried out through Bandels correlation, which is stated below [13]

$$\left(\frac{dp}{dL}\right)_{t.tp} = G(1-x)^{1/C} + Bx^{C} \qquad \textbf{\textit{(2.10)}}$$

Where G is a combined effect of Oil and Gas Pressure drop stated as

$$G = A+2(B-A)x \qquad \textbf{\textit{(2.11)}}$$

Where A and B are pressure drop due to oil and gas respectively, C=3 and x is flow quality

$$\left(\frac{dp}{dL}\right)_{f,l} = f_l \frac{m2}{2\rho_l d} = A \qquad \textbf{\textit{(2.12)}}$$

$$\left(\frac{dp}{dL}\right)_{f,g} = f_g \frac{m2}{2\rho_g d} = B \qquad \textbf{\textit{(2.13}}$$

Where m is mass velocity

The friction factors are given as

$f_{g=} \frac{0.3164}{Re^{1/4}}$, $f_{l=} \frac{0.3164}{Re^{1/4}}$, for Re_l, Re_g>1187, $f_g = \frac{64}{Re_g}$, $fl = \frac{64}{Re_l}$ for Re_l, Re_g <1187

Where Reynolds numbers are calculated as.

$Re_l = \frac{md}{\eta_l}$, $Re_g = \frac{md}{\eta_g}$

Where, η is kinematic viscosity.

3. Viscosity and Density

The viscosity of crude oil has become more important with the increase in demand of fossil fuels from the super powers and growing economies of the world. Therefore, it has become more important to improve research to increase the usage and reduce the residual of crude. Moreover, according to International Energy Agency (IEA) and the World Energy Council (WEC) project that the demand of fossil fuels will grow by 66% by 2030.

3.1.Viscosity:

It is the ratio between the shear rate and the shear stress. In a one-dimensional pipeline flow, in case of a Newtonian fluid the following is true.

$$\tau = \mu \left(\frac{dv}{dx}\right) \qquad \textit{(3-1)}$$

Where *dx* is the shear stress and *dv* is the shear rate and μ is the dynamic viscosity. The dynamic viscosity's SI-unit is Pa.s and field unit is cP (centi poise). Often it is divided by the density, giving the kinematic viscosity, which is:

$$\nu = \frac{\mu}{\rho}, \quad \left[\frac{m^2}{s}\right] \qquad \textit{(3-2)}$$

3.2.Composition of crude oil

Viscosity of crude oil is dependent on its composition. Crude oil is a complex mixture of various compounds with several functional groups. Crude oil is characterized in terms of the contents of the fractions dominated by saturated, aromatic, resins, and asphaltenes.

Saturates are single bond compounds like aliphatic hydrocarbons and alicyclic hydrocarbons are part of this classification and they constitute the lightest fraction of the oil. Aromatics consist of one or more benzene rings, which may contain aliphatic chains and/or naphthenic rings attached to the benzene ring. Resins are defined as the fraction of oil soluble in light alkanes. They have aromatic and polar characteristics, besides having in their structure heteroatoms, such as nitrogen and oxygen. Asphaltenes are defined as the fraction of oil insoluble in n-alkanes (such as n-pentene and n- heptane) and soluble in aromatic solvents. In addition, these are the components of higher polarity and higher molar mass present in the oil and essentially responsible for viscosity variation. [5]

Moreover, according to different authors crude oils can be divided into non- colloidal liquids, maltenes (groups other than asphalts) and asphaltenes; asphaltenes being the main cause of increase in viscosity.

3.2.1. Newtonian Behavior:

Studies have shown the influence of asphaltene concentration on the viscosity of heavy crudes. The tests were conducted in sample of maltene containing quantities of asphaltenes ranging from 0 to 20%. Shear stress was applied with range of 0.03 - 596 Pa at 20 °C. The results showed that all the samples behaved as Newtonian fluids, and the viscosity increased with rising asphaltene concentration. For example, the viscosity of the maltenes was about 20000 cP while that of the sample containing 17% asphaltenes reached 600000 cP.

3.2.2. Non-Newtonian Behavior:

Some other tests with mixtures of maltenes and asphaltenes revealed that, above a critical asphaltene concentration (10% by weight), these components not only dramatically increase the viscosity, they also intensify the elastic character of the mixture and results in non-newtonian properties.

3.2.3. Ghanavati et al. (2013)

The experiment was carried out on a dehydrated heavy crude oil sample. Ten asphalt free solutions were prepared by extracting 14.9% asphalt with hexane. Then different concentrations of asphaltenes were added to these samples. The results showed that as the concentration was low the increase in viscosity was relatively linear with increase in asphalt concentration, and it was not highly dependent on temperature. Once high asphalt concentration was reached the viscosity and concentration relation was no longer linear, as viscosity increased sharply, at the same temperature. It was concluded that as concentration of asphaltenes increased in the solution created a closer spacing between asphaltene molecules and hence increased the viscosity sharply. Besides this, with same concentration of asphaltenes the temperature has an evident impact on viscosity.[5]

3.2.4. Luo and Gu (2005)

The researchers used reconstituted samples of crude oil for the effect of asphalt concentration. The viscosity of the samples with 14.5 % by weight of asphaltenes was 23199 cP at 23.9 °C, while that of only maltenes (without asphaltenes) was only 767 cP. The researchers concluded that the viscosity of samples depend upon asphalt concentration as soon as the asphaltene get to accumulate in sample. [5]

3.3. Classification of crude oil

Crude oil can be classified into heavy to light oil depending on its gravity and viscosity as follows. [5]

(1) Light oil: °API > 22, viscosity < 100 cP, density < 934kg/m3;

(2) Heavy oil: °API 10-22, viscosity > 100 cP, density 934- 1000Kg/m3

(3) Extra-heavy oil (bitumen): °API< 10, viscosity > 10.000 cP and density > 1000 Kg/m3.

Besides viscosity, density, and °API, heavy and extra heavy oils also have other physical and chemical properties that are very different than those of conventional crudes, such as higher concentrations of heavy metals, high carbon/hydrogen (C/H) ratios, and high heteroatom contents.

However, in most cases viscosity and specific gravity of oil are directly related to and vary with the composition of oil .Moreover, viscosity also depends on many parameters including pressure, temperature and chemical forces. Here we only discuss the relation of pressure and viscosity.

3.4.Correlations for kinematic viscosity

The temperature dependence of the viscosity is a sensitive issue which must also be addressed thorough proper model. In this research, fluid temperature of at worst case is nearly 0°C. The values of fluid temperature below 20°C give irrational values and are obtained through extrapolating the values. In this study various models are stated and the values for temperature below minimum measure point 20°C are calculated through most realistic model that gives more realistic and rational values with least % error with the experimental values. Various different temperature-viscosity Models are studied to apply the most representative on which satisfy the following three requirements.

- Represents the calculated viscosity values with least % error with experimental values.
- Easy and least data required for calculation.
- Gives more rational values below 20°C.

3.4.1. Amin and Maddox [1]

The equation reported by Amin and Maddox (1980) has the form:

$$\eta = A\,[\exp(B/T)] \qquad \textit{(3.3)}$$

Where η is the kinematic viscosity in cst, T is absolute temperature in Kelvin, A and B are constants. The equation gave viscosity predictions with standard percentage errors of less than 3% for fractions of American crude oil.

The simplest one is the exponential function, applying to examine Crude Oil, predicting $26250 * 10^{-6}$. The figure 5-2 shows plot for exponential function.

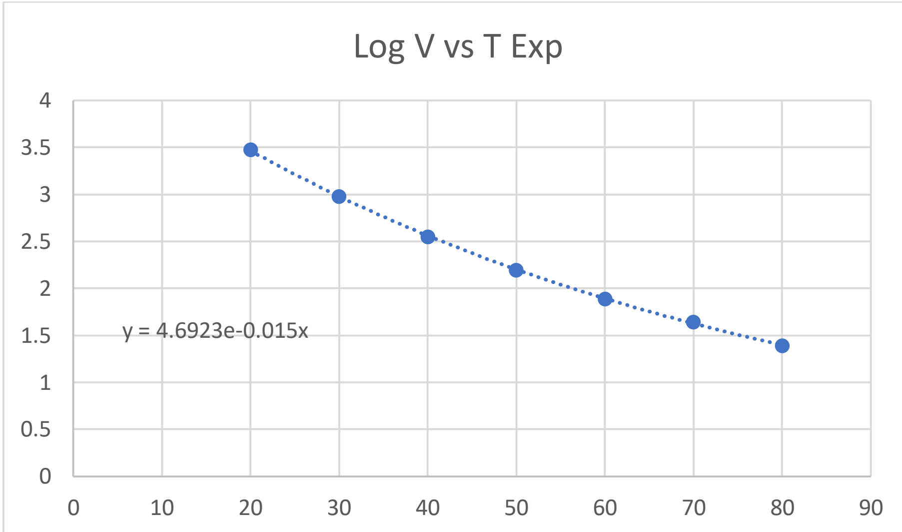

Figure3-1:Exponential function

3.4.2. Sanderson correlation: [8]

He developed an equation based on double logarithm for calculating kinematic viscosity of oil.

$$\text{Log Log } (K_v+0.6) = CP^{1/2} + D \qquad \textbf{\textit{(3.4)}}$$

Where
C and D are constants for any given oil,
P is the pressure
Kv is the kinematic viscosity at the required pressure

3.4.3. Walters Correlation: [1]

The following correlation has been found useful in calculating dead oil viscosity

$$\text{Log Log } (v+0.8) = A + B \log T \qquad \textbf{\textit{(3.5)}} \qquad \textbf{[1]}$$

Where
A and B are constants for any given oil that can be found if two values of v and T are known,
T is the temperature
v is the kinematic viscosity at given temperature.

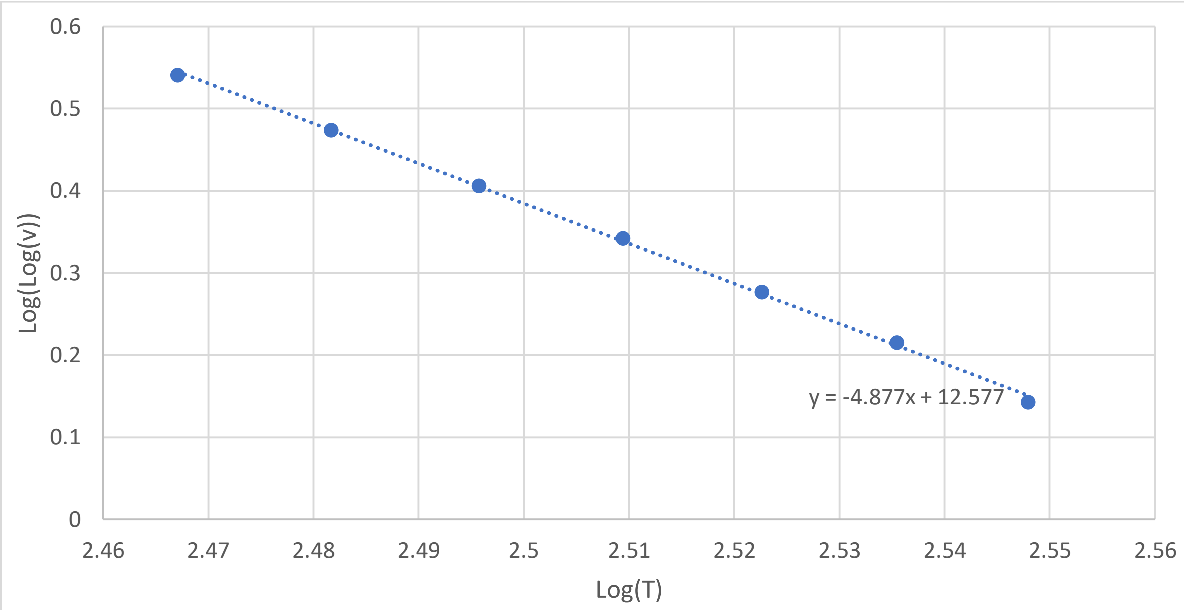

Figure: 3-2:Walther's Correlation

3.4.4. Singh et al Correlation:[1]

The following correlation was proposed for light crude oil

$$\log \mathrm{v} = B*[\frac{310.93}{(t+273.15)}]^{s} - C$$

Or simplified as

$$\log \mathrm{v} = \frac{b}{(1+\frac{T-37.78}{310.93})^{s}} + C \qquad \textbf{(3.6)}$$

Where,

b = log v (at 37.78 C,1 atm) - C

s = 0.28008* b + 1.6180 **(3.7)**

C = -0.86960 **(3.8)**

The parameter b is indicative of the oil kinematic viscosity v, obtained at 37.78 C and 1 atm. It is of high significance that only single value of v is required to determine constant b. A non-linear regression technique was used to determine values given in equation 5 and 6.The kinematic viscosity calculation are made through this correlation because it has far more easier approach and significantly least error in comparison with experimental values.

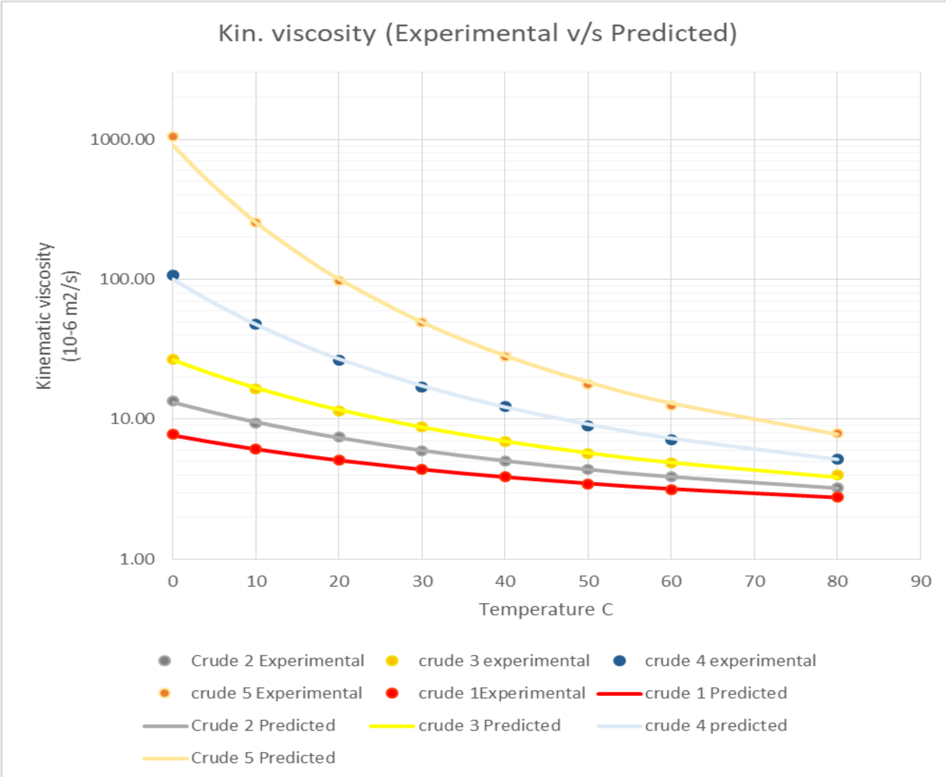

Figure: 3-3 *Plot for One point value Experimental v/s Predicted*

The above given plot validates the model with comparison between experimental and predicted values. It can be seen that both lines almost overlap each other stating a higher accuracy of the model.

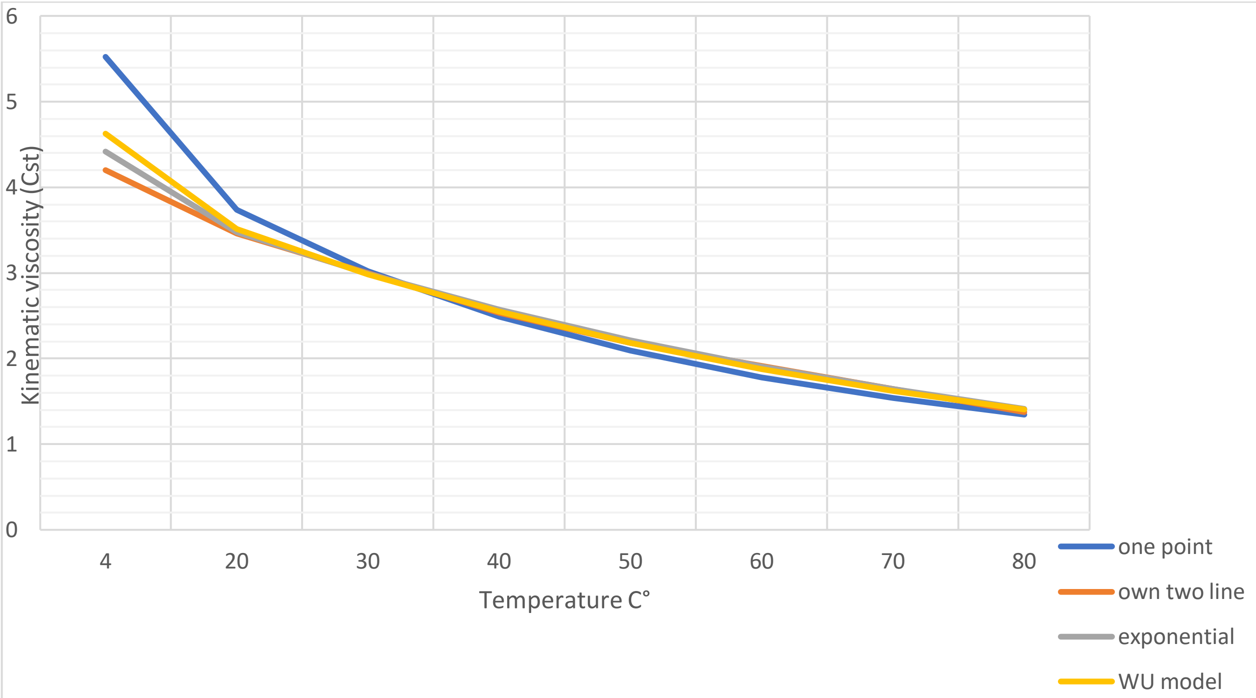

Figure: 3-4 Plot for comparison of viscosity model

In the above plot it is seen that out of four models one point method exhibits an increasing trend of viscosity from 30C and another jump in values for kinematic viscosity at 20C. However, it is observed that the one-point model predicts more realistic values among all the models.

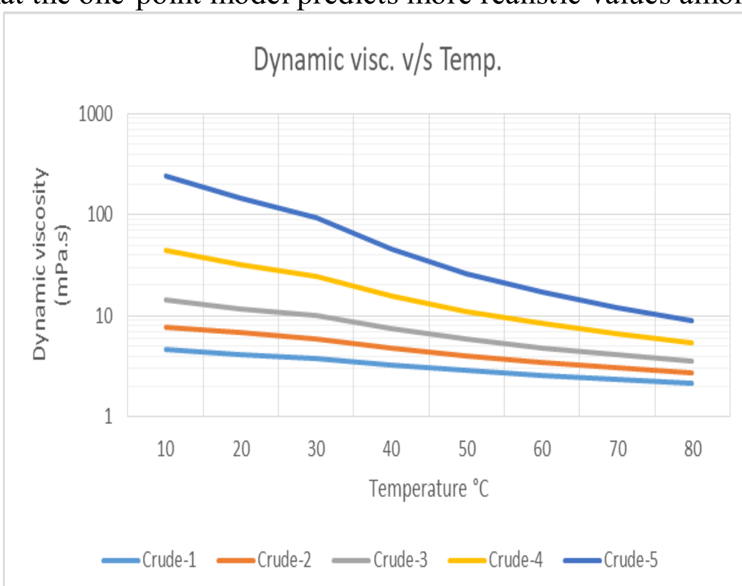

Figure:3-5 Dynamic viscosity v/s Temperature

3.5. Effect of other Parameters:

For reference point 4" diameter and 300 m3/day flow rate is considered in the study. However during the lifetime the flow rate of crude oil does change and also prior to design of pipeline study of different ID is also important so that over the lifetime pressure losses can be predicted.

3.5.1. Flow rate

The oil flow rate changes during the lifetime of the well, therefore the flow parameters change and effects the pressure loss. Three flow rates are considered for the analysis of pressure loss 200, 300 and 400 m3/day. The Pressure drop due to the flow along pipeline is shown in the figure 5-7 for different flow rates.

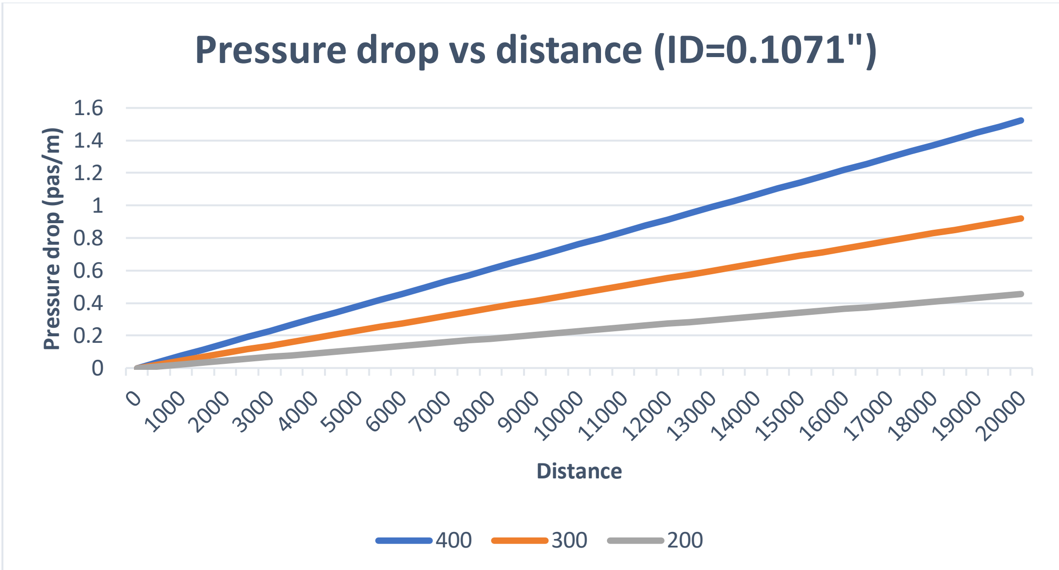

Figure:3-6 The influence of the flow rate on the Pressure drop

3.5.2. Pipe diameter

Pipeline Inner Diameter highly effects the pressure loss. Smaller the ID of pipeline higher the frictional losses and greater the pressure loss. It is highly recommended to design the pipeline neither too small nor too large and it should be designed according to the flow parameters required. Figure 5-8 indicates its distribution at different pipe diameters. Different dimension of the examined pipes is listed in table 5-1.

	3”	4”	6”	8”
ID(mm)	82.5	107.1	159.3	210.1
OD (mm)	88.9	114.3	168.3	219.1

Table 1 *Pipe line Internal Diameters*

S#	Temperature °C	Experimental viscosity (cSt)	Predicted viscosity (cSt)	Error%
(a) Crude-II Kinematic viscosity @37.78°C =0.7188 cSt (curve fit)				
1	0	1.130	1.122	0.74
2	10	0.973	0.9808	-0.8
3	20	0.871	0.8686	0.28
4	30	0.778	0.7779	0.02
5	40	0.702	0.7035	-0.21
6	50	0.640	0.6417	-0.27
7	60	0.591	0.5899	0.18
8	80	0.509	0.50885	0.1
Average absolute deviation=0.29%				
(a) Crude-III Kinematic viscosity @37.78°C =1.5031 cSt (curve fit)				
1	0	3.020	2.958	2.05
2	10	2.410	2.410	0.01
3	20	1.990	2.003	-0.65
4	30	1.690	1.694	-0.24
5	40	1.450	1.455	-0.35
6	50	1.25	1.267	-1.33
7	60	1.100	1.116	-1.45
8	80	0.8990	0.8932	0.65
Average absolute deviation=0.90%				
(a) Crude IV Kinematic viscosity @37.78°C =1.1187 cSt (curve fit)				
1	0	2.03	2.001	1.43
2	10	1.68	1.678	0.10
3	20	1.42	1.432	-0.84
4	30	1.23	1.240	-0.81
5	40	1.090	1.088	0.20
6	50	0.9530	0.9653	-1.29
7	60	0.857	0.8654	-0.98
8	80	0.717	0.714	0.42
Average absolute deviation=0.89%				
(a) Crude V Kinematic viscosity @37.78°C =0.8638 cSt (curve fit)				
1	0	1.430	1.425	0.33

2	10	1.220	1.225	-0.43
3	20	1.060	1.069	-0.82
4	30	0.9440	0.9440	0.0
5	40	0.8420	0.8432	-0.14
6	50	0.7580	0.7606	-0.34
7	60	0.6890	0.6920	-0.44
8	80	0.600	0.5858	2.36
Average absolute deviation=0.61%				

Table 2: Experimental and Predicted Kinematic viscosities of five types of Crude oil.

Density of Crude oil

	Crude 2	Crude 3	Crude 4	Crude 5
0	820.544	949.544	928.544	862.544
4	818.8896	947.8896	926.8896	860.8896
8	817.2352	946.2352	925.2352	859.2352
12	815.5808	944.5808	923.5808	857.5808
15	814.34	943.34	922.34	856.34
20	812.272	941.272	920.272	854.272
30	808.136	937.136	916.136	850.136
40	804	933	912	846
50	799.864	928.864	907.864	841.864
60	795.728	924.728	903.728	837.728
70	791.592	920.592	899.592	833.592
80	787.456	916.456	895.456	829.456

Table 3: Densities of five crude oil

Crude 1		
Temperature	Density (Kg/m3)	Kinematic visc (m2/s)
20	965.4	2989.4
30	961.3	950.1
40	957.2	354.7
50	953	158.2
60	949	77.78
70	944.7	43.9
80	940.6	24.55

Table 4: Crude-1 Density and Viscosity at various temperatures

4. Methods for reducing crude oil viscosity

Historically, the demand for heavy and extra- heavy crudes has been low because their high viscosity and complex composition make them difficult and costly to extract, transport and refine. Overcoming these challenges requires significant technological advances. Different methods have been used or studied to reduce the viscosity of crude oil to improve their flow through pipelines. Among these methods are:

- The dilution with light oils or alcohols,
- Heating of production lines or the oil itself,
- Forming Oil water Emulsion
- Core Annular Flow.

4.1. Dilution method:

Mixing of lighter crude oil fractions hydrocarbons with heavier crude oil fractions is called dilution. These methods are used since 1930. High crude viscosity is a major setback to heavy-crude transportation via pipeline

Dilution of heavy-crude is one of the best methods to improve the transportation by reducing viscosity of crude oil. The blending fluid or diluents is always less viscous than the heavy-crude. Hence lower the viscosity of diluents, the lower is the viscosity of blended mixture of heavy-crude The resulting blend of heavy crude oil and diluents has lower viscosity and therefore it is easier to pump at reduced cost

Following are the diluents which, at present, are commonly used for viscosity reduction purpose

- Condensate from natural gas production
- Naphtha
- Kerosene
- Lighter crude oil, etc.

However, the type of diluents and use of dilution is subjected to availability and ease of access and thorough economic considerations

Based on extensive literature review which was substantiated by experiments, E.L. Lederer proposed a modified version of the classic Arrhenius expression to represent the mixture viscosity which significantly coincides with experimental data. [20]

$$\log\mu=\left(\frac{\alpha V_o}{\alpha V_o+V_s}\right)\log\mu_o+\left(1-\frac{\alpha V_o}{\alpha V_o+V_s}\right)\log\mu_s \tag{4-1}$$

where V_O, μ_O, V_S, μ_S are respectively the volume fraction and the viscosity for the oil (O) and the solvent (S)

where α is an empirical constant varying between 0 and 1 depends on viscosities and densities of oil and solvent. A generalized expression of α able to represent the viscosity of heavy oils or bitumen diluted with light hydrocarbons. A correlation of this parameter with the viscosity ratio and the densities of solvent ρ_S and oil ρ_O:

$$\alpha = \frac{17.04(\rho_O - \rho_S)^{0.5237}\rho_O^{3.2745}\rho_S^{1.6316}}{\ln\left(\frac{\mu_O}{\mu_S}\right)} \tag{4-2}$$

Advantage: A Research [9] states that addition of 20% of light crude oil reduces viscosity by 96%. Although it becomes expensive when large volumes are involved due to assembling of pumping units and separate pipelines.

Drawbacks: it does not prevent flocculation of asphaltenes in pipeline.

4.2.Heating Method:

Heating of crude oil decreases crude oil viscosity and increases flow in pipeline.

Two most effective mode of heating:

4.2.1. Induction

The electric conducting wire is wound around pipeline. The Alternating current supplied to the coil generates high frequency electromagnetic waves inside the material to be heated. The electromagnetic energy through waves is absorbed in fluid and is heated.

Microwaves have 300-3000MHz.

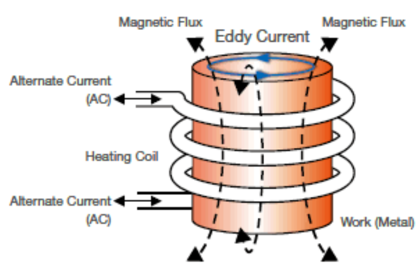

Figure 4-1: Electromagnetic Heating

4.2.2. Electric:

In the Di-electric heating system, the pipe to be heated is an active conductor in a single-phase electric circuit (AC), together with a single core power cable as the forward conductor, located in parallel with and close to the heated pipe.

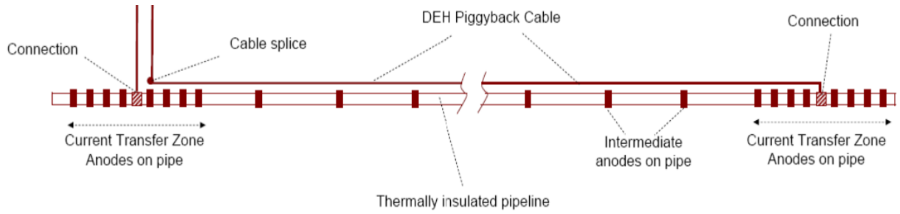

Figure:4-2 Direct Current Heating[17]

- **Factors effecting:**
  - Pipe characteristics
  - Design
  - Cable data

4.2.3. Heat transfer coefficient:

The heat transfer per unit surface area of pipe to the ground per unit temperature difference. The heat flux is described by the heat transfer coefficient $k*$ which depends on the parameters of the flow system.

There are two different type of heat transfer co-efficient used. The first one is defined earlier However, the more practical type of the heat transfer coefficient in examined case is the second one, which is related to pipe length

$$k = \pi d k^*$$

k is the heat flux transferred through 1 m of pipe due to 1 K temperature difference. The following formulae is used to calculate heat transfer co-efficient.

$$K = \frac{\pi}{\frac{1}{\alpha_1 di} + \frac{1}{2\lambda p}\ln\frac{do}{di} + \frac{1}{2\lambda in}\ln\frac{d_{in}}{do} + \frac{1}{\alpha_2 d_{in}}} \quad \left[\frac{W}{mK}\right] \qquad \textit{(4-3)}$$

where

di is the inside diameter of the steel pipe?

do is the outside diameter of the steel pipe

din is the outside diameter of the pipe enlarged by the insulation? If no insulation is installed then it is equal to .

λp is the thermal conductivity of the pipe.

λin is the thermal conductivity of the insulation (if any)

The other parameters α1 is internal convection factor, heat transfer per unit temperature difference from pipe center to pipe wall.

$$\alpha_1 = Nu\frac{\lambda_f}{d_i}, \quad \left[\frac{W}{m^2K}\right] \qquad 4\text{-}4$$

where Nu is Nusselt number

and α2 describes thermal behavior of soil in heat exchange

$$\alpha_2 = \frac{2\lambda_s}{d_{in} \ln \frac{4h}{d_{in}}} \qquad 4\text{-}5$$

In the above relationship, there are four main components in the denominator of the right side. The first component describes the heat transfer inside the oil, as the temperature of the oil at pipe center will be higher than temperature of the oil at wall because of heat transfer to the surrounding. the second one is the effect of the insulation due to pipe material. In many cases this value is negligible because of higher conductivity value of pipe material. Pipes are usually made of steel which has a very high conductivity value and has a very small thickness. However, incase pipes are not made of steel or in case of thick walled pipes this value is considerable. The third one is due to insulation if there is external insulation applied to the system for reducing the heat losses to the surrounding. and the last one is the soil's thermal insulating capability.

Advantages: It is found that heavy crude viscosity decreases from 10.0 to 2.5 Pas when the temperature is increased from 25˚C to 75˚C. [8]

Drawbacks: The pipeline expands due to continuous heating and effects flow parameters Over a large area it has a high capital and operational cost. The pipeline deteriorates internally due to continuous heating. It cannot be applied under water.

4.3.Core Annular Flow:

In this method water creates a thin film in the inner side of walls of pipeline. The oil does not adhere to walls and is effectively transported through pipeline. In liguid-liquid system, the CAF

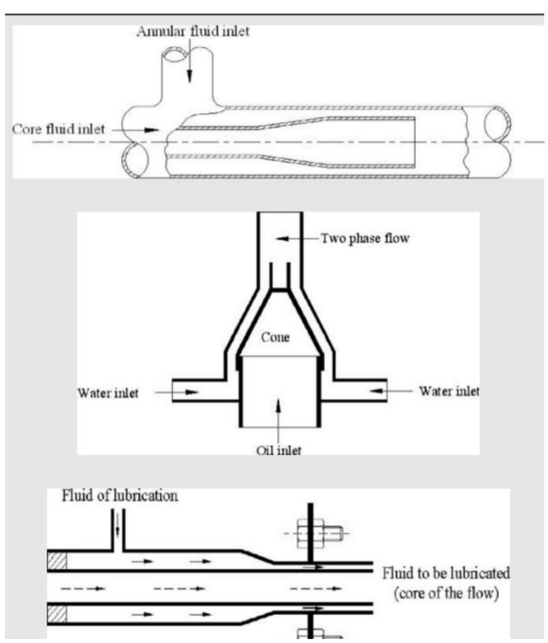

Figure:4-3 Design for nozzles for core annular flow appears most attractive for pressure loss reduction and power saving in heavy oil wells and for the transportation of viscous oils. The viscous oil forms the core phase, which is surrounded and

lubricated by water as the annular phase. A stable Core annular flow is fully developed flow pattern, where both the core and annular phases are distinct and continuous. Provided this flow pattern is established, the pressure drop is almost independent of the oil viscosity, and slightly higher than obtained in single phase water flow at the mixture flow rate.

In case of viscous oil the flow in core is laminar and the flow in annulus can be laminar or turbulent, depending on its flow rate and tube diameter. [10] Pressure drop measurements for oil-

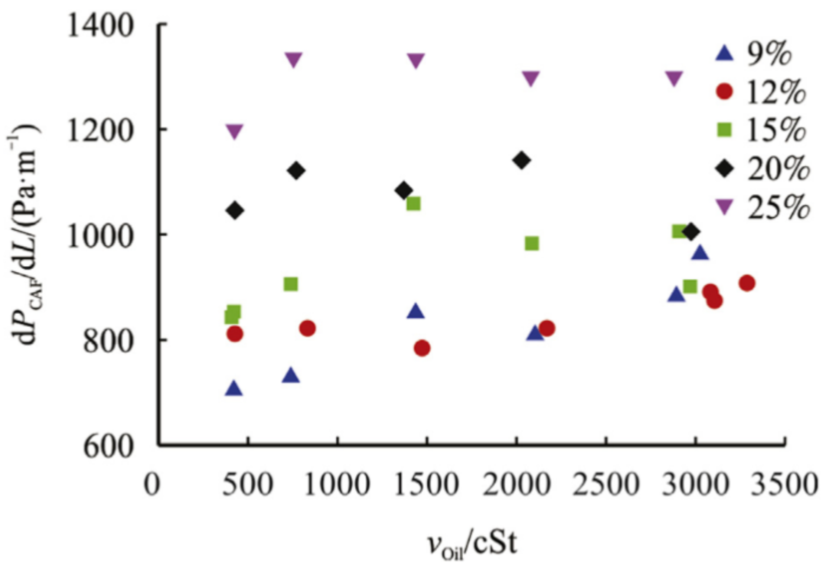

Figure:4-4 Measured non scale pressure drop for core annular flow as function of oil viscosity at different water cut

water core-annular flow were performed and compared to previous results by Ingen Housz et al. The scaled pressure drop as a function of the viscosity ratio is presented, from which it is concluded that transport by means of core annular flow is more beneficial at high viscosity ratio. In the lower viscosity ratio the amount of water needed to lubricate the oil core causes an increase in pressure drop.[14]

Drawbacks: As it requires a continuous injection of the water mixed with solvents to create a film, therefore any disruption in the process will form two phases in pipeline and cause hindrance in transportation and includes additional processing cost.

4.3.1. Two-phase oil and water flow.

If no Emulsion is formed then oil and water flow in separate phases either in stratified pattern or concentric flow.

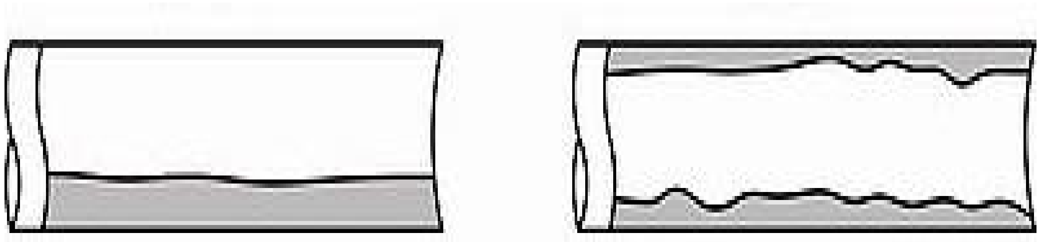

Figure:4-5 Stratified flow and concentric flow

4.3.1.1. Concentric Flow:

In this flow water surrounds oil and spreads to walls of pipeline. It occurs in case of heavy oil where crude and water densities are similar. The experimental results of such flow are shown in figure 6-12. The pressure gradient reduction factor is plotted against the oil viscosity in cP. [7]

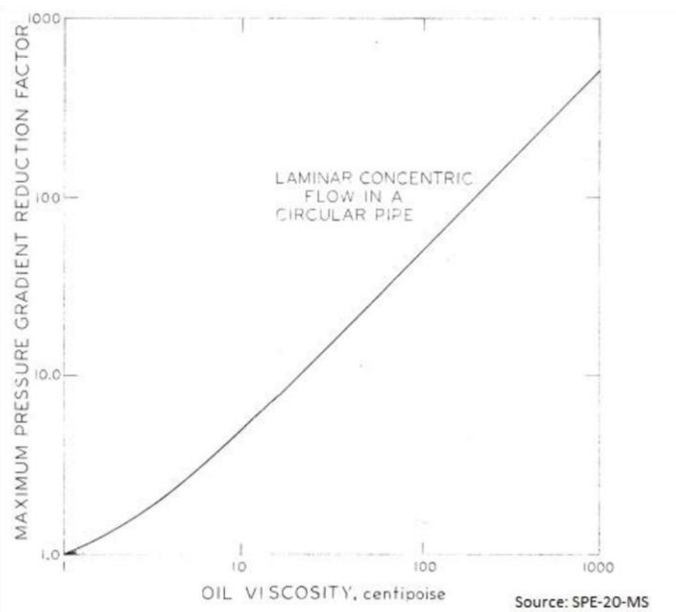

Figure:4-6 Concentric flow pressure gradient [7]

$$\text{Pressure gradient reduction factor}=\frac{\nabla p_f^{oil}}{\nabla p_f^{conc}} \qquad \textbf{\textit{(4.6)}}$$

Where ∇p_f^{conc} and ∇p_f^{oil} are the friction pressure gradients of the single-phase oil flow and concentric oil-water flow.

4.3.1.2. Stratified Flow:

In the stratified flow no emulsion is formed and due to density differences segregation of water and crude oil occurs. [7]

Advantages: The water flows quickly so it creates a drag phenomenon to pull crude oil out and It creates a laminar flow.

The results for stratified oil and water flow are shown in the figure 6-14. This research was carried out on various oil viscosity at different velocities and reduction of pressure gradient was predicted [7]. Significant results were observed when water cut was increased above 20%.

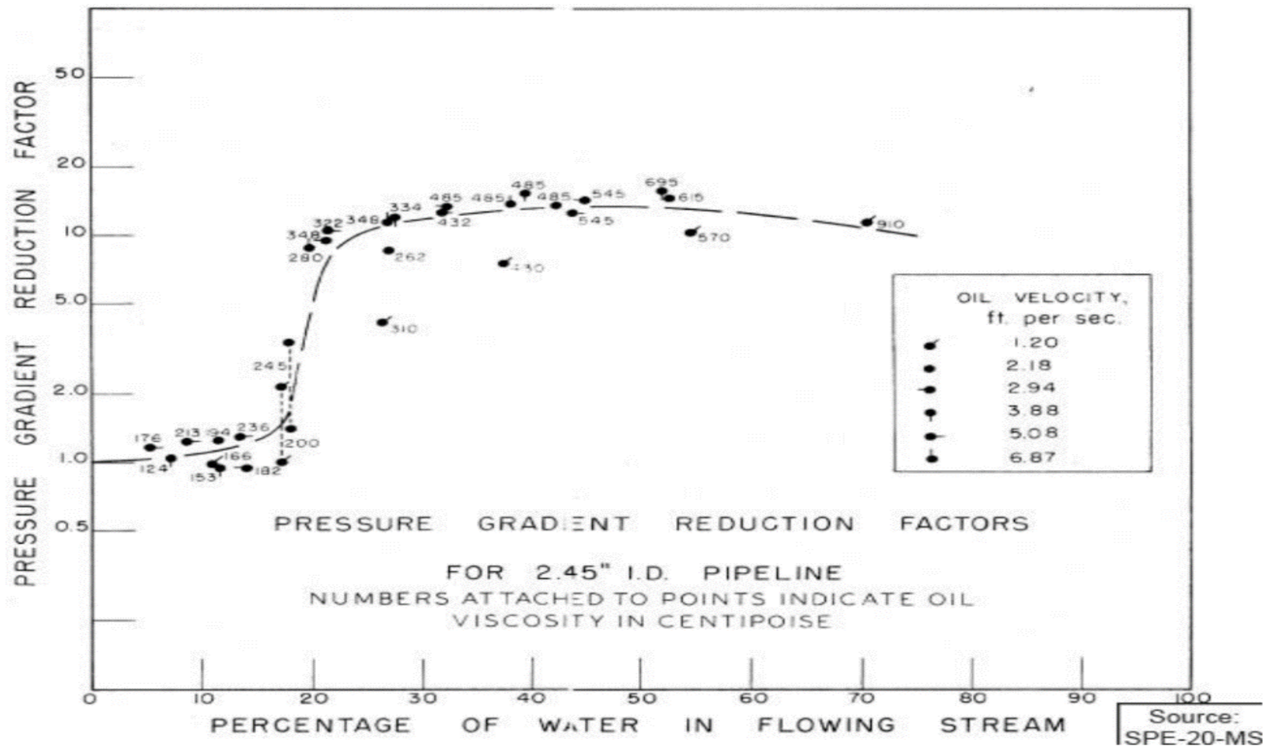

Figure 4-7: Stratified flow pressure gradient[7]

Drawbacks: Heating of water is required to give good results. In complex emulsion formation addition of water can increase pressure loss. Accurate con

4.4.Oil in Water Emulsion:

In this method surfactants are used to reduce viscosity of fluid; the oil disperse in the water phase and stable oil-in-water emulsions are formed. If the crude oil is the continuous phase which disperse the water, then it is called water-in-oil emulsion, or W/O. The other way around it is called oil-in-water emulsion or O/W. The viscosity of crude oil can be reduced to 50-200 cP. [10]

Advantages: This method can be used in colder regions, forming stable emulsion that can reduce crude oil viscosity higher than 1000cp. Due to natural surfactants a stable mixture is formed which sustains the properties for a longer period of time even if the emulsion process is halted.

Drawbacks: If the well starts to produce water, it forms W/O emulsion. If appropriate amount of water is not added it will form W/OW emulsion which forms a complex emulsion and the sole purpose is not fulfilled and increased phase volume of water.

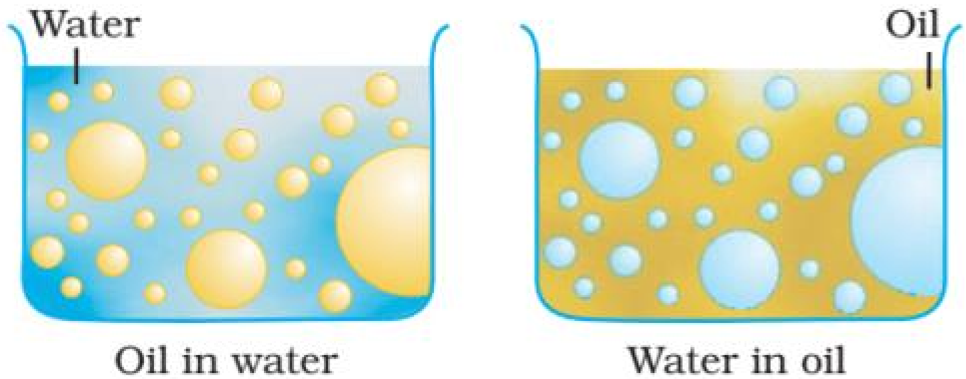

Figure 4-8: Oil in water and water in oil Emulsion

4.4.1. Correlations for Emulsion:

Three different correlations are compared at constant temperature of 20°C.

4.4.1.1. The Einstein Function:

The Einstein function assumes a linear increase of the continuous phase viscosity with the phase volume in the following form: [12]

$$\eta = \eta_c(1 + 2.5\phi) \qquad (4.7)$$

4.4.1.2. Taylor's Function:

Taylor extended the Einstein relationship so that it considers the viscosity value of the dispersed phase too. [12]

$$\eta = \eta_0\left[1 + 2.5\phi\left(\frac{\eta_d + 0.4\eta_c}{\eta_d + \eta_c}\right)\right] \qquad (4.8)$$

4.4.1.3. Leviton and Leighton Function:

They modified the Taylor equation, extending it with power series of the phase volume and suggesting an exponential variation.

$$\eta = e^{\left[2.5\left(\frac{\eta_d+0.4\eta_c}{\eta_d+\eta_c}\right)\left(\phi+\phi^{\frac{5}{3}}+\phi^{\frac{11}{3}}\right)+\ln \eta_c\right]}$$

this equation can be re arranged to the following equation for ease in calculation. [12]

$$\ln\frac{\eta}{\eta_c} = 2.5\left(\frac{\eta_d + 0.4\eta_c}{\eta_d + \eta_c}\right)\left(\phi + \phi^{\frac{5}{3}} + \phi^{\frac{11}{3}}\right) \qquad (4.9)$$

With the inserted power series, this equation can be used at higher concentrations too.

4.4.2. Phase inversion:

The Phase inversion here means to shift of fluids from one phase either Oil water emulsion or Water oil emulsion into the other, The quantity of water determines the shift into the required phase. Arrirachakran et al Correlation for Phase inversion uses dynamic viscosity of oil and relative viscosity 1 mPa.s The relative viscosity here is the water dynamic viscosity.[16]

$$\varepsilon^{I}_{W} = \mathbf{0.5\text{-}0.1108\ log_{10}}(\eta_c/\eta_d);\ \eta_c = 1\ \text{mpa-s} \qquad (4.10)$$

4.4.3. De-Emulsification

In case of W/O emulsion the demulsification is carried out by adding emulsifiers.

De-emulsification is the process in which the separation of water and oil is promoted by some additives. These additives are called de-emulsifiers which work opposite to surfactants, de-emulsifiers reduce the surface tension on the border of the water-oil phases, consequently separation is faster. De-emulsifiers are used at gathering stations to reduce the settling time which is needed to separate water from crude oil.

A little concentration of de-emulsifiers is added with little flow rate that breaks the W/O emulsion. The breaking of emulsion requires time and the more delay is occurred better concentric flow of O/W emulsion is formed.

Equipments: The addition of demulsifying agents is shown in Figure 6-15. The upper picture shows, the treated well and its area. The lower part highlights and enlarged the equipment's. These equipment's are: black container (a) who stores emulsifiers and is added by pumps to the

Figure 4-9: De-Emulsifier Package

pipeline(c) through a small diameter tube (b). The pressure is measured with the help of pressure gauges (d).

Drawbacks: A small concentration is required to be injected continuously. The container is for solvents needs to be regularly refilled and monitored. The solvent is toxic and needs better handling.

5. Results:

5.1. Reynolds number:

The Reynolds number of 05 five wells before treatment was calculated through eq 2.7:

$$Re=\rho VL/\mu=VL/v$$

S#	Well	Reynolds number
1	PK#1	13.81
2	PK#2	4140464.21 (gas) 7519.49 (Oil)
3	PK#3	85.75
4	PK#4	860.79
5	PK#5	2520.9

Table 5: Reynold numbers of five crude oil

5.2. Friction Factor:

The friction factor is calculated through using eq:2.8 as

$$\lambda=64/Re$$

S#	Well	Friction factor
1	PK#1	4.64
2	PK#2	0.0069(gas) 0.034 (oil)
3	PK#3	0.75
4	PK#4	0.111
5	PK#5	0.025

Table 6: Friction factor

5.3. Frictional losses:

The frictional losses are calculated through eq: 2.9:

$$h_L=f\frac{L}{D}\frac{v^2}{2g}$$

S#	Well	Pressure drop (bars)
1	PK#1	310.27
2	PK#2	109.13
3	PK#3	43.28
4	PK#4	15.26
5	PK#5	5.39

Table 7: Frictional losses

5.4.Target Pressure drop and viscosity:

The Pressure required for Gathering system to treat and process the crude oil is 17.24 bar according to which the Target pressure drop and Target viscosities are obtained.

S#	Well	Pressure drop (bars)	Kinematic vis (m2/s)
1	PK#1	10.76	9.96E-05
2	PK#2	51.71	3.1E-06
3	PK#3	10.34	7.67E-05
4	PK#4	6.76	2.32E-05
5	PK#5	4.76	1.40E-05

Table 8: Target Pressure drop and Viscosities of five crude oil

5.5.Core annular Flow

Two phase flow with water on the annulus of pipeline. Using Ullman and Brauner Correlation.[19]

$$\frac{dP_{CAF}}{dP_{oil}} = \frac{X^2}{\alpha^2_{water}} \tag{5-1}$$

Where X2 is the Lockhart Martinelli parameter: It is the ratio of the pressure drop found for single phase water flow and pressure drop for single phase oil flow.

$$X^2 = \frac{0.046}{16}\left(\frac{\nu_{water}}{\nu_{oil}}\right)^{0.2}\frac{\rho_{water}}{\rho_{oil}}\frac{\mathrm{Re}^{0.8}_{s,oil}}{Q^{*1.8}}. \tag{5-2}$$

αwater is the fraction of pipe cross sectional area covered by annulus water.

$$\alpha_{water} = \frac{0.5\ c_i - X^2Q^*/F_i + 0.5\ c_i\sqrt{1+4X^2(Q^*/c_i)^2/F_i}}{c_i + Q^* - X^2Q^*/F_i}. \tag{5-3}$$

$$\mathrm{Re}_{s,oil} = \frac{U_{s,oil}D}{\nu_{oil}} \qquad U_{s,oil} = \frac{Q_{oil}}{\pi D^2/4} \qquad Q^* = \frac{Q_{oil}}{Q_{water}}$$

Where,

Res oil: Reynolds number oil
Us oil: Velocity of oil
Ci & Fi constants for interfacial stress
The flow rate of water is taken as 10% of flow of oil for all the wells

S#	Well	Pressure drop (bars)
1	PK#1	2.51
2	PK#2	N/A
3	PK#3	2.47
4	PK#4	3.70
5	PK#5	3.38

Table 9: Pressure drop with Core annular flow

The core annular flow applies to all wells accept Pk#2 as it is a two phase fluid with oil and gas and water can create additional pressure drop in such conditions. Core annular flow is favorable with low water content and heavy crude oil

5.6. Dilution:

The criteria for solvent addition depends on following conditions

- The degree of viscosity reduction(%) should be higher than 70%. And
- DVR= (ηo-ηm/ ηo)x100
- The difference between order of magnitude of solvent and mixture viscosity should be less than 03.
- If does not meet both conditions then maximum limit for solvent addition is 25% of crude oil.

S#	Well	Kinematic Viscosity of oil before (m2/s)	Kinematic viscosity of Lighter crude oil (m2/s)	Target viscosity (m2/s)	Solvent of original oil (%)	Kinematic Viscosity of mixture after (m2/s)	DVR %
1	PK#1	2.989E-03	7.08E-07	9.96E-05	25	6.70E-05	97.8
2	PK#2	7.39E-06	7.07E-07	3.1E-06	15	3.94E-06	63.4
3	PK#3	3.21E-04	8.05E-07	7.67E-05	15	6.90E-05	78.5
4	PK#4	8.57E-05	8.05E-07	2.32E-05	20	1.87E-05	78.2
5	PK#5	2.18E-05	8.44E-07	1.40E-05	25	5.55E-06	74.6

Table 10: Pressure drop with dilution

5.7. Heating

Heating carried out through direct Electric current in the study, where the temperature rise was calculated through following equation.[18]

$$dt=P.R(1-e^{-\alpha t}) \tag{5-4}$$

Where ,

Dt is rise in Temperature,

P is power

R is thermal resistance, R=0.6

α is time constant, α=0.14

t is time

Power is calculated through the following formula

$$P=69\ k\ I\ 10^{-3} \tag{5-5}$$

Where,

I is conductor, current A

k is electric phase constant, k=1 for three phase

Where, following limitations were established to make heating a possible option

5.7.1. Target viscosity Criteria for heating:

- More than 75% of degree of viscosity reduction.

- Difference of magnitude of logarithm should be lower than 03.
- If does not fulfils both conditions then maximum heating limit is 80 °C.
- Voltage=440 V and heating time =6hrs

Well	Length (m)	k (1m deep) [W/m-K]	k (on surface) [W/m-K]	k (2m deep) [W/m-K]	Heating terminals	η before heating m2/s	Target η m2/s	Temperature rise °C	η after heating at m2/s	DVR %
PK#1	10000	2.67	3.76	2.20(4)	1.2	2.98E-03	9.96E-05	40	7.78E-05	97
PK#2	2000	2.26	4.66	2.16(4)	4	7.39 E-06	3.1E-06	60	3.22E-06	56
PK#3	20000	2.52	3.89	2.27(9)	20	3.21E-04	7.67E-05	22	4.94E-05	84
PK#4	30000	2.33	4	2.1(8)	15	7.19E-05	2.32E-05	22	1.74E-05	75
PK#5	20000	2.53(6)	4.4	2.28(5)	0.5	2.18E-05	1.40E-05	16	1.17E-06	77

Table 11: Pressure drop with Heating

5.8. Oil water Emulsion

The calculations were carried out with Leviton and Leighton correlation because it has more conservative value. The following graphs shows the viscosity before and after phase inversion. The phase inversion calculated through Arrirachakaran correlation.

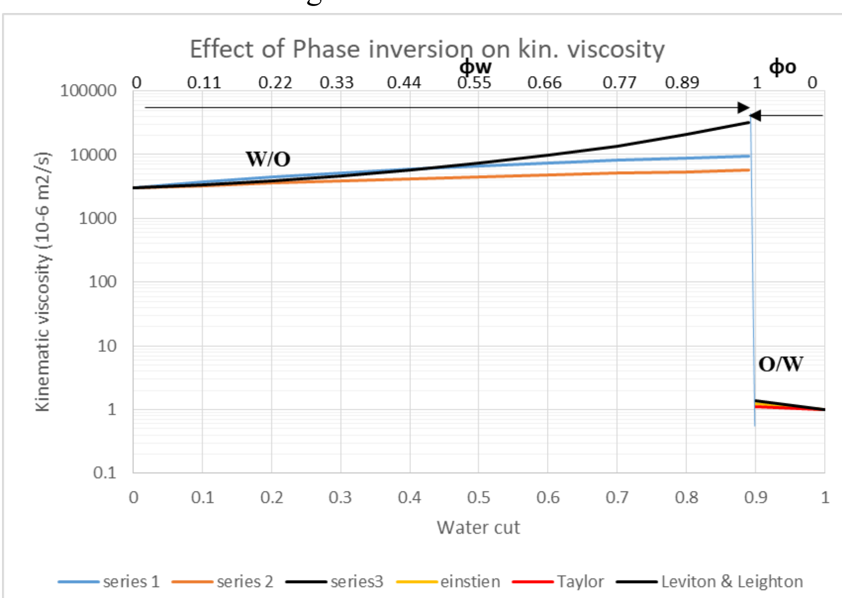

Figure5-1:Phase Inversion for PK#1

In Figure 5-1 we can see that as Crude type-1 is a heavy crude oil it requires large quantity of water. The emulsion is 89% water and only 11% oil. Similarly in Figure 5-2 it can be seen that since it is a light oil there is less water required for emulsion and its 58% water and 42% oil.

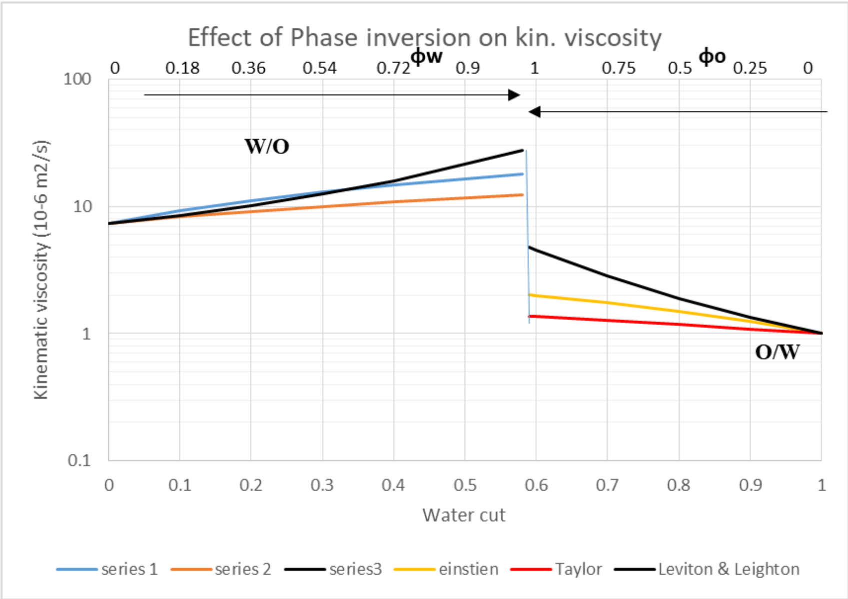

Figure5-2 Phase Inversion for PK#2

In Figure 5-3 it can be seen as it is a slightly heavier crude oil it requires larger quantity of water to form Emulsion. Hence there is 78% water and only 22% of crude oil in the Emulsion.

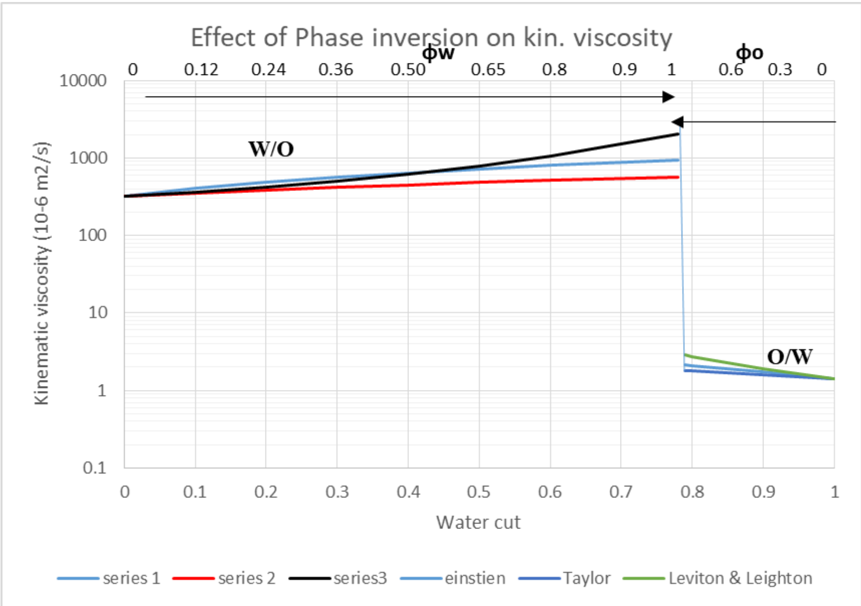

Figure 5-3 Phase Inversion for PK#3

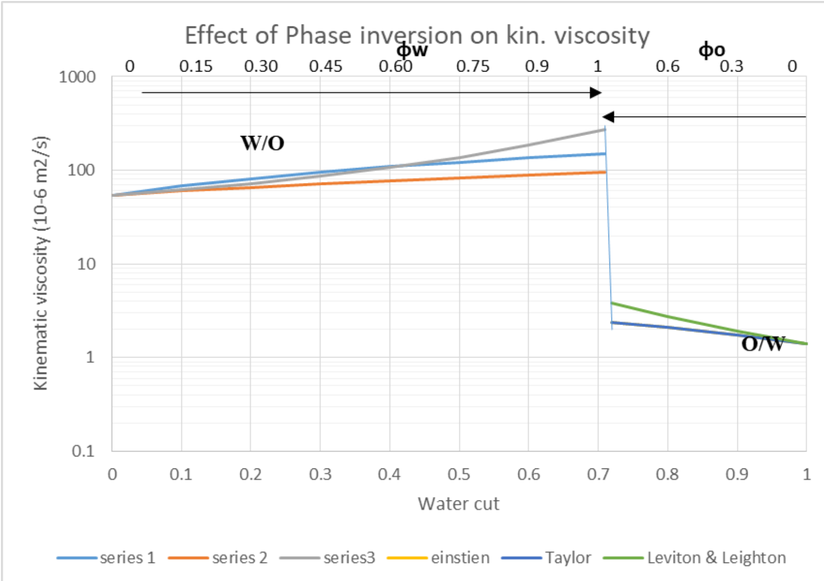

Figure 5-4 Phase Inversion for PK#4

n Figure 5-4 we can see that as Crude type-4 is a water oil Emulsion crude oil. It contains 20% of water and in whole requires 71% of water. Therefore additional 51% water is added to form an oil water Emulsion. Similarly in Figure 5.5 it can be seen that since it is a light oil there is less water required for emulsion and its 65% water and 35% oil.

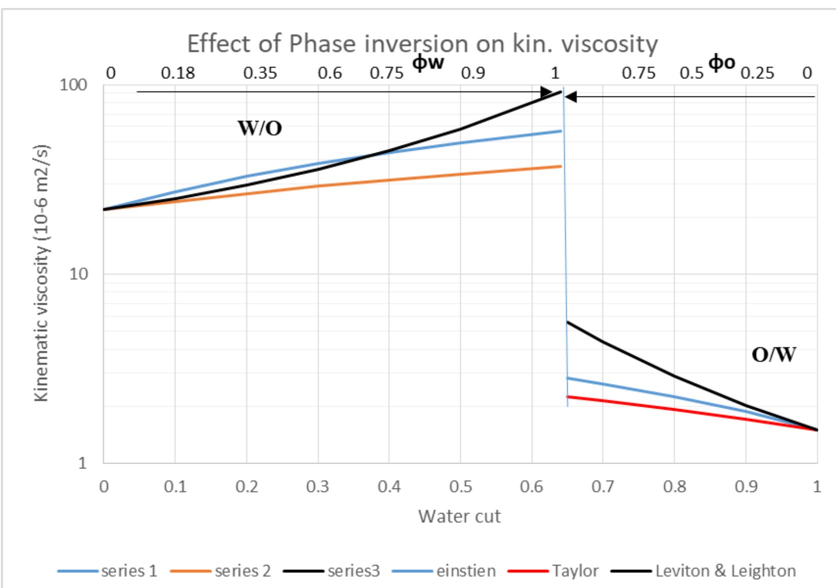

Figure 5-5 Phase Inversion for PK#5

S#	Well	Phase Inversion	Fluid flow (m3/d)	Pressure drop (bars)
1	PK#1	0.89	3000	1.413
2	PK#2	0.58	1666	1212.23
3	PK#3	0.79	952	7.11
4	PK#4	0.71	1071	2.03
5	PK#5	0.65	1379	4.57

Table 12: Pressure drop with O/W Emulsion

Oil water Emulsions decrease viscosity of crude oil at a large extent but at the same time large quantity of water is added which is difficult to handle. The oil water Emulsion works for all wells except Pk#2 because it is a two phase flow which by adding water increases mass velocity and hence pressure drop is increased instead of decreasing.

6. Comparison of Different Methods

The application of each of the four Methods is carried out in light of various factors that helps to choose which method is the best fit. Some of the factors can be:

- Target Pressure drop
- Source
- Ease of handling/application
- Cost
- Re-cycling/Re-usability
- Compatibility with fluid
- Installations

Each of the above factors are discussed for all four methods to evaluate the most suitable one.

6.1. Target Pressure Drop:

The Target pressure drop is the most important factor that is necessary to check if the method is effective enough that can fulfil the requirement of the project.

1. **O/W emulsion:** In the Oil water emulsions the viscosity of the crude oil is greatly reduced and frictional losses are decreased but at the cost of high concentration of water. It requires larger diameter of pipes or more pipes parallel to each other to transport the required flow of oil.
2. **Core annular flow:** In core annular flow the water is adhered to wall of pipes that makes the flow of crude oil almost independent of its viscosity and frictional losses are greatly reduced. The amount of water is not higher than 10% of the fluid flow.
3. **Heating:** In Heating the reduction in viscosity is controlled through amount of heating provided but it might become practically impossible to provide large amount of heat to attain the required pressure drop because it might even damage pipeline
4. **Dilution:** In dilution the viscosity of crude oil is reduced by adding solvent. The availability of the solvent in large quantity might not be possible at times and the less amount of solvent may not fulfil the requirement.

6.2. Source:

The ease of availability of source is also very important because the oil fields are remotely located and far from markets it is difficult to transport fluids and make its availability possible timely.

1. **O/W emulsion:** For oil water Emulsions large quantity of water is required, almost 90% of fluid is water in heavy oil emulsions. Providing water in such large quantity in a remote area is troublesome and at some places might not be possible.
2. **Core annular flow:** It only requires 10-15% water of the fluid flowing in pipelines, which can be made available easily.
3. **Heating:** There are various types of heating electric heating, hot water heating. The availability of power for heating throughout the pipeline is difficult and requires large resources to ensure the continuation of heating without interruption.
4. **Dilution:** To make a lighter crude oil available from a nearby field or markets is quite expensive because it includes not only fluids cost but also the transport charges. In case a source available already on field makes a suitable option to opt for dilution.

6.3. Ease of Handling/Application:

The simplicity of the method and less number of installations, less number of processes and less quantity of fluids to handle make it more suitable with handling point of view.

1. **O/W emulsion:** In O/W Emulsions the handling of large quantity of water is a troublesome job and makes it quiet complex to emulsify and then de-emulsify at the end point.
2. **Core annular flow:** It does not require mixing nor the quantity of water is high. It can be added at starting point and easily separated at collection point.
3. **Heating:** Heating requires a source either electric or furnace oil, handling of electric wire or furnace oil is a difficult job, it takes great care so that any mishap can be prevented.
4. **Dilution:** The amount of solvent needs to be mixed properly to reduce viscosity, similarly it requires to be separated at the collection point so that it can be re-used. The mixing and de-mixing may also cause loss of amount of solvent.

6.4. Cost:

The cost of a project is determined through various factors such as durability of project, market value of the product and low investment.

1. **O/W emulsion:** Emulsions have high range of applications, but availability of water and emulsifying and de-emulsifying units add up into cost of project.
2. **Core annular flow:** In contrast to emulsions it does not require large quantity of water or proper mixing and de-mixing units so it is not costly.
3. **Heating:** Setting up heating terminals along the entire pipeline will cost high, it might be cost-effective for a well near to a gathering system.

4. **Dilution:** Procurement of solvents is costly and it might not be a good option where large quantity of solvent is required.

6.5. Re-cycling/Re-usability:

It is one of the most important factor not only with respect to cost effectiveness but also in regards to environmental impact. The re-usability prevents the factor of disposal of large quantity fluids into environment that can be hazardous to the surroundings.

1. **O/W emulsion:** The advantage of O/W emulsions is the water can be utilized again but the storage and recycling of large quantities of water from the point of de-emulsification to emulsification requires a network of piping system along with pumps to push large quantities of water.
2. **Core annular flow:** It does not require large quantity of water hence it will not require water to be recycled for re-use once separated. Every time fresh water source can be used although there is always option for storage of water.
3. **Heating:** The heat supplied is consumed through the soil during transportation and it cannot be recycled.
4. **Dilution:** The solvent mixed can be re-used and in this way it can be cost-effective.

6.6. Compatibility with fluids:

In an oil field there can be various zones with different type of fluids, the range of the method that it can be used with different crude oils effectively makes it a better option with respect to versatility of usage.

1. **O/W emulsion:** Emulsions have high range of application and it can be used in wide range of conditions either turbulent or laminar.
2. **Core annular flow:** It is most effective with heavy oils with laminar flow as in a turbulent flow fouling may occur and water may get mixed with oil causing additional pressure drop.
3. **Heating:** Heavy crude oil requires large amount of heat and this method is widely used in cold areas of Canada to avoid clogging in pipes due to bitumen.
4. **Dilution:** It also suits medium oils to be cost-effective and a ready choice to go for.

6.7. Installations:

All methods require installation for mixing and de-mixing of fluids. A method that uses least number of installations or can have only main units at starting and end points makes it eaier for maintenance and handling.

1. **O/W emulsion:** It requires emulsifying units and de-emulsifying units to break water.
2. **Core annular flow:** It requires nozzle and a pump to inject water into pipeline along walls and a knockout vessel to separate water at collection point

3. **Heating:** It requires heating terminals along the pipeline to ensure smooth flow of crude oil.
4. **Dilution:** It requires mixing and de-mixing units at starting and end points.

6.8. Sensitivity Analysis:

A sensitivity analysis is the hypothesis of what will happen if variables are changed. More specifically, it is analyzing what will happen if one or more parameters decreased over time and then what will be the effect on the viscosity reduction methods. For example if the Well head flowing pressure decrease and with it flow of the well decreases then what parameters of the treating method needs to be increased or decreased to meet the required pressure drop.

The change in well flowing parameters have been carried out as following:

S#	Well	Pipe length m	Well Pressure (Bars)	Well Temp: °C	η (m2/s)	ρ (kg/m3)	Flow rate m3/d
1	PK#1	10000	23	20	2.98E-03	965.4	200
2	PK#2	2000	55	15	8.34E-06 1.22E-05	814.3 0.893	225 (m3/d) 0.15(mmscf/d)
3	PK#3	20000	20	4	5.22E-04	948	150
4	PK#4	30000	20	4	1.14E-04	967	315
5	PK#5	20000	20	4	2.18E-05	861	200

Table 13: Flow parameters of well for condition 2

6.8.1. Target Pressure drop and viscosity:

The Pressure required for Gathering system to treat and process the crude oil is 17.24 bar according to which the Target pressure drop and Target viscosities are obtained.

S#	Well	Pressure drop (bars)	Kinematic visc: (m2/s)
1	PK#1	5.76	6.663E-05
2	PK#2	37.76	8.87E-07
3	PK#3	2.76	2.711E-05
4	PK#4	2.76	3.34E-05
5	PK#5	2.76	1.493E-05

Table 14: Target Pressure drop and Viscosity for Condition 2

In order to study the sensitivity analysis following variables have been analyzed in order to see the change with the change in the well flowing parameters.

- **O/W Emulsion:** As water is the essential part for phase inversion it is key to analyze the change in Quantity of water (m3/d) with change in viscosity and flow of fluids
- **Core Annular Flow:** The technique for core annular flow uses quantity of water to adhere to walls of pipeline. A nominal 10% water of flow of fluid is sufficient to form a layer of water on pipelines. Here also quantity of water with change in flow of fluid is analysed.

- **Heating:** As with decrease in well head temperature viscosity of crude oil increases which requires larger quantity of heat to acquire required pressure drop. The specific heat (KJ / Kg K) is a good indicator of heat required to raise unit degree of unit mass.
- **Dilution:** Dilution is also dependent on viscosity of fluid and flow of fluid. The increase in viscosity increases amount of solvent to be added.

Following results were obtained for change in flow parameters for sensitivity analysis.

PK#1				
Condition	**O/W Quantity of water (m3/d)**	**Heating (J/Kg K)**	**Dilution Quantity of solvent (m3/d)**	**CAF Quantity of water (m3/d)**
1	3000	4.27E+03	75	30
2	1800	6.60E+03	50	20
PK#2				
Condition	**O/W Quantity of water (m3/d)**	**Heating (J/Kg K)**	**Dilution Quantity of solvent (m3/d)**	**CAF Quantity of water (m3/d)**
1	412	8.14E+03	68.75	N/A
2	337	9.83E+03	56.25	N/A
PK#3				
Condition	**O/W Quantity of water (m3/d)**	**Heating (J/Kg K)**	**Dilution Quantity of solvent (m3/d)**	**CAF Quantity of water (m3/d)**
1	752	1.22E+03	30	20
2	639	5.24E+03	37.5	15
PK#4				
Condition	**O/W Quantity of water (m3/d)**	**Heating (J/Kg K)**	**Dilution Quantity of solvent (m3/d)**	**CAF Quantity of water (m3/d)**
1	1071	1.13E+03	70	37
2	711	5.61E+03	44.25	31
PK#5				
Condition	**O/W Quantity of water (m3/d)**	**Heating (J/Kg K)**	**Dilution Quantity of solvent (m3/d)**	**CAF Qunatity of water (m3/d)**
1	980	6.48E+02	40	40
2	734	2.93E+02	30	30

Table 15: Sensitivity Analysis for Condition 1 and Condition2

6.9. Choices for individual well:

For each well more than one method is applicable, in order to evaluate which method is the best option we need to consider all the factor that has been discussed in the comparison of methods from Target pressure drop to installations required.

6.9.1. Well Pk#1:

For well no: 1 the scenario of the methods in both the conditions is as under, as it can be seen all the methods can be applied in both conditions. The least pressure drop is attained through O/W emulsion and Core annular flow, moreover in O/W emulsion a large quantity of water is required but in core annular only 10% water of fluid flow is required. In addition to it as it is heavy bituminous crude with a laminar flow, core annular flow is most suitable.

Condition	Pressure Drop before treatment (bars)	Target Pressure drop (bars)	O/W (bars)	Core annular flow(bars)	Heating (bars)	Dilution (bars)
1	310.27	10.33	1.41	2.51	7.94	9.28
2	206.849	5.76	1.6	1.3	2.98	4.06

Table 16: Pressure drop for Pk#1 in Condition1 & Condition 2

6.9.2. Well Pk#2:

For well no:2 the scenario of the methods in both the conditions is as under, as it can be seen that none of the methods are helpful in reaching the required pressure drop. As it is a two phase flow with oil and gas addition of fluids in O/W emulsions and Dilution increase the mass velocity which is directly related to pressure drop for liquid and gas. Moreover, in heating also the rise in temperature increases gas flow rate and gas viscosity. The gas flow increases the flow quality (denoted as "x" in the correlation) of gas which increases the pressure drop. <u>Here, increase in pipeline diameter is only possible method, as it decreases the mass velocity and hence decreases pressure drop. [15]</u>

Condition	Pressure Drop before treatment (bars)	Target Pressure drop (bars)	O/W (bars)	Core annular flow(bars)	Heating (bars)	Dilution (bars)
1	59.6	51.71	344	NA	73.2	81
2	41.6	37.76	237	NA	54.86	64.62

Table 17: Pressure drop for Pk#2 in Condition1 & Condition

6.9.3. Well Pk#3:

For well no:3 the scenario of the methods in both the conditions is as under, as it can be seen all methods can be applied for pressure drop reduction. As the flow parameters changed the solvent quantity in dilution and the specific heat capacity (from the sensivity analysis table) increased because it is also slightly heavy crude oil. <u>However, the core annular flow is equally effective and the quantity of water also decreased due to decrease in fluid flow rate and can be termed most suitable.</u>

Condition	Pressure Drop before treatment (bars)	Target Pressure drop (bars)	O/W (bars)	Core annular flow(bars)	Heating (bars)	Dilution (bars)
1	43.28	10.34	7.11	2.28	1.57	2.60
2	53.25	2.76	5.30	1.41	1.67	2.65

Tab#le 18: Pressure drop for Pk3 in Condition1 & Condition

6.9.4. Well Pk#4:

For well no:4 the scenario of the methods in both the conditions is as under, it is a water oil emulsion well where except core annular flow all the methods are applicable in both conditions. <u>However, dilution can be suggested as the best choice for reduction in pressure drop as the quantity of solvent also decrease with decrease in fluid flow at the same time fulfilling the requirement of Target pressure drop.</u>

Condition	Pressure Drop before treatment (bars)	Target Pressure drop (bars)	O/W (bars)	Core annular flow(bars)	Heating (bars)	Dilution (bars)
1	15.26	6.76	2.03	3.70	1.70	1.45
2	18.36	2.76	2.54	3.09	1.82	2.13

Table 19: Pressure drop for Pk#4 in Condition1 & Condition

6.9.5. Well Pk#5:

For well no:5 the scenario of the methods in both the conditions is as under, as all the methods are applicable but fluid of Pk#5 is light, core annular flow is not suitable for light oils and oil water Emulsions require large water quantity but heating and dilution are equally effective in both conditions. Dilution here provides least pressure drop at lower quantity of solvent and can be termed as most suitable.

Condition	Pressure Drop before treatment (bars)	Target Pressure drop (bars)	O/W (bars)	Core annular flow(bars)	Heating (bars)	Dilution (bars)
1	5.39	4.76	4.57	3.38	1.18	1.46
2	4.04	2.76	3.31	2.43	2.5	0.88

Table 20: Pressure drop for Pk#5 in Condition1 & Condition

7. Conclusion:

The main purpose of this study was analysis of pressure loss during the transportation of light crude oil. The kinematic viscosity of crude oil below 20°C increases rapidly and the values predicted can be erroneous. In this study various kinematic viscosity models have been discussed and most suitable model for viscosity analysis for low temperature has been used to predict the kinematic viscosity. The kinematic viscosity model has been validated through experimental data as well. Five types of crude oil for five wells with different flow parameters with, viscosity and density have been taken for transportation through pipelines for different distances. All crude oil exhibit different trend of pressure loss and it is observed that more the crude oil contains fractions of higher boiling point greater is the pressure drop due to friction losses.

Hence, to reduce the pressure losses over a larger distance it is important to alter the composition of crude oil. The reduction in crude oil kinematic viscosity reduces friction losses which ultimately decreases the pressure losses. Therefore, methods for alteration of crude oil composition to reduce kinematic viscosity have been discussed in detail which includes dilution, emulsification, heating and de-emulsification. All the methods were discussed in detail with comparison and sensitivity analysis. Most suitable method was chosen for all five wells considering various factors for overall sustainability and feasibility. Nevertheless, there still remains some points that can be discussed in detail in this area such as effect of temperature on friction losses.

Finally based on the results extracted from the study and keeping in view the cost, environment and technology it can be suggested that Core annular flow is the most suitable condition for heavier crude oil at low temperatures.

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Raw Results

Condition#1

O/W Emulsion Results Pk#1

Water %	Einstein	Tylor	Leviton and Leighton
	cst	cst	cst
0	2989.4	2989.4	2989.4
0.1	3736.75	3288.490549	3376.682803
0.2	4484.1	3587.581099	3920.99028
0.3	5231.45	3886.671648	4673.178761
0.4	5978.8	4185.762198	5739.080214
0.5	6726.15	4484.852747	7310.035399
0.6	7473.5	4783.943297	9739.13389
0.7	8220.85	5083.033846	13709.82747
0.8	8968.2	5382.124395	20628.88584
0.89	9640.815	5651.30589	31881.06553
0.9	1.255	1.104767757	1.361150336

1	1.004	1.004	1.004

O/W Emulsion Results Pk#2

Water %	Einstein	Tylor	Leviton and Leighton
	cst	cst	cst
0	7.39	7.39	7.39
0.1	9.2375	8.261586848	8.531224643
0.2	11.085	9.133173695	10.17473934
0.3	12.9325	10.00476054	12.5132175
0.4	14.78	10.87634739	15.94244777
0.58	18.1055	12.44520372	27.6598301
0.59	2.0331	1.367853667	4.800860628
0.6	2.008	1.358979187	4.557514346
0.7	1.757	1.27023439	2.829870763
0.8	1.506	1.181489594	1.883598685
0.9	1.255	1.092744797	1.331819566
1	1.004	1.004	1.004

O/W Emulsion Results Pk#3

Water %	Einstein	Tylor	Leviton and Leighton
	cst	cst	cst

0	320.8843809	320.8843809	320.8843809
0.1	401.1054761	353.1819067	362.7210383
0.2	481.3265713	385.4794326	421.5686289
0.3	561.5476665	417.7769584	502.9709775
0.4	641.7687617	450.0744843	618.4563317
0.5	721.989857	482.3720101	788.8922154
0.6	802.2109522	514.669536	1052.851928
0.78	946.6089236	572.8050825	2051.107847
0.79	2.135	1.809812014	2.866989533
0.8	2.1	1.790297156	2.752592029
0.9	1.75	1.595148578	1.896629432
1	1.4	1.4	1.4

O/W Emulsion Results Pk#4

Water %	Einstein	Tylor	Leviton and Leighton
	cst	cst	cst
0	54.44153	54.44153	54.44153
0.1	68.05191	60.09041	61.77297
0.2	81.66229	65.7393	72.12918
0.3	95.27267	71.38819	86.52748
0.4	108.8831	77.03708	107.0762
0.5	122.4934	82.68596	137.6153
0.6	136.1038	88.33485	185.3055

0.71	151.0752	94.54863	274.7061
0.72	2.38	2.365258	3.834992
0.8	2.1	2.08947	2.729486
0.9	1.75	1.744735	1.889463
1	1.4	1.4	1.4

O/W Emulsion Results Pk#5

Water %	Einstein	Tylor	Leviton and Leighton
	cst	cst	cst
0	21.83	21.83	21.83
0.1	27.2875	24.22353365	24.94785287
0.2	32.745	26.6170673	29.38748978
0.3	38.2025	29.01060094	35.61947928
0.4	43.66	31.40413459	44.61426698
0.5	49.1175	33.79766824	58.16032775
0.64	56.758	37.14861535	91.79922561
0.65	2.8125	2.236867767	5.5605124
0.7	2.625	2.131600943	4.387477204
0.8	2.25	1.921067295	2.878167222
0.9	1.875	1.710533648	2.009973994
1	1.5	1.5	1.5

Condition#2

O/W Emulsion Results Pk#1

Water %	Einstein	Tylor	Leviton and Leighton
	cst	cst	cst
0	2989.4	2989.4	2989.4
0.1	3736.75	3288.594855	3376.826262
0.2	4484.1	3587.78971	3921.361239
0.3	5231.45	3886.984565	4673.90693
0.4	5978.8	4186.17942	5740.385769
0.5	6726.15	4485.374275	7312.315295
0.6	7473.5	4784.56913	9743.146196
0.7	8220.85	5083.763985	13717.11137
0.8	8968.2	5382.958841	20642.78692
0.89	9640.815	5652.23421	31907.39271
0.9	2.125	1.988835746	2.304638712
1	1.7	1.7	1.7

O/W Emulsion Results Pk#2

Water %	Einstein	Tylor	Leviton and Leighton
	cst	cst	cst
0	8.3488	8.3488	8.3488
0.1	10.436	9.395540521	9.725736029
0.2	12.5232	10.44228104	11.728907
0.3	14.6104	11.48902156	14.61392683
0.4	16.6976	12.53576208	18.90530304
0.5	18.7848	13.5825026	25.60112643
0.59	20.66328	14.52456907	35.28051694
0.6	3.4	2.66043436	7.351809268
0.7	2.975	2.42032577	4.635146815
0.8	2.55	2.18021718	3.125711967
0.9	2.125	1.94010859	2.234750888
1	1.7	1.7	1.7

O/W Emulsion Results Pk#3

Water %	Einstein	Tylor	Leviton and Leighton
	cst	cst	cst
0	522.504	522.504	522.504
0.1	653.13	575.008573	590.5089147
0.2	783.756	627.5131461	686.1433562

0.3	914.382	680.0177191	818.3963756
0.4	1045.008	732.5222921	1005.9642
0.5	1175.634	785.0268652	1282.678195
0.6	1306.26	837.5314382	1711.04593
0.7	1436.886	890.0360112	2412.240698
0.8	1567.512	942.5405843	3636.117004
0.81	2.5075	2.247319262	3.21247398
0.9	2.125	1.988062769	2.303513173
1	1.7	1.7	1.7

O/W Emulsion Results Pk#4

Water %	Einstein	Tylor	Leviton and Leighton
	m/s2	m/s2	m/s2
0.33	0.000208	0.000153	0.000191
0.4	0.000228	0.000161	0.000222
0.5	0.000257	0.000172	0.000284
0.6	0.000285	0.000184	0.000381
0.7	0.000314	0.000196	0.00054
0.73	0.000322	0.000199	0.000607
0.74	2.64E-06	2.63E-06	4.03E-06

O/W Emulsion Results Pk#5

Study of Light crude oil Transportation

Water %	Einstein	Tylor	Leviton and Leighton
	cst	cst	cst
0	21.83	21.83	21.83
0.1	27.2875	24.24957671	24.98411813
0.2	32.745	26.66915342	29.48270119
0.3	38.2025	29.08873013	35.80973838
0.4	43.66	31.50830684	44.96258952
0.5	49.1175	33.92788355	58.78375609
0.6	54.575	36.34746026	80.77778746
0.64	56.758	37.31529095	93.24513258
0.65	3.1875	2.638420952	6.261064173
0.8	2.55	2.236240544	3.251388801
0.9	2.125	1.968120272	2.274663978
1	1.7	1.7	1.7

Dilution:

S#	Well	Kinematic Viscosity of oil before (m2/s)	Kinematic vis-cosity of Lighter crude oil (m2/s)	Solvent of origi-nal oil (%)	Target vis-cosity (m2/s)	Kinematic Viscosity of mixture after (m2/s)	DVR %
1	PK#1	2.989E-03	7.08E-07	25	6.663E-05	4.69E-05	97.8
2	PK#2	8.34E-06	7.45E-07	25	8.87E-07	4.49E-06	65

3	PK#3	5.22E-04	8.44E-07	25	2.711E-05	2.08E-05	88.2
4	PK#4	1.14E-04	8.44E-07	15	3.34E-05	2.29E-05	80
5	PK#5	2.18E-05	8.44E-07	10	1.493E-05	1.33E-05	74.6

Heating

Well	Length (m)	K (1m deep) [W/m-K]	K (on surface) [W/m-K]	K (on surface) [W/m-K]	Total no: of Heating Terminals (1m deep)	Viscosity before heating m2/s	Target Viscosity m2/s	Temperature rise °C	Viscosity after heating at m2/s	Total Heat (J)	DVR %
PK#1	10000	2.64	4.01(33)	2.2(17)	20	2.98E-03	6.66E-05	50	4.39E-05	3.67E+05	98.5
PK#2	2000	2.73	4.65(4)	2.15(2)	2	8.34E-06	8.87E-07	60	3.89E-06	9.06E+02	56.6
PK#3	20000	2.48	3.85(50)	2.25(22)	25	5.22E-04	2.71E-05	46	1.85E-05	5.35E+04	90.6
PK#4	30000	2.65	3.75(38)	2.19(15)	19	1.14E-04	3.34E-05	46	9.23E-06	1.30E+04	91.9
PK#5	20000	2.55	4.35(12)	2.28(5)	6	2.18E-05	1.49E-05	15	1.39E-05	6.18E+02	36.3