Sudan University of Science & Technology

College of Petroleum Engineering

Department of Petroleum Engineering

Flow Assurance Study for a Waxy Crude Oil
A Case Study from Bara Field, Sudan

دراسة لضمان الجريان لخام نفطي شمعي
نموذج دراسي لحقل بارا, السودان

A thesis

Submitted to the College of Petroleum Engineering

As requirement for the Degree of

B.S.C. (Honors)

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Khartoum- October- 2018

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Date: / / 2018

بسم الله الرحمن الرحيم

قال تعالي : {يَرْفَعِ اللَّهُ الَّذِينَ آمَنُوا مِنكُمْ وَالَّذِينَ أُوتُوا الْعِلْمَ دَرَجَاتٍ [المجادلة: 11]

Dedication

We dedicate this work to each other's, to Ahmed's wife and our supportive families.

We also dedicate it to Diana Hussein, Grandpa Abd-Allateef, Father Ali Mohammed Ali and every dear person we lost along the way; we believe you are watching us with pride. May Allah rest your souls in peace.

Acknowledgment

First of all we thank Allah for gracing us with the gift of Education, as its one of his greatest blesses on earth. We thank him for putting us in this path, for opening our eyes and minds with knowledge and finally we ask him to give us the faith and strength to develop our country.

Secondly we want to express our deep gratitude to Teacher Muhanned Khiary, we appreciate every moment he has devoted teaching, guiding and supporting us, and we wouldn’t make it this far without his advices.

We are deeply thankful to every Teacher in Sudan University broadly, especially in College of petroleum engineering for being candles lighting up our lives.

Thanks also extended to Petroleum Laboratory Staff, and to everybody honored us with his precious time.

Abstract

Flow assurance is a relatively new term in oil and gas industry. It refers to ensuring successful and economical flow of hydrocarbon from reservoir to the point of sale. The term was considered by Petrobars in the early 1990s. Beside network modeling and transient multiphase simulation, flow assurance involves effectively handling many solid deposits and also includes thermal investigation of pipelines, making sure the temperature is above the wax appearance temperature and hydrate's formation temperature.

Crude oil flow in Bara filed is restricted by wax deposition during production, resulting in complex production operations, pipelines detraction and eventually complete well shut-down. This project aims to improve production performance by guaranteeing flow assurance of crude through well tubing, Flow lines and Trunk line.

In this study wax deposition problem was evaluated by laboratory analysis of a crude sample from the field and analyzed in Central Petroleum Laboratories; Field performance model constructed and studied using Multi-Flash & OLGA Software.

Thermal treatment of crude above the Wax Appearance Temperature using Down-Hole Heater found to be effective in preventing wax accumulation and deposition and in improving production performance.

This is the first study of its kind to be applied in Bara field. In addition, the network model by using OLGA software was created for the first time for this field. Finally down-hole heaters application is relatively new technique in Sudanese fields.

Down-hole heaters found to be very effective in solving wax deposition problems both technically and economically. It is recommended to be used to overcome flow assurance hindrances.

تجريد

ضمان الجريان يعتبر مصطلح جديد في مجال الصناعة النفطية ويشير الى ضمان نجاح التدفق تقنيا واقتصاديا من المكمن الى نقاط البيع وقد تم اطلاق هذا المصطلح بواسطة شركة بتروبار في اوائل التسعينات. الى جانب نمذجة مجموعة الابار والمحاكاة متعددة الاطوار, ينطوي ضمان التدفق على التعامل الفعال مع العديد من الرواسب الصلبة. يشمل ضمان التدفق الفحص الحراري لخطوط الانابيب , والتأكد من ان درجة الحرارة فوق درجه حرارة ظهور الشمع ودرجه حرارة تكوين الهيدريتات.

يتم إعاقة الجريان في حقل بارا بسبب ترسب الشمع مما يؤدي إلى تعقيد عمليات الأنتاج وتقليل قطر الأنبوب ,ممايؤدي إلى إغلاق قطر الأنبوب إذا لم يتم تفادي الترسيب الشمعي.

هدفت هذه الدراسه لتحسين اداء الانتاج عن طريق ضمان التدفق من عمق البئر مروراً بأنبوب الانتاج في البئر حتى أنابيب التدفق السطحية.

في هذه الدراسه تم تحليل مشكلة ترسب الشمع عن طريق اجراء تجارب مختبرية في مختبرات النفط المركزية لعينة من الخام. تمت محاكاة ادائية البئر باستخدام برنامجي ال OLGA و ال Multi-Flash.

المعالجة الحرارية للخام فوق درجة حرارة ظهور الشمع عن طريق إنزال سخان حراري داخل البئر اثبتت فعاليتها في منع ترسب وتراكم الشمع وتحسين ادائية الإنتاج.

تعتبر هذه الدراسة هي الأولى من نوعها التي يتم تطبيقها في حقل بارا, بالاضافة لتطبيق برنامج ال OLGA لأول مرة لهذا الغرض. اخيراً إستخدام تقنية السخان داخل الأبار هي تقنية جديدة نسبياً في الحقول السودانية.

اثبتت الدراسة ان استخدام السخانات داخل البئر طريقةفعالة جدا من الناحية التقنية والاقتصادية في حل مشكلة تجمع الشمع. يوصي باستخدام هذه الطريقة لمعالجة مشاكل إعاقة الجريان.

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CHAPTER 1
INTRODUCTION

Sudanese crudes mostly contain high content of wax, which result in poor rheology and affect the flow assurance of this crude.

When the flow is restricted by the crystallization or deposition of organic or non-organic components as a result of changing in flow conditions, flow assurance term is introduced.

It's relatively a new term which means insuring successful and economical flow of hydrocarbons from downstream to the upstream sections.

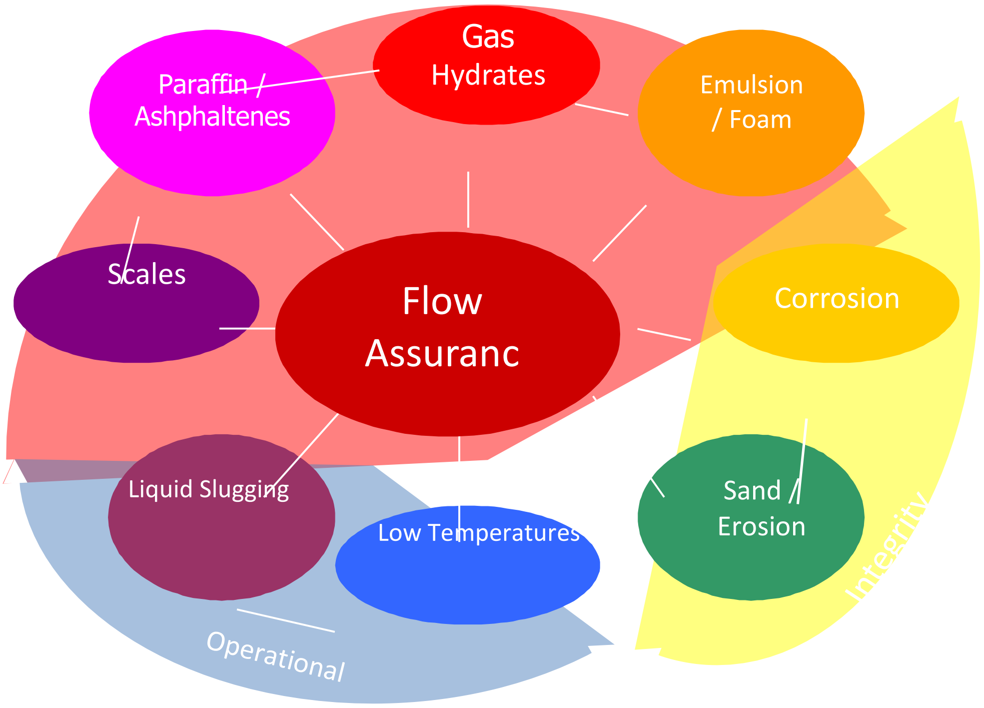


Figure (1.1): Flow hindrance elements.

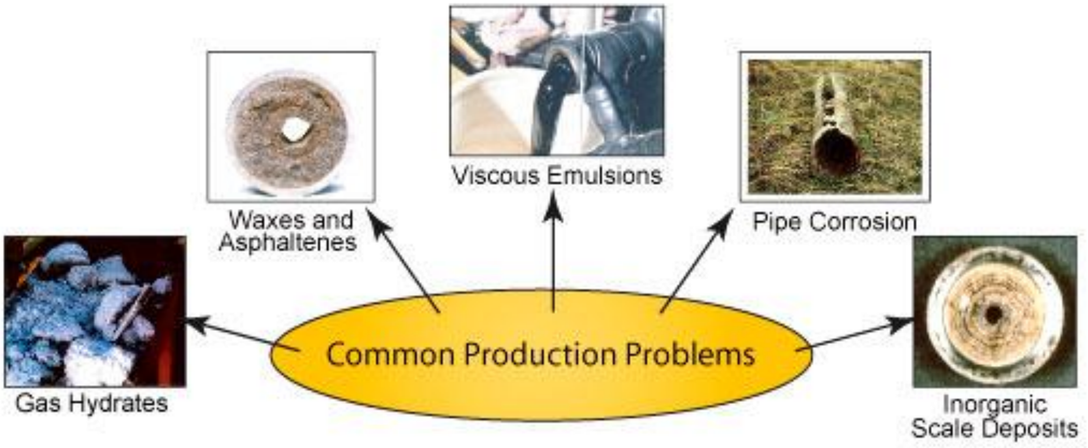
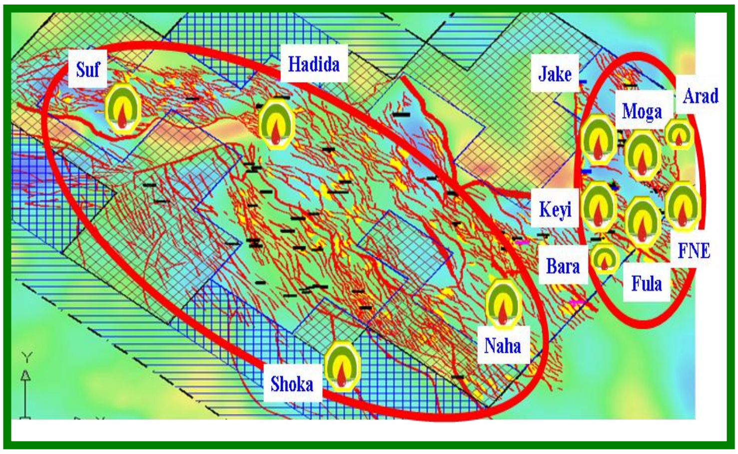


Figure (1.2): problem associated with production.

1.1 About the field:

-Bara field location:



Bara Oil field is located in the Southwest part of the Fula sub-basin of block VI, i.e. in fula sub basin (Fula Depression).

Figure (1.3): Areal map for Bara field. Petroenergy production Reports(2017)

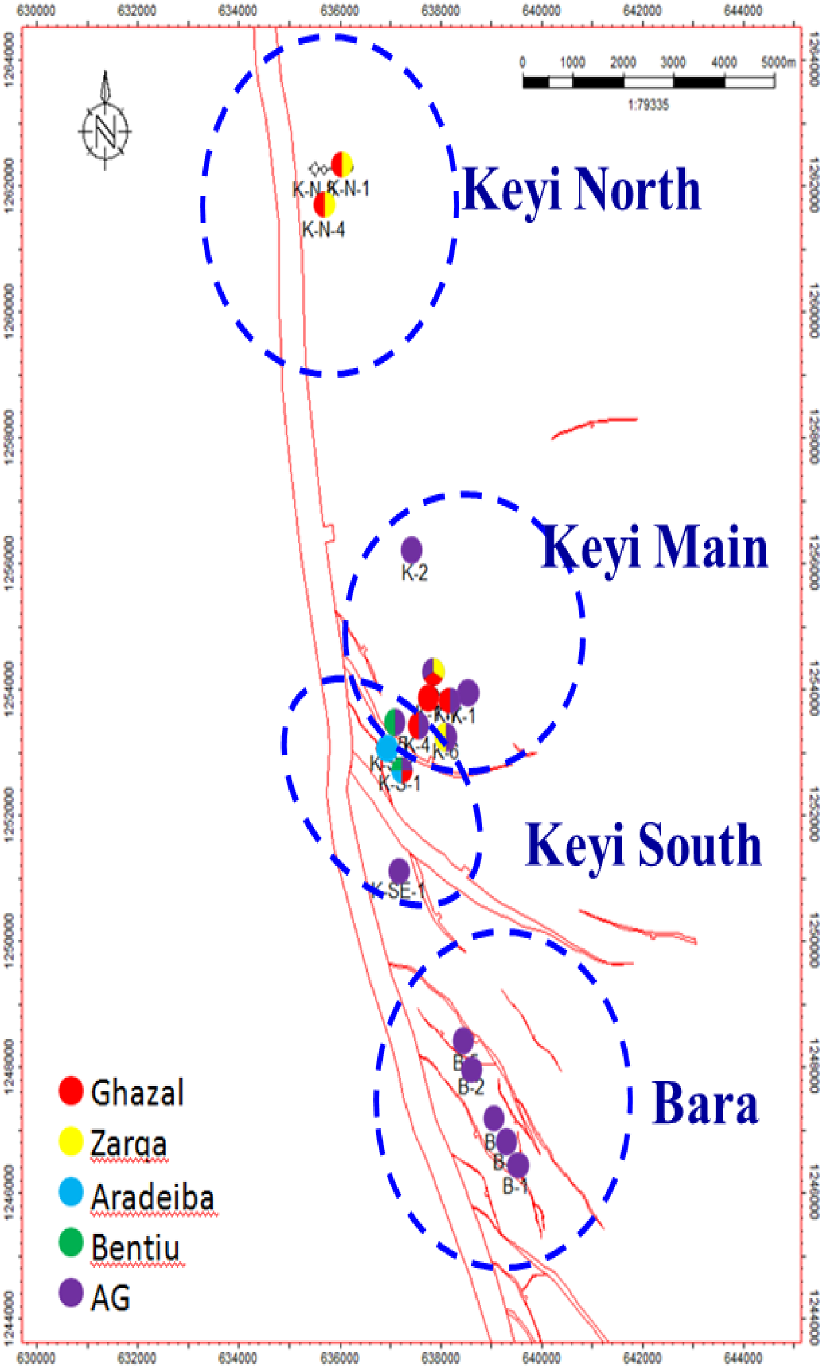


Figure (1.4): Bara field layers. Petroenergy production Reports(2017)

Structure:

-In Bara field; faults are generally characterized as normal faults.

-The reservoir type is layered reservoir in Bara field.

-The major producing zone in Bara AG (sub-layers formations AG1a, AG1b, AG1c &AG1d).

-OOIP accounted in AG1b and AG1d.

Pressure and Temperature System:

Normal pressure & temperature system:

-Pressure Gradient is 0.93 ~1.07 psi/100 m.

-Temperature gradient is 1.95 ~3.34ºC/100 m.

-The crude API is 35.8, with lower density of 0.835~0.851 g/cm^3 in Abu-Gabra formation.

-The oil in AG formation has high pour point (32-49 ℃).

-Low GOR &low acid number.

-Accordingly; the reservoir has good porosity (22%) and medium to low permeability.

Production performance:

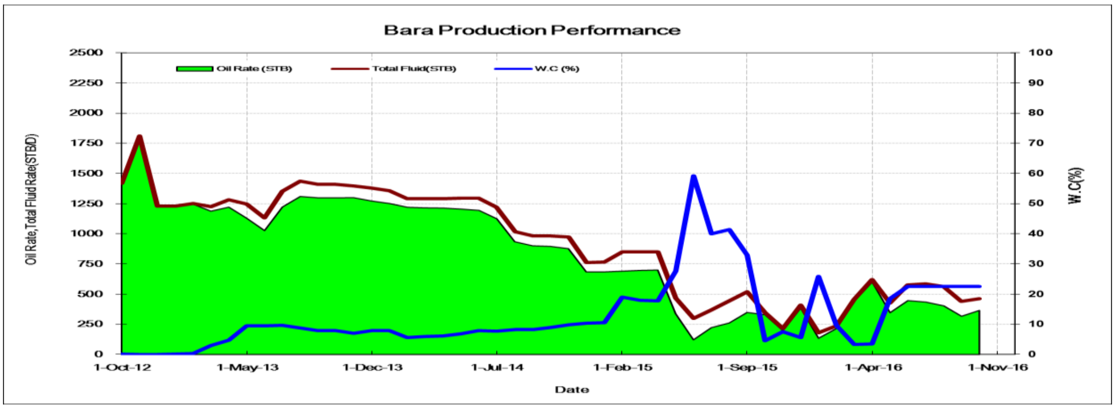


Figure (1.5): Bara Field production performance. Petroenergy production Report (2017)

-Total number of wells is 7 (6 producers (3 active+ 3non active) +1 dry).
-B-5 completed in AG1b but it is not commissioned due to high pour point.
-B-7 has been commissioned successfully in last Aug.2015.
-There are 2 idle wells in Bara field out of 7 total wells.

-Bara field started production since Oct.2012.
-Bara oil field has been completed with single layer in the upper part of AG formation.
-Currently, As per Oct.31st, 2016 Bara production is as below:
Cum Oil = 1.295 MMSTB, Ql= 465 STB/D, Qo= 367 STB/D, WC= 21%
-Sharply declined due to stop production (natural flow) from B-2 which is the most important well in Bara Field.

1.2Problem statement:

Wax deposition in Bara field causes restriction of flow in well tubing, flow-lines and trunk lines. As well as diameter reduction, equipment damage, difficult production operations and higher cost of repair and maintenance.

1.3 Project objectives:

- To analyze wax effect on the flow and how best to treat it with heating method according to laboratory measurement (PVT) data.
- To build a model for Bara field using OLGA software.
- To study and implement different heating scenarios to validate the use of down-hole heaters in Bara field.
- To select the scenario which results in great reduction of wax deposition in well tubing, flow lines and trunk line.
- To conduct an economic study for the evaluation of the effectiveness of heat treatment method in lowering of work-over and maintenance costs.

1.4 Limitation:

- Difficult data access.
- DSC device not available.
- Wax content measuring device not available.

CHAPTER 2
LITRETURE REVIEW

2.1 General back ground:

Flow assurance is the technical discipline that guarantees accomplishment of lifting and transport system lifetime production targets from the near wellbore to offloading tanks by forecasting, preventing and solving problems instigated by the behavior of the transported material (gases, liquids or solids) either separated or multiphase conditions. (Di Lullo, 2012)

Flow assurance involves guaranteeing fluid flow in well, flow line and trunk line. Transportation of heavy/waxy crude oils with high viscosity makes flow through pipelines problematic and challenging. It has been recognized that n-paraffin's are principally responsible for this problem. These solid elements deposit in production tubing, pipelines, processing equipment and eventually cause plugging in the operations. Challenging flow assurance and field development issues affect both well completion design and production operation schemes. Flow assurance is a significant area for multiphase flow of oil, gas and water to minimize economical loss for the petroleum industry.

In the last decade Flow Assurance has emerged as a major technical discipline and has gained attention due to its impact in the petroleum industry. It has given rise to an inter disciplinary research wherein along with the development in laboratory and use of various chemicals, emphasis on modeling and simulating the pipeline under various conditions has been studied at large. This has led to the development of real time data monitoring software and Flow Assurance Advisory systems. These systems rely on good model predictions and available sensor readings in the production system. This software is still growing and various rigorous and robust models for flow assurance issues have been customized based on specific field characteristics. (Kondapi and Moe, 2013).

While flowing through a long pipeline, it is important to take an account of viscosity, acidity and salt content for field operations. All these aspects can affect pipeline dimensions. The process of ensuring a continuous flow of oil despite different issues which can cause flow complications is known as Flow Assurance.

Although Flow Assurance consists of a variety of issues, four main issues are: corrosion, salts, asphaltenes and waxes. (Manafi et al., 1999)

Asphaltenes are the complex carbon-based molecules characterized by groups of consistent aromatic rings. They can cause flow problems, mostly in the wellhead itself as well as in the refinery lines. Asphaltene solubility and precipitation needs extensive consideration.

In 1927 paraffins were informed as irritant to the upstream industry due to their precipitation and buildup in the wall of the well, in the oil string and on the face and in the pores of the sand, causing condensing of oil in the transportation lines and in tank bottoms (Reistle Jr, 1927),

During flow through pipeline, wax may be deposited on pipe walls. A thermal gradient between the outside ambient conditions and the internal oil flow must exist for flow deposition. The internal wall temperature due to the gradient must be beneath the initial wax appearance temperature. In addition, internal shear forces in the flow must be low enough to allow crystal growth. Wax deposits, can grow and restrict flow. While it is rare for deposition to entirely shut down a pipeline, the loss in production capacity is a foremost concern during waxy crude oil transportation through pipelines(Gupta and Anirbid, 2015).

Flow assurance is successful operations that generate a controllable and gainful flow of fluids from the reservoir to the sales point. The flow assurance discipline that enables these operations is an integration of disciplines, from operations to engineering to business to science.

The study based on a comprehensive review of fluid flow assurance issues to show the risk of scale deposition associated to asphaltenes, and wax precipitation in wellbores and pipelines that reduce production, and presented hydrates and emulsion formation, corrosion and erosion and identify the appropriate chemical strategy to guarantee the production(Theyab, 2018).

2.2 Deposition Materials and Mechanism:

2.2.1 *Hydrates*:

Hydrates are crystalline materials similar to ice in structure and form; at high-pressure and low-temperature conditions when light hydrocarbons (e.g. methane, ethane, propane, isobutene and inorganic molecules such as CO_2 and H_2S) meet with water, resulting in crystalline molecular complexes form that causes blockages in gas flow lines(Johal, 2012, Larsen et al., 2003) as shown in figure.

Figure (2.1): Hydrate Plug Formed in a Subsea Hydrocarbon Pipeline(Chaudhari, 2016, Bauck, 2013).

These crystalline composites of water and low boiling gases are creating a singular form of molecular structure. Because of their hydrogen bonding properties, the water molecules are able to form voids, which can house low molecular weight molecules. The insertion of these gas molecules stabilizes the metastable water matrix structure. There are different kinds of common hydrate structure, which comprise numerous small and large cavities. Only molecules of modest size and appropriate geometry are able to enter the cavities(Dorstewitz and Mewes, 1995)

Oil dominated systems (i.e., water dispersed in the oil phase) as shown in Figure (2.2) are commonly encountered through the initial periods of a well’s life where the quantity of produced water is relatively little. However, this kind of flow pattern is a function of oil properties, salt content, temperature, surfactants present (natural or artificial), and flow parameters associated with the system. Oil dominated flow lines are proven to be disposed to hydrate formation at subsea low temperatures and high pressure environments, thereby leading to hydrate-related flow assurance concerns(Chaudhari, 2016).

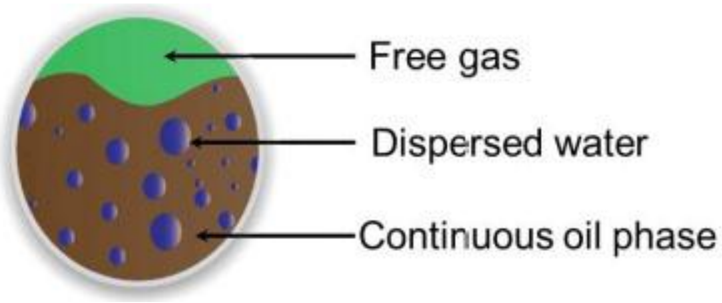


Figure (2.2): Cross Sectional View of the Pipeline Depicting Oil Continuous System with Complete Water Dispersion(Chaudhari, 2016).

As identified, in oil dominated systems, water is present in the form of dispersed droplets along with a free gas phase. At high pressure and low temperature conditions, hydrate shells are formed around the dispersed water droplets therefore altering the water droplets to hydrate particles(Theyab, 2018).

These partly converted and wholly changed particles can remain homogeneously dispersed in the continuous oil phase depending on flow conditions. When a certain hydrate concentration is reached, the chance of the hydrate particles coming in contact with each other rises. As these hydrate particles come in interaction, the cohesive force between hydrate particles, via liquid capillary bridge, induces agglomeration. The agglomeration process can result in the formation of a large hydrate bulk in the flow line, therefore increasing the viscosity of the entire system. This large hydrate bulk eventually may result in settling/accumulation and formation of a moving and/or stationary bed thereby leading to the formation of a hydrate plug in a pipeline(Chaudhari, 2016, Larsen et al., 2003).

2.2.2 Wax Deposition:

Wax deposition is, a common problem, a serious operational challenge and one of the main flow assurance problems in the oil industry around the world including the offshore and onshore oil fields. Wax deposition occurs when paraffin components in crude oil (alkanes with carbon numbers greater than 20) precipitate and deposit on the cold pipeline wall when the inner wall temperature drops below the wax appearance temperature.(Singh et al., 2000)

The formation of wax in the pipe during the fluid production from the bottom hole of the well to the surface can restrict the flow of crude oil, creating pressure irregularities and causing an artificial blockage, as shown in figure 5, leading to the reduction or even termination of production (Siljuberg, 2012, Bern et al., 1980, Trina and Johansen, 2015, Botne, 2012, Kjøraas and Steinar, 2012, Tordal, 2006). Wax deposition also leads to formation damage near the wellbore, reduction in permeability, changes in the reservoir fluid composition and fluid rheology due to phase separation as wax solid precipitates(Zhu et al., 2008).

Wax precipitation is impacted by several factors, such as: crude oil composition(Singhal et al., 1991), flow rate, temperature gradient(Salam et al., 2014), pipe wall temperature (inlet coolant temperature), crude oil temperature, shear stress, recirculate time of oil in the rig (production time in the field) and oil viscosity(Valinejad and Nazar, 2013).

Figure (2.3): Wax Deposition Plug in the Wellbore On Platform C in the North Sea(Akpabio, 2013).

Wax deposition in crude oil production systems can be reduced or prevented by a chemical, mechanical, or thermal remediation method or by a combination of some of them(Woo et al., 1984). If preventive methods for wax deposition (e.g. insulation of pipeline, injection of wax inhibitor, or combination of both) are not effective, a wax gel layer grows quickly in thickness and obstructs the flow of oil due to the flow restriction (Singh et al., 2000, Lee, 2008), Those justification methods become progressively important as the oil industry continues to expand deep-water operations to greater depths and distances in cold environments, which poses a great challenge to the industry(Zhu et al., 2008, Bott and Gudmundsson, 1977, White, 2008, Aiyejina et al., 2011, Huang et al., 2016)

Successful management of wax deposition will become more important in the future because new explorations and productions are being made farther offshore. The wax deposition management cost to the petroleum production industry is huge and will increase both in terms of capital costs (e.g. preventive methods) and operating costs (e.g. corrective methods(Lee, 2008).

Recently, three technologies are used for mitigating wax deposition in the offshore and onshore oil fields around the world, namely, wax inhibitors (chemical inhibitors), thermal treatment, and pigging. Most of the oil companies are using the wax inhibitors, as a main mitigation method to reduce wax, combined with pigging or thermal insulation(Theyab, 2018).

2.2.3 Asphaltenes:

Asphaltenes are polar compounds, as shown in figure 6, which present in the heaviest fractions of the crude oil and are defined by their solubility characteristics. Asphaltene that typically leads to choking in pipelines and reservoirs' wells is a highly viscose compound with a high boiling temperature. Generally, due to its high propensity toward association and aggregation, it is called as "Cholesterol of Petroleum". Chemically, Asphaltene consists of some simple heteroatoms, such as carbon, hydrogen, nitrogen, oxygen and sulfide, and has aromatic cyclic structures(Mohammadi and Richon, 2007, Pan and Firoozabadi, 1997, Bahman et al., 2018, Johal, 2012, Joshi et al., 2003).

Asphaltenes have different ratios of solubility with different solvents. Although they have a strong solubility with benzene and toluene,

Their insolubilities in n-pentane and n-heptane in room temperature is clear. Asphaltene in heavy oil can find a chance to precipitate when the oil's conditions are operated by changing pressure or temperature and composition of phases. These variations can be occurred during the primary recovery, secondary recovery, and tertiary recovery in porous media in reservoirs or in wells, pipelines, separators and refinery facilities(Bahman et al., 2018).

Asphaltene precipitation is more expected to occur in an under-saturated, light reservoir fluid than a heavy hydrocarbon system. Various problems outcome due to asphaltene precipitation, including drop in the production rate, and other operational problems, such as higher viscosity and water-oil emulsion, etc.

Usually, asphaltene dispersant chemicals can be used successfully. However, the chemical injection point must be at the reservoir depth. This requires high-pressure injection at appreciable rates (e.g. 300 ppm in oil). Asphaltene inhibition is exceeded in injection facilities, volume, and cost only by hydrate inhibition(Brown, 2002). In the industry, there is a agreement that the prevention principle is the best way to solve the problems caused by solids deposition(Johal, 2012, Joshi et al., 2003).

There is a confined area termed Asphaltene deposition enveloped (ADE) region where provokes Asphaltenes of heavy oils to be agglomerated and to be dropped down. So far, a large number of researchers have attempted at identifying the ADE region for a specific crude oil by presenting an effective manner, whereby Asphaltenes precipitation due to either gas injection or pressure reduction can be quantitatively valued or even to be inhibited(Bahman et al., 2018).

Figure (2.4): Polar Compounds of Asphaltenes(Theyab, 2018).

2.2.4 Slugging:

Slug flow is one of the flow patterns occurring in multiphase pipelines. It is characterized by a chain of liquid plugs (slugs) separated by relatively large gas pockets, as shown in figure 7. Slugging in production pipelines and risers has been a major operational concern due to the creation of instability in production flow as a consequence of pressure fluctuation, thereby causing considerable and undesired loss in production and income(Guo et al., 2005).

Severe slugging is a phenomenon occurring in two-phase flow through a downward inclined flow line followed by a vertical riser at low gas flow rates. In this phenomenon, the liquid accumulations in the riser and curvature section of the flow line blocking the passage of gas in the lowest point of the system. As a result, the gas front penetrates the liquid blockage irregularly, causing tremendously large slug, severe fluctuations, and flooding of downstream equipment(Barreto et al., 2017).

There are several procedures that can be used to prevent production slugging, such as the riser base gas-lift system, complex detection and control systems, use of large slug catchers, and intelligent slug mitigation systems(Johal, 2012, Guo et al., 2005, Barreto et al., 2017, Malekzadeh, 2012).

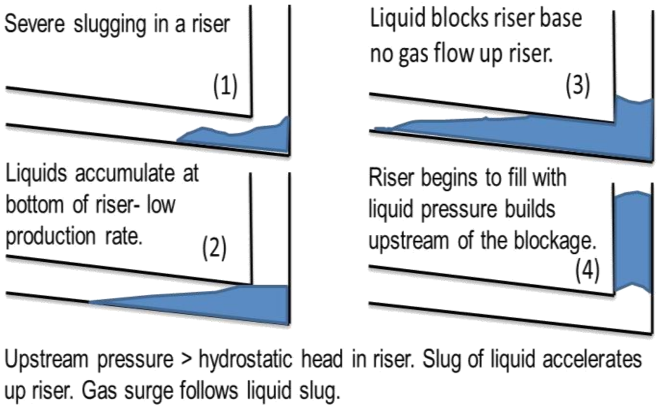


Figure (2.5): Slug Formation in the Riser of the Hydrocarbon Pipeline, Modified from (Johal, 2012).

2.2.5 Naphthens:

Over the previous two decades, many operators have faced the complex deposition problem of naphthenate along with other higher organic and inorganic scale. Such deposits can obstruct oil production in two potential ways, formation of hard and sticky deposit, and creation of sludgy foam contributing to forming tough emulsion. Naphthenates can cause serious oilfield problems, such as the potential shutdown of the offshore facilities due to naphthenate deposits, or the formation of tough micro Emulsion contributes to a decline in oil quality and production rate(Mohamed et al., 2016).

Naphthenates are formed from the salts of naphthenic acids when they precipitate as acidic fractions resulting from the processing of petroleum products. A naphthenate is composed of a heavy mixture of organic acids such as cycloalkyl carboxylic acids(Johal, 2012).

The formation of naphthenate salts is a developing problem and happens in the production of crudes with significant quantity of naphthenic acids and produced water with significant quantities of alkali or alkali earth metals(Junior et al., 2013).

Generally, all kinds of naphthenates can cause production losses in oil fields. Naphthenates can also have a major influence on separation efficiency of the host processing facilities, particularly calcium and sodium types, which the most are commonly found naphthenates in oil fields(Johal, 2012, Junior et al., 2013).

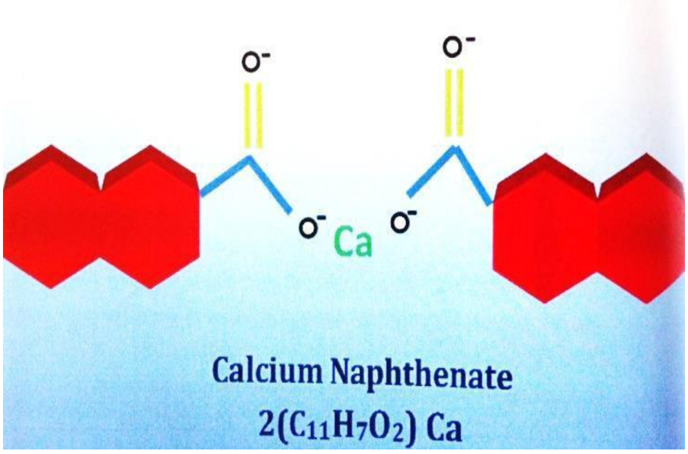


Figure (2.6): An Example of a Naphthenic Acid Structure(Johal, 2012).

2.2.6 Scales:

Scales can develop in the transportation system as a result of water forming deposits, as a crystalline growth of insoluble salt or oxides held within the water component. Scale compounds will precipitate out of water when their individual solubility in water is exceeded as a result of incompatibility, and this will reduce the transport capacity of flow lines and potentially cause plugging. The formation of scale deposits depends on temperature, the concentration of scale forming species, pH, water quality and hydrodynamic conditions(Abdel-Aal et al., 2015).

There are various types of scale inhibitors for preventing different kinds of inorganic salt formation; including CaCO3 Scale inhibition mechanism is based on the prevention of nucleation and salt crystal growth in the Solution(Abdel-Aal et al., 2002, Khormali et al., 2017). Several existing techniques are followed to reduce scale, such as mechanical means, chemical dissolution and scale inhibitors(Khormali et al., 2017, Johal, 2012).

Deposition of inorganic salts such as calcium carbonate (CaCO3) can cause formation damage and production equipment failure during the development of a reservoir. In case of water flooding, complex geochemical processes between the injection water, formation water and rock happen and the concentration of ions increases.Major contribution of scale control concentrates on understating the conditions of scale formation and its inhibition(Khormali et al., 2016).

Inorganic salt precipitation can occur throughout the fluid flow in reservoir and wellbore as well as the wellhead in petroleum operations. Salt deposition could have enormously unwanted consequences such as reduction of production rate, well productivity and the turnaround time of electrical submersible pumps, as well as plugging the perforations, premature failure of down-hole equipment and formation damage(Khormali et al., 2016, Naseri et al., 2015, Yi et al., 2014). These phenomena could result in a significant deterioration of development process. The control of the inorganic salt formation is complicated due to the complex reservoir fluid composition(Kelland, 2014). Calcium sulfate, calcium carbonate, barium sulfate and magnesium carbonate are the most common types of inorganic salts deposited in oil and gas industry.

A water system with a high concentration of salt-forming ions is necessary for precipitation. Different circumstances and parameters affect CaCO3 deposition throughout the oilfield operations. CaCO3 precipitation can be determined by the loss of chemical equilibrium between ions, and carbon dioxide (CO2) in water. The CO2 balance determines the possibility of CaCO3 precipitation. When the pressure is below the saturation pressure, gas releases from the liquid primarily in the reservoir and on the walls of the production equipment. Therefore, multiple interfaces are formed in phase separation. This condition is satisfactory for the nucleation and crystal growth of CaCO3.

Salt deposits can also work as adsorbents to the heavy components of the reservoir fluid and result in adhesion of solid particles to gas bubbles(Abdel-Aal et al., 2015, Khormali et al., 2017).

Organic components, specifically naphthenic acids and their salts, have a profound influence on scale formation. Aromatic compounds, unsaturated hydrocarbons, sulfur compounds, asphaltenes, resins and paraffin are the most public types of organic components, which affect the salt precipitation. The effect of the inorganic components in CaCO3 scale formation is explained by hydrophobization of the salt crystals due to adsorption of a water-soluble organic material in porous media, substantially naphthenic acids and their salts. Adhesion of CaCO3 particles on the walls of down-hole tools is described solely by the hydrophobicity of solid surfaces(Khormali et al., 2017).

Water flooding is the main method of secondary oil recovery. In this case, complex geochemical processes of interaction between the injection water and formation water and rock occur in the reservoir(Naseri et al., 2015). These methods lead to formation of saturated solution with ions. Scale formation depends on reservoir temperature, pressure, level of solution saturation with ions in the mixture of injection and formation waters and hydrodynamic behavior of fluid flow. These parameters control the amount and morphology of salt crystals during water flooding. Hence, when mixing two incompatible waters with high concentrations of bicarbonate and calcium ions, CaCO3 crystallization and its precipitation occurs in the near wellbore formation zones depending on the reservoir pressure and temperature(Khormali et al., 2017).

Inhibitor injection into reservoirs is extensively used for reservoir and equipment protection from salt deposits. This treatment offers a reliable long-term protection against scaling(Khormali et al., 2017). The efficiency of scale prevention relay on the processes which affect the formation of inorganic salts in the saturated solution.

Figure (2.7): Formation of Scale in the Pipe(Theyab, 2018).

In current years the number of corrosion failures in onshore and offshore pipelines has steadily decreased due to the introduction of corrosion management strategies by pipeline operators. A vital component in effective corrosion management is an accurate determination of corrosion growth rates.

Pipeline corrosion is one of the main causes of subsea pipeline failure. It is necessary to monitor and analyses pipeline condition to effectively predict likely failure. Subsea pipeline corrosion weakens the resistance of pipelines to internal and external forces, and it becomes the leading factor that causes the integrity loss of the pipelines.

When carbon steel pipes are used in transporting oil and multiphase flow containing a fraction of water, there is usually a high risk of corrosion. The decision to use carbon steel is usually economic in order to reduce capital expenditure and its use usually requires the application of a full internal corrosion management strategy to control corrosion levels throughout the system life.

Various mechanisms have been assumed for the corrosion process; all of these involve the formation of a carbonic acid ion or bicarbonate when CO2 is dissolved in water. This process can lead to corrosion, see figure 10, of the material at a rate that is larger than that from general acid corrosion with the same pH value.

The mechanism of corrosion is reliant on the quantity of the CO2 dissolved in the water phase, and predictions of corrosion levels are currently based on the knowledge of CO2 partial pressure and the use of correlations such as De Waard Milliams(Johal, 2012, Yang et al., 2017).

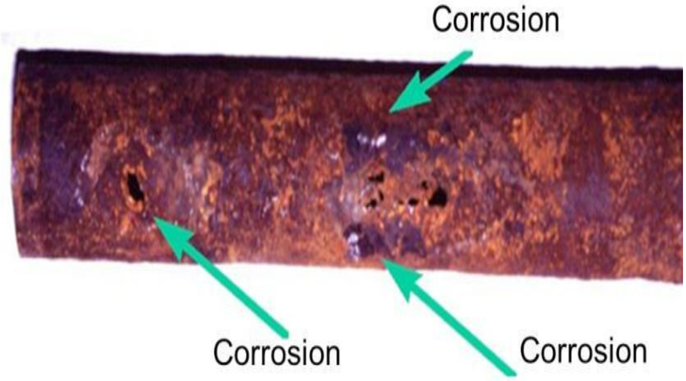


Figure (2.8): Corrosion Formation in the Pipe(Theyab, 2018).

2.2.7 Corrosion:

Corrosion is the deterioration of a metal as a result of chemical reactions between it and the surrounding environment. Both the type of metal and the environmental erosion conditions, particularly gasses that are in contact with the metal, govern the form and rate of deterioration. Erosion occurs when solid particles in the multiphase-fluid flow, or droplets in the gas flow, impinge or scrape against the walls of pipes and equipment(Theyab, 2018).

Erosion due to solid particles is a major problem in many industrial applications, particularly in the field of oil and gas(Zamani et al., 2017). Sudden change in the flow direction in elbows leads to considerable changes in particle distribution in the flow and accordingly higher erosion rate. For example Lin et al. showed that the erosion rate of 90º elbows is 50 times bigger than in straight pipes(Lin et al., 2015).

Erosion due to sand production has been considered the cause of a number of problems associated with separation efficiency, material loss and flow path blockages. Sand screens are mostly installed in the horizontal sections of production well bores in order to reduce sand production. The erosion predictive methods should include the mechanisms of kinetic energy imparted by the sand particle velocity and size, and the angle of the impact on the material should also be included in the erosion prediction calculations in order to estimate an accurate erosion rate(Johal, 2012, Lin et al., 2015, Zamani et al., 2017)

There are some proposals to reduce erosion on the pipes and equipment, for example, the number of bends and twists should be limited. Moreover, the bends and twists should also be as gradual as possible. Since impingements happen when the flow domain changes, making a straighter pipe will limit this variance in flow. For areas that are disposed to erosion, for instance, engineers can change the material of the pipe or guarantee a liquid film along the pipe. Since the rate of erosion is dependent on the material properties of the pipe, stronger, harder pipes will practice less erosion. The liquid film, however, acts as a shield slowing down the particle impingement(Theyab, 2018).

2.2.8 Emulsions:

With a combination of low ambient sea temperature and high fluid viscosity due to inversion water cut conditions, tight emulsions can occur between the water and oil phases. This can weaken the separation efficiency at the processing facility, and thus cause a loss in the production of the asset. In system shutdown conditions, the rheology of the fluids may change from Newtonian to non-Newtonian, exhibiting characteristics of high yield stress during low shear rate production start-up operations. In these conditions there may be a need to inject de-emulsifiers into the subsea facilities and also to ensure that enough pressure is available to re-start the system following an unintended shutdown(Johal, 2012, Zhang et al., 2017).

Unsuitable handling and management of the petroleum emulsions can cause serious damaging effects on public health and environment due to its high toxicity and high production quantity worldwide; naphthenic acids and heavy metals are the major toxic components in the petroleum emulsions, which are highly deadly for micro-organisms, aquatic algae and aquatic organisms(Zhang et al., 2017).

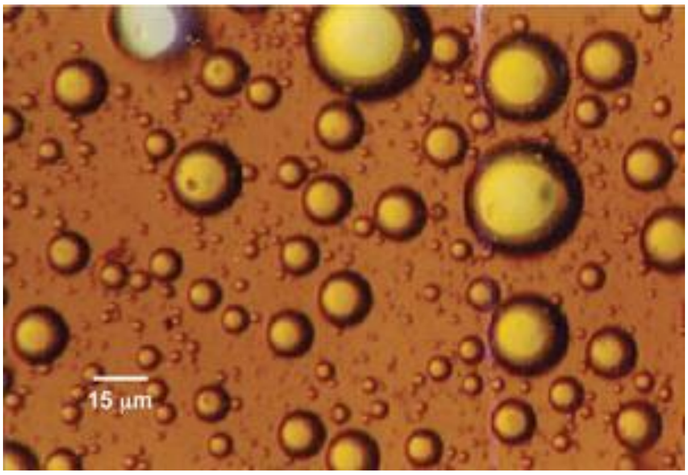


Figure (2.9): Photomicrograph of a Water-in-Oil Emulsion(PetroWiki, 1 July 2015).

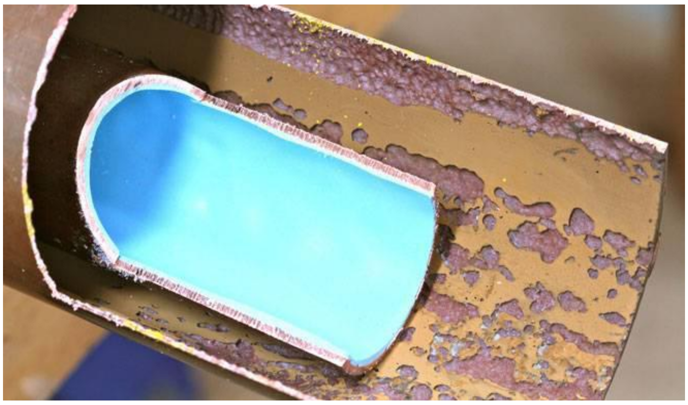


Figure (2.10): Erosion Formation in the Pipe(Theyab, 2018).

2.3 Treating Mechanisms:

The current work reviewed the most effective solutions to resolve the fluid flow assurance issues involved, for hydrate, use of the chemical inhibitors such as monoethylene glycol (MEG) or methanol, Pipeline insulation, depressurization, or direct electrical heating. Three technologies are used for mitigating wax deposition in the offshore and onshore oil fields around the world, namely, wax inhibitors, thermal management, and pigging. Usually, asphaltene dispersant chemicals can be used successfully. However, the chemical injection point must be at the reservoir depth. There are several techniques that can be used to mitigate production slugging, such as the riser base gas-lift system, complex detection and control systems, use of large slug catchers, and intelligent slug mitigation systems. Inject de-emulsifiers to reduce emulsion and using anti-corrosive and anti-scale chemical into the subsea facilities to ensure the production.

2.3.1 Thermal Treatment:

The Cold Flow procedure claimed that, if solid slurry is formed in the first segment of the pipe, it will be transported in a stable way without further solid deposition. At the exit of the process, the oil is at the same temperature as the external water and all potential waxes have been precipitated. The idea of Cold Flow is based on the pioneering work of (Coberly, 1942)

He showed that the presence of foreign elements decreased the tendency of wax crystals to deposit. They acted as nucleation sites which made wax solids precipitate in the bulk, limiting the quantity of solids that truly adsorbed to the wall surface. (Merino-Garcia and Correra, 2008)claimed that in order to validate the feasibility of Cold Flow, temperature gradient between hot oil and cold wall should be eliminated. Also, all waxes have precipitated and are transported as a solid dispersion.

During 1920-1930, most of the developments were in thermal methods for the solution to paraffin problems. These treatment methods typically consisted of minimizing radiation heat losses and addition of external heat to the system. Insulation of flow lines and maintaining a higher pressure in the flow lines that minimized cooling through dissolved gas expansion were two examples of minimizing radiation losses. Methods such as steaming the flow lines, installing bottom-hole heaters and circulation of hot oil and hot water are examples of the application of heat in an effort to melt or increase the solubility of the deposit. However, both mechanical and thermal methods did not change the primary oil wettability of the surfaces of pipelines and, therefore, could not prevent additional deposition of waxes. As a result, the frequencies of such measures generally required to be high(Gupta and Anirbid, 2015).

The use of unconventional energy in the upstream and midstream industry is now possible. A Dynamic Simulator has been developed to evaluate the pressure drop and temperature profile of a solar heated pipeline which can compare it with a bare pipeline under average sunshine conditions. This technology is an innovative and economically attractive alternative to the conventional electric or steam heat tracing of pipelines or utilization of Drag Reducing Agents (DRA's) or pour point depressants. Depending upon process requirements, this technology is specifically suitable for tropical and mid-latitudes. This technology is also suitable for vessels. (Lasich and Kaila, 2001)

2.3.2Mechanical Treatment:

The mechanical approaches used scrappers, cutters, pigs etc. and were relatively economical but not entirely efficient. Running a scrapper that mechanically cuts the deposit from the tubing was used widely and pigging of pipelines was also frequently used.

The problems associated with these methods were the chances of perforation plugging and an increase in oil-in-water emulsion stability.

One of the most frequently used remedial methods in the fields is pigging. In pigging, a pig (a solid object with the diameter smaller than the inner diameter of the pipe) passes through the pipeline to scrape off the wax deposit.

However, the pigging method cannot efficiently be utilized without a proper wax deposition prediction. For example, pigs at times get stuck inside the pipeline in the presence of dense hard deposits making the situation worse, which occurred in a Gulf of Mexico pipeline. In the worst cases, production must be stopped in order to replace the plugged portion of the line, which is estimated to cost approximately $40,000,000 per incident (Huang et al., 2016)

2.3.3 Chemical Treatment:

The chemical strategy and choosing the optimum injection points are the best way to avoid deposit build up and to avoid any future criticalities; and allow re-establishing the anticipated production flow rate.

Till 1966 it was understood that the rate of deposition due to the precipitation of wax could be controlled with addition of additives (Shock et al., 1955, Jorda, 1966)Tests of various plastic coatings showed that most smooth, non-paraffinic plastics were capable of reducing paraffin deposition in oil wells, but flexible, highly polar, non-paraffinic plastics were more suitable for providing long term resistance to paraffin deposition in oil wells if the flow stream contained abrasive materials. Paraffin deposition was studied in the laboratory under simulated conditions in well tubing and it was proposed that paraffin deposits were introduced by the precipitation of paraffin directly on or adjacent to the pipe wall and grown by diffusion of paraffin from solution to the deposit (Hunt Jr, 1962)

During 1950-1970 developments in laboratory scale technology were carried out to identify and categorize wax as well as simulating the conditions of paraffin deposition in the laboratory. Prediction of wax deposition behavior in tubing /trunk line was also simulated in order to understand the wax formation mechanism.

The chemical control methods may be classified as:
i) Those in which a solvent is used to dissolve the deposit once it has formed.
ii) Those which inhibit wax crystal growth or inhibit its adherence to the surface wells.

(Rose and Marsden Jr, 1970)made an effort to study the nature of low temperature flow of Prudhoe Bay crude oil through pipeline (a long tubular conduit or series of pipes, often underground, with pumps and valves for flow control, used to transport crude oil, natural gas, water, etc.) and its emulsions with synthetic brine. They found a significant lowering of apparent viscosity and pressure drop through the flow resistance due to the use of oil-water emulsions.

(Van Engelen et al., 1981) experiential that properties such as pour point, plastic viscosity and yield value measurements are quick and helpful methods for the initial screening of fluidity improvers.

Paraffin deposition can be prevented or greatly retarded by using chemical surfactants called "dispersants"(McClaflin and Whitfill, 1984). The choice of using batch or continuous treatment is ruled by the type and number of wells demanding treatment.

(Woo et al., 1984)discussed the use of a blend of crystal modifiers in a controlled-release matrix form and a commercially available ethylene-vinyl acetate copolymer solid. Among the chemicals used, crystal modifiers and paraffin/wax dispersants are quite common. The paraffin crystal modifiers change the crystallization behavior of waxes. The efficiency of the crystal modifier depends, to a large extent, on the type of aggregate- forming waxes that are present in the oil. Thus, the choice of a crystal modifier is a key to accomplishment for the treatment. They perform well in water free or low-water content crude oil. These polymers co-crystallize with paraffin crystals and thus paraffin crystals are kept in a dispersed position in the crude oil. In this way,

The formation of a three dimensional network takes place at lower temperatures which results in a considerable reduction in the viscosity and pour point of the crude oil (Dobbs, 1999)

(Roenningsen et al., 1991)discussed three different techniques for determination of Wax Precipitation Temperature (WPT), namely Polarization Microscopy, Differential Scanning Calorimetry (DSC) and Viscometry. The results gained by these methods were compared and it emerged that Microscopy invariably gave the highest WPTs and probably the most relevant values for predicting the onset of wax deposition on cold surfaces.

Thermodynamic paraffin model and the complementary laboratory test methods were described by (Erickson et al., 1993).The method consisting of a periodical application of detergent designed to remove the deposit and simultaneously destroy the water-in-oil emulsion were suggested by (Bernadiner, 1993). (Chanda et al., 1998) used Poly Behenyl Acrylate (PBA) with a range of molecular weights and their efficacy as Flow Improver (FI)/Pour Point Depressant (PPD) were evaluated.

During the period of 1991-2000, laboratory progresses along with modern chemical developments were remarked. It was established that selection of chemical combinations was well specific and based upon individual experience. Also many new solvents and additives were exposed which case specific were(Gupta and Anirbid, 2015).

2.3.4 Additional Treatment Methods:

Since conventional methods like thermal application and chemical injection are turning out to be expensive, an alternative approach has now been developed. These method use application of magnetic, electric and piezoelectric effect on crude oil to improve its rheological properties.
(Chow et al., 2000)made a successful use of Magnetic Fluid Conditioning (MFC) technology to reduce the viscosity of crude oil. Their results identified state of wax saturation as an important factor for undergoing magnetic treatment. (Tung et al., 2001)found that the effects of magnetic treatment were strongly depending on temperature, magnetic intensity and time of exposition.

(Tao and Xu, 2006) studied the application of electric field pulse and discovered significant decrease in viscosity of paraffin-base crude oil. Although the viscosity reduction is not permanent, it would last several hours.

(Ajienka, 2011) developed a tool that could control wax deposition using of piezoelectric effect. The mechanism of semiprecious metals (Zinc, Cobalt and Lead) quartz and were studied and found to be successful in decreasing / eliminating wax deposit in the production system through the generation of piezoelectric reaction.

(Karan et al., 2000) used a new High-Pressure Microscope (HPM) which was developed for visual detection of organic solids precipitation during isobaric cooling, isothermal de-pressurization and isothermal-isobaric titration tests. The microscope was rated to 138 MPa (20,000 psi) and 200°C.

CHAPTER 3

METHODOLOGY

The main target of this project is to improve waxy crude flow characteristics to run the well at the optimum production rate, in order to accomplish this target a certain process was selected based on analyzing waxy crude properties.

The process depends on heat treatment of oil by heating it to a certain temperature using a down-hole heater.

Lab work performed on a sample from BARA field.

- In order to accomplish our target, an oil crude sample brought from Bara field and analyzed in Central Petroleum Laboratory (CPL) to determine wax content, wax apparent temperature (WAT) and carbon content using gas chromatography.
- Resulting data was processed by Multi-flash calculation program, in order to gain data file process-able by Olga software to design a well model for testing different operating conditions and to evaluate the wax parameters each time, then the single well model will be as a part of a field network to evaluate how the surface facility will be affected.
- This model will be tested for inline heating as a possible solution for the wax deposition problem.

3.1 Sample specifications:

Table (3.1): Sample Specification

Parameter	Bara Field
Oil gravity, deg API	**35.8**
Pour point, °C	**38-49**
Viscosity, cp @ reservoir conditions	**6.15**
Viscosity, cp @ Pb pressure	**5.60**
Viscosity, cp @ surface conditions	**23-53 @ 50 °c**
Bo @ Pb	**1.1360**
Rs, SCF/STB	**181.9**

3.2 Lab work:

All laboratory tests conducted in CPL and resulted in PVT data file.

Laboratory test devices:

3.2.1Gas chromatography:

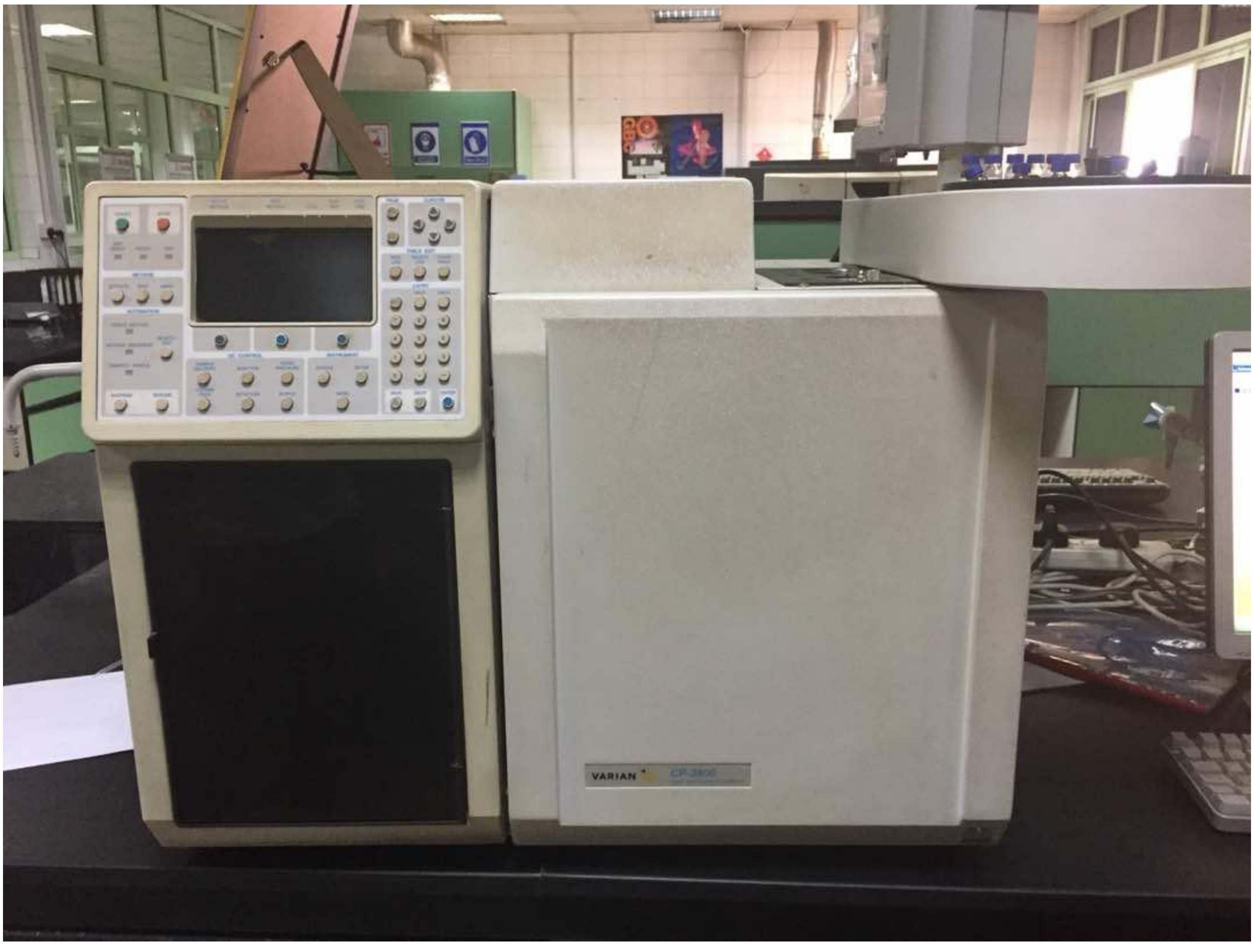


Figure (3.1): Gas chromatography device.

AIM:

To analyze the sample of unknown concentrations using Gas Chromatography.

APPARATUS:

1. Gas Chromatograph.
2. GC analyzer.
3. Normal syringes.
4. One micro syringe, Beakers, Sample bottles and Electronic weight.

CHEMICALS:

1. Methanol.
2. Isopropyl Alcohol.
3. Water.

THEORY:

A Gas Chromatograph is used to detect the components based on the selective affinity of components towards the adsorbent materials. The sample is introduced in the liquid/gas form with the help of GC syringe into the injection port, it gets vaporized at injection port then passes through column with the help of continuously flowing carrier stream (mobile phase), mainly H2 (for TCD), and gets separated/detected at the detection port with suitable temperature programming. We visualize this on computer in the form of peaks. Different chemical constituents of the sample travel through the column at different rates depending upon:

1. Physical properties
2. Chemical properties, and
3. Interaction with a specific column filling (stationary phase).

As the chemicals exit the end of the column, they are detected and identified electronically. The function of the stationary phase in the column is to separate different components, causing each one to exit the column at a different time (retention time). Other parameters that can be used to alter the order or time of retention are the carrier gas flow rate, and the temperature.

Physical Components involve inlet port, Adsorption column, detector port, flow controller (to control the flow of carrier gas), etc.

PROCEDURE:

The samples were prepared for calibration with various compositions. The amount of Isopropyl alcohol was kept equal to 2 grams in each sample.

Started the apparatus by switching on the hydrogen supply and set the parameters:

Oven temperature = 170 °C

TCD temperature = 150 °C

Injector temperature = 200 °C

Carrier Gas Pressure = 4 kg/cm2. START THE ISOTHERM.

Before injection of sample, waited till the base line of recorder became perfectly horizontal; which indicated that GC is stabilized or conditioned properly.

The sample was injected with a micro syringe at the injector port and started the run.

After all the peaks attained, the run stopped and the integration results were obtained. The retention time and area of peak of each of the constituents for each sample were noted.

The calibration curves were plotted and the response factor (slope of the calibration curve) was found out for each of the constituents with respect to IPA. The curves were used for analysis of unknown samples.

3.2.2 DSC:

Figure (3.2): DSC device.

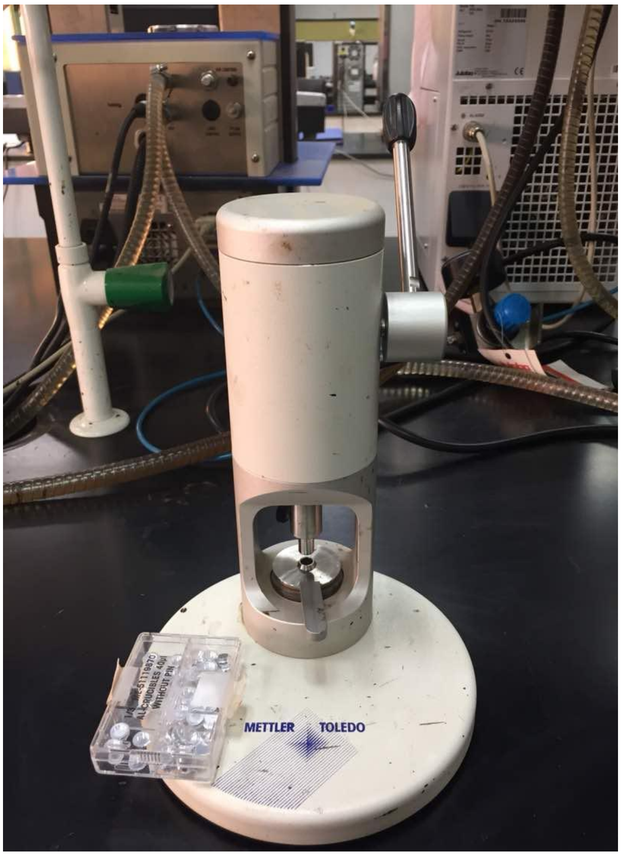


Figure (3.3): DSC device piston.

Aim:

The DSC measures heat flow associated with thermal transitions of a material such as glass transition, melting point, and crystallization temperature.

Sample Preparation Procedure:

1. The sample was thoroughly dried in the solid state to avoid damaging the equipment. The sample being tested was weighted (2-10 mg) in a Tzero hermetic aluminum pan. The sample was directly placed in the pans, transferring the sample from the weigh paper to the pan can lead to a loss in material.
2. The lid was placed on the pan with the indention facing down.
3. The covered pan was putted in the blue holder. Assuring that the lid was flushed with the top of the holder.
4. The holder was placed under the press. Again assuring that the lid is flushed with the top of the holder.
5. The handle was pulled down; this sealed the pan and lid.
6. Repeated with an empty pan to be used as a reference.

Note that both the pans and the press are located in room 2182 next to the weighing scale.

Procedure:

1. The sealed pan was placed in the sample tray. Slot number was noted.

2. The reference pan was placed in a reference slot. Slot number was noted.

3. The reference pan was an empty sealed pan.

4. Reference pan was kept so that multiple runs can be performed with it.

5. The power was turned on to the cooler. It was one eleven mode.

6. The software, TA Universal Analysis was opened on the desktop of the computer.

7. In the Control tab, we scrolled down to event and pressed ‘On’. This started the cooler. It may be necessary to press ‘Go to standby temp’ so

that the cell does not freeze. The temperature of the cell was shown in the status bar.

8. The nitrogen gas tank was turned on, which was held at 20 psi, and the sample purge flow was 50 ml min-1. If the sample purge flow (located in the signal Value box in the upper right corner) shows no flow, it may be necessary to open the smallest black knob on the gas tank.

9. On the program in the center panel we entered the data for the sample that we were running. We filled out all the information including: sample name, sample weight, sample slot number, reference slot number, and data storage location. We also selected an operating procedure.

10. On the second tab, Procedure, the parameters for the operating procedure were entered. Here we altered the method previously chosen in the first tab. We also loaded a standard procedure that we have saved.

- We Clicked on Test to adjust the procedure type.
- Clicked on Editor to set the temperatures, ramp rates, holding times, cycle names, etc. Note that the operating range of the equipment is -80 °C to 400 °C.
- Clicked Ok to accept the parameters.
- At this time we saved a procedure to be used in further experiments

11. On the far right panel, Experiment, we added runs. We did this by selecting the button. After a run has been added the appropriate data information was added. Runs can also be deleted. The order of the runs can also be adjusted on the panel by clicking and dragging the run to the appropriate location.

12. Once all of the sample information has been entered and the runs are in the appropriate order we began the program. There was an arrow next to the run which began first. We clicked at the top of the window to start. Note once you begin an experiment you cannot change the program.

13. When the program ended, the cooling system was automatically turned off. However, the nitrogen tank needed to be turned off after the test.

3.3 Data Analysis:

1. The results were tabled in excel sheets.
2. Graphs were drawn.
3. Resultant PVT data processed by OLGA software.

3.3.1 Multi-Flash:

Multi-flash is a powerful and versatile system for modeling physical properties and phase equilibrium. It can be used as a stand-alone program or in conjunction with other software.

Multi-flash can provide:

1. All the thermodynamic and transport properties needed for engineering studies.
2. Comprehensive fluid characterization and model tuning for petroleum fluids.

3. Flash calculations to determine the phases present at specified conditions and their type, composition and amounts.

4. Complete phase envelopes, showing phase boundaries and critical points.
5. Modeling solids formation, including pure solids, halide scales, hydrates, waxes and asphaltenes.
6. Multi-flash has a comprehensive set of configurable options, making it easy to specify all aspects of a study. Each configuration can be saved for future use with Multi-flash or other compatible applications.

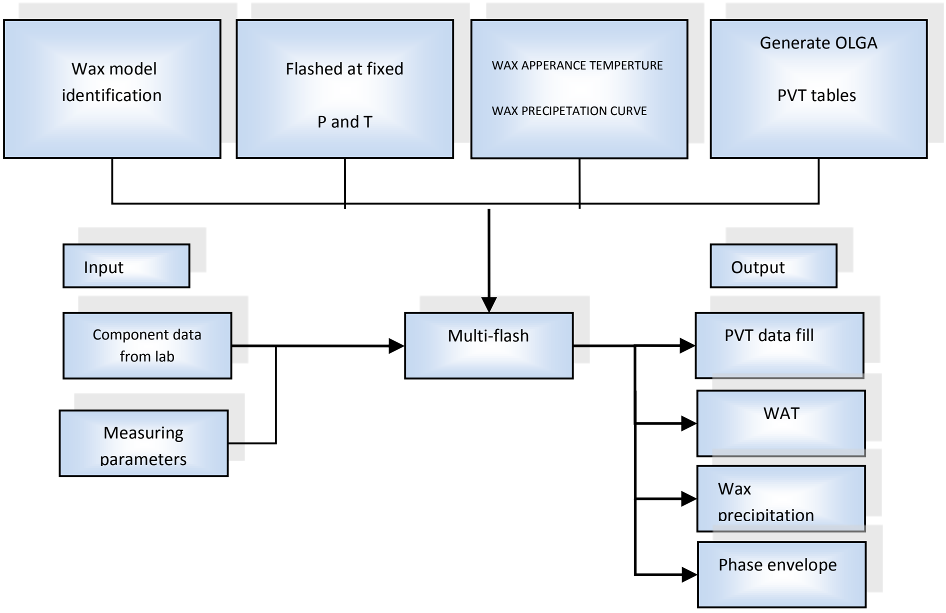


Figure (3.4): Multi-Flash procedure flow diagram.

3.3.2 Olga software:

Wax deposition can occur in two ways, either by diffusion of dissolved wax due to a temperature difference between fluid and wall, or by transfer of precipitated wax due to shear.

The wax deposition rate due to molecular diffusion may be described by:

$$G = D\rho_{\text{oil}}\ \frac{(mfr_{\text{wax,bulk}} - mfr_{\text{wax,wall}})}{L} \text{ ....} \textbf{Equation 1}$$

Where G [kg/ (cm^{2}s)] is the mass transfer rate of wax deposited and D [cm^2/s] is the molecular diffusion coefficient.

The deposition rate constant K* (=COEFSHEAR) determines the volume rate of precipitated wax deposited due to shear by the following formula:

$$vol_{\text{shear wax}} = \frac{K^*\ C\text{wall}\ \gamma A}{\rho\text{wax}}\ \left[\frac{m^3}{s}\right] \text{............................} \textbf{Equation 2}$$

Where C wall is the volume fraction of precipitated wax in the oil at the inner wall temperature, γ is the shear rate at the wall [1/s], A is the surface area available for deposition [m2] and ρ wax is the average density of the wax [kg/m3].

The equation for the rate of change in wax layer thickness is as follows:

$$\frac{d\sigma}{dt} = \frac{1}{1 + C_2 N_{SR}^{C_3}} \left(\frac{d\delta}{dt}\right)_{diff} \text{ ... ...} \textbf{Equation 3}$$

Where C_2 and C_3 are constants. Values: $C_2 = 0.055$ and $C_3 = 1.4$. $\left(\frac{d\delta}{dt}\right)_{diff}$ is the change rate due to diffusion, and porosity effects.

The constant $C_1 = 15.0$ is included in $\left(\frac{d\delta}{dt}\right)_{diff}$ for the MATZAIN model only. N_{SR} is a flow regime dependent Reynolds number.

$$N_{SR} = \frac{\rho_o v_o \delta}{\mu_{of}} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \textbf{Equation 4}$$

For single phase, stratified flow:

$$N_{SR} = \frac{\rho_m v_l \delta}{\mu_{of}} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \textbf{Equation 5}$$

For bubble and slug flow:

$$N_{SR} = \frac{\sqrt{\rho_m \rho_o} v_l \delta}{\mu_{of}} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \textbf{Equation 6}$$

For annular flow:

Where ρ_o is the oil density [kg/m^3], v_o is the oil velocity [m/s], δ is the wax layer thickness [m], μ_{of} is the oil viscosity kg/(m s), ρ_m is the average density of the gas-oil mixture and v_l is the liquid velocity.

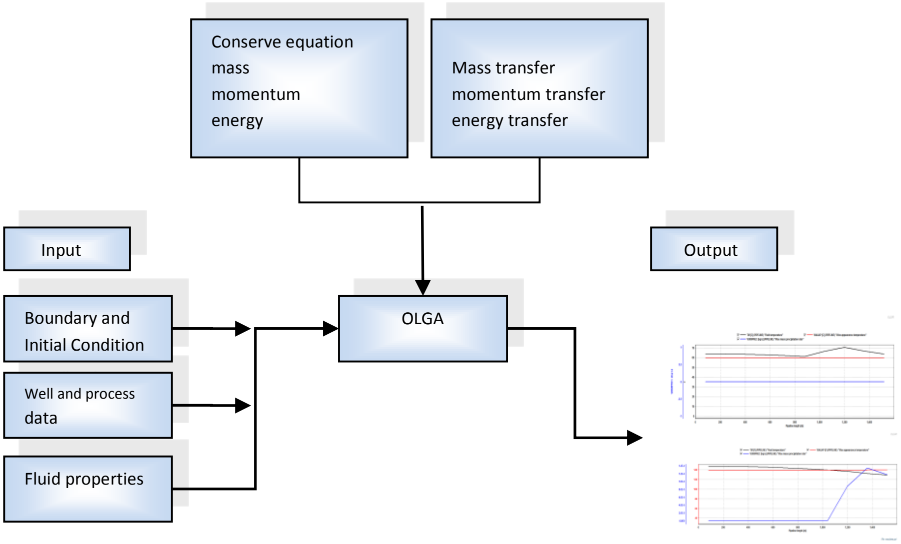


Figure (3.5): OLGA procedure flow diagram.

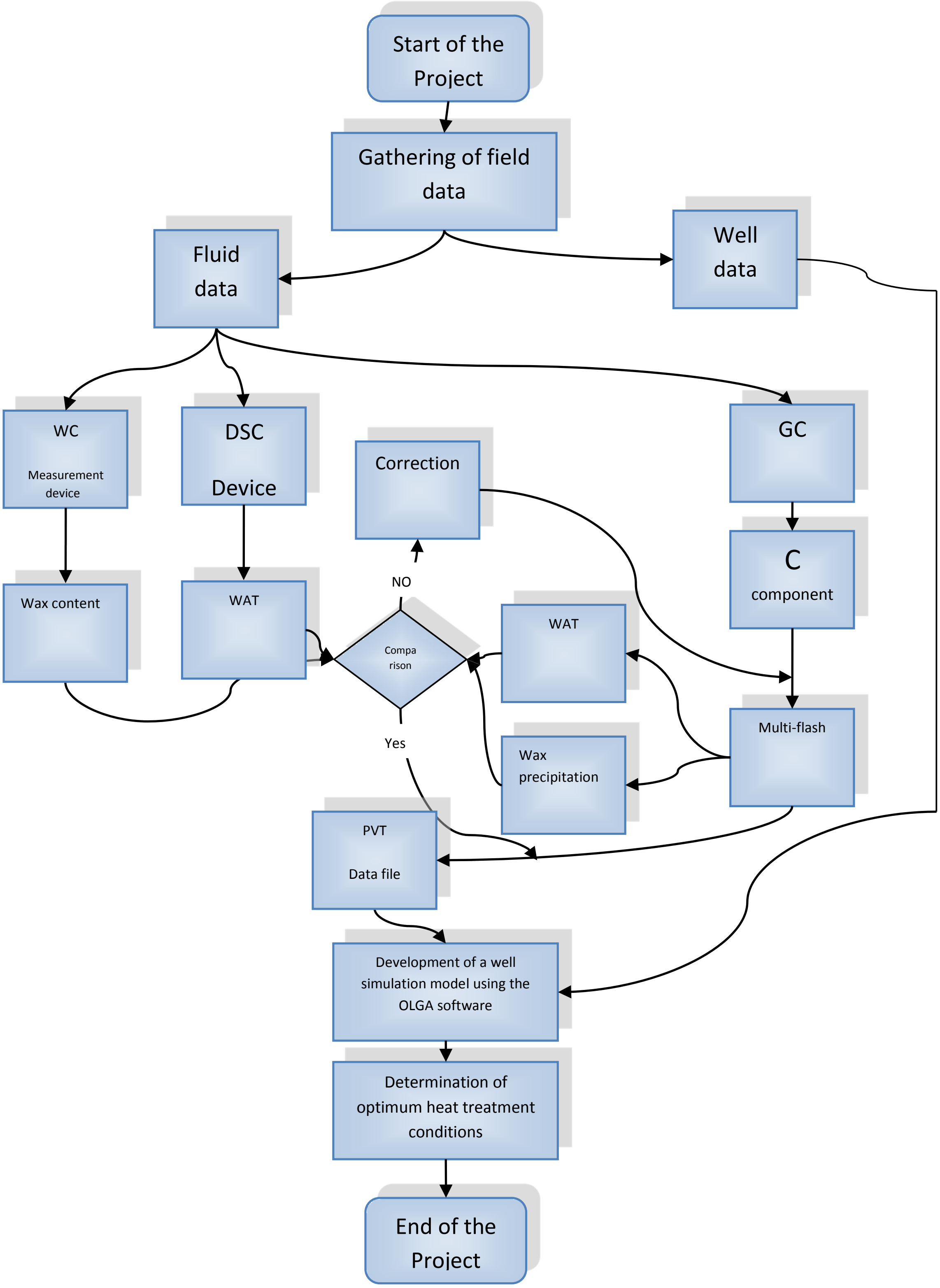


Figure (3.6): Methodology flow diagram.

CHAPTER 4
RESULTS AND DISCUSSION

4.1 Multi-Flash Results:

The following Figures plotted by processing the received data from CPL in Multi-Flash Software.

4.1.1Phase Envelope:

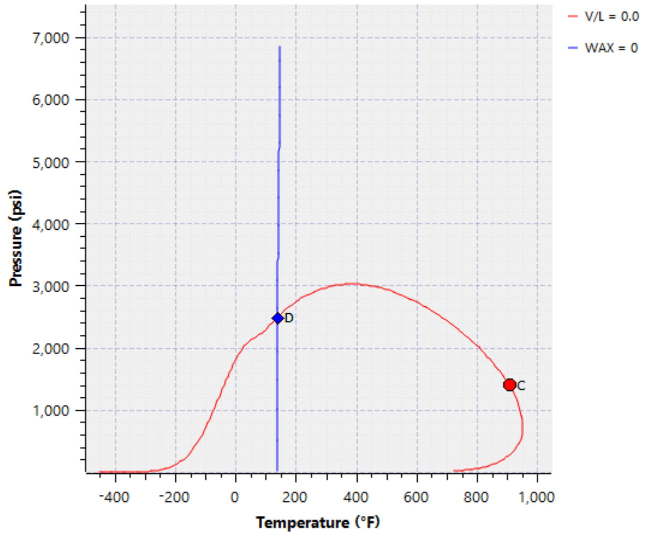


Figure (4.1): Phase Envelope Curve.

-The phase envelope presents the main characters of Bara waxy crude without any gas in the sample.

- Wax Appearance Temperature (WAT) is 139 °F.

- The figure was plotted by Multi-Flash Software using data in Appendix.

4.1.2Wax Precipitation Curve:

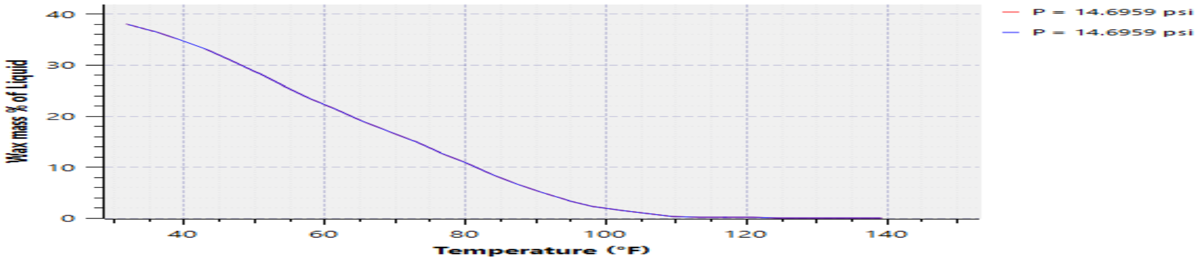


Figure (4.2): Wax Precipitation vs. Temperature Curve.

-It was found that Wax precipitation starts at 139°F, and wax mass increase as the temperature further decrease.

-The figure was plotted by Multi-Flash Software using data in Appendix.

4.2 OLGA SOFTWARE Results:

OLGA Software was used to model Bare Field wells performance before and after the heat treatment for one hour.

4.2.1First Scenario:

In the first scenario we implemented heat treatment to a single well (Bara-4), because it is the closest well to the Gathering Manifold, by installing a down-hole heater inside the well tubing (at 320 m, vertical depth).

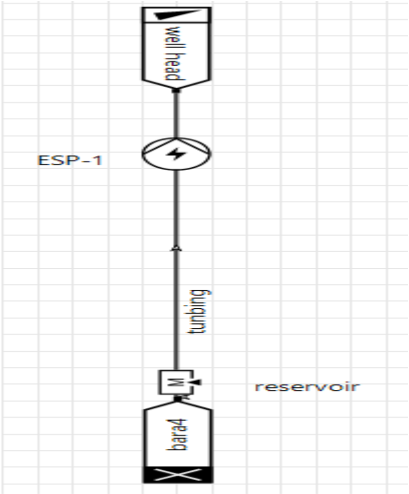


Figure (4.3): Single Well OLGA Model.

Figure (4.4): Bara-4 performance curve before Treatment.

-Fluid Temperature decline from 147°F to 109°F at the end of time.

-Wax mass precipitation rate vary with temperature and time.

-Thickness of wax layer deposition at wall start near 139°F (WAT), and increase as Fluid temperature decrease below (WAT).

-Note that for this scenario wax precipitation take place in well tubing and flow line.

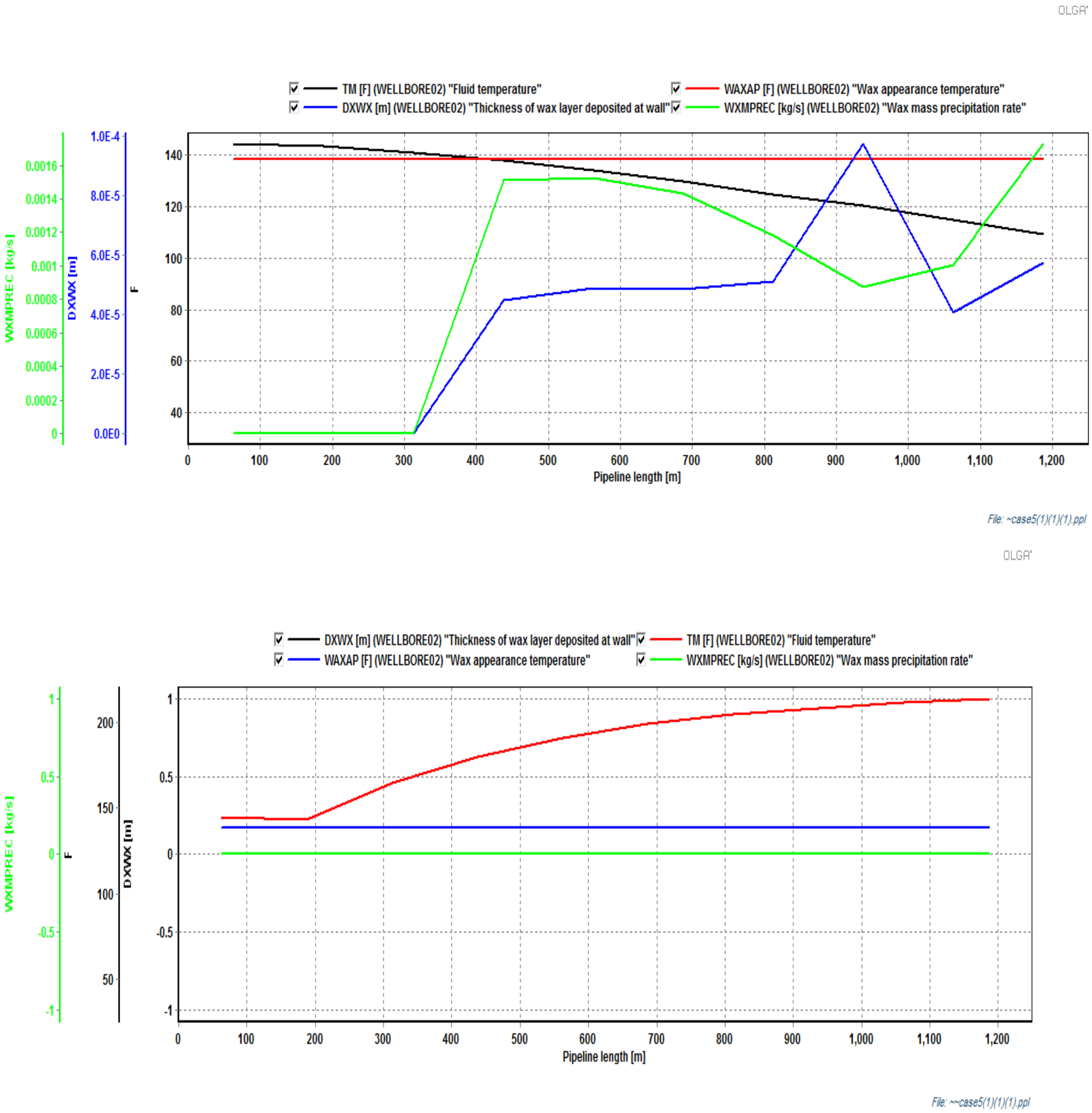


Figure (4.5): Bara-4 performance curve after Treatment.

-Fluid Temperature increase from 147°F to 220° F.

-Wax mass precipitation rate equals to zero.

-Thickness of wax layer deposited at the wall equals to zero.

-Note that for this scenario after the treatment there is no wax precipitation in well tubing or flow line.

4.2.2 Second scenario:

In the second scenario we implemented heat treatment in two wells (Bara-1and Bara-2), because they are the wells with longest pipelines, by installing a down-hole heater inside the two wells tubing (at 300 m and 332 m, vertical depth respectively).

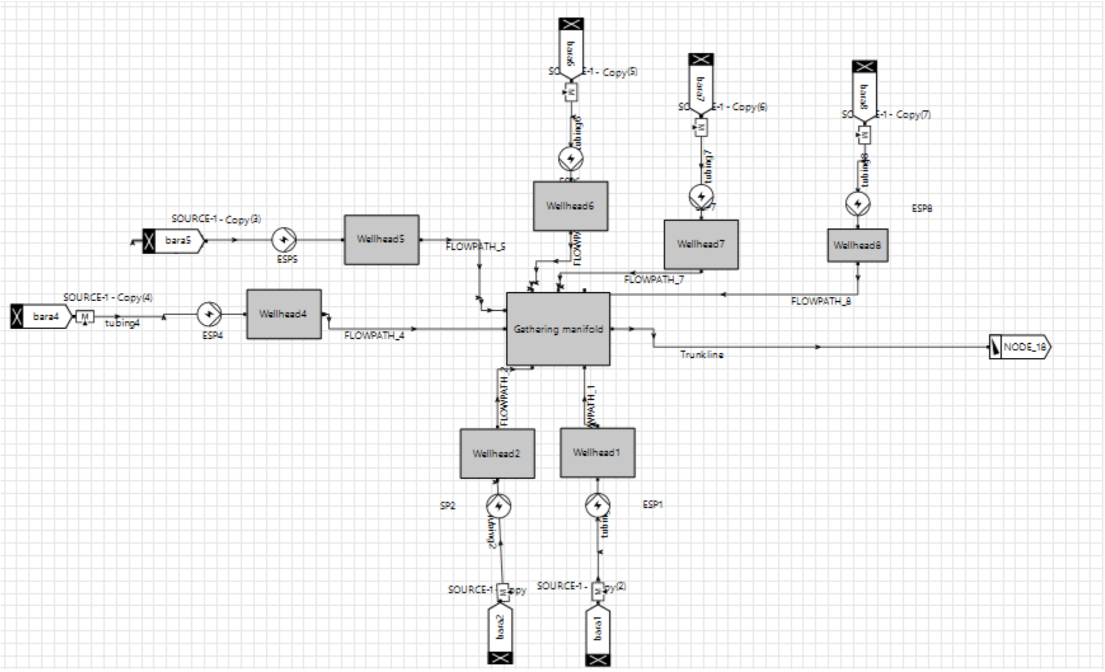


Figure (4.6): OLAGA Network Model for Bara Field.

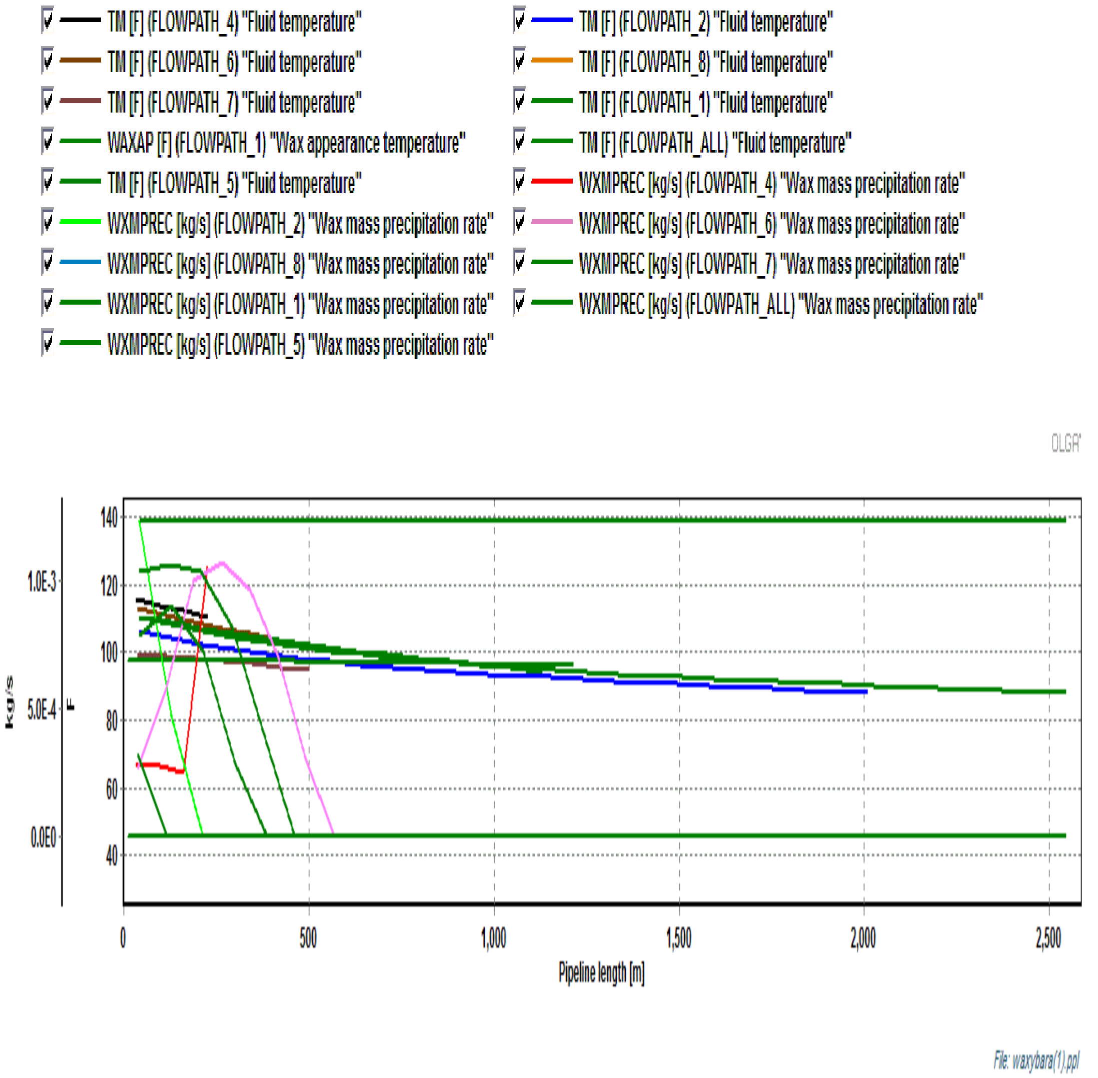


Figure (4.7): Bara Field wells performance curve before Treatment along Flow lines and Trunk line (FLOWPATH_ALL).

-Fluid Temperature decrease along the flow line for each well and trunk line.

-Note that Wax deposition is highly investigated in all Well tubing, all Flow lines and in the Trunk line.

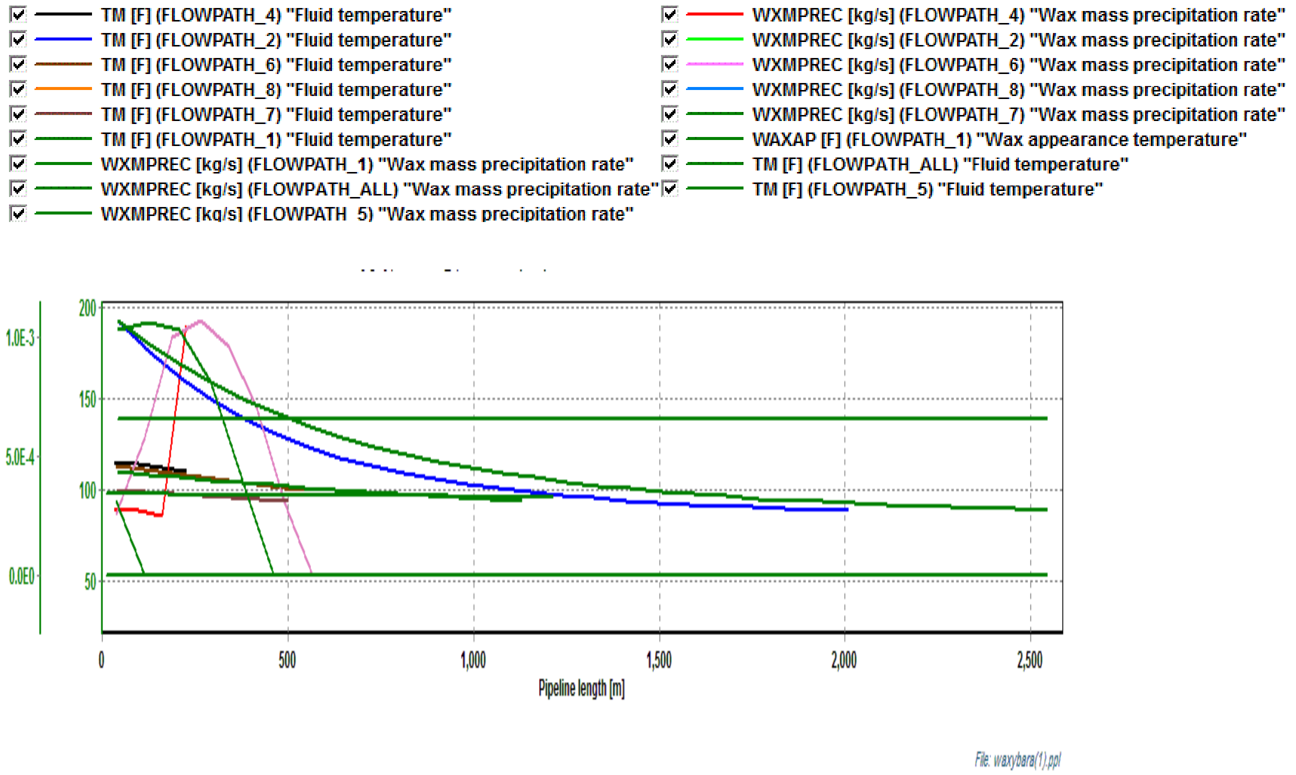


Figure (4.8): Bara Field wells performance curve after treating Bara-1 and Bara-2, along Flow lines and Trunk line (FLOWPATH_ALL).

-Fluid Temperature of Tubing1 and tubing2 increase from 147°F to 220°F. Other wells temperatures decrease along the well tubing and flow lines.

-Note that Wax deposition is highly investigated in all Wells tubing (except tubing1 and tubing2); all Flow lines and in the Trunk line.

- Wax precipitation takes place in FLOWPATH_1 and FLOWPATH_2 despite of heat treatment as a direct result of long flow path distance.

4.2.3 Third scenario:

In this scenario we implemented heat treatment in three wells (Bara-1, Bara-2 and Bara-4), because (Bara-1 and Bara-2) are the wells with longest pipelines, and (Bara-4) is the closest well to the Gathering Manifold. Heat treatment implemented by installing a down-hole heater inside the three wells tubing (at 300 m, 332 m, and 320, vertical depth respectively).

-Figure for this scenario same as Figure (4.5) mentioned above.

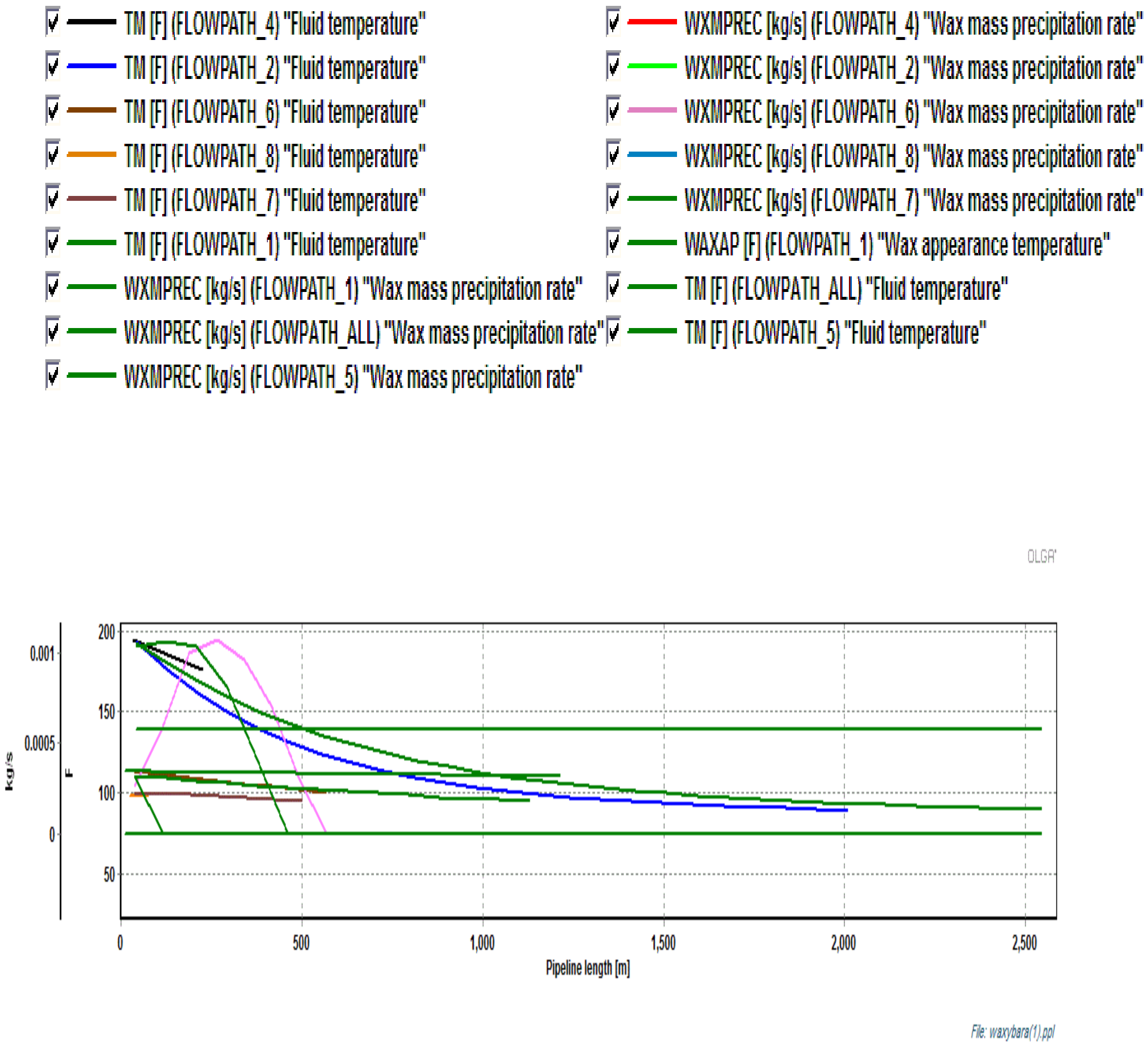


Figure (4.9): Bara Field wells performance curve after Treatment along Flow lines and Trunk line (FLOWPATH_ALL).

-Fluid Temperature of Tubing1, tubing2 and tubing4 increase from 147°F to 220°F. Other wells temperatures decrease along the well tubing and flow line.

-Note that Wax deposition is investigated in all Wells tubing (except tubing1, tubing2 and tubing 4), all Flow lines (except FLOWPATH_4).

-No wax precipitation along the Trunk Line.

- Wax precipitation takes place in FLOWPATH_1 and FLOWPATH_2 despite of heat treatment as a direct result of long flow path distance.

4.3Economic Evaluation of Proposed Solution:

In this economical study we found that using down-hole heater for heat treatment improves productivity quantity and quality which therefore improve field revenue by reducing operation and maintenance costs.

The two cases present the deferent between using the down hole heater for a single well and its NPV and not using it and run the well with 4 work overs per year 600000 USD.

The heater price is estimated to be 250,000 USD.

Table (4.1): Net Present Value for Heat treatment and Work over for a single well.

Years	Net flow rate bb/d	Net flow rate bb/year	price of oil $/y	P.V (Heat treatment)	P.V(Work over)
0			-250000	-250000	-600000
1	500	178000	5340000	4,604,545.50	4,254,546
2	450	164250	4927500	8,676,859.50	8,326,859.50
3	400	142400	4272000	11,886,476.33	11,536,476.40
4	350	124600	3738000	14,439,580.63	14,089,580.70
5	300	106800	3204000	16,429,012.54	16,079,012.60
			N.P.V	55786474.5	53686474.7

-Oil barrel price= 30$ (minimum oil price).

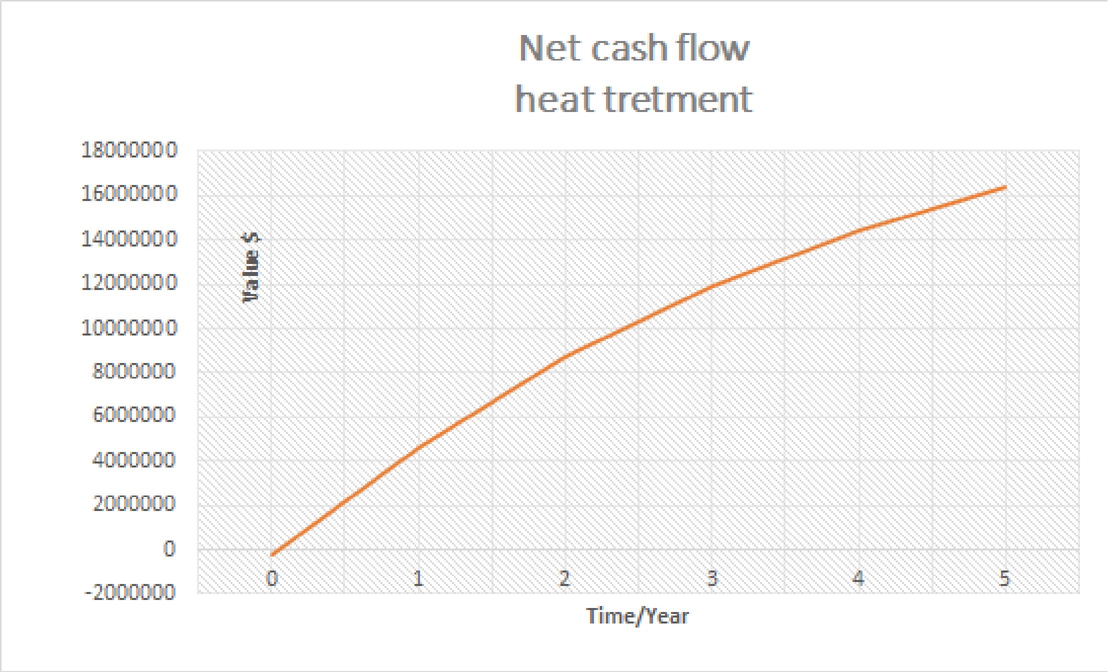


Figure (4.10): Net cash flow diagram for heat treatment.

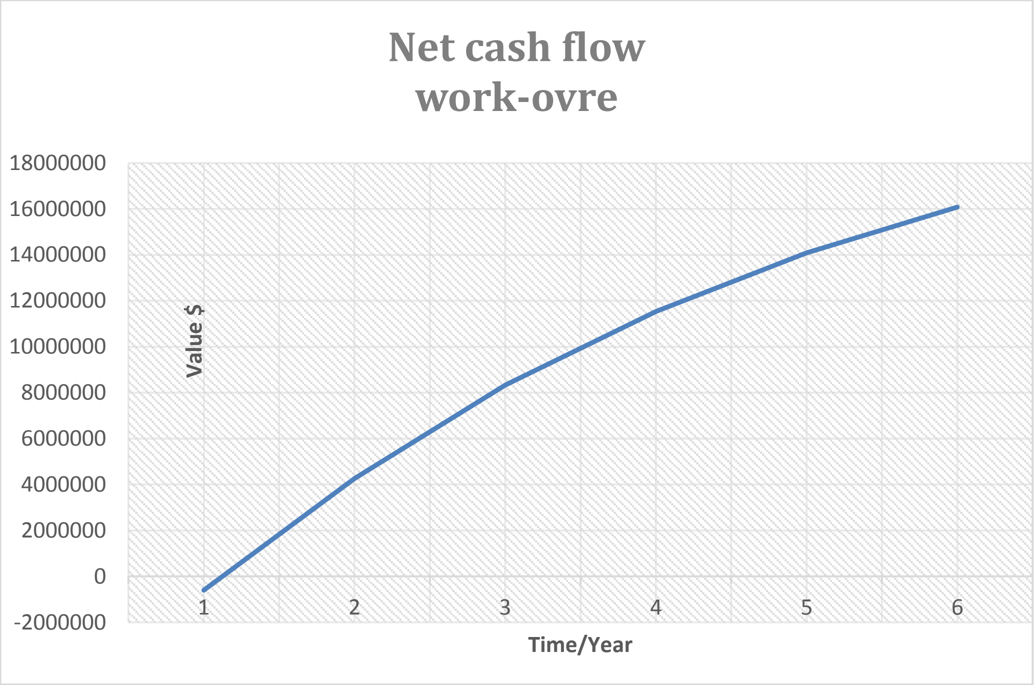


Figure (4.11): Net Cash Flow for Work Over.

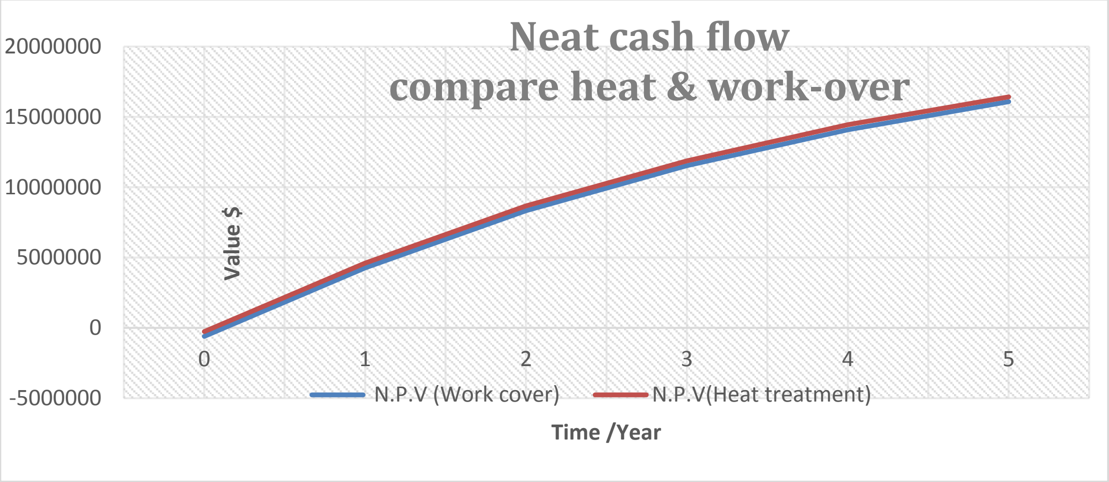


Figure (4.12): Comparison between Heat treatment and Work-Over Net Cash Flow.

-Work-Over cost in 2017 was 150,000$ in Bara-1 for one year (Four work-over operations implemented in that year).

-Estimated heat treatment cost by a down-hole heater is 250,000$.

-After compression between heat treatment method and work-over operations, we found that heat treatment implementation reduce operation costs by 400,000$ per year.

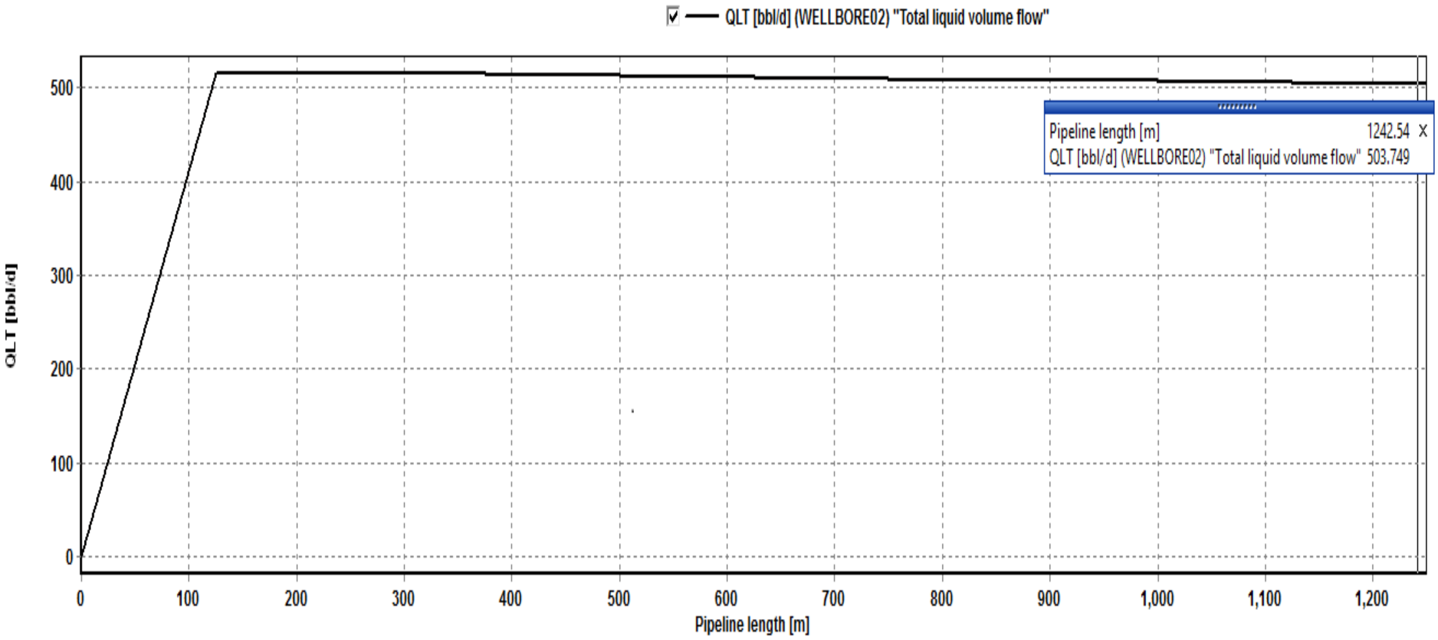


Figure (4.13): W curve before heat treatment.

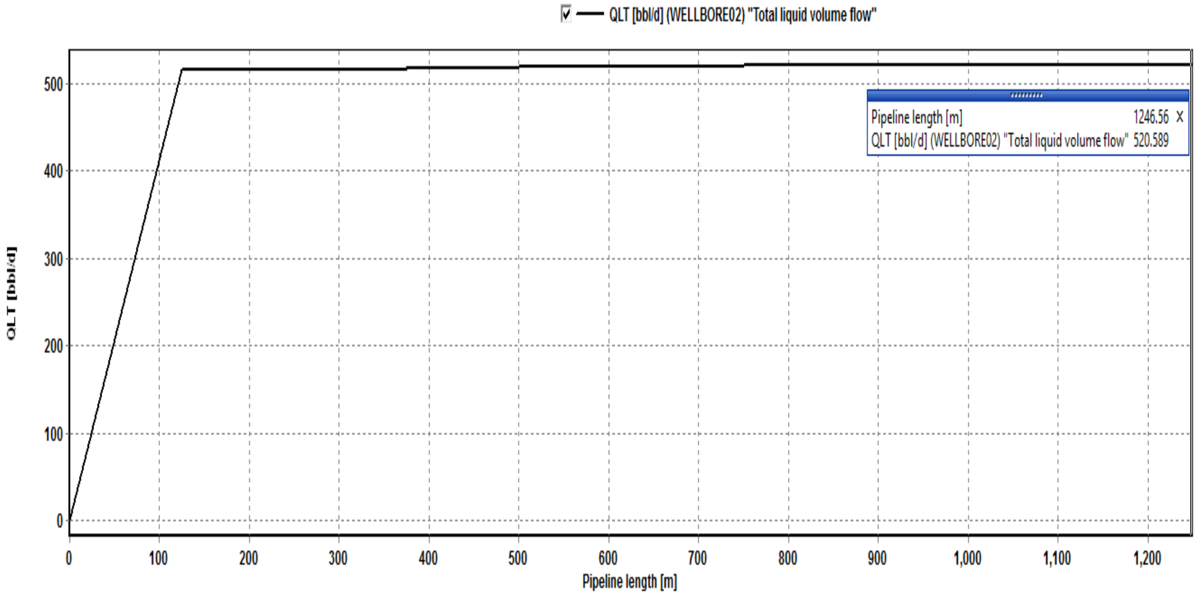


Figure (4.14): Well flow rate curve after heat treatment.

-The above two figures represent a comparison between well flow rate before and after heat treatment.

-Flow rate before treatment was 503 bbl\day. atment well flows After trerated increase to 520 bbl\day

CHAPTER 5

CONCLUSION AND RECOMMENDATIONS

5.1Conclusion:

A waxy crude sample was brought from Bara oil filed for the purpose of analysis and study. Laboratory tests conducted on the sample in Central Petroleum Laboratories to determine the wax appearance temperature wax content and sample components.

Sample components successfully obtained by analyzing it in Gas chromatography device, wax appearance temperature test successfully conducted on the sample using DSC device but the results were not obtained due to a technical failure in CPL software. Wax content test was not available in CPL due to malfunction in testing device.

Resultant PVT Data from CPL was processed by Multi-Flash software, Phase envelope and wax precipitation vs. temperature curves was plotted. A simulation model for Bara field was built using OLGA software, in which different heating scenarios were implemented.

In the first scenario heat treatment was implemented to Bara-4, as a result model showed no wax precipitation in well tubing or flow line. Second scenario embodied heat treatment for Bara-1 and Bara-2; as a result the simulation model showed no wax precipitation in the tubing of those two wells, wax precipitation took place in the flow lines of both wells due to long flow-lines effect, wax was also investigated in trunk line. In third scenario three down-hole heaters were installed into three wells (Bara-1, Bara-2 and Bara-4); model showed no wax precipitation in trunk line, wax was investigated in all flow lines except of FLOWBATH-4, and all wells tubing except of tubing 1, 2 and 4.

Economic study for the evaluation of the effectiveness of down-hole heater treatment method was conducted.

Heat treatment method found to be very effective technically and economically, the well recovers all heating and operating costs in less than a year, results showed reduction in work-over and maintenance costs after using the heaters. Also results showed slight improvement in production after using the heater

5.2 Recommendations:

After studying Bara filed waxy crude effect on production performance, and after modeling the field and studying various heating scenarios we recommend:

- Carry on a comprehensive flow assurance study to test all the factors that affect the production performance in the future.
- Implement the third scenario to the actual field by installing down-hole heater in Bara-1, Bara-2 and Bara-4 operating at 220°F.
- Keep updating the created OLGA model to test the production scenarios with time.

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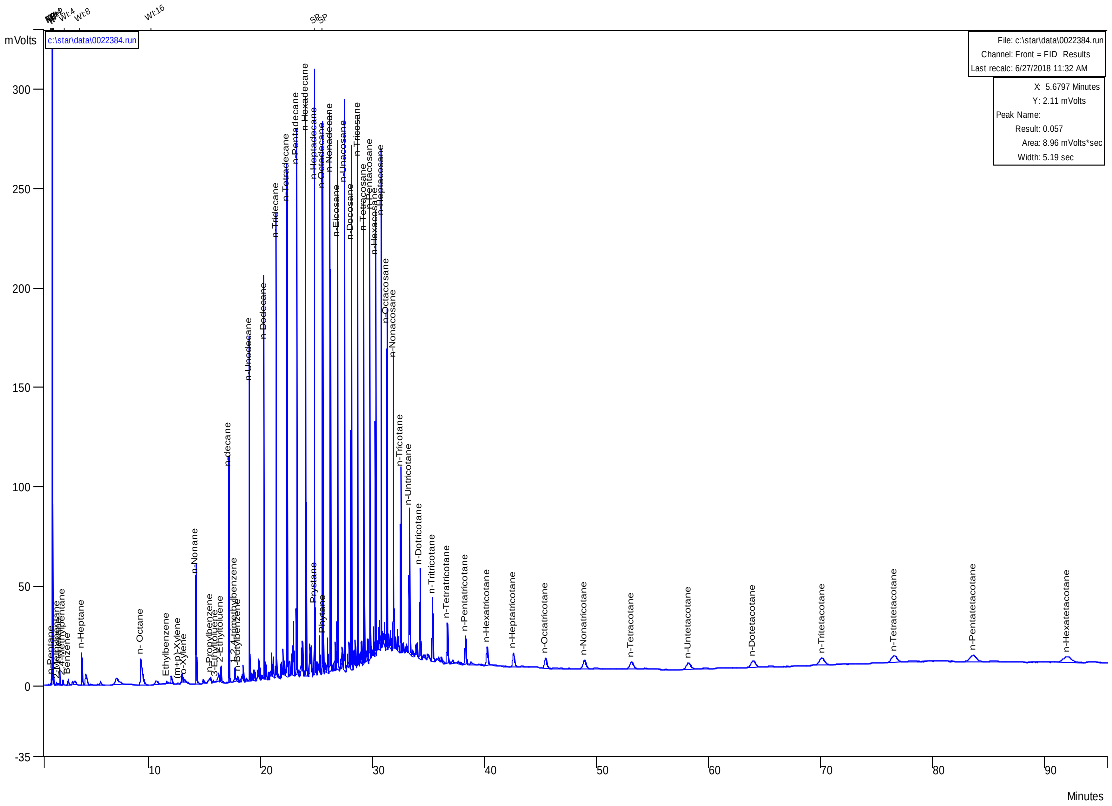
Appendix:

PVT data obtained from CPL and used for field simulation by OLGA software.



										C7+			
Component	Formula	MW	Liquid Density,gm/cc	mass%	mole fr	mole%	mole fr	Av.mwt	av dens	mole%	mole fr	Av.mwt	av dens
n-Pentane	n-C5	72.150	0.63050	0.013216	0.000183	0.038322	0.000383	0.02765	0.000242				
Hexanes	C6	86.180	0.63340	11.34138	0.131601	27.53265	0.275326	23.72763	0.174392				
Benzene		78.110	0.88200	0.097374	0.001247	0.26081	0.002608	0.203719	0.0023				
Heptanes	C7	100.200	0.68740	0.679881	0.006785	1.41956	0.014196	1.422399	0.009758	1.41956	0.019891	1.993056	0.013673
Octanes	C8	114.230	0.70610	1.98328	0.017362	3.632389	0.036324	4.149278	0.025648	3.632389	0.050897	5.813942	0.035938
Ethyle-Benzene		106.170	0.87350	0.041138	0.000387	0.081064	0.000811	0.086066	0.000708	0.081064	0.001136	0.120595	0.000992
Meta/Para-Xylene		106.170	0.86710	0.03255	0.000307	0.064141	0.000641	0.068099	0.000556	0.064141	0.000899	0.09542	0.000779
Ortho-Xylene		106.170	0.88400	0.060448	0.000569	0.119116	0.001191	0.126465	0.001053	0.119116	0.001669	0.177202	0.001475
Nonanes	C9	128.260	0.72120	2.204946	0.017191	3.596626	0.035966	4.613032	0.025939	3.596626	0.050396	6.463751	0.036345
n-Propylbenzene		120.190	0.87970	0.027801	0.000231	0.048393	0.000484	0.058163	0.000426	0.048393	0.000678	0.081498	0.000597
3-Ethyltoluene		120.190	0.87970	0.013312	0.000111	0.023172	0.000232	0.02785	0.000204	0.023172	0.000325	0.039024	0.000286
2-Ethyltoluene		120.190	0.87970	0.22096	0.001838	0.384622	0.003846	0.462277	0.003384	0.384622	0.005389	0.647739	0.004741
Decanes	C10	142.285	0.73340	2.351836	0.016529	3.458091	0.034581	4.920345	0.025362	3.458091	0.048455	6.894356	0.035537
1,2,4-trimethylbenzene		142.285	0.73340	0.279677	0.001966	0.411231	0.004112	0.58512	0.003016				
n-Butylbenzene		134.000	0.86970	0.084574	0.000631	0.132045	0.00132	0.17694	0.001148	0.132045	0.00185	0.247927	0.001609
Undecanes	C11	147.000	0.78900	2.376171	0.016164	3.381807	0.033818	4.971257	0.026682	3.381807	0.047386	6.965693	0.037387
Dodecanes	C12	161.000	0.80000	2.75689	0.017124	3.582466	0.035825	5.76777	0.02866	3.582466	0.050197	8.081763	0.040158
Tridecanes	C13	175.000	0.81100	3.22727	0.018442	3.858209	0.038582	6.751866	0.03129	3.858209	0.054061	9.460671	0.043843
Tetradecanes	C14	190.000	0.82200	3.024307	0.015917	3.330127	0.033301	6.327241	0.027374	3.330127	0.046662	8.86569	0.038356
Pentadecanes	C15	206.000	0.83200	3.887377	0.018871	3.948007	0.03948	8.132895	0.032847	3.948007	0.055319	11.39576	0.046026
Hexadecanes	C16	222.000	0.83900	3.493781	0.015738	3.292541	0.032925	7.309441	0.027624	3.292541	0.046135	10.24194	0.038707
Heptadecanes	C17	237.000	0.84700	3.043235	0.012841	2.686431	0.026864	6.366841	0.022754	2.686431	0.037642	8.921177	0.031883
Octadecanes	C18	251.000	0.85200	3.503693	0.013959	2.92039	0.029204	7.330178	0.024882	2.92039	0.04092	10.271	0.034864
Nondecanes	C19	263.000	0.85700	3.993819	0.015186	3.177029	0.03177	8.355585	0.027227	3.177029	0.044516	11.70779	0.03815
Eicosanes	C20	275.000	0.86200	3.448865	0.012541	2.623808	0.026238	7.215471	0.022617	2.623808	0.036765	10.11027	0.031691
Eeneicosanes	C21	291.000	0.86700	3.461584	0.011895	2.488688	0.024887	7.242081	0.021577	2.488688	0.034871	10.14756	0.030233
Docosanes	C22	305.000	0.87200	3.581164	0.011742	2.456478	0.024565	7.492258	0.02142	2.456478	0.03442	10.4981	0.030014
Tricosanes	C23	318.000	0.87700	3.596074	0.011308	2.365865	0.023659	7.523451	0.020749	2.365865	0.03315	10.54181	0.029073
Tetracosanes	C24	331.000	0.88100	3.27825	0.009904	2.072061	0.020721	6.858523	0.018255	2.072061	0.029034	9.610118	0.025579
Pentcosanes	C25	345.000	0.88500	3.534886	0.010246	2.143605	0.021436	7.395438	0.018971	2.143605	0.030036	10.36244	0.026582
Hexacosanes	C26	359.000	0.88900	2.931113	0.008165	1.708152	0.017082	6.132267	0.015185	1.708152	0.023935	8.592493	0.021278
Heptacosanes	C27	374.000	0.89300	3.514811	0.009398	1.96616	0.019662	7.353439	0.017558	1.96616	0.02755	10.30359	0.024602
Octacosanes	C28	388.000	0.89600	2.844478	0.007331	1.533767	0.015338	5.951015	0.013743	1.533767	0.021491	8.338525	0.019256
Nonacosanes	C29	402.000	0.89900	2.945846	0.007328	1.533107	0.015331	6.16309	0.013783	1.533107	0.021482	8.635683	0.019312
Triacosanes	C30	416.000	0.90200	2.416865	0.00581	1.215479	0.012155	5.056394	0.010964	1.215479	0.017031	7.084987	0.015362
Eentriacosanes	C31	430.000	0.90600	2.119778	0.00493	1.03136	0.010314	4.434849	0.009344	1.03136	0.014451	6.214083	0.013093
Dotriacosanes	C32	444.000	0.90900	1.769992	0.003986	0.834021	0.00834	3.703052	0.007581	0.834021	0.011686	5.188693	0.010623
Tritriacosanes	C33	458.000	0.91200	1.297147	0.002832	0.592533	0.005925	2.713799	0.005404	0.592533	0.008303	3.802558	0.007572
Tetratriacosanes	C34	472.000	0.91400	1.042118	0.002208	0.461916	0.004619	2.180245	0.004222	0.461916	0.006472	3.054946	0.005916
Pentatriacosanes	C35	486.000	0.91700	0.966193	0.001988	0.415926	0.004159	2.021401	0.003814	0.415926	0.005828	2.832374	0.005344
n-Hexatricotane	C36	500.000	0.9190	0.767062	0.001534	0.320959	0.00321	1.604793	0.00295	0.320959	0.004497	2.248625	0.004133
n-Heptatricotane	C37	514.000	0.92100	0.633926	0.001233	0.258026	0.00258	1.326255	0.002376	0.258026	0.003615	1.85834	0.00333
n-Octatricotane	C38	528.000	0.92300	0.593542	0.001124	0.235183	0.002352	1.241767	0.002171	0.235183	0.003295	1.739955	0.003042
n-Nonatricotane	C39	542.000	0.92500	0.648292	0.001196	0.250242	0.002502	1.356311	0.002315	0.250242	0.003506	1.900454	0.003243
n-Tetracotane	C40	556.000	0.92700	0.665102	0.001196	0.250266	0.002503	1.391479	0.00232	0.250266	0.003507	1.949732	0.003251
n-Untetacotane	C41	570.000	0.92900	0.685745	0.001203	0.251696	0.002517	1.434667	0.002338	0.251696	0.003527	2.010246	0.003276
n-Dotetacotane	C42	584.0000	0.93100	0.697792	0.001195	0.249978	0.0025	1.459871	0.002327	0.249978	0.003503	2.045562	0.003261
n-Tritetacotane	C43	584.0000	0.93100	0.855056	0.001464	0.306316	0.003063	1.788888	0.002852	0.306316	0.004292	2.506578	0.003996
n-Tetratetacotane	C44	584.0000	0.93100	0.877082	0.001502	0.314207	0.003142	1.834969	0.002925	0.314207	0.004403	2.571147	0.004099
n-Pentatetacotane	C45	584.0000	0.93100	0.981743	0.001681	0.351701	0.003517	2.053933	0.003274	0.351701	0.004928	2.877958	0.004588
n-Hexatetacotane	C46	584.0000	0.93100	1.0866	0.001861	0.389265	0.003893	2.273308	0.003624				
				99.98002	0.477982	100	1	209.1711	0.778135	71.36772	1	255.5128	0.833095

C7+	
Av density	0.8331
AV M.wt	255.5128
Mole%	71.368

Bulk	
Av density	0.7781
AV M.wt	209.1711
Mole%	100.000