Paper 60C

Subsea Oil System Design and Operation to Manage Wax, Asphaltenes, and Hydrates

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Abstract

Design and operating guidelines for subsea oil systems have been developed to ensure the control of hydrates, wax, asphaltenes, and other solids, which may impede flow. System designs are primarily driven by the need to avoid the formation of a hydrate plug in any portion of the system. Remediation of hydrate plugs may require system shut-in for weeks or even months. Design and operation guidelines for wax management are also well developed. Asphaltenes present a new challenge to subsea system design and operation. A number of subsea projects now being designed are likely to experience some asphaltene deposition in flowlines and wellbores. Strategies have been developed to manage asphaltenes, but have not yet been tested in the field. The design and operating guidelines for control of solids in subsea oil systems are a product of the flow assurance process.

Introduction

Oil production from the deep water Gulf of Mexico is playing an increasingly important role in Shell Oil Co.'s portfolio. To date, the bulk of deep water oil production has been from wells located on the tension leg platforms. The existing deep water infrastructure of tension leg platforms and export pipelines facilitates the development of many smaller fields as subsea developments. Existing subsea development includes a number of both gas and oil fields. There is a clear trend toward more complex subsea developments that incorporate features such as multiple projects tied back to one host, longer offset distances between the subsea wells and the host, and a growing number of oil wells vs. gas wells. As system designs continue to expand beyond the boundaries of proven technology and intervention costs have continued to rise, system reliability has become a much greater concern. Consequently, a much greater effort must be spent on developing reliable guidelines for design and operation of systems to prevent the formation of hydrates, wax, and asphaltenes in the system.

The formation of solids must be avoided in order in insure continued production at desired levels for project profitability. This is the objective of an engineering analysis process referred to as flow assurance or production flow management. The techniques for control of hydrates and wax have been under development for a number of years, supported by an intensive research effort and by field experience, both within Shell and industry-wide. Asphaltenes are a relatively new problem for subsea oil production in the Gulf of Mexico and control techniques are still in the early stages of development. There is essentially no field experience for the control of asphaltenes in subsea systems. Finally, a number of new technologies, including electrically heated flowlines and low dosage hydrate inhibitors, promise to yield new opportunities for improved subsea oil system designs.

Subsea Oil System Design Principles

Operation of subsea systems presents many challenges that are not encountered onshore or for offshore platform wells. The deep waters of the Gulf of Mexico are quite cold, 38-42^{o}F as shown in Fig. 1, which makes control of hydrates and wax deposition difficult.

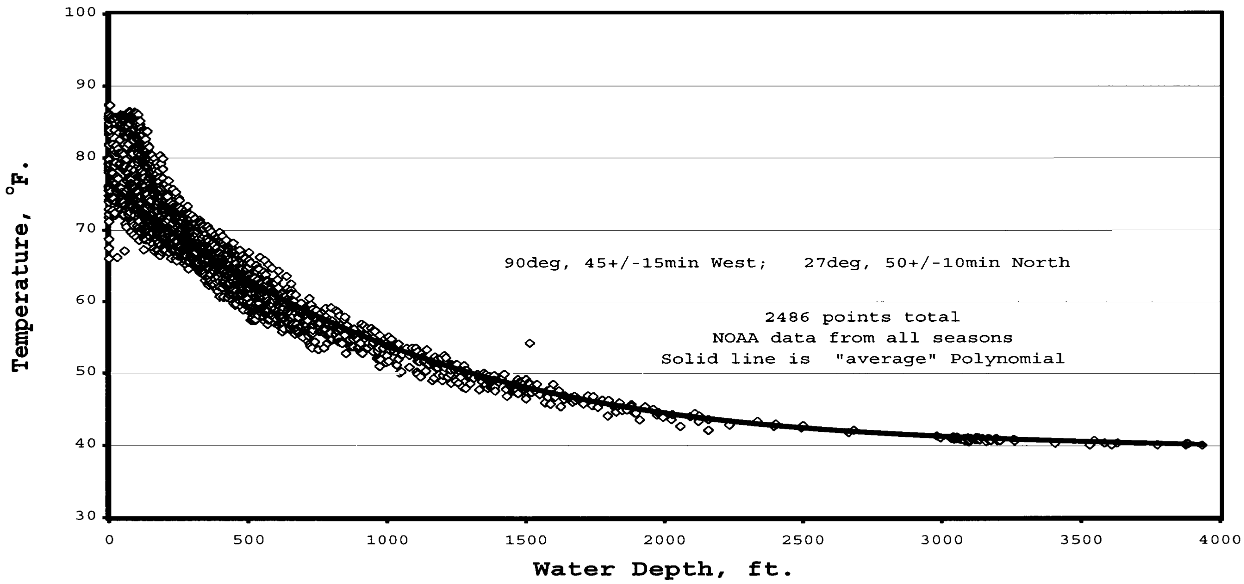


Fig. 1 – Gulf of Mexico Seawater Temperature vs. Depth

Subsea system pressures are high, which further stabilizes hydrates. From a systems standpoint, the subsea environment is similar to outer space. Both environments are remote and hostile to mankind and mechanical devices. Equipment failures, if they occur, are difficult and expensive to repair. As an example, subsea well intervention activities, such as running coiled tubing, require specialized vessels, which are not only expensive but also may require that operators wait weeks or months until they are available. All the while, revenue is being lost, as the ordinarily highly productive subsea wells are shut-in waiting for a problem to be fixed.

The Shell design and operating guidelines for subsea oil systems are founded on the following basic principles:

- Do not allow the system to enter a pressure/temperature region where hydrates are stable
- Prevent wax deposition in the wellbore
- Remove wax from the flowline by pigging
- Design to inhibit and remove asphaltenes

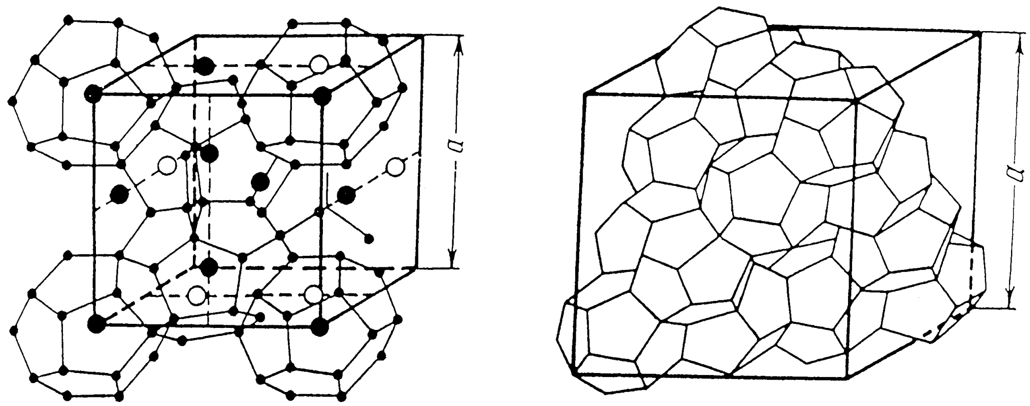
These principles were adopted due to the need to prevent costly downtime and intervention activities. However, they impose substantial restrictions on subsea design. Hydrate prevention requires that the entire system, including portions of the wellbore, must be insulated to increase the time that the Operations staff members have to stabilize the system by methanol injection and pressure reduction. Hydrate control also greatly complicates system operation, for example, by requiring the injection of large volumes of methanol injection during startup and shutdown. Dual flowlines are required to facilitate pigging operations for removal of wax. As a result, there is an ongoing effort to improve designs and operating strategies by developing a greater understanding of the nature of the solids that must be controlled.

The Nature and Control of Solids

Subsea system designs and operating guidelines are intended to control solids. As a result, it is essential to develop an understanding of the solids. The solids of primary concern are hydrates, wax, and asphaltenes. The nature and guidelines for control of these solids are discussed below. The design of control strategies depends heavily upon input from the flow assurance process, as is discussed.

Hydrates

Natural gas hydrates are a solid form of water, composed of a lattice of water molecules stabilized by "guest" gas molecules occupying key positions in the crystal structure. There are several hydrate crystal structures (Fig. 2), with Type 2 being the most commonly encountered in oil and gas production systems. In general, the hydrates of importance to oil and gas systems are stabilized by light hydrocarbons, such as methane, ethane, and propane. Hydrates look like water ice, but unlike ice they can form at temperatures well above 32^{o}F in pressurized systems. And, unlike ice, hydrates contain sufficient hydrocarbon to burn.



TYPE 1, a = 12 Angstroms TYPE2,a = 17.3 Angstroms

Fig. 2 – Hydrate Crystal Structures Found in Oil and Gas Production Systems

The thermodynamic stability of hydrates, with respect to temperature and pressure, may be represented by a hydrate curve like the one shown in Fig. 3.

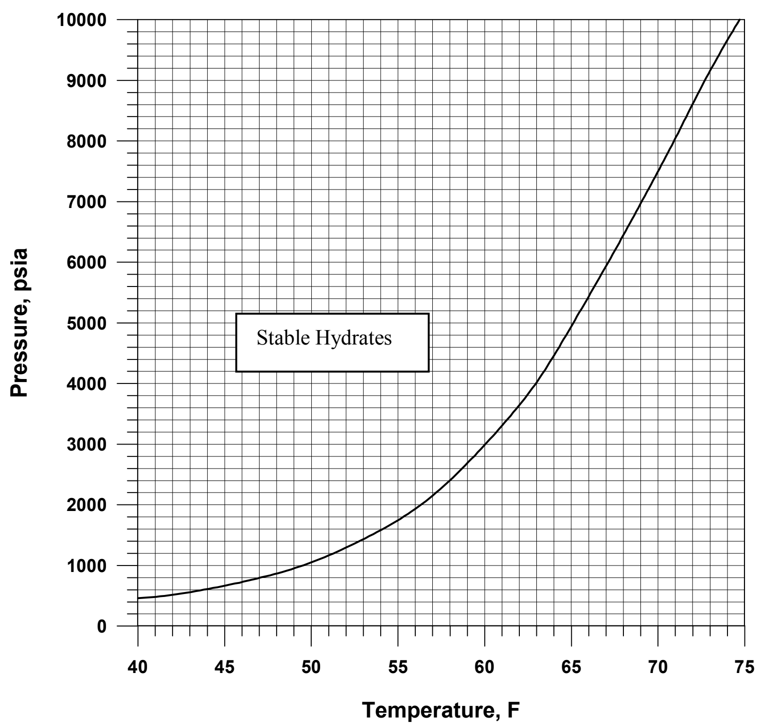


Fig. 3 – Example of a Hydrate Curve for a Black Oil

As may clearly be seen, the stability of hydrates increases with increasing pressure and decreasing temperature. A curve of this type may be generated by a series of laboratory experiments, or more commonly, is predicted using thermodynamic software based the composition of the hydrocarbon and aqueous phases in the system. The hydrate curve represents the thermodynamic boundary between hydrate stability and dissociation. A crystal of hydrate will dissociate into liquid water, releasing the guest hydrocarbon molecules, when brought to the pressure and temperature along the curve. However, if a hydrocarbon system containing water (note: water does not have to present in the liquid form for hydrates to form) is brought to the temperature and pressure condition on the equilibrium curve, hydrates may not form for hours, days, or even at all. Instead, a certain amount of "subcooling" is required for hydrate formation to occur at rates sufficient to have a practical impact on the system. How much subcooling is required to be a concern? Opinions vary widely, but in general, Shell flow assurance guidelines assume that the subcooling is on the order of 5°F to reach, by definition, the "hydrate formation temperature".

The thermodynamic understanding of hydrates indicates the conditions of temperature, pressure, and composition that a hydrate will form. However, it does not indicate where or when a hydrate plug will form in the system. The mechanics of plug formation are not yet well understood, although it is known that certain geometries, such as flow restrictions at chokes, are prone to hydrate plug formation.

Control of hydrates relies upon keeping the system conditions out of the region in which hydrates are stable. During production, temperatures are usually well above the hydrate formation temperature, even with the high system pressures seen at the wellhead (on the order of 5000-10000 psia). However, during a system shut-in, even well insulated systems will fall to ambient temperatures within one day, which in the deep Gulf of Mexico is a chilly 38-40°F. Gas systems typically produce only small quantities of water, which allows them to be continuously treated with methanol or glycol to prevent hydrate formation. These inhibitors prevent the formation of hydrates by shifting the hydrate stability curve to lower temperatures for a given temperature. Increasing salt content in the produced brine also shifts the hydrate curve to lower temperatures in much the same way (Fig. 4).

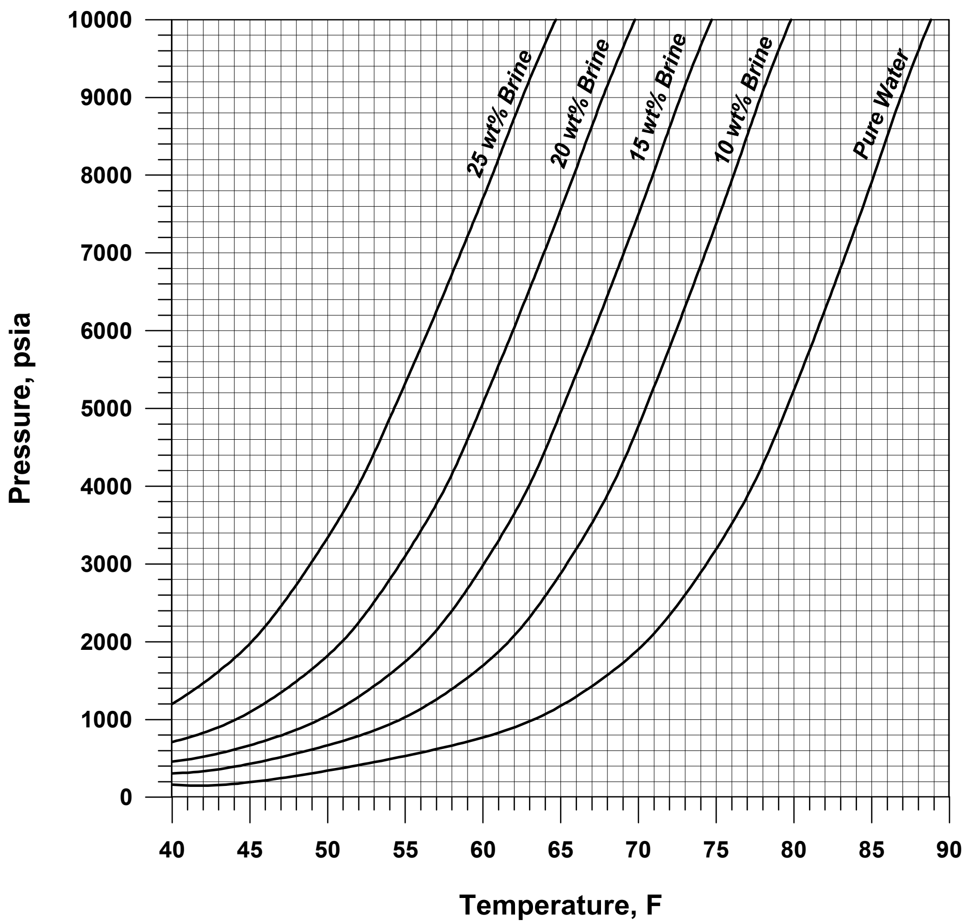


Fig. 4 – Effect of Salt Content on Hydrate Curve

Oil systems, on the other hand, typically will produce too much water to economically treat with methanol. As a result, the system design must incorporate insulation of almost all components and complex operating strategies are developed to control hydrate formation during transient activities such as system startup and shut-in.

Guidelines for hydrate control utilized in subsea oil system design and operations are:

- Ensure the subsea system operates outside the hydrate stability regime during steady state conditions
- During transient operations, such as start up, inject methanol at the subsea tree to prevent the formation of hydrates in the choke and downstream
- Warm up the wellbore quickly to avoid the formation of hydrate plug. Utilize insulated tubing where required
- Provide adequate system cooldown so that there is time to stabilize the system with a combination of methanol dosing and depressurization

Steady state temperature calculations from the flow assurance process are used to indicate the flow rates and insulation systems that are needed to keep the system above the hydrate formation temperature during production. Transient temperature calculations are used to examine the startup and shut-in conditions. It is essential that each part of the system has adequate cooldown time to permit it to be stabilized against hydrate formation. The wellbore, tree, well jumpers, and manifolds are stabilized by displacing produced fluids with methanol. Part of the flow assurance process is the computation of the rate at which methanol can be delivered to these components via the umbilical system and the total time for treatment. Typical treatment times are on the order to 1-2 hours for each well bore, tree, and jumper combination. It is not necessary to treat the entire well bore, only the section for which temperatures fall below the hydrate dissociation temperature after the tubing has completely cooled. The current strategy in well bore design is to locate the subsurface safety valve at the point at which formation temperatures are high enough to guarantee that hydrates will not form. Methanol is "bullheaded" into the well bore to push the produced fluids below this point and the subsurface safety valve is then closed. The flowline is typically stabilized by depressurization (blow down). This process may take up to 5-7 hours for longer flow lines. Rates of depressurization must be controlled to avoid excessive liquid carryover to the host facilities.

The subsea system is also at risk from hydrate formation during the warm-up period. At the worst, the entire system has cooled to ambient temperature, which is about 40°F in the deep Gulf of Mexico. Before start up, it is necessary to remove all water that has not been stabilized with methanol from the system. This is done to prevent hydrate formation that would occur if this water came into contact with the gas-saturated fluids from the wells, which are initially cold as well. Water removal is accomplished by using pigs to push dry or hot oil around the system. Then the produced fluids must be treated with methanol to prevent hydrates until all portions of the system, from the wellbore to the riser, are warmed above the hydrate dissociation temperature. Only then can methanol injection cease. The flow assurance calculations are key to understanding how long methanol injection must be continued and to determining the potential benefits from warming the flowline by heating the oil used for water displacement.

Hydrate control requires constant attention during operation. Hydrates plugs can form within a few hours and then take days, weeks, or even months to remediate. The most commonly used method to remediate a hydrate plug is to depressurize the system to a pressure below the point at which hydrates are stable at the ambient (seawater) temperature. This pressure is on the order of 400 psi. The depressurization of the flowlines, known as blowdown, creates many operational headaches. Not only does the host facility have to handle large quantities of gas and liquid exiting the flowlines; they must also be prepared to patiently wait until the plug dissociates. Since multiple plugs are common, the process can be extremely long and much revenue is lost. Some subsea system configurations, such as flowlines with a number of low spots, can be extremely difficult to blow down. The best policy is to operate, if at all possible, in a manner to prevent hydrates from forming in the first place.

<u>Wax</u>

Wax deposits in oil production flowlines are comprised primarily of normal paraffins of C20+ in length. The deposition of paraffins is controlled by temperature, that is, as the temperature in a system drops, paraffins that are in the liquid phase begin to come out of solution as solids. Wax deposits form at the wall of the pipe where the temperature gradient is at its highest. The deposit is complex in nature, comprised of a range of normal paraffins of different lengths, some branched paraffins, and incorporated oil. The build-up of wax over time can eventually reach a point that flow rates are restricted.

In addition to wax deposition, the formation of sufficient wax solids can cause oil to "gel" at sufficiently low temperature during a system shut-in. This occurs when approximately 4% of the wax in the oil is in the solid form. Once this occurs, it is difficult, or even impossible to restart flow in the system due to the very high viscosity of the gelled oil.

The wax properties of oils are typically characterized by cloud point and pour point measurements. The cloud point essentially measures the point at which wax first visibly comes out of solution as oil is cooled at atmospheric pressure. The pour point is the temperature at which the oil ceases to flow when the vessel it is in is inverted for 5 seconds (Method ASTM D97). These measurements give a general understanding of the temperatures at which wax deposition will become a problem and when crude oil gelling will become a problem. Shell has greatly expanded upon these empirical tests however in order to greatly improve predictive capabilities. The key to wax deposition prediction is a precise analysis of the concentration of the normal paraffins in the oil sample. This is carried out using the high temperature gas chromatography technique. An example of an HTGC analysis is shown in Fig. 5.

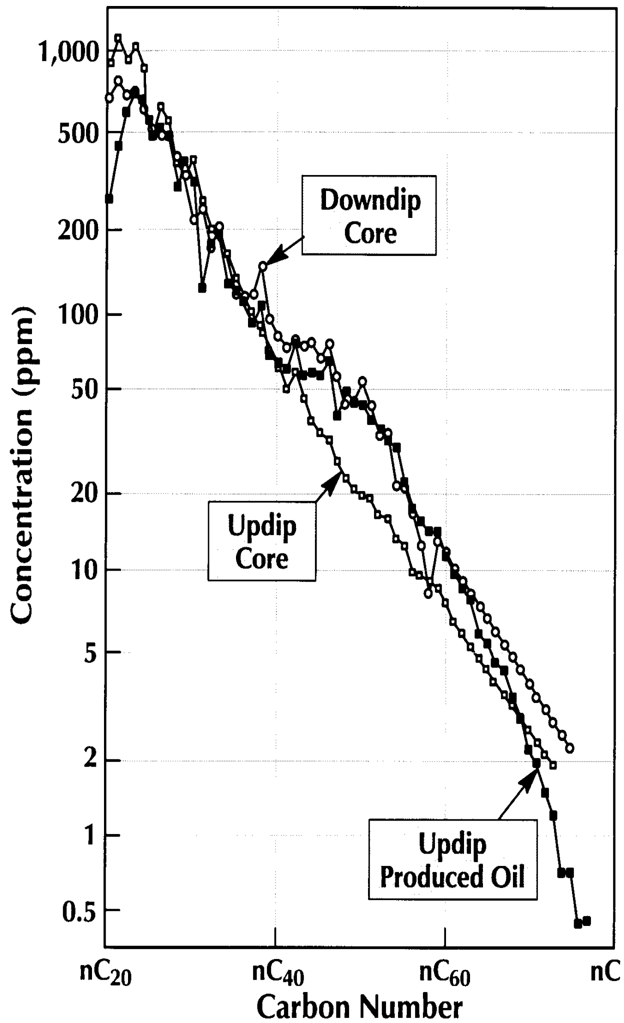


Fig. 5 – Example of an HTGC Analysis Curve for a Black Oil

The paraffin composition data is then used to construct a thermodynamic model for prediction of wax deposition rates in the flowline as well as for predicting the cloud point and pour point dependence on pressure. The thermodynamic model is combined with the steady state thermal-hydraulic model of the flowline, developed by the flow assurance process, to predict where wax deposits will occur, how fast wax will accumulate, and the frequency at which the line must be pigged.

In contrast to hydrates, wax deposits relatively slowly and, in addition; deposition can be controlled by controlling system temperature. Cloud points for deepwater GOM crude oils cover a broad range, but cloud points on the order of 80-100°F are not uncommon. If the system is operated at a temperature approximately 10-20°F above the cloud point, wax will not deposit. A "rule of thumb" which has been frequently used is CP + 15°F (Fig. 6). Although this can usually be achieved for the wellbore and subsea tree, it is often not possible to operate at this high of a temperature in the flowline.

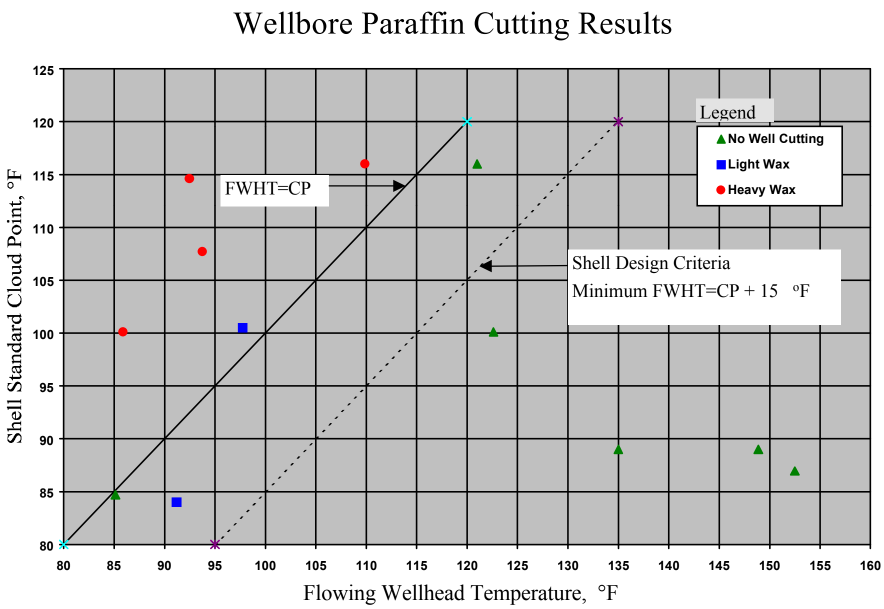


Fig. 6 – Basis for "Rule of Thumb" for Wax Deposition Prevention

During late life, the reservoir temperature may have dropped to the point that host arrival temperatures are substantially below the cloud point leading to significant deposition. The rate of deposition can be reduced by flowline insulation and by the injection of wax dispersant chemicals, which can reduce deposition rates by up to five times by the addition of wax dispersant chemicals. However, it must be emphasized that these chemicals do not completely stop the deposition of wax. Therefore, it is necessary to physically remove the wax by pigging the flowline. To facilitate pigging, a dual flowline system with a design that permits pigging must be built. Pigging must be carried out frequently to avoid the buildup of large quantities of wax. If the wax deposit becomes too thick, there will be insufficient pressure to push the pig through the line as the wax accumulates in front of it. Pigging also requires that the subsea oil system be shutdown, stabilized by methanol injection and blow down, and finally, restarted after the pigging has been completed. This entire process may result in the loss of 1-3 days of production. The deposition models created based on the fluids analysis work and the flow assurance calculations are the key to establishing pigging intervals that are neither too frequent to be uneconomical or too infrequent to run the risk of sticking the pig in the flowline.

On the other hand, wax can only be removed from wellbores by a mechanical process such as coiled tubing, which is prohibitively expensive for subsea wells. As a result, it is important to control the temperature of the tubing, tree, and other components that cannot be pigged (such as jumpers) above the point at which wax deposition occurs. The flowing wellhead temperatures and pressures from flow assurance are used to check that the tubing and tree remain above the point at which wax deposition occurs. The need to prevent wax deposition in the wellbore, tree, and jumpers may set a minimum late life production rate, based on the temperature predictions from flow assurance.

High pour point oils present a potentially serious problem somewhat akin to the rapid formation of hydrates. Wax formation during shut-in can be sufficient to make line restart difficult, or even impossible. Even though temperatures may be well above the pour point during steady state operation, it is impossible to know when a shut-in may occur. As a result, it is essential that high pour point oils be continuously treated with a pour point depressant.

Wax control guidelines can be summarized as follows:

- Operate the well at sufficiently high production rates to avoid deposition in the wellbore and tree
- Remove wax from flowlines by pigging and pig frequently enough to ensure that the pig does not stick
- Utilize insulation and chemicals to reduce pigging frequency
- Identify and treat high pour point oils continuously

Asphaltenes

Asphaltenes are a class of compounds in crude oil that are defined as being that component of crude oil that is not soluble in n-heptane. Aromatic solvents such as toluene, on the other hand, are good solvents for asphaltenes. From an organic chemistry standpoint, they are large molecules comprised of polyaromatic and heterocyclic aromatic rings, with side branching. Asphaltenes originate with the complex molecules found in living plants and animals, which have only been partially broken down by the action of temperature and pressure over geologic time. Asphaltenes carry the bulk of the inorganic component of crude oil, including sulfur and nitrogen, and metals such as nickel and vanadium. They are also the component of oil that gives it its black color. A conceptual view of what an asphaltene molecule may look like is shown in Fig. 7.

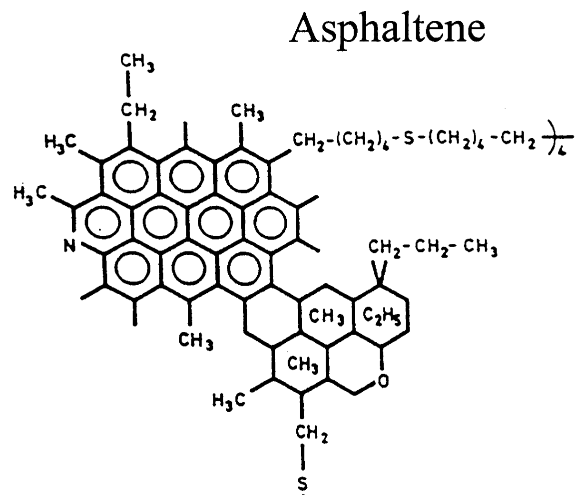


Fig. 7 – Structure of an Asphaltene Molecule

All oils contain a certain amount of asphaltene. Asphaltenes only become a problem during production when they are unstable. Asphaltene stability is a function of the ratio of asphaltenes to stabilizing factors in the crude such as aromatics and resins. The factor having the biggest impact on asphaltene stability is pressure. Asphaltenes stability is at a minimum near the crude oil bubble point, as shown in Fig. 8.

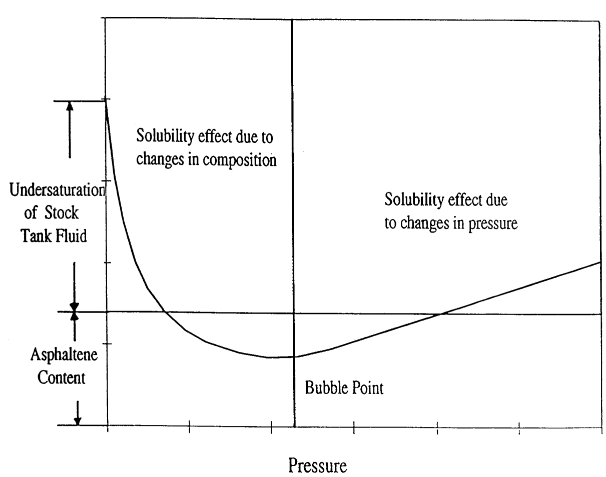


Fig. 8 – Asphaltene Stability vs. Pressure

Asphaltenes may also be destablized by the addition of acid or certain types of completion fluids and by the high temperatures seen in the crude oil refining process. Asphaltene solids are typically black coal like or tar-like substances. They tend to be sticky, making them difficult to remove from surfaces. In addition, asphaltenes solids are electrically charged and tend to stabilize water-oil emulsions, complicating oil separation and water treatment at the host.

Very few problems have been seen with asphaltenes in Shell Gulf of Mexico production up to this point. It is felt that asphaltenes will be a problem for a relatively small fraction of deepwater projects. Current research efforts have focused on improving screening tests for asphaltene and finding how screening test results relate to field problems. Three screening tools are used. The first, a test known as the P-value test, involves the titration of the crude oil with cetane, the normal paraffin with a carbon chain length of 16. Additions of normal paraffins tend to destabilize asphaltenes in the crude oil. The stability of the oil increases with the amount of cetane that can be added before visible amounts of asphaltenes come out of solution. The SARA screen test examines the stability of asphaltenes by determining the concentration of the primary components of crude oil, saturated hydrocarbons, aromatics, resins, and asphaltenes. The ratio of saturates to aromatics and asphaltenes to resins are computed and used to determine the stability of the oil. The PVT screen utilizes two values available from a PVT analysis, the in-situ density and the degree of undersaturation (difference between reservoir pressure and bubble point) to make a general assessment of asphaltene stability. In general, increasing undersaturation and decreasing in-situ density are associated with decreasing asphaltene stability.

There are currently no standard design and operating guidelines for the control of asphaltenes in subsea systems. Some experience has been gained from asphaltene control programs used for onshore wells. Approaches have varied from allowing the wellbore to completely plug with asphaltenes, then drilling the material out to utilizing periodic solvent washes with coiled tubing to remove material. Relatively few operators have chosen to control asphaltene deposition with dispersants, possibly due to the treating expense and variable results.

In subsea wells, direct intervention with coiled tubing is very expensive and is not a viable means of control. Therefore, the strategy that has been proposed for control of subsea wells utilizes a combination of techniques to minimize deposition, with direct intervention and removal as a method of last resort. This strategy is as follows:

- Inject an asphaltene dispersant continuously into the wellbore (injection must be at the packer to be effective)
- Install equipment to facilitate periodic injection of an aromatic solvent into the wellbore for a solvent soak
- Be financially and logistically prepared to intervene with coiled tubing in the well bore to remove deposits
- Control deposition in the flowline with periodic pigging with solvents

This strategy requires the installation of additional umbilical lines for delivery of asphaltene dispersant and large volumes of solvent, as well as a downhole line for injection of dispersant immediately above the packer. These hardware requirements add considerable project cost.

Currently, there are no models for asphaltene deposition as a function of system pressure or other parameters. The flow assurance modeling is helpful in understanding the pressure profile in the subsea system, especially where the bubble point is reached. Since the bubble point is typically the pressure where asphaltenes are least stable, deposition problems would be expected to be the worst at this location.

The Flow Assurance Process

As stated in the Introduction, flow assurance is an engineering analysis process that yields design and operating guidelines for the control of hydrates, wax, and asphaltenes in subsea systems. Depending on the characteristics of the fluids to be produced, the flow assurance process may also considered corrosion, scale deposition, and erosion. The needs of each project are unique and require the development of project specific strategies. However, over the last several years, the flow assurance process itself has become standardized and documented. In this way, the thorough analysis of each project is insured.

The flow assurance process consists of the following steps:

- Obtain fluid samples and perform fluids analysis for PVT properties. Run wax and asphaltene screening tests.
- Develop hydrate stability curves and methanol dosing requirements (requires PVT data and salinity estimates)
- Construct a thermal-hydraulic model of the well(s) and generate flowing wellhead temperature and pressures for a range of production conditions. Also run wellbore temperature transient studies
- Model riser cool down as a function of riser base temperature. Utilize information to determine required system insulation properties.
- Construct steady state flowline models and use to compute riser base temperatures and boarding temperatures and pressures

- Perform transient analysis on blow down and warm up processes
- Utilize flow assurance results together with solids control strategies as input into system design and operation procedures

Additional detail on each step is given below. Some of these steps may occur in parallel, and there is considerable "looping back" to earlier steps when new information, such as a refined fluids analysis or a revised reservoir performance curve, becomes available.

Fluid Sampling and Analysis

The validity of the flow assurance process is dependent upon careful analysis of samples from the wellbore. In the absence of samples, an analogous crude, for example, one from a nearby well in production may be used. This always entails significant risk because fluid properties may vary widely, even within the same reservoir. The key analyses needed for input into the flow assurance are PVT properties (GOR, phase composition, bubble point, etc.), wax properties (cloud point, pour point, high temperature gas chromatography), and asphaltene stability screening. More information on wax property measurements and asphaltene screening was given in The Nature and Control of Solids section above. Knowledge of the anticipated produced water salinity is also important, but water samples are seldom available. Salinity is typically inferred from resistivity logs. The composition of the brine is key to scaling tendency assessment, but in the absence of samples, a prediction of composition can be made based on information in an extensive database of deep water GOM brine compositions.

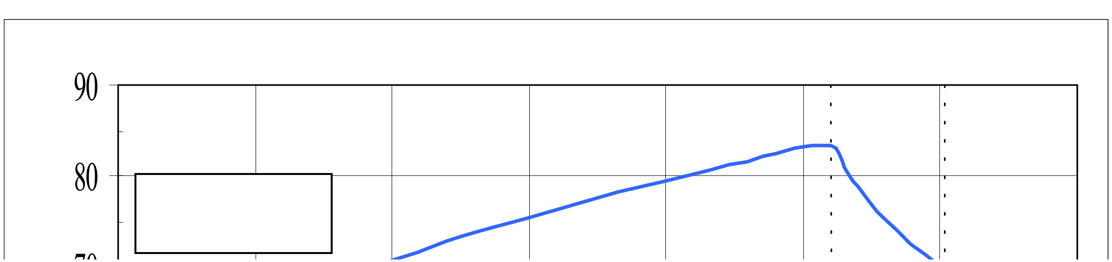
Hydrate calculations

Hydrate curves show the stability of natural gas hydrates as a function of pressure and temperature. These are computed utilizing the hydrocarbon phase and aqueous phase compositions utilizing any number of available thermodynamic packages. The hydrate curves lie at the heart of the remainder of the flow assurance process because they define the temperature and pressure envelope in which the entire system must operate in at steady state conditions. Methanol dosing calculations indicate how much methanol must be added to the produced water at a given system pressure to ensure that hydrates will not form at ambient temperature. Methanol dosing is the way hydrate formation is controlled when system temperatures drop into the range in which hydrates are stable during activities such as a system startup from completely cold conditions. The methanol dosing requirements are later used to determine the requirements for methanol storage, pumping capacities, and number of methanol lines in order to ensure that methanol can be delivered at the required rates for treating wells during startup and shut-in operations.

Well Bore Modeling

A well bore thermal hydraulic model is constructed using an Shell enhanced version of a commercial wellbore modeling software package in order to predict the steady state and transient flowing wellhead temperature as a function of reservoir pressure, temperature, productivity index, and production rate. The Shell proprietary program NEWPRS is used to generate steady state pressure profiles in the well bore. The steady state temperature and pressures generated by these programs are then used to define the flowline inlet pressure and temperatures to be used in the steady state flowline models. In addition, the steady state flowing wellhead temperatures are compared to the critical wax deposition temperature to determine the minimum production rate that must be maintained in order to prevent wax deposition in the well bore and tree.

The transient well bore temperature modeling includes studies to determine how quickly the well bore warms up from a cold earth condition and the response of the well bore temperature to a sudden shut-in of flow. These transient studies are illustrated in Figure 9 and 10. One of the objectives of these modeling studies is to determine how long it takes the wellbore to reach a temperature at which it has 8 to 12 hours of cooldown. As shown in the Figures 9 and 10, which were based on a target cooldown of 12 hours, these times can be substantial. However, warmup times can be substantially reduced when insulated tubing is used, as is discussed below. These transient results are key to understanding how hydrates can be controlled with methanol injection during startup and shut-in.



HDT = 70°F

Fig. 9 – Wellbore Transient Warmup Curve from Cold Earth (time to reach 8 hour cooldown = 52 hours)

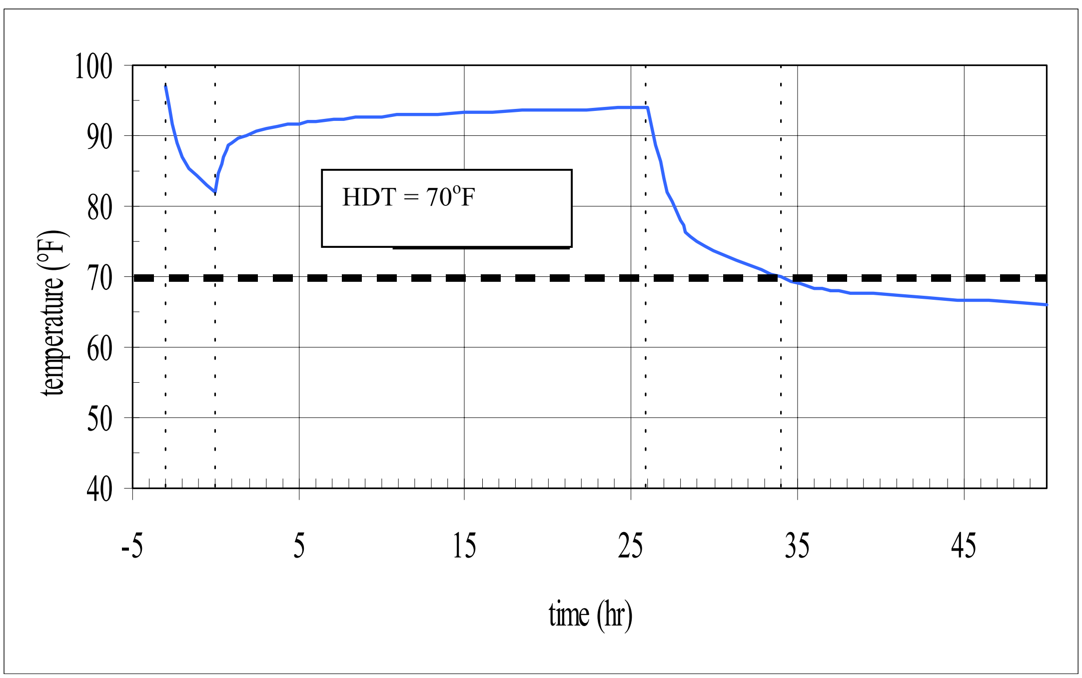


Fig. 10 – Wellbore Transient Curve for Three Hour Interruption of Production (time to reestablish 8 hour cooldown = 26 hours)

The impact of well bore insulation, with vacuum insulated tubing (VIT) on flowing wellhead temperature during startup is often investigated. Use of 3000 – 4000 ft of VIT results in warm-up of the wellbore to temperatures above the hydrate temperature in typically 2 hours or less. These warm-up rates are rapid enough to ensure that little or no hydrates form in the wellbore, based on recent hydrate kinetic laboratory studies. Essentially, the warm-up strategy is to “outrun” the hydrates. This makes it possible to eliminate the downhole injection of methanol above the subsurface safety valve during warm-up. Instead, methanol is injected upstream of the choke to prevent any hydrates that may be formed during warm-up from plugging the choke. One drawback of VIT, however, is that it cools more quickly than bare tubing since the wellbore it insulates the tubing from the earth which also warms up during production. As a result of this quick cooling, it is necessary to quickly treat the wellbore with methanol in the case that a production shut-in occurs during the warm-up period.

<u>Riser Cooldown</u>

The most vulnerable portion of the subsea system, in terms of hydrate formation, is typically the riser base. It is here that steady state temperatures are near their lowest point. The available riser insulation systems are not as effective as pipe-in-pipe insulation that is used for some flowlines. The riser is subject to more convective heat transfer, and finally, may be partially or completely gas filled during shut-in conditions, leading to much more rapid cooling.

The riser cooldown process begins by defining the desired cooldown time before the hydrate temperature is reached. The minimum cooldown time is determined by the following formula:

$$\text{Min. CD} = 3 + (t\_treat) + (t\_blowdown) \tag{1}$$

Min CD = minimum cooldown, hrs
t_treat = time to treat well bores, trees, jumpers, and manifolds with methanol, hrs
t_blowdown = time to blowdown flowlines, hrs

The three hour time period in the minimum cooldown equation is the time in which Operations staff can try to correct problems without having to take any action to protect the subsea system from hydrates. Analysis of TLP and platform operations experience indicates that many typical process and instrumentation interrupts can be analyzed and corrected in three hours. Inclusion of this time in the minimum cooldown calculation ensures that it will often by unnecessary for Operations staff to take any action toward the subsea system at all.

Once the minimum cooldown is determined, the required cooldown may be set at a longer period for a variety of reasons, such as the complexities of operating a host with two or more subsea projects. Cooldown times are typically on the order of 12 – 24 hours. Fig. 11 shows cooldown curves for an 8” riser with various insulation systems. Increasing the desired cooldown time increases the need for better flowline insulation and higher minimum production rates. The desired cooldown then dictates a minimum riser base temperature for a given riser insulation system. This temperature then becomes the target to be reached or exceeded during steady state operation of the flowline system. Analysis of riser cooldown is performed with a Shell proprietary software package known as COOLDOWN, a transient model of radial heat transfer that can also be applied to flowlines and risers.

<u>Steady State Flowline Calculations</u>

The steady state flowline model is generated in the software HYSYS (Hyprotech) which has been modified with the proprietary Shell multiphase fluid dynamics module TWOPHASE. The steady state modeling has several objectives. Foremost is that the steady state flowline temperatures and pressures are checked to ensure that the flowline never enters the hydrate region during steady state operation. Then, the riser base temperature is determined as a function of flow rate and the combined well bore/flowline insulation system. The goal is chose an insulation combination that allows the maximum range of production rates without falling below the minimum riser base temperature for cooldown. The steady state calculations are also used to determine the maximum flow throughput of the system and to determine if host arrival temperatures exceed any upper limits set by the separation and dehydration processes or by the equipment design.

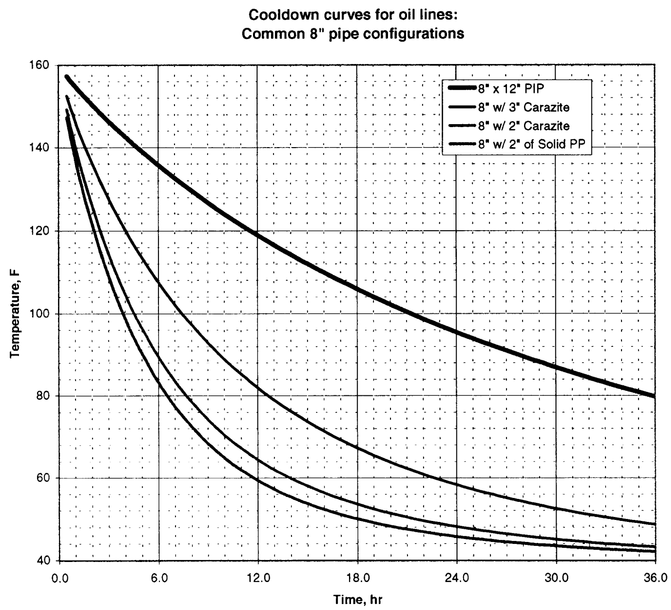


Fig. 11 – Riser Cooldown for Several Insulation Systems

Transient flowline modeling

Transient flowline models are constructed with the commercial software packages to examine the flowline depressurization and warm-up processes. Flowline depressurization, or blowdown, is used as a method to keep the flowline out of the hydrate region during shut ins exceeded the cooldown period. The results indicate how long blowdown takes and liquid carryover during blowdown, as well as indicating if the target pressure to avoid hydrate formation can be reached. Blowdown times for long flowlines may be on the order of 5-7 miles. Shorter blowdown times are accompanied with greater liquid carryover, as is shown in Fig. 12. An upper limit is often set on liquid carryover, to ensure that if the host's processing facilities are not operating, the flare scrubber can contain the entire amount of liquids. Blowdown rate may also be limited to reduce the amount of Joule-Thompson cooling downstream of the blowdown valve, to prevent the possibility of brittle fracture of the flowline.

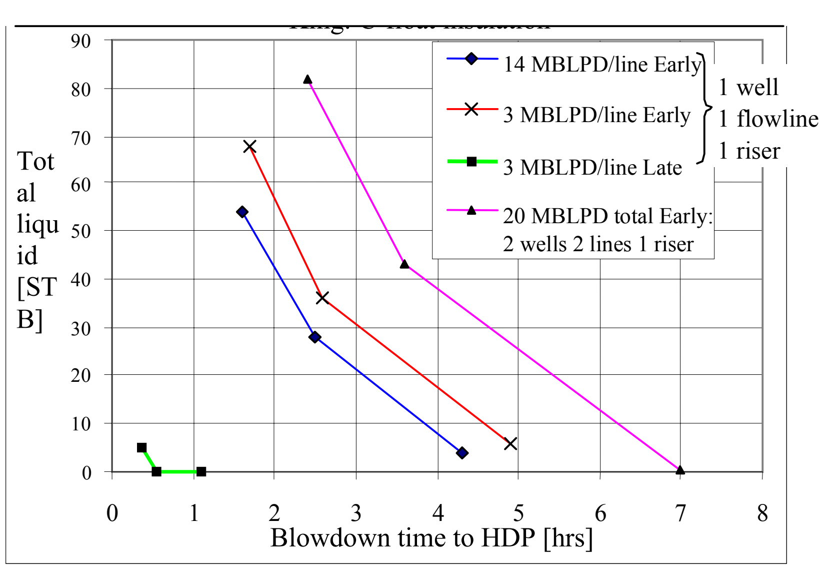


Fig. 12 – Flowline Blowdown vs. Production Rate

Proprietary models have been developed to examine another key aspect of blowdown, the minimum void fraction. During blowdown, sufficient gas must be evolved to ensure that the remaining volume of depressurized fluids exerts a hydrostatic pressure that is less than the hydrate dissociation pressure at ambient temperature. The time to reach minimum void fraction after production is initiated is a key factor. Until the blowdown criterion is met, the only way to protect the flowline from hydrate formation is to inject methanol.

Transient thermal-hydraulic models can be used to examine several options for flowline warmup, including warmup with the produced fluids (Fig. 13) and use of hot oiling to reduce warm up time (Fig. 14). During the warm-up process, methanol must be injected until two criteria are met, first, flowline temperatures must exceed the hydrate dissociation temperature at every location, and second, the flowline minimum void fraction, discussed above, must be met. Hot oiling has two beneficial effects; first, it reduces or eliminates the time required to reach the hydrate dissociation temperature in the flowline. This means that once the minimum void fraction is reached, methanol injection can be safely stopped. Reduction of the methanol injection time is a tremendous advantage for projects with limited available methanol volumes. Hot oiling also warms up the pipeline and surrounding earth, resulting in a much longer cooldown time during the warm up period than is accomplished by warm up with produced fluids. This gives more flexibility at those times when the system must be shut-in before it has reached steady state.

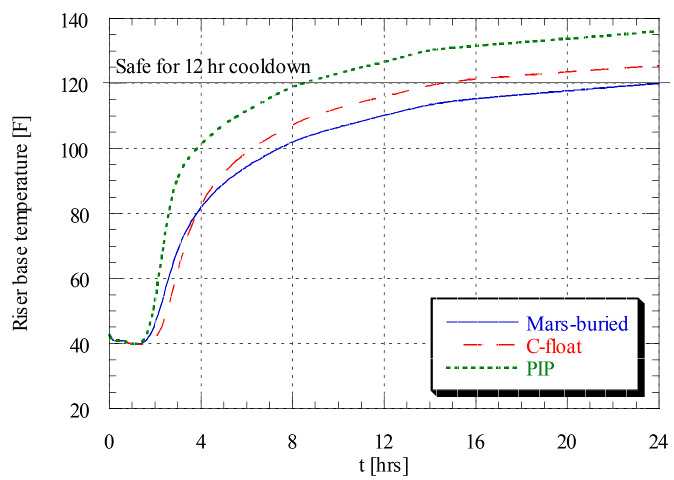


Fig. 13 – Flowline Warm-up from Cold Earth, Effect of Flowline Insulation

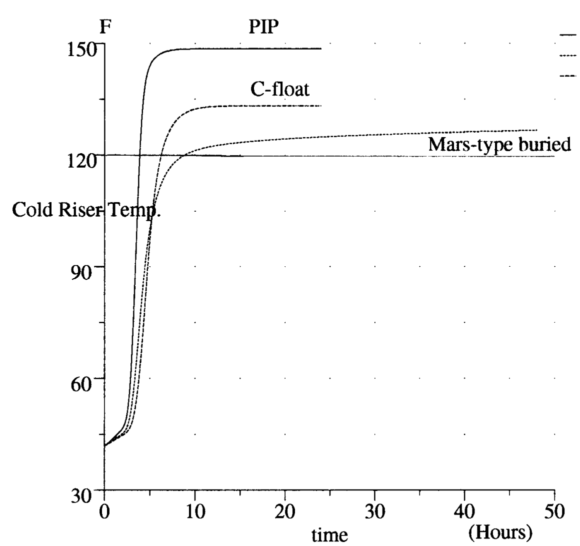


Fig. 14 – Flowline Warm-up With Hot Oiling, Effect of Insulation

System Design and Operability

The flow assurance results are translated into both the system design, for example, insulation requirements, and into operational procedures. The objective is to avoid the formation of solids, especially hydrates. A great deal of effort is spent in determining if the methanol volumes and injection pumps are sufficient to pump the required volumes and rates of methanol. The operational procedures are summarized in logic charts, which cover different scenarios, such as cold startup and shut-in. An example of a logic chart for a cold startup is shown in Figure 15.

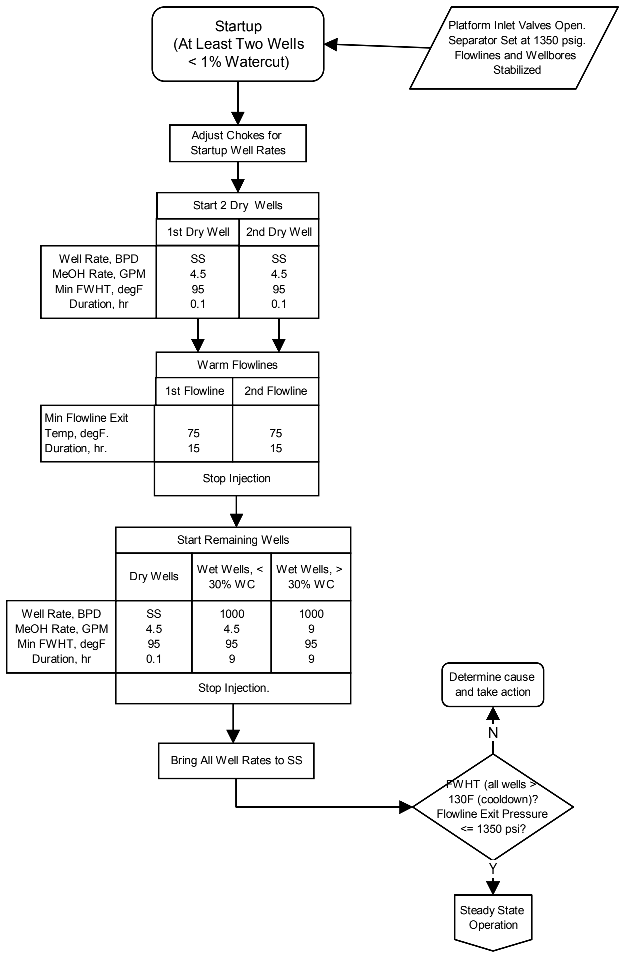


Fig. 15 – Example Operability Chart for Cold Startup (early life)

The Promise of New and Developing Technology

Two developing technologies which hold promise for reducing the complexity of the design and operation of subsea systems are electrically heated flowlines and low dosage hydrate inhibitors. Electrically heated flowline technology, which will be ready to be utilized in the very near future, will reduce hydrate concerns in subsea systems. Instead of relying on the lengthy process of blowdown for hydrate remediation, electrical heating would provide a much faster way to heat the flowline and remove the plug. Low dosage hydrate inhibitors hold the promise of reducing the volume of chemicals that must be transported and injected into the subsea system. Methanol treatment rates, for hydrate control, are on the order of one barrel of methanol for each barrel of produced brine. The low dosage hydrate inhibitors may be able to accomplish the same task at dosage rates of or less than 1%. This would clearly lead to a reduction in umbilical size and complexity. However, it must be noted that the hydrate inhibitors must be injected continuously so that they are present to prevent hydrate formation in the event of an unexpected shut-in.

The other area of rapid technical development is in asphaltene screening and control. Efforts are under way to improve the screening tests and better link them to field experience. In addition, methods for screening the effectiveness of asphaltene dispersants are under development. Much of the technology for removal of deposits once formed, such as pigging flowlines with solvent, and solvent soaking of tubing will have to be developed in the field rather than in the laboratory.

Summary and Conclusions

This paper has described the process of flow assurance and how the results from fluids analysis and thermal-hydraulic system models are used to establish guidelines and operational procedures for control of solids including hydrates, wax, and asphaltenes. Hydrates have, by the far, the strongest impact on system design and operation. The need to avoid hydrate formation sets insulation requirements, minimum flow rates, and required methanol volumes and delivery rates. The majority of the flow assurance calculations are focused on determining how the system can be kept out of the hydrate region.

Wax control, on the other hand, is relatively straightforward. Shell has invested considerable energy in developing the capability to predict wax deposition in flowlines, and using this to determine pigging frequencies, and in linking laboratory measurements to field experience with wax deposition.

Asphaltenes design and control guidelines are still in the early stages of development. There is no predictive model for asphaltene deposition, as there is for wax and hydrates. The asphaltene screens are used to indicate if asphaltenes are expected. If so, modifications to the system hardware, in the form of additional umbilical lines, and adjustments to project economics, to account for the need to periodically remove asphaltenes from wellbores and flowlines are necessary and costly.

Conclusions are:

- Flow assurance is central to the design of subsea systems
- Great progress has been made in understanding the behavior and control strategies for wax and hydrates.
- Hydrate control is responsible for many of the features of current subsea system design and operation, including insulated tubing and flowlines, pigging facilities, methanol injection, and design of operational activities to fit within a cooldown window.
- Design and operation guidelines for asphaltene control are still under development.
- New technologies, such as electrically heated flowlines and low dosage hydrate inhibitors, hold promise for the reduction of the complexity of subsea oil system design and operation

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