STIMULATION & OPTIMIZATION OF OFFSHORE WELLS WITH ASPHALTENE RELATED PRODUCTION ISSUES

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ABSTRACT

Anadarko Petroleum Corporation operates numerous deep water production facilities in the Gulf of Mexico (GOM). In a continuing effort to maximize production and the recovery efficiency of existing assets, Anadarko has invested heavily into researching and developing effective operational methods and practices to remediate asphaltene inhibited wells in a bid to offset premature well decline.

At the heart of Anadarko's efforts to maintain production in asphaltene compromised wells is a vessel-based stimulation program that seeks to arrest production losses by reverse injecting volumes of various solutions (namely xylene, diesel, and/or dry oil) in a bid to flush detrimental asphaltene deposits away from the lower completion zone.

This paper will review a comprehensive analysis and present the findings of a project undertaken in the summer of 2015 to examine and identify the most efficient stimulation techniques for wells experiencing compromised production due to asphaltene deposits. Specifically, this report will establish the most effective stimulation fluid to be used, the optimal volume of stimulation fluid to be injected, and the most cost effective frequency of treatment.

INTRODUCTION

Unprocessed crude oil is comprised of a myriad of hydrocarbons, most of which have commercial applications and value when efficiently produced and effectively refined downstream. Some crude products however need attention in situ as their pre-refinery materialization is detrimental to the upstream production process. Asphaltenes represent such an unwanted production byproduct and crudes that exude them are known as 'asphaltene unstable' crudes.

Asphaltenes are high molecular weight, long chain hydrocarbons primarily consisting of: carbon, hydrogen, oxygen, nitrogen, nickel and vanadium and are held in suspension in liquid crude oils. Asphaltenes in solution are of little interest to upstream operators and only become of concern when they begin to precipitate in production conduits as they can prove to be extremely problematic to operations and are difficult and expensive to remove. The formation and deposition of heavy organic molecules, like asphaltenes, essentially act as arterial blockages in the production string, and as highly polar compounds that first bind together and then harden when deposited, their accumulation severally affects a well's ability to flow and can significantly impede production output.

Of particular concern is the amalgamation of asphaltene platelets in the lower completion zones: in perforations, in the proppant pack or screen, and at the sand face. Accumulations in these regions prove extremely difficult to physically access, and limit the scope of remedial solutions – specifically mechanical methods of removal. This issue is especially prominent in offshore production settings and explains the sizeable investments made, both in terms of capital expenditure and scientific experimentation, to identify the most effective strategies to both ward-off of the onset of asphaltene deposits and to remediate the resulting decline in production rates when detrimental levels of asphaltene accumulations become evident.

There are many factors which can promote the onset of asphaltene deposits, but the primary mechanism is dropping pressure. Specifically, asphaltenes will begin to precipitate when they reach a reduced and critical pressure known as 'onset pressure' and the rate of asphaltene production will continue to rise with further pressure losses until saturation pressure is reached.

Temperature, pH, and flow regime can also contribute to solid asphaltene accumulation, but these variables are strictly deemed to be secondary and far less problematic than the issue of dropping pressure as experienced by flowing asphaltene unstable crudes.

The negative effects of asphaltene accumulation can be further appreciated when we recall that not only do heavy deposits throttle-off flow (like an in-line choke), but that the resulting restrictions simultaneously serve to exacerbate further pressure drops of greater magnitude. It is precisely because of this negative, self-perpetuating cause and effect style cycle that a productive and profitable well can quickly be reduced a state of poor economic performance unless successful intervention techniques are timely employed.

The preferred workover method (for the purposes of this paper we will refer to work-overs as "stimulations" or "campaigns") for deep water offshore wells employs a method of reverse injecting large volumes (up to 1050+ barrels per well) of either dry oil or solvents, such as xylene, toluene, or diesel, in a bid to both loosen and flush the viscous sludge-like asphaltene deposits from bottom hole equipment, and to arrest the formation of heavy organic molecular clusters that are in the elementary stages of coagulation.

CHEMISTRY

One of the most challenging aspects of managing wells with asphaltene-related production issues stems from an inability to predict that they were ever prone to becoming asphaltene unstable, and this forced, reactionary position leads to the unfavorable practice of well repair rather than well maintenance. It should be noted that the inability to predict a well's likelihood of reaching the status of 'asphaltene unstable' is no failure on the part of reservoir or production engineers but is instead tied to the fact that there is no known correlation between with the quantity of dissolved asphaltenes present in a particular reservoir fluid and the likelihood of reaching such status. For example, some oils with 1% asphaltene or less will form deposits in the production string, while others with 10% or more asphaltenes will form no observable or operationally limiting deposits whatsoever.

If this single, unforecastable property alone was not problematic enough, the issue of production management only worsens when we consider that asphaltene chemistry not only varies from field to field, but well to well. As such, asphaltenes contained in oil from a well in the North Sea for example are not only chemically different from asphaltenes found in Venezuela fields, but may be different to those found in other, neighboring, North Sea wells also. Unfortunately, the chemistry dictating these depositions is not well defined but nevertheless some generalities are possible which can aid in the design of prevention and remediation technology for a given, single well.

In laboratory testing, asphaltenes are soluble in light aromatic solvents such as toluene, benzene, and xylene (benzene is a known carcinogen and its field use is very limited), but so far none of these solvents have proven to comprehensively dissolve and flush sizeable asphaltene deposits off of and away from deep water bottom hole assemblies during remedial field operations.

Chemical companies are actively working to develop solutions that will improve operator's abilities to reverse the effects of asphaltene related production losses, and most efforts fall under one of two methodologies. Firstly there's the drive to produce additives that can be mixed in concentrations with host solvents (such as xylene, diesel, and toluene). Alternately, some companies are attempting to develop independent batch solvents that will pumped exclusively during stimulation campaigns.

Some of the developmental solvents being tested have shown early promise when allowed so sit, soak, and saturate (pickle) equipment coated in asphaltenic gunk, but this method is not always applicable in the field as it can require the subject well to be shut-in for extended periods of time. Aside from the issue of lost production during the extended shut-in period, there is also the concern that asphaltene plugs may form during long periods of zero flow, yielding a well that will not only fail to achieve higher levels of future production, but may in fact fail to return to production at all once the stimulation-pickling procedure is complete.

Many procedural refinements have been made over the years with respect to Anadarko's stimulation campaigns, and each successive campaign represents an evolution towards identifying and isolating the safest, most expedient, consistent, and cost effective methods of deep-water well work-overs.

Asphaltene deposits can also prove arduous to contend with when present in surface facilities as in addition to restricting tubular flow their heavy, sludge-like nature impedes heat transfer in liquid crude oil. This can pose unique problems when designing and operating equipment such as heater treaters and separators, but these matters are beyond the scope of this paper.

HISTORY OF STIMULATION CAMPAIGNS AND ANALYSIS

In 2012 a similar lookback study of offshore stimulation campaigns was performed by Production Engineering Intern Dave Hughey, also of Anadarko Petroleum Corporation, to assess the effectiveness of all the stimulation campaigns performed by the company up to that point in time. Hughey's work investigated fifty one stimulation procedures performed on eight wells over a four year period (2008-2012). In his study Hughey examined the effectiveness of using one of three different stimulation fluids (dry oil, xylene, and diesel) per stimulation with various volumes injected. His recommendations led Anadarko to pursue a greater number of stimulation projects that utilized diesel over xylene and called for larger injection volumes. Over the next three years Anadarko incorporated Hughey's recommendations but continued to experiment with varying stimulation techniques in their deep water GOM wells using experimental combinations of fluids, volumes, and stimulation frequencies.

By June of 2015 there had been 132 stimulation operations performed, on nine wells, over a total period of seven and half years - yet few definitive correlations had been firmly established that linked fundamental stimulation operation variables and the resulting changes in productivity indices of affected wells.

In the summer of 2015 it was decided a second lookback study should be performed to further narrow-down the scope of future stimulation campaigns and to limit the focus of the investigation to conclusively answering three fundamental questions:

1. Which stimulation fluid to use
2. What volume of stimulation fluid to inject (per well)
3. How often should asphaltene affected wells be stimulated

MATERIALS AND METHODS

One of two fundamental stimulation methods can be employed when attempting to reverse inject/flush a deep water, asphaltene inhibited well. The first method utilizes the injection of small batches (up to 150 bbls) of stimulating fluid (xylene, diesel, dry oil, or combination thereof) down the production system's subsea umbilical lines/methanol injection lines. Umbilicals are control lines that connect the production platform with subsea trees, manifolds, and jumpers and they supply energy (electric, hydraulic), communication, and chemicals as needed to carry out production operations. Umbilical cords range in size and are specified based on the number of functions they need to perform. For example, some umbilicals may only need to serve as communication links, so while fiber optic strands are absolutely required, tubular components to inject chemical or transmit hydraulic power are not.

Anadarko has all but terminated the practice of stimulation via umbilical lines as the maximum injection rates achievable are severely reduced due to the limited sizes of the injection tubes (up to 2" max) contained within the control lines. For example, maximum injection rates through a ¾" ID injection line is around 8 GPM at 7000psi.

Since downtime is extremely expensive, both in terms of manpower and lost production, bull-heading via production risers/flowlines (these terms will be used interchangeably) is the preferred method of stimulation as it allows for high injection rates and larger batch volumes. By comparison, stimulating wells through risers rates as high as 10 BPM (42 GPM) at 4900 psi can be achieved. Of note, Anadarko has an operational policy never to exceed 5000psi BHP during any campaign for fear of damaging the immediate formation around the injection site, and a 100psi safety factor is routinely employed. As an additional precaution, a maximum working surface pressure of 1500psi is also never exceeded. This practice assumes that hydrostatic pressure between the production facility (sea level) and the formation (subsea) will never exceed 3400psi (BHP = $P_{surface} + P_{hydrostatic} – P_{friction}$), neglecting friction.

The research performed in 2015 analyzed all previous stimulation campaigns (those employing both umbilical injection and bull-heading via rises/flowlines) but the operational assessment of this paper will focus solely on the method of stimulation via production risers.

At the heart of the stimulation operations lies a (rented) marine vessel which houses all external pumping equipment (multiple skid-based engine driven pumps), the workover contracting crew, and sometimes (depending on the stimulation fluid being used) the volumes of stimulation fluid to be injected. When dry/dead oil is to be injected it is drawn and pumped from storage tanks held on the production facility. When xylene is being used, it must be stored in dedicated containers on the vessel's deck until needed on the spar. The US Coastguard deems xylene too volatile to transport in a vessel's hull tanks and as such, injection volumes are limited to whatever can be transported solely on the ship's deck. Diesel however, can be stowed and transported both above and below deck – a benefit that affords stimulations of far greater volumes per well, or the treatment of more wells per campaign.

Using the bull-head via flowline stimulation method, the stimulation vessel is connected to the production facility via a multi-stage coupling system that begins with a vessel mounted, custom-built coiled flex hose connected to 5K psi rated Chiksan piping, and finally through a bespoke hanger mounted directly to the spar's internal piping via an externally accessible point on the side of the spar. Once the stimulation fluid reaches the production spar it can be manipulated by production operators and routed to whichever wells need to be stimulated, in whatever order best suits the production schedule.

HYDRATE CONSIDERATIONS

Before any well stimulations can begin, the production risers (flowlines connecting the subsea trees to the production facility) need to be flushed of produced fluids and displaced with dry oil (which is held in storage tanks on the production facility). This flushing process is typically completed prior to the arrival of the stimulation vessel to save vessel rental time and is a critical step taken to ensure that no hydrates are formed between the time the wells are shut-in and the time the stimulation operation begins. This flushing process is time consuming and significantly adds to the total production down-time of the project but it is an essential step as the severity of the cold conditions in the deep waters of the gulf can quickly lead to hydrate formation and plugging.

Once the flowlines have been displaced with dry oil, the pre-job safety meeting and operational overview has been completed, and the stimulation vessel has connected to the spar then the stimulations can commence – one well at a time.

QUANTIFYING RESULTS

To critically assess the effectiveness of a stimulation operation it is necessary to monitor the subject well's production data both before and after the workover. However, as stimulation operations often lower bottom hole flowing pressure, it is not enough to simply compare the magnitudes of produced volumes before and after as this data does not compensate for the changes in drawdown. As such, the preferred method of assessment is to study and profile the changes in a well's Productivity Index (PI) or J value.

Productivity Index is defined as the flow rate per unit pressure drop and serves as an indicator or the production potential of the well.

Mathematically, PI can be defined as:

$$PI = \frac{Q}{Pr - Pwf} = \frac{Q}{\Delta P} \qquad \left(\frac{bpd}{psi}\right)$$

Where,

PI = Flow rate / Drawdown (STB/d/psi)

Q = Flow rate (STB/day)

P_r = Reservoir pressure ≈ $P_{BH\text{ shut-in (soft) @10 mins}}$ (psi)

P_{wf} = Bottom hole flowing pressure (BHFP) (psi)

Δ P = Drawdown pressure (psi)

Using PI magnitudes as reference points, an in-depth study was performed to establish correlations between all known stimulation operation parameters (inputs) and increased productivity indices post stimulation (output). Input variables considered included: stimulation fluid(s) used, stimulation volume(s) per well, number of days since last stimulation, combinations of stimulation fluids used and order of fluids injected, stimulation injection rates, chemical additives used versus not, and the total number of stimulations performed on a given well. Unfortunately, no consistent or definitive trends could be clearly established between any single or combination of input variables and PI, and as such, a case by case study was required.

Additionally, however useful the PI metric is as a well-performance yardstick, it cannot be used exclusively when determining the overall effectiveness of a stimulation campaign as it makes no accommodation for the stimulation costs incurred or differential revenue generated. As such, we must look to establish how many 'barrels over base production' any single stimulation process actually yields, on a well-to-well and campaign-to-campaign basis, to determine how long it takes for the resulting uplift in production to actually payout the stimulation OPEX. Only when we have ascertained this information are we in a position to make a critical assessment of the financial effectiveness of a given operation, or predict the fiscal viability and *timing* of future campaigns.

With respect to this last point. *Only* when we have a solid understanding of our production position with respect to unstimulated-baseline performance can we precisely and consistently identify when additional stimulations should be performed, as stimulating too soon does not allow for the realization of all enhanced production associated with the previous stimulation, and stimulating too late results in a period of depressed production (baseline production), until the next campaign is executed. The identification of this intersection facilitates an answer to the last question posed in this study, what is the optimal frequency of stimulation? And the short answer is, immediately before we begin to trend with baseline production after our last stimulation campaign.

DATA CONDITIONING

In order to accurately compare pre and post-production performance characteristics of a treated well, or to be sure we're comparing 'apples to apples', it is critical that we accommodate for production variables that may skew the data in either or both intervals, variables such as downtime.

There are many reasons why a well may need to be shut-in during normal day to day operations. Maintenance, safety inspections, and sim-ops (simultaneous operations) are just a few examples, but regardless of the specific reason, *all* downtime lowers the performance profile of a well when studying production rates – whether the down time is directly related to the well being analyzed or not. This issue become of particular concern when assessing performance indicators which are time sensitive, such as payout periods and IROR.

Not accounting for such events will almost certainly pollute the sample data and lead to unsound conclusions, absent a well-defined bias. For the purposes of this study downtime was proportionally factored, both pre and post-stimulation, before any production rates were cited and before any profitability studies were performed.

PRODUCTION MODELLING

The true economic performance of any single stimulation operation can only be resulted once we are able to perform thorough Profit Investment Ratio (PIR) calculations. To do this, as mentioned earlier, it is necessary to study uplifted production data (barrels over base production) and contrast this with the forecasted decline of the same well unstimulated (base production).

To aid in the process of allocating production gains directly to specific stimulation efforts, a mathematical model was developed to integrate over-base production for each well (post-stimulation). In tandem with the downtime biasing tool, the resulting data produced by this model allowed for the efficient identification of stimulation variables and practices that consistently produced the highest PIR (Profit to Investment Ratio) and shortest time to payout. Applying this standardized method of analysis to all stimulation campaigns over the past seven years yielded answers to the first two question in this study: which type of stimulation fluid to use, and what is the optimum volume of stimulation fluid to inject?

CONCLUSIONS & RECOMMENTATIONS

A thorough fluid performance and financial analysis of all previous stimulations concluded that diesel is just as effective as xylene when stimulating asphaltene inhibited wells. Further, diesel offers comparable uplifts in PI magnitude, uplift duration, and total above-base production volumes – both in terms of BOPD and BOEPD. Add to these findings that more wells can be stimulated per campaign due to the marine vessel's ability to stow diesel in its hull-based tanks, that diesel is approximately half the cost per unit volume (over xylene), is a far safer material to handle than xylene (diesel has a 50% higher flashpoint), and that no special PPE is required for crewmen to work with diesel (full protective suits and masks are required with xylene handling) and diesel is the clear choice.

With respect to the question of how much fluid to pump per stimulation (per well) – 580bbls. This number was derived by plotting both the average PI increase for thirty days post stimulation against various injection volumes, and the highest PIR projects undertaken versus various injection volumes. Larger volumes pumped (up to 1056 bbls per well) yielded no discernable benefit to future production operations and lower volumes were typically attributable to xylene treatments and umbilical style stimulations.

Dry oil injections also showed promise but at the time of this study, too few examples were available from which to draw any conclusive answers. Of particular interest when using dry oil as a stimulating medium is that it is stored on the production facility in large quantities at all times (removing the need to purchase it and transport it via rented marine vessels). New engineering solutions are currently under development to utilize the same pigging pump that is used to displace produced fluids with dry oil from risers/flowlines (to avoid hydrate formation) to also stimulate wells with dry oil (instead of pumping diesel or xylene from a stimulation vessel). Again, the financial upsides of using dry oil become readily apparent when we consider that no third-party contracting crew is required to perform a stimulation of this kind as all equipment and materials are self-contained on the Anadarko owned production facility. Dry oil stimulations are expected to commence in 2016.

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Figure 1. GOM Spar Style Production Facility

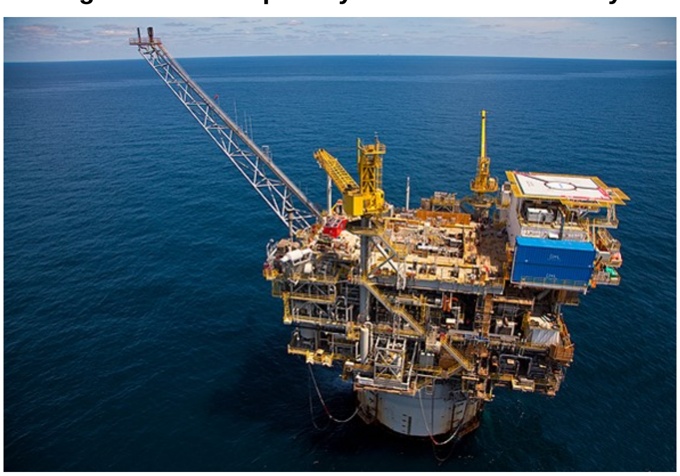

Figure 2. Location of Production Facility

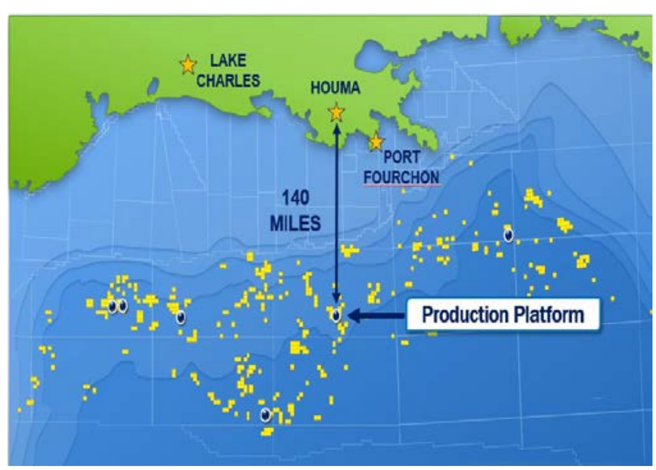

Figure 3. Asphaltene Coated Slickline

Figure 4. Asphaltene Coated Tubing

Figure 5. Vessel-based Stimulation Equipment

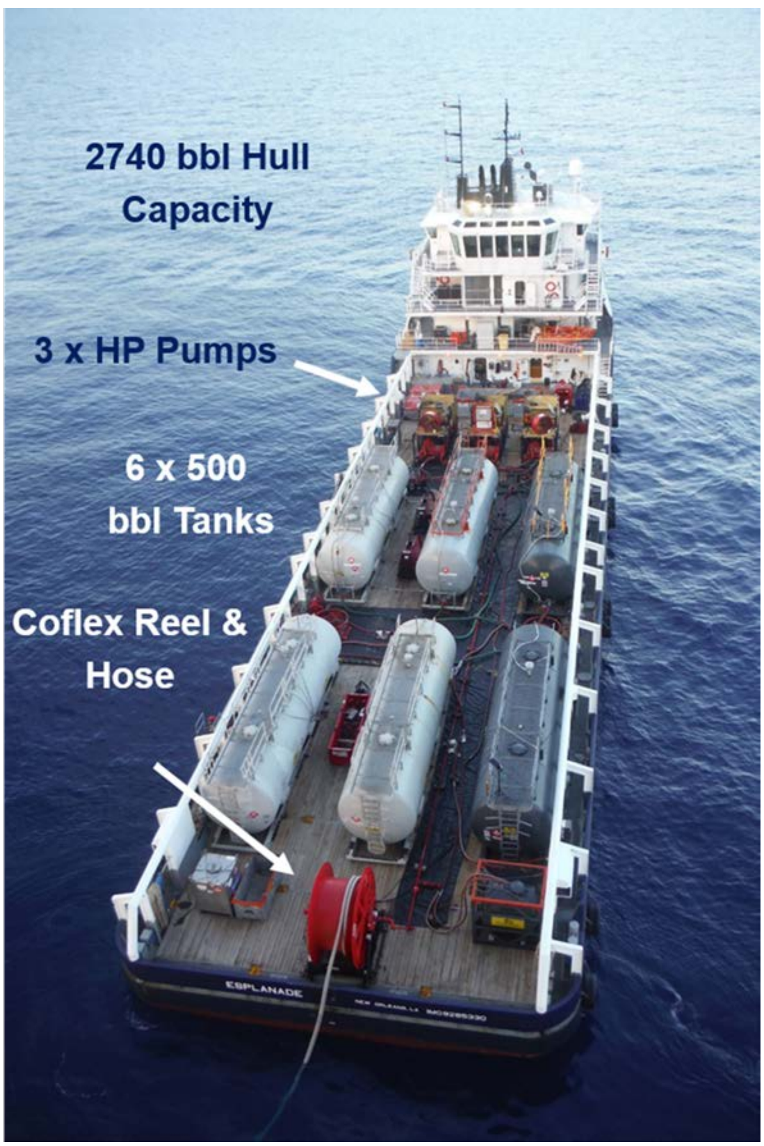

Figure 6. Production vs. Time – Dry Tree Well

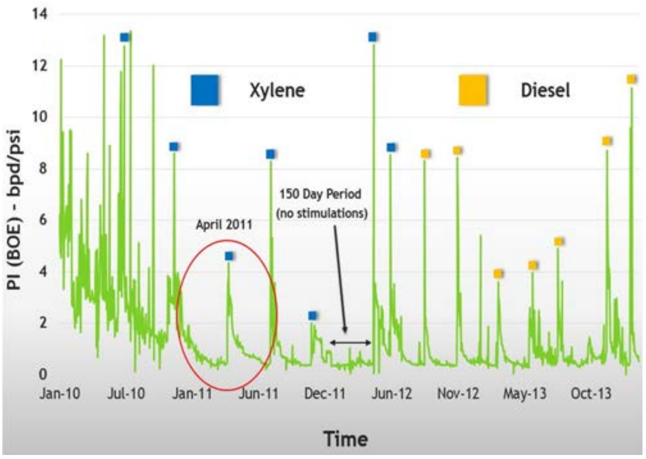

Figure 7. Barrels Over Base Decline Analysis

Figure 8. Pressure Dependence of Asphaltene Precipitation at Constant Temp. (100F)

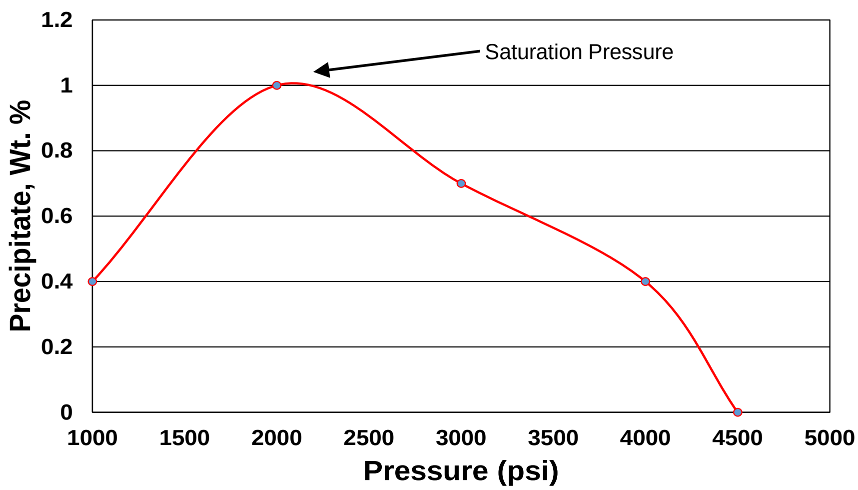

Figure 9. PT Phase Diagram for Stability Asphaltenes in Crude