A close look at the H-C phase Diagram and Hydrocarbon Reservoir Classification and Behavior

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Abstract

H-C phase diagram of reservoir fluids is an important tool used in explaining reservoir fluids behavior during the life period of any reservoir. In this paper, detailed analysis of certain terms of the Pressure–Temperature Diagram (P-T diagram) are presented and discussed. Some of these terms are redefined since the already existing definitions does not fit all cases and conditions of reservoir pressure and temperature, and hence, new definitions are given to such terms so as to make them fit all possible conditions that might exist in the reservoir. Special attention was given to explain and analyze the phase behavior inside the phase envelope (two phase region) of the P-T diagram. Among such terms for example, new definitions and analysis are given to the quality lines to give them much more interest and importance in the P-T diagram as they should be given than just representing the percentages of both liquid and gas phases. The new given definition will open new interpretations and add more interesting and valuable importance to the quality lines. Another new definition is given herein to the Cricondenbar Pressure to make it fit all possible conditions on the P-T diagram since the existing definition does not fit all pressure and temperature conditions. This paper also include some explanations regarding the retrograde gas condensation process and region on the P-T diagram. Finally, the herein mentioned factors and definitions will add more important and wider interpretations and applications for the P-T Diagram for a better understanding of H-C reservoirs. Such interpretations might be applied, also to the fluid flow control inside the reservoir and in the choosing of the best EOR method to apply whenever and wherever it is necessary.

Keywords: *P-T Diagram; Bubble Point Pressure (Saturation Pressure); Critical Point; Quality Lines; Cricondenbar Pressure; Dew Point Curve; Cricondentherm Temperature***.**

1. Introduction

One of the most important tools in understanding and analyzing hydrocarbon reservoir fluids behavior and classification of reservoir fluids is the Phase Diagram of the reservoir hydrocarbon fluids, which is also known as the Pressure–Temperature Diagram (P-T Diagram). The phase behavior diagram shows the way H-C fluids behave when reservoir Pressure and Temperature experience changes during production [1, 2, 3, 4].

Studying the phase behavior Diagram of the reservoir fluids will help reservoir engineers to predict reservoir fluid performance and take necessary actions to maintain production at its best rate so as to assure the highest possible fluid recovery from the reservoir. It will also lead to good prediction of future reservoir planning and performance and when and which secondary or tertiary recovery methods will be suitable to apply on such type of reservoirs.

Although the principle of the P-T diagram is well known for most of the researchers in the field of petroleum reservoir engineering, hence, it looks that not many effort has been done to explain in details some of its main and very important features as it should be, and what is the effect of these features on reservoir performance during production and/or on the process of selecting which EOR method will be the best suitable to apply in the reservoir.

The aim of this paper is to discuss and explain some very important features of the P-T diagram and their role in the reservoir fluids behavior during the life of the reservoir, besides suggesting new, more general definitions for some of those features since the existing definitions do not fit for some cases, while others need to be explained with more details. This fact is one of the main goals of this paper.

2. Pressure -Temperature Diagram (P-T Diagram)

Craft and Hawkins [1] in their book, presented a typical P-T diagrams Figure. 2 for a multicomponent H-C reservoir fluid system with a specific overall composition.

Nevertheless, different hydrocarbon systems would have different phase diagrams (P-T diagrams); hence, the general configuration is almost similar, but their shapes will vary a lot from one fluid to another depending on the type of the fluid in the reservoir.

These multicomponent Pressure-Temperature Diagrams are essentially used to classify H-C reservoirs.

The main factors effecting reservoir fluid performance in the reservoir are:

1. Reservoir Pressure
2. Reservoir temperature, and,
3. Reservoir fluid composition.

Some researchers went to classify H-C reservoirs fluids according to their API gravity. Such classification will depend on the reservoir H-C system Carbon Number. Accordingly, high API gravity reservoir fluids will yield light reservoir fluids and low carbon number components, while low API gravity reservoir fluids will yield heavy reservoir fluids with high carbon number components. G. Ali Mansoori [2] in his paper (2009) gave a diagram, Figure 1. where he classified H-C fluids according to their Carbon number.

Mansoori classification is presented in Figure 1. as follows:

1. Oil shale with Carbon numbers 20-40.
2. Tar Oil with Carbon numbers 18-33.
3. Heavy Crude oil with Carbon numbers 18-26.
4. Intermediate Crude oil with Carbon number (11-20).
5. Light Crude oil with Carbon number (7-15).
6. Gas Condensate reservoirs approximately have Carbon number (1-10).
7. Natural Gas reservoirs with Carbon number (1-6).

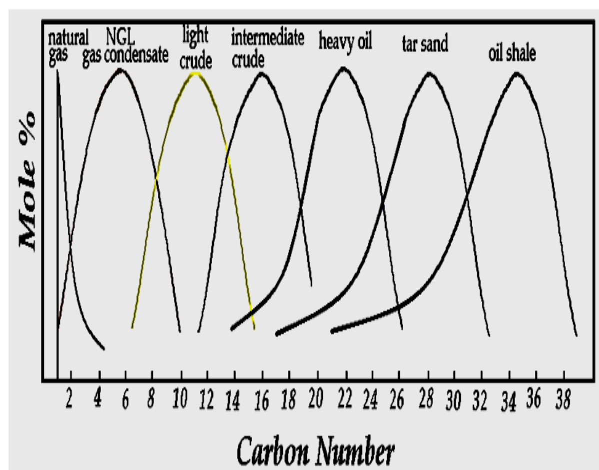


Fig 1. Various categories of natural gas and liquid hydrocarbon reserves and their distributions according to their carbon number.

To fully understand the significance of the pressure-temperature diagrams, it is necessary to identify and define the key features on these diagrams.

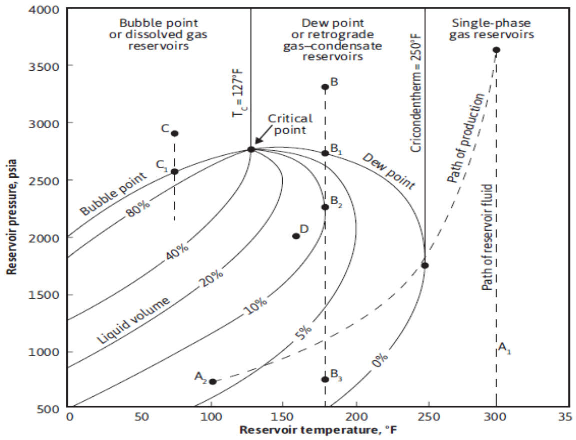


Fig 2. Pressure-temperature phase diagram of a reservoir fluid.

3. Main features of the P-T diagram

3.1 Critical Point (C):

The critical point (point C) in Figure 2. for a multicomponent H-C mixture refers to the state of pressure and temperature at which all intensive properties of the gas and liquid phases are equal and boundaries between liquid and gas phases disappear or difficult to recognize.

3.2 Bubble-Point Curve:

The bubble-point curve is the curve separating the single liquid-phase region from the two-phase region.

Bubble-Point pressure is the pressure at which the first bubble of gas evolves out of solution from the liquid oil phase. In oil fields practice, the **bubble point pressure** is usually referred to as the **Saturation Pressure (Ps)**; a term most near to petroleum reservoir terminology since it expresses the reservoir pressure at which the oil (Liquid phase) has sufficient gas in solution to fully saturate the oil.

3.3 Dew-Point Curve:

The dew-point curve is defined as the curve separating the gas phase region from the two-phase (oil & gas) region.

Or, it is the conditions of pressure and temperature at which the last drop of liquid disappears as reservoir temperature and/or pressure increases and the whole system changes into the gas phase.

3.4 Phase Envelope (Two-Phase Region):

The Phase Envelope (Two-Phase Region) is a term used to express the region enclosed by the bubble-point curve and the dew-point curve, wherein gas and liquid coexist in equilibrium.

3.5 Phase Envelope (Two Phase Region) Boundary Curve:

This term is very important to be introduced to the rest of the already existing terms since it represents *the curve composed of the bubble-point curve and the dew-point curve which meet at the Critical Temperature point to form one curve that encloses the phase envelope separating the two phase region from the single phase region***.**

This new ***Phase Envelope Boundary Curve*** term introduced here is very important in the process of classification of H-C reservoirs, since all points of reservoir Pressure and Temperature conditions that have values less than those of the Phase Envelope Boundary Curve will belong to the 2-phase region, and hence represent Gas Cap reservoirs; while points of reservoir Pressure and Temperature conditions that have values greater than those of the Phase Envelope Boundary Curve will represent the single phase reservoirs.

3.6 Quality Lines (Curves):

All literatures use the term **Quality Lines** to represent the state of Liquid and Gas volume percentages at the two phase region in the reservoir, while the correct term to be used should be **Quality Curves** and not **Quality Lines** as it is mentioned in all P-T Diagrams, and there is a lot of difference between the two terms.

Each of these Quality Curves describes the pressure and temperature conditions for certain volume percentages of the liquid and gas phases of the reservoir H-C system. All Quality Curves converge at the critical point **(point C).**

Nevertheless, **Quality Curves** actually have a much more important role in the phase behavior of the reservoir H-C system and reservoir engineering calculations than just to represent the volume percentages of oil and gas phases inside the reservoir. We will discuss the quality curves and their importance later in this paper since they represent a very important feature of the H-C system inside the reservoir.

3.7 Cricondenbar Pressure (P_{cb}):

The Cricondenbar Pressure Figure 3. and Figure 4. is defined in approximately all petroleum reservoir engineering references as; "**the maximum pressure above which no gas can be formed regardless of temperature".**

If we study different types of H-C Phase Diagrams, we can find that this definition of the **Cricondenbar does not always fit**, and it only fits for certain reservoir conditions.

It is also well-known that reservoir temperature is always considered to be **constant** for a certain reservoir and cannot change unless human intervention is applied by changing (increasing) reservoir temperature through EOR thermal methods only. This fact contradict the above mentioned Cricondenbar definition which refers to temperature change in the phrase (***regardless of temperature***), while actually reservoir temperature is always considered to be constant.

Initial reservoir temperature and composition of a H-C system have a great influence on the **Cricondenbar Pressure point** location on the P-T Diagram for a certain reservoir.

To clarify this argument of Cricondenbar definition, let us take a look at Figure 2. above. We can see that the mentioned definition does not fit if the Cricondenbar point **lies on the dew point curve**. In such a case, only gas will exist as pressure goes higher than the Dew-point curve pressure, where the cricondenbar pressure point is located. As pressure increases isothermally we will inter into the gas region (condensate gas region); a fact that contradict the above mentioned definition of the Cricondenbar (**the maximum pressure above which no gas can be formed**), since, as pressure continues to increase, we will be having only gas.

This above mentioned definition of the Cricondenbar Pressure is correct only under the condition that the **Cricondenbar Temperature (T_{cb})** is less than the critical point temperature **(T_c)** and hence the Cricondenbar point will lie on the ***Saturation Pressure Curve (Bubble Point curve)*** Figure 3 below.

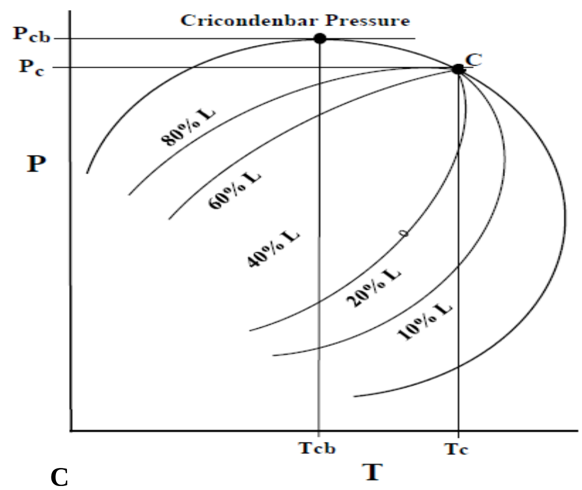


Fig 3. Cricindenbar Pressure (Pcb) and critical point (C).

Only in such cases the Cricondenbar Pressure (P_{cb}) can be considered as the maximum pressure above which no gas can exist since if reservoir pressure goes above Saturation or Bubble point pressure (in such a case it is the Cricondenbar Pressure), the system will inter into the liquid phase region where there will be only the liquid oil phase that exists and no gas can form**.**

These facts imply that there must be a certain definition for the Cricondenbar Pressure to be suitable for all cases of pressures and temperatures conditions inside the reservoir indifferent of the shape of the P-T diagram and/or the location of the Cricondenbar point.

Accordingly, I introduce here below what I believe the best suggested definition for the

Cricondenbar pressure and it can be one of the following two definitions:

1. It is the point with the highest pressure value on the Phase Envelop Boundary Curve (Bubble Point-Dew Point curve) Figure 3 and Figure 4.

2. It is represented by the pressure resulting from the point of the horizontal tangent line to the Phase Envelop Boundary Curve (Bubble Point-Dew Point curve) Figure 4, and Figure 5.

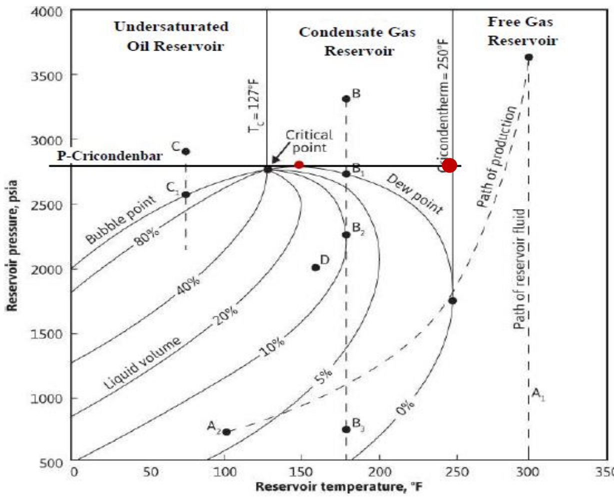


Fig 4. a P-T Diagram a H-C system.

These above two definitions might be the best to define the Cricondenbar Pressure point on the P-T Diagram, since they do not bind the definition with the idea of gas formation or the existing reservoir temperature.

Another fact to be mentioned here is that the **Cricondenbar Pressure (P_{cb})** value is always higher than the **Critical pressure (P_c)** value indifferent of the shape of the P-T diagram.

3.8 Cricondentherm Temperature ($T_{ct.}$)

The Cricondentherm Temperature is defined as the maximum temperature above which liquid cannot exist regardless of pressure. It is, also, the temperature represented by the touching point of the vertical tangent to the dew point curve. Its value can be read at the x-axis of the P-T diagram, and is usually referred to as ($T_{ct.}$). This temperature is used to separate between the regions of the Gas Condensate Reservoirs and the Free Gas Reservoirs.

4. Reservoirs classification

Classifying hydrocarbon reservoirs according to the P-T Diagram cab be done as follows:

1. Single phase reservoirs (either only Liquid or only Gas), and this will include all reservoirs with pressure and temperature conditions that fall outside the two phase region (Phase Envelope).
2. Two phases reservoirs (Liquid and Gas) or ***Gas Cap Reservoirs*** which include all reservoirs with pressure and temperature conditions that fall inside the two phase region (Phase Envelope).

The two temperature points ($T_{c.}$ and $T_{ct.}$) will help later to complete the final classification process of H-C reservoirs on the P-T Diagram as it is in Figure 2 above or in Figure 8 later.

Accordingly, in brief, the general classification of H-C reservoirs as mentioned in most of reservoir engineering articles and books will be:

4.1 Oil Reservoirs (only Liquid)

If reservoir temperature is less than the critical temperature of the reservoir H-C system **($T_{res.} < T_c$)**, with a condition of having initial reservoir pressure greater than or equal to oil saturation pressure ($P_{res.} \geq P_s$); such reservoirs are classified as Oil Reservoirs.

If reservoir pressure drops below saturation pressure, then, the reservoir is called a Gas Cap reservoir.

These oil reservoirs are further sub-classified into 2 main types as follows:

A. According to initial reservoir pressure (Pi) and its relation to saturation pressure (P_s). According to this classification we will have 3 types of oil reservoirs;

1. Under-saturated Oil reservoirs; if reservoir pressure is greater than Bubble point Pressure (Saturation Pressure, Ps); $P_{res.} > P_s$

2. Saturated Oil Reservoirs; ($P_{res.} = P_s$)

3. Gas Cap reservoirs; ($P_{res.} < P_s$) ; (This type is included in our initial classification of H-C reservoirs as being within the region of the two phase reservoir, Oil & Gas), hence it is classified as ***Gas Cap Reservoir*** as a continuity of reservoir system phase changes due to pressure changes inside the reservoir.

B. The second sub-classification of oil reservoirs will be according to physical properties and chemical composition of the reservoir's oil system. Accordingly, we will have four types of oil reservoirs;

1. Low Shrinkage Oil Reservoirs (Heavy crude oils).
2. Black oil Reservoirs (Normal or intermediate crude oils).
3. Volatile Crude oil Reservoirs (very light crude oil).
4. Near Critical Oil reservoirs (extra light crude oil).

We must realize that this classification depends, also, on reservoir temperature **($T_{res.}$)** of each of the four reservoir types above.

The lower the reservoir temperature is, the heavier is the oil, and visa versa.

The type of the oil inside the reservoir will become lighter and lighter as reservoir temperature gets nearer to the critical temperature of the system; a fact that implies that as reservoir temperature approaches the critical temperature, the H-C system will be having less Carbon number components in its composition and this means lighter H-C system.

4.2 Gas Reservoirs:

If reservoir temperature is greater than the critical temperature of the H-C system and their pressure conditions are outside the phase envelope of the reservoir H-C fluid system, then the reservoir is classified as a Gas Reservoir. Such Gas Reservoirs are more sub-classified into:

A. Gas Condensate Reservoirs (also called Retrograde Gas Condensate Reservoirs)

Such reservoirs exist if Reservoir temperature ($T_{res.}$) is greater than the critical temperature of the H-C system and less than its Cricondentherm temperature (**$T_c < T_{res.} < T_{ct}$).**

They are called retrograde condensate reservoirs because of the fact that when reservoir pressure declines below the value of the dew point pressure, liquid (oil) will start to condense out of the gas phase; a fact that opposes the normal behavior of gases which usually expands by decreasing pressure.

This phenomenon occur within a certain region inside the two phase region of the P-T Diagram.

To locate the exact region where the retrograde condensation takes place, we have to draw vertical tangents to each Quality Curve under the dew point curve of the P-T diagram, and then, join all tangents points with the critical point and the Cricondentherm point with a curve; the region between this curve and the dew point curve will define the retrograde condensation region Figure 8.

As reservoir pressure continues to decline, the process of gas condensation will end, and more reduction of reservoir pressure will lead to the normal gas expansion process and the evaporation of the condensed liquid into the gas phase again.

B. Free Gas Reservoirs: If Reservoir temperature ($T_{res.}$) is greater than the

cricondentherm temperature of the H-C system ($T_{res.} > T_{ct.}$).

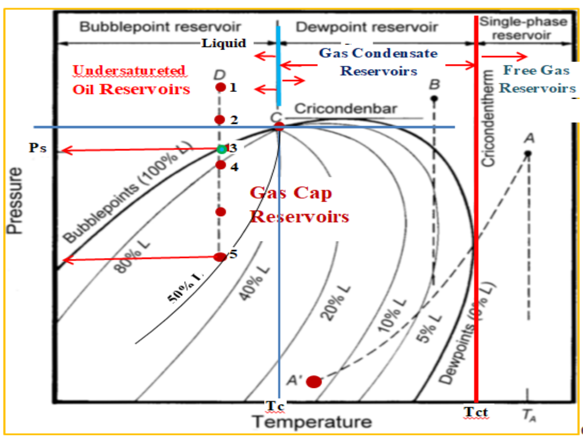
Depending on the production (separator) conditions, these Free Gas Reservoirs are further sub-classified into:

1. Dry Gas reservoirs.
2. Wet Gas reservoirs.

Dry Gas Reservoirs means that reservoir gas composition will be composed of gases from C_1 to C_6 only and no liquid can be recovered at the separator conditions at the surface.

While Wet gas reservoirs means that gas properties and composition has some volatile low carbon number (C_7-C_{10}) components that appear in the gas phase at reservoir conditions due to high reservoir temperature. These components will turn to their normal phase as liquids at the surface conditions due to temperature and pressure reduction to ambient conditions.

A very detailed diagram of the H-C reservoir classification is presented in Figure 5. and Figure 6. below.



Typical P-T diagram for a multicomponent system

Fig 5. Detailed Classification of H-C reservoirs according to P-T Diagram.

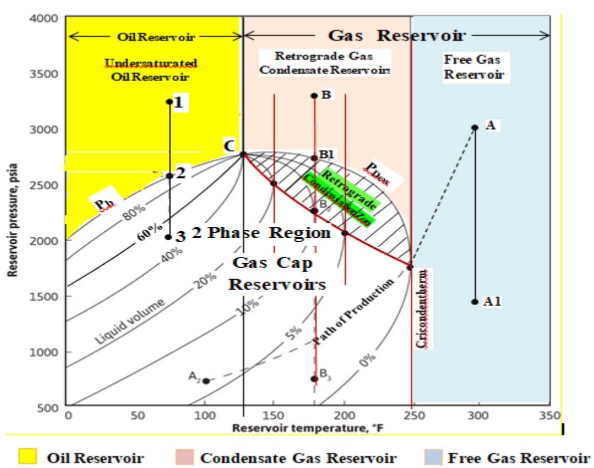


Fig 6. Classification of H-C reservoirs according to P-T Diagram.

5. Interpretation of the P-T Diagram

We will discuss here one of the very important features of the P-T Diagram; the **Quality curves,** and we will define them and explain what they really represent.

Quality Curves (Quality Lines) are curves that converge out of the critical point **(C)** of the P-T diagram inside the two phase region. From the numbers usually indicated on each curve, one can see that they represent the ratio of the Liquid phase volume present in the reservoir, usually represented as a percent of the total reservoir hydrocarbons volume.

Assuming that the reservoir initially was an undersaturated or saturated oil reservoir (only liquid), with reservoir pressure **(P_i)** greater than or equal to the initial saturation pressure (P**$_{si}$**), which means that initially no free gas is present in the reservoir. The gas phase will appear after a period of production associated with reservoir pressure dropping to a value below initial saturation pressure (P_{si}) Figure 7.

If reservoir pressure drop continues and reaches a value less than the reservoir initial saturation pressure **(P_{si}),** it will lead to the formation of a free gas layer inside the reservoir and eventually a gas cap. The quantity of each of the liquid phase volume and the gas phase volume created inside the reservoir will be represented by the number written on each quality curve.

However, if we take a closer look at **Quality Curves**, we will see that these curves do not represent only the volume percentages of the gas and the liquid phases in the reservoir, but, actually, they represent something more important than that.

Therefore, let us take a look to what actually these Quality Curves represent:

1. Each quality curve inside the two phase region of the P-T Diagram represents the location of a new saturation pressure for the liquid phase (Oil) inside the reservoir. This fact means that for undersaturated oil reservoirs, there will be an initial and the only original saturation pressure (P_{si}) for the H-C system present in the reservoir, and multi other saturation curves.

2. As reservoir pressure goes down due to oil production operations, and the absence of any source of natural energy for maintaining it above (P_{si}), and/or any sort of intervention for pressure maintenance operations in the reservoir, each step the pressure goes down below reservoir initial saturation pressure and settles as the new reservoir pressure, this last reservoir pressure actually will represent the new saturation pressure of the liquid phase in the reservoir.

Hence, this means that when reservoir pressure declines below initial reservoir saturation pressure, we will be having many new saturation pressures for the liquid phase; one at each pressure drop step, and each one of these new saturation pressures will be less than the previous one, as long as the reservoir experience continuous pressure drawdown Figure7.

3. This process of gas liberation inside the reservoir is actually equivalent to the Laboratory PVT analysis Flash and Differential liberation tests, where pressure is continuously reduced during the test in many stages below initial saturation pressure, and at each of these stages we will be having a certain saturation pressure different and less than the previous one as it is seen in Figure 7.

4. Such pressure drawdown will cause variation in reservoir oil properties. To obtain the properties of the reservoir liquid phase in such cases (properties at each pressure drawdown step), we have to refer to the PVT Flash & Differential Tests and study the properties of the liquid phase.

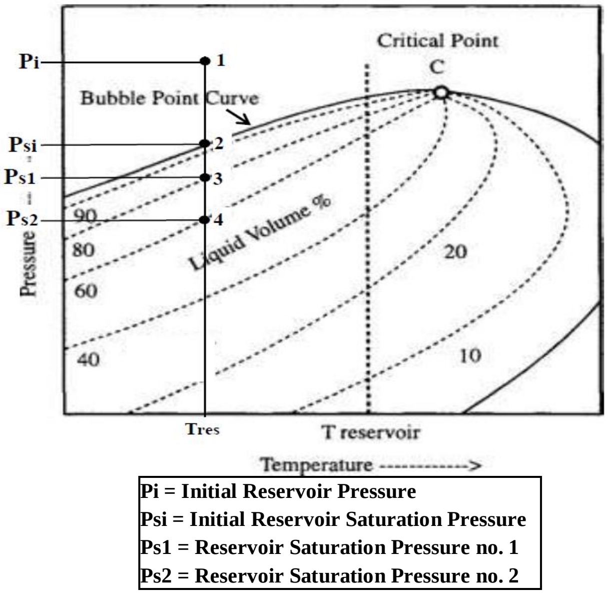


Fig 7. P-T Diagram of a H-C system showing different saturation pressures.

5. Let us take a look to how oil properties inside the reservoir will change when reservoir pressure drops to a value below saturation pressure and gases evolve out of solution forming a free gas phase inside the reservoir.

As gas evolves out of the oil phase inside the reservoir due to pressure reduction below saturation pressure, the remaining oil phase will suffer the following changes:

A. Overall oil (liquid phase) composition will suffer a change in its chemical composition and accordingly a change in its physical properties since a certain amount of very light hydrocarbon components (C_1 to C_6) are removed out of the oil phase escaping into the gas phase due to this pressure reduction forming a free gas. More reduction in pressure inside the reservoir will lead to another new saturation pressure inside the reservoir, hence, another new chemical composition of the oil phase, and new oil phase physical properties.

B. Such changes in liquid oil composition will have a great influence on the oil flow behavior inside the reservoir since any change in oil composition will lead to changes in reservoir oil physical properties; such as Density Figure 8, Viscosity Figure 9, Gas Oil Ratio Figure 10, Oil Compressibility factor and other properties related to oil flow performance in porous media. Getting such information from P-T Diagram and good PVT analysis is very important for the production process and oil flow in porous media toward production wells.

It is important to mention that (Figures 8, 9, 10) are real PVT data for an Iraqi reservoir crude oil sample done in PRC-Iraq during the seventies of the last century.

6. Quality curves (lines), also can give us the size of the gas cap generating inside the reservoir. Such information will help a lot in the process of calculating and predicting the flow behavior of liquid and gas inside the reservoir and to propose the suitable method for enhancing production and maintaining reservoir pressure.

7. If we look at the two phase region closely, we can recognize that the Critical Temperature line divides the two phase region into two sectors:

A. The left sector (under the Saturation Pressure Curve) where Quality Curves show high percentages of liquid phase and low percentages of gas phase. This is due to the fact that originally the prevailing phase in the reservoir is the liquid phase. Gas will appear if reservoir pressure declines below the initial saturation pressure. The higher the pressure drop below initial saturation pressure is, the higher will be the volume of gas formed inside the reservoir.

b. On the other side, the right sector of the phase envelope (under the Dew Point curve), the Quality Curves show a much less liquid percent and a very high gas percent. This is due to the fact that reservoir temperature is higher and greater than the critical temperature besides that originally the reservoir is a gas reservoir and the liquid will appear only if reservoir pressure declines below the Dew Point curve pressure where we will witness the condensation of some of the gas components into the liquid phase. The value of such condensed gas is usually small around 5-15% of the total gas volume.

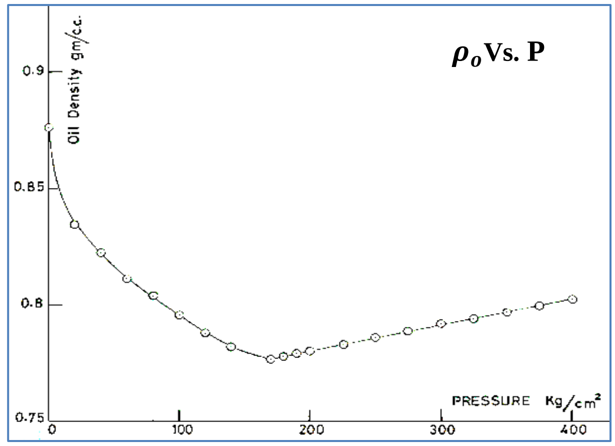


Fig 8. Variation of reservoir oil density with reservoir pressure

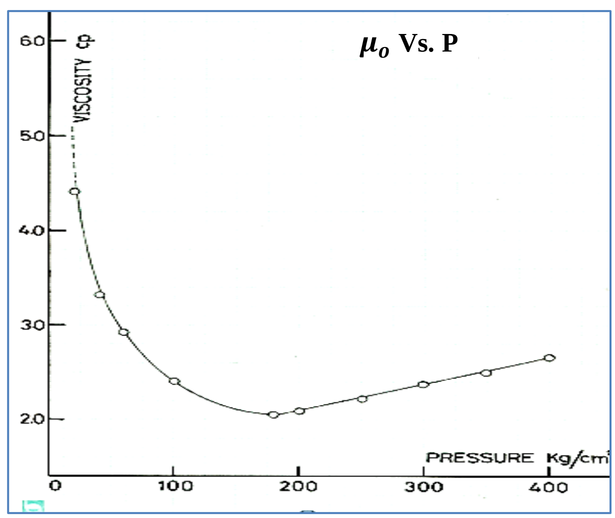


Fig 9. Variation of reservoir oil viscosity with reservoir pressure.

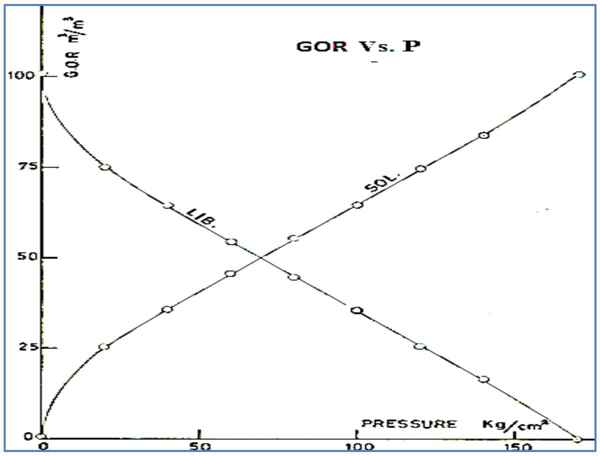


Fig 10. Variation of reservoir oil GOR with reservoir pressure.

6. Fluid flow inside the reservoir

When gas evolves out of solution from the oil phase inside the reservoir, it will form a gas saturation inside the pores beside the oil phase. This volume of gas will affect the flow of oil toward production wells. Such effect can be explained as follows:

1. If the gas saturation inside the pore spaces is less than its critical saturation, this means that the gas will not flow and remains in the pore space occupying some of its space. Accordingly, this free gas will have two side effects on the flow of the oil;

A. First, by occupying part of the pores space in the porous media, gas will displace some of the oil (equivalent to its volume) inside those pores forcing it to flow toward production wells. Such effect can be considered as a positive effect since it helps to move the oil toward production wells.

B. On the other hand, occupying part of the pore space, the evolved gas will restrain the flow of the oil inside the reservoir; an effect which can be considered as a negative one. Usually relative permeability data of the reservoir medium will be the decisive factor in such cases.

2. Another effect of gas liberation inside the reservoir is that the process of gas liberation out of solution from the oil phase will lead to a change in oil physical properties by leaving the oil phase with a higher viscosity (since gas in solution is considered as a dilution agent for the liquid oil phase), and thus, the escaped gas will surely make the flow of the oil through the porous media more difficult since oil viscosity is directly proportional to the difficulty of oil flow ability (the more the oil viscosity the more difficult the oil flow will be, and vice versa) Figure 9.

It is well known that one of the used EOR methods is to inject miscible gases into the reservoir with the aim of dissolving these gases into the oil phase to reduce oil viscosity to make oil less viscous and hence easier to flow of course besides viscosity, the oil phase will suffer changes in density Figure 8, GOR Figure 10 and all other properties.

7. Conclusions

In general, the final conclusions of this paper are:

1. Understanding and good interpretation of the reservoir H-C system phase Diagram is very important to understand the H-C reservoir system and its fluid behavior during the process of reservoir exploitation.

2. The already existing definition of the Cricondenbar in most of the literature papers ***should be reconsidered*** to include, or to be replaced by the herein mentioned definitions to avoid any inconsistency of some cases on the P-T diagram which might lead to some sort of scientific argument and/or discrepancy with the already existing pressure and temperature conditions in the reservoir as it is mentioned and explained above, and to allow the definition of the Cricondenbar to have a wider range of correct interpretation for all possible cases on the P-T Diagram.

3. The proposed definition and interpretation of the ***quality curves (lines)*** which nominate the quality curves as not only representing percentages of liquid and gas phases, but, to represent oil saturation pressure at each stage of pressure reduction in the reservoir within the two phase region of the P-T diagram. This proposed definition of quality curves gives the P-T diagram a more important role in knowing and understanding reservoir fluid behavior leading to the right way to interpret reservoir components and predict its fluid properties and behavior.

4. Good and correct interpretation of the P-T Diagram, associated with good and reliable reservoir oil PVT analysis data will lead to a better selection of the best drive mechanism to produce an oil reservoir depending on the initial reservoir conditions, expected oil properties variation due to reservoir pressure variation during production period, the way these properties behave and vary during the production process and hence, the selection of the best recovery method to be applied.

Symbols:

API Gravity = American Petroleum Institute
Gravity for crude oil = $\frac{141.5}{\gamma_o}$ - 131.5
EOR = Enhanced Oil Recovery
FIG.- = Figure Number
GOR = Gas Oil Ratio
$GOR_{Lib.}$ = Liberated Gas Oil Ratio
$GOR_{Sol.}$ = Solution Gas Oil Ratio
H-C = Hydro-Carbon
P = Pressure
P_c = Critical Pressure
$P_{cb.}$ = Cricondenbar Pressure
P_i = Initial Reservoir Pressure
P-T Diagram = Pressure Temperature Diagram
P_s = Saturation Pressure
P_{si} = Initial Saturation pressure
PRC = Petroleum Research Center-Iraq
PVT = Pressure Volume Temperature Test
ρ_o = Oil Density
T = Temperature
$T_{c.}$ = Critical Temperature
$T_{cb.}$ = Cricondenbar Temperature
$T_{ct.}$ = Cricondentherm Temperature
$T_{res.}$ = Reservoir Temperature
μ_o = Oil Viscosity
γ_o = Oil specific gravity

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