

Chapter 2: Reservoir Fluids

2.1 Introduction

Reservoir fluids fall into three broad categories; (i) aqueous solutions with dissolved salts, (ii) liquid hydrocarbons, and (iii) gases (hydrocarbon and non-hydrocarbon). In all cases their compositions depend upon their source, history, and present thermodynamic conditions. Their distribution within a given reservoir depends upon the thermodynamic conditions of the reservoir as well as the petrophysical properties of the rocks and the physical and chemical properties of the fluids themselves. This chapter briefly examines these reservoir fluid properties.

2.2 Fluid Distribution

The distribution of a particular set of reservoir fluids depends not only on the characteristics of the rock-fluid system now, but also the history of the fluids, and ultimately their source. A list of factors affecting fluid distribution would be manifold. However, the most important are:

Depth The difference in the density of the fluids results in their separation over time due to gravity (differential buoyancy).

Fluid Composition The composition of the reservoir fluid has an extremely important control on its pressure-volume-temperature properties, which define the relative volumes of each fluid in a reservoir. This subject is a major theme of this chapter. It also affects distribution through the wettability of the reservoir rocks (Chapter 7).

Reservoir Temperature Exerts a major control on the relative volumes of each fluid in a reservoir.

Fluid Pressure Exerts a major control on the relative volumes of each fluid in a reservoir.

Fluid Migration Different fluids migrate in different ways depending on their density, viscosity, and the wettability of the rock. The mode of migration helps define the distribution of the fluids in the reservoir.

Trap-Type Clearly, the effectiveness of the hydrocarbon trap also has a control on fluid distribution (e.g., cap rocks may be permeable to gas but not to oil).

Rock structure The microstructure of the rock can preferentially accept some fluids and not others through the operation of wettability contrasts and capillary pressure. In addition, the common heterogeneity of rock properties results in preferential fluid distributions throughout the reservoir in all three spatial dimensions.

The fundamental forces that drive, stabilise, or limit fluid movement are:

- Gravity (e.g. causing separation of gas, oil and water in the reservoir column)
- Capillary (e.g. responsible for the retention of water in micro-porosity)
- Molecular diffusion (e.g. small scale flow acting to homogenise fluid compositions within a given phase)
- Thermal convection (convective movement of all mobile fluids, especially gases)
- Fluid pressure gradients (the major force operating during primary production)

Although each of these forces and factors vary from reservoir to reservoir, and between lithologies within a reservoir, certain forces are of seminal importance. For example, it is gravity that ensures, that when all three basic fluids types are present in an uncompartimentalised reservoir, *the order of fluids with increasing depth is GAS:OIL:WATER*, in exact analogy to a bottle of french dressing that has been left to settle.

2.3 Aqueous Fluids

Accumulations of hydrocarbons are invariably associated with aqueous fluids (formation waters), which may occur as extensive aquifers underlying or interdigitated with hydrocarbon bearing layers, but always occur within the hydrocarbon bearing layers as connate water. These fluids are commonly saline, with a wide range of compositions and concentrations; Table 2.1 shows an example of a reservoir brine. Usually the most common dissolved salt is NaCl, but many others occur in varying smaller quantities. The specific gravity of pure water is defined as unity, and the specific gravity of formation waters increases with salinity at a rate of about 0.075 per 100 parts per thousand of dissolved solids. When SCAL measurements are made with brine, it is usual to make up a simulated formation brine to a recipe such as that given in Table 2.1, and then deaerate it prior to use.

Table 2.1 Composition of Draugen 6407/9-4 Formation Water

Component	Concentration, g dm ⁻³
Pure water	Solvent
NaCl	34.70
CaCl ₂ .6H ₂ O	4.90
MgCl ₂ .6H ₂ O	2.70
KCl	0.40
NaHCO ₃	0.40
SrCl ₂ .6H ₂ O	0.12
BaCl ₂ .6H ₂ O	0.06
Final pH = 7	

Why a connate water phase is invariably present in hydrocarbon bearing reservoir rock is easily explained. The reservoir rocks were initially fully or partially saturated with aqueous fluids before the migration of the oil from source rocks below them. The oil migrates upwards from the source rocks, driven by the differential buoyancy of the oil and the water. In this process most of the water swaps places with the oil since no fluids can escape from the cap rock above the reservoir. However, the water is not completely displaced as the initial reservoir rock is invariably water-wet, leaving the water-wet grains covered in a thin layer of water, with the remainder of the pore space full of oil. Water also remains in the micro-porosity where gravity segregation forces are insufficient to overcome the water-rock capillary forces.

The aqueous fluids, whether as connate water or in aquifers, commonly contain dissolved gases at reservoir temperatures and pressures. Different gases dissolve in aqueous fluids to different extents, and this gas solubility also varies with temperature and pressure. Table 2.2 shows a selection of gases. If gas saturated water at reservoir pressure is subjected to lower

pressures, the gas will be liberated, in exactly the same way that a lemonade bottle fizzes when opened. In reservoirs the dissolved gas is mainly methane (from 10 SCF/STB at 1000 psi to 35 SCF/STB at 10 000 psi for gas-water systems, and slightly less for water-oil systems). Higher salinity formation waters tend to contain less dissolved gas.

Table 2.2 Dissolution of Gases in Water (dissolved mole fraction) at 1 bar

Gas	$10^4 \times X_{\text{gas}} @ 1 \text{ bar}$	
	25°C	55°C
Helium	0.06983	0.07179
Argon	0.2516	0.1760
Radon	1.675	0.8911
Hydrogen	0.1413	0.1313
Nitrogen	0.1173	0.08991
Oxygen	0.2298	0.0164
Carbon dioxide	6.111	3.235
Methane	0.2507	0.1684
Ethane	0.3345	0.01896
Ammonium	1876	1066

X_{gas} = mole fraction of gas dissolved at 1 bar pressure, i.e. = $1/H_{\text{gas}}$.

Aqueous fluids are relatively incompressible compared to oils, and extremely so compared to gases (2.5×10^{-6} to 5×10^{-6} per psi decreasing with increasing salinity). Consequently, if a unit volume of formation water with no dissolved gases at reservoir pressure conditions is transported to surface pressure condition, it will expand only slightly compared to the same initial volume of oil or gas. It should be noted that formation waters containing a significant proportion of dissolved gases are more compressible than those that are not gas saturated. These waters expand slightly more on being brought to the surface. However the reduction in temperature on being brought to the surface causes the formation water to shrink and there is also a certain shrinkage associated with the release of gas as pressure is lowered. The overall result is that brines experience a slight shrinkage (< 5%) on being brought from reservoir conditions to the surface.

Formation waters generally have densities that are greater than those of oils, and dynamic viscosities that are a little lower (Table 2.3). The viscosity at high reservoir temperatures (>250°C) can be as low as 0.3 cP, rises to above 1 cP at ambient conditions, and increases with increasing salinity.

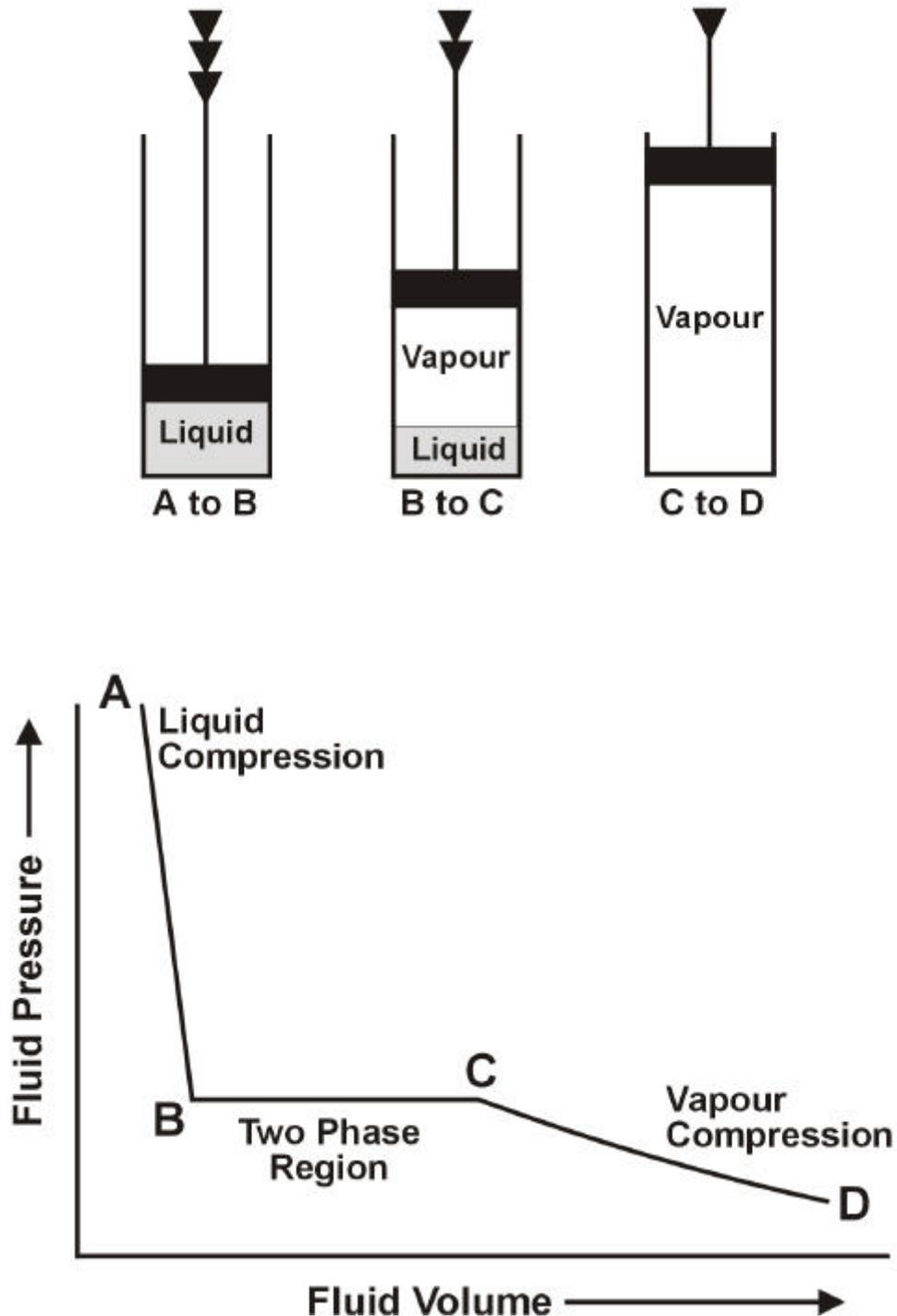
Table 2.3 Densities and Viscosities for a Typical Formation Water and a Refined Oil

Brine Component		Composition, g/l	
Pure water		Solvent	
NaCl		150.16	
CaCl ₂ .6H ₂ O		101.32	
MgCl ₂ .6H ₂ O		13.97	
Na ₂ SO ₄		0.55	
NaHCO ₃		0.21	
Fluid	Temperature, °C	Density, g/cm ³	Dynamic Viscosity, cP
Brine	20	1.1250	1.509
Brine	25	1.1237	1.347
Brine	30	1.1208	1.219
Kerosene	20	0.7957	1.830
Kerosene	25	0.7923	1.661
Kerosene	30	0.7886	1.514

2.4 Phase Behaviour of Hydrocarbon Systems

Figure 2.1 shows the pressure versus volume per mole weight (specific volume) characteristics of a typical pure hydrocarbon (e.g. propane). Imagine in the following discussion that all changes occur isothermally (with no heat flowing either into or out of the fluid) and at the same temperature. Initially the component is in the liquid phase at 1000 psia, and has a volume of about 2 ft³/lb.mol. (point A). Expansion of the system (A→B) results in large drops in pressure with small increases in specific volume, due to the small compressibility of liquids (liquid hydrocarbons as well as liquid formation waters have small compressibilities that are almost independent of pressure for the range of pressures encountered in hydrocarbon reservoirs). On further expansion, a pressure will be attained where the first tiny bubble of gas appears (point B). This is the *bubble point* or *saturation pressure* for a given temperature. Further expansion (B→C) now occurs at constant pressure with more and more of the liquid turning into the gas phase until no more fluid remains. The constant pressure at which this occurs is called the *vapour pressure* of the fluid at a given temperature. Point C represents the situation where the last tiny drop of liquid turns into gas, and is called the *dew point*. Further expansion now takes place in the vapour phase (C→D). The pistons in Figure 2.1 demonstrate the changes in fluid phase schematically. It is worth noting that the process A→B→C→D described above during expansion (reducing the pressure on the piston) is perfectly reversible. If a system is in state D, then application of pressure to the fluid by applying pressure to the pistons will result in changes following the curve D→C→B→A.

Figure 2.1 PV Phase Behaviour of a Pure Component



We can examine the curve in Figure 2.1 for a range of fluid temperatures. If this is done, the pressure-volume relationships obtained can be plotted on a pressure-volume diagram with the bubble point and dew point locus also included (Figure 2.2). Note that the bubble point and dew point curves join together at a point (shown by a dot in Figure 2.2). This is the *critical point*. The region under the bubble point/dew point envelope is the region where the vapour phase and liquid phase can coexist, and hence have an interface (the surface of a liquid drop or of a vapour bubble). The region above this envelope represents the region where the

Figure 2.2 PV Phase Behaviour of a Pure Component

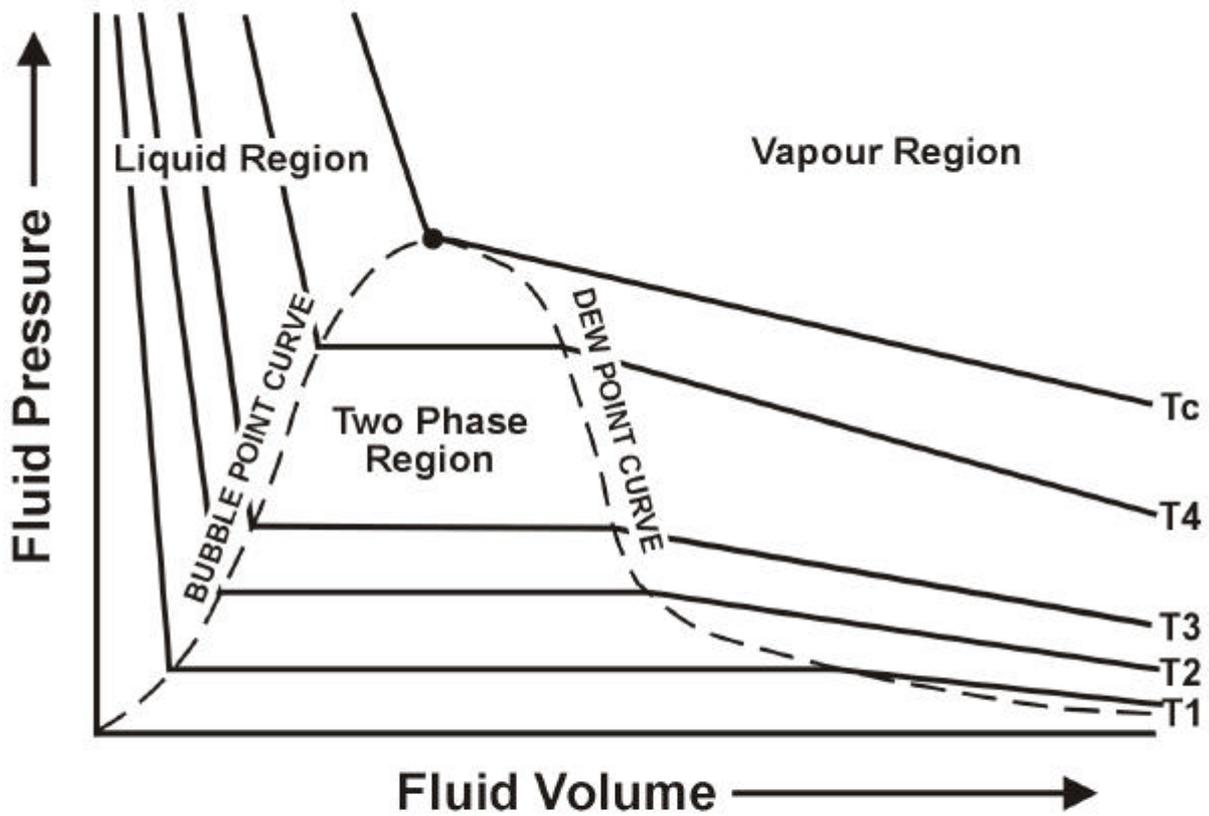
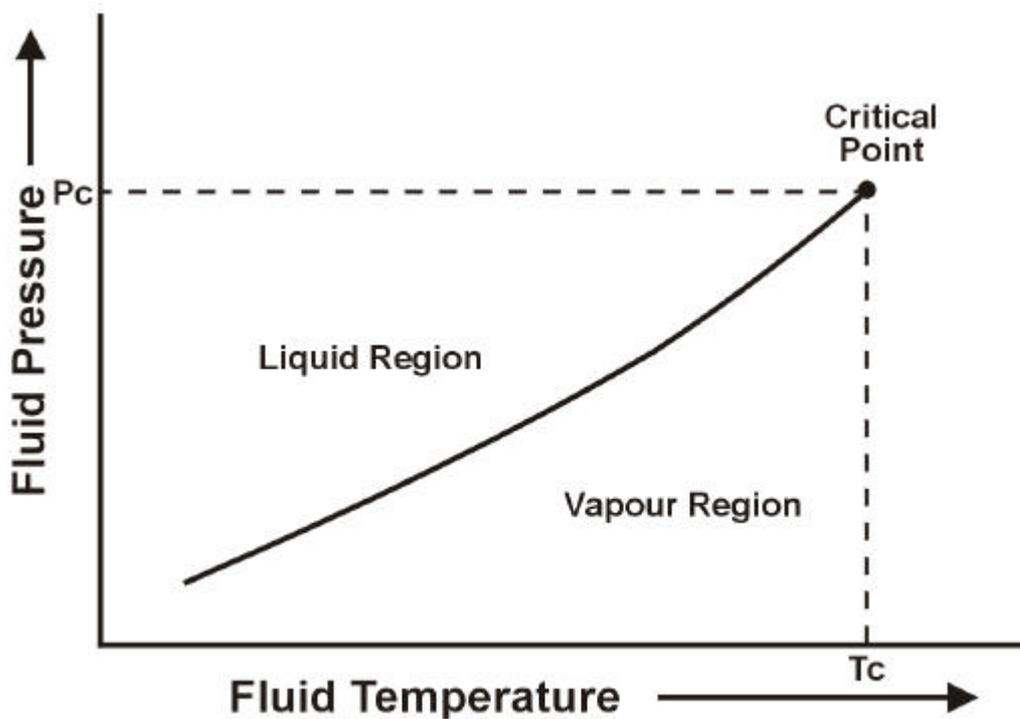


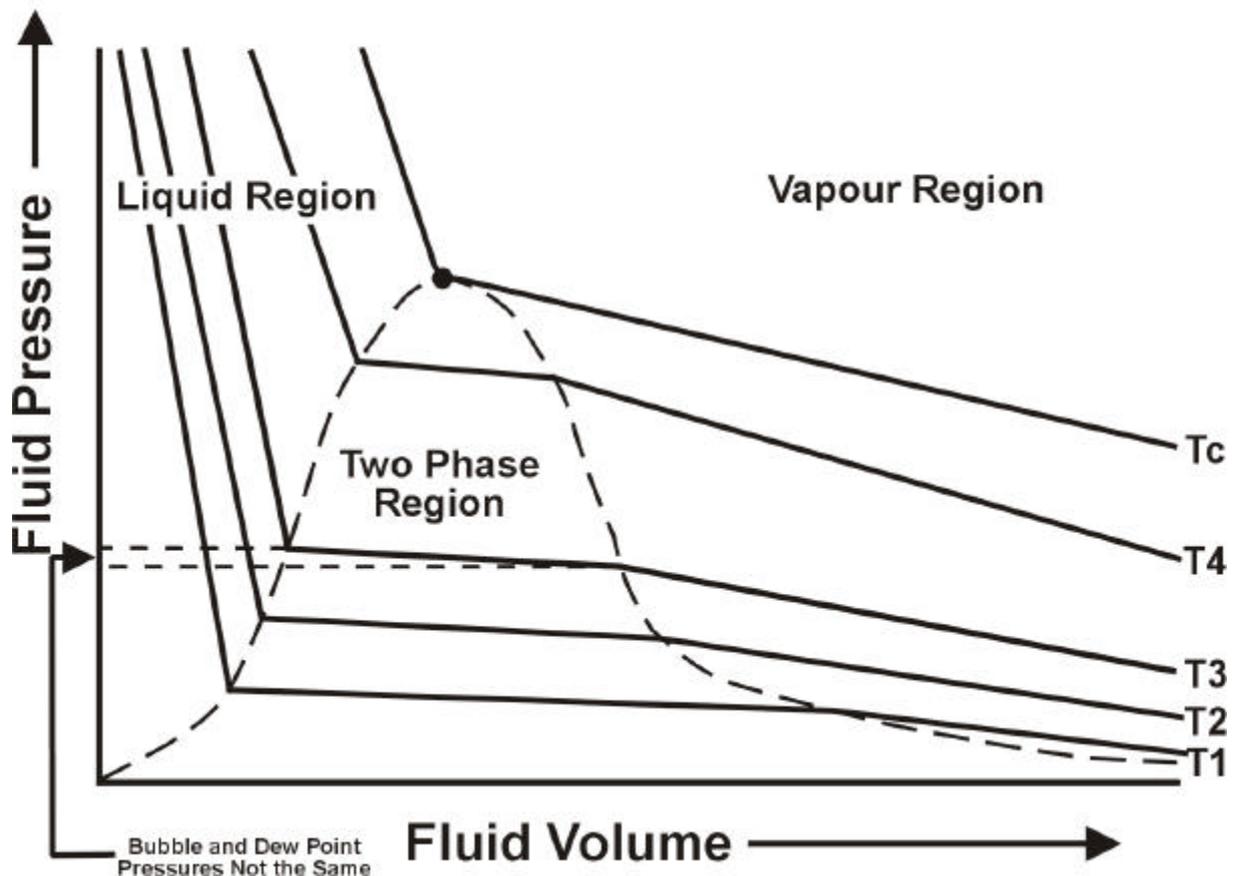
Figure 2.3 PT Phase Behaviour of a Pure Component



vapour phase and liquid phase do not coexist. Thus at any given constant low fluid pressure, reduction of fluid volume will involve the vapour condensing to a liquid via the two phase region, where both liquid and vapour coexist. But at a given constant high fluid pressure (higher than the critical point), a reduction of fluid volume will involve the vapour phase turning into a liquid phase without any fluid interface being generated (i.e. the vapour becomes denser and denser until it can be considered as a light liquid). Thus the critical point can also be viewed as the point at which the properties of the liquid and the gas become indistinguishable (i.e. the gas is so dense that it looks like a low density liquid and *vice versa*).

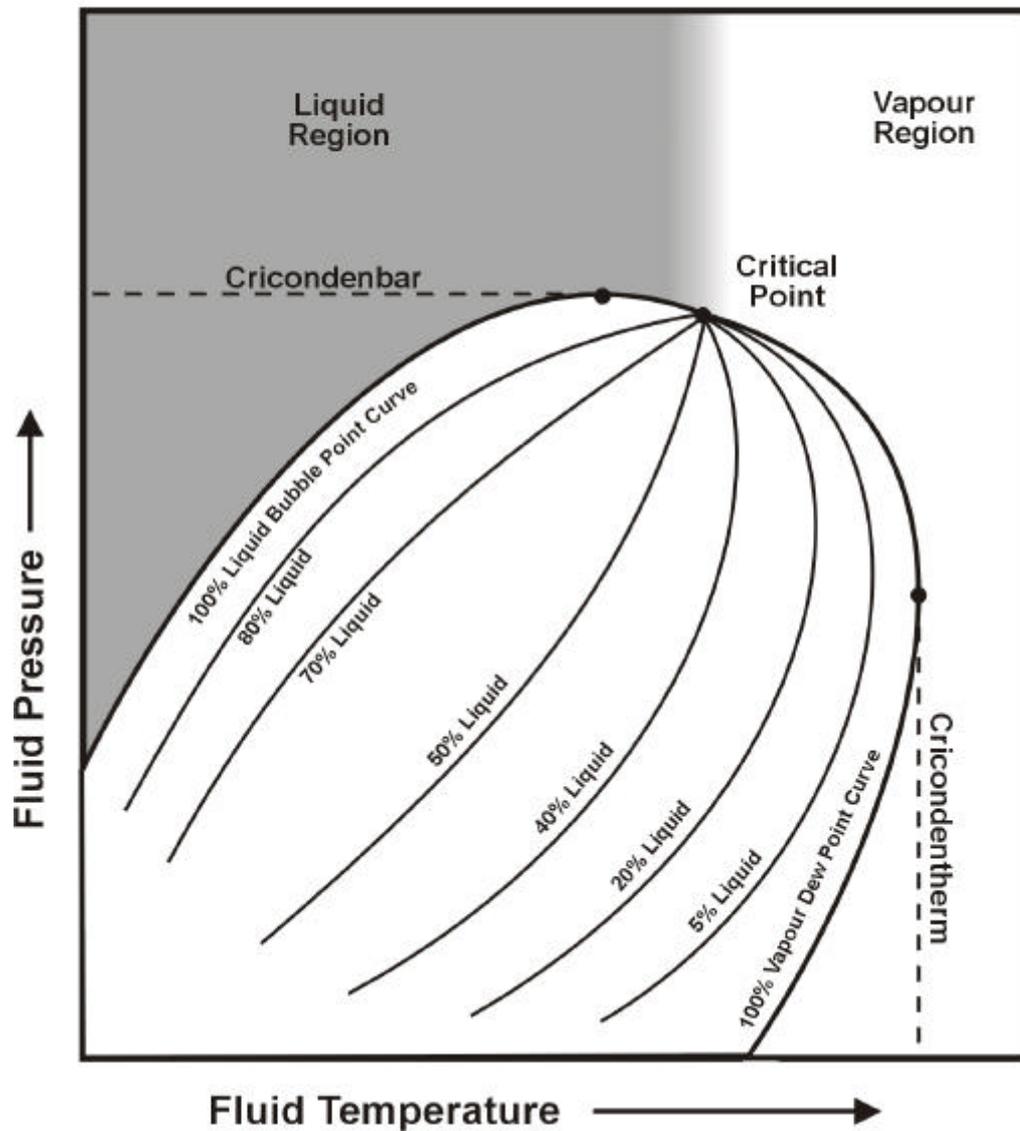
Suppose that we find the bubble points and dew points for a range of different temperatures, and plot the data on a graph of pressure against temperature. Figure 2.3 shows such a plot. Note that the dew point and bubble points are always the same for a pure component, so they plot as a single line until the peak of Figure 2.2 is reached, which is the *critical point*.

Figure 2.4 PV Phase Behaviour of Multi Component Systems



The behaviour of a hydrocarbon fluid made up of many different hydrocarbon components shows slightly different behaviour (Figure 2.4). The initial expansion of the liquid is similar to that for the single component case. Once the bubble point is reached, further expansion does

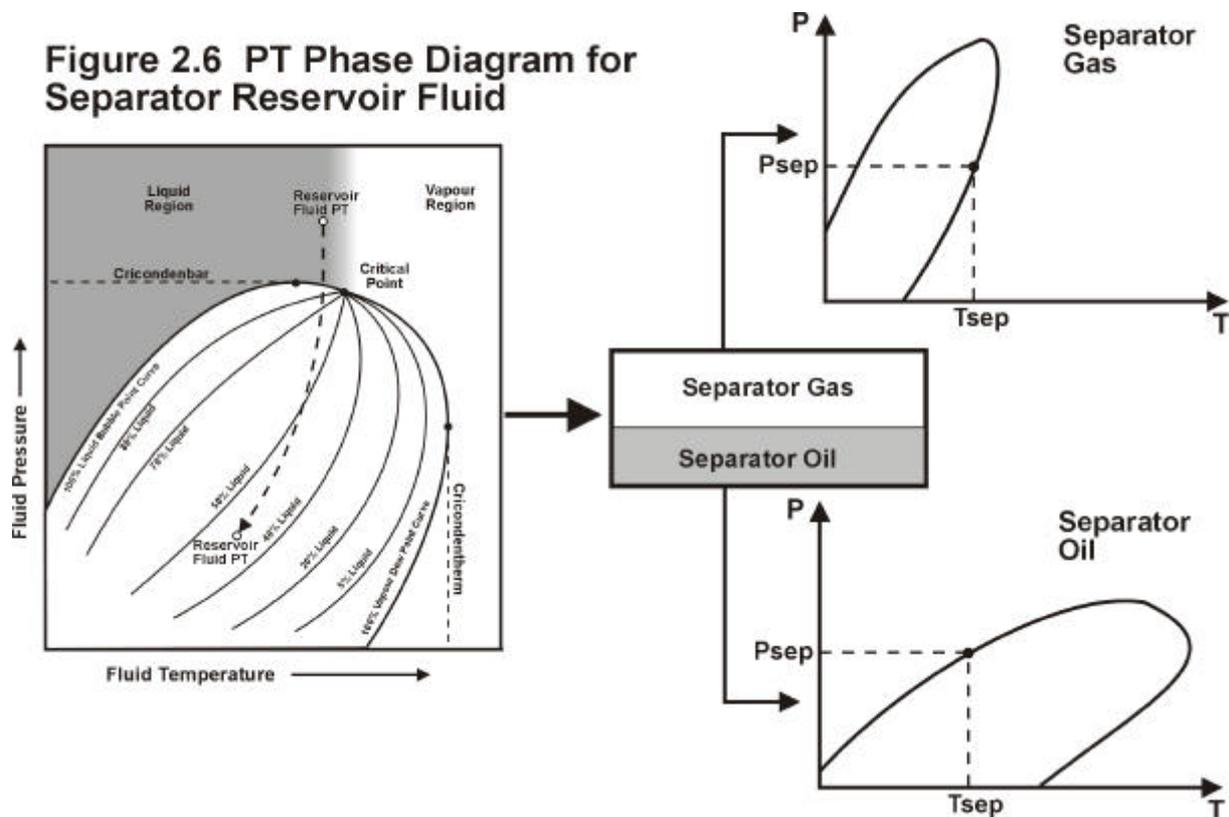
Figure 2.5 PT Phase Diagram for a Multi-component Fluid



not occur at constant pressure but is accompanied by a decrease in pressure (vapour pressure) due to changes in the relative fractional amounts of liquid to gas for each hydrocarbon in the vaporising mixture. In this case the bubble points and dew points differ, and the resulting pressure-temperature plot is no longer a straight line but a *phase envelope* composed of the bubble point and dew point curves, which now meet at the critical point (Figure 2.5). There are also two other points on this diagram that are of interest. The *cricondenbar*, which defines the pressure above which the two phases cannot exist together whatever the temperature, and the *cricondentherm*, which defines the temperature above which the two phases cannot exist together whatever the pressure. A fluid that exists above the bubble point curve is classified as *undersaturated* as it contains no free gas, while a fluid at the bubble point curve or below it is classified as *saturated*, and contains free gas.

Figure 2.6 shows the PT diagram for a reservoir fluid, together with a production path from the pressure and temperature existing in the reservoir to that existing in the separator at the

surface. Note that the original fluid was an undersaturated liquid at reservoir conditions. On production the fluid pressure drops fast with some temperature reduction occurring as the fluid travels up the borehole. All reservoirs are predominantly isothermal because of their large thermal inertia. This results in the production path of all hydrocarbons initially undergoing a fluid pressure reduction. Figure 2.6 shows that the ratio of vapour to liquid at separator conditions is approximately 55:45. If we analyse the PT characteristics of the separator gas and separator fluid *separately* then we would find that the separator pressure-temperature point representing the separator conditions falls on the dew point line of the separator gas PT diagram, and on the bubble point line of the separator oil PT diagram. This indicates that the shape of the PT diagram for various mixtures of hydrocarbon gases and liquids varies greatly. Clearly, therefore *it is extremely important to understand the PT phase envelope as it can be used to classify and understand major hydrocarbon reservoirs.*

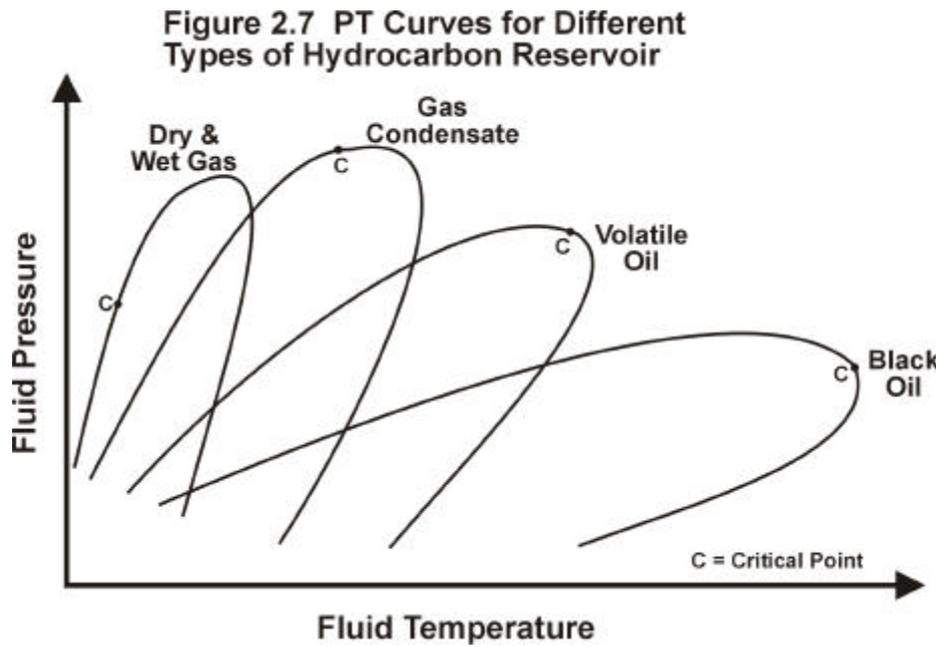


2.5 PVT Properties of Hydrocarbon Fluids

2.5.1 Cronquist Classification

Hydrocarbon reservoirs are usually classified into the following five main types, after Cronquist, 1979:

- Dry gas
- Wet gas
- Gas condensate
- Volatile oil
- Black oil



Each of these reservoirs can be understood in terms of its phase envelope. The typical components of production from each of these reservoirs is shown in Table 2.4, and a schematic diagram of their PT phase envelopes is shown in Figure 2.7.

Table 2.4 Typical Mol% Compositions of Fluids Produced from Cronquist Reservoir Types

Component or Property	Dry Gas	Wet Gas	Gas Condensate	Volatile Oil	Black Oil
CO ₂	0.10	1.41	2.37	1.82	0.02
N ₂	2.07	0.25	0.31	0.24	0.34
C ₁	86.12	92.46	73.19	57.60	34.62
C ₂	5.91	3.18	7.80	7.35	4.11
C ₃	3.58	1.01	3.55	4.21	1.01
iC ₄	1.72	0.28	0.71	0.74	0.76
nC ₄	-	0.24	1.45	2.07	0.49
iC ₅	0.50	0.13	0.64	0.53	0.43
nC ₅	-	0.08	0.68	0.95	0.21
C _{6s}	-	0.14	1.09	1.92	1.16
C ₇₊	-	0.82	8.21	22.57	56.40
GOR (SCF/STB)	∞	69000	5965	1465	320
OGR (STB/MMSCF)	0	15	165	680	3125
API Specific Gravity, γ_{API} , °API	-	65.0	48.5	36.7	23.6
C ₇₊ Specific Gravity, γ_o	-	0.750	0.816	0.864	0.920

Note: Fundamental specific gravity γ_o is equal to the density of the fluid divided by the density of pure water, and that for C₇₊ is for the bulked C₇₊ fraction. The API specific gravity γ_{API} is defined as; $\gamma_{API} = (141.5/\gamma_o) - 131.5$.

2.5.2 Dry Gas Reservoirs

A typical dry gas reservoir is shown in Figure 2.8. The reservoir temperature is well above the cricondentherm. During production the fluids are reduced in temperature and pressure. The temperature-pressure path followed during production does not penetrate the phase envelope, resulting in the production of gas at the surface with no associated liquid phase. Clearly, it would be possible to produce some liquids if the pressure is maintained at a higher level. In practice, the stock tank pressures are usually high enough for some liquids to be produced (Figure 2.9). Note the lack of C_{5+} components, and the predominance of methane in the dry gas in Table 2.4.

Figure 2.8 PT Phase Diagram for a Dry Gas

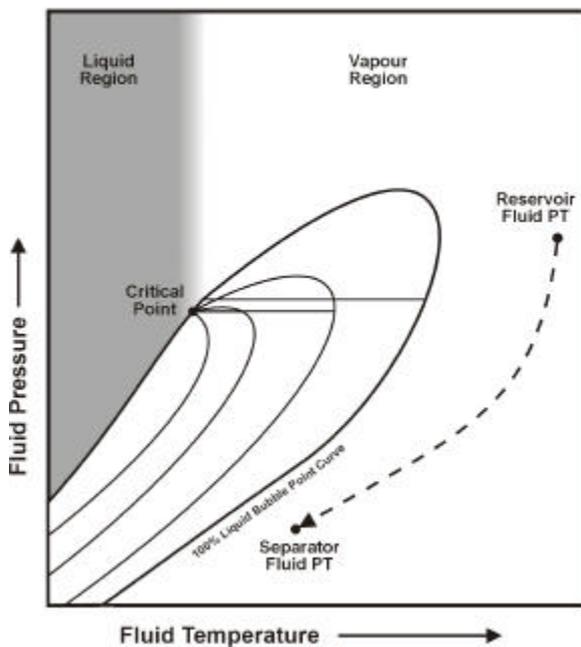
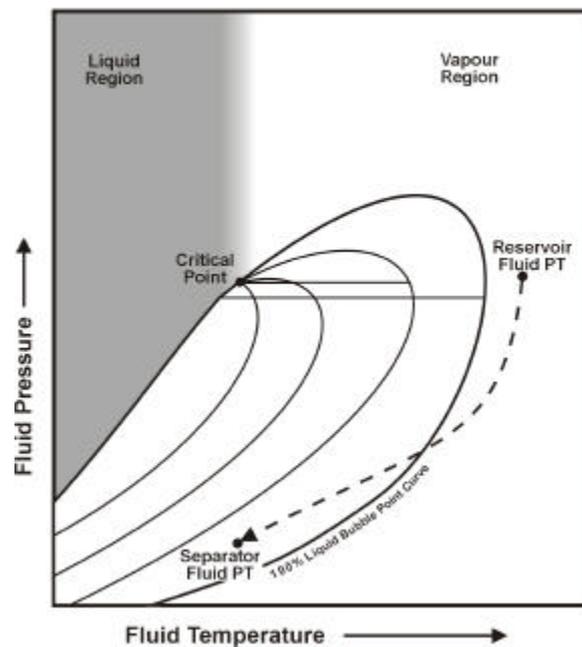


Figure 2.9 PT Phase Diagram for a Wet Gas



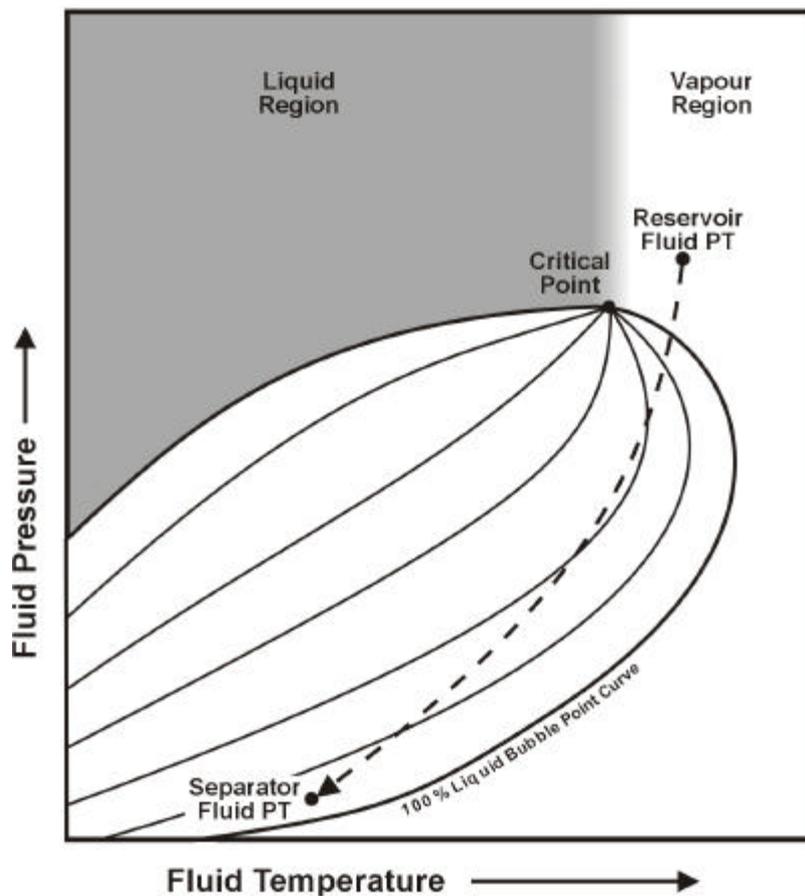
2.5.3 Wet Gas Reservoirs

A typical wet gas reservoir is shown in Figure 2.9. The reservoir temperature is just above the cricondentherm. During production the fluids are reduced in temperature and pressure. The temperature-pressure path followed during production just penetrates the phase envelope, resulting in the production of gas at the surface with a small associated liquid phase. Note the presence of small amounts of C_{5+} components, and the continuing predominance of methane in the wet gas in Table 2.4. The GOR (gas-oil ratio) has fallen as some liquid is being produced. However, this liquid usually amounts to less than about 15 STB/MMSCF. Note also the small specific gravity for C_{7+} components (0.750), indicating that the majority of the C_{7+} fraction is made up of the lighter C_{7+} hydrocarbons.

2.5.4 Gas Condensate Reservoirs

A typical gas condensate reservoir is shown in Figure 2.10. The reservoir temperature is such that it falls between the temperature of the critical point and the cricondentherm. The production path then has a complex history. Initially, the fluids are in an indeterminate vapour phase, and the vapour expands as the pressure and temperature drop. This occurs until the dewpoint line is reached, whereupon increasing amounts of liquids are condensed from the vapour phase. If the pressures and temperatures reduce further, the condensed liquid may re-evaporate, although sufficiently low pressures and temperatures may not be available for this

Figure 2.10 PT Phase Diagram for a Gas Condensate



to happen. If this occurs, the process is called *isothermal retrograde condensation*. Isobaric retrograde condensation also exists as a scientific phenomenon, but does not occur in the predominantly isothermal conditions of hydrocarbon reservoirs. Thus, in gas condensate reservoirs, the oil produced at the surface results from a vapour existing in the reservoir. Note the increase in the C_{7+} components and the continued importance of methane in Table 2.4. The GOR has decreased significantly, the OGR has increased, and the specific gravity of the C_{7+} components is increasing, indicating that greater fractions of denser hydrocarbons are present in the C_{7+} fraction.

2.5.5 Volatile Oil Reservoirs

A typical volatile oil reservoir is shown in Figure 2.11. The reservoir PT conditions place it inside the phase envelope, with a liquid oil phase existing in equilibrium with a vapour phase having gas condensate compositions. The production path results in small amounts of further condensation, and re-evaporation can occur again, but should be avoided as much as possible by keeping the stock tank pressure as high as possible. Reference to Table 2.4 shows that the fraction of gases is reduced, and the fraction of denser liquid hydrocarbon liquids is increased, compared with the previously discussed reservoir types. Changes in the GOR, OGR and specific gravities are in agreement with the general trend.

2.5.6 Black Oil Reservoirs

Figure 2.11 PT Phase Diagram for a Volatile Oil

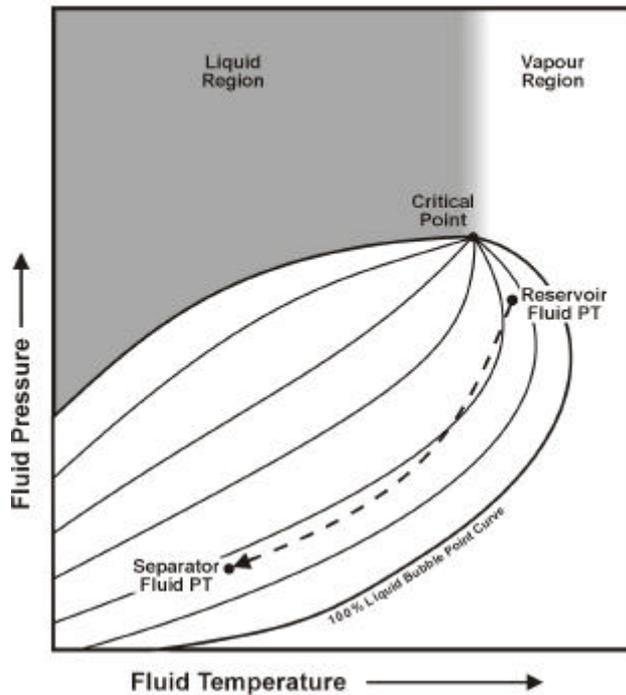
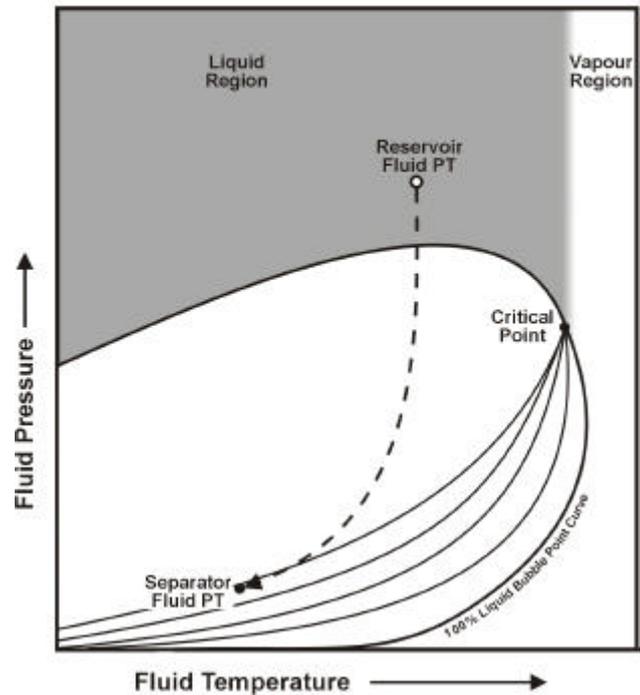


Figure 2.12 PT Phase Diagram for a Black Oil



A typical gas condensate reservoir is shown in Figure 2.12. The reservoir temperature is much lower than the temperature of the critical point of the system, and at pressures above the cricondenbar. Thus, the hydrocarbon in the reservoir exists as a liquid at depth. The production path first involves a reduction in pressure with only small amounts of expansion in the liquid phase. Once the bubble point line is reached, gas begins to come out of solution and continues to do so until the stock tank is reached. The composition of this gas changes very little along the production path, is relatively lean, and is not usually of economic importance when produced. Table 2.4 shows a produced hydrocarbon fluid that is now dominated by heavy hydrocarbon liquids, with most of the produced gas present as methane. The GOR, OGR and specific gravities mirror the fluid composition.