

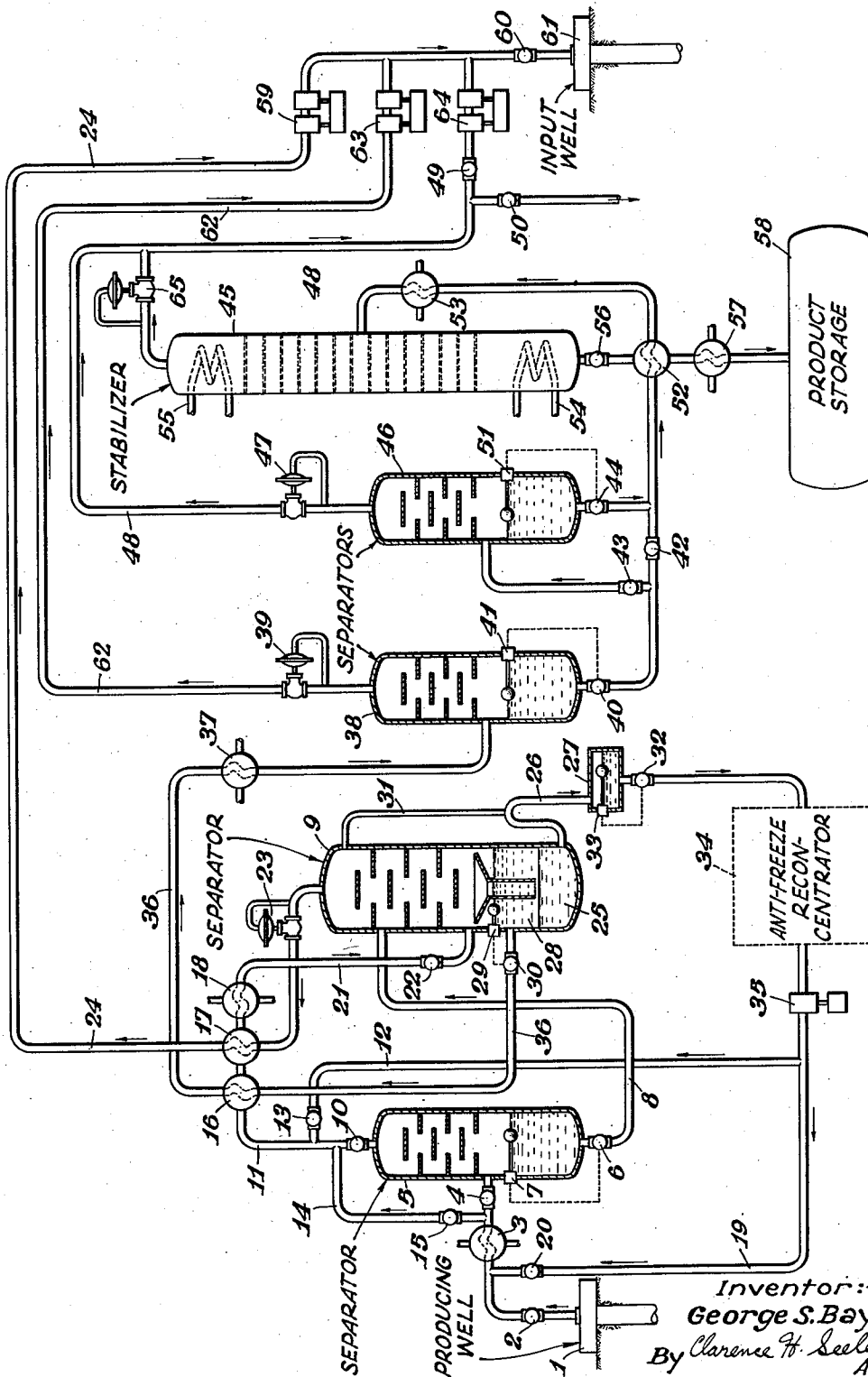
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RECOVERY OF LIQUID HYDROCARBONS FROM WELL FLUIDS

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RECOVERY OF LIQUID HYDROCARBONS
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11 Claims. (Cl. 62-175.5)

This invention relates to the recovery of liquid hydrocarbons from well fluids and more particularly to improved methods and apparatus for economically recovering light liquid hydrocarbons from well fluids produced at high pressures with higher total recoveries of these hydrocarbons from the producing formations than has heretofore been possible.

Before the advent of deep drilling, wells were classified as oil or gas wells depending upon whether a substantial amount of crude oil was obtained or whether the only product was natural gas, and it was early recognized that the natural gas from different wells varied considerably in "wetness", i. e., the content of liquefiable hydrocarbons capable of being recovered therefrom by well-known methods such as cooling, compression, absorption in a liquid medium, adsorption or combinations of these. In recent years, however, certain fields have been discovered in which the only products are natural gas and a relatively small amount of a volatile hydrocarbon mixture which is called distillate. Some wells have also been found which produce at a high gas-oil ratio relatively small amounts of heavier hydrocarbons such as those usually associated with the term "crude oil" together with the more volatile distillate.

My invention is primarily concerned with distillate wells but can also be advantageously applied to wells of the latter type. These wells have many characteristics in common, including high pressure and high gas-oil ratio, and for purposes of simplicity both will be referred to herein as "distillate wells" and the marketable products therefrom as "distillates".

The specifications which distillates must meet in order to be readily marketable vary considerably depending upon the uses to which they are to be put, and these specifications may be for example those for natural gasoline, motor fuel or pipe line crude oil. In any of these cases those constituents lighter than butane cannot be present in very large amounts and in some cases only a limited amount of butane can be present in the distillate. Unstabilized hydrocarbon liquids recovered from well fluids will therefore be referred to herein as "condensates" to distinguish them from marketable distillates.

The reservoirs from which distillates are produced are invariably at quite high pressures and temperatures, e. g. 3000-4000 pounds per square inch and 175°-225° F., and it is believed that in many cases the hydrocarbons therein exist in a single phase and that in others a portion of

the heavy constituents is in a separate liquid phase. In any case the composition, pressure and temperature of the well fluids at the well head are usually such that a small amount of condensate is formed and can be separated at that point. The usual treatment is to reduce the pressure of the well fluid in one or more stages to a relatively low value, e. g. atmospheric pressure to 200-500 pounds per square inch and separate additional condensate from each stage. This procedure does not give the maximum yield of either total condensate or marketable distillate from the well fluid, and in addition gradually lowers the reservoir pressure to a point at which more and more of the valuable heavier hydrocarbons are precipitated in the pores of the producing formation, and consequently are not recovered.

It would normally be expected that decreasing the pressure on a hydrocarbon mixture would cause increased vaporization rather than condensation. It is well understood, however, that every mixture of hydrocarbons has a critical pressure and temperature at which the liquid and vapor phases have identical properties including composition, and so are indistinguishable. Below this critical temperature, the reduction of pressure isothermally causes vaporization of any liquid present, the lighter constituents being vaporized more rapidly than the heavier ones. There is, however, a range of temperature above the critical at which a hydrocarbon mixture under sufficiently high pressure exists in a single phase and isothermal pressure reduction of such a single phase mixture within that range of temperature will cause the gradual separation or condensation of a liquid phase richer in heavy constituents than the original mixture. This phenomenon, which is known as retrograde condensation, continues until a certain pressure is reached and further isothermal expansion causes normal evaporation of the separated liquid phase. When this procedure is reversed and the hydrocarbon mixture, which is now in the vapor phase, is subjected to isothermal compression, at first a portion of the heavier constituents condense out as a separate liquid phase until the same pressure is reached, after which the condensed phase vaporizes. This vaporization is sometimes known as retrograde vaporization but it is the same phenomenon as retrograde condensation carried out in the opposite direction. Since this invention relates primarily to the recovery of condensates by pressure reduction, the phenomenon will hereinafter be referred to as retrograde

condensation, and the pressure at which the maximum amount of retrograde condensate is obtained will be referred to as the critical retrograde condensation pressure.

- 5 From the above it will be seen that the separation of condensate from the well fluid from a distillate well by pressure reduction is due to retrograde condensation. It would normally be expected therefore that the best method of re-
- 10 covering distillate from a distillate well would be to reduce the pressure to the point at which the maximum amount of marketable distillate separates out as a liquid phase and withdraw the separated condensate containing this maximum
- 15 amount of distillate from the residual gas. Because of the fact that in the retrograde condensation range the equilibrium liquid phase composition gradually becomes richer in valuable heavy constituents with decreasing pressure, the
- 20 pressure for maximum distillate recovery is considerably lower, e. g. 100-300 pounds per square inch lower than the critical retrograde condensation pressure.

I have found that the maximum economic ultimate yield of distillate from a given reservoir requires the use of certain optimum separator conditions above the critical retrograde condensation pressure and reinjection of the residual gas into the reservoir to maintain the pressure therein. By this means I am able to pick up and produce as a part of the well fluid any heavy hydrocarbons which may be in the liquid phase in the reservoir as well as to avoid the undesirable loss of such constituents mentioned above.

- 35 It is an object of my invention to provide a method of economically producing valuable liquid hydrocarbons from high pressure wells and simultaneously insuring against loss of such hydrocarbons in irrecoverable form in the reservoir.
- 40 Another object is to provide a novel unitary process for the economical production of marketable distillate simultaneously with maximum ultimate recovery from the producing formation. A further object is to provide novel apparatus which
- 45 is particularly suitable for practicing my improved methods of distillate recovery. Further objects and advantages of my invention will be apparent from the following detailed description read in conjunction with the drawing which represents schematically a suitable apparatus for practicing my invention.

- In one of its broadest aspects my invention comprises the separation of condensate rich in valuable normally liquid constituents under substantially equilibrium conditions from the well fluid from a distillate well at a temperature about 25°-150° F. above the critical temperature for the particular well fluid and a pressure about
- 60 100-500 pounds per square inch above the critical retrograde condensation pressure, and compressing the residual gas for reinjection into the producing formation through an input well to maintain the pressure therein. Preferably the
- 65 temperature used is in the lower portion of this range because a larger yield of condensate and of the valuable heavier hydrocarbon in the well fluid is obtained, thereby reducing the amount of residual gas which must be compressed for
- 70 recycling to the producing formation to obtain a given ultimate yield therefrom. Equilibrium separation in the temperature and pressure ranges specified has the great advantage that excellent yields of marketable distillate are ob-
- 75 tained and simultaneously the cost of compress-

ing the residual gas for reinjection is kept at a minimum.

Obviously the actual values for the optimum separator conditions vary considerably with varying well compositions, some typical compositions being given in terms of mol fractions in the following table:

	A	B	C	D
CH ₄	0.8540	0.8854	0.9164	0.9074
C ₂ H ₆	.0480	.0497	.0377	.0446
C ₃ H ₈	.0211	.0235	.0155	.0179
C ₄ H ₁₀	.0124	.0125	.0092	.0096
C ₅ H ₁₂	.0073	.0057	.0044	.0045
C ₆ H ₁₄	.0068	.0051	.0038	.0029
C ₇ H ₁₆ and heavier.....	.0188	.0181	.0130	.0131

It is recognized that the critical temperature and critical retrograde condensation pressure of a particular mixture are rather difficult of experimental determination. In view of the fact that all of the well fluids to which my invention is applicable contain a very large proportion of methane, certain temperature and pressure ranges can be stated which will be optimum for a great majority of such well fluids. For example, in most cases I prefer to carry out the equilibrium separation step at a temperature of about -50° to +100° F. and preferably at about -35° to +25° F., and a pressure of about 800 to 1500 pounds per square inch and preferably at about 950 to 1200 pounds per square inch.

My invention also comprises many additional features and these can best be understood from the following specific example. Referring now to the drawing, a producing well 1 is shown which is of the distillate type as herein defined. The well fluid flowing therefrom at the well head will be at a relatively high pressure and temperature, for example, about 2000-4000 or more pounds per square inch and 75°-200° F. depending primarily upon the bottom hole temperature and pressure, the composition and the rate of production. The pressure at the well head decreases as the rate of flow increases, such pressure drops for example ranging up to 1000 pounds per square inch below the pressure in the subsurface reservoir at high rates of production, and the temperature at the well head is in the neighborhood of 50°-150° F. below the reservoir temperature. In most cases such pressure and temperature drops will cause the formation of condensate as the well fluid flows upward through the tubing, and it is important that the rate of flow be sufficiently high to prevent any liquid flow down the tubing, which would give rise to slugging and erratic pressure and temperature conditions. For purposes of example, it will be assumed that the well fluid produced by well 1 has a well head pressure of 3000 pounds per square inch and temperature of 135° F., and that it contains a small amount of liquid condensate.

The well fluid passes through valve 2 which is normally wide open and therefore does not serve to give any substantial pressure reduction and thence through cooler 3, preferably utilizing water as the cooling medium, which lowers the temperature of the well fluid to a temperature above that at which natural gas hydrates form under these conditions due to the small amount of moisture present therein. At 3000 pounds per square inch this temperature will generally lie in the range 80-90° F., and will be higher at higher pressures. The cooled fluid

preferably passes through valve 4 into separator 5 in which the liquid phase entering the base of the well, that formed in the upward passage through the well and that formed in cooler 3 are separated out, are withdrawn through valve 6 controlled by liquid level controller 7 and pass through line 8 to separator 9. The gases from separator 5 pass out through valve 10 and line 11 and a small amount of antifreeze solution which can, for instance, be a calcium chloride solution or other brine, glycerine, glycol or the like, is injected into line 11 from line 12 under the control of valve 13. Line 14 by-passing separator 5 is controlled by valve 15, which is kept closed in the type of operation being described. The gases carrying the antifreeze material, the purpose of which is to avoid clogging of the apparatus by natural gas hydrates, pass through three successive coolers 16, 17 and 18 although it is to be understood that other cooling arrangements can be used. As shown, cooler 16 operates by indirect heat exchange with the low temperature condensate from separator 9, cooler 17 operates by indirect heat exchange with the low temperature gases from separator 9 and cooler 18 operates by indirect heat exchange with an external cooling medium which can be cold water or brine, or ammonia or other refrigerant supplied by a conventional refrigeration cycle.

With the arrangement as hereinbefore described, and when operating upon a well fluid which is relatively high in moisture content, it is possible that there will be enough moisture contained in the liquids collected in separator 5 to cause the formation of gas hydrates in line 8 after the considerable pressure drop which occurs across valve 6. To provide for this contingency, an additional antifreeze line 19 controlled by valve 20 is shown for the injection of antifreeze material into the well fluid before it enters cooler 3.

While reference is made herein to the use of a liquid antifreeze material which can be reconcentrated and recycled as will be described below, it is not imperative that the prevention of gas hydrate formation be handled in this manner. For instance, a gaseous antifreeze material can be used in the same way, recovered and recycled, or the well fluid can be dried by adsorption, preferably before cooling, to eliminate hydrate-forming tendencies.

The cooled fluids which can suitably be at a temperature of from about -25°F. to about $+75^{\circ}\text{F.}$, or preferably from about 0°F. to about $+60^{\circ}\text{F.}$, pass through line 21 and valve 22 and are expanded into separator 9. The pressure in separator 9 is controlled by valve 23 leading to line 24 for recompression and ultimate reinjection into the producing formation. The main pressure drop between separators 5 and 9 is across valves 6 and 22.

The pressure maintained in separator 9 lies within the range of about 100 to 500 pounds per square inch above the critical retrograde condensation pressure in accordance with my invention. As stated above in most cases the pressure in separator 9 can be from about 800 pounds per square inch to about 1500 pounds per square inch, and preferably from about 950 to about 1200 pounds per square inch.

The pressure reduction is, of course, accompanied by a temperature reduction due to the Joule-Thomson effect and the temperature in separator 9 (which should, of course, be suitably insulated) can be from about -50°F. to about

$+100^{\circ}\text{F.}$, or preferably from about -35°F. to about $+25^{\circ}\text{F.}$ The temperatures in the lower portion of this range are made possible by the use of antifreeze, and result in improved recovery of marketable distillate.

The following example shows the improvement in yield of valuable liquid hydrocarbons obtained by lowering the temperature of separation under the high pressures specified above: A typical distillate well fluid (Katy Field, Texas) contains 1.181 gallons of hydrocarbons having more than four carbon atoms per 1000 cubic feet (under standard conditions) of gas composed of hydrocarbons having three or less carbon atoms per molecule. When separation is carried out at 1000 pounds per square inch and 80°F. , 68.0 per cent of these heavy hydrocarbons are in the liquid condensate, while at the same pressure and 0°F. , 78.7 of the heavy hydrocarbons are in the condensate.

The pressure and temperature reduction result, of course, in the formation of an additional quantity of condensate, and the total condensate together with the antifreeze material settles to the bottom of separator 9, where stratification takes place since the aqueous antifreeze material is substantially hydrocarbon insoluble. The lower layer of antifreeze is withdrawn through water leg 26 into trap 27.

The upper layer 28 of hydrocarbon condensate in separator 9 has its upper surface maintained at a constant level by means of float control 29 operating on valve 30. As the antifreeze accumulates the interface between antifreeze 25 and condensate 28 rises until a point is reached at which the hydrostatic head of liquid in separator 9 is sufficient to carry the antifreeze over the hump of water leg 26. The pressures in separator 9 and in trap 27 are maintained equal by means of connecting vapor pipe 31. From trap 27 the antifreeze passes through valve 32 controlled by liquid level controller 33 into antifreeze reconcentrator 34 which can be of conventional design and which is not shown in detail. The reconcentrated antifreeze passes through pump 35, line 12 and valve 13 back into the hydrocarbon fluid entering coolers 16 to 18, and also under some conditions through line 19 and valve 20 as stated above. The condensate passes through valve 30, line 36 and heat exchanger 16, in which it serves to lower the temperature of the fluid passing to separator 9.

By passing condensate from separator 5 through line 8 to separator 9, I find that the total yield of distillate containing butane and heavier hydrocarbons can be materially increased. Thus, for example, with South Jennings, Louisiana well fluid, separator 5 can be operated at well head pressure and temperature, 3140 pounds per square inch and 130°F. (without using cooler 3), and separator 9 can be operated at 1200 pounds per square inch and 0°F. With these conditions the total yield of butanes and heavier separated as liquid is 1.076 gallons per 1000 cubic feet of total propanes lighter if condensate is separately withdrawn from separators 5 and 9, while with the condensate from separator 5 passing to separator 9 to alter the phase conditions existing therein, the total yield is increased to 1.109 gallons per 1000 cubic feet.

While I prefer to use separator 5 to remove condensate from the well fluid at substantially well head pressure and to pass this condensate into separator 9 as described above, since by

this means I am able to obtain more contact of gas and liquid and consequently a somewhat closer approach to equilibrium conditions in separator 9, these steps are not essential parts of my invention and may be omitted by opening valve 15 in separator by-pass line 14 and closing valves 4 and 10.

After passing through heat exchanger 16, the temperature of the condensate is additionally increased by means of heater 37. Thus, for instance, this heater can increase the temperature to a value within the range from about 200° F. to about 400° F., for instance 350° F., at about the pressure existing in separator 9 although there is, of course, some slight pressure drop. The purpose of this heating is to drive off a considerable quantity of the methane and ethane contained in the condensate before the pressure thereof is reduced as will hereinafter appear. By using heat to drive off methane and ethane under relatively high pressure conditions, for instance 800 to 1500 pounds per square inch, recompression and stabilization costs are greatly reduced.

From heater 37 the condensate, now containing a considerable amount of vapor phase material, passes into separator 38 where the liquid fraction and the vapors separate. The vapors pass overhead through back pressure control valve 39 while the liquid fraction collects in the bottom of the separator and is withdrawn through valve 40 controlled by liquid level controller 41. This fraction can be passed through valve 42 (valves 43 and 44 being closed) directly into stabilizer tower 45, or additional methane and ethane can be removed by flashing the distillate at a lower pressure prior to introduction into stabilizer tower 45, and this is usually preferable. It can be accomplished by closing valve 42 and opening valves 43 and 44 whereupon the liquid fraction passes into separator 46, the pressure in which is controlled by back pressure control valve 47 at some value substantially less than that existing in separator 38, for instance 300 to 500 pounds per square inch. At this pressure the remaining liquid collects at the bottom of the separator 46 and the low pressure gas passes out through control valve 47 and line 48, whence it passes either through valve 49 for recompression and ultimate reinjection into the producing formation or through valve 50 for other use.

Valve 44 is controlled by liquid level controller 51 and the liquid removed through this valve or that coming directly from separator 38 passes through heat exchanger 52 where its temperature is raised by indirect heat exchange with the hot stabilized distillate from stabilizer 45. Supplemental heat is then added by means of heater 53 and the liquid passes into stabilizer tower 45 which can be of conventional design and which is preferably operated at from about 200 to about 400 pounds per square inch, for instance about 350 pounds per square inch. Heat is applied to the bottom of the stabilizer by means of heating coil 54 and reflux is provided by means of dephlegmating coil 55. The stabilized distillate passes through valve 56, heat exchanger 52 and cooler 57 to product storage tank 58.

While I have shown stabilizer 45 as my preferred means of producing a distillate of a quality meeting specifications, the same products can be obtained, although with lower yields, by further stages of expansion and separation in a manner well known in the art, and this procedure is also

contemplated as an alternative method of carrying out my invention.

Relatively high pressure gases from separator 9 pass through line 24, are recompressed by compressor 59 to a pressure substantially higher, e. g. 500-1000 pounds per square inch higher, than that of the fluid leaving producing well 1, and then pass through valve 60 into input well 61 for reinjection into the producing formation. Similarly the gases at slightly lower pressure from separator 38 pass through line 62, are recompressed by compressor 63 and injected into input well 61, and, as previously mentioned, the gases from separator 46 can be recompressed if desired by compressor 64 and similarly reinjected. Likewise the off-gases from stabilizer 45 pass through back pressure control valve 65 and line 48 and can then be reinjected with gases from separator 46 by means of compressor 64 or they can be withdrawn through valve 50.

Alternatively, of course, a single set of compressors can be used for all of these gases but since they exist at varying pressures it is preferably to use the arrangement shown.

From the above description it can be seen that I have provided a novel and economical process of recovering marketable distillate from high pressure distillate wells and simultaneously maintaining the reservoir pressure so as to prevent precipitation and loss of valuable heavy constituents in the producing formation, and also to cause any such constituents which are present in the formation in the liquid state to enter the producing well as a part of the well fluid.

This is a continuation-in-part of my copending patent application Serial No. 232,401 filed September 29, 1938.

While I have described my invention in connection with certain specific embodiments thereof, it is to be understood that these are by way of illustration and not by way of limitation, and I do not mean to be bound thereby but only to the subject matter of the appended claims.

I claim:

1. The method of recovering liquid hydrocarbons from a fluid produced by a well of the distillate type which comprises expanding said fluid into a separation stage maintained at a temperature within the range from about -50° to about +100° F. and a pressure within the range from about 800 to about 1500 pounds per square inch, separating the hydrocarbon condensate formed at said temperature and pressure, from the residual gas, heating said condensate to an elevated temperature and passing it to a second separation stage maintained at substantially the same pressure as that in said first separation stage to remove a gaseous fraction containing substantial quantities of light hydrocarbon gases therefrom, and compressing said residual gas and said gaseous fraction for reinjection into the formation from which said fluid was produced.

2. The method of recovering liquid hydrocarbons from a fluid produced by a well of the distillate type which comprises expanding said fluid into a separation stage maintained at a temperature within the range from about -50° to about +100° F. and a pressure within the range from about 800 to about 1500 pounds per square inch, separating the hydrocarbon condensate formed at said temperature and pressure, from the residual gas, heating said condensate to an elevated temperature and passing it to a second separation stage maintained at substantially the same pressure as that in said first separation stage to

remove a gaseous fraction containing substantial quantities of light hydrocarbon gases therefrom, withdrawing the liquid condensate from said second separation stage and removing further quantities of light hydrocarbon gases therefrom at a further reduced pressure to form a marketable distillate product, and compressing said residual gas and said gaseous fraction for reinjection into the formation from which said fluid was produced.

3. The method of recovering liquid hydrocarbons from a fluid produced by a well of the distillate type which comprises expanding said fluid into a separation stage maintained at an elevated pressure in the retrograde condensation range, separating the hydrocarbon condensate formed at said pressure from the residual gas, heating said condensate to an elevated temperature and passing it to a second separation stage maintained at substantially the same pressure as that in the first separation stage to remove a gaseous fraction containing substantial quantities of light hydrocarbon gases therefrom, withdrawing the liquid condensate from said second separation stage and removing further quantities of light hydrocarbon gases therefrom at a further reduced pressure to form a marketable distillate product.

4. The method of recovering liquid hydrocarbons from a fluid produced by a well of the distillate type which comprises expanding said fluid into a separation stage maintained at an elevated pressure in the retrograde condensation range, separating the hydrocarbon condensate formed at said pressure from the residual gas, heating said condensate to an elevated temperature and passing it to a second separation stage maintained at substantially the same pressure as that in the first separation stage to remove a gaseous fraction containing substantial quantities of light hydrocarbon gases therefrom, withdrawing the liquid condensate from said second separation stage, and subjecting said last-mentioned condensate to fractionation at a pressure below that in said second separation stage to stabilize the same and form a marketable distillate product.

5. The method of recovering liquid hydrocarbons from a fluid produced by a well of the distillate type which comprises expanding said fluid into a separation stage maintained at an elevated pressure in the retrograde condensation range, separating the hydrocarbon condensate formed at said pressure from the residual gas, heating said condensate to an elevated temperature and passing it to a second separation stage maintained at substantially the same pressure as that in the first separation stage to remove a gaseous fraction containing substantial quantities of light hydrocarbon gases therefrom, withdrawing the liquid condensate from said second separation stage, and introducing the same into a third separation stage maintained at a further reduced pressure to remove further quantities of light hydrocarbon gases therefrom, withdrawing the liquid condensate from said third separation stage, and subjecting said last-mentioned condensate to stabilization to form a marketable distillate product.

6. The method of recovering liquid hydrocarbons from a fluid produced by a well of the distillate type which comprises separating the liquid fraction from said fluid at about well head pressure and a temperature above that at which natural gas hydrates are formed at said pressure, admixing said fluid after separation of

said liquid fraction with an antifreeze material, cooling and expanding the resulting mixture into a second separation stage maintained at an elevated pressure in the retrograde condensation range, introducing said liquid fraction into said second separation stage, withdrawing streams of hydrocarbon condensate, antifreeze material and residual gas from said second separation stage, heating said condensate to an elevated temperature and passing it to a third separation stage maintained at substantially the same pressure as that in said second separation stage to remove a gaseous fraction containing substantial quantities of light hydrocarbon gases therefrom, withdrawing the liquid condensate from said third separation stage and removing further quantities of light hydrocarbon gases therefrom at a further reduced pressure to form a marketable distillate product, and compressing said residual gas and said gaseous fraction from said third separation stage for reinjection into the formation from which said fluid was produced.

7. The method of recovering liquid hydrocarbons according to claim 6 wherein said second separation stage is maintained at a temperature within the range from about -50° to about $+100^{\circ}$ F. and a pressure within the range from about 800 to about 1500 pounds per square inch, and said third separation stage is maintained at a temperature within the range from about 200° to about 400° F.

8. The method of recovering liquid hydrocarbons according to claim 6 wherein said second separation stage is maintained at a temperature within the range from about -35° to about $+25^{\circ}$ and a pressure within the range from about 950 to about 1500 pounds per square inch, said third separation stage is maintained at a temperature within the range from about 200° to about 400° F. and light hydrocarbon gases are removed from the condensate from said third separation stage by fractionation at a pressure within the range from about 200 to about 400 pounds per square inch.

9. Apparatus for recovering liquid hydrocarbons from a fluid produced by a well of the distillate type comprising a separator, means for cooling and expanding said fluid into said separator, means for withdrawing and heating liquid condensate from said separator, a second separator, means for introducing said heated condensate into said second separator, means for removing liquid condensate from said second separator, means for removing further quantities of light hydrocarbon gases from said condensate from said second separator, means for removing gases from both of said separators and means for recompressing said last-mentioned gases for reinjection into the formation from which said fluid was produced.

10. Apparatus for recovering liquid hydrocarbons from a fluid produced by a well of the distillate type comprising a first separator, means for introducing said fluid into said first separator, means for withdrawing and cooling gases from said first separator, a second separator, means for expanding said cooled gases into said second separator, means for introducing liquid from said first separator into said second separator, means for withdrawing and heating liquid condensate from said second separator, a third separator, means for introducing heated liquid condensate into said third separator, means for removing gases from said second and third separators, means associated with said last-mentioned

means for maintaining desired pressures within said second and third separators, means for recompressing said gases from said second and third separators for reinjection into the formation from which said fluid was produced, a stabilizing tower, means for passing liquid condensate from said third separator to said stabilizing tower, and means for withdrawing stabilized distillate from said stabilizing tower.

11. Apparatus for recovering liquid hydrocarbons according to claim 10 including a fourth separator, means for expanding condensate from said third separator into said fourth separator, means for maintaining the pressure in said fourth separator at a desired value, and means for passing liquid condensate from said fourth separator to said stabilizing tower.

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