RAILROAD COMMISSION OF TEXAS

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THE APPLICATION OF BURLINGTON RESOURCES O&G CO. LP. TO CONSIDER PERMANENT GAS WELL CLASSIFICATION FOR THE KUNDE LEASE WELL NO. 1, WILDCAT FIELD, LIVE OAK COUNTY, TEXAS

Heard by: Thomas H. Richter, P.E., Technical Examiner
Hearing Date: February 9, 2007
Appearances: **Representing:**

Jamie Nielson, attorney — Burlington Resources O&G Company, LP.
Greg Cloud

EXAMINER'S REPORT AND RECOMMENDATION
STATEMENT OF THE CASE

Burlington Resources O&G Company requests that the Kunde Lease Well No. 1, (API No. 42-297-34621), which is currently classified in the Wildcat Field for District 2, be permanently classified as a gas well. The proposed name for the field upon classification of the well will be Sugar Cane (Cretaceous) Field. The examiner recommends approval.

DISCUSSION OF EVIDENCE

The Burlington Resources O&G Company, LP., Kunde Lease Well No. 1 was completed December 5, 2005 through the two sets of perforations from 11,440' to 11,470' and 11,490' to 11,520' subsurface depth and potentialed at 542 MCFD. The gas gravity is 0.734 and the condensate gravity is 57.5° API. The initial gas/liquid ratio was 3,226:1.

Burlington has attempted to classify the well as a gas well but a new "gas" field designation can not be approved until the well is classified as a gas well. Completion forms were submitted in September 2006. The Commission advised Burlington in November 2006 that the well will be classified as an oil well based on the Form G-5 that was submitted. In the alternative, if there was disagreement with the classification, 1) a new G-5 test could be submitted; 2) a Compositional C7+ Analysis and/or PVT analysis showing the gas/liquid hydrocarbon ratio exceeds 100,000:1 or 3) a hearing maybe requested. A PVT analysis was performed on the well in September 2006.[1]

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[1] There was no assertion the PVT analysis was previously submitted to the Commission.

The original static reservoir pressure was 7,867 psia at 287°F. The mathematical Constant Composition Expansion (CCE) results show a measured dew point pressure of 5,072 psia at 287°F. The analysis shows that the reservoir fluid exists as a single phase system at initial reservoir conditions. Continued reservoir pressure reduction below the dew point will result in greater retrograde condensate liquid formation in the reservoir. This is anticipated in a retrograde gas condensate reservoir. The hydrocarbon liquids condense from the gas phase in the formation and should be immobile. Compositional analysis indicates the wellstream to be 61.2 mol% methane and 10.409 mol% heptanes plus. The CCE analysis measured the maximum hydrocarbon liquid volume in the two-phase envelope would occupy 32.37% of the hydrocarbon pore volume (HCPV) at 3000 psig. [2] A water saturation of 35% provides for a total HCPV of 65%, thus the maximum the hydrocarbon liquid volume could occupy is 21%. The reservoir is a chalk formation and extremely tight and liquid mobility would be essentially non-existent. Any liquid hydrocarbon in a reservoir is essentially immobile until it reaches a saturation of at least 10 to 20% depending other reservoir and physical factors.[3] Typical retrograde gases contain less than 12.5 mole percent of Heptanes Plus and the stock-tank liquid gravities are between 40° and 60° API.

Burlington believes the subject well should be classified as a gas well because the well does have a measured dew point pressure indicating the well to be a gas condensate well and meets the parameters of a retrograde gas condensate well, meets the requirements of the C7+ analysis pursuant to Commission Memo dated March 16, 2006 and the liquid hydrocarbon in the pore space of the reservoir would not be mobile.

EXAMINER'S OPINION

The Texas Administrative Code, Title 16, Part 1, Chapter 3, Rule §3.69 Definitions Subsection (11)(C) and Statewide Rule 79 defines a gas well as "....A well which produces hydrocarbon liquids, a part of which is formed by a condensation from a gas phase and a part of which is crude petroleum oil, shall be classified as a gas well unless there is produced one barrel or more of ***crude petroleum oil*** (emphasis added) per 100,000 cubic feet of natural gas; and that the term "crude petroleum oil" shall not be construed to mean any liquid hydrocarbon mixture or portion thereof which is not in the liquid phase in the reservoir, ***removed from the reservoir in such liquid phase*** (emphasis added), and obtained at the surface as such."

The statute requires for a well with a gas-hydrocarbon liquid ratio of less that 100,000:1, a series of tests must be passed to be classified as a gas well. For prima facie gas well classification, the Commission uses the data from Form G-5 (Gas Well Classification Report) for a well and compares it to Commission Guidelines. The key guideline parameters are:

* Gas-liquid hydrocarbon ratio of at least 12,500:1

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[2] This percentage is the maximum space the liquid condensate will occupy of the "hydrocarbon pore volume" and not the "total pore volume".

[3] For consolidated sandstones the range can be as high as 35%.

* API gravity of the liquid hydrocarbon of at least 50 degrees

* On the ASTM Distillation Test of the liquid:

  Initial Boiling Temperature must be less than 120°F

  At 80% recovery, the boiling temperature must not exceed 520°F

  The end point must not exceed 720°F with at least 95% recovery

The subject well's Form G-5 (date of test September 8, 2006) failed the gas-hydrocarbon liquid parameter. The FESCO A.S.T.M. distillation test (dated December 7, 2005) failed the 80% temperature parameter.

To be classified as a gas well pursuant to Rule 79 if the initial producing gas-hydrocarbon liquid ratio is less than 100,000:1, the following requirements must be met:

* There must be a measured dew point pressure (condensation point or saturation pressure), wherein the hydrocarbon liquid begins to form in the reservoir; and

* The liquid hydrocarbon that forms in the reservoir (condensate) must be immobile in the reservoir and not produced at the surface.

The subject well at original reservoir conditions was single phase i.e. gas. According to the PVT CCE analysis, as the reservoir pressure continues to decline below the saturation pressure, a greater volume of liquid will condense from the gas phase into the pore space of the formation to a maximum of 32.37% of the HCPV.

Technically, anytime there is hydrocarbon liquid dropout in the reservoir, the well is a "retrograde gas condensate well". A true "wet gas" will not condense liquid until it is cooled. Reservoirs remain at constant temperature. If PVT analysis shows condensation with pressure reduction, then the reservoir is above the critical temperature. It is the critical temperature which dictates a gas condensate versus a volatile oil. The hydrocarbon liquid volume and gas composition in this case indicates a rich retrograde condensate. The classification of reservoirs properly depends upon (a) the composition of the hydrocarbon accumulation and (b) the temperature and pressure of the accumulation in the formation. Because compositions can vary in every conceivable proportion and the temperature and pressure gradient vary, the reservoir types may blend in with one another and even overlap. [4] The determination of an accurate dew point (or bubble point) is dependent upon several parameters. The correct recombination ratio of the collected gas and liquid from the separator should be as accurate as possible in the early life of the well. An incorrect dew point pressure may occur because an operator did not properly flow-condition the well before sampling. Ideally, a well

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[4] Applied Petroleum Reservoir Engineering, B.C. Craft and M.F. Hawkins, Petroleum Engineering Department, Louisiana State University, Prentice-Hall Inc. Englewood Cliffs, New Jersey, Copyright 1959.

should be cleaned up on a higher rate and then the well rate is lowered sequentially in stabilized rate steps to determine the lowest rate that completely unloads all fluids from the wellbore. Few operators take the time and expense to determine the best recombination GOR for laboratory work. The sampling should be performed in the early life of a well before pressure depletion effects the composition of the samples. If this is not performed and the original reservoir pressure is not accurately obtained, the dew point (bubble point) pressure will be in error. If this is accurate, this must be taken into account in the evaluation process.

Retrograde gas-condensate reservoirs are unique and a general understanding of the geological and reservoir/chemical characteristics must be understood to differentiate this reservoir from a volatile oil reservoir. Reservoir temperature is essential in the classification of the type of reservoir i.e. volatile oil or retrograde gas condensate. A fluid composition might be classified as a volatile oil in one reservoir and a gas condensate in a deeper and hotter reservoir. Reservoirs should not be mistakenly classified on the basis of the production characteristics observed at the surface i.e. the yield of hydrocarbon liquid per mmcf of gas. If the reservoir temperature lies between the critical temperature and the cricondentherm of the reservoir fluid, the reservoir is classifiedas a retrograde gas-condensate reservoir. If the initial reservoir pressure is above the dew point pressure, the hydrocarbon system exists as a single phase (vapor) in the reservoir. As the reservoir pressure declines isothermally (constant temperature) becauseof production depletion to the dew point pressure or "saturation" pressure, liquids begin to condense out of the gas into the formation. As the pressure is further decreased, instead of expanding (if a gas) or vaporizing (if a liquid)as would be expected, the hydrocarbon mixture tends to condense even more. The retrograde condensation process continues with decreasing pressure until the liquid drop-out reaches its maximum. At this point, some of the liquid which formed in the reservoir may vaporize or near wellbore condensate banking occurs.[5]

The heptanes plus (C_7+) composition is 10.409 mol%. Subsequent research indicates there is a sharp dividing line between oils and condensates from a compositional basis. Reservoirs containing in excess of 12.5 mol% C_7+ components are almost always in the liquid phase (hence oils). Those with less than12.5mol% are almost always in the gas phase in the reservoir. Oils have been observed with heptanes and heavier concentrations as low as 10% and condensates as high as 15%, but these cases are very rare and exhibit very high tank liquid gravities.[6] A research study on hundreds of wells that were properly conditioned and tested, tracked the C_7+ mol% versus PVT analysis of each well for the determination of dew point or bubble point. The analysis determined that wells with over 12.5 mol% C_7+ had measured bubble points (oil well) and wells with less than 12.5 mol% C_7+ had measured dew points (gas wells).[7] The Commission adopted a Heptanes plus test and guideline (Commission Memo dated March 16, 2006), as an alternative to the performing

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[5] If the reservoir temperature is near the critical temperature, when the dew point pressure is reached, there will be a rapid liquid build-up (condensation) and subsequently a dramatic increase in the GOR. It should be noted that the composition and mol percent of the hydrocarbons in the reservoir changes significantly with depleting reservoir pressure.

[6] Engineering Applications of Phase Behavior of Crude Oil and Condensate Systems , by Phillip L. Moses, SPE, Core Laboratories, Inc., copyright 1986 Society of Petroleum Engineers, published in the Journal of Petroleum Technology, July 1986.

[7] Research by William McCain, Phd. Professor at Texas A&M University.

of a PVT analysis, that if the C_7+ mol% was equal to or less than 11 mol%, a well would be classified as a gas well.

The liquid hydrocarbons produced at the surface have "flashed" at the surface separation equipment and do not meet the statutory definition of *crude petroleum oil*. The hydrocarbon "liquid" that exists in a retrograde gas condensate reservoir will be the result of *gas condensation*. In a retrograde gas condensate reservoir, the condensed liquids should not be considered in determining the gas-oil ratio because the liquids produced at the surface. The flash condensate at the surface is caused by the pressure/temperature reduction. There is no substantiating data that crude petroleum oil is being produced at the surface.

The examiner recommends the application be approved and the well should be classified as a gas well. The subject well meets the following guide lines:

* There is a measured dew point (saturation) pressure and subsequent pressure reduction result in the condensing of liquid hydrocarbon as shown by a PVT analysis.

* The mol percentage of heptanes plus is < 11 mol%.

* The maximum percentage of hydrocarbon liquid occupies no more that 32.37% of the HCPV. The reservoir is a chalk formation and extremely tight and liquid mobility would be essentially non-existent.

* The reservoir is above the critical temperature (this temperature does not necessarily have to be measured if there is a clear demonstration that condensate forms and increases with pressure reductions below the dew point or reservoir pressure, whichever is lower).

FINDINGS OF FACT

1. Notice of this hearing was given to all affected persons at least ten days prior to the date of hearing. No protests were received.

2. The Burlington Resources O&G Company, LP., Kunde Lease Well No. 1 was completed December 5, 2005 through the two sets of perforations from 11,440' to 11,470' and 11,490' to 11,520' subsurface depth and potentialed at 542 MCFD.

   a. The gas gravity is 0.734 and the condensate gravity is 57.5° API. The initial gas/liquid ratio was 3,226:1.

3. The Burlington Resources Company, LP., Kunde Lease Well No. 1 should be classified as a gas well.

   a. The original static reservoir pressure was 7,867 psia at 287°F.

b. The mathematical Constant Composition Expansion (CCE) results show a measured dew point pressure of 5,072 psia at 287°F.

c. The analysis shows that the reservoir fluid did exist as a single phase system at initial reservoir conditions.

d. Any hydrocarbon liquids that condense from the gas phase in the formation are immobile.

e. Compositional analysis indicates the wellstream to be 61.2 mol% methane and 10.409 mol% heptanes plus.

f. The CCE analysis measured the maximum hydrocarbon liquid volume in the two-phase envelope will occupy 32.67% of the hydrocarbon pore volume at 3000 psig.

g. The reservoir is above the critical temperature as demonstrated by gas-condensation through reservoir pressure reduction at constant temperature.

4. The liquid hydrocarbons produced at the surface have "flashed" at the surface separation equipment and do not meet the statutory definition of crude petroleum oil.

CONCLUSIONS OF LAW

1. Proper notice of this hearing was issued.

2. All things have been accomplished or have occurred to give the Commission jurisdiction in this matter.

3. The Burlington Resources Company, LP., Kunde Lease Well No. 1 meets the requirements for gas well classification pursuant to Rule No. 79(a)(11)(C).

RECOMMENDATION

Based on the above findings and conclusions of law, the examiner recommends that the Burlington Resources Company, LP., Kunde Lease Well No. 1, (API No. 42-297-34621) meets the requirements for gas well classification without further administrative review.

Respectfully submitted,

Thomas H. Richter, P.E.
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