PVT and Geochemical Properties of Wet Gas in the Barnett Formation, Fort Worth Basin, Texas

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The Barnett Formation is a prolific gas shale play in the Fort Worth Basin where this oil-prone source rock was buried deeply enough to enter the wet gas window. A significant amount of information has been published about the properties of Barnett source rocks, and the geological processes that control the generation and retention of oil and natural gas in this unconventional reservoir. However, the properties of Barnett petroleum fluids under reservoir conditions (including the saturation state of the gas phase) have not been described in detail. We have studied the PVT properties of recombined samples of natural gas and condensate produced from two wells in Parker County, Texas – and compared those data to geochemical data obtained on three kinds of rock and fluid samples: (1) thermally-mature Barnett source rocks; (2) HCs extracted from conventional cores; and (3) produced condensate and natural gas samples. We conclude that the relatively lean wet gas samples we studied are saturated under reservoir conditions. In addition, we show that this unconventional reservoir apparently contains two petroleum phases under reservoir conditions: (1) saturated wet gas; and (2) a liquid phase ("paleo"-condensate) that probably precipitated from the wet gas when it passed through its dew point during uplift of the Fort Worth Basin.

<u>Geochemical Properties of Barnett Source Rock and Produced Fluid Samples</u>. We analyzed core plugs from ~300 ft of conventional core obtained from an exploration well on the Muir lease. At this location the Barnett Formation is a good oil-prone source rock that has reached the wet gas window. Most source rock samples contain ~3-10 wt% TOC, and exhibit relatively low HI values (~40-85) and high Tmax values (~465-480^{o}C) because they are thermally mature. Visual kerogen analysis confirms that these core samples contain principally oil-prone structureless organic matter (~50-80%) and pyrobitumen (~20-50%). Reflectance data obtained on the pyrobitumen confirms that the Muir core is well into the wet gas window (VR ~ 1.4-1.5).

The molecular and C isotopic composition of natural gas and condensate samples produced from a horizontal well on the Muir lease exhibit inconsistent values. For example, the condensate is very light (~65^{o}API) and contains low concentrations of C_{15+} n-alkanes (suggesting it was generated at very high maturity). However, the relatively low C_1 /C_2 ratio (~6.2) of gas produced from the same well, and the C isotopic composition of methane (-45.2 per mil), ethane (-33.5 per mil), and propane (-29.4 per mil) suggest that the gas was generated at a lower level of thermal maturity (VR ~ 1.0). Sophisticated geochemical analysis of the Muir source rock and condensate samples produced more unexpected results. Pyrolysis-FID and RockEval analysis of native core samples and aliquots rinsed with an organic solvent indicate the core samples contain moderate amounts of soluble petroleum that exhibits a PFID yield at T < 300 ^{o}C and a RockEval yield at T < 400 ^{o}C. Furthermore, high-temperature simulated distillation (HTSD) analysis of the Muir condensate and HCs extracted from a Muir core sample using CS_2 demonstrates that although the C_{20+} fraction of both kinds of petroleum is very similar, the Muir condensate contains an additional component that is enriched in C_8-C_{15} compounds (Figure 1). One way to resolve these disparate geochemical maturity parameters is to interpret the data as evidence that the Barnett reservoir contains very light condensate dissolved in wet gas, plus a second liquid phase (heavier condensate or oil) that is more enriched in C_{20+} compounds.

<u>PVT Properties of Recombined Gas and Condensate Samples.</u> High-quality samples of gas and condensate were obtained from two wells in the Muir area using a test separator operated at different

conditions (i.e., T = 86^{o}F, p = 135 psi, and CGR ~8 bbl/MMcf; T = 97^{o}F, p = 412 psi, and CGR ~16 bbl/MMcf). Gas and condensate production rates were monitored for several hours to ensure that accurate CGR ratios were determined, and that separator samples were not collected when the wells were slugging. Standard PVT data were obtained on recombined samples from each well under reservoir conditions (i.e., T =170^{o}F; p = 2815 psi).

"Flashed" condensates from both wells exhibit the same anomalous composition: i.e., C_{16+} compounds are more abundant than expected based on the concentration of the C_8-C_{15} fraction. In addition, the recombined samples from both wells exhibit dew points that are several hundred psi higher than the reservoir pressure (implying the Barnett contains two petroleum phases under reservoir conditions). This interpretation was tested using EOS modeling software to evaluate the PVT data, which were adjusted by: (1) using the C_8-C_{15} fraction of a flashed condensate to estimate the composition of the C_{16+} fraction dissolved under reservoir conditions; and (2) setting the dew point pressure of a recombined sample equal the reservoir pressure. Under these conditions – which utilize the PVT data to constrain the composition of the liquid dissolved in a saturated gas – the modeled dropout of liquid below the dew point matches the measured liquid dropout. This result indicates that trace amounts of a liquid phase enriched in C_{16+} compounds also are present under reservoir conditions. The presence of a small amount of a heavier liquid as well as saturated gas influences the dew point of the recombined wet gas sample, but it does not have a significant effect on the CGR (Figure 2).

Geological Interpretation. These results and our interpretation can be explained by considering the geological history of the Barnett Formation in the Fort Worth Basin (where it was buried much deeper in the past). At maximum burial, Barnett source rocks generated natural gas that probably was moderately wet (i.e., CGR >20 bbl/MMcf). This wet gas phase dropped below its dew point when the temperature and pressure of the reservoir decreased during uplift of the Fort Worth Basin. Some of the condensate that continued to precipitate from the saturated gas phase during additional uplift may have been expelled from the reservoir when gas expanded as the pressure continued to drop. However, the Barnett apparently retained enough of this condensate to influence the composition of the C_{15+} fraction of the liquid now produced from the reservoir – which is dominated by condensate that precipitates from the lean (but saturated) gas during production. "Paleo"-condensate that precipitated during uplift, which can be detected by analyzing Barnett core samples using HTSD and/or RockEval techniques, may flow into wellbores via fractures or due to viscous stripping by the wet gas phase. Finally, the modest amount of very light (>60 ^{o}API) condensate that forms during the production of Barnett gas simply represents the composition of petroleum that is soluble in gas under current reservoir conditions – not the composition of the C_{10+} fraction of petroleum that the Barnett generated at maximum burial.

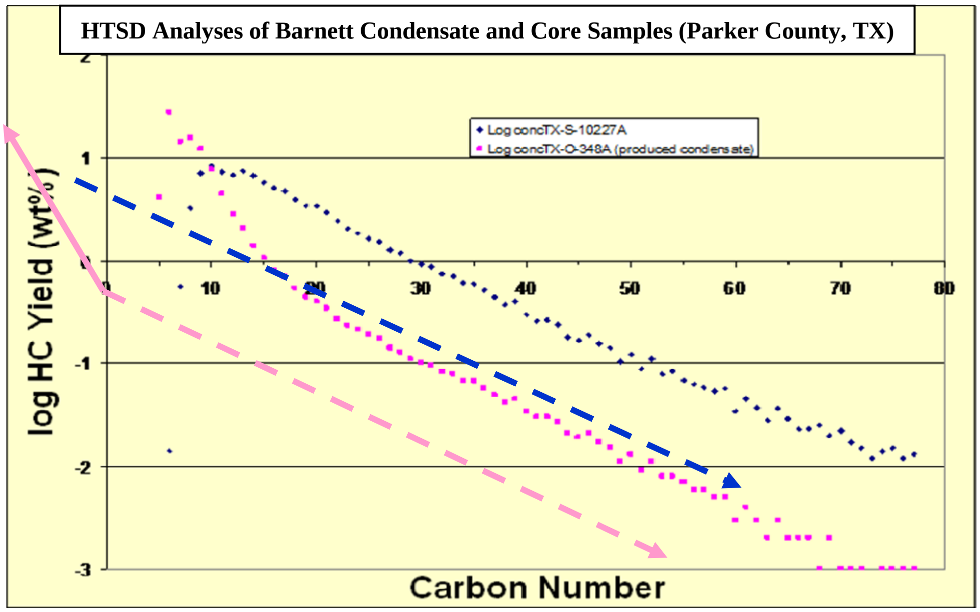

Figure 1. HTSD analysis of a condensate sample produced from a well on the Muir lease (pink), and petroleum extracted from a core sample using CS_2 (blue). The C_{20+} fraction of both kinds of petroleum is very similar, but the light C_8-C_{15} fraction of the condensate displays a different slope.

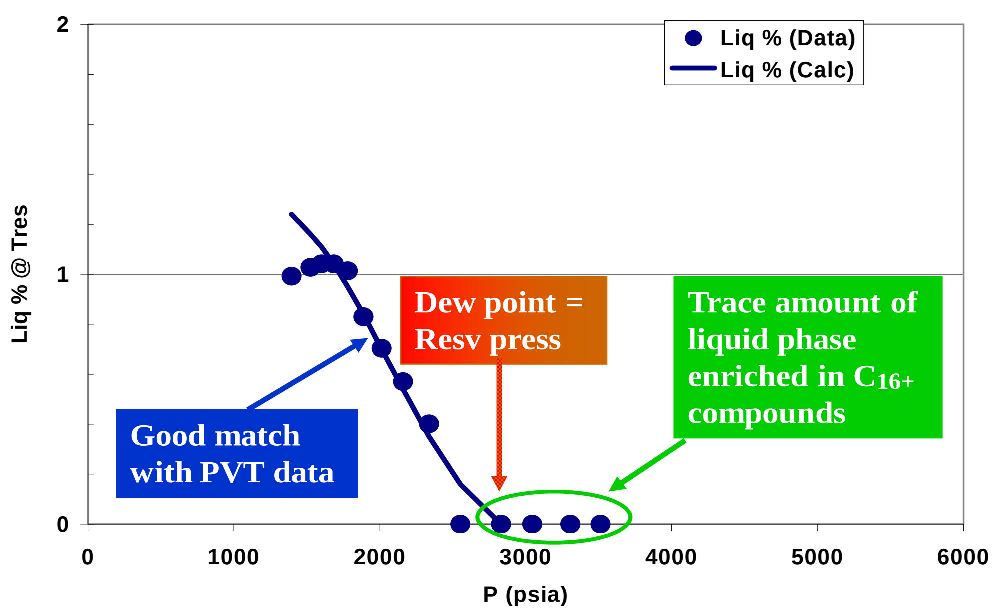

Figure 2. Evaluation of PVT data obtained on recombined samples of separator gas and condensate produced from the Barnett Formation. The good match between the modeled and measured liquid dropout supports the interpretation that the reservoir contains saturated wet gas plus a liquid.