Definitive indicators of hydrocarbon production character in horizontal shale exploration.

Adapted from "Definitive indicators of hydrocarbon production character in horizontal shale exploration using mass spectrometer (DQMS) data for 100+ wells".

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Introduction

There has been a notable increase in shale exploration recently in the US. In certain shale plays, significant variation in production character exists within a small geographical area. Operators typically elect to not run electric log suites in shale laterals due to expense and risk factors. A low cost and low risk alternative which can provide a degree of analytical insight for many shale laterals is mud gas analysis. A common method used in mud gas analysis of non-shale exploration has been gas component ratio calculations, such as Wetness, Character, and Balance equations, Wh, Ch, and Bh respectively. Here in use is a variant of Wh which the authors introduce as Wh_1

These ratio calculations were originally formatted for vertical penetrations of reservoirs as a lab technique. Typical mud gas analysis is conducted with gas chromatograph (GC) field instruments on a high percentage of drilled wells. One thing which should be expected of data collected this routinely is definitive scalable output. Here we demonstrate that the DQMS-derived data is capable of data quality sufficient to allow the DQMS-derived data to be reliably used to predict the hydrocarbon production character in shale laterals. This DQMS data has been demonstrated to correlate to lab and production calculations very well.

Methods

Continuous gas sample extracted from drilling mud was analyzed while drilling the (eventual) producing portion of 105 wells from 5 basins within the mid-continent region. Component ratio data was calculated for these shale laterals. DQMS measurements were made using the DQ 1000 ™. This data was collected in the normal course of work for these laterals and was not screened or selected for reasons other than permission. Of the 105 wells, 52 were drilled with water-based drilling mud (WBM) and 53 were drilled with oil-based drilling mud (OBM).

The use of OBM and hydrocarbon-containing mud additives contribute to the wet hydrocarbon composition of the mud gas profile. DQMS data was transformed using proprietary algorithms and techniques to calculate for the effects of diesel and other mud additives and to correct for underrepresented species due to lower discovery limits (LDL). These methods standardize the data between OBM and WBM allowing geologic composition of wells to be compared.

Averages for concentrations for each of C1, C2, C3, C4, and C5 were prepared from the horizontal portion of each well. These concentration averages were then used in the following equations to calculate the Wh_1, Bh, and Ch for each well:

Eq. 1 $Wh_1 = (C2+C3+C4+C5)/(C1+C2+C3+C4+C5)$
Eq. 2 $Bh = (C1+C2)/(C3+C4+C5)$
Eq. 3 $Ch = (C4+C5)/C3$

These ratio values were catalogued by basin and production type. Unless indicated otherwise, the differentiation between dry wells, trace liquids, and wet wells was based solely on published production numbers. Trace liquids is defined as 0 to 0.5 Bbls/mmcf.

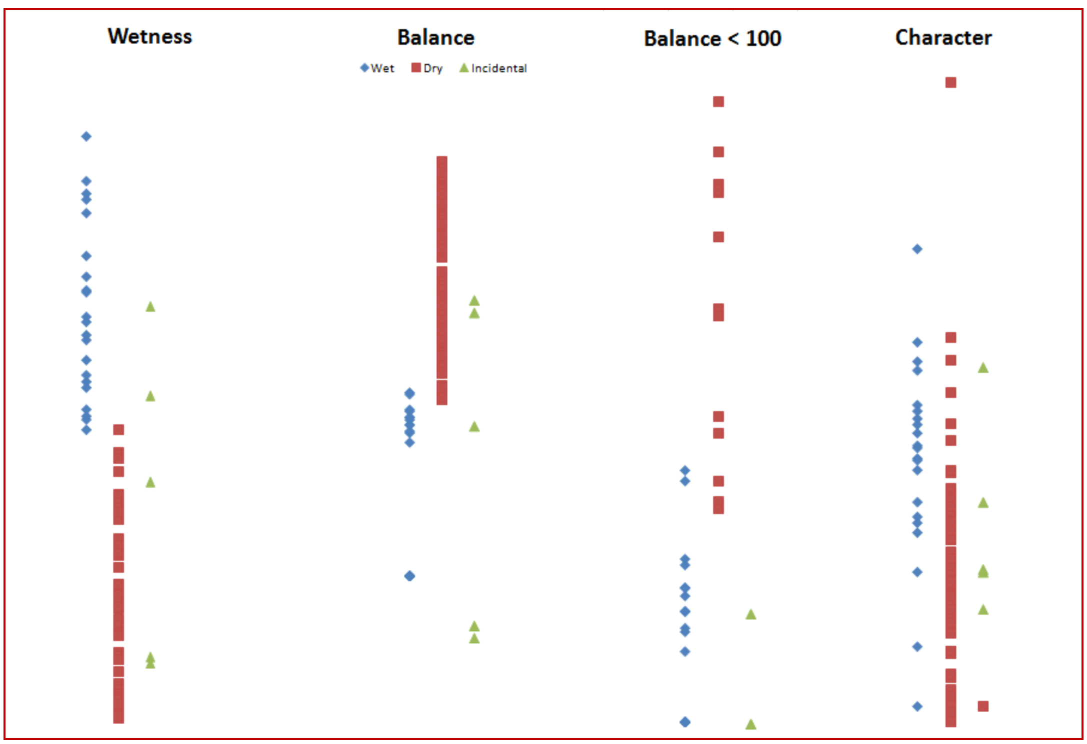

Figure 1

Figure 1 illustrates DQMS-derived results for Wh_1, Ch, and Bh calculations for the 105 shale laterals in the study. The blue diamond markers represent liquid producing wells (>0.5 bbl/mmcf), green triangles represent minimal liquids production (<0.5 bbl/mmcf), and red squares represent gas only wells (0 bbl/mmcf).

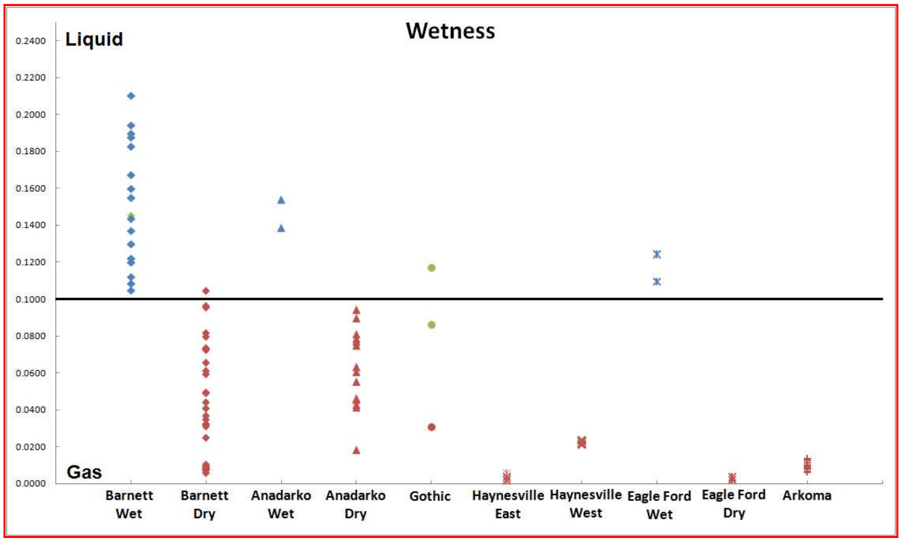

Figure 2

Figure 2 represents Wh_1 by basin for all wells within the study. The detail line which divides liquids producers from gas producers is drawn at the 0.1 value level.

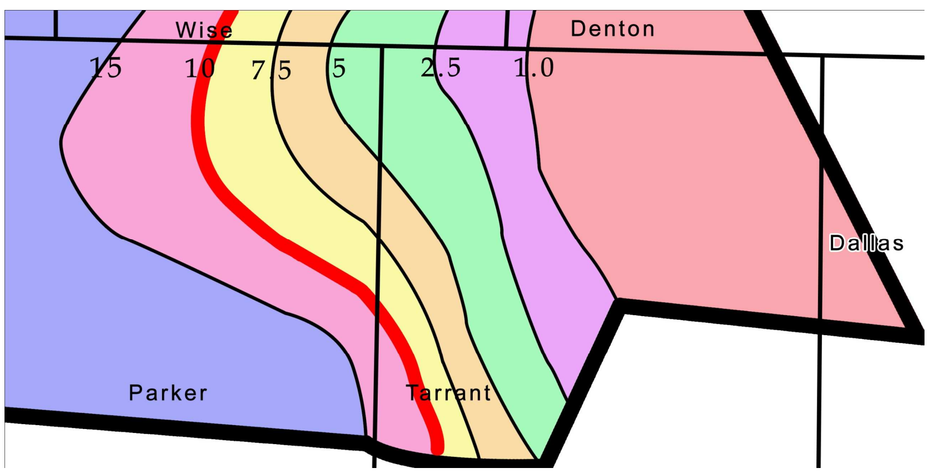

Figure 3

Figure 3 represents an initial estimate for a **proposed** Wh data (Wh_1 data expressed in Wh scale) contour map for a portion of the Barnett Shale. West of the bold red contour would be expected to produce more than the 0.5 Bbls/mmcf defined earlier as "nominal liquids".

The values for Wh_1 suggest variability in the significant digit range for this value set given that 10% to 15% variability can exist between nearest data points . This may be related to differences in drilling programs from one well to another, etc. The general trend is obvious in the data, but the data is imprecise enough that one should be cautious of suggesting this data be used to correct regional maps for such as Ro or BTU in areas where data density for the Wh_1 data is low, although augmenting these maps with Wh_1 information might be useful.

Conclusions

A value for DQMS-derived Wh_1 exists above which there will be liquids production and below which only gas is produced for shale laterals. Wh_1 above 0.1 predicted liquids production with one false positive. Wh_1 below 0.1 predicted dry gas with 3 false negatives, all 3 of which were nominal liquids producers (<0.5bbl/mmcf). Bh results inversely mimic Wh_1. The raw accuracy percentages for both Wh_1 and Bh are the same, 96.2%.

Wh_1 is effective alone as an indicator of liquids production. With 96.2% of the wells studied being sorted accurately, it is with good confidence that predictions of production type can be derived from mud gas analysis using DQMS data. This data is available as soon as a well reaches TD, and may be useful in correlation with other thermal maturity indicators to increase map point density. Even though Bh and Ch are not necessary to define liquids production, they should be investigated as indicators for other parameters concerning the hydrocarbon profile of a shale lateral. It has not been critically examined yet, but data suggests it to be worthwhile to investigate how correlative the wetness profile may be in providing an estimate of bbls/mmcf.