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FORMATION EVALUATION of UNCONVENTIONAL RESERVOIRS

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Formation evaluation of unconventional reservoirs including coalbed methane (CBM) and shale gas reservoirs requires core data for log calibration. In most cases, open-hole log data do not indicate that gas is present because the gas content only about 1% by weight of the reservoir. This poster session will present the coal and shale specific core data that are required and illustrate examples of calibrated log interpretation.

The gas content in CBM reservoirs is adsorbed within micropores within organic material originally deposited as plants. The three most important coalbed methane reservoir properties are the gas-in-place volume (based upon thickness, density, and gas content), the degree of gas saturation (gas content divided by the gas storage capacity), and the absolute permeability of the coal natural fracture system (cleats).

The gas content is determined by measuring the gas volume and gas composition that escapes from core samples placed in aluminium desorption canisters. The samples are obtained by coring the coal seams of interest with equipment resulting in core diameters of 48 to 89 mm and retrieving the samples to surface as quickly as possible preferably with wireline retrieval methods. On the surface the core is cut into 300 mm lengths and sealed in canisters. The gas volume released from the canisters is measured by water displacement in graduated cylinders. The volume of gas that was lost while retrieving the samples is estimated from the measured gas volumes. The samples are crushed at the end of desorption to release the remaining gas content. The total gas content is the sum of the lost, measured, and crushed volumes divided by the sample mass. The coal thickness and density are determined by open-hole density logs run after coring. The degree of gas saturation is determined by comparison of adsorption isotherm gas storage capacity to the gas content. Proper comparison often requires measuring isotherm data for multiple gas components; the most common of which are methane, ethane, propane, carbon dioxide and nitrogen. These steps have been well documented.[1] Permeability estimates require either open-hole drill stem tests or water injection falloff tests in either open or cased holes. [2]

In addition to the data described above, a substantial amount of additional coal core analyses are required to determine the coal mineral matter content, the organic composition, and the thermal maturity of the coal. These estimates require a combination of proximate, ultimate, moisture holding capacity, calorific value, maceral composition, and vitrinite reflectance analyses.

Gas content is often proportional to organic content and inversely proportional to density. These core interrelationships are determined to create calibrated log analysis methods. Gas content and gas storage capacity can be computed from density-based organic content estimates.

The gas content in shale gas reservoirs is stored by one of two mechanisms; free-gas compressed within gas-filled pores or adsorbed within micropores of organic material.[3] The organic material was usually deposited as animal remains in anoxic marine environments but can contain plant debris as well. Core data are required to determine the properties of both the inorganic and organic components of the reservoir.

As for CBM reservoirs, gas content of shale can be determined by placing freshly cut core samples into desorption canisters and determining the lost, measured and crushed gas content, and by summation, the total gas content. The total gas content is usually a combination of free and adsorbed gas if lost gas volume is low. Shale samples tend to lose gas more rapidly than coal samples and usually must be cut with wireline retrievable coring systems for accurate gas content estimates.

Shale gas core analysis methods require that the rock samples be crushed due to the low permeability of the unfractured matrix, which is often in the microdarcy range.[4] Matrix permeability is determined on crushed samples. The oil and water content is quantified by toluene cleaning, retort methods, or both. The cleaned sample grain density and original bulk density are used to determine the porosity and fluid saturations. The rock composition is determined with a combination of X-ray diffraction including clay components, thin section, and scanning electron microscope methods.

The total organic carbon (TOC) weight fraction must be determined, usually by combustion or by pyrolysis. The gas storage capacity of the organic material is determined with adsorption isotherm measurements in the same manner as for coal. Depending upon the thermal maturity of the reservoir, the original gas composition can be highly dominated by methane when the thermal maturity is in the gas window or by a combination of methane, heavier hydrocarbons, and carbon dioxide when thermal maturity is in the oil or gas condensate windows. When multiple gas species are present, the gas storage capacity must be determined for each species or with a mixture of gases. Gas storage capacity is often directly related to TOC.

Thermal maturity is usually determined by pyrolysis, specifically Tmax, the temperature at which the maximum gas generation occurs during pyrolysis. Vitrinite reflectance can also be used when sufficient organic material is present. The presence and properties of natural fractures are often determined by visual studies on whole and slabbed core.

These reservoirs must be hydraulically fractured to be commercially exploited. Rock mechanical properties combined with acoustic velocities and fluid sensitivity studies are important precursors to stimulation.

Calibrated log interpretation methods are developed based upon core sample property interrelationships. TOC is often calculated from a combination of spectral gamma ray (thorium, uranium, and potassium) total gamma ray, density, and neutron response. The TOC estimates are used with isotherm data to estimate the adsorbed gas storage capacity. Porosity is computed from density log data accounting for the free gas and TOC. Shaley sand gas and water saturation calculation methods are modified to match core gas and water saturation. The combination of porosity and gas saturation allows the free gas storage capacity to be estimated. The sum of the free gas and adsorbed gas storage capacity determines the total gas storage capacity. Gas content and gas storage capacity are usually equal as the reservoirs are saturated at the initial reservoir pressure.

We have found for both coal and shale samples that sample handling in one of the most important components for accurate core data. Both rock types lose water rapidly after crushing and the original water content cannot be reintroduced. Once samples are crushed, the analyses must be performed immediately or the samples must be sealed in foil laminate bags purged of air with helium and refrigerated.

References:

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