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Introduction

When considering tight-shale formation characterization and completion design, one should evaluate the formation characteristics conducive to economic production: reservoir quality (RQ), representing the multiple properties defining reservoir potential, and completion quality (CQ), representing the multiple properties defining the potential for creating and sustaining a large surface area in contact with the reservoir. RQ and CQ properties vary in the near-wellbore and far-wellbore regions. For CQ, the far-wellbore region represents the region of contact between the created fracture and the reservoir. Well production depends on this surface area being in contact with good RQ, and depends on conditions of containment, fracturability, rock/fluid interactions, and loss of surface area and fracture conductivity during production. The near-wellbore region represents the choking point between the created surface area and the wellbore. The goal is to maximize connectivity between the fracture system and the wellbore. This goal is attainable by minimizing near-fracture tortuosity, maximizing fracture width, reducing breakdown pressures, and limiting the risk of solids production. The result is a nonscientific and consistent method that provides a means for understanding variability in fracture performance along wellbores (e.g., inferred from microseismic monitoring, trace analysis, and stage-by-stage flow measurements) and for selecting perforation stages on the basis of measured or log-inferred rock properties. The method also provides a means for monitoring consistency between the predicted values and measured results.

Surface-Area Requirements

Numerical simulations with single-phase gas production through a fracture were conducted as a function of reservoir-fluid properties to provide information on the surface-area requirements for attaining a desired production rate. Sensitivity analysis of input variables indicated that reservoir pressure, reservoir permeability, and fracture-surface area are the dominant input properties. By fixing reservoir pressure to the normal pressure gradient of 0.45 psi/ft, it was possible to analyze surface-area requirements to attain a desired gas-production rate as a function of reservoir permeability alone. Results indicated a nonlinear increase in surface area with decreasing permeability. Fig. 1 shows typical results of this analysis, indicating a required surface area for production rates of 1 and 5 MMcf/D, for tight-shale reservoirs with permeability ranging from 0.1 to 100 nanodarcies and from 100 to 600 nanodarcies. For a 300-nanodarcy reservoir, a surface area of $6 \times 10^6$ ft$^2$/well is required for 5-MMcf/D production, and $1.7 \times 10^6$ ft$^2$/well is required for 1-MMcf/D production. For wellbores with six producing stages, the required surface area per stage is $1 \times 10^6$ ft$^2$ for 5 MMcf/D and $0.28 \times 10^6$ ft$^2$ for 1 MMcf/D. This corresponds to an equivalent fracture half-length of 2,500 and 708 ft, respectively, for a 200-ft-thick reservoir.

In the comparison, the authors used 483,000 gal of slickwater and 390,000 lbm of sand, and, by assuming an average fracture width of 0.15 in., they calculated a created fracture-surface area of $10.7 \times 10^6$ ft$^2$/stage and $64.3 \times 10^6$ ft$^2$ for 6 stages. Comparison with Fig. 1 indicates that significantly more fracture-surface area is created than required for economic production, and the ratio of these areas varies from 10:1 to 38:1. It is reasonable to assume that a significant portion of the created surface area extends outside the reservoir thickness as a result of lack of containment, and because of the heterogeneous distribution of RQ. If the fracture is complex, the fracture branches will support smaller fracture widths and some branches may become inaccessible to the proppant and be disconnected from the rest of the fractured system. It is possible that some level of inhibition may take place, thus reducing the liquid volume available for creating surface area. First-principle calculations suggest that inhibition may be limited to 1–3% of the total volume pumped. Therefore, a considerable portion of the created surface area is ineffective and does not contribute to pro-

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dution. Also, microseismic monitoring during fracturing provides a measure of the total created surface area, not a measure of the effective surface area. The calculations also show the importance of improving the efficiency of the hydraulic-fracturing process.

**Heterogeneity**

Vertical and lateral heterogeneity in tight-shale formations (organic-rich mudstones) results from post-depositional, diagenetic transformations within the stratigraphic column. Vertical heterogeneity is evident from log interpretations and from core measurements. The lateral heterogeneity is more difficult to visualize and becomes apparent only after multiwell analysis and integration of this with seismic data. A direct consequence of the strong diagenetic transformations is the significant variability in material properties (e.g., observed as differences in log responses, differences in gas compositions from mud-log analysis, and different properties measured on cuttings along the length of the well). This is the case even when horizontal wells are steered. Wellbore steering helps reduce the bigger contrast in properties between lithological units and limits the variability to diagenetic alterations within these units. The latter, however, are still significant in most tight-shale plays.

**CQ and RQ**

This method suggests that well productivity is the product of RQ and CQ. RQ is defined by such properties as hydrocarbon-filled porosity, permeability, pore pressure, organic content, and organic maturation, which together describe the reservoir potential. CQ is defined by such properties as containment of fracture-height growth, fracture openness, low rock/fluid sensitivity, and low propensity to solids production, which together describe the ability for creating a large-surface-area fracture in contact with the reservoir. Maintaining surface area in contact with the reservoir, while preserving fracture conductivity during long-term production, is the challenge. Fracturability describes the amount of surface area created per unit of reservoir volume (i.e., fracture complexity by branching). It is desirable for this property to be reasonably high. However, too much complexity results in high net pressures (because of stress-shadowing interactions) and in limitations of proppant transport (because of tortuosity and changes in fracture width). Unfortunately, poor proppant transport is the source of loss of surface area and loss of fracture conductivity during production.

Rock/fluid sensitivity describes potential problems associated with water imbibition (large reduction in relative permeability to gas); reduction in surface hardness (increased risk of proppant embedment and associated loss of surface area and loss of fracture conductivity); and salt dissolution, mixing, and possible precipitation along the propped section of the fracture. Because of the large surface area exposed to the fracturing fluid, even minor conditions of rock/fluid sensitivity may result in severe reduction in overall production. Also, the propensity of solids production is controlled predominantly by reservoir pressure, rock permeability, and the tensile strength of the rock. Solids production results from a tensile failure (spalling) at the fracture face, resulting from excessive drawdown pressures, which is otherwise desirable to accelerate the production of fracturing water and promote higher initial production. The problem is most frequent in over-pressured reservoirs and increases as the permeability and tensile strength of the reservoir decrease.

**Near- and Far-Wellbore Conditions**

RQ and CQ properties may be different in the region near the wellbore and away from the wellbore. The farwellbore region represents the region of contact between the created hydraulic fracture and the reservoir. Well production depends on this surface-area contact with good RQ and depends on conditions of containment, fracturability, rock/fluid interactions, and prevention of loss of surface area and loss of fracture conductivity during production. The near-wellbore region represents the choking point between the created surface area and the wellbore. Here the goal is to maximize connectivity between the fracture system and the wellbore by minimizing near-fracture tortuosity, maximizing fracture width, reducing breakdown pressures, and limiting the risk of solids production. This goal is achievable by evaluating the variability of rock properties along the horizontal wellbore and selecting rock types with properties most amenable to satisfying the goals. See the complete paper for details of the evaluation process.

**Applications**

**Near-Wellbore CQ for Various Rock Facies.** Results from evaluating near-
tight shales are strongly anisotropic and cannot be approximated by use of isotropic models. These will lead to inappropriate conclusions and production strategies.

stress concentrations at the horizontal wellbore face in anisotropic rocks depend on rock elastic properties. Thus, they are different rock types with different stress concentrations, breakdown pressures, and fracture widths.

the fracture-width evaluation assumes the generation of a single near-wellbore fracture, which may not always be the case. However, it provides a basis of comparison for the fracture-width development as a function of the rock type.

the far-field horizontal stress depends on the anisotropic elastic rock properties, which change from rock type to rock type. Thus, one needs to understand the combined effect of the anisotropic rock properties on the far-field stress and on the near-wellbore-stress concentrations on a rock-class by rock-class basis to estimate the breakdown pressures and near-wellbore fracture widths.

hra of logs is used to identify rock classes uniquely and nonsubjectively along the length of the horizontal wellbore. Because all the measured logs are included in the analysis, this provides higher sensitivity and more-consistent identification of rock classes, compared with the use of fewer logs.

the analysis is based on fracture-width, breakdown-pressure, and solids-production predictions that...
are derived from physical properties and on the basis of physical principles regarding the consequences of these properties on hydraulic fracturing. Therefore, it is easy to understand and implement.

Combined assessment of these conditions enables selecting the best rock types for perforation and anticipating problems on others. JPT

Fig. 3—Near-wellbore-CQ analyses along a horizontal wellbore. Rock classes are identified by HRA of well logs.