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Initial Potential Test Data From Deep Wells in the United States

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GEOLOGIC CONTROLS OF DEEP NATURAL GAS RESOURCES IN THE UNITED STATES

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ABSTRACT

A study was made of initial potential (IP) test data and well pressures from deep (>15,000 ft, >4,572 m) wells in the United States. Basinwide, pressures are above normal in the deep parts of the Uinta, Wind River, and Greater Green River basins. Pressures also are above normal in the Anadarko, Permian, and Gulf Coast basins.

The initial potential data were plotted in order to compare hydraulically fractured or acidized wells and unstimulated wells. It is well known that low-permeability shallow (<10,000 ft, <3,050 m) wells generally show significant increases in IPs when stimulated. However, we found that deep gas wells do not show consistent increases when stimulated. Variations in natural fractures and variations in matrix permeabilities are two significant factors but also deep, hot wells do not seem to respond well to hydraulic fracturing because of the high treatment pressures needed, degradation of fracturing gels and the need for long propped fractures in low-permeability formations. Crushing of the proponent used in artificial fracturing is also one of the factors decreasing the effectiveness of this stimulation method.

INTRODUCTION

In this paper, we briefly summarize the distribution of reservoir pressures and show initial production rates from deep natural gas wells in the United States compiled from computerized data files. We present these data in order to better predict reservoir behavior in deep reservoirs and to begin to explain the causes of the differences in behavior.

Understanding deep (>15,000 ft, >4,572 m) reservoir pressures is important because (1) abnormally high pore pressure (>0.55 psi/ft, 12.44 kPa/m) may reduce the rates of porosity and permeability loss with increasing burial depth and (2) gas reservoirs having high pore pressure will have more gas in place than low-pressure reservoirs at the same temperature and porosity owing to the high compressibility of natural gas. Shallow (<8,000 ft, <2,400 m) reservoirs are usually normally pressured (0.465 psi/ft, 10.52 kPa/m) or underpressured (<0.43 psi/ft, 9.73 kPa/m), whereas deep (>15,000 ft) hot reservoirs may have normal to above normal pressures. In order to determine the general distribution of abnormally high pressures and predict their occurrence in undrilled areas, it is helpful to consider possible causes of high pore pressures.

No single cause can adequately explain all occurrences of above normal pressures; however, most proposed mechanisms require that reservoirs be semi-isolated or fairly well sealed in order to maintain abnormal pressure. Some of the more commonly accepted causes of overpressuring are dewatering of shales owing to compaction, clay-mineral transformations that release water, and aquathermal pressuring caused by thermal expansion of water.

The physical dewatering of clayey sediments such as shale by compaction caused by weight of overburden is a widely accepted mechanism of overpressuring (Dickenson, 1953; Morgan and others, 1968; Chapman, 1980; Chiarelli and Duffaud, 1980). This type of overpressuring is most likely in depocenters characterized by geologically young, rapidly deposited sediments. Diagenetic alteration of smectite-bearing shale and claystone to a more stable mixed-layer illite-smectite or illitic shale also releases water and is a popular mechanism to explain overpressuring in the Gulf Coast Basin of the United States (Powers, 1967; Burst, 1969; Bruce, 1984); however, Hunt and others (1994) recently concluded that gas generation is a major cause of deep Gulf Coast overpressuring.

Aquathermal pressuring was proposed by Barker (1972) as the cause of some of the high pore pressure along the northern coast of the Gulf of Mexico. In Barker's model, the reservoirs must be essentially isolated from pressure bleed-off. If the temperature of a reservoir rock enclosed in excellent seals is increased, the thermal expansion of pore water will cause an increase in reservoir pressure. Magara (1975) suggested that aquathermal pressuring is responsible for reservoir pressures in the Gulf Coast that exceed the weight of overburden. Daines (1982) concluded that aquathermal pressuring could occur at shallow depth in impermeable sediments in areas of high geothermal gradients; however, he concluded that even good clay-rich shales will, over geologic time, bleed off pressure caused by the relatively small water volume increase caused by thermal expansion. Barker (1972, p. 2068) noted that aquathermal pressuring might not be the only mechanism for abnormal pressure in an area, but that it could add to the reservoir pressure caused by other mechanisms.

Other mechanisms for overpressuring are discussed by Fertl (1976) and Gretner (1981). They identified causes of abnormally high pressure such as tectonic loading (stress), osmosis, chemical changes including the conversion of gypsum to anhydrite, pressure transfer along faults, salt diapirism, secondary cementation of pores, long hydrocarbon columns, and thermal conversion of organic matter to oil and gas.

Active or recently active (last few million years) hydrocarbon generation is a likely explanation for overpressuring in basins in which (1) rich source beds are present at high temperature (generally >212˚F, >100˚C), (2) the pressuring phase is oil or gas, and (3) the sediments are well compacted (Spencer, 1987).

REGIONAL BASIN PRESSURES

Pressure data for this study were obtained from (1) drillstem test reports in Petroleum Information Corporation's 1991 Well History Control System (WHCS) data file and (2) reservoir-pressure data compiled by the NRG Associates (1993) in the Significant Oil and Gas Fields of the United States file. The NRG file contains data collected through July 1991 on about 10,000 fields, of which about 250 are deeper than 14,000 ft (4,267 m) and have some form of recorded reservoir pressure. It contains data for fields containing more than 1 MMB of recoverable oil or more than 6 BCF of recoverable gas. Much of the original data analyzed in this study is presented in Spencer and Wandrey (1993).

The definition of normal pressure varies somewhat among different basins but usually ranges from 0.43 to 0.465 psi/ft (9.73–10.52 kPa/m), depending on reservoir salinity and other factors. Overpressured deep significant gas reservoirs as defined by NRG are present in the Rocky Mountain region in the Wind River and Greater Green River basins. The Rocky Mountain region also contains overpressured shallower gas-producing reservoirs in the depth range from 10,500 to more than 13,000 ft (3,200–3,960 m), but data for these reservoirs were not included in this study. Most of the overpressured gas-bearing rocks in the Rocky Mountain region are of Tertiary and Cretaceous age, and the overpressuring is caused by active hydrocarbon generation (Spencer, 1987).

About 35 percent of the deep NRG reservoirs (>14,000 ft, >4,267 m) in the Permian Basin are overpressured. Most of the overpressuring is in rocks of Early Permian (Wolfcampian), Pennsylvanian Atokan and Morrowan, and Mississippian age. Dominant reservoir lithologies are sandstone, limestone, and dolostone. Minor overpressuring is in Devonian limestone. The origin of the overpressuring is not well defined but may be caused by the thermal conversion of previously migrated oil to gas and active generation of gas from deep basin source beds. More research in the Permian Basin is needed in order to identify the causes of overpressuring.

The Gulf Coast Basin contains extensive overpressured reservoirs. Much of the overpressuring in younger Miocene and Oligocene sandstone and shale is probably caused by undercompaction of sediments (Dickenson, 1953; Chapman, 1980). These reportedly undercompacted, overpressured gas areas have been studied in recent years as part of the U.S. Department of Energy's Geopressured–Geothermal Energy Program. Overpressuring in Cretaceous and Jurassic sandstone and carbonate rocks in the Eastern Gulf Basin may be caused by several mechanisms. More work needs to be done in order to better predict the distribution of overpressuring.

SUMMARY OF NATURAL GAS INITIAL PRODUCTION FROM DEEP WELLS

In order to evaluate deep (>15,000 ft, >4,572 m) natural gas well completions, we compiled data on gas flow rates from initial potential tests because computerized production data were not available to us. The WHCS file current to November 1991 was used for this compilation (Petroleum Information Corporation, 1993). The data were grouped by basin and producing formation. A wide range of initial potential values were noted in most basins.

Initial potential is not necessarily a full indication of well productivity, but, in general, it represents the potential of a given formation and basin. Many factors can affect initial potential test results, including well-completion method, choke size, back pressure, number of perforations, pay thickness, and natural fracturing.

In order to normalize variables that affect initial potential results for many wells, we identified wells that were stimulated by hydraulic fracturing and those that were stimulated by acid and were not hydraulically fractured. Hydraulic fracturing is a well-known method to increase formation permeability by creating downhole artificial fractures. Hydraulic fracturing involves injecting a slurry of proppant (usually well-sorted, clean sand) suspended in a liquid-carrying (gel) medium. The mixture is injected at a pressure higher than the natural fracture gradient of the rock so that the crack will propagate away from the wellbore. Such artificial fractures are almost always vertical and are oriented in a direction that is 90˚ to the minimum horizontal stress direction. The proppant helps to keep the artificially created fractures open after the injection process is stopped and the well is produced.

Comparison of initial potential tests for hydraulically fractured (propped) wells with those for wells that were treated (usually with acid injection) but not hydraulically fractured (nonpropped) shows that, in general, hydraulic fracturing does not provide any significant improvement in initial well productivity. Historically, most hydraulic fracturing has been attempted on conventional and low-permeability (tight) unconventional reservoirs but has been most successful in stimulating “near tight” reservoirs having permeability of from 0.1 to 1 or 2 millidarcies (mD). Hydraulic fracturing is the method of choice for improving productivity in most low-permeability (0.1–<0.1 mD) natural gas wells. At depths of less than 10,000 ft (3,050 m), initital potential tests of low-permeability wells are greatly improved, in some cases three to more than five times those of unfractured wells.

We believe that the lack of consistent improvement with hydraulic fracturing in permeabilities in deep wells is mostly caused by the detrimental effects of high-closure stress and high temperature. When an artificial fracture is created, the rock stresses will act to try to close the crack and the proppant is designed to prevent or reduce this closure. The ability of the proppant to resist breaking or crushing is critical to the effectiveness of the treatment. Laboratory studies have been made to measure the ability of different proppants to resist crushing at various closure pressures (Snyder and Suman, 1979). Figure 1 shows a plot of relative permeability versus closure stress for various hydraulic fracture proppants between two steel plates and using a hydraulic ram to force the plates together (closure stress). Common sand (frac sand) shows a gradual decrease in permeability owing to grain crushing such that, at about 9,000 psi (62 MPa), permeability has been reduced to about 5 percent of the original unstressed permeability. Glass beads lose permeability very rapidly at stresses higher than 7,000 psi (48 MPa), whereas sintered bauxite is the highest strength proppant and shows only nominal permeability decrease at closure stresses as high as 10,000 psi (69 MPa). In theory, bauxite should be used in any hydraulic fracture treatment in deep wells, but the increased cost may not be justified.

In our retrieval of proppant type data from the WHCS file, only two deep wells reportedly were treated with bauxite. We know that many more deep completions used bauxite, but these data are not in the WHCS file. In addition, well records in the WHCS file are incomplete for many deep wells, in that the type of treatment, if any, was not recorded. We were not able to determine if a deep well was stimulated or completed naturally.

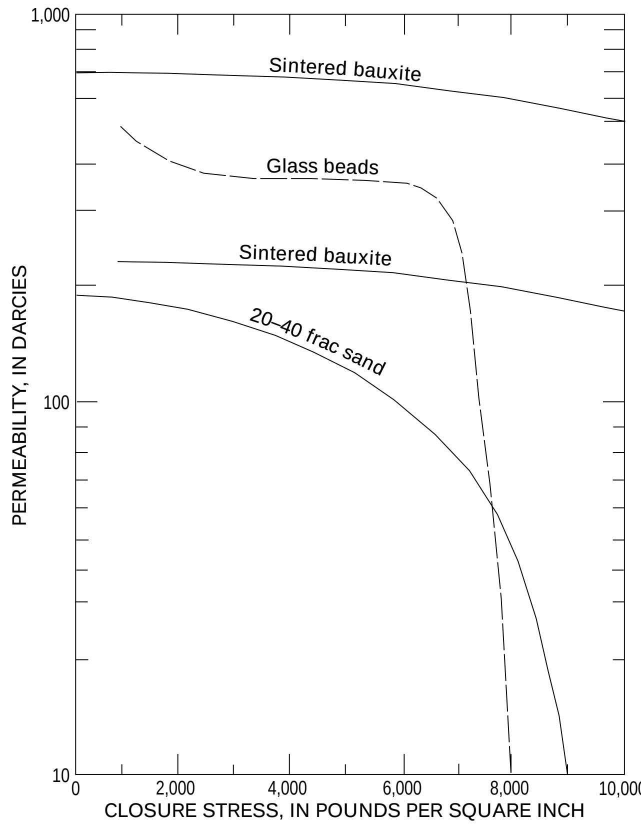

Figure 1. Relative permeability of various hydraulic fracture proppants versus closure stress as measured in the laboratory. Modified from Snyder and Suman (1979, fig. 57).

Proppant crushing is not the only factor affecting deep well initial production values and subsequent natural gas deliverability. Proppant embedment also reduces the permeability of an artificial fracture. Embedment occurs when a fracture propagates out of the perforated reservoir into or across a soft (low-strength) bed. As fracturing pressure is decreased, a soft formation such as shale will squeeze in on the proppant. Figure 2 illustrates the development of proppant crushing and embedment during and after hydraulic fracturing.

Other factors influence the effectiveness of hydraulic fracturing. Artificially created fractures are almost always vertical and generally are oriented parallel with the natural fracture system. The ideal artificial fracture should be oriented 90˚ to the natural fracture system in order to intersect and produce gas from the greatest number of natural fractures. The high temperature of deep wells may destabilize the proppant-carrying gels (Conway and Harris, 1981), and more gel residue may remain in the formation than in shallower low-temperature wells.

Deep wells are commonly injected with acid to stimulate increased productivity. Acid is injected into the well (1) to remove drilling mud and other debris that might block gas flow in the formation and in the perforations and (2) to

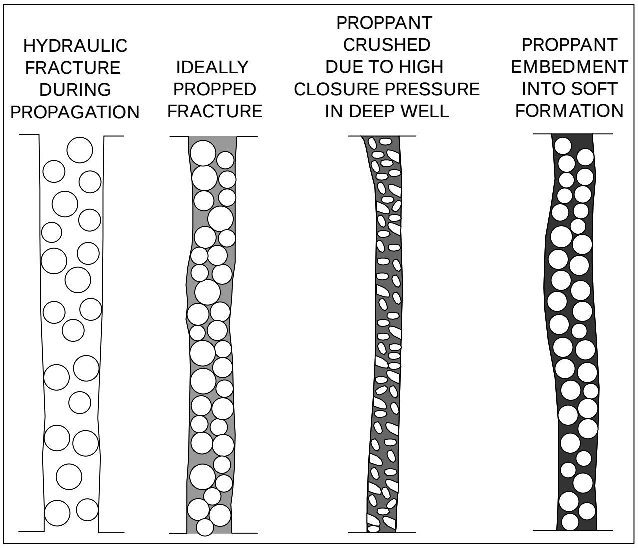

Figure 2. Downhole conditions during and after hydraulic fracturing. Modified from Spencer (1989, fig. 13).

remove matrix and fracture-filling carbonate cements in sandstone and thus enhance the permeability of fracture and matrix porosity in carbonate reservoirs.

We compiled plots of initial potential value versus depth for deep stimulated wells in the United States from the WHCS file. Retrieval criteria included all wells for which (1) the base of perforation interval was greater than 15,000 ft (>4,572 m) and (2) the type of stimulation was reported. Initial potential values for hydraulically fractured (propped) wells were compared with those for nonpropped wells. Most of the stimulated nonpropped wells were acidized. Data were sufficient to make crossplots for initial potential values from 11 deep producing formations. Results are described for five of these formations.

Figure 3 illustrates initial natural gas production versus depth for wells penetrating Tertiary-age deep reservoirs in the Uinta Basin of Utah. These wells are stimulated mostly by acid (fig. 3, nonpropped); only 10 wells were reported in the WHCS file as hydraulically fractured with a proppant (fig. 3, propped). Most initial production values are less than 1 MMCFD, and some are less than 100 MMCFD. A 15,000-ft (4,572 m)-deep well that initially produces less than 1 MMCFD is probably only marginally commercial if it experiences a decline rate typical for low-permeability gas reservoirs in the Uinta Basin. The plot does not show a strong correlation between propped and nonpropped wells by depth. Initial production values shown in figure 3 are generally lower than those shown in figures 4 through 7 and described in the following paragraphs.

Figure 4 illustrates initial natural gas production versus depth for wells penetrating reservoirs in the Upper Cretaceous Shannon Sandstone Bed of the Wind River Basin of Wyoming. Wells were stimulated by acid (nonpropped) or by fracturing (propped). No well is shown that has its lowest perforations between 15,000 and 17,000 ft (4,572–5,182 m). Generally, the deep wells here are

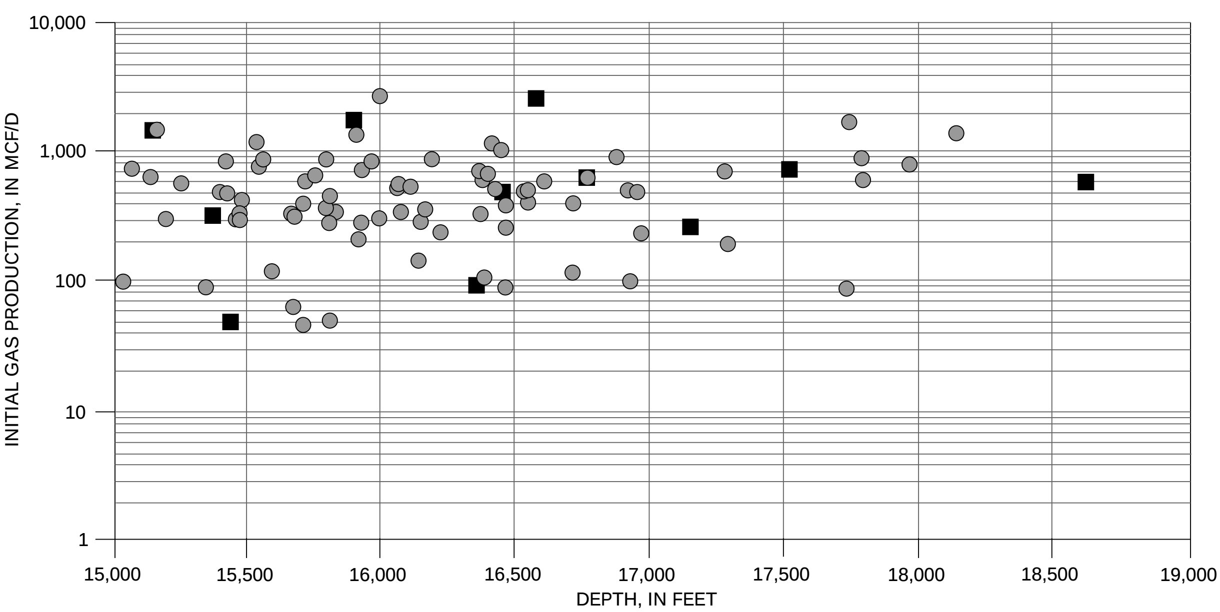

Figure 3. Initial natural gas production versus depth for deep stimulated wells completed in the Tertiary Green River, Wasatch, and Flagstaff Formations, Uinta Basin, Utah. Most gas production also includes condensate. Propped wells (squares) were hydraulically fractured, and nonpropped wells (circles) were acidized or received other treatment. Initial natural gas production values were obtained from initial potential tests, Well History Control System (Petroleum Information Corporation, 1993).

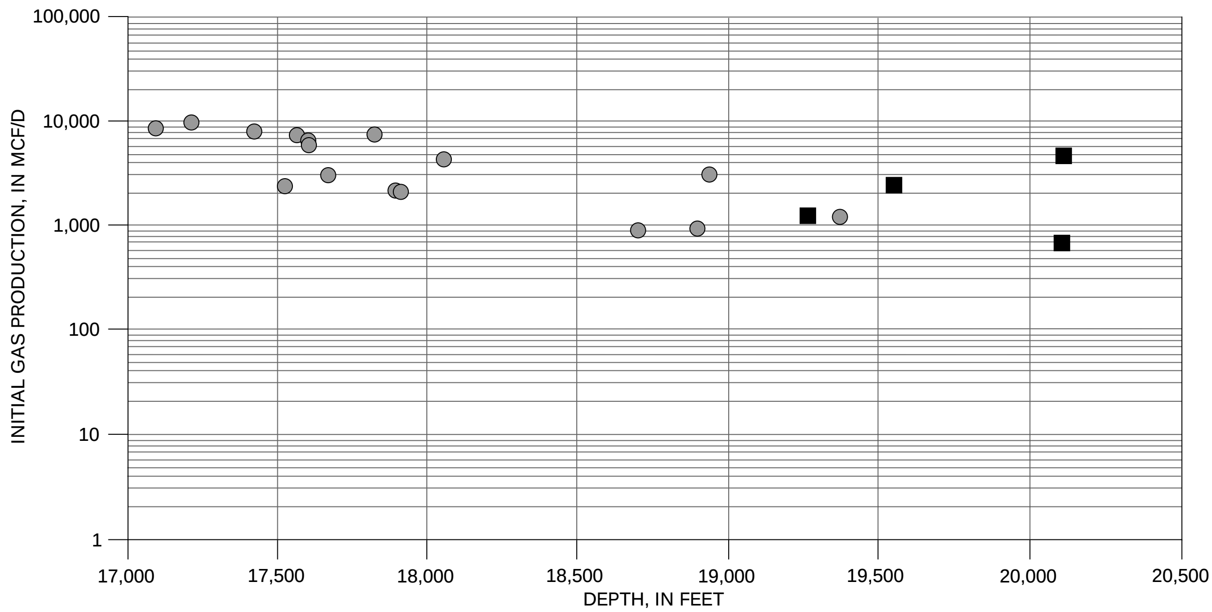

Figure 4. Initial natural gas production versus depth for deep stimulated wells completed in the Upper Cretaceous Shannon Sandstone, Wind River Basin, Wyoming. Propped wells (squares) were hydraulically fractured, and nonpropped wells (circles) were acidized or received other treatment. Initial natural gas production values were obtained from initial potential tests, Well History Control System (Petroleum Information Corporation, 1993).

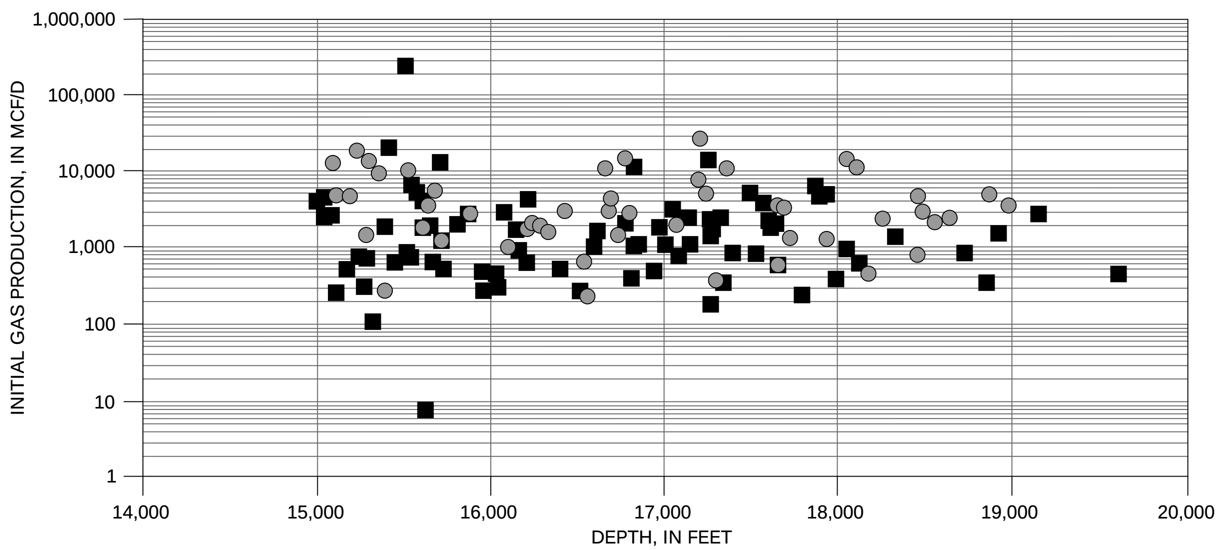

Figure 5. Initial natural gas production versus depth for deep stimulated wells completed in Pennsylvanian reservoirs of Morrowan age, Anadarko Basin, Oklahoma. Propped wells (squares) were hydraulically fractured, and nonpropped wells (circles) were acidized or received other treatment. Initial natural gas production values were obtained from initial potential tests, Well History Control System (Petroleum Information Corporation, 1993).

deeper and have higher initial production values than do Tertiary wells in the Uinta Basin. This increase in initial productivity is partly related to better reservoir quality and partly to increased fracturing. The deep Uinta wells are mostly drilled on gentle regional dip, whereas many of the deep Wind River Basin wells are located on seismic structures where more natural fracturing occurs.

Figure 5 illustrates initial natural gas production versus depth for wells penetrating Lower Pennsylvanian (Morrowan) reservoirs in the Anadarko Basin of Oklahoma. Initial production values for wells stimulated with acid and for hydraulically fractured wells are similar. The average initial production value is 5,074 MCFD for acidized Morrow wells and 5,289 MCFD for fractured Morrow wells.

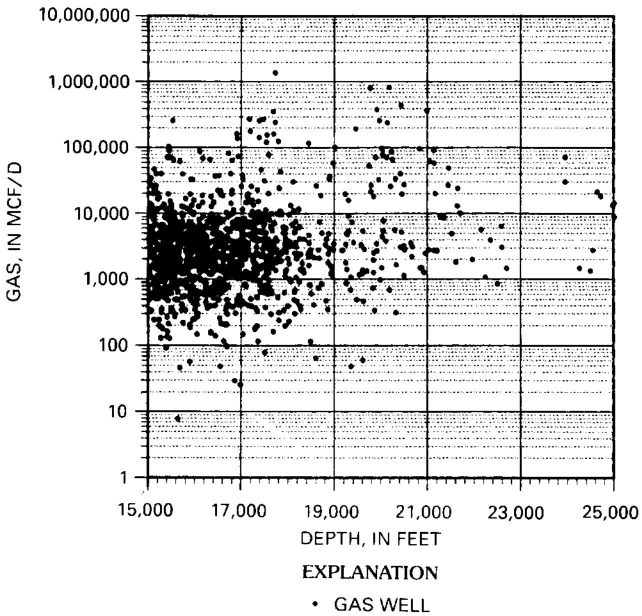

Figure 6. Initial natural gas production for all deep gas wells in the Anadarko Basin, Oklahoma. Initial natural gas production values were obtained from initial potential tests, Well History Control System (Petroleum Information Corporation, 1993).

Figure 6 illustrates initial natural gas production versus depth for all deep wells (regardless of reservoir) in the Anadarko Basin. Comparison of figures 5 and 6 indicates that the Morrowan reservoirs are similar to reservoirs of other geologic ages in the basin. Most deep gas wells are concentrated between 15,000 and 18,000 ft (4,572–5,486 m) and wells in this depth range have initial production values mostly between 500 MCFD and 10 MMCFD. Wells deeper than 18,000 ft show much variation.

Figure 7 illustrates initial natural gas production versus depth for deep wells penetrating the Lower Ordovician Ellenburger Group in the Permian Basin of western Texas and southeastern New Mexico. Data for Ellenburger carbonate rocks show that most deep wells were stimulated by acid (nonpropped, fig. 7). According to the WHCS data file, only four wells were hydraulically fractured, but the file may not record all fractured wells. Acidizing is the stimulation method of choice in carbonate reservoirs. Deep Ellenburger wells have some of the highest initial production values identified in this study. These range from about 1 to 263,500 MMCFD. The average initial production value is 29,547 MMCFD for acidized wells in the Permian Basin and 15,751 MMCFD for hydraulically fractured wells.

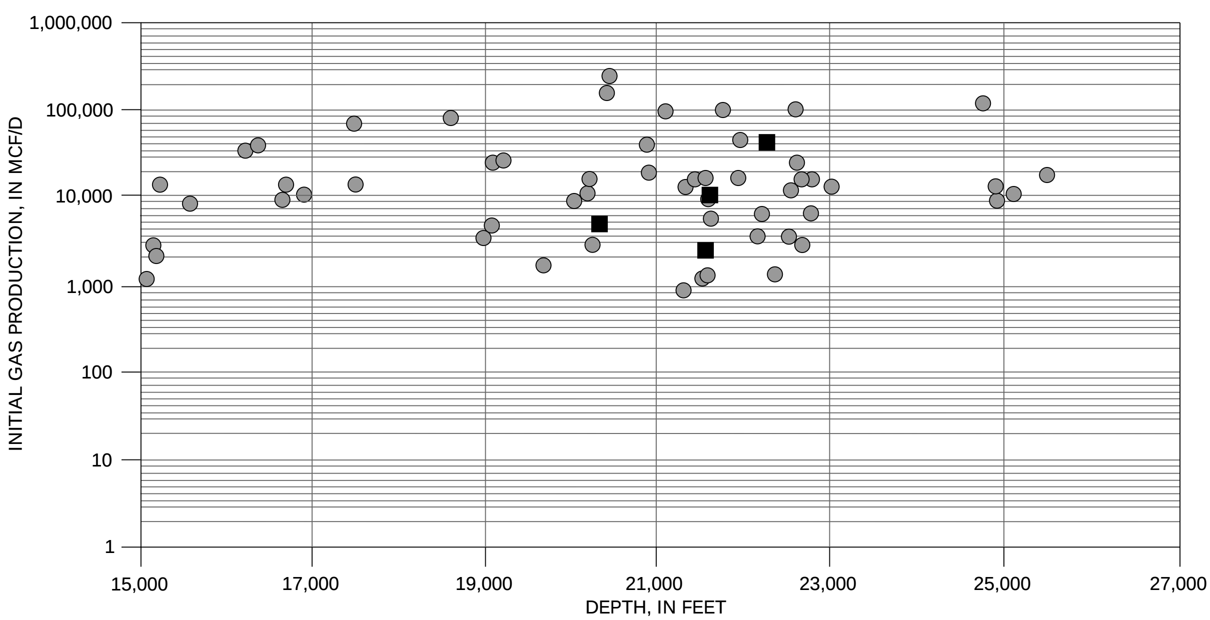

Figure 7. Initial natural gas production versus depth for deep stimulated wells completed in the Lower Ordovician Ellenburger Group, Permian Basin, western Texas and southwestern New Mexico. Propped wells (squares) were hydraulically fractured, and nonpropped wells (circles) were acidized or received other treatment. Initial natural gas production values were obtained from initial potential tests, Well History Control System (Petroleum Information Corporation, 1993).

CONCLUSIONS

Deep gas reservoirs can be overpressured or normally pressured. Basinwide overpressuring is present in the deep parts of the Uinta, Wind River, and Greater Green River basins owing to presently active hydrocarbon generation. Overpressuring is also present in some deep reservoirs in the Permian, Anadarko, and Gulf Coast basins.

Initial natural gas potential tests of deep wells were compiled using the Petroleum Information Corporation (1993) WHCS data file. Many deep wells require stimulation such as hydraulic fracturing or acidizing because deep reservoirs generally have lower matrix porosity and permeability than shallower reservoirs. Data for many wells are incomplete in that the presence or absence of well treatment is not known; however, a compilation was made of initial natural gas potential value and depth for those wells for which the stimulation treatment was known.

We conclude from the initial production data that initial production values vary greatly between and within basins. This variation is probably related partly to the degree of natural fracturing and partly to reservoir quality. Hydraulic fracturing in sandstone reservoirs does not significantly improve initial production in deep wells. The lack of effectiveness is in part caused by proppant crushing and proppant embedment due to high closure stresses at depths of more than 15,000 ft (4,572 m).

Initial gas flow rates are highest in Permian Basin wells that were completed in Ellenburger Group carbonates after acidizing. Values as high as more than 100,000 MMCFD have been recorded. The lowest initial production values in deep wells are in Tertiary rocks of the Uinta Basin, although some of these wells also produce oil and condensate.

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