Chapter 3
Characteristics of Coalbed Methane Production and Associated Hydraulic Fracturing Practices

Understanding the practice of hydraulic fracturing as it pertains to coalbed methane production is an important first step in evaluating its potential impacts on the quality of USDWs. This chapter presents the following: an overview of the geologic processes leading to coal formation, an overview of coalbed methane production practices, a discussion of fracture behavior, a review of the literature on the use and recovery of fracturing fluids, a discussion of mechanisms affecting fluid recovery, and a summary of the methods used for measuring and predicting fracture dimensions and fracturing fluid movement. In addition, several diagrams have been included at the end of this chapter to help illustrate many of these topics. Specifically, Figures 3-1 through 3-8 show the location of the coal basins, the geography of a peat-forming system, the geometry of natural cleats and hydraulically induced fractures, an overview of the hydraulic fracturing process, the relationship between water and gas production rates, and side and plan views of vertical hydraulic fractures.

3.1 Introduction

Coalbed methane is a gas formed as part of the geological process of coal generation, and is contained in varying quantities within all coal. Coalbed methane is exceptionally pure compared to conventional natural gas, containing only very small proportions of "wet" compounds (e.g., heavier hydrocarbons such as ethane and butane) and other gases (e.g., hydrogen sulfide and carbon dioxide). Coalbed gas is over 90 percent methane, and is suitable for introduction into a commercial pipeline with little or no treatment (Rice, 1993; Levine, 1993).

From the earliest days of coal mining, the flammable and explosive gas in coalbeds has been one of mining's paramount safety problems. Over the centuries, miners have developed several methods to extract the coalbed methane from coal and mine workings. Coalbed methane well production began in 1971 and was originally intended as a safety measure in underground coalmines to reduce the explosion hazard posed by methane (Elder and Deul, 1974).

In 1980, the United States Congress enacted a tax credit for "Non-conventional energy production." In 1984, there were only several hundred coalbed methane wells in the United States and most were used for mine de-methanization. By 1990, the anticipated expiration of the tax credit contributed to a dramatic increase in the number of coalbed methane wells nationwide. In addition, DOE and GTI supported extensive research into coalbed exploration and production methods. Federal tax credits and State Severance Tax exemptions served to subsidize the development of coalbed methane resources (Soot, 1991; Pashin and Hinkle, 1997). The federal tax credits and incentives expired at the end of 1992, but coalbed methane exploration, development, and reserves have remained stable or increased (Stevens et al., 1996). At the end of 2000, coalbed methane production from 13 states totaled 1.353 trillion cubic feet, an increase of 156 percent from 1992. During 2000, a total of 13,973 coalbed methane wells were in production (GTI; EPA Regional Offices, 2001). By the end of 2000, coalbed methane production accounted for about 7 percent of the total United States dry gas production and 9 percent of proven dry gas reserves (EIA, 2001).

Coal is defined as a rock that contains at least 50 percent organic matter by weight. The precursor of coal is peat, plant matter deposited over time in fresh-water swamps associated with coastal deltaic rivers. The coal resources from which coalbed methane is derived have similar geologic origins. In the United States, they are usually found in geologic formations that are approximately 65-325 million years old. Coal formation occurred during a time of moderate climate and broad inland oceans. Sea level rose and fell in conjunction with tectonic forces (i.e., subsidence and uplift of land masses) and melting/freezing cycles of decreases and increases in the polar ice masses. As a result, coastal environments such as coastal deltas and peat swamps migrated landward when sea levels rose and moved seaward when sea levels fell, marked by cycles of submergence and emergence. With these cycles of rising and falling sea levels, what was a peat swamp at one time would later be under 100 feet of water. The cycle of sea level rising and falling is marked in the geologic record as cycles of inter-layered deep and shallow water sediments.

The type of sediments deposited at a given location varied with the depth of submergence (Figure 3-2). Generally, carbon-rich organic plant matter was deposited in shallow peat swamps, sand was deposited along beaches and other near-shore, shallow marine environments, and silts and clays and calcium-rich muds were deposited further off-shore in deeper marine environments. Subjected to high pressure over considerable time (due to burial under subsequent sediments), the peats were transformed into coal, the sand into sandstone, the silts and clays into shales, siltstones, and mudstones, and the calcium-rich muds were transformed into limestones. These coal-bearing inter-layered sedimentary sequences are sometimes referred to as “coal cycles.” The idealized coal cycle consists of repeated sequences of very fine-grained sediments (shales and limestones) overlain by coarser sediments (siltstones and sandstones), and then capped by coal. The sequence repeats with shales and limestones over the coal, followed by siltstones and sandstones, then more coal, and so on. Sometimes certain formations are missing from the sequences, so coal is often, though not always, overlain by shales and limestones.

The sedimentation patterns in these fluctuating coastal environments over geologic time scale determined the presence, thickness, and geometry of present-day coalbeds. The number of coal cycles determines the number of resulting coalbeds. For example, the Black Warrior Basin of Alabama includes up to 10 cycles, whereas the San Juan Basin (New Mexico and Colorado) contains as few as 3. The short, rising and falling sea level cycles reflected in the Black Warrior Basin geology produced many thin coalbeds, ranging from less than 1 inch to as much as 4 feet thick (Carrol et al., 1993; Pashin, 1994a and 1994b), whereas the stable, long-term cycles of the San Juan Basin produced fewer, but thicker coalbeds, with single coalbeds up to 70 feet thick (Kaiser and Ayers, 1994).

Peat is transformed into coal when it is buried by accumulating sediment and heated in the subsurface over geologic time. The "rank" of coal describes the amount of energy (measured in British thermal units or Btus) it contains, and is a function of the proportion and type of organic matter, the length and temperature of burial, and the influences of subsequent hydrogeologic and tectonic processes (Carrol et al., 1993; Levine, 1993; Rice, 1993). Methane is generated as part of the process whereby peat is transformed into coal. The origin of methane in coal of low rank, such as bituminous coal, is primarily biogenic (i.e., the result of bacterial action on organic matter) (Levine 1993, as cited by the Alabama Oil and Gas Board, 2002). Low rank coals tend to have lower gas content than high rank coals such as anthracite. Anthracite can have extremely high gas content, but the gas tends to desorb so slowly that anthracite is an insignificant source of coalbed methane (Levine, 1993, as cited by the Alabama Oil and Gas Board, 2002). Commercial coalbed methane production takes place in coals of mid-rank, usually low- to high-volatile bituminous coals (Levine, 1993; Rice, 1993).

A network of fractures, joints, and a sub-network of small joints called cleats commonly characterize the physical structure of coalbeds. Joints are larger, systematic, near-vertical fractures within the coal, generally spaced from several feet to several dozen feet apart (Close, 1993; Levine, 1993). There are two types of cleats: the primary, more continuous cleats are called *face cleats*, while the abutting cleats are called *butt cleats* (Laubach and Tremain 1991; Close, 1993; Levine, 1993) (Figure 3-3). The butt cleats appear as the rungs on a ladder that are bounded on each side by the face cleats. The spacing between cleats is often roughly proportional to the thickness of coal cut by the cleats; thin coals have more closely spaced cleats and thick coals more widely spaced cleats (Laubach et al., 1998, as cited by Olson, 2001).

The primary (or natural) permeability of coal is very low, typically ranging from 0.1 to 30 millidarcies (md) (McKee et al., 1989). According to Warpinski (2001), because coal is a very weak (low modulus) material and cannot take much stress without fracturing, coal is almost always highly fractured and cleated. The resulting network of fractures commonly gives coalbeds a high secondary permeability (despite coal's typically low primary permeability). Groundwater, hydraulic fracturing fluids, and methane gas can more easily flow through the network of fractures. Because hydraulic fracturing generally enlarges pre-existing fractures and rarely creates new fractures (Steidl, 1993; Diamond, 1987a and b; Diamond and Oyler, 1987), this network of natural fractures is very important to the extraction of methane from the coal.

3.2 Hydraulic Fracturing

This section provides an overview of the hydraulic fracturing process, and the factors that affect fracture behavior and fracture orientation. Figure 3-4 provides a simplified graphical representation of a hypothetical hydraulic fracturing event in a coalbed methane well. This diagram shows the fracture initiation and propagation stages, as well as the proppant placement and fracturing fluid recovery stages. Only horizontal fractures are shown in this diagram, although hydraulically induced fractures are often vertically oriented.

3.2.1 The Hydraulic Fracturing Process

Hydraulic fracturing is a technique used by the oil and gas industry to improve the production efficiency of oil and coalbed methane wells. The extraction of coalbed methane is enhanced by hydraulically enlarging and/or creating fractures in the coal zones. The resulting fracture system facilitates pumping of groundwater from the coal zone, thereby reducing pressure and enabling the methane to be released from the coal and more easily pumped through the fracture system back to the well (and then through the well to the surface). To initiate the process, a production well is drilled into the targeted coalbeds. Fracturing fluids containing proppants are then injected under high pressure into the well and specifically into the targeted coalbeds in the subsurface.

The fracturing fluids are injected into the subsurface at a rate and pressure that are too high for the targeted coal zone to accept. As the resistance to the injected fluids increases, the pressure in the injecting well increases to a level that exceeds the breakdown pressure of the rocks in the targeted coal zone, and the rocks "breakdown" (Olson, 2001). In this way, the hydraulic fracturing process "fractures" the coalbeds (and sometimes other geologic strata within or around the targeted coal zones). This process sometimes can create new fractures, but most often opportunistically enlarges existing fractures, increasing the connections of the natural fracture networks in and around the coalbeds (Steidl 1993; Diamond 1987a and b; Diamond and Oyler, 1987). The pressure-induced fracturing serves to connect the network of fractures in the coalbeds to the hydraulic fracturing well (which subsequently will serve as the methane extraction or production well). The fracturing fluids pumped into the subsurface under high pressure also deliver and emplace the "proppant." The most common proppant is fine sand; under pressure, the sand is forced into the natural and/or enlarged fractures and acts to "prop" open the fractures even after the fracturing pressure is reduced. The increased permeability due to fracturing and proppant emplacement facilitates the flow and extraction of methane from coalbeds.

Methane within coalbeds is not structurally "trapped" by overlying geologic strata, as in the geologic environments typical of conventional gas deposits. Only about 5 to 9 percent of the coalbed methane is present as "free" gas within the joints and cleats of coalbeds. Most of the coalbed methane is contained within the coal itself (adsorbed to the sides of the small pores in the coal) (Koenig, 1989; Winston, 1990; Close, 1993).

Before coalbed methane production begins, groundwater and injected fracturing fluids are first pumped out (or "produced" in industry terminology) from the network of fractures in and around the coal zone. The fluids are pumped until the pressure declines to the point that methane begins to desorb from the coal (Gray, 1987).

Coalbed methane production initially requires pumping and removing significant amounts of water to sufficiently reduce the hydrostatic pressure in the subsurface so that methane can desorb from the coal before methane extraction can begin. Coalbed methane is produced at close to atmospheric pressure (Ely et al., 1990; Schraufnagel, 1993). The proportion of water to methane pumped is initially high and declines with increasing coalbed methane production (Figure 3-5). In contrast, in the production of conventional petroleum-based gas, the production of gas is initially high, and as gas production continues over time and the gas resources are progressively depleted, gas production decreases and the amount of water pumped increases.

Almost every coalbed targeted for methane production must be hydraulically fractured to connect the production well bore to the coalbed fracture network (Holditch et al., 1988). Although the general hydraulic fracturing process (described above) is generally similar across the country, the details of the process can differ significantly from location to location depending on the site-specific geologic conditions. For example, although most hydraulic fracturing wells are completely cased except for openings at the targeted coal zone, many wells in the San Juan Basin are fractured by creating a cavity in the open-hole section. Also, in contrast to the typical fracturing job, many wells in the Black Warrior Basin are stimulated more than once. Here, when wells are open to multiple coal seams, the hydraulic fracturing process may involve several or multiple fracturing events, using from 2 to 5 hydraulic fracture treatments per well (depending on number of seams and spacing between seams). Many coalbed methane wells are re-fractured at some time after the initial treatment in an effort to re-connect the wellbore to the production zones to overcome plugging or other well problems (Holditch, 1990; Saulsberry et al., 1990; Palmer et al., 1991a and 1991b; Holditch, 1993). Also, in response to site-specific coal geology and the economics of coalbed methane production where coal seams are thin and vertically separated by up to hundreds of feet of intervening rock) operators might design fracture treatments to enhance the vertical dimension and perform several fracture treatments within a single well to produce methane in an economically viable fashion, (Ely, et al., 1990; Holditch, 1990; Saulsberry et al., 1990; Spafford, 1991; Holditch, 1993).

3.2.2 Factors Affecting Fracture Behavior

Fracture behavior is of interest because it contributes to an understanding of the potential impact of fracturing fluid injection on USDWs; the opportunities for fracture connections within or into a USDW are affected by the extent to which a hydraulically induced fracture grows. Specifically, when hydraulic fracturing fluids are injected into formations that are not themselves USDWs, the following scenarios are of potential concern:

- The hydraulically induced fracture may extend from the target formation into a USDW.
- The hydraulically induced fracture may connect with natural (existing) fracture systems and/or porous and permeable formations, which may facilitate the movement of fracturing fluids into a USDW.

Fracture behavior through coal and other geologic formations commonly present above and below coalbeds depends on site-specific factors such as the following:

1. Physical properties, types, thicknesses, and depths of the targeted coalbeds as well as those of the surrounding geologic formations.
2. Presence of existing natural fracture systems and their orientation in the coalbeds and surrounding formations.
3. Amount and distribution of stress (i.e., in-situ stress), and the stress contrasts between the targeted coalbeds and surrounding formations.
4. Hydraulic fracture stimulation design including volume of fracturing fluid injected into the subsurface as well as the fluid injection rate and fluid viscosity.

Many of these factors are interrelated and together will influence whether and how far hydraulic fractures will propagate into or beyond coalbeds targeted for fracturing. These factors are discussed below.

Properties of Coalbeds and Surrounding Formations

Coalbed depth and rock types in the coal zone have important fundamental influences on fracture dimensions and orientations. According to Nielsen and Hansen (1987, as cited in Appendix A: DOE, Hydraulic Fracturing), generally, at depths of less than 1,000 feet, the direction of least principal stress tends to be vertical and, therefore, at these relatively shallow depths fractures typically have more of a horizontal than a vertical component. Here, horizontal fractures tend to be created because the hydraulically induced pressure forces the walls of the fracture to open in the direction of least stress (which is vertical), creating a horizontal fracture. At these shallower depths, the horizontal fractures result from the low vertical stress due to the relatively low weight of overlying geologic material (due to the shallow depth). Shallow vertical fractures are most likely due to the presence of natural (existing) vertical fractures, from which hydraulically induced vertical fractures can initiate. Generally, in locations deeper than 1,000 feet, the least principal stress tends to be horizontal so vertical fractures tend to form. Vertical fractures created in these greater depths can propagate vertically to shallower depths and develop a horizontal component (Nielsen and Hansen, 1987 as cited in Appendix A: DOE, Hydraulic Fracturing). In the formation of these "T-fractures," the fracture tip may fill with coal fines or intercept a zone of stress contrast, causing the fracture to turn and develop horizontally, sometimes at the contact of the coalbed and an overlying formation.

In many coalbed methane basins, the depths, lithologic properties, and stress fields of the coal zones result in hydraulic fractures that are higher than they are long ("length" refers to horizontal distance from the well bore) (Diamond, 1987a; Morales et al., 1990; Zuber et al., 1990; Holditch et al., 1989; Palmer and Sparks, 1990; Jones and Schraufnagel, 1991; Steidl, 1991; Wright, 1992; Palmer et al., 1991a and 1993a). Almost all of the sites studied by Diamond (1987a and b) had vertical fractures, and about half had horizontal fractures.

Naceur and Touboul (1990) state that the primary mechanisms controlling fracture height are contrasts in the physical properties of the rock strata within and surrounding the coal zone being fractured. Contrasts in strata stresses, moduli, leakoff, and toughness affect fracture growth, with stress contrasts being the most important mechanism controlling fracture height (Naceur and Touboul 1990). (Stress is discussed in more detail later in this section.) Moduli are the ratios of stress to strain in various formations. Leakoff is the magnitude of pressure exerted on a formation that causes fluid to be forced into the formation. The fluid may be flowing into the pore spaces of the rock or into cracks opened and propagated into the formation by the fluid pressure. Toughness can be defined as the point at which enough stress intensity has been applied to a rock formation, so that a fracture initiates and propagates. Coal is generally very weak (with low modulus) and easily fractures. Siltstones, sandstones, and mudstones (other rock types commonly occurring in coal zones) tend to have higher moduli, greater toughness and fracture less easily (Warpinski, 2001). Thick shales, which commonly overlie coalbeds, often act as a barrier to fracture growth (see Appendix A).

Another factor controlling fracture height can be the highly cleated nature of some coalbeds. In some cases, highly cleated coal seams will prevent fractures from growing vertically. When the fracturing fluid enters the coal seam, it is contained within the coal seam's dense system of cleats and the growth of the hydraulic fracture will be limited to the coal seam (see Appendix A).

The low permeability of relatively unfractured shale may help to protect USDWs from being affected by hydraulic fracturing fluids in some basins. If sufficiently thick and relatively unfractured shales are present, they may act as a barrier not only to fracture height growth, but also to fluid movement. The degree to which any formation overlying targeted coalbeds will act as a hydraulic barrier will depend on site-specific factors.

The lithology of coalbeds and surrounding formations is variable in the basins where coalbed methane is produced. Although common, the idealized coal cycle (with shales overlying coalbeds) is not always present in all coal basins or necessarily in all parts of any basin. Although Holditch (1993) states that fracture heights can grow where the coal seam is bounded above or below by sandstone, Warpinski (2001) states that highly layered formations or very permeable strata, such as some sandstones, can act to inhibit fracture growth. Some of the coal seams of the San Juan Basin are bounded below by sandstone. In some locations in each of the other basins, coalbeds are underlain by, overlain by, or interbedded with sandstones. Additional detail on the stratigraphy within each basin is provided in the attachments to this study.

Differences in fracture behavior may also be due in part to very small (but influential) layers or irregularities that exist in the rocks as part of the sedimentation process that created them. Therefore, a valid measurement of rock properties relevant to fracture behavior at one location may not adequately represent the properties of similar rock at another location (Hanson et al., 1987; Jones et al., 1987a and 1987b; Palmer et al., 1989; Morales et al., 1990; Naceur and Touboul, 1990; Jones and Schraufnagel, 1991; Palmer et al., 1993b; Elbel, 1994). For example, the presence of a shallow clay layer as thin as 10 millimeters at the upper contact of a coal seam can cause a vertically propagating, shallow hydraulic fracture to "turn" horizontal and fail to penetrate the next overlying coal seam (Jones et al., 1987a; Palmer et al., 1989; Morales et al., 1990; Palmer et al., 1991b and 1993b). In other cases, hydraulic fractures may penetrate into or even, as shown in the case of some thin shales, completely through overlying shale layers (Diamond, 1987a and b; Diamond and Oyler, 1987). Warpinski et al. (1982) found that even microscopically-thin ash beds can influence hydraulic fracture propagation. In other words, the site-specific geology can play a key role in influencing fracture behavior. In addition to the effects of the rock type and sometimes even thin layers within strata, natural fractures also play a role in fracture behavior and fracture propagation.

Natural Fracture Systems

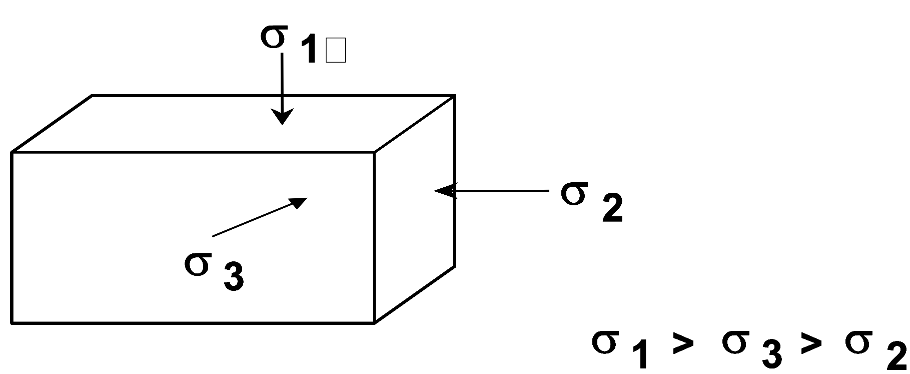
Steidl (1993), based on his "mined-through" studies, concluded that high coalbed methane production depends greatly on the presence of pre-existing natural fracture systems. Hydraulic fracturing tends to widen naturally occurring planes of weakness and rarely creates new fractures, as based on observations by Diamond (1987a and b) and Diamond and Oyler (1987) in their mined-through studies. ("Mined-through" studies provide unique subsurface access to investigate coalbeds and surrounding rock after hydraulic fracturing. Mined-through studies are reviewed in more detail in section 3.4.1.) Diamond and Oyler (1987) also noted that this opportunistic enlarging of preexisting fractures appears to account for those cases where hydraulic fractures propagate from the targeted coalbeds into overlying rock, and their studies found penetration into overlying layers in nearly half of the fractures intercepted by underground mines.

Importantly, in several locations in the Diamond (1987a and b) study sites, fluorescent paint was injected along with the hydraulic fracturing fluids and the paint was found in natural fractures from 200 to slightly more than 600 feet beyond the sand-filled ("propped") portions of hydraulically induced or enlarged fractures. This suggests that the induced/enlarged fractures link into the existing fracture network system and that hydraulic fracturing fluids can move beyond, and sometimes significantly beyond, the propped, sand-filled portions of hydraulically induced fractures (Steidl 1993; Diamond 1987a and b; Diamond and Oyler, 1987). The mined-through studies did not conduct systematic assessments of the extent of the fractures into or through the roof rock shales that were immediately above the mined coal (the rock strata immediately above a mined coal layer is referred to as the "roof rock").

In-Situ Stress and Stress Contrasts

In-situ stress and the relative stress of neighboring geologic strata are important influences on fracture behavior. A discussion of in-situ stress is provided in DOE's paper "Hydraulic Fracturing" (provided as Appendix A). In-situ stress is described as:

> "Underground formations are confined and under stress… [The graphic below] illustrates the local stress state at depth for an element of formation. The stresses can be divided into 3 principal stresses… [In the graphic below,] σ_1 is the vertical stress, σ_2 is the maximum horizontal stress, while σ_3 is the minimum horizontal stress, where $\sigma_1 > \sigma_2 > \sigma_3$. This is a typical configuration for coalbed methane reservoirs. However, depending on geologic conditions, the vertical stress could also be the intermediate (σ_2) or minimum stress (σ_3). These stresses are normally compressive and vary in magnitude throughout the reservoir, particularly in the vertical direction (from layer to layer). The magnitude and direction of the principal stresses are important because they control the pressure required to create and propagate a fracture, the shape and vertical extent of the fracture, the direction of the fracture, and the stresses trying to crush and/or embed the propping agent during production."



Local in-situ stress at depth.

According to (Naceur and Touboul 1990), the contrast in stress between adjacent rock strata within and surrounding the targeted coal zone is the most important mechanism controlling fracture height. Stress contrast is important in determining whether a fracture will continue to propagate in the same direction when it hits a geologic contact between two different rock types. Often, a high stress contrast results in a barrier to fracture propagation. An example of this would be where there is a geologic contact between a coalbed and an overlying, thick, higher-stress shale.

Hydraulic Fracture Stimulation Design

The procedures and fracturing fluids used to stimulate coalbed methane wells can differ from operator to operator in a single basin due to local characteristics of geology and depth and to perceived advantages of cost, effectiveness, production characteristics, or other factors. On a larger scale, although fracture stimulations in coalbed methane projects in different basins may share common rock types and characteristics, fracture behavior can differ significantly. Discussions on hydraulic fracturing practices in 11 individual coal basins are included in Chapter 5 and in Attachments 1 through 11.

Aspects of fracture behavior, such as fracture dimensions (height, length, and width), are affected by the different fracturing approaches taken by the operator during a hydraulic fracturing event. Generally, the larger the volume of fracturing fluids injected, the larger the potential fracture dimensions. Fluid injection rates and viscosity can also affect fracture dimensions (Olson, 2001; Diamond and Oyler, 1987). Large injection volumes also often result in extensive networks of induced fractures. Gelled water treatments may result in the widest and longest fractures, but this occurrence cannot be concluded with certainty from the mined-through studies (Diamond and Oyler, 1987; Diamond 1987a and b).

The effects of these operator-controlled actions interact with and are influenced by the physical properties, depths, and in-situ stress of the geologic formations being fractured (as listed above). For example, if a hydraulically induced fracture has a relatively constant height due to a geologic layer acting as a barrier to fracture propagation, and the fracture is forced to grow and increase in volume (through an increased volume of fracturing fluid), the fracture will mainly grow in length. Also, increasing fluid viscosity can increase the pressure due to injection, resulting in greater fracture width, and thus often shorter fractures (Olson, 2001).

3.3 Fracturing Fluids

The fluids used for fracture development are pumped at high pressure into the well. They may be "clear" (most commonly water, but may include acid, oil, or water with friction-reducer additives) or "gelled" (viscosity-modified water, using guar or other gelling agents). Some literature indicates that coalbed fracture treatments use from 50,000 to 350,000 gallons of various stimulation and fracturing fluids, and from 75,000 to 320,000 pounds of sand as proppant (Holditch et al., 1988 and 1989; Jeu et al., 1988; Hinkel et al., 1991; Holditch, 1993; Palmer et al., 1991b, 1993a, and 1993b). More typical injection volumes, based on average injection volume data provided by Halliburton for six coalbed methane locations, indicate a maximum average injection volume of 150,000 gal/well and a median average injection volume of 57,500 gal/well (Halliburton, Inc., 2003).

Depending on the basin and treatment design, the composition of these fluids varies significantly, from simple water and sand to complex polymeric substances with a multitude of additives. Types of fracturing fluids are discussed in greater detail in Chapter 4.

3.3.1 Quantifying Fluid Recovery

Several studies have evaluated the recovery rates of hydraulic fracturing treatment fluids in coal and non-coal formations as discussed in more detail below. Non-coal formations were evaluated to augment the available flowback data.

Coal Formation

Palmer et al. (1991a) measured flowback rates in 13 hydraulic fracturing wells to compare the gas production resulting from the use of water versus gel-based fracturing fluids. This study was conducted in a coal seam with permeabilities from 5 to 20 md. Ten samples collected over a 19-day flowback period indicated a recovery rate of 61 percent. Palmer et al. (1991a) predicted total recovery to be from 68 percent to as much as 82 percent.

Non-Coal Formations

Willberg et al. (1997) conducted a flowback analysis in 10 wells in a heterogeneous sandstone and shale environment that was highly impermeable (i.e., with a permeability of 0.01 md). The fluids used in this study were recovered at an average efficiency of 35 percent during the 4 to 5 day flowback period. Three wells were then sampled every 4 to 8 hours during the subsequent gas production phase to assess long-term polymer recovery, which was found to be minimal (3 percent). Sampling of injected fluid and chloride concentrations indicated that as the flowback and gas production periods progressed, decreasing proportions of the extracted water consisted of the injected fluid, while increasing proportions were natural formation water. In other words, natural formation water was able to bypass viscous gel trapped in the formation and flow into the production wells.

The authors further cited laboratory studies indicating that water may flow past the gel in sand such as that used as proppant in these studies (Willberg et al., 1997). Because the gel is more viscous than water, it is easier for water to respond to pumping and flow through the formation towards the production well. As Willberg et al. (1997) writes, “Production of formation water effectively competes and eventually supersedes residual fracturing fluid recovery, thereby limiting the overall cleanup efficiency.” Given that the environments in which coalbed methane is produced are also generally saturated with water, and similar sands are used as proppants, it is possible that gel recovery is impeded in much the same way in coalbed methane stimulations.

Willberg et al. (1998) conducted another flowback analysis and described the effect of flowback rate on cleanup efficiency in an initially dry, very low permeability (0.001 md) shale. Some wells in this study were pumped at low flowback rates (less than 3 barrels per minute (bbl/min). Other wells were pumped more aggressively at greater than 3 bbl/min. Thirty-one percent of the injected fluids were recovered when low flowback rates were applied over a 5-day period. Forty-six percent of the fluids were recovered when aggressive flowback rates were applied in other wells over a 2-day period. Additional fluid recovery (10 percent to 13 percent) was achieved during the subsequent gas production phase, resulting in a total recovery rate of 41 percent to 59 percent. Willberg speculated that the lower recovery rate in the 1997 study was due to the pumping of large amounts of formation water during the recovery process, compared to the 1998 study that was conducted in a relatively dry environment.

3.3.2 Mechanisms Affecting Fluid Recovery

A variety of site-specific factors will influence the recovery efficiency of fracturing fluids. These factors are summarized as follows:

- Fluids can “leakoff” (flow away) from the primary hydraulically induced fracture into smaller secondary fractures. The fluids then become trapped in the secondary fractures and/or pores of porous rock.

- Fluids can become entrapped due to the “check-valve effect,” wherein fractures narrow again after the injection of fracturing fluid ceases, formation pressure decreases, and extraction of methane and groundwater begins.

- Some fluid constituents can become adsorbed to coal or react chemically with the formation.

- Some volume of the fluids, moving along the hydraulically induced fracture, may move beyond the capture zone of the pumping well, and thus cannot be recovered during fluid recovery. The capture zone of the production well is that portion of the aquifer that contributes water to the well.

- Some fluid constituents may not completely mix with groundwater and therefore would be difficult to recover during production pumping.

Each of these mechanisms is discussed in greater detail in this section.

Fluid Leakoff

Fluids can be "lost" (i.e., remain in the subsurface unrecovered) due to "leakoff" into connected fractures and the pores of porous rocks (Figure 3-7). Fracturing fluids injected into the primary hydraulically induced fracture can intersect and flow (leakoff) into preexisting smaller natural fractures. Some of the fluids lost in this way may occur very close to the well bore after traveling minimal distances in the hydraulically induced fracture before being diverted into other fractures and pores. The volume of fracturing fluids that may be lost in this way depends on the permeability of the rocks and the surface area of the fracture(s).

The high injection pressures of hydraulic fracturing can force the fracturing fluids to be transported deep into secondary fractures. The cleats in coal are presumed to play an important role in leakoff (Olson, 2001). Movement into smaller fractures and cleats can be to a point where flowback efforts will not recover them. The pressure reduction caused by pumping during subsequent production is not sufficient to recapture all the fluid that has leaked off into the formation. The loss of fluids due to leakoff into small fractures and pores is minimized by the use of cross-linked gels, discussed in more detail in Chapter 4.

Check-Valve Effect

A check-valve effect occurs when natural or propagating fractures open and allow fluids to flow through when fracturing pressure is high, but subsequently prevent the fluids from flowing back towards the production well as they close after fracturing pressure decreases (Warpinski et al., 1988; Palmer et al., 1991a). A long fracture can be pinched off at some distance from the well. This reduces the effective fracture length available to transport methane from various locations within the coalbed to the production well. Fluids trapped beyond the "pinch point" are unlikely to be recovered during flowback.

In most cases, when the fracturing pressure is released, the fracture closes in response to natural subsurface compressive stresses. Because the primary purpose of hydraulic fracturing is to increase the effective permeability of the target formation and connect new or widened fractures to the well, a closed fracture is of little use. Therefore, a component of coalbed methane production well development is to "prop" the fracture open, so that the enhanced permeability from the pressure-induced fracturing persists even after fracturing pressure is terminated. To this end, operators use a system of fluids and "proppants" to create and preserve a high-permeability fracture-channel from the well into the formation.

The check-valve effect takes place in locations beyond the zone where proppants have been emplaced (or in smaller secondary fractures that have not received any proppant). Because of the heterogeneous, stratified, and fractured nature of coal deposits, it is likely that some volume of stimulation fluid cannot be recovered due to its movement into zones that were not completely "propped."

Adsorption and Chemical Reactions

Adsorption and chemical reactions can prevent the fluid from being recovered. Adsorption is the process by which fluid constituents adhere to a solid surface (i.e., the coal, in this case) and are thereby unavailable to flow with groundwater. Adsorption to coal is likely; however, adsorption to other surrounding geologic material (e.g., shale, sandstone) is likely to be minimal. Another possible reaction affecting the recovery of fracturing fluid constituents is the neutralization of acids (in the fracturing fluids) by carbonates in the subsurface.

Movement of Fluids Outside the Capture Zone

Fracturing fluids injected into the target coal zone flow into fractures under very high pressure. The hydraulic gradients driving fluid flow away from the well during injection are much greater than the hydraulic gradients pulling fluid flow back towards the production well during flowback and production pumping. Some portion of the coalbed methane fracturing fluids could be forced along the hydraulically induced fracture to a point beyond the capture zone of the production well. The size of the capture zone will be affected by the regional groundwater gradients, as well as by the drawdown caused by the well. If fracturing fluids have been injected to a point outside of the well's capture zone, they will not be recovered through production pumping and, if mobile, may be available to migrate through an aquifer. Site-specific geologic, hydrogeologic, injection pressure, and production pumping details would provide the information needed to estimate the dimension of the production well capture zone and the extent to which the fracturing fluids might travel, disperse, and dilute.

Incomplete Mixing of Fracturing Fluids with Water

Steidl (1993) documented the occurrence of a gelling agent that did not dissolve completely and formed clumps at 15 times the injected concentration in the fracture induced by one well. Steidl (1993) also directly observed, in his mined-through studies, gel hanging in stringy clumps in many other fractures induced by that one well. As Willberg et al. (1997) noted, laboratory studies indicate that fingered flow of water past residual gel may impede fluid recovery. Therefore, some fracturing fluid gels appear not to flow with groundwater during production pumping and remain in the subsurface unrecovered. Such gels are unlikely to flow with groundwater during production, but may present a source of gel constituents to flowing groundwater during and after production.

3.4 Measuring and Predicting the Extent of Fluid Movement

Because fractures can possibly connect with or even extend into USDWs, fracture height is relevant to the issue of whether hydraulic fracturing fluids can affect USDWs. Current methods of measuring or predicting fracture growth, including mathematical models, are described. The models are effective in setting parameters for a given hydraulic fracture operation. Coalbed methane well operators have a financial incentive to keep the hydraulically induced fracture generally within the target coal zone so that expenditures on hydraulic horsepower, fracturing fluids, and proppants are minimized for commercial extraction of methane from the coal. In addition, a detailed review is included on "mined-through" studies that were conducted primarily by the U.S. Bureau of Mines. These studies provide unique information on the direct measurement of the dimensions and other characteristics of fractures created in coal seams and surrounding strata by hydraulic fracturing. Paint, injected with the fracturing fluids, was used as a tracer in some of these studies, enabling one of the most direct measurements of the extent of fluid movement due to hydraulic fracturing.

The particular stratigraphy of a fracturing site will determine what fracture heights are significant with respect to USDWs. That is, a given fracture height may be considered small at a particular site in one basin, but may be more significant in another basin where there is a smaller vertical separation between hydraulically fractured coalbeds and a USDW. The extent of fracturing is controlled by the characteristics of the geologic formations (including the presence of shales or natural fractures), the volume and type of fracturing fluid used, the pumping pressure, and the depth at which the fracturing is performed. Several methods are available to operators to measure or predict the extent to which fracture stimulation fluid moves and the related values of maximum induced fracture extension and "propped" fracture height. Propped height (i.e., height in the fracture to which proppant has been distributed) was found to be 60 percent to 75 percent of total vertical fracture height (Mavor et al., 1991; Rahim and Holditch, 1992; Nolte and Smith, 1981; Nolte and Economides, 1991; Zuber et al., 1991). Furthermore, in cases where proppant "screens out" or emplacement partially fails, proppant may exist in 20 percent or less of fracture height.

Both the current and some older methods for estimating fracture dimensions are discussed below. In general, these methods fall into three areas: direct measurements; indirect measurements; and model estimates. Terminology in the literature regarding fracture dimensions is sometimes inconsistent; some articles describe "measured" fracture dimensions when referring to indirect measures or even model estimates.

3.4.1 Direct Measurements

Direct measures include mined-through (or mineback) studies (where mining of subsurface coal seams that were previously hydraulically fractured allows direct access to fractures for measurement); dye tracing conducted in conjunction with mined-through studies; downhole cameras (used to visually inspect fractures in the borehole), including borehole image logging and downhole video logging; surface and downhole tiltmeters; and microseismic monitoring (or imaging). Fracture geometry is most dependably measured by microseismic monitoring or downhole tiltmeters (Warpinski, 2001), or by tracers (Diamond and Oyler, 1987). Downhole cameras can be used only in open bore holes (uncased wells), so fracture measurements using cameras do not reflect conventional coalbed methane fracturing that typically occurs in cased wells. Both downhole cameras and mined-through approaches to fracture measurements are limited to areas exposed by the wellbore and mining activities, respectively. Nonetheless, the mined-through studies provide the most direct approach for estimating fracture dimensions.

Mined-Through Studies

Twenty-two coalbeds were hydraulically fractured, subsequently mined-through, and investigated several months to several years later in Pennsylvania, Alabama, West Virginia, Illinois, Virginia, and Utah (Diamond 1987a and b; Diamond and Oyler 1987). Similar studies have been conducted by Jeffrey et al. (1993) in Queensland, Australia, and Steidl (1991a; 1991b; 1993) in the Black Warrior Basin, Alabama. The Diamond studies were designed to evaluate the effect of the hydraulic fracturing treatment on mining safety. All the mined-through studies enabled direct observation of induced fractures and surrounding material and evaluation of the movement of sand proppant and fracturing fluids through both induced and natural fractures. Eight of the treatments included fluorescent paint in the injected fluid to aid in mapping fluid movement (Diamond 1987a and b).

Steidl (1993) found that fracture widths were typically 0.1 inch, but could be as wide as 4 inches. Measured sand-filled (propped) fractures were 2 to 526 feet in length (Steidl 1993, Jeffrey et al., 1993), although Steidl found a sand-free extension of a sand-filled fracture 870 feet from the borehole. Diamond (1987a and b) found treatment fluids beyond the sand-filled portions of the fractures using paint injected with the fracturing fluids. In most of the wells where paint was injected, the paint was found 200 to 300 feet beyond the sand-filled portions of fractures. However in one borehole, paint extended out from the well bore for 630 feet, although the sand-filled portion of the fracture was only 95 feet in extent (Diamond, 1987a and b). These paint-coated fractures were produced using typical hydraulic fracturing processes in fairly typical coalbed methane geologic conditions.

Fluorescent paint was observed in locations that indicated fluids did not travel in a direct linear path from the induced fracture. Fluids often followed a stair-step pathway through the coalbed (Diamond and Oyler, 1987). The fluorescent paint was also useful for identifying small fractures penetrated by treatment fluids but not by sand proppant. Multiple small, parallel fractures were penetrated by treatment fluids at many of the locations studied. Given that treatment fluids have been documented to travel more than six times farther than sand proppant, studies looking at the dimensions of sand-filled fractures alone are unlikely to capture the extent of fluid movement within and beyond coalbed methane reservoirs (Diamond, 1987a and b).

About half of the sites studied by Diamond (1987a and b) and Diamond and Oyler (1987) had fractures penetrating beyond the coalbeds into the roof rock (the rock overlying the coal in the mined areas). Jeffrey et al. (1993) found that most of the proppant in three of their four treatments was found in the roof rock. Thus, mined-through studies in Australia and in six states in the United States found that hydraulic fracturing fluids penetrated into, and, when shales were very thin, through strata surrounding coalbeds in 50 percent of stimulations in the United States and 75 percent of the stimulations in Australia. The mined-through studies, however, generally cannot provide measures of how far the fractures actually extend, since mining did not extend beyond the coal and into the roof rock.

Other Direct Measurements

A discussion of other fracture diagnostic methods is provided in DOE's paper "Hydraulic Fracturing" (provided as Appendix A).

> "Fracture diagnostics involves analyzing the data before, during and after a hydraulic fracture treatment to determine the shape and dimensions of both the created and propped fracture. Fracture diagnostic techniques have been divided into several groups (Cipolla and Wright, 2000).
>
> **Direct far field techniques**
>
> Direct far field methods are comprised of tiltmeter fracture mapping and microseismic fracture mapping techniques. These techniques require delicate instrumentation that has to be emplaced in boreholes surrounding and near the well to be fracture treated. When a hydraulic fracture is created, the expansion of the fracture will cause the earth around the fracture to deform. Tiltmeters can be used to measure the deformation and to compute the approximate direction and size of the created fracture. Surface tiltmeters are placed in shallow holes surrounding the well to be fracture treated and are best for determining fracture orientation and approximate size. Downhole tiltmeters are placed in vertical wells at depths near the location of the zone to be fracture treated. As with surface tiltmeters, downhole tiltmeter data can be analyzed to determine the orientation and dimensions of the created fracture, but are most useful for determining fracture height. Tiltmeters have been used on an

experimental basis to map hydraulic fractures in coal seams (Nielson and Hanson, 1987).

Microseismic fracture mapping relies on using a downhole receiver array of accelerometers or geophones to locate microseisms or micro-earthquakes that are triggered by shear slippage in natural fractures surrounding the hydraulic fracture. … In essence, noise is created in a zone surrounding the hydraulic fracture. Using sensitive arrays of instruments, the noise can be monitored, recorded, analyzed and mapped.

…Microseismic monitoring has traditionally been too expensive to be used on anything but research wells, but its cost has dropped dramatically in the past few years, so although still expensive (on the order of $50,000 to $100,000), it is being used more commonly throughout the industry. … If the technology is used at the beginning of the development of a field, however, the data and knowledge gained are often used on subsequent wells, effectively spreading out the costs.

Direct near-wellbore techniques

Direct near-wellbore techniques are run in the well that is being fracture treated to locate or image the portion of fracture that is very near (inches) the wellbore. Direct near-wellbore techniques…[include] borehole image logging [and] downhole video logging, and caliper logging. If a hydraulic fracture intersects the wellbore, these direct near-wellbore techniques can be of some benefit in locating the hydraulic fracture.

However, these near-wellbore techniques are not unique and cannot supply information on the size or shape of the fracture once the fracture is 2-3 wellbore diameters in distance from the wellbore. In coal seams, where multiple fractures are likely to exist, the reliability of these direct near-wellbore techniques are even more speculative. As such, very few of these direct near-wellbore techniques are used on a routine basis to look for a hydraulic fracture."

3.4.2 Indirect Measurements

Indirect measures of fracture dimensions include pressure analyses (sometimes referred to as net, treating, or bottom hole pressure analyses that are sometimes analyzed in conjunction with proppant volume assessments) and radioactive tracing. (Radioactive tracing can be conducted on either fracturing fluids or proppants. It is sometimes referred to as a "tagged" study, and is typically measured through gamma ray logging.) Pressure analyses generally monitor bottom hole pressures (BHPs) over time to infer fracture propagation. For example, declining net pressure during water/gel pumping stages indicates rapid fracture height growth (Saulsberry, et al., 1990). Proppant volumes and historical fracturing and methane production data are used to improve estimates based on pressure analyses. Fracture heights and lengths that are inferred by pressure analyses are commonly described in the literature as "measured." Radioactive tracers provide only approximate estimates of fracture dimensions because they are measured in near-wellbore environments.

3.4.3 Model Estimates

The other main category of indirect measures of fracture dimensions is hydraulic fracture modeling. The basic elements of fracture modeling were developed between 1955 and 1961 (Nolte and Economides, 1991). Many modeling studies were conducted to aid in the design of fracture stimulation treatments (i.e., to determine the volume and pump rate of fluids and proppants that are required to achieve a desired fracture geometry).

Model estimates of fracture heights and lengths are common, including estimates using three-dimensional (and quasi-three dimensional) models. Modeling capabilities have advanced considerably in the last several 15 years, and the newest P3D (pseudo 3 dimensional) models simultaneously predict height, width, and length based on treatment input data and reservoir parameters (Olson, 2001). A discussion of indirect fracture modeling techniques is provided by DOE in the "Hydraulic Fracturing" paper (provided as Appendix A). An excerpt from that paper is provided below.

> "The indirect fracture techniques consist of hydraulic fracture modeling of net pressures, pressure transient test analyses, and production data analyses. Because the fracture treatment data and the post-fracture production data are normally available on every well, the indirect fracture diagnostic techniques are the most widely used methods to estimate the shape and dimensions of both the created and the propped hydraulic fracture.
>
> The fracture treatment data can be analyzed with a P3D fracture propagation model to determine the shape and dimensions of the created fracture. The P3D model is used to history match the fracturing data, such as injection rates and injection pressures. Input data, such as the in-situ stress and permeability in key layers of rock can be varied (within reason) to achieve a history match of the field data.
>
> Post-fracture production and pressure data can be analyzed using a 3D reservoir simulator to estimate the shape and dimensions of the propped fracture. Values of formation permeability, fracture length and fracture conductivity can be varied in the reservoir model to achieve a history match of the field data.
>
> The main limitation of these indirect techniques is that the solutions are not unique and require as much fixed data as possible. For example, if the engineer has determined the formation permeability from a well test or production test prior to the fracture treatment, so that the value of formation permeability is

> known and can be fixed in the models, the solution concerning values of fracture length become more unique. Most of the information in the literature concerning post-fracture analyses of hydraulic fractures has been derived from these indirect fracture diagnostic techniques."

There are several caveats regarding the use and interpretation of model estimates. In-situ stress values of the target coal seams and surrounding strata are important model inputs. Actual in-situ stress measurements are very difficult to obtain and are rarely conducted (Warpinski, 2001). Therefore, almost all modeling is conducted using inferred stress values (as estimated, for example, from the mechanical and lithological properties of rocks from, or similar to those in, the target coal zone). Given the geologic variability and site-specific influences on fracture behavior described above, the reliability of fracture height and length estimates obtained from various models is obviously influenced by the quality of the inferred model inputs regarding geologic factors.

Models also necessarily rely on simplifying assumptions to simulate fracture propagation and behavior through sometimes complex geologic zones. As with all modeling, the reliance on inferred input variables and some assumptions introduces some subjectivity to the modeling process. Dependable modeling requires knowledge of and allowance for the detailed stratigraphy of the geologic strata throughout the coal zone. (It was noted in section 3.2.2 that thin clay layers or ash beds can influence fracture behavior.) Simplified geologic models might represent the subsurface as 2 to 3 distinct geologic layers, to reduce computing and data requirements, when a 30- or 50-layer model may be necessary to accurately predict fracture height (Rahim et al., 1998). Nevertheless, models are necessary simplifications of fracture behavior in the geologic subsurface, and significant research has been conducted in the last several decades so that model estimates of fracture behavior in methane-producing coalbeds are now an invaluable tool for industry.

3.4.4 Limitations of Fracture Diagnostic Techniques

Warpinski (1996) discussed many of these same fracture diagnostic techniques. In general, the best fracture diagnostics techniques are expensive and used only in research wells. Fracture diagnostic techniques can provide important data when entering a new production area or a new formation. However, for coalbed methane wells, where costs must be minimized to maintain profitability, the best fracture diagnostic techniques are rarely used and are often considered to be prohibitively expensive.

Warpinksi (2001) further provided other general conclusions regarding estimates of fracture dimensions:

- Fracture heights inferred from pressure data are almost always greater than the corresponding heights measured with the more dependable microseismic monitoring or tiltmeters.

- Actual fracture lengths may be greater or less than the lengths estimated from models or inferred from pressure analyses, depending on many site-specific geologic factors.

- Fracture geometry can be accurately measured using microseismic monitoring and measured somewhat using downhole tiltmeters. These technologies have been found to be invaluable for determining how fractures actually behave.

Table 3-1 lists certain diagnostic techniques and their limitations.

Table 3-1. Limitations of Fracture Diagnostic Techniques (Appendix A: DOE, Hydraulic Fracturing)

Parameter	Technique	Limitation
Fracture Height	Tracer logs	Shallow depth of investigation; shows height only near the wellbore
Fracture Height	Temperature logs	Difficult to interpret; shallow depth of investigation; shows height only near wellbore
Fracture Height	Stress profiling	Does not measure fracture directly; must be calibrated with *in-situ* stress tests
Fracture Height	P3D models	Does not measure fracture directly; estimates vary depending on which model is used
Fracture Height	Microseismic	Optimally requires nearby offset well; difficult to interpret; expensive
Fracture Height	Tiltmeters	Difficult to interpret; expensive and difficult to conduct in the field
Fracture Length	P3D models	Length inferred, not measured; estimates vary greatly depending on which model is used
Fracture Length	Well testing	Large uncertainties depending upon assumptions and lack of prefracture well test data
Fracture Length	Microseismic	Optimally requires nearby offset well; difficult to interpret; expensive
Fracture Length	Tiltmeters	Difficult to interpret; expensive and difficult to conduct in the field
Fracture Azimuth	Core techniques	Expensive to cut core and run tests; multiple tests must be run to assure accuracy
Fracture Azimuth	Log techniques	Requires open hole logs to be run; does not work if natural fractures are not present
Fracture Azimuth	Microseismic	Analysis intensive; expensive for determination of azimuth
Fracture Azimuth	Tiltmeters	Useful only to a depth of 5,000 feet; requires access to large area; expensive
From: Appendix A, DOE, Hydraulic Fracturing		

3.5 Summary

Coalbed methane development began as a safety measure to extract methane, an explosion hazard, from coal prior to mining. Since 1980, coalbed methane production has grown rapidly, spurred by tax incentives to develop non-conventional energy production. At the end of 2000, coalbed methane production from 13 states totaled 1.353 trillion cubic feet, an increase of 156 percent from 1992. At year-end 2000, coalbed methane production accounted for about 7 percent of the total United States dry gas production and 9 percent of proven dry gas reserves (EIA, 2001).

Methane within coalbeds is not "trapped" under pressure as in conventional gas scenarios. Only about 5 to 9 percent of the methane is present as "free" gas within the natural fractures, joints, and cleats. Almost all coalbed methane is adsorbed within the micro-porous matrix of the coal (Koenig, 1989; Winston, 1990; Close, 1993).

Coalbed methane production starts with high-pressure injection of fracturing fluids and proppant into targeted coal zones. The resulting induced or enlarged fractures improve the connections of the production well to the fracture networks in and around the coal zone. When production begins, water is pumped from the fractures in the coal zone to reduce pressure in the formation. When pressures are adequately reduced, methane desorbs from the coal matrix, moves through the network of induced and natural fractures in the coal toward the production well, and is extracted through the well and to the surface.

Fractures that are created at shallow depths (less than approximately 1,000 feet) typically have more of a horizontal than a vertical component. Vertical fractures created at deeper depths can propagate vertically to shallower depths where they may develop a horizontal component. These "T-fractures" may involve the fracture "turning" and developing horizontally at a coalbed-mudstone interface.

Fracture behavior through coal, shale, and other geologic strata commonly present in coal zones depends on site-specific factors such as relative thicknesses and in-situ stress differences between the target coal seam(s) and the surrounding geologic strata, as well as the presence of pre-existing natural fractures. Often, a high stress contrast between adjacent geologic strata results in a barrier to fracture propagation. This occurs in coal zones where there is a geologic contact between a high-stress coal seam and an overlying, thick, relatively low-stress shale.

The fluids used for fracture development are injected at high pressure into the targeted coal zone in the subsurface. These fluids may be "clear" (primarily consisting of water, but may include acid, oil, or water with friction-reducer additives) or "gelled" (viscosity-modified water using guar or other gelling agents). Hydraulic fracturing in coalbed methane wells may require 50,000 to 350,000 gallons of fracturing fluids and 75,000 to 320,000 pounds of sand as proppant to prop or maintain the opening of fractures after the injection (fracturing) pressure is reduced (Holditch et al., 1988 and 1989; Jeu et al., 1988;

Hinkel et al., 1991; Holditch, 1993; Palmer et al., 1991b, 1993a, and 1993b). More typical injection volumes, based on average injection volume data provided by Halliburton for six coalbed methane locations, indicate a maximum average injection volume of 150,000 gal/well and a median average injection volume of 57,500 gal/well (Halliburton, Inc., 2003).

In any fracturing job, some fracturing fluids cannot be recovered and are said to be "lost" to the formation. Palmer (1991a) observed that for fracture stimulations in multi-layered coal formations, 61 percent of stimulation fluids were recovered during a 19-day production sampling of a coalbed methane well in the Black Warrior Basin. He further estimated that from 68 percent to possibly as much as 82 percent would eventually be recovered. A variety of site-specific factors, including leakoff into the coal seams and surrounding strata, the check-valve effect, adsorption and other geochemical processes, and flow through the hydraulic fracture beyond the well's capture zone will serve to reduce recovery of hydraulic fracturing fluids injected into subsurface coal zones to promote coalbed methane extraction.

The mined-through studies by the U.S. Bureau of Mines (see Diamond, 1987a and b) and others provide important directly-measured characteristics of hydraulic fracturing in coal seams and surrounding strata. Further, paint tracer studies conducted as part of Diamond's (1987a and b) mined-through studies can provide estimates on the extent of hydraulic fracturing fluid movement, which may be greater than the extent of sand-filled (propped) hydraulic fracture heights or lengths given fluid movement through natural fractures. These estimates of the extent of fluid movement are usually limited by the area exposed to mining.

A significant amount of diagnostic research has been conducted in the last decade enabling industry to develop a practical, applied understanding of general fracture behavior as it relates to methane production. Operators use a number of techniques to estimate fracture dimensions to design fracture stimulation treatments to minimize expenditures on hydraulic horsepower, fracturing fluids, and proppants. Modeling is increasingly more sophisticated, but still commonly depends on at least some inferred (and subjective) input data. Reliable fracture height and length can be measured accurately by microseismic monitoring and tiltmeters (Warpinksi, 2001).

Figure 3-1. Major United States Coal Basins

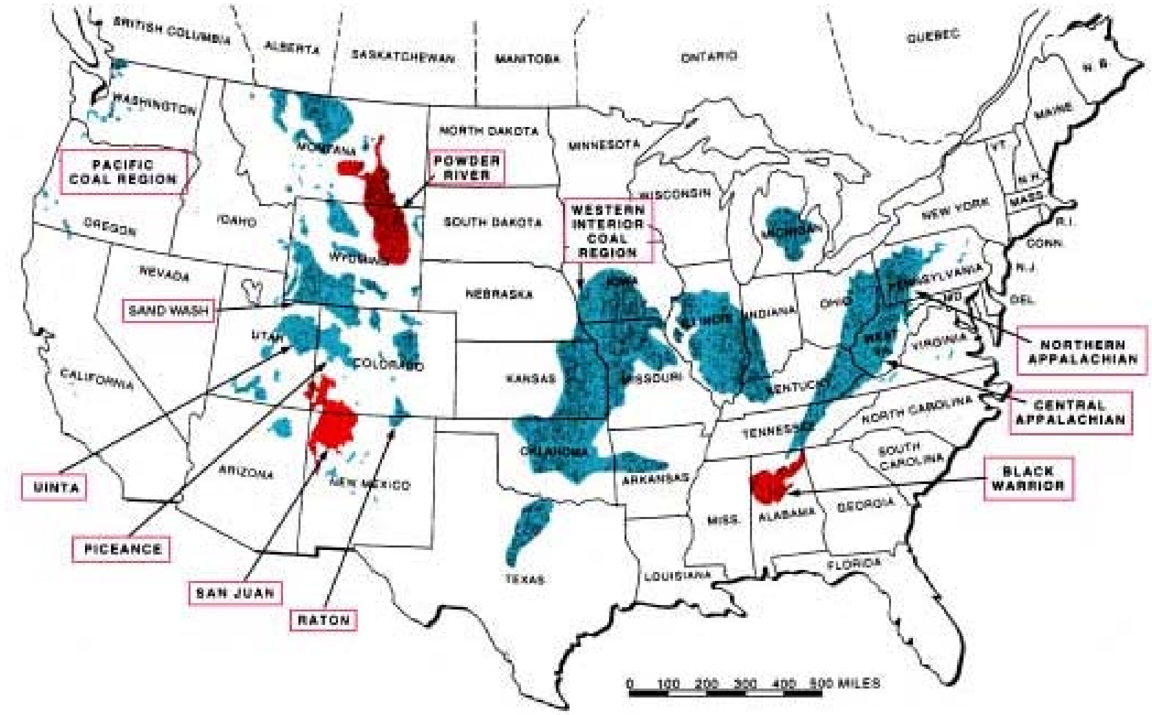
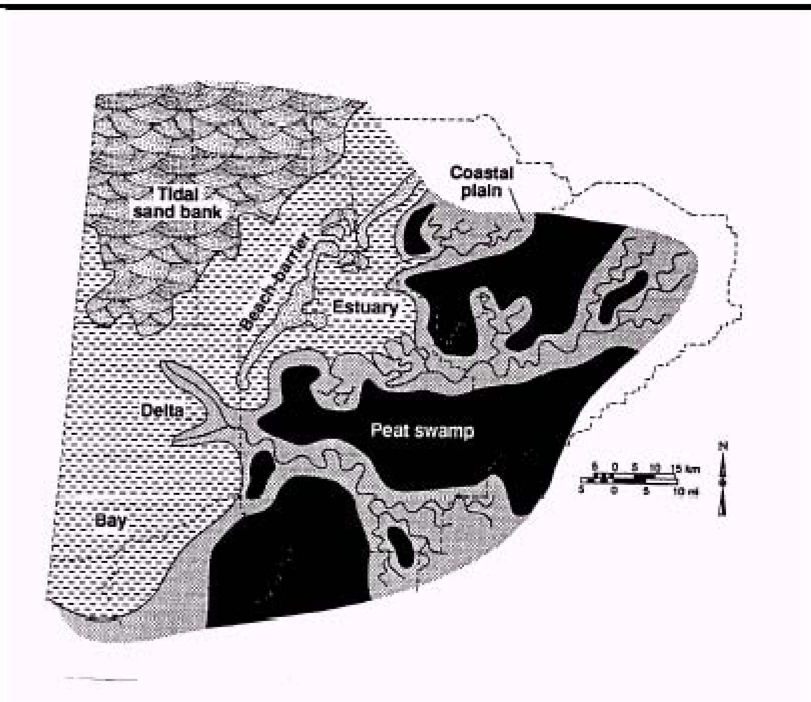


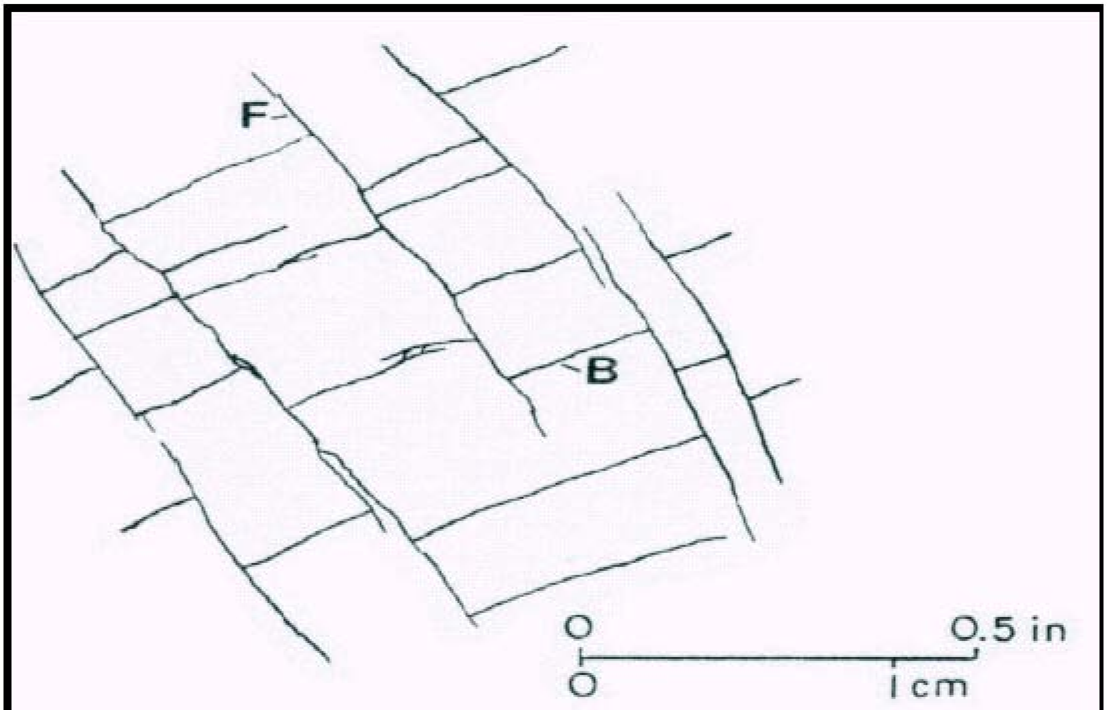
Figure 3-2. Geography of an Ancient Peat-Forming System



Geography of an Ancient Peat-Forming System (example from Black Warrior Basin, Alabama)
(Pashin and Hinkle, 1997)

Figure 3-2

Figure 3-3. Schematic Representation of "Face Cleat" (F) and "Butt Cleat" (B)



Schematic Representation of "Face Cleat" (F) and "Butt Cleat" (B) (Ayers et al., 1994)

Figure 3-3

Figure 3-4. A Graphical Representation of the Hydraulic Fracturing Process in Coalbed Methane Wells

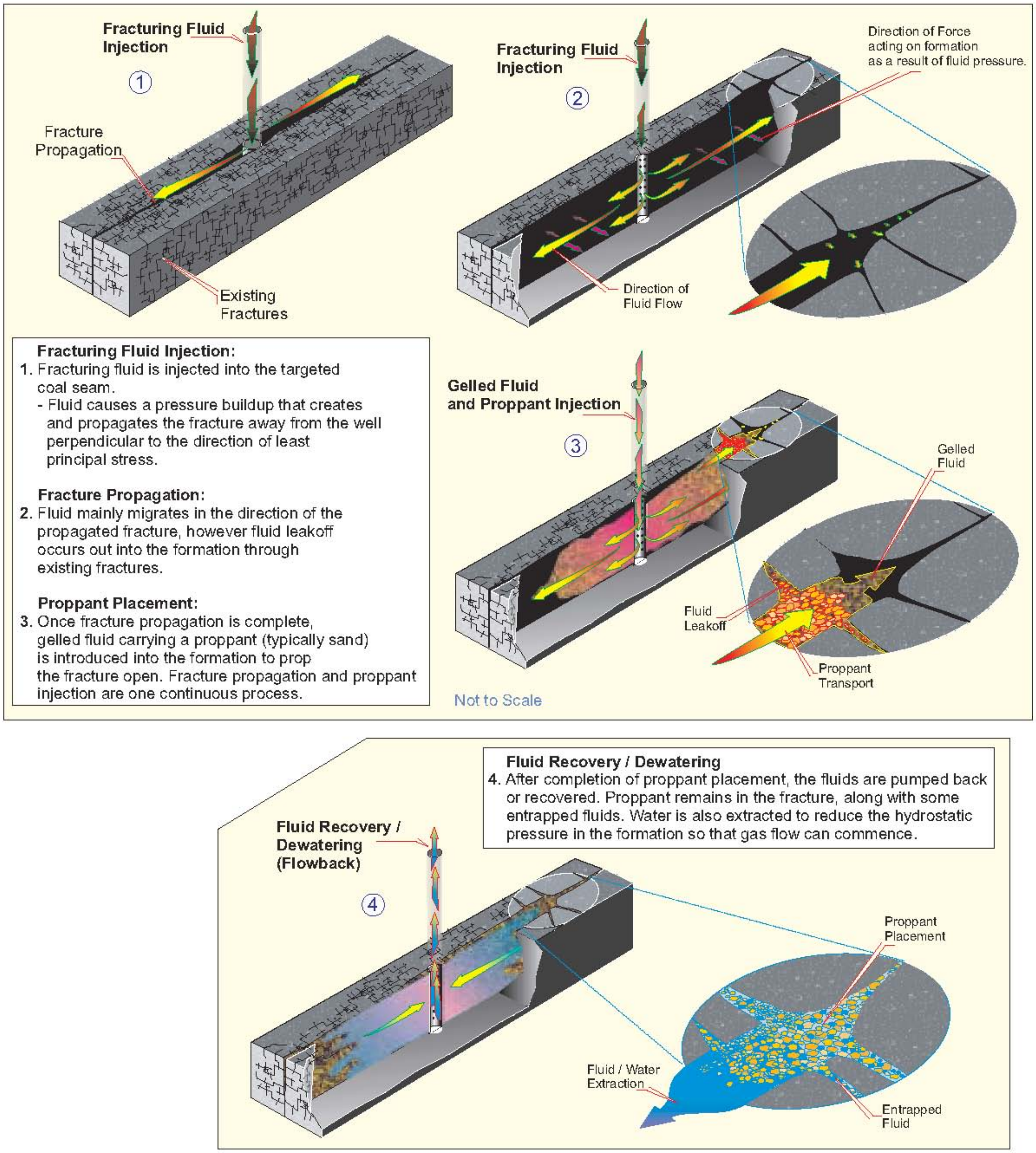
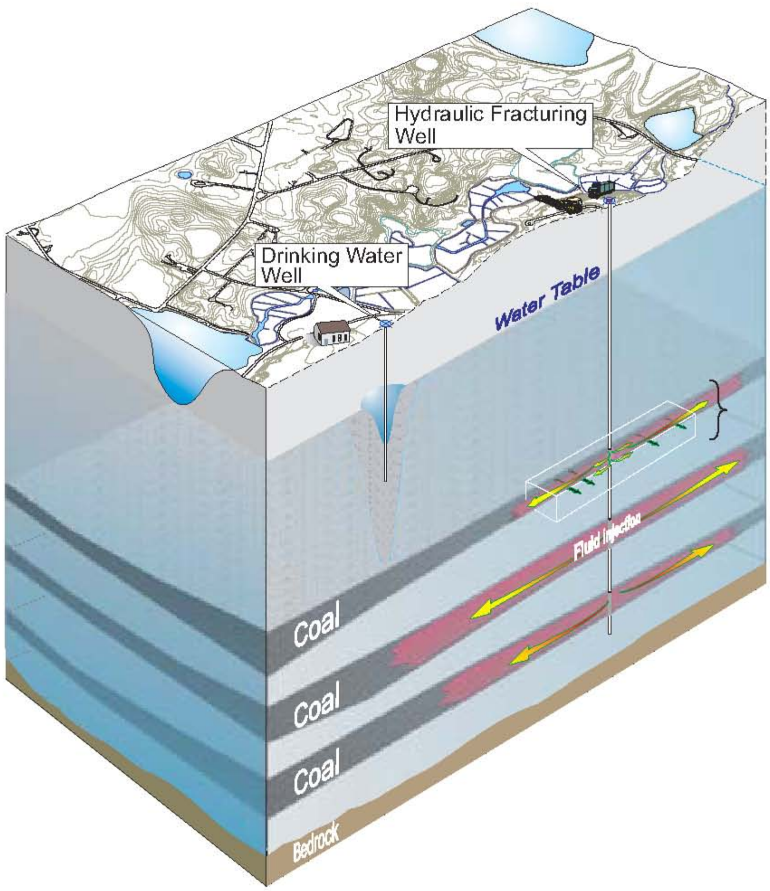


Figure 3-4. A Graphical Representation of the Hydraulic Fracturing Process in Coalbed Methane Wells (Continued)



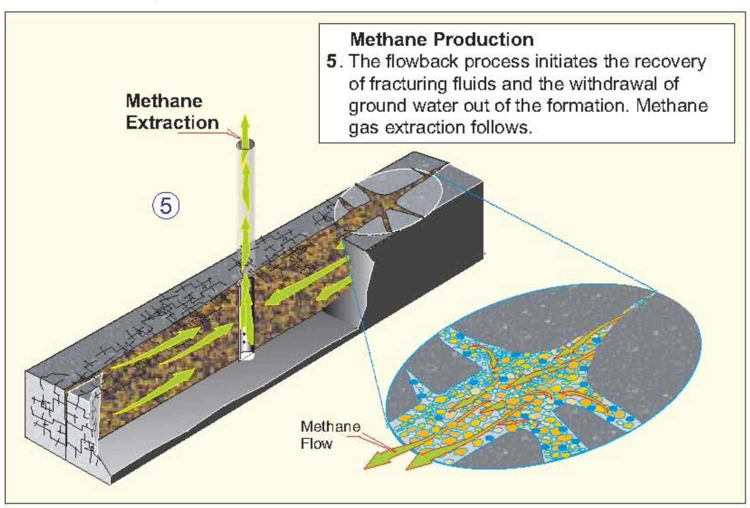
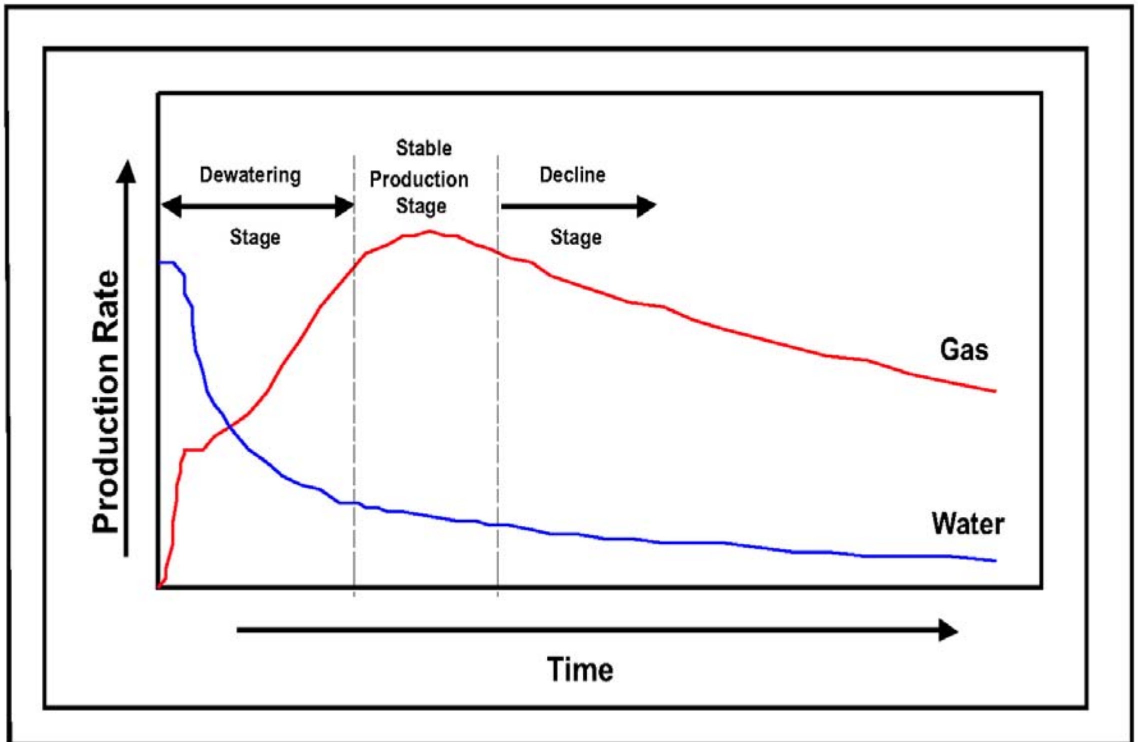


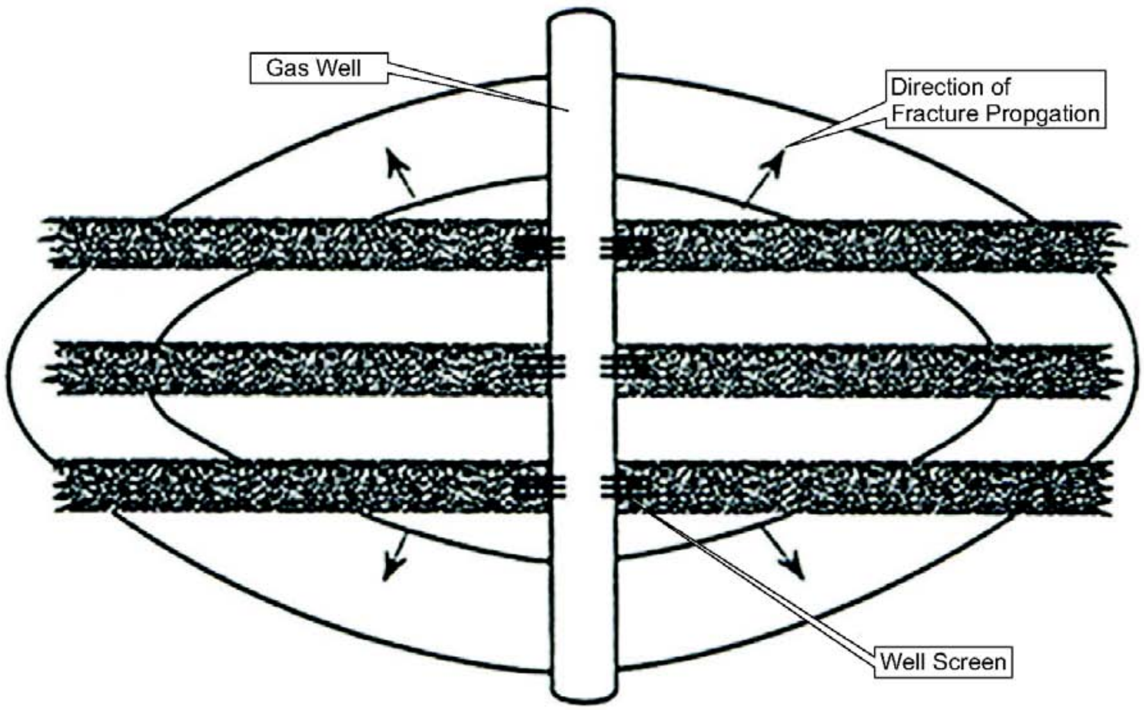
Figure 3-5. Water And Gas Production Over Time



Water and Gas Production Over Time (Saulsberry et al., 1996)

Figure 3-5

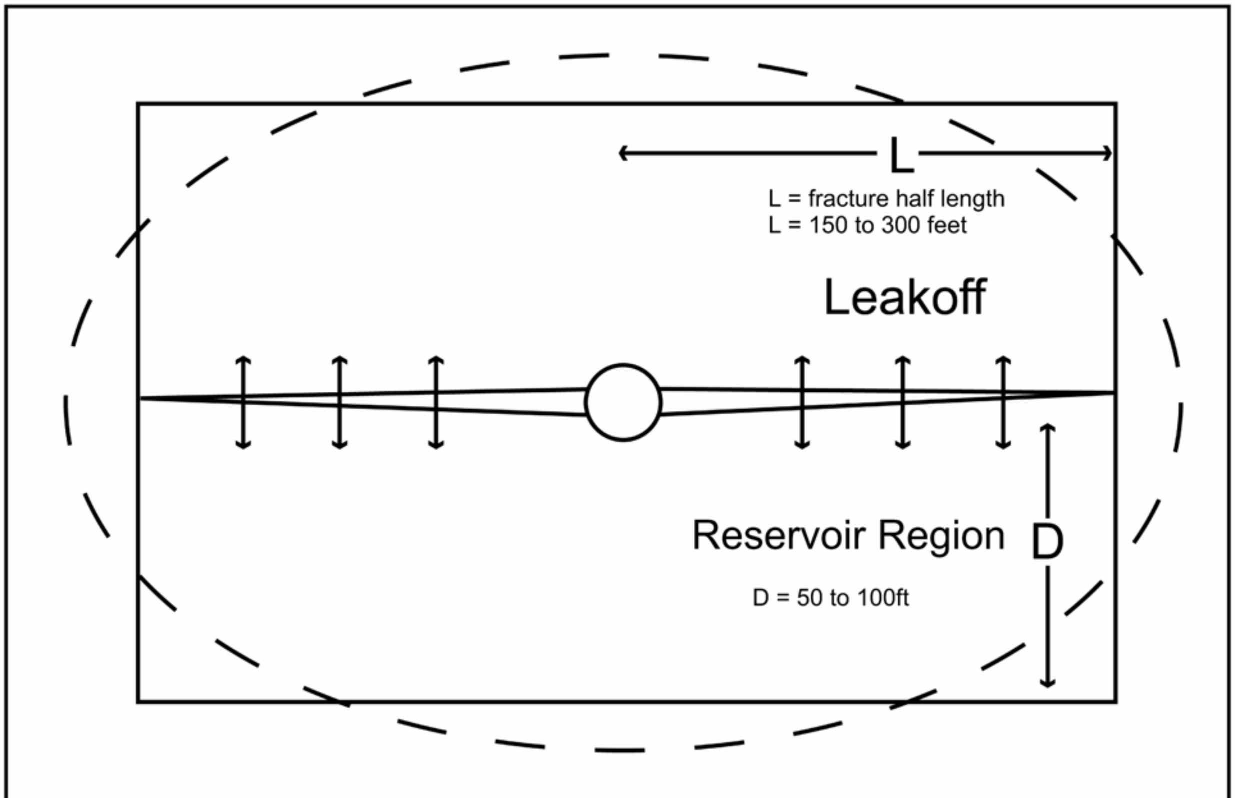
Figure 3-6. Side-View of a Vertical Hydraulic Fracture Typical of Coalbeds



Side-View of a Vertical Hydraulic Fracture Typical of Coalbeds
Most hydraulic fractures penetrate several coal seams.
(Palmer et al., 1991)

7/14/01 kk 1027-HF-3-08.cdr | Figure 3-6

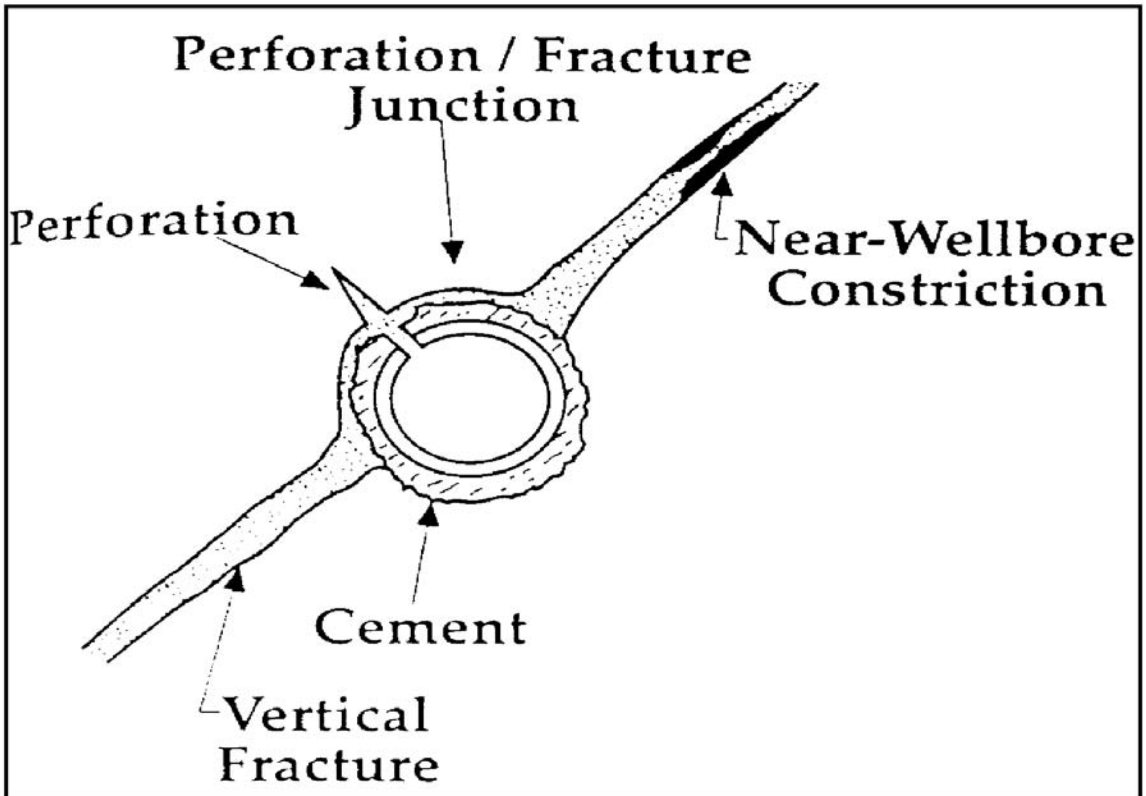
Figure 3-7. Plan View (Looking Down the Wellbore) of Vertical, Two-Winged Coalbed Methane Fracture Showing the Reservoir Region Invaded by Fracturing Fluid Leakoff



Plan View of a Vertical, Two-Winged Coalbed Methane Fracture Showing the Reservoir Region Invaded by Fracturing Fluid Leakoff (Palmer et al., 1991).

7/14/01 kk 1027-3-7.cdr | Figure 3-7

Figure 3-8. Plan View of a Vertical Hydraulic Fracture



Plan View (Looking Down the Wellbore) of a Vertical Hydraulic Fracture (Palmer et al., 1991)

1027-hf/1027-3-8.eps Figure 3-8