AN ADVISORY SYSTEM FOR THE DEVELOPMENT OF UNCONVENTIONAL GAS RESERVOIRS

A Dissertation

by

YUNAN WEI

Submitted to the Office of Graduate Studies of
Texas A&M University
in partial fulfillment of the requirements for the degree of

DOCTOR OF PHILOSOPHY

May 2009

Major Subject: Petroleum Engineering

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Approved by:

Chair of Committee,	Stephen A. Holditch
Committee Members,	Duane A. McVay
	Walter B. Ayers
	Thomas R. Ioerger
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ABSTRACT

An Advisory System for the Development of Unconventional Gas Reservoirs.

(May 2009)

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Chair of Advisory Committee: Dr. Stephen A. Holditch

With the rapidly increasing demand for energy and the increasing prices for oil and gas, the role of unconventional gas reservoirs (UGRs) as energy sources is becoming more important throughout the world. Because of high risks and uncertainties associated with UGRs, their profitable development requires experts to be involved in the most critical development stages, such as drilling, completion, stimulation, and production. However, many companies operating UGRs lack this expertise. The advisory system we developed will help them make efficient decisions by providing insight from analogous basins that can be applied to the wells drilled in target basins.

In North America, UGRs have been in development for more than 50 years. The petroleum literature has thousands of papers describing best practices in management of these resources. If we can define the characteristics of the target basin anywhere in the world and find an analogous basin in North America, we should be able to study the best practices in the analogous basin or formation and provide the best practices to the operators.

In this research, we have built an advisory system that we call the Unconventional Gas Reservoir (UGR) Advisor. UGR Advisor incorporates three major modules: BASIN, PRISE and Drilling & Completion (D&C) Advisor. BASIN is used to

identify the reference basin and formations in North America that are the best analogs to the target basin or formation. With these data, PRISE is used to estimate the technically recoverable gas volume in the target basin. Finally, by analogy with data from the reference formation, we use D&C Advisor to find the best practice for drilling and producing the target reservoir.

To create this module, we reviewed the literature and interviewed experts to gather the information required to determine best completion and stimulation practices as a function of reservoir properties. We used these best practices to build decision trees that allow the user to take an elementary data set and end up with a decision that honors the best practices. From the decision trees, we developed simple computer algorithms that streamline the process.

DEDICATION

To my Family

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Thanks also go to my friends and colleagues in the development of UGR software and the department faculty and staff for making my time at Texas A&M University a great experience. I would especially like to thank my colleagues including Kirill Bogatchev, Raj Malpani, Kalwant Singh, Sara Old, and Obinna Ogueri. Without their efforts on this project, the software would have been impossible to complete.

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1 INTRODUCTION

1.1 Unconventional Gas Reservoirs and the Resource Triangle

Substantial volumes of natural gas are accumulated in low-permeability geologic environments that differ from conventional, high-permeability petroleum traps. This gas is called *unconventional gas,* and these reservoirs are called *unconventional gas reservoirs* (UGRs). Tight gas sandstones (TG), gas shales (GS), and coalbed methane (CBM) seams are typical UGRs. In the 1970s, the United States (US) government defined a tight gas reservoir as a reservoir with an expected value of permeability to gas flow of 0.1 md or less. However, this definition is a political definition that has been used by both state and federal government agencies to establish incentives for operators who choose to produce gas from unconventional reservoirs. In his distinguished author series article for SPE, Holditch (2006) defined a tight gas reservoir as "a reservoir that cannot produce at economical rates nor recover economic volumes of natural gas unless the well is stimulated by a larger hydraulic fracture treatment or produced by use of a horizontal wellbore or multilateral wellbores."

All natural resources, including oil and gas reservoirs, are distributed lognormally in nature (Holditch 2006). A "resource triangle" can be used to conceptually describe the distribution of natural resources, such as gold, silver, copper, iron, oil, gas, and virtually all other minerals. As shown in Fig. 1.1, the high- to medium-quality petroleum reservoirs that can be found with conventional seismic geology can be produced

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This dissertation follows the style of *SPE Journal.*

economically with very low stimulation requirements. In fact, most of the reservoirs that we have discovered and produced during the 20th century can be classified as “high” quality or “medium” quality, near the peak of the resource triangle. Deeper into the resource triangle, the reservoir deposits are lower grade, which means the reservoir permeability is decreasing. These low-permeability reservoirs, however, contain much more hydrocarbons than the higher-quality reservoirs. As shown in Fig. 1.1, natural gas reservoirs including TG, GS, and CBM appear in the lower portions of the triangle. To develop these low-quality reservoirs, operators need better technology that can properly locate, drill, complete, stimulate, and produce at economical flow rates and volumes. The most important information shown in the resource triangle is that the lower-quality rocks contain enormous volumes of hydrocarbon in place, but better technology and high product price are required to produce most of this gas economically, as compared with the smaller, higher quality reservoirs.

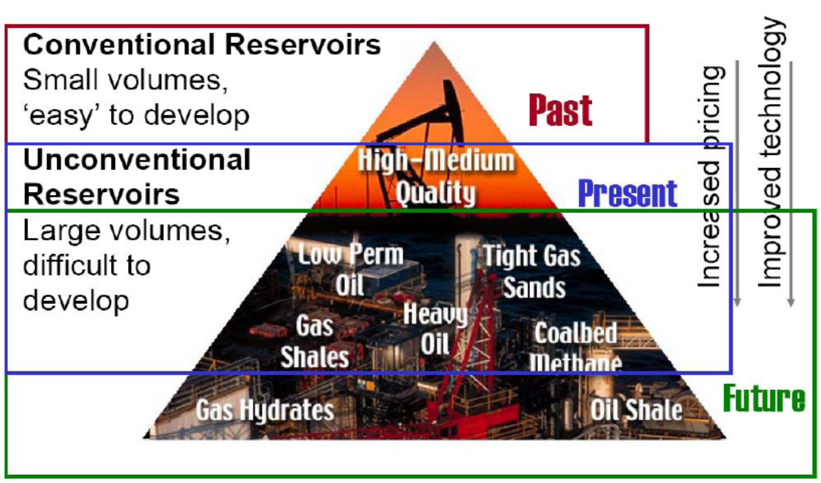


Fig. 1.1—The resource triangle (Holditch 2006) locates unconventional resources among the most difficult to produce.

1.2 Why Are Unconventional Gas Reservoirs Important?

As the economies of most nations in the world continue to expand and the demand for energy continues to increase, conventional oil and gas resources are being developed to meet the demands for energy. However, most experts realize that the quantity of oil and gas from conventional reservoirs is finite, and we will need to develop more unconventional oil and gas reservoirs to keep up with demand. In fact, the US, Canada, Mexico, and Venezuela have already produced substantial volumes of unconventional oil and gas.

UGRs have played an important role as an energy source in the US for several decades. McKinney reported in 2003 that around 25% of the natural gas used presently in the US comes from unconventional reservoirs. Tight gas sands in the US account for over 69% of the gas production from all unconventional gas resources and for 19% of US production (McKinney 2003). These percentages have all increased in the past 5 years.

According to the estimation by IHS resources (Chew 2005), the world annual natural gas consumption, some 75 Tcf, is increasing faster than that of any other fossil fuel. From the same IHS study, the worldwide conventional gas reserves are about 6,920 Tcf (see Fig. 1.2). Most of the conventional gas reserves are carried by pipelines and burned as fuel in heating or electricity generation. Some of the gas is used as feedstock for the petrochemical industry. In future years, much of the gas will be moved to liquid natural gas (LNG) or turned into gas to liquid (GTL) to use as motor fuel for transportation.

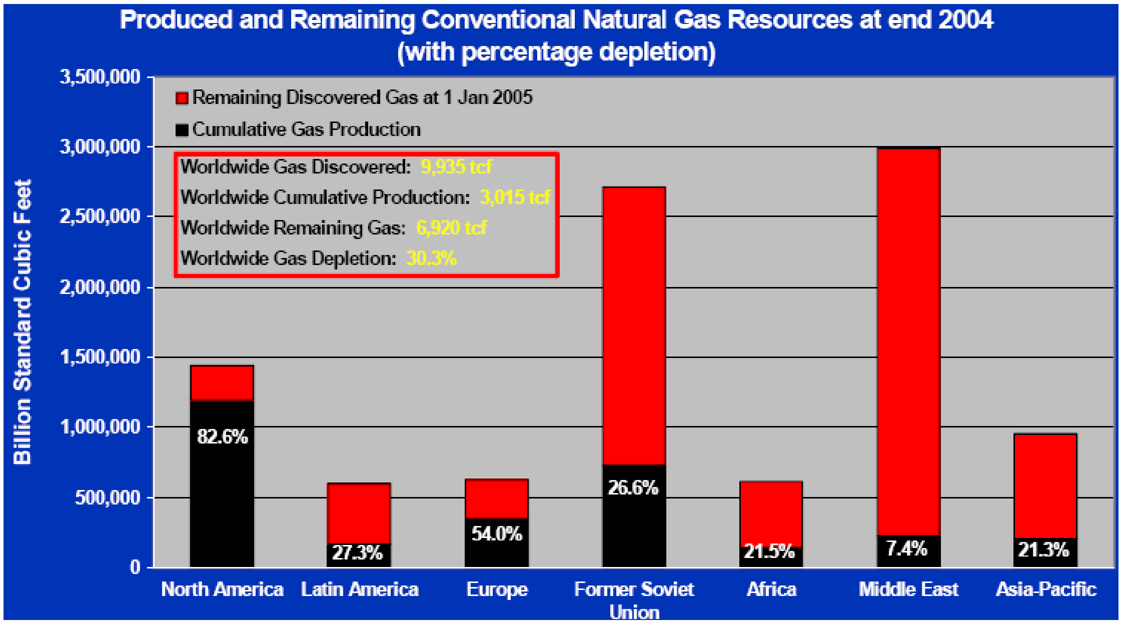


Fig. 1.2—Although most gas reserves in the US and Europe have been depleted, large reserves remain on all other continents (Chew 2005).

Terasaki and Fujita (2005) estimated the UGRs for the main regions of the world. (Table 1.1).

Table 1.1—Recoverable Resources of Unconventional Natural Gas

Region	**TG,** Tcf	**CBM,** Tcf	**SG,** Tcf
USA	350.7	68.9	45.2
Asia & Oceana	703.6	238.1	340.9
Middle East	321.1	0.0	52.9
East Siberia & Far East	31.1	45.9	1.1

Terasaki and Fujita's estimated total recoverable UGRs for the USA at about 465 Tcf, of which TG is the most promising resource. Kawata and Fujita (2001) summarized and updated Rogner's (1997) UGR estimates (Table 1.2). The estimated total volume of UGRs is quite large, amounting to 32,598 Tcf. The United States Geological Survey

(USGS) has estimated worldwide technically recoverable gas from UGRs to be 19,829 Tcf (Rogner, 1997).

Table 1.2—World Unconventional Gas Resources

	Terasaki and Fujita's (2001) Estimate, Tcf				USGS Estimate, TCF
	CBM	SG	TG	Total	Resources (1993)
North America	3,017	3,840	1,371	8,228	2,194
Latin America	39	2,116	1,293	3,448	1,465
Western Europe	157	509	353	1,019	952
Central and Eastern Europe	118	39	78	235	129
Former Soviet Union	3,957	627	901	5,485	7,601
Middle East and North Africa	0	2,547	823	3,370	4,745
Sub-Saharan Africa	39	274	784	1,097	901
Centrally Planned Asia & China	1,215	3,526	353	5,094	678
Pacific OECD	470	2,312	705	3,487	153
Other Pacific Asia	0	313	549	862	705
South Asia	39	0	196	235	306
World	**9,090**	**16,103**	**7,405**	**32,598**	**19,829**

The difference between Table 1.1 and Table 1.2 is that the values in Table 1.1 represent volumes of gas that should be recoverable and are known to exist. The data in Table 1.2 are volume of gas resources which cannot be counted as recoverable at this time.

The estimated volume of gas in Table 1.2 shows that the potential for production from UGRs is very large, easily larger than from conventional resources. From these estimates and using the US as an analogy, we believe that unconventional gas production will increase significantly around the world in the coming decades for the following reasons.

1. Following the premise of the resource triangle, UGRs should be present in every oil and gas basin around the world.
2. With the large volume of gas in place, improvements in technology will turn these resources into technically recoverable gas in virtually every oil and gas basin worldwide where demand exists. The global need for energy, particularly natural gas, will continue to be an incentive for worldwide unconventional gas resource development.
3. The gas produced from UGRs including TG, CBM, and SG have already been critical to North America and will be an important energy source worldwide in the future.
4. The improved technologies that have been developed in North America over the past 30 years and the new technologies in the petroleum industry that will further increase global development of UGRs are rapidly becoming available worldwide through the efforts of major service companies.

1.3 Problems with Drilling, Completion, and Stimulation of UGRs

A major difference between UGRs and conventional reservoirs is the fact that the low-quality reservoirs in UGRs result in small flow rates for vertical, unstimulated wells. In these wells, the gas cannot flow at high rates or in sufficient volume to be economical. In addition, the area that a well drains in a UGR is much smaller than the drainage area for a conventional reservoir.

Compared with conventional gas reservoirs, UGRs are more complicated and difficult to drill, complete, stimulate, and produce; performing these tasks is a challenge to the petroleum industry worldwide. Besides recognizing and solving technical problems, petroleum engineers have to deal with the fact that low-permeability reservoir rocks may be vulnerable to secondary skin effects. Mechanical damage caused by drilling, stimulating, and producing UGRs can be an ongoing problem.

1.3.1 Tight Gas Sands

The literature provides several definitions of tight gas sands (TGs). Misra (2003) explained that "reservoirs having low permeability (< 0.1 md) and which cannot be produced at economic flow rates or do not produce economic volumes without the assistance from massive stimulation treatments or special recovery processes and technologies, such as fracturing, steam injection etc, are categorized as tight reservoirs." Acknowledging that TG is "often viewed as a 'new resource,'" (Kuuskraa 2003) described it as "merely an arbitrary delineation of a natural geologic continuity in the permeability of reservoir rock."

The dominant characteristic of a TG is its low in-situ flow capacity (low permeability). Formations are called *tight* when their in-situ permeability is less than 0.1 md. In addition, such reservoirs often contain discontinuous (lenticular) pay zones and other heterogeneous geologic properties. Most of the reservoirs are sandstone, but significant volumes of natural gas are also produced from low-permeability carbonates. In common, all definitions emphasize that the permeability of the reservoir is low (less than 0.1 md).

TG formations are heterogeneous in nature and usually consist of sandstone, siltstone, and shale dispersed vertically and horizontally throughout the formation. These diverse layers can present a high contrast in values of permeability, porosity, and gas saturation, depending on various geological aspects such as depositional environment, depth/time of burial, deposition sequence, and post-depositional activities (such as tectonics and digenesis). A significant challenge in TG formations is the completion of multilayered pay zones (Ogueri 2007). Thick, highly layered formations are being completed by operators on a daily basis in some areas. Many challenges are involved when completing these reservoirs.

The distribution, orientation, and density of natural fractures in the formation are important to proper field development planning and well scheduling to ensure the economic recovery of gas from TG reservoirs (Arevalo-Villagran et al. 2001); the natural fractures and other characteristics are sufficiently complex that some cases require highly sophisticated tools to direct drilling accurately. Advanced methods of gas production in these environments take advantage of gas flow from natural fractures in the reservoir rock. Reservoir engineers need detailed analyses of the effects of interstitial clays and fluids.

When gas is being produced from TG reservoirs, some form of stimulation is required to boost the production rate. This process is usually hydraulic fracturing. To achieve an economically adequate production rate, wells completed in tight reservoir rocks have to be stimulated by one or several hydraulic fractures. TG reservoirs often show a much weaker response to the fracture treatments than more permeable rocks, resulting in low production rates and a high economic risk. “An understanding of the petrophysical properties such as the lithofacies associations, facies distribution, in situ porosities, saturations, effective gas permeabilities at reservoir conditions, and the architecture of the distribution of these properties is required in order to comprehend the gas production from low permeability rocks" (Arevalo-Villagran et al. 2001).

1.3.2 Coalbed Methane

"Coalbed methane [CBM] is a by-product of the transformation of decayed plant material into coal. Coal beds are self-sourcing reservoirs that can contain thermogenics, migrated thermogenics, biogenic, or mixed gas….Coalbed gas is stored primarily within micropores of the coal matrix in an adsorbed state and secondarily in micropores and fractures as free gas or solution gas in water" (Ayers 2002). Coal is a dual-porosity reservoir rock that has a microporous matrix and a network of natural fractures known as cleats.

Moore (2007) described the characteristics of CBMs as: (1) compared to most rocks, coal is a weak, friable material with low compressive strength; (2) Mid rank, bituminous coals are brittle and usually highly fractured, giving them pre-existing weaknesses along the cleats. High rank, semianthracite and anthracite coals are stronger, but still not like most other rocks; (3) Coal's weakness makes it sensitive to stress in several ways. Lateral stresses induced normal to the cleats fractures will close their apertures, dramatically reducing permeability; (4) Hoop and release stresses make the borehole through the coal formation prone to sloughing. Sometimes this sloughing has a time-dependent manifestation. It may produce large volumes of fines during drilling, completing, or operating, particularly while the well is dewatering.

A CBM gas system is a self-sourcing reservoir (Palmer 2007). Gas generated by the thermal maturation of the coal is stored on the coal matrix as adsorbed gas. The hydraulic pressure in the coal cleats (fractures) assists in keeping the gas adsorbed. Thus, the coal matrix acts as the primary reservoir rock, with secondary gas storage in cleats as free gas or as solution gas in water (Scott et al. 1994). A major difference between CBM and sandstone gas reservoirs is that many of the coal seams are initially saturated with water. Thus, a larger volume of water has to be pumped out of the coal seams to reduce the pressure so that desorption will occur before any significant gas production.

CBM wells are drilled, completed, and stimulated similarly to conventional reservoirs. However, engineering practices differ somewhat because of the differences in the reservoir properties between conventional and CBM reservoirs and because of differences in CBM properties from one case to another. Therefore, identifying and understanding the geological and reservoir parameters of coal are necessary for optimal operations design.

Among the CBM reservoir properties that play important roles in determining engineering best practices are the depth of coal occurrence, thickness of individual coal seams and net coal thickness, number of coal seams and their vertical distribution, lateral extent of the coal, thermal maturity, structural dip, and adjacent formations (e.g., aquifer sandstones, fracture barriers, etc.) (Palmer 2007).

The primary concerns in selecting the appropriate coalbed drilling method are formation damage, lost circulation because of high permeability, overpressure, gas/water flow, and wellbore stability (Ramaswamy 2007). Most CBM wells are vertical. The commonly used methods for drilling vertical CBM wells are rotary percussion drilling and conventional rotary drilling. The formation hardness determines the type of drilling method to be used. For softer formations the rotary method can be used, whereas for harder formations, rotary percussion drilling can achieve a faster rate of penetration. The most commonly used drilling fluids in coal are air/mist, aerated mud, and formation water. The selection of fluid is dependent on the coal seam reservoir properties. To prevent formation damage while drilling, the coal is drilled underbalanced. “Horizontal drilling is used to increase the footage of the production zone contacted by the borehole. Horizontal drilling increases the production rate and ultimate reserves recovered” (Ramaswamy 2007).

The number of effective coal seams and their vertical distribution affect the type of completion to be used, single zone or multizone. The areal extent of the coal also plays an important role in selecting well locations and in deciding whether to drill a vertical or horizontal well. If the dip of the coal is greater than 15º, then keeping a horizontal wellbore inside the coal seam is very difficult, and drilling a horizontal well may be uneconomical (Palmer 2007).

After completion, CBM reservoirs typically undergo dewatering to reduce reservoir pressure and allow gas to desorb. Therefore, the wellbore configuration and completion techniques must be designed to accommodate water and gas production needs (Palmer 2007).

Hydraulic fracturing is commonly used in the CBM industry. The stimulation design depends on the reservoir properties. The four major reasons that stimulation treatments are used in cased-hole wells are to bypass near-wellbore formation damage, to stimulate production and accelerate dewatering by creating a high-conductivity path in the reservoir, to distribute the pressure drawdown and thus reduce coal fines production, and to effectively connect the wellbore to the natural fracture system of the coal reservoir.

Various fracturing techniques, fluid types, and procedures have been developed for coals (Holditch et al. 1990).

1.3.3 Shale Gas

"Shale gas is an unconventional source of natural gas that is produced from reservoirs predominantly composed of shale with lesser amounts of other fine grained rocks rather than from more conventional sandstone or limestone reservoirs" (Centre for Energy 2008). Shale consists mainly of consolidated clay-sized particles, and it is the Earth's most common sedimentary rock. Shale generally has ultralow permeability. In many oil fields, shale forms the geological seal that retains the oil and gas within the reservoir, preventing hydrocarbons from escaping to the surface. However, "in some basins, layers of shale—sometimes hundreds of feet thick and covering millions of acres—are…the source of the natural gas to the reservoir storing the gas" (Frantz and Jochen 2007). These shales have one common characteristic: they are rich in organic carbon. Shale source rock retains part of the generated hydrocarbons, thus acting as both source and potential reservoir rock. Natural fractures are usually essential for a shale gas system to store hydrocarbons and to serve as permeable pathways for migration to the wellbore (Frantz and Jochen 2007).

Because SG formations have very low matrix permeability, fractures (natural or artificial) are essential to provide permeable pathways in SG systems for migration of natural gas into the wellbore (Faraj et al. 2004). Because of the low permeability of SG reservoirs, recovery rates are only about 20% of original gas in place compared to 70 to 80% for conventional reservoirs. Generally, SG reservoir characteristics include low production rates (20 Mcf/D to 500 Mcf/D), long production lives, low decline rates (usually less than 5% per year), thick reservoirs (up to 1,500 ft), typically rich organic content, and huge gas reserves (5 Bcf to 50 Bcf per section); and they rely on natural fracture systems for porosity and permeability (very low matrix porosity/permeability) and stimulation to be economical (Centre for Energy 2008).

Shale is a fine-grained sedimentary rock characterized by layers that break with an irregular curving fracture parallel to the bedding planes (Frantz and Jochen 2008). "Shale is typically deposited in slow-moving water and is often found in lake and lagoon deposits, river deltas, offshore beach sands and on floodplains" (Frantz and Jochen 2008).

Shale has such low permeability that it releases gas very slowly, which is why SG is the last major source of natural gas to be developed. However, shale reservoirs can hold enormous amounts of natural gas. The most prolific shales are relatively flat, thick, and predictable. The formations of SG are so large that their wells will continue producing gas at a steady rate for decades. The potentially achievable recovery rate is about 20%. In practice, this recovery rate is not achieved for most SG wells.

Production of gas from shale and gas produced from other unconventional sources such as TG are fundamentally different. A TG may yield a large gas flow rate for the first few months, but then production declines significantly and often levels off near the economic limit after a few years. However, SG is completely different; SG wells may not come on as strong as tight gas, but once the production stabilizes, they will produce consistently for 30 years or even more.

The ultimate goal of the completion operation in SG reservoirs is to expose and interconnect the maximum surface area of shale to the wellbore in the area of the reservoir (Deshpande 2007). Therefore, economical completion must connect a large quantity of rock surface area by creating factures to generate sufficient production volumes. The limits on bottomhole pressure, rate, and fluid volume require knowledge of the boundary rock layers to design optimal completion plans. In case of water-bearing zones, a horizontal wellbore may be used to contain the height and increase fracture complexity, thereby exposing a maximum surface area to the gas shale. “Variations in the horizontal well technology abound as engineers experiment with the perforation cluster design, lateral length, and number of stages, pump rate, fluid type and volume, and proppant selection, seeking to find the optimal combination for a particular type of geology within the region” (Deshpande 2007).

Shale gas development experience in the US shows that stimulation techniques, especially hydraulic fracturing, are almost always necessary for shale gas production (Holditch et al. 2007). The rock around the wellbore must be hydraulically fractured before the well can produce economically. The design of fracture treatment in a shale gas reservoir depends on many issues; one of the main ones is economics because SG reservoirs are long-term investments: the payout period may be long while drilling, but most shale gas wells can be produced for many years. Optimal stimulation treatments are low cost but effective. “In the fracturing process, the pumped fluid, under pressure up to 8,000 psi, is enough to crack shale as much as 3,000 ft in each direction from the wellbore” (Frantz and Jochen 2005).

The low permeability of shale may drive stimulation design toward large-volume, light-sand fracturing (water fracture treatment), the most economical and practical way to stimulate SGs. Fluid volumes in excess of 100,000 bbl have been pumped on a single zone (Developing 2007). Only 10 to 20% of gas in place is recovered with the initial completion (Kennedy 2006). In 1998, light sand fracturing was introduced; it has been used in many areas of the Barnett Shale and appears to improve productivity. Refracturing the reservoir may also increase the recovery rate by an additional 8% to 10%. Simple reperforation of the original interval and pumping a job volume at least 25% larger than the previous fracture has produced positive results in vertical shale gas wells (Kennedy 2006).

1.4 Challenges with Drilling, Completion and Stimulation of UGRs

In general, operators encounter six challenges in unconventional gas reservoir operations (Bennion 1998):

1. poor reservoir permeability
2. adverse initial saturation conditions
3. damage induced during drilling and completion
4. damage induced during hydraulic or acid fracturing
5. damage induced during workover
6. damage induced during production operations

These challenges deserve further discussion:

1. Poor reservoir permeability. By definition, the reservoir permeability in a UGR is very low. No documented case histories of economic production from formations indicate an interconnective matrix permeability better than 10^{-6} Darcy, even in the presence of successful large-scale fracturing treatments (Bennion et al. 1998). These low-permeability reservoirs require special technology, treatments, considerations, and design to obtain economical production.

2. Adverse initial saturation conditions. In some cases, the permeability of the reservoir may be acceptable but economical production cannot be achieved because of the adverse capillary forces, high in-situ saturations of trapped water, and in some cases, the presence of liquid hydrocarbons. The presence of high immobile fluid saturation may lead to a relative permeability effect that is adverse to natural gas flow, and the immobile trapped fluid occupies a majority of the pore space and thus limits the gas in place and technically recoverable gas available for production.

3. Damage induced during drilling and completion. The formation rock can only tolerate minimum damage because of the low permeability. Low-permeability formations also have a high degree of sensitivity to capillary retentive effect and to rock/fluid and fluid/fluid compatibility.

Any extremely damaged zone will be adjacent to the wellbore because of the low permeability of the matrix, high fluid viscosity, and high hydrostatic pressure in the wellbore during drilling. Shallow invasive damage will not be significant if hydraulic fracturing is subsequently used to fracture through the damage. Any damage induced during the fracture treatment may become important, but drilling-induced damage becomes more important in openhole, horizontal wells.

One of the most important issues for UGRs is the fluid retention effects encountered during drilling, completion, fracturing, and workover operations. This phenomenon is commonly referred to as hydrocarbon phase trapping. The capillary pressure, which is defined as the difference in pressure between the wetting (generally water in most gas reservoirs) and nonwetting (generally gas in most gas reservoirs) phases in the porous media, is the dominant factor in fluid retention effects.

Mud invasion of natural or artificial solids may occur during drilling, completion, and workovers during operations in hydrostatically overbalanced, openhole conditions. The invasion is not normally observed because of the very small pore throats of the low-permeability formation.

Horizontal drilling has been used in geographic areas with limited surface access and landowner restrictions. Horizontal wells provide greater wellbore contact than vertical wells within the reservoir rocks. For SG reservoirs, horizontal drilling is the primary enabling technology behind the recent surge in production in the ultralow-permeability environment.

4. Damage induced during hydraulic or acid fracture treatments. By their nature, low-permeability UGRs require hydraulic fractures to make production economical. Significant laboratory and field evidence indicates that the formation can be damaged during the fracture treatment. The damage can result from capillary retentive effects or from rock/fluid and fluid/fluid incompatibility issues. The capillary retentive effects cause permanent retention of both water and hydrocarbon fluids.

5. Damage induced during workover operations. The mechanisms of damage to perforated openhole or fractured wells during hydrostatic workover treatment are similar to those described for drilling and completion.

6. Damage induced during production operations. Potential damage during normal production in tight gas formations can include physical fines migration, retrograde concentration dropout phenomena in rich gas systems, paraffin deposition, or elemental sulfur precipitation. Also, water production from UGRs can cause scale and mineral

precipitation that damages the formation near the wellbore, in the perforations, and even in the wellbore.

1.5 Research Objectives

Because of the complex nature of these reservoirs and their high risks and uncertainties, profitable development of a UGR requires experts to be involved in the most critical development stages, such as drilling, completion, stimulation, and production. However, for most of the UGRs outside North America, operators have little or no experience in development. An advisory system based on the experience of experts will be valuable both for operators outside of North America and for many of the young engineers inside the US who have limited experience in the development of UGRs.

In the oil and gas industry in the US, the average age of the exploration and production workforce in 2002 was approximately 48 (Gibson 2002). In 2008, the average age should be closer to 51 or 52. This average age means that as much as 50% of the working engineers will reach retirement age within 10 years. As experts retire, the practicing knowledge base in the industry will be reduced if the knowledge is not captured in a way that will be accessible to others. To avoid the loss of expertise, useful knowledge should be quantified, recorded, and included in permanent records. An advisory system is one approach to solving this problem.

Currently, many engineers with minimal experience conduct engineering studies and field operations with minimal supervision. Without proper supervision by an expert, some of the work by inexperienced engineers may be less than optimal. Normally, it is not feasible to have all decisions and calculations of every engineer checked by a human expert. Thus, an advisory system can be used to improve the decision process of inexperienced engineers.

In this project, we are building UGR Advisor, which will incorporate three major modules that we call BASIN, PRISE, and D&C Advisor. The objectives of this project phase, which included initial development of the completions module and the structure for the remainder of the module, were as follows.

(1) Determine a methodology to capture the best practices for a given target for:

- completing
- stimulating
- producing

from gas wells producing that target:

- tight gas sands
- coal seams
- gas shales

as a function of the specific basin and formation geologic parameters. This part will be the main body of the D&C Advisor in the UGR Advisor system. A related project will do the same work for drilling these reservoirs.

(2) Work with others to determine the best practices for UGRs that should be included in the D&C Advisor.

(3) Develop software to allow the user to input a single data set that can be used to run BASIN, PRISE, and D&C Advisor under the general umbrella of UGR Advisor.

2 EXPERT AND ADVISORY SYSTEMS

Since the 1980s, systems have been developed to capture expert knowledge and capture it to guide decision making. While most of them incorporate some approach to cased-based reasoning, many expert systems have targeted a narrow domain or discipline, some of them in the field of petroleum engineering. These systems rely on the rules and structure of expert systems and may incorporate fuzzy logic; they have been used extensively in the petroleum industry.

Advisory systems, on the other hand, provide cased-based guidance for decision making without the limitations of defined structure or rules that are fundamental to expert systems. STIMEX™ software is a good example of an advisory system in the petroleum engineering industry. Like STIMEX, our UGR Advisor borrows concepts from the domain of expert systems but functions instead as an advisory system.

2.1 Case-Based Reasoning

In computer science, case-based reasoning (CBR) refers to an approach to problem solving that emphasizes the role of prior experience during future problem solving. A new problem can be solved by reusing and, if necessary, adapting the solutions to similar problems that have been solved in the past (Lopez et al. 2005). For example, a drilling engineer who has experienced two dramatic blowout situations can quickly be reminded of one or both of these situations when the combination of critical measurements matches those of a blowout case. In particular, he may remember a mistake he made during a previous blowout and use this to avoid repeating the error.

CBR has been a mature subfield of artificial intelligence in computer science, but its use is not limited to computer reasoning; it is also a pervasive behavior in everyday human problem solving. Even for experts, CBR is a predominant problem-solving method. The fundamental principles of CBR have been established, and numerous applications have demonstrated its role as a useful technology.

"In CBR terminology, a case usually denotes a problem situation. A previously experienced situation, which has been captured and learned in a way that it can be reused in the solving of future problems, is referred to as a past case, previous case, stored case, or retained case….Correspondingly, a new case or unsolved case is the description of a new problem to be solved. Case-based reasoning is a cyclic and integrated process of solving a problem, learning from this experience and solving a new problem" (Aamodt and Plaza1994).

Aamodt and Plaza (1994) formalized the following four-step process for case-based reasoning.

1. Retrieve: Given a target problem, retrieve cases from memory or a database that are relevant to solving it. A case consists of a problem, solution, and annotations about how the solution was derived.
2. Reuse: Map the solution from the previous case to the target problem. This may involve adapting the solution as needed to fit the new situation.
3. Revise: Having mapped the previous solution to the target situation, test the new solution in the real world and, if necessary, revise.
4. Retain: After the solution has been successfully adapted to the target problem, store the resulting experience as a new case in memory.

In our project, the process we have used is in fact a CBR process. First, we found that thousands of papers in the petroleum literature describe best practices in drilling, completion, stimulation, and production of unconventional gas reservoirs in North America. All of these papers describe the "old" cases we are trying to use. Second, we developed the BASIN analog computer program to find similar basins or formations in North America. This process is the retrieve process. Third, we built Tight Gas Sand Advisor, Shale Gas Advisor, and CoalBed Methane Advisor to find solutions for target reservoirs from the old cases. This process adapts the reuse and revise processes. Fourth, we designed a process to allow operators to apply the solution to the target reservoir and then report and document it in the literature. This is the retain process.

2.2 Expert Systems

Expert systems are capable of emulating the behavior of human experts in a specialized area of knowledge. In computer science, the concepts for expert system development come from the subject domain of artificial intelligence (AI). An expert system is defined as a computer program designed to simulate the problem-solving behavior of a human expert in a narrow domain or discipline (Giarratano and Riley and Riley 2005). An expert system can also be called a knowledge-based system, or knowledge-based expert system (Giarratano and Riley 2005). As shown in Fig. 2.1, all expert systems are composed of four basic components: a user interface, a database, a knowledge base, and an inference engine. The knowledge the expert system uses to solve a problem must be represented in a fashion that can be coded into the computer and then be available for decision making by the inference engine (Giarratano and Riley 2005). The user interacts with the system through an interface that may use menus, natural language, or any other style of interaction. The inference engine is used to reason with expert knowledge.

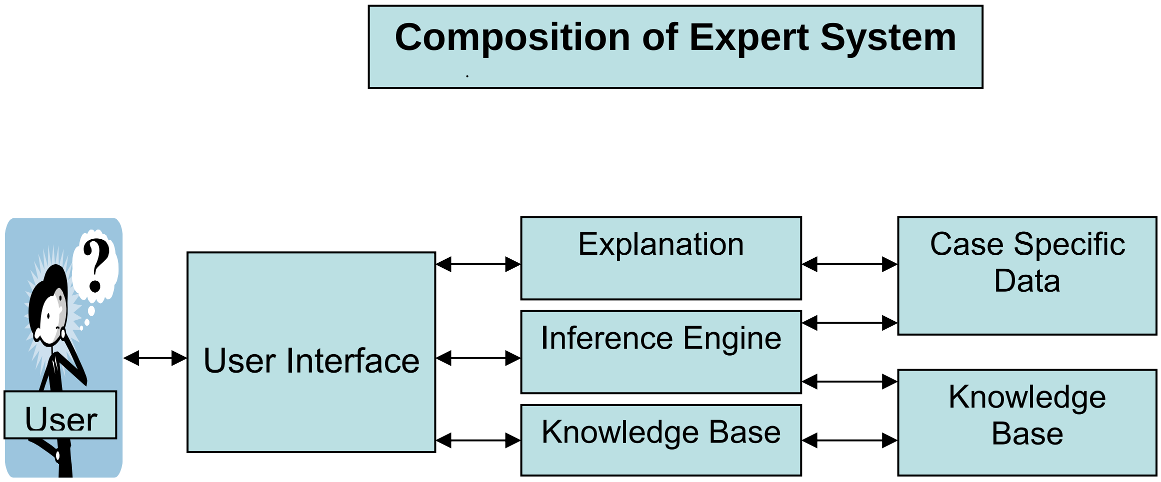


Fig. 2.1—The expert system processes user information through complex inference tools to deliver case-specific knowledge to the user.

One of the most powerful attributes of expert systems is their ability to explain reasoning to the end user. Because the expert system remembers its logical chain of reasoning, a user may ask for an explanation of a recommendation and the system will display the factors it considered in providing a particular recommendation. This attribute enhances user confidence in the recommendation and acceptance of the expert system.

A distinctive characteristic of expert systems that distinguishes them from conventional programs is their ability to incorporate incomplete or incorrect data. This characteristic is really useful in the petroleum industry. For most cases, especially for new reservoirs, the user may have only a partial data set; in that case, an expert system is likely to have less than absolute certainty in its conclusion. The degree of certainty can be quantified in relative terms and included in the knowledge base. The certainty values are assigned by the expert during the knowledge acquisition phase of developing the system. By incorporating rules with different certainty values into its knowledge base, the system can offer solutions to problems without a complete set of data.

Another advantage is that expert systems can often give multiple solutions and rank by confidence. Some systems also have a knowledge base editor that helps the expert or knowledge engineer to easily update and check the knowledge base.

The user interacts with the system through a user interface that may use menus, natural language, or any other style of interaction. An inference engine is used to reason with both the expert knowledge and the data specific to the particular problem being solved.

A shell is a special purpose tool designed for certain types of application in which the user must supply only the knowledge base (Giarratano and Riley 2005). An expert system shell is a tool that simplifies the process of creating an expert system. It can be considered the development environment for building and maintaining knowledge-based applications. By using an expert system shell, domain experts who may not have artificial intelligence backgrounds can be directly involved in structuring and encoding the knowledge.

Building expert systems by using an expert system shell offers significant advantages. An expert system can be built for a specific domain to perform a unique task by entering into a shell all the necessary knowledge about the task domain, such as selecting a fracture fluid or selecting hydraulic fracturing for a candidate well. The inference engine and the other facilities are built into the shell so that an expert can enter the knowledge himself without knowing the details of artificial intelligence.

Many expert system shells are available today; they range in price from free to tens of thousands of dollars and in complexity from simple, forward-chained, rule-based systems requiring two days of training to those so complex that only highly trained knowledge engineers can use them to advantage. We reviewed the CLIPS, Prolog, and Jess expert-system shells.

CLIPS (C Language Integrated Production System) is a productive development and delivery expert system tool that provides a complete environment for the construction of rule- and/or object-based expert systems. CLIPS was created in 1985 and is widely used throughout the government, industry, and academia. The good news is that CLIPS is free for any users.

Prolog (PROgramming in LOGic) is a logical and a declarative programming language. Prolog was invented in the early 1970s at the University of Marseilles. It is a logic language that is used by programs that use nonnumeric objects. For this reason, it is frequently used in artificial intelligence, where manipulation of symbols is a common task. Unlike the most common procedural programming languages, where the programmer must specify how to solve a problem, Prolog is a declarative language. In declarative languages the programmers only give the problem, and the language itself finds how to solve it (Loiseleur and Vigier 2008).

Jess (Java Expert System Shell) is a rule engine and scripting environment written entirely in Java language. Jess allows users to build a Java program with the capacity to "reason" using knowledge supplied by an expert in one specific domain (maybe you) in the form of declarative rules. Jess is small and one of the fastest rule engines available.

2.2.1 Rule-Based Expert Systems

The most popular type of expert system today may be the rule-based system. The rule-based system represents knowledge in terms of rules (called production rules). In fact, any mathematical or logic system can be considered as a set of rules specifying how to change one string of symbols into another set of symbols (Giarratano and Riley 2005). Given an input string, called an antecedent or premise, a production rule can produce a new string called a consequence or conclusion. An example of a production rule could be:

$Antecedent \rightarrow Consequent$

$Person\ has\ fever \rightarrow Give\ aspirin$

We can interpret this rule in terms of the IF-THEN format:

IF a person has a fever, THEN give aspirin

The production rule can also have multiple antecedents. For example, the rule above can be more reasonably changed into "*IF a person has fever AND the fever is greater than 102ºF, THEN give aspirin*" where AND means that the rule has multiple antecedents.

An expert system consists of a group—which can be more than 1,000—of production rules. One of the main tasks to building an expert system, knowledge acquisition and representation, is to acquire the expert knowledge and represent it into rules.

Rule-based expert systems can be data-driven reasoning that uses a forward-chaining algorithm. Forward chaining is an example of the general concept of data-driven reasoning. The reasoning process starts with the known data, then uses the inference rules to conclude more data until a desired goal is reached. An inference engine using forward chaining searches the inference rules until it finds one in which the IF-clause is known to be true. It then concludes the THEN-clause and adds this information to its data. It continues to do this until a goal is reached. Because the data available determines which inference rules are used, this method is called data-driven (Russell and Norvig 2003).

Rule-based expert systems can also use goal-driven reasoning through a backward-chaining algorithm. Backward chaining starts with the query. If the query is known to be true, then no work is needed. Otherwise, an inference engine using backward chaining would search the inference rules until it finds one that has a THEN-clause that matches the desired query. If the IF-clause of that inference rule is not known to be true, then it is added to the list of queries (Russell and Norvig 2003).

As defined by Giarratano and Riley (2005), an expert system can be used to solve problems "in a narrow domain or discipline." If the problem to be solved is large and general, the rule-based expert system may not be the appropriate tool. For example, if we plan to solve the large-domain application problems of drilling, completion, stimulation, and production of UGRs, an expert system may not be the appropriate tool. The problem of UGR development is complex, and it requires hundreds of input parameters, calculations, and decisions. A simple expert system cannot solve all the specific problems involved in UGR development.

2.2.2 Fuzzy Logic and Fuzzy Expert Systems

Fuzzy logic is a superset of conventional (Boolean) logic that has been extended to handle the concept of partial truth—truth values between "completely true" and "completely false" (Zadeh 1965). Fuzzy logic can be used to deal with reasoning that is approximate rather than precise.

While Boolean logic only allows true or false, fuzzy logic allows all things in between. In other words, Boolean logic has two values, which are usually called *false* (0) or *true* (1). With fuzzy logic, any value between 0 and 1 is possible.

A good example may be human height. In one survey, for a specific purpose, we need to define the fuzzy concept of "height," which may have the values of "Tall," "Medium," and "Short." We might have several separate membership functions defining particular height ranges as tall, medium, and short. Each function maps the same height value to a truth value in the 0 to 1 range (Fig. 2.2).

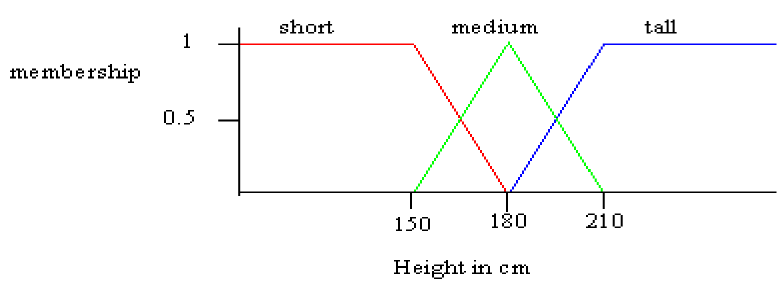


Fig. 2.2—Fuzzy logic membership functions map allows values to range within membership functions.

A fuzzy expert system, which uses fuzzy logic instead of Boolean logic, is a collection of membership functions and rules that are used to reason about data (Horstkotte 2008).

The rules in a fuzzy expert system are usually of a form similar to the following (Horstkotte 2008):

IF x is low AND y is high THEN z = medium, where *x* and *y* are input variables and *z* is an output variable. The *low* is a membership function defined on *x*, *high* is a membership function defined on *y,* and *medium* is a membership function defined on *z*. The IF and THEN part of the rule is the rule's antecedent. This is a fuzzy logic expression that describes to what degree the rule is applicable. The THEN part of the rule is the rule’s consequence (or conclusion). This part of the rule assigns a membership function to the output variables.

For many petroleum engineering applications, fuzzy logic may be a good tool to deal with approximate input data. We all know it is very difficult or expensive to obtain accurate values of parameters such as permeability, porosity, thickness of the pay zone, and drainage area in the entire the reservoir. This is especially true for a newly or undeveloped unconventional gas reservoir or field. In some cases, the values of important parameters are estimated according to experience of an expert. Fuzzy logic systems can be programmed to consider data on the basis of the fuzzy set of confidence limits set by the user.

2.2.3 Model-Based Expert Systems

Model-based reasoning is an inference method based on a model of the physical world. In artificial intelligence, “causal rules reflect the assumed direction of causality in the world: some hidden property of the world causes certain percepts to be generated” (Russell and Norvig 2003). For example, a pit causes all adjacent squares to be breezy:

$$\forall r : \mathrm{Pit}(r) \longrightarrow [\mathrm{Adjacent}\ (r, s) \rightarrow \mathrm{Breezy}(s)]$$

“A system that reasons with the causal rules is called a model-based reasoning system because the causal rules form a model of how the environment operates” (Russell and Norvig 2003). This application is valuable to the UGR system in its ability to predict outcomes of actions.

2.3 Expert Systems in Petroleum Engineering

Expert systems have found wide use in petroleum engineering, especially in the area of well stimulation and

2.3.1 Expert Systems in Well Stimulation

Because of the complexity of designing and pumping larger stimulation treatments, the application of artificial intelligence to solving well stimulation problems was essentially nonexistent until the 1990s. In 1990, an expert system called Acidman was developed to select fluid for matrix acidizing treatments (Blackburn 1990). Van Domelen et al. (1992) developed an expert system called Maxs that was designed to assist in fluid selection for matrix acidizing. Recent expert systems for well stimulation treatments can identify optimal fracture geometry and length and can diagnose formation damage and recommend stimulation treatments.

In 1999, an expert system was created to allow an engineer to identify the desired fracture geometry and length for a given formation and well. The engineer enters the value of fracture length along with the reservoir characteristics into the intelligent software tool (Mohaghegh 1999). The expert system then solves the problem and provides the engineer with the fluid, proppant, and treatment schedule that will produce the desired fracture length in that particular well of that reservoir.

In gas storage wells, many different types of formation damage can occur that dramatically curtail injection and withdrawal rates. Xiong et al. (2001) designed a comprehensive computer model to help engineers diagnose formation damage and select the best stimulation treatment for gas storage wells. The model combines domain knowledge bases with the best available expertise using fuzzy logic and expert system technologies. After diagnosing the most likely formation damage mechanism(s) from input data, the program will select the best treatment method and recommend treatment fluids and additives for the stimulation.

2.3.2 Expert Systems in Production Engineering

Production engineering may be the petroleum engineering area that has received the most attention for the use of expert systems. All kinds of expert systems for different aspects of production engineering have been developed over the years. Exprod is an expert advisor program developed in 1980s for rod pumping. Sepa is a menu-driven conversational diagnosis system that assists the user in identifying and solving problems encountered in the production and operation of water wells. Esmer is an expert system for multiphase measurement and regime identification. Recently developed expert systems for petroleum production engineering can analyze well performance, predict asphaltene deposition, optimize exploitation of gas-condensate reservoirs, and estimate monthly production.

Management of well production for wells on artificial lift can be improved using expert system technology to combine real-time sensor information with production engineering knowledge rules. By applying expert system technology and elements of artificial intelligence, operations personnel can visualize well performance in relation to the well design in real time. Arco Alaska Inc. used a commercial expert system software package to manage wells equipped with electric submersible pumps on West Sak field

(McLean 1999). The expert application can be extended easily to multiple well sites or multiple platforms and fields.

BP developed an expert system for well performance systems 1996 to retain expertise within a mobile workforce with an increasing daily workload (Hutchins 1996). Use of expert analysis to highlight potential problem wells allowed engineers to quickly high-grade their work, while reducing the risk that a problem may be overlooked. This consequently reduces well downtime.

Asphaltene precipitation from crude oils can cause serious problems in the reservoir, wellbore, and production facilities. A rule-based fuzzy expert system developed to predict asphaltene precipitation (Labadidi et al. 2002) uses production data in conjunction with composition data on the crude for predicting the potential of asphaltene precipitation.

Gas-condensate reservoirs have been the subject of intensive research throughout the years as they represent an important class of the world's hydrocarbon reserves. Their exploitation for maximum hydrocarbon recovery involves additional complexities. Artificial neural network technology provides a very good tool for the exploitation of gas-condensate reservoirs. Ayala et al. (2004) developed a powerful tool that is capable of screening the eligibility of different gas-condensate reservoirs for exploitation as well as of assisting in designing the optimized exploitation scheme for a particular reservoir under consideration for development.

Schrader et al. (2005) developed a neural network to predict production potential for a single formation, prior to drilling, over a 16,000-sq mile area of southeast New Mexico. The process involved gathering data for use as potential inputs, collecting production data at known wells, selecting optimal inputs, developing and testing various network architectures, making predictions, and analyzing and applying the results. The inputs include the thickness of the primary source rock, total organic carbon, production index (PI), paleothickness, curvature of paleostructure, and permeability. The neural network was trained to identify the production at a set of wells that attempted production from the formation. Once trained, the network was used to predict production over the entire region. Results were evaluated by inspecting a map of predicted production and performing statistical testing, including a correlation of predicted and actual production.

The Multilateral Expert System, developed in 2003 by Garrouch et al. (2003), allows the use of multilaterals in a much wider range of well scenarios and allows accounting for a large number of production-style constraints and rock property conditions. The system features the use of fuzzy logic for handling ambiguous completion scenarios.

In 2004, Garrouch et al. improved the expert system into a Web-based fuzzy expert system. The system has been fully implemented to run on the Web and provides an excellent example of how a number of heterogeneous tools and applications can be integrated on the Web. Web-based technologies enable the rapid dissemination of information and facilitate distributed decision-making.

2.3.3 Expert Systems in Drilling

In the 1980s, several drilling expert systems had been developed to solve specific problems in drilling engineering. Process control is one of the main themes in drilling and completion. Drilling Advisor, the first drilling expert system (built in 1983), was developed to assist a drilling supervisor in resolving problems related to various drilling mechanisms within the borehole. The expert system called Mud was developed to help engineers maintain optimal drilling fluid properties. Calpin, developed in 1989 by Fenoul, was used for planning drilling operations and helping decision-making directly on the rig site. TDAS, a tubular design and analysis system, can generate an optimal casing string design based on both API load capacity performance rating and von Mise's equivalent stress intensity. Many other artificial intelligence (AI) drilling programs, such as Drill Bit Diagnosis, Drilling Monitoring, and Cement Slurry Design, were also developed before 1990.

Garrouch et al. (2003) developed a knowledge-base development tool, ReSolver, for selecting a candidate UBD technique. ReSolver used fuzzy logic modeling among other confidence modes. Membership functions were defined to assist the expert system in making decisions when the decision variables fall in a "gray area." These membership functions included variables such as lost circulation, clay swelling, fines migration, hard drilling potentials, cost benefit, gas and water influx potentials, fire potential, and stuck pipe potential. When the final outcome consisted of a set of drilling fluids rather than a single one, these drilling fluids options were screened even further by the expert system to assure that the UBD fluid density would be adequate within the pressure window. If the expert system still recommended more than a single drilling fluid option, a confidence level was given with each option.

2.4 Advisory Systems

For our project, we call our work an *advisory system.* An advisory system is a program that can be used to provide advice to the user on a general topic such as drilling, completion, and stimulation of UGRs. Although the expert system called Drilling

Advisor used the term *advisor* in its name, it does not meet our definition of advisory systems because it is method-oriented rather than goal-oriented, it is controlled by an inference engine, and it is governed by rules. By our definition, advisory systems do all of these.

2.4.1 An Early Advisory System

One of the earliest advisory systems was Silverman's (1975) program called Digitalis Therapy Advisor (DTA) to advise physicians regarding the administration of digitalis in a qualitative and quantitative fashion. This system can cope with the full complicity of a clinical setting and formulate its recommendations in the same way a cardiologist would.

DTA was formulated by several constituents, including computation facilities to deal with information that is adequately described in quantitative terms; model-tailoring facilities that can tailor-make a patient-specific model to formulate recommendations from answers to questions about the patient; explanation capabilities to look at the reasoning behind decisions; and extensibility options to identify and correct incorrect portions of the model (Silverman 1975).

Swartout (1977) extended DTA with automatically generated explanations of recommendations. The extended program can explain, in English, both the methods it uses and how those methods were applied during a particular session. In addition, the program can also explain how it acquires information and tell the user how it deals with that information.

2.5 A Model for Petroleum Industry Advisory System: STIMEX^{TM}

The software model called STIMEX^{TM} was a comprehensive software package designed to help engineers make sound and economical stimulation treatment decisions (Xiong 1993; Xiong et al. 1994a, 1994b; Xiong and Holditch 1995a, 1995b; Xiong et al. 1996). According to our definition, STIMEX^{TM} is a typical example of advisory systems. In fact, many of the features of UGR Advisor have been modeled after STIMEX^{TM}.

2.5.1 Problems Solved by STIMEX^{TM}

STIMEX^{TM} was not restricted to a specific problem in stimulation, but was designed to resolve a wide range of problems associated with stimulation design. STIMEX^{TM} was built to help engineers look at both matrix stimulation and fracture stimulation for both sandstone and carbonate reservoirs. To solve the complicated problems of stimulation treatment design, STIMEX^{TM} divided the total system into smaller modules or even submodules, where each module was responsible for solving a single problem in a narrow domain and had its own functions that were different from the other modules. Thus, all modules were easily built and integrated to implement the required series of tasks.

STIMEX^{TM} used a series of friendly and intelligent interfaces to acquire the large amount of data needed to evaluate reservoirs, design stimulation treatments, and forecast reserves and economics. In these interfaces, the user was guided through a series of screens specific to his problem. More importantly, STIMEX^{TM} helped the user make many decisions, such as selecting fracturing fluids and additives, selecting proppants, and selecting pumping schedules and pumping techniques; the problems solved by STIMEX^{TM} are shown in Table 2.1. STIMEX^{TM} included several databases from which a considerable amount of information could be accessed automatically, such as typical formation data, fluid rheology, and proppant conductivities. STIMEX^{TM} also provided a powerful expert help facility. In addition, from the fracture simulation results, the system produced data sets that could be used to run reservoir performance simulators and economics software.

Table 2.1—Tasks Solved by STIMEXTM (Xiong 1996)

Task	Task Description
1	Select and qualify a target well, including wellbore condition evaluation
2	Select and qualify a target zone, evaluate the potential lower and upper barrier, and check if the zone is suitable for a fracture treatment.
3	Select the optimal fracturing fluid(s)
4	Select the optimal proppants
5	Determine the possible pumping schedules, injection rates, etc.
6	Optimize the treatment size and pumping schedule using the results of multiple fracture model runs combined with production and economic evaluation.

2.5.2 Method Used to Build STIMEX^{TM}

STIMEX^{TM} used different programming methods as required. Fuzzy logic models (Table 2.2), databases (Table 2.3), and numerical simulations (Table 2.4) were all applied as needed in the development of STIMEX^{TM}.

Table 2.2—Fuzzy Logic Application in STIMEXTM (Xiong 1996)

Fuzzy Evaluator	Functions
Well Stimulation Candidate	Identify well potential for stimulation
Barrier Candidate	Check quality of rock layer as a barrier to fracture height growth
Treatment Type	Select optimal treatment type for a specific reservoir
Injection Method	Select optimal fluid injection method
Fracturing Fluids and Additives	Select optimal fracturing fluids and additives
Formation Damage Diagnosis	Diagnose possible formation damage mechanisms
Acid Fluids	Select acids and additives for acid fracture treatment
Matrix Treatment Fluid	Select fluid and additives for matrix treatment

Table 2.3—Database Built and Used in STIMEXTM (Xiong 1996)

Fuzzy Evaluator	Functions
Fluids	Store all data related to stimulation fluids.
Proppant	Store all data related to proppants.
Formation	Store reservoir properties including rock properties, payzones, etc
Casing	Stores casing dimensions and mechanical properties.
Tubing	Store tubing dimensions and mechanical properties.

Table 2.4—Numerical Simulation Summary in STIMEXTM (Xiong 1996)

Software Name	Functions
ACIDFRAC	Design acid and acid fracturing treatments
BUCKLE	Analyze tubular movement
ECOANA	Calculate economics
FRACDES	Calculate fracture dimensions and proppant transport
PROMAT	Forecast hydrocarbon production
SIMPLEX	Optimize design within economic constraints

We designed UGR Advisor to incorporate many of these same functionalities. However, we used updated technology, new solutions, and Microsoft programming tools so UGR Advisor will run on virtually any PC.

2.6 Differences between Our Advisory System and Expert Systems

In general, our advisory system can not be considered an expert system for the reasons that follow. First, our UGR Advisor is a procedure program while an expert system is a nonprocedure program. We have used many algorithms to build portions of the UGR Advisor. An algorithm is a method of solving a problem by following steps. For most of our models in UGR Advisor, we specify exactly how a problem solution is coded. For example, the model used to calculate the optimal fracture half length, the model used to select proppant, and the model used to plan the pumping schedule, are typical procedure programs. However, in an expert system, the program lets the user specifies the goal while the underlying mechanism of the implementation tries to satisfy the goal.

In other words, in an expert system, the emphasis is on specifying "what" is to be accomplished and letting the system determine how to accomplish it (Giarratano 2005).

Second, our UGR Advisor is controlled by statement order while an expert system is controlled by an inference engine. The UGR Advisor program does not have an inference engine. The procedure to solve a problem is programmed in the form of code. However, in an expert system, the program is controlled by inference engine. The inference engine infers by deciding which rules are satisfied by facts, prioritizing the satisfied rules, and executing the rules with highest priority.

Third, some of the expert knowledge in our UGR Advisor is represented as decision charts or mathematical models or just expert rules. However, in an expert system, the expert knowledge is represented as rules and these rules compose the knowledge base. Then, based on knowledge, the inference engine relies on inferences to achieve a reasonable solution.

Fourth, from the point of program design, an advisory system is a structured design while an expert system has little or no structure. In our UGR Advisor, all models are built in a structured manner (this can be seen in detail in Section 3). However, building an expert system does not need structure. Building an expert system is focused on knowledge acquisition and knowledge representation. The knowledge engineer first consults with the human expert to acquire knowledge. The knowledge engineer then codes the knowledge into the knowledge base. The expert evaluates the system until satisfied that it functions appropriately.

Instead, we define our advisory system as a complex, multicomponent computer program designed to provide advice, recommendations, and/or best practices for a broad array of issues that describe a large and interconnected set of solutions required to develop a UGR. A human expert can use many different methods to solve a problem, such as logical reasoning, numerical simulation, rules, or personal experiences. Likewise, our advisory system can use different kinds of programming technologies to solve problems, such as the normal algorithm-based programs, database systems, fuzzy logic methods, numerical simulations, and traditional, knowledge-based expert systems. Although we have used different kinds of programming methods or programming languages to build our advisory system, all the subroutines are accessible from a common user interface.

For a complicated problem such as drilling, completion, stimulation, and production of UGRs, a question will never have a single, unique solution but will always have more than one possible solution. Therefore, different experts could have different solutions for one specific problem with the same dataset. For example, for the same reservoir with the same dataset, 10 experts could provide 5 or 6 or even more solutions. All of the solutions could be correct and could work well on the target reservoir. Our UGR Advisor provides a single, reasonable solution to the specific problem. We can not ensure that the solution provided by the UGR system is the optimal one, but we can ensure that the solution is reasonable and it is a good starting point for the development of the new UGR. By following the advice/best practice, engineers will reduce mistakes in the development of UGRs.

A typical engineering project requires knowledge, expertise, experience, and tools to solve the problem. Therefore, our advisory system is designed to help users compile the data set, then it performs necessary calculations, makes decisions, and provides advice. The user should have some domain knowledge to be sure the advice is reasonable; if not, the user should check the data or question the logic in the program.

Our advisory system is modularized and the modules are task-oriented and, as much as possible, independent of each other. An independent module can be used in different applications to solve similar problems in different applications of the advisory system. Each module is designed to provide answers or advice to a smaller, more defined problem, on a stand-alone basis. The modules can then be called as needed from anywhere in the advisory system.

Because providing useful and meaningful help information whenever it is necessary is a basic requirement for the success of any advisory system, we included a help module. The help module gives advice on how to develop realistic data sets or values for specific data items and explanations of the reasons behind the advice. Furthermore, our help system can review a situation and provide the user with explanations in the form of related references, algorithms, or advice from human experts for how conclusions were derived. This function provides a better understanding of the solution and instills greater user confidence in the conclusion and in the system, a feature that is important to engineers.

Our advisory system is also programmed to address problems associated with imprecise or incomplete data by allowing users to assign confidence values with the input data. For many petroleum engineering applications, the values of important parameters are estimated from the experience of an expert with very little hard data available; obtaining accurate values of parameters such as permeability, porosity, depth, and drainage area for most wells is difficult. In these cases, assigning confidence limits in UGR Advisor is appropriate to allow the results to be better interpreted.

Our objective was to build a comprehensive advisory system that can provide much-needed expertise to operators in newly developing UGR reservoirs. With UGR Advisor, we have done so.

3 OVERVIEW OF THE UGR ADVISORY SYSTEM

In North America, unconventional gas reservoirs (UGRs) have been in development for more than 50 years. The petroleum literature has thousands of papers describing best practices in drilling, completion, stimulation, and production of these UGRs. Since the 1970s, various private and governmental agencies in the United States have conducted research to evaluate UGRs. The reports and papers from this prior research provide a wealth of information concerning the development of unconventional gas in various basins in North America. UGR Advisor comprises three major components, BASIN, PRISE, and D&C Advisor (Fig. 3.1). Within the next few months, all three components will be incorporated into the umbrella of UGR Advisor and will work together to provide a complete design solution for the development of target UGRs.

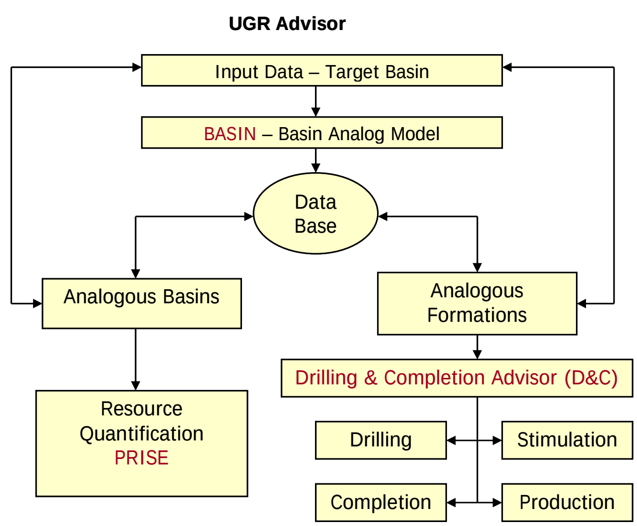


Fig. 3.1—UGR Advisor processes user input data through three major components—BASIN, PRISE, and D&C Advisor.

3.1 Quality Development Procedure

The development of an advisory system usually proceeds through several phases, including problem selection, defining the task the software can perform, modularizing the software package, defining the format of each module and the relationship among modules, defining the method for every task on every module, and programming, testing and evaluating the software. We have met each of these standards in the development of UGA Advisor.

1. **Define the tasks that the software should be able to perform.** UGR Advisor should be able to provide the best practices on drilling, completion, production, and stimulation for target UGRs. For every aspect of the problem, UGR Advisor includes all tasks that an engineer should perform for that aspect.
2. **Modularize the tasks so that each module performs only one task.** For every task, review published literature to find the existing models and avoid duplicating work. If no models existed for special tasks, we developed new models to perform the tasks. We defined these tasks precisely to ensure that each module fills a single, unique role.
3. **Design the layout of all modules and submodules in the advisor.** The layout should follow the order of the working process. The modules of UGR Advisor that will be performed first are located in front of the other modules.
4. **Define the format of each module and the relationships among the modules.** We formatted the modules to be numerical simulators, mathematical calculations, logic operations, IF-THEN knowledge bases, or databases. As Fig. 3.1 shows, we clearly defined how these modules relate within the greater Advisor program.

5. **Select the software development tools to be used on the basis of tasks to be performed.** Success of an advisory system may be determined by the nature of its user interface. For this reason, we selected Microsoft Visual Studio 2005 (VS 2005) as our developing platform because it is one of the best tools to build good user interfaces. It is also very easy to use, simplifies building a Windows-based, flexible user interface, and can perform all tasks required by our project. The fact that VS 2005 has been widely used as programming tool means we can readily get technology support and maintenance.
6. **Write the program.** Our programming development included designing the user interface, prototyping the interface, and developing every module that had been planned.
7. **Testing and Evaluation.** The last stage, testing, involves considerably more than finding and fixing syntax errors. In an upcoming project, we will ask experts to run the program, and we will interview the experts to make sure the system works well. This step will cover the verification of individual relationships, validation of program performance, and evaluation of the utility of the software package.
8. **Maintenance of the UGR Advisor.** The Crisman Institute at Texas A&M University will be able to maintain UGR Advisor as a long-term project. We will update and improve UGR advisor with the changing and advancing technology as required by the companies who sponsor the research. We will also give the source code to all of the Crisman members, who can modify and use UGR Advisor as they wish. The Visual Basic (VB) programming language we have used is commonly used in industry, which will simplify modifications.

3.2 Identifying Best Practices with UGR Advisor

If we can define the characteristics of a specific or target basin anywhere in the world and find an analogous basin in North America, we should be able to study the best practices in drilling, completion, production, and stimulation in the analog and apply that knowledge in the target basin. More importantly, some of the experience, lessons learned, and failures in the development of the analogous UGR can be extracted and used in the target basin. All of these successful and unsuccessful practices can be used by the operator that will be developing the target basin.

3.2.1 BASIN Analog Component

To apply the best practices, users will first apply our successful BASIN analog component (Singh 2006) to identify the basin in North America that is the best analog to their target basin. We designed UGR Advisor to request data from the user through a needs-driven model, which means that the advisory system asks the user to input data only when the data are needed, and data will be input only one time for use by all parts of the system. The input system will be able to distinguish reasonable data from unreasonable data so that if the user inputs unreasonable data, UGR Advisor will ask the user to replace it. If necessary, UGR Advisor will give advice on how to obtain the data.

Currently, we are improving BASIN and adding data to the data base. We are in the process of loading the data base with geological data from the 25 basins in North America that contain the most UGRs and from abundant data available in the public domain literature. We call these the reference basins.

To apply BASIN, the user must input data from a frontier or target basin other than the North American basins into the database. BASIN is programmed to perform a basin analogy to let the user know which one or two basins in North America are the most analogous to the target basin. BASIN also performs a formation analogy to let the user know which one or two formations in North America are the most analogous to any specific formation in the target basin (Fig. 3.2). Singh's 2006 thesis and subsequent technical paper (Singh et al. 2006) describe BASIN in detail.

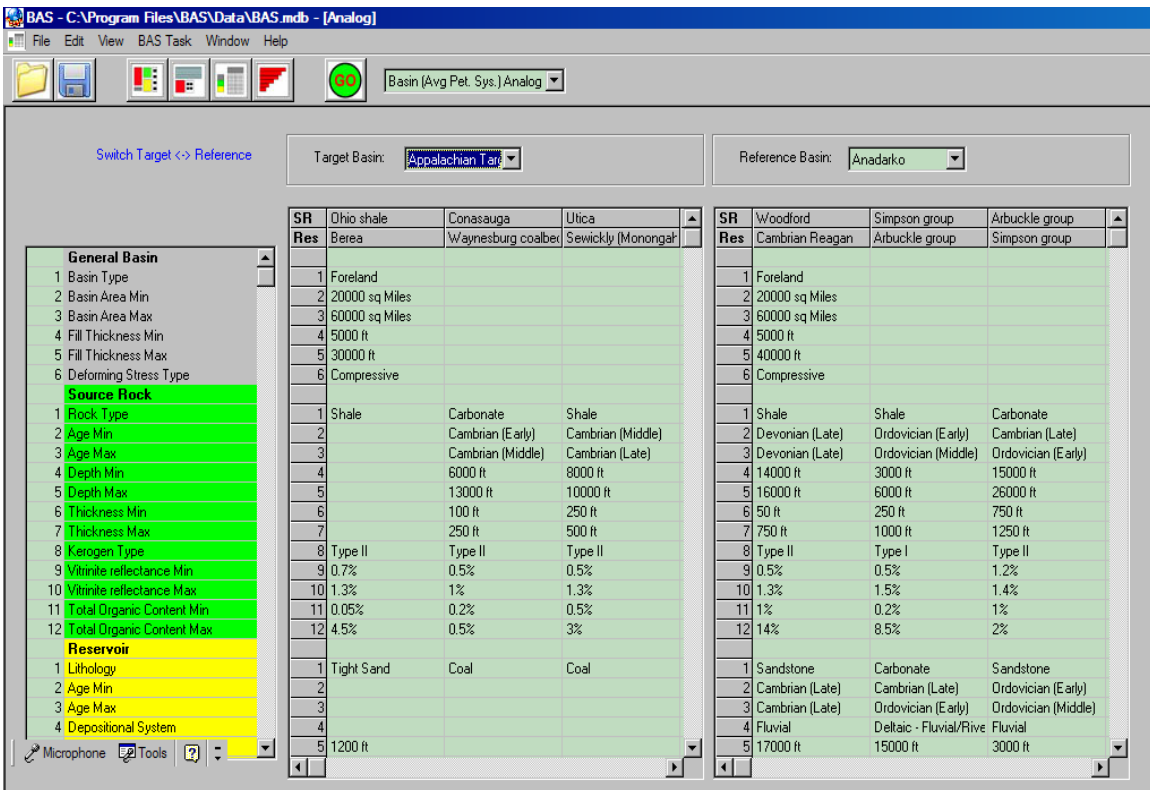
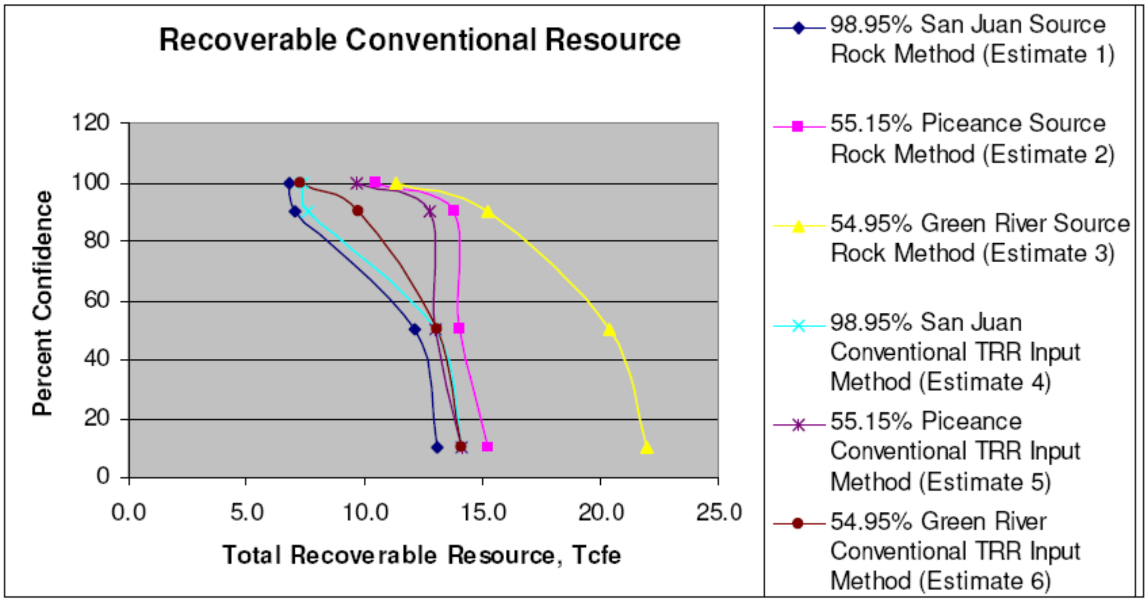


Fig. 3.2—Data analysis in BASIN reveals analogs to target reservoirs (Singh 2006).

3.2.2 PRISE Fluids Estimates

Once the analogous basins have been identified, PRISE can then estimate the technically recoverable gas volume in the target basin. Old (2008) developed the PRISE model to estimate the technically recoverable gas volume. Fig. 3.3 is exhibits two screenshots showing some of the output from PRISE.



San Juan Target

Recoverable Conventional Resource

	Recoverable Resource Volume			
Confidence	Estimate 1	Estimate 2	Estimate 3	
100	6.9	10.5	11.4	Tcfe
90	7.1	13.8	15.3	Tcfe
50	12.2	14.0	20.4	Tcfe
10	13.1	15.2	22.0	Tcfe
Confidence	Estimate 4	Estimate 5	Estimate 6	
100	7.4	9.7	7.3	Tcfe
90	7.6	12.8	9.8	Tcfe
50	13.1	13.0	13.1	Tcfe
10	14.1	14.1	14.1	Tcfe

Fig. 3.3—Two Screenshots showing the output that provide predicted fluids information from PRISE (Old 2008).

3.2.3 D&C Advisor

Additionally, once we know which reference formations are most analogous to the target formation, we can use our system to provide advice for the development of the target reservoir.

Once completed, D&C Advisor will be able to capture best practices for drilling, completion, stimulation, and production of unconventional gas reservoirs and to make decisions similar to those reached by a team of human experts. For a given target reservoir, the Drilling module of UGR Advisor can select the optimal hole diameter, casing, rig type, drilling type, mud type, and mud additives for drilling the well. The completion module of D&C Advisor will select optimal diversion technologies; determine perforation design including perforation phasing, perforation interval, and shot density; and evaluate limited-entry design conditions in case limited-entry is selected as the diversion technology. The stimulation module will determine whether the target formation is a good candidate to be fracture treated, select the fracture fluid and additives, select the proppant, select the injection method, determine the pumping schedule, and compute optimal fracture length.

For a given target well and target formations, D&C Advisor will analyze all the input layers, identify barriers to vertical fracture height growth, and group the layers. From the calculated average properties for the groups, the user can choose any one group to consider for completion and stimulation designs.

For the selected group, D&C Advisor provides advice to determine which diversion technologies can be used if a multistage treatment is required. Then, from an economics analysis, the alternative diversion technologies can be ranked to choose the best method. D&C Advisor provides advice to select the fracture fluid and additives and the proppant and injection method to inject them into the formation. It also provides advice to help users make basic decisions on fracture design, such as pumping schedule, optimal fracture half-length and width as a function of reservoir properties, and economics input.

For the target well (or wells), D&C Advisor can suggest how to perforate, including perforation phasing, perforation interval, and perforation shot density. Where limited entry is selected as the diversion technology, D&C Advisor has a spreadsheet to help determine the best injection rate, fluid distribution, surface injection pressure, and number of holes per layer required to successfully divert the fluid. From another function, D&C Advisor analyzes whether the groups are good candidates to be fracture treated. In the case of multiple wells, D&C Advisor can be used to determine the best candidate well.

3.2.4 Help Component

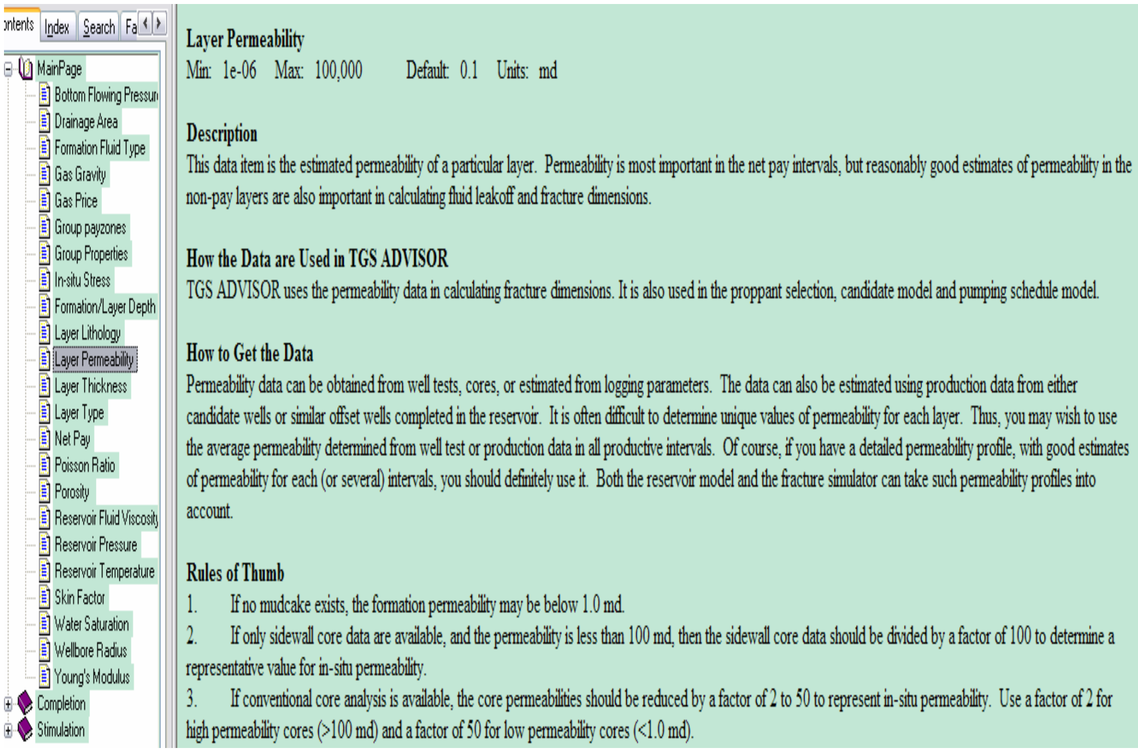
We also designed UGR Advisor to have a flexible and user-friendly interface and to provide good help. The interface guides the user through the advisory system to perform the tasks smoothly, easily, and efficiently; for example, once a dataset has been entered into the system, it is available to all parts of the system and need never been entered again. Additionally, UGR Advisor identifies the current module or task the user is working on, and it guides the user to the next task. As required, UGR Advisor will aid the user in understanding data requirements and how the program works.

The help system includes definitions, how the data item is used in the software, how to get the data, rules of thumb if available, equations to calculate values, minimum and maximum allowable values, and system default values.

Because the reason and logic concerning how the solution is obtained are very important for the engineer designing the well completion and stimulation treatment, the help system will explain what model, if any, is involved, or the reasoning procedure if a reasoning issue exists, or the contents of the rule of thumb from a human expert if a rule of thumb is involved. Furthermore, UGR Advisor will also provide references in case the user wants to know details about the models.

The help and explanation portion of the software will be easy to use. In our design, it can be obtained by clicking the help button or the F1 key. In some cases, the help function can be reached by just left double-clicking the mouse.

For example, if the user needs help on the data input of permeability, the user can put the cursor of the mouse on the top of the permeability input location and double clicking the mouse to open the help system (Fig. 3.4, top). If the user wants background information on a specific tool, such as hydra-jet fracturing with coiled tubing (Fig. 3.4, bottom), UGR Advisor can provide the explanation.



Layer Permeability

Min: 1e-06 Max: 100,000 Default: 0.1 Units: md

Description

This data item is the estimated permeability of a particular layer. Permeability is most important in the net pay intervals, but reasonably good estimates of permeability in the non-pay layers are also important in calculating fluid leakoff and fracture dimensions.

How the Data are Used in TGS ADVISOR

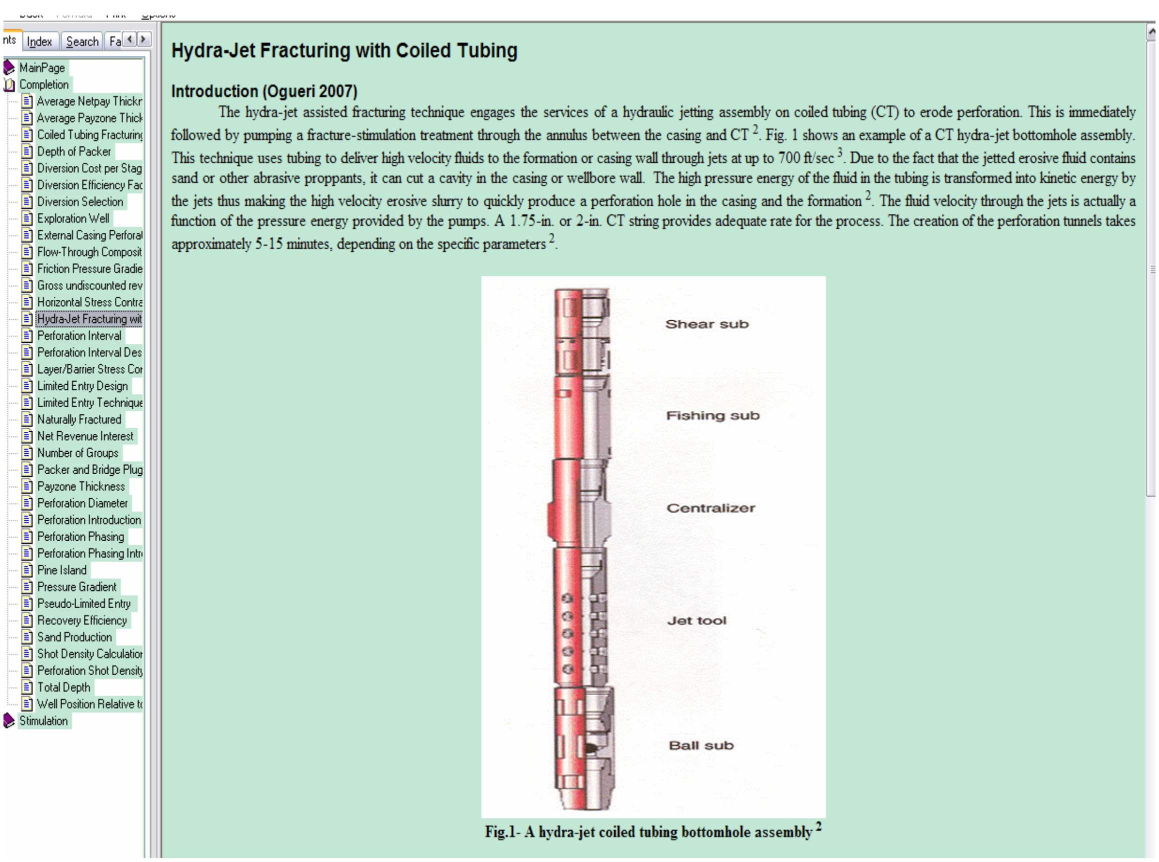
TGS ADVISOR uses the permeability data in calculating fracture dimensions. It is also used in the proppant selection, candidate model and pumping schedule model.

How to Get the Data

Permeability data can be obtained from well tests, cores, or estimated from logging parameters. The data can also be estimated using production data from either candidate wells or similar offset wells completed in the reservoir. It is often difficult to determine unique values of permeability for each layer. Thus, you may wish to use the average permeability determined from well test or production data in all productive intervals. Of course, if you have a detailed permeability profile, with good estimates of permeability for each (or several) intervals, you should definitely use it. Both the reservoir model and the fracture simulator can take such permeability profiles into account.

Rules of Thumb

1. If no mudcake exists, the formation permeability may be below 1.0 md.
2. If only sidewall core data are available, and the permeability is less than 100 md, then the sidewall core data should be divided by a factor of 100 to determine a representative value for in-situ permeability.
3. If conventional core analysis is available, the core permeabilities should be reduced by a factor of 2 to 50 to represent in-situ permeability. Use a factor of 2 for high permeability cores (>100 md) and a factor of 50 for low permeability cores (<1.0 md).



Hydra-Jet Fracturing with Coiled Tubing

Introduction (Ogueri 2007)

The hydra-jet assisted fracturing technique engages the services of a hydraulic jetting assembly on coiled tubing (CT) to erode perforation. This is immediately followed by pumping a fracture-stimulation treatment through the annulus between the casing and CT [2]. Fig. 1 shows an example of a CT hydra-jet bottomhole assembly. This technique uses tubing to deliver high velocity fluids to the formation or casing wall through jets at up to 700 ft/sec [3]. Due to the fact that the jetted erosive fluid contains sand or other abrasive proppants, it can cut a cavity in the casing or wellbore wall. The high pressure energy of the fluid in the tubing is transformed into kinetic energy by the jets thus making the high velocity erosive slurry to quickly produce a perforation hole in the casing and the formation [2]. The fluid velocity through the jets is actually a function of the pressure energy provided by the pumps. A 1.75-in. or 2-in. CT string provides adequate rate for the process. The creation of the perforation tunnels takes approximately 5-15 minutes, depending on the specific parameters [2].

Fig.1- A hydra-jet coiled tubing bottomhole assembly [2]

Fig. 3.4 —Help screens provide background information and instructions.

3.3 Team Members and Responsibilities in Building UGR Advisor

The project to develop UGR Advisor has been underway in the Crisman Institute at Texas A&M University for the past three years. The team to build various components of the program includes the principal investigator, seven master's degree students, and me, as shown below.

1. Dr. Stephen A. Holditch (Department Head and Principal Investigator)
   - Team leader, supervises the performance of the whole project
2. Kalwant Singh (MS Graduate)
   - Built and programmed BASIN as a stand-alone program using VB language
3. Sara Old (MS Graduate)
   - Built and programmed PRISE as a stand-alone program using Excel
4. Raj Malpani (MS Graduate)
   - Built and programmed a model to select fracture fluid in tight gas sand as a stand-alone program using Excel
5. Kirill Bogatchev (MS Graduate)
   - Built and programmed the model for perforation design, including perforation phasing, perforation interval, and perforation shot density using Excel
6. Obinna Ogueri (MS Graduate)
   - Built and programmed the diversion selection model using Excel
   - Built and programmed the injection method for fracturing treatment using Excel

7. Nicolas Pilisi (MS Student)

- Built and programmed the drilling module of D&C Advisor using VB

8. Yunan Wei (PhD Candidate)

- Designed, laid out, and programmed the D&C Advisor
- Evaluated, tested, and programmed the models built by Malpani, Bogatchev, Ogueri, and Pilisi; transformmed the Excel model into VB form and then incorporated them into the UGR umbrella; improved the models when necessary and incorporated all the models into the D&C Advisor
- In cases where no models were available for some specific problems, built and programmed the model for the D&C Advisor (the proppant selection model and the model to calculate optimal fracture half-length are in this module)
- Designed, laid out, programmed, and tested UGR Advisor software

Because BASIN and PRISE had already been developed and described by Singh and Old respectively, I focused on designing and building D&C Advisor as shown in Fig. 3.1. Also, I developed the software needed to integrate BASIN, PRISE, and the D&C Advisor so all modules work together, using the same input data file and database.

From our objective, the D&C Advisor will take into consideration the complicated aspects of drilling, completing, stimulating, and producing a UGR reservoir description for reservoirs in tight gas sands (TGS), coalbed methane (CBM), and shale gas (SG) reservoirs. I completed the module for tight gas sands; the remainder should be complete within a few months of this dissertation.

3.4 Procedure for Building Modules for UGR Advisor

Our design for UGR Advisor contains tens of models to solve specific reservoir management problems associated with UGRs. Some of the models were built by the team members discussed in Section 3.3, often to solve specific problems associated with their individual graduate research topics. Here, we show Ogueri's (2007) process for building the model for selecting diversion techniques as an example of our model-building procedure.

1. Perform a complete literature review of the different diversion techniques involved in completing tight gas sands with thick, multiple pay zones.
2. Evaluate each of these diversion techniques, documenting their technologies, advantages, limitations and applications.
3. Develop decision charts to aid decisions being made in choosing diversion techniques and injection methods over various alternatives.
4. Develop Microsoft Excel programs encompassing the decision charts; the program, which provides recommendations, requires the user to input certain reservoir data to get the desired output.
5. Test and validate the developed programs by comparing our solutions with various case studies from the petroleum literature.
6. Deliver the finished Excel program to team for evaluation.
7. Reprogram models that met project requirements into a Visual Basic program that adapted to build the UGR Advisor.
8. Incorporate the VB program of this model into the D&C Advisor as one module to solve the diversion selection for tight gas sand.

Most of the models were built following the procedure above or a similar one. The models for the completion portion of D&C Advisor are complete; when the drilling modules are built and incorporated, the D&C Advisor will be ready for integration with BASIN and PRISE into the UGR Advisor. At that time, the complete UGR Advisor will be ready for delivery to our sponsors.

4 THEORETICAL FOUNDATIONS OF D&C ADVISOR

The Drilling & Completion (D&C) Advisor has four modules: drilling, completion, stimulation, and production, each designed to perform a specific task. All of the modules are relatively independent from each other, although they are incorporated into a single advisory system to solve many of the problems encountered during the development of a UGR. Each of them is built on the strong theoretical basis of previous research. Our work so far has addressed the input system and the completions and stimulations models; the drilling module will be completed by a later project.

4.1 Overview of D&C Advisor

Figs. 4.1 to 4.3 illustrate our module and submodule concept. Fig. 4.1 shows how the input data lead to definition of barriers and candidate layers that guide drilling and stimulation programs. Fig. 4.2 carries the treatment design through the selection of fluids, proppants, and techniques, and Fig. 4.3 shows the drilling submodule that will ensure that the well will be completed properly.

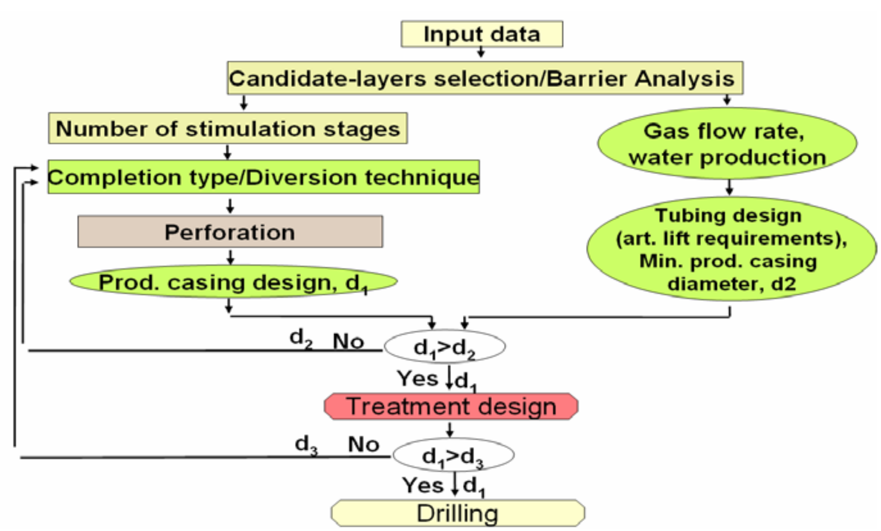


Fig. 4.1—Input data drive selection of drilling and stimulation techniques.

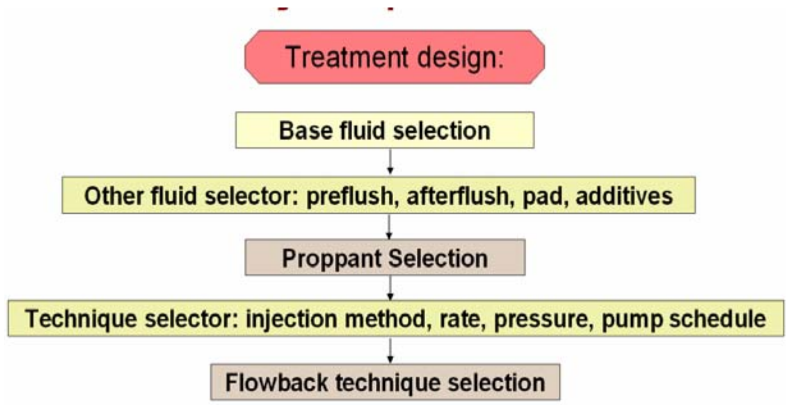


Fig. 4.2—Information on proper treatment type leads to decisions on fluids, proppants, and technique.

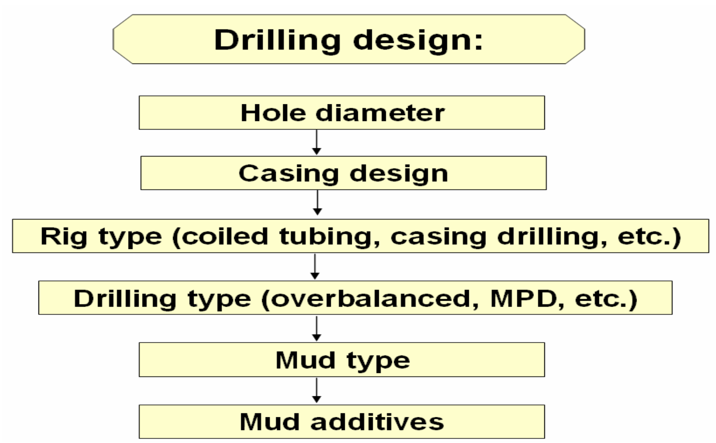


Fig. 4.3—Drilling module will answer important questions about drilling practices.

Fig. 4.4 (from Malpani 2006) is an example decision tree that shows the kinds of data the Advisors consider in their analyses. Although this figure was designed as a flow chart to be used by engineers when selecting a base fluid for fracture treatment of tight gas sand reservoirs, it is a natural starting place for an artificial intelligence program to make similar decisions.

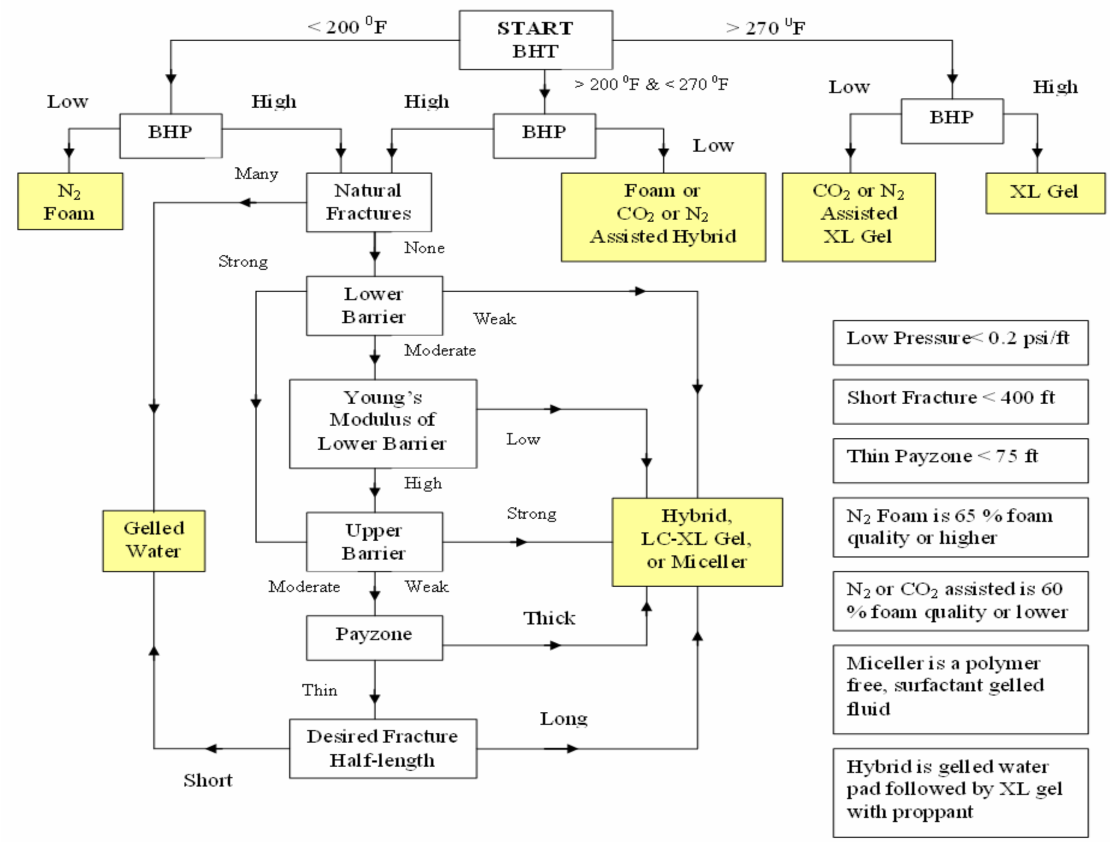


Fig. 4.4—Flow chart guides fluid selection module for TGS (Malpani 2006).

The combination of all of the submodules will give the stimulation module the ability to provide recommendations, best practices, and basic decisions on the stimulation of UGRs.

4.2 D&C Advisor Input System

The first step to any petroleum engineering design is to prepare a dataset describing the reservoir. After the complete data are entered by layer, we try to determine the best way to group the layers to proceed with the completion and stimulation design.

In D&C Advisor, the input system is designed to help the user solve the following problems.

1. Why do we need to group pay zones?
2. How should we group them?
3. How do we classify and identify barrier layers?
4. How do we group layers and define group properties?

4.2.1 Why Do We Need to Group the Pay Zones?

The first step in a completion or stimulation design is to group the initial dataset for each rock layer into pay zone groups. The initial layer dataset is compiled from different resources such as well logs, drilling reports, PVT experiments, and geologic records. The dataset will be entered by layers. Commonly, to describe a UGR we use from 8 to 20 layers that will typically be from 10 to 100 ft thick. Since most fracture treatments will have fracture height of 300 to 400 ft or more, we need to group the input layers into pay zone groups that will all be connected after the fracture treatment. Thus the completion and stimulation should designed be for specific pay zone groups. A typical pay zone group will be composed of an upper barrier layer, one or more pay zone layers, and a bottom barrier layer. After grouping and determining the average properties of the pay zone group such as permeability, porosity, Young's modulus, and water saturation, we can design the completion and stimulation of the target group from simple models.

4.2.2 How Should We Group Pay Zones?

The basic logic to divide the dataset into layer groups is to determine which layers can stop vertical fracture growth during fracture treatment. Most UGRs will contain more than one pay zone. In our software, we compute whether any of the zones will be likely barriers to vertical fracture growth. If good barriers lie between pay zones, then multiple groups will be formed and a multistage fracture treatment will be designed. The other factor that impacts the group result may be the distance between the pay zones. If the distance between two adjacent target pay zones is more than 300 ft, treatment should be pumped in two stages (Xiong 1993).

Because the layers are grouped mainly according to the information of whether the barriers between pay zones are good, we need a model to evaluate whether a layer can act as barrier to stop fracture growth on vertical direction.

4.2.3 What Is a Good Barrier Layer?

Xiong (1993) used fuzzy logic to develop models to determine whether a particular layer can act as a barrier to stop fracture propagation in the vertical direction. First, he classified every layer as either strong barrier, a weak barrier, a questionable barrier, or no barrier. A strong barrier can prevent or significantly limit vertical fracture growth; a weak barrier may prevent vertical propagation to some extent; a questionable barrier will probably not prevent vertical fracture propagation; and zones with no barrier will definitely not prevent vertical fracture propagation.

Xiong (1993) identified seven factors that impact whether a specific layer or rock will act as a barrier. The factors, in order of importance from high to low, include:

1. in-situ stress difference between the potential barrier and the payzone, $\Delta\sigma$

2. barrier thickness, h_b

3. pay zone thickness, h_p

4. pay zone Young's modulus, E_p

5. the ratio of barrier Young's module to pay zone Young's module, E_b/E_p

6. barrier Young's module, E_b

7. the ratio of pay zone permeability to fluid viscosity in the pay zone, k/μ.

One way to reflect the importance of each parameter is to use a weighting factor. Based on expert experience, Xiong (1993) assigned the values of the seven weighting factors listed above so that the total of the weighting factors should equal to 1.0. The values are shown in Table 4.1.

Table 4.1—Weighting Factors Used to Determine Barrier Evaluation

Factor	$\Delta\sigma$	h_b	h_p	E_p	E_b/E_p	E_b	k/μ	∑(total)
I_x	0.4	0.15	0.15	0.1	0.075	0.05	0.075	1.0

Working from expert advice and logic, Xiong (1993) developed the membership functions to quantify the importance of each parameter. The membership functions, according to the order above, are shown as Eq. 4.1 to 4.7 respectively.

$$F_{\Delta\sigma}\begin{cases} 0 & (\Delta\sigma \le 100 \text{ psi}) \\ \dfrac{1}{1+90000(\Delta\sigma-100)^{-2}} & (\Delta\sigma \ge 100 \text{ psi}) \end{cases} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad (4.1)$$

$$F_{h_b}\begin{cases}0 & (h_b \le 5\,\text{ft})\\ \dfrac{1}{1+\dfrac{2000000}{(h_b-5)^{3.2}}} & (h_b \ge 5\,\text{ft})\end{cases} \quad \text{...} \quad (4.2)$$

$$F_{h_p}\begin{cases}0 & (h_p \le 40\text{ ft})\\ 1-Exp\left[-0.00015(h_p-40)^2\right] & (h_p \ge 40\text{ ft})\end{cases} \quad \text{........................} \quad (4.3)$$

$$F_{E_p}\begin{cases}0 & (E \le 1\times10^6\text{ psi})\\ \dfrac{1}{1+0.1(E-1)^{2.6}} & (E > 1\times10^6\text{ psi})\end{cases} \quad \text{...} \quad (4.4)$$

$$F_{E_{bpr}}\begin{cases}0 & (E_{bpr} \le -10)\\ 0.0015(E_{\text{bpr}}+10)^2 & (-10 < E_{bpr} \le 0)\\ 0.0035(E_{\text{bpr}}{}^2+0.005E_{\text{bpr}}+0.15)^2 & (0 < E_{bpr} \le 10)\\ 1 & (E_{bpr} > 10)\end{cases} \quad \text{............} \quad (4.5)$$

$$F_{E_b}\begin{cases}0 & (E \le 1\times10^6\text{ psi})\\ \dfrac{1}{1+0.1(E-1)^{2.6}} & (E > 1\times10^6\text{ psi})\end{cases} \quad \text{...} \quad (4.6)$$

$$F_{k/\mu}\begin{cases}0 & (\Delta\sigma \le 100\text{ psi})\\ \dfrac{1}{1+90000(\Delta\sigma-100)^{-2}} & (\Delta\sigma \ge 100\text{ psi})\end{cases} \quad \text{...............................} \quad (4.7)$$

The sum of the contribution of each factor can be calculated by using Eq. 4.8. The sum of the contribution is used to determine the barrier classification. In Eq. 4.8, I_x represents the weighting factor of X variable and F_x represents the value of the membership function of X variable. If the value of F_b is larger than 0.7, the layer can be classified as a strong barrier. If F_b is larger than 0.5 and less than 0.7, the layer is classified as a weak barrier. If the value of F_b is larger than 0.3 and less than 0.5, the layer is classified as a questionable barrier, while if the value of F_b is less than 0.3, the layer is classified as no barrier.

$$F_b = \min(1, I_{\Delta\sigma} F_{\Delta\sigma} + I_{hb} F_{hb} + I_{hp} F_{hp} + I_{Ep} F_{Ep} + I_{\frac{Eb}{Ep}} F_{\frac{Eb}{Ep}} + I_{Eb} F_{Eb} + I_{\frac{k}{\mu}} F_{\frac{k}{\mu}}) \quad \ldots. (4.8)$$

4.2.4 Algorithm Used to Group Layers

By applying the barrier evaluation model, I developed the algorithm to group layers/formations into pay zone groups that we are using in D&C Advisor. The procedure is described as follows.

1. Beginning from the upper layers and going down to the bottom layer, search for pay zones. Number pay zones from 1 to n. If there is only one pay zone, group all layers into one group.
2. If the formation contains more than one pay zone, for pay zone No.1, run the barrier evaluation model for all nonpay-zone layers from the first layer downward to find the bottom barrier. If no barriers are found, group all layers from the top layer to the bottom layer into one group. If a barrier is

found and the barrier is located below the first pay zone, group all layers from the first layer to the barrier layer as one group.

3. Repeat Steps 1 and 2 from the barrier layer (this layer now is regarded as the first layer) from Step 2 to the bottom layer until all layers are grouped.

4.2.5 Determination of Group Properties

For every group, we need to determine the properties of that group for the completion and stimulation design and to forecast production. The basic idea is to average the layers in the group according to specific rules. The rules we use are as follows:

1. If the group contains only one pay zone, consider all properties of that pay zone as the properties of the group.
2. If the group contains two or more pay zones, average the permeability, saturation, porosity and composition with the thickness-weighted average method. However, assign the value of temperature and viscosity as the maximum value from all the pay zones; assign the pressure as the minimum value from all pay zones. Average the value of Young's modulus, Poisson ratio and fracture gradient by the thickness-weighted method.

4.3 D&C Advisor Completion Module

The completion module of D&C Advisor is composed of submodules to solve the following problems:

1. A diversion submodule to provide advice concerning which diversion technologies can be used for the target TG Reservoir
2. A perforation submodule to provide advice concerning the perforation interval, perforation length, perforation phasing, and shot density
3. A limited entry design submodule to provide advice concerning the injection rate, fluid distribution, and number of holes to shoot in each layer when limited entry is required.

Because our target reservoir is a UGR, we assume the reservoir will have to be fracture treated to make it profitable. Therefore, the completion should be designed to obtain optimal stimulation results. Based on the best practice from literature review, we have developed decision charts as a function of the target reservoir properties for a variety of decisions the design engineer must make during the process. To evaluate the decision charts, we have compared the results from the decision charts with the best practices as documented in the petroleum literature.

4.3.1 Diversion Selection Model for the Target TG Reservoir

Ogueri's (2007) literature review evaluated appropriate diversion technologies for tight gas sand (TG) reservoirs, documenting the advantages, disadvantages, and limitations of eight available technologies: limited entry, ExCAPE, flow through composite frac plugs (FTCFP), coiled tubing (CT) fracture, packer and bridge plug, Pine Island, hydrajet fracturing with CT, and pseudolimited entry with ball sealers.

Using the results of the literature review and expert rules, Ogueri (2007) designed decision charts (Fig. 4.5) to provide advice concerning the appropriate ways to divert fracture treatments.

The decision chart begins by looking at the depth and bottomhole pressures under which these various diversion techniques can be effectively operated. The depth is classified as shallow or deep; a shallow well has depth less than 10,000 ft while a deep well is deeper than 10,000 ft. However, the user can change the "fuzzy" definition of shallow and deep as necessary to allow the program to provide meaningful advice. The bottomhole pressure is classified as normal/low or geopressured. The normal/low pressured formation is regarded as one with a gradient less than or equal to 0.4 psi/ft while the geopressured or overpressured formation is regarded as one with a gradient greater than 0.4 psi/ft.

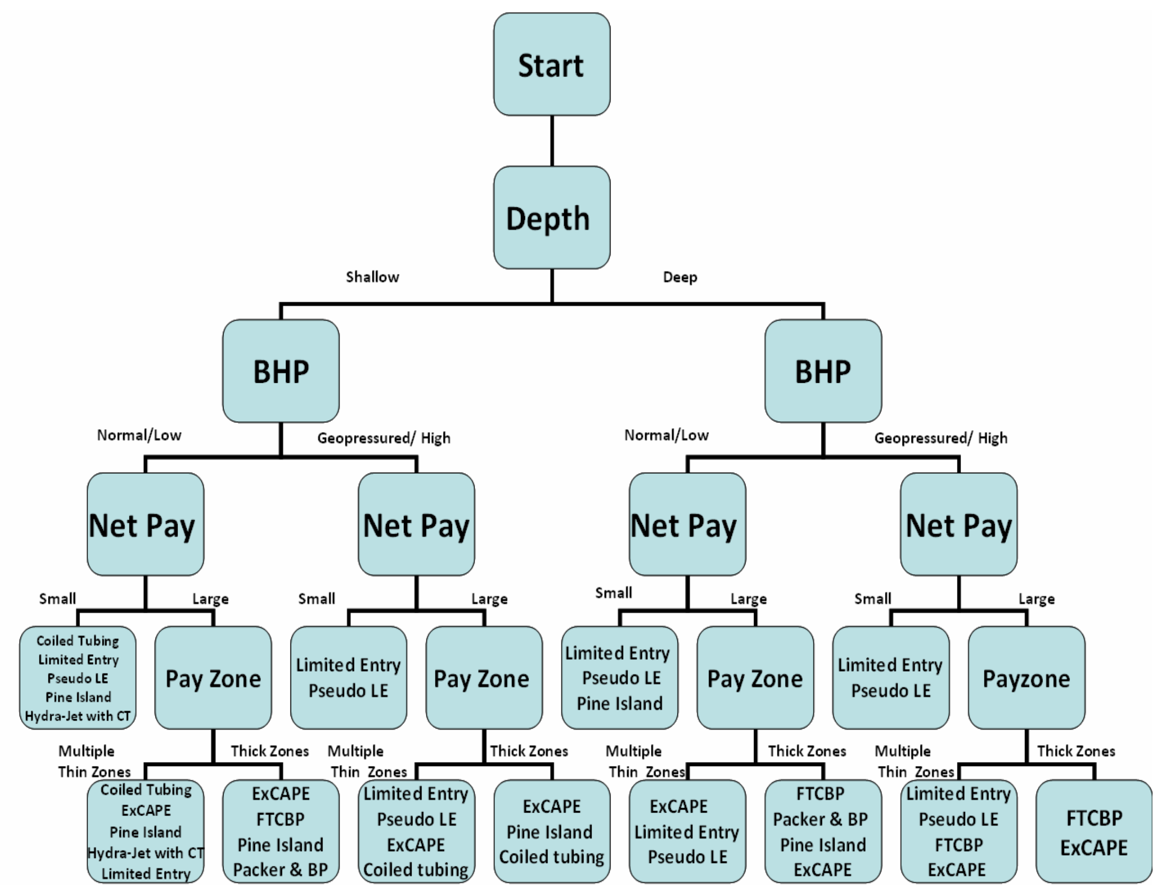


Fig. 4.5—Decision chart guides selection of diversion technology (Reorganized from Ogueri 2007).

Another parameter involved in the decision charts is the net pay, which is categorized into small or large. The small value of net pay thickness is one with a thickness less than or equal to 25 ft while the larger net pay is regarded as one with a thickness greater than 25 ft. The small net pay and large net pay are further categorized into multiple thin zones or thick zones. We represented the thin zones as intervals with less than 10 ft of pay while the thick zones have pay intervals greater than 10 ft. these Decision factors enable us to classify and group the diversion techniques as shown in Fig. 4.5.

In some cases, users may have different opinions about the definitions of high or low pressure, deep or shallow reservoirs, and thick or thin pay zones. In D&C Advisor, the user can alter these values.

4.3.2 Perforation Design Model

Normally, to make a TG reservoir profitable, the reservoir will be fracture treated upon initial completion and before any meaningful gas production occurs. Therefore, the perforation scheme should be designed to optimize the fracture treatment. An ideal perforation scheme for fracture initiation should have minimal pressure drop across the perforations (perforation friction pressure), initiate only a single fracture (bi-wing), and generate a fracture with minimal tortuosity (turning from the initiated fracture into the preferred fracture plane) at an achievable fracture initiation pressure. Three major perforating parameters influence the outcome of a hydraulic fracture treatment, including perforation phasing, perforation interval, and perforation shot density.

4.3.3 Perforation Phasing

By studying the literature and consulting with experts, Bogatchev (2007) developed a decision chart to determine perforation phasing (see Fig. 4.6).

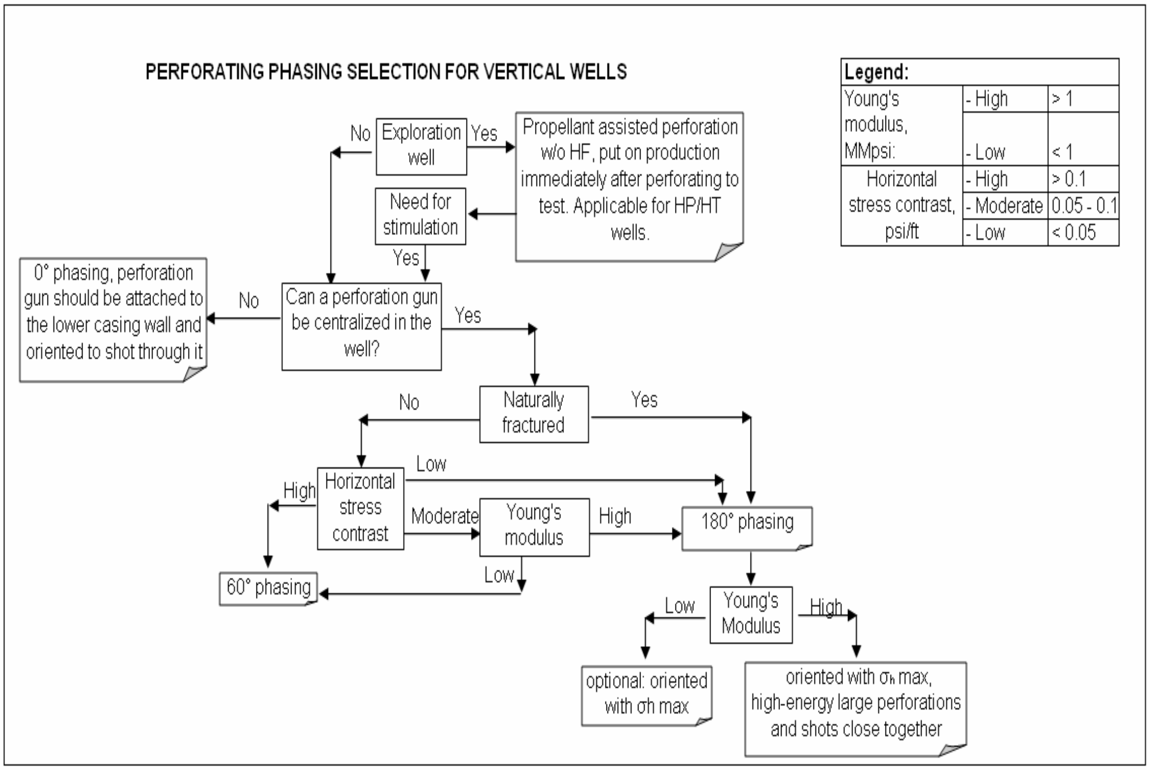


Fig. 4.6—Decision chart aids in design of perforation phasing (Bogatchev 2007).

The basic idea behind the decision chart is that for successful hydraulic fracturing treatments, the perforations should be oriented within 30° of the preferred fracture plane. Only 60° and oriented 180° phasing guarantees that some of the perforation shots will be within the 30° angle of the preferred fracture plane. However, in specific cases, 0° phasing should be applied. Since oriented 180° phasing perforation is more expensive than nonoriented perforating, it can compromise some of the cost advantages of nonoriented 180° phasing. Thus, only 0°, 60°, and 180° phased perforation are considered in our D&C Advisor.

From the literature review, Bogatchev (2007) found that 60° phased perforation should be used when a reservoir can be characterized as follows: no natural fractures; no formation sand production; low Young's modulus; or high horizontal stress contrast.

The 180° phased perforation should be used when a reservoir can be characterized as naturally fractured, high Young's modulus, low horizontal stress contrast, or unconsolidated formation. In case of high Young's modulus, oriented 180° phased perforation is preferred.

Bogatchev (2007) developed a fuzzy logic approach to be linked with the decision chart to capture the complexity of the perforation-phasing decision. For each parameter that could impact the perforation decision, Bogatchev defined two membership functions: one for 60° phasing and the other for 180° phasing. The membership functions range between null and unity to quantify the independent influence each particular parameter has on the outcome. The membership functions for Young's modulus (*E*), natural fractures (*NF*), formation sand production (fines migration, *SF*), and horizontal stress contrast ($\sigma h_{\min}/\sigma h_{\max}$, *HC)* are shown as Eq. 4.9 through 4.12.

$$F_{180}(E)\begin{cases} 0.1\mathrm{E} & (\mathrm{E} < 5\ \mathrm{MMPsi}) \\ \dfrac{1}{1+1.6^{5-E}} & (\mathrm{E} \ge 5\ \mathrm{MMpsi}) \end{cases} \qquad F_{60}(E)\begin{cases} 1-\mathrm{Exp}\left(\dfrac{E-5.8}{1.5}\right) & (\mathrm{E} < 5\ \mathrm{MMPsi}) \\ \dfrac{0.7}{0.7+4^{E-5}} & (\mathrm{E} \ge 5\ \mathrm{MMpsi}) \end{cases} \quad \text{..} \quad (4.9)$$

$$F_{180}(NF)\begin{cases} 0 & (\text{Very few } NF\text{s}) \\ 0.5 & (\text{Moderatel y } NF) \\ 1 & (\text{Highly } NF) \end{cases} \quad F_{60}(NF)\begin{cases} 0.8 & (\text{Very few } NF\text{s}) \\ 0.5 & (\text{Moderatel y } NF) \\ 0 & (\text{Highly } NF) \end{cases} \quad \text{....................} \quad (4.10)$$

$$F_{180}(SP)\begin{cases}1 & \text{(Considerable } SP\text{)}\\ 0 & \text{(No } SP\text{)}\end{cases} \quad F_{60}(SP)\begin{cases}0.5 & \text{(No } SP\text{)}\\ 0 & \text{(Considerable } SP\text{)}\end{cases} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad (4.11)$$

$$F_{180}(HC)\begin{cases}1 & \text{(Low } HC\text{)}\\ 0.4 & \text{(Moderate } HC\text{)}\\ 0 & \text{(High } HC\text{)}\end{cases} \quad \mathrm{F}_{60}(HC)\begin{cases}0 & \text{(Low } HC\text{)}\\ 0.5 & \text{(Moderate } HC\text{)}\\ 0.8 & \text{(High } HC\text{)}\end{cases} \quad \ldots\ldots\ldots\ldots\ldots\ldots \quad (4.12)$$

The impact of every parameter in the dataset on the final recommendation is determined by using weighting factors. The values of the weighting factors for the four parameters above are assigned as E = 0.2875, NF = 0.2875, SP = 0.1375, and HC = 0.1375, respectively.

Finally, the values of the perforation phasing indices for 180°- and 60°-phased perforations are calculated by using Eqs. 4.13 and 4.14 respectively.

$$I_{180} = F_{180}(E) \bullet W_E + F_{180}(NF) \bullet W_{NP} + F_{180}(SP) \bullet W_{SP} + F_{180}(HC) \bullet W_{HC}\,. \quad \ldots\ldots \quad (4.13)$$

$$I_{60} = F_{60}(E) \bullet W_E + F_{60}(NF) \bullet W_{NP} + F_{60}(SP) \bullet W_{SP} + F_{60}(HC) \bullet W_{HC}\,. \quad \ldots\ldots\ldots \quad (4.14)$$

The recommendation concerning which perforation phasing to choose is derived from comparison of the perforation phasing indices. The perforation phasing index is a number between null and one, reflecting the degree of confidence in the recommendations. The higher the value of the perforation phasing index, the more confidence we can have in designing that perforation phasing.

4.3.4 Perforation Interval

Bogatchev (2007) also developed the following logic to determine the perforation interval for a TG reservoir. He found that the perforation interval length for one stage of a multistage hydraulic fracturing treatment depends upon pay zone thickness (gross thickness) and number of potential separate fractures to be created. Pay zone thickness can divided into three categories: thin pay zone (< 50 ft), moderate pay zone (50 to 150 ft), and thick pay zone (> 150 ft). In a single-layer pay zone, only one hydraulic fracture is expected, so the length of the perforation interval is a function only of layer thickness. If a pay zone is thin, the entire interval should be perforated. To prevent multiple fractures caused by a long perforated interval in the case of a moderate or thick pay zone, only the most porous zone should be perforated. As with all fuzzy parameters in UGR Advisor, the definition of thin, moderate, and thick can be changed if the user has identified a good reason to do so.

For a multilayer pay zone case, where shales are not strong barriers, one hydraulic fracture may cover the entire thickness of the pay zone including shales, so only one layer can be perforated. If all layers are perforated, several fractures may be created that might interfere with each other. In that case, the layer with the highest sum of porosity-thickness and permeability-thickness products is perforated. However, if shales are thick and/or have a much higher Young's modulus than sands, they might confine fracture height growth. In this case, perforations should cover every layer of interest to generate several separated fractures simultaneously and stimulate all layers of interest during hydraulic fracturing.

Third, Bogatchev found that if a moderately thick pay zone contains up to three fractures, if a moderately thick zone has up to three fractures, we need to perforate the most porous zone in every productive layer.. Point-source perforation is a preferred technique when the well is not normal to formation bed boundaries (for example, a deviated well or vertical well in a dipping reservoir). Moreover, if a low or moderate stress contrast exists between a barrier and sand, point-source perforation should be used to minimize the creation of multiple fractures. A barrier/sand stress contrast is considered low where a difference between the barrier's and the sand's horizontal stresses is less than 0.05 psi/ft; moderate contrast where the stress difference is between 0.05 and 0.1 psi/ft; or high contrast where the stress difference is greater than 0.1 psi/ft.

Furthermore, if a moderately thick pay zone has four or more fractures, perforation of only those layers with major gas in place or the limited-entry technique can assure that stimulation fluid and proppant are not wasted in low-productivity, uneconomic horizons. The limited-entry technique can also be applied in thick pay zones regardless of the number of the separate fractures, but it carries the risk of creating multiple fractures in thick intervals.

Finally, where a formation is naturally fractured, Bogatchev recommended limiting the perforation interval to 6 ft per separate fracture to avoid excessive fluid leakoff and the possibility of creating multiple fractures. Also, the interval with the highest degree of natural fractures should be perforated.

4.3.5 Perforation Shot Density

By reviewing the literature and interviewing experts, Bogatchev (2007) found that the main concerns about perforation shot density in TG wells are their impact on proppant settling in the well during the hydraulic fracture treatment and pressure drop across the perforations. The perforation friction pressure drop, Δp_{perf}, can be calculated with Eq. 4.15.

$$\Delta p_{\text{perf}} = 0.2369 \bullet \rho \bullet \left(\frac{q}{C \bullet N_{\text{perf}} \bullet D_{\text{perf}}^{2}} \right)^{2} \quad \text{...} \quad (4.15)$$

where N_{perf} is the number of perforations, D_{perf} is the perforation diameter, and C is the discharge coefficient.

The perforation friction pressure drop is a function of the total injection rate divided by the number of perforations. Thus, to minimize the perforation friction pressure drop, we could maximize the number of perforations. However, if too many perforations are shot, we can have problems with proppant dropping out in the wellbore because of low velocities per perforation and/or multiple fractures causing near-wellbore tortuosity and high near-wellbore pressure drops. Thus, when deciding on the number of perforations needed, the design engineer must balance the need to minimize perforation friction by shooting more holes with the need to minimize proppant dropout in the wellbore, near-wellbore tortuosity, and multiple fractures by shooting fewer holes.

Because of the complexity and inaccuracy of fluid velocity calculations near perforations, Bogatchev applied a rule of thumb suggested by Holditch to compute perforation shot density. The injection rate in every perforation should be between 0.25 and 0.5 bbl/min for conventional hydraulic fracturing. Perforations for limited-entry hydraulic fracturing are designed to create a considerable pressure drop across the perforations, so all productive zones get enough treatment fluid and are adequately stimulated. So we suggest that for limited-entry fracturing, the average injection rate across each perforation should be between 1 and 2 bbl/min. Also, we set the maximum allowable perforation density to 8 shot/ft, because of casing integrity limitations.

Not all perforations are open and accept fluid during a fracture treatment, especially if high shot density is used on the well. Assuming that a hydraulic fracture is propagated only in perforations shot closest to the preferred fracture plane, the shot density for 60° phasing should be 3 times the shot density for 180° phasing and 6 times the shot density for 0° phasing to allow for the fact that not all the perforations will take fracture fluid (Bogatchev 2007).

4.3.6 Limited-Entry Design

If the D&C advisor recommends that the limited-entry design diversion technology be applied, the user needs to decide how many holes to shoot in each layer. Ogueri (2007) developed a limited-entry design model to provide advice with the design. This program can perform three tasks:

1. Calculate and provide the amount of treatment fluid that would go into the individual pay zones
2. Calculate the injection rate per zone
3. Calculate the surface injection pressure

D&C Advisor uses the following equations to perform the three tasks.

$$p_{ppf} = \frac{(0.2369) \times i_{pf}^{\ 2} \times L_f}{d_{pf}^{\ 4} \times \alpha^2} \quad \ldots\ldots (4.16)$$

$$i_{pf} = \sqrt{\frac{p_{ppf} \times d_{pf}^{\ 2} \times \alpha^2}{(0.2369) \times L_f}} \quad \ldots\ldots (4.17)$$

$$p_{\mathrm{BHT}} = \sigma \times D_{TV} \quad \ldots\ldots (4.18)$$

$$p_h = D_{TV} \times G_f \quad \ldots\ldots (4.19)$$

$$p_{\mathrm{surf}} = p_{\mathrm{BHT}} - p_h + p_{pf} + p_{ppf} \quad \ldots\ldots (4.20)$$

$$p_{pf} = D_{TV} \times G_{pf} \quad \ldots\ldots (4.21)$$

D_{TV} is the depth of the packer and G_{pf} is the friction pressure gradient, which can be calculated by interpolating between injection rates in the friction tables. Table 4.3 shows rate vs. friction pressure gradient for slick water. With an estimated injection rate of 30 bbl/min, the friction pressure gradient was interpolated to be 754 psi/1,000 ft.

Table 4.2—Friction Pressure vs. Rate for Slick Water

	Rate, bbl/min	Friction Pressure, psi/1,000 ft
Low	1.6	10
Pivot	13	200
High	39.3	1000

4.4 D&C Advisor Stimulation Module

From the results from the submodules, the stimulation module provides recommendations, best practices, and basic decisions on the stimulation of UGRs. The module answers at least these eight questions:

1. Is the reservoir a good candidate for fracturing?
2. What kind of fracture fluid should be used?
3. What kind of additives should be selected or should not be used?
4. What type of proppant should be chosen, what proppant mesh size should be used, and what are other related properties, such as conductivity, price, and specific gravity of the proppant?
5. How should the fracture fluid and proppant be injected into the wellbore/reservoir?

6. What pumping schedule should be used during the treatment?
7. What optimal fracture half-length and width are identified by the PKN, GDK, and UFD fracture propagation and design models?
8. How do results from the PKN, GDK and UFD models compare?

4.4.1 Fracture Candidate Model

Before performing a fracture treatment design, we must determine whether the reservoir is a good candidate to be fracture treated. We call this problem the fracture candidate selection problem. Xiong (1993) developed a fuzzy logic model to determine whether a reservoir/well is good candidate to be fracture treated. The model can also be used to choose the best candidate when multiple reservoirs/wells are potential candidates.

Xiong (1993) found nine parameters that can impact the candidate problem (Table 4.3). The parameters impact the candidate problem differently, and therefore weighting factors are assigned according to their importance.

Table 4.3—Weight Factors for Candidate Problems

Parameter	Weight
Permeability/viscosity ratio, k/μ	0.25
Porosity ϕ;	0.05
Skin factor, s	0.2
Net pay thickness, h	0.1
Water saturation, S_w	0.1
Formation depth, D	0.05
Formation pressure gradient, g_p	0.1
Drainage area, A	0.05
Wellbore condition, W_d	0.1

To apply fuzzy logic, one import step is to build the membership functions for all of the fuzzy variables that impact the problem. The membership functions can be built on the basis of the domain knowledge and expertise. Xiong (1993) developed membership functions for the nine parameters to represent the degree of truth or the degree of compatibility in a fuzzy set. Each membership function was divided into levels of Excellent, Good, Possible, and Not a Candidate, assigned weighting factors of 1, 0.7, 0.5 and -1 respectively. The member functions for the skin factor is shown as Eq. 4.22 (Xiong 1993); all nine parameters are shown in Appendix D.

(1) Level 1 " Excellent Candidate"

$$F_1(s)\begin{cases} 1 & (s > 15) \\ 1 - \mathrm{Exp}\left(- \dfrac{s - 5.5}{-5.40506} \right) & (5.5 \le s < 15) \\ 0 & (s < 5.5) \end{cases}$$

(2) Level 2 - " Good Candidate"

$$F_2(s)\begin{cases} \mathrm{Exp}\left[-\left(\dfrac{s+1}{-2.40224} \right)^2 \right] & (1 \le s < 10) \\ 1 - \mathrm{Exp}\left[-\left(\dfrac{s+2.5}{-4.20393} \right)^2 \right] & (-6 \le s < 1) \\ 0 & (\text{otherwise}) \end{cases}$$

(3) Level 3 -" Possible Candidate"

$$F_3(s)\begin{cases} 1 - \mathrm{Exp}\left[-\left(\dfrac{s-5.5}{-5.40505} \right)^2 \right] & (1 \le s < 5.5) \\ \mathrm{Exp}\left[-\left(\dfrac{s+2.5}{-4.20393} \right)^2 \right] & (-6 \le s < 1) \\ 0 & (\text{otherwise}) \end{cases}$$

(4) Level 4 - " Not a Candidate"

$$F_4(s)\begin{cases} 1 - Exp\left[-\left(- \dfrac{s+2.5}{-4.20393} \right)^2 \right] & (s \le -2.5) \\ 0 & (s > -2.5) \end{cases}$$

…………………………………………………………………………….…………(4.22)

With known membership functions of the nine parameters, Xiong generated a 9 × 4 relation matrix (Eq. 4.23).

$$R = \begin{bmatrix} F_{11} & F_{12} & F_{13} & F_{14} \\ F_{21} & F_{22} & F_{23} & F_{24} \\ \cdots & \cdots & \cdots & \cdots \\ F_{91} & F_{92} & F_{93} & F_{94} \end{bmatrix} \quad \text{(4. 23)}$$

The elements F_{ij} in the matrix are values of the membership function of parameter i at level j. For example, F_{12} is the value of the membership function of k/μ for the good candidate level. Combining R with the nine-parameter weighting factor, N, Xiong generated a 1 × 4 matrix, B (Eq.4.24), where the values of b_j are the relative stimulation indices. The b_1, b_2, b_3, b_4 calculated from Eq. 4.25 represent the "possibilities" that a particulate well/formation is an excellent, good, or possible candidate or not a candidate, respectively. For a single-well case, the largest b_j of all four values implies that the well/formations belongs to the j level category.

$$b_j = \mathrm{Min}\left\{1, \sum_{i=1}^{9} a_i F_{ij}.\right\} \quad \text{(4.24)}$$

where a_i is the parameter weighting factor.

$$B = N \times R = [b_1, b_2, b_3, b_4] \quad \text{(4.25)}$$

Finally, Xiong derived a comprehensive stimulation index of I_{cs} from Eq. 4.26.

$$I_{cs} = \sum_{j=1}^{4} b_j w_j \quad \text{(4.26)}$$

where b_j is the relative stimulation index from Eq. 4.25. The w_j is the level weighting factor.

As the value of comprehensive stimulation index increases, the well/formation is considered a better candidate for stimulation. If the value of I_{cs} is larger than 0.899, it is considered an excellent candidate. If the value of I_{cs} is between 0.5 and 0.899, it is consider as good candidate. If the value of I_{cs} is between 0.15 and 0.5, it is considered a possible candidate and if the value of I_{cs} is smaller them 0.15, it is not considered a candidate. For a number of wells/groups/formations, those wells/ groups/ formations can be ranked as stimulation candidates using their values of I_{cs}.

4.4.2 Fracture Fluid and Additives Selection Model

Malpani (2006) developed a decision chart to provide advice on the selection of a fracture fluid for a particular set of conditions. The decision chart includes eight key parameters to guide engineers to the appropriate fluid for a TG reservoir. The eight key parameters include bottomhole temperature, bottomhole pressure, presence of natural fractures, type of lower and upper barrier, modulus of the formation, height of the pay, and desired fracture half-length. As Fig.4.7 shows, the decision chart can guide users to select the appropriate fracture fluid.

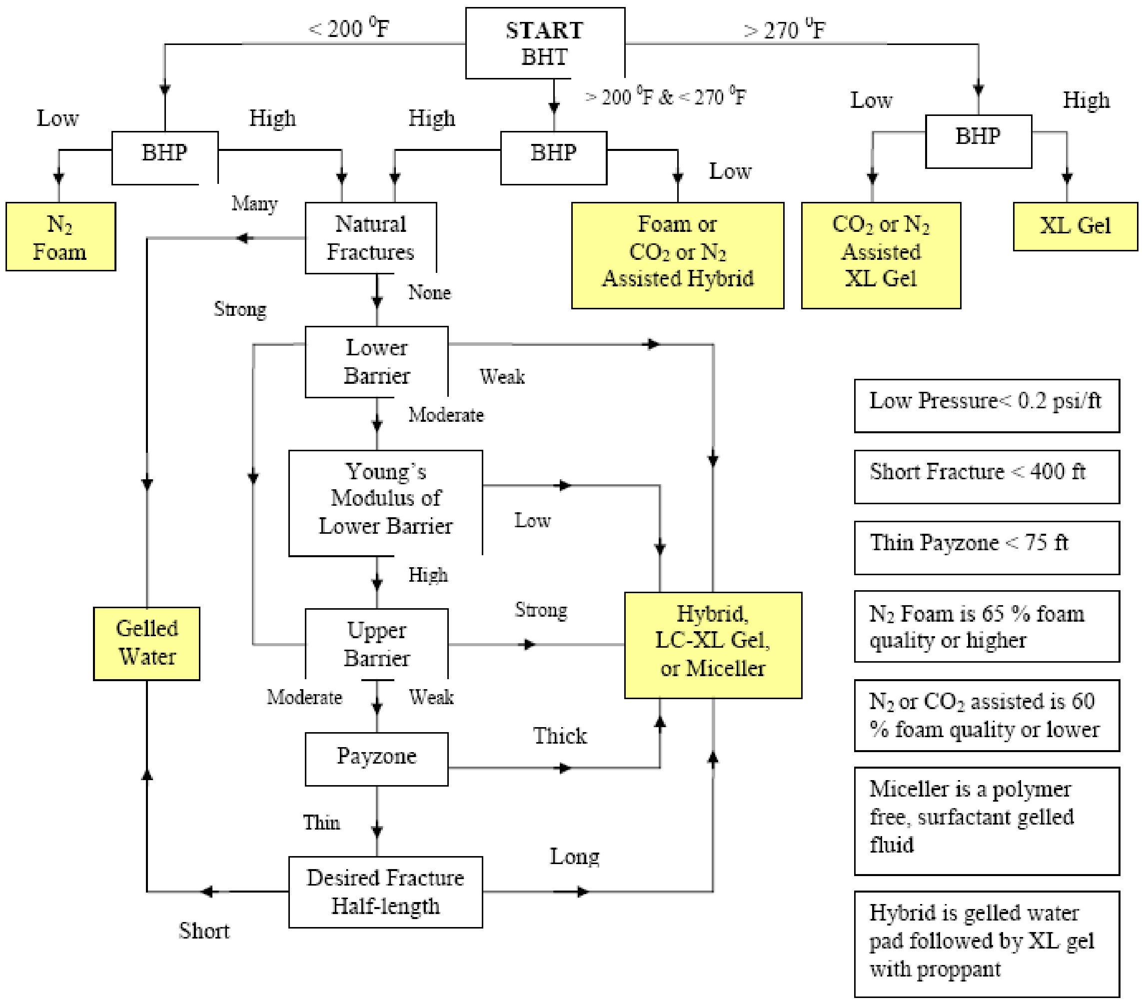


Fig. 4.7—Decision chart guides users to select correct TG fracture fluid.

Modern fracturing fluids are complex; they often have as many as seven or eight different additives in a typical fracturing fluid to keep them working properly. The additives may include bactericides, breakers, clay stabilizers, temperature (gel) stabilizers, fluid loss additives, friction reducers, iron controllers, surfactants, and diverting agents. Xiong (1993) developed simple rules to determine for choosing additives (Table 4.4; details appear as Appendix E).

Table 4.4—Guidelines for Choosing Additives

Additive	Purpose
Bactericides	Prevent viscosity loss
	Protect formation from anaerobic bacterial growth
Breaker	Thin viscous fluids
	Enhance proppant distribution
	Facilitate closure
Clay stabilizer	Prevent fines migration
	Prevent clay swelling
	Prevent disaggregation
Temperature (gel) stabilizers	Remove free oxygen to prevent degradation at high temperature
Fluid loss additives	Improve efficiency by preventing leakoff
Friction reducers	Reduce friction caused by fluid flow
Iron controllers	Keep subsurface iron ions in solution
	Prevent formation damage from iron
Surfactants	Reduce surface tension
	Minimize emulsion problems
	Maintain relative permeability
Diverting agent	Plug perforations as needed to divert fracturing fluid to a different interval

4.4.3 Proppant Selection Model

The purpose of hydraulic fracturing is to improve production and thus make the UGR reservoir profitable. Therefore, we must ensure that the selected proppant has higher conductivity than a specified value (the required fracture conductivity) under reservoir condition. Furthermore, the main purpose of proppant in hydraulic fracturing is to hold open the fracture after release of the fracturing fluid hydraulic pressure. Therefore, the proppant must be strong enough to bear closure stress. Thus the proppant selection procedure must satisfy at least two requirements: be strong enough to bear the closure stress and maintain conductivity equal to or larger than the required fracture conductivity.

Satisfy the Proppant Strength Requirement

In the market, the two main categories of proppants are naturally occurring sands and manmade ceramic or bauxite proppants. Different types of proppants can bear different stresses. However, the price of high-strength proppant is much higher than the low-strength proppant. Therefore, to satisfy the strength requirement, the first step of the procedure is to select the proppant type economically according to the closure stress.

Economides et al. (2002) recommended a general proppant selection guide of popular proppant types based on the dominant variable of closure stress (See Fig. 4.8). According to the guide, if the closure stress is known, two or three proppant types can be determined. We will apply this guide to the UGR Advisor System as the first step to choose a proper proppant.

Fig. 4.8—Proppant selection as a function of closure stress (Economides 2002).

After the possible proppant types are determined, we need to determine the mesh size for the selected proppant type. The proppant market offers many mesh sizes ranging from 12/18 to 40/70 mesh. In practice, we do not need consider all the mesh sizes for every proppant type. According to expert experience and industry practices, we recommend the following rules:

1. If the formation depth is less than 6,000 ft, consider only the 12/20, 16/30, 20/40 mesh sizes.
2. If the formation depth is larger than 6,000 ft and less than 10,000 ft, consider only the 16/30, 20/40, 30/50 mesh sizes.
3. If the formation depth is larger than 10,000 ft, consider only the 20/40, 30/50, 40/70 mesh sizes.

Using these simple rules can greatly reduce the number of candidate proppants. The maximum number of proppant after the screen out of closure stress and mesh size is 9.

Satisfy the Fracture Conductivity Requirement

Holditch and Bogotchev (2008) used Eq. 4.27 to evaluate fracture conductivity and pointed out that a good design goal for determining the fracture conductivity in a particular well was a value of $C_r \approx 10$.

$$Cr = \frac{wk_f}{\pi \cdot k \cdot L_f}, \quad \text{(4.27)}$$

where wk_f is fracture conductivity and C_r is the dimensionless conductivity factor.

By transforming Eq. 4.27 with a dimensionless damage factor, D_r (Eq. 4.28), they obtained

$$wk_f = \pi \cdot L_f \cdot C_r \cdot k \cdot D_r \quad , \quad \text{(4.28)}$$

where C_r becomes an input parameter that can be set by the user. For C_r of 10 or more, the pressure drop is considered minimal down the fracture. The damage factor, D_r, is defined to account for the damaged to fracture conductivity caused by proppant embedment, proppant crushing under formation closure stress and temperature, etc. For example, if a damage factor of 3 is used, actually we need to achieve 3 times higher wk_f initially to obtain optimal conductivity. Holditch and Bogotchev recommended Eq. 4.29 to determine the damage factor value.

$$\begin{cases} 2 \text{ to } 5 & (\sigma_{fc} \leq 6000 \text{ psi}) \\ 5 \text{ to } 10 & (6000 \text{ psi} < \sigma_{fc} \leq 10000 \text{ psi}) \\ 10 & (\sigma_{fc} > 10{,}000 \text{ psi, or } D > 10{,}000 \text{ ft, or } T_f > 275 \text{F}) \end{cases} \quad \text{.} \quad \text{..............} \quad 4.29$$

To use Eq. 4.28, we need to know the value of *w,* the fracture width. For a given proppant concentration, Eq. 4.30 can be used to approximately calculate fracture width by assuming a proppant porosity under reservoir condition (we assume the value is about 0.3).

$$w = \frac{c}{\rho_p (1 - \phi_p)}, \quad \text{..} \quad (4.30)$$

where ρ_p is the proppant density in lb/ft^3 and ϕ_p is the proppant porosity. With known proppant type from Step One, proppant density can be obtained easily. The c is the proppant concentration in lb/ft^2.

To use Eq. 4.28, we also need to know the value of proppant permeability, k_f. This is the most difficult task because so many types of proppants are available in the market. The problem is further complicated by the dependence of proppant values on closure stress. For every type of proppant, permeability decreases dramatically with increasing closure stress. In the literature, most of the available models solve this problem by using database, such as Xiong's model (1993) or Bogatchev's model (2008). However, we do not use a database in the UGR Advisor System.

Instead, we calculate proppant permeability. Fortunately, the proppant permeability is provided by the manufacturers for each different mesh size. By using these data, we can plot proppant permeability vs. closure stress for most available mesh sizes of every proppant type. With the plot, we can generate a series of equations to calculate proppant permeability for most available mesh sizes of every proppant type. By using these equations, for a specific proppant type of a specific mesh size, we can easily obtain proppant permeability. The plots and equations generated from the plots are shown from Fig. 4.9 to Fig. 4.14. For example, Eq. 4.31 calculates the approximate proppant permeability for the 20/40 mesh. In Fig. 4.12, the dashed curves represent the trendlines from which the equations for proppant permeability with the increasing closure stress are obtained, while the solid lines represent the real data for four 20/40 mesh size sands from the manufacturers.

$$\begin{cases} y = 2\text{E - }06x^2 - 0.048x + 327.08 & \text{(for sand)} \\ y = -0.0261x + 309.48 & \text{(for resin - coated sand)} \\ y = -0.0331x + 419.45 & \text{(for intermediate - strength ceramic)} \\ y = -2\text{E - }07x^2 - 0.0214x + 429.38 & \text{(for intermediate - strength bauxite)} \\ y = 659.66\,\text{Exp}(-1\text{E - }04x) & \text{(for high - strength bauxite)} \end{cases} \quad \ldots\ (4.31)$$

where y is the proppant permeability and x is the closure stress.

Up to this point, Eq. 4.28 can be used to evaluate all the candidate proppants obtained from Step One. The left-hand side represents the real conductivity of the proppant. With known proppant type and mesh size, the proppant permeability, k_f, can be calculated by using Eq. 4.31 or other similar equations (Fig. 4.9 to Fig. 4.14). The fracture width, *w*, can be calculated by using Eq. 4.30. The right-hand side of Eq. 4.28 represents the required fracture conductivity. The optimal fracture half-length can be calculated by Eq. 4.30. The damage factor can be determined by Eq. 4.29. Since the permeability is known for every specific reservoir, the required fracture conductivity is a known value for all the proppants selected from Step 1. Thus, the second step of the proppant selection procedure is to evaluate whether the real conductivity of the candidate proppants is larger than the required conductivity. If the real conductivity of the candidate proppant is larger than the required conductivity, it is treated as a qualified proppant. In D&C Advisor, all the qualified proppants populate a results table for the user to choose.

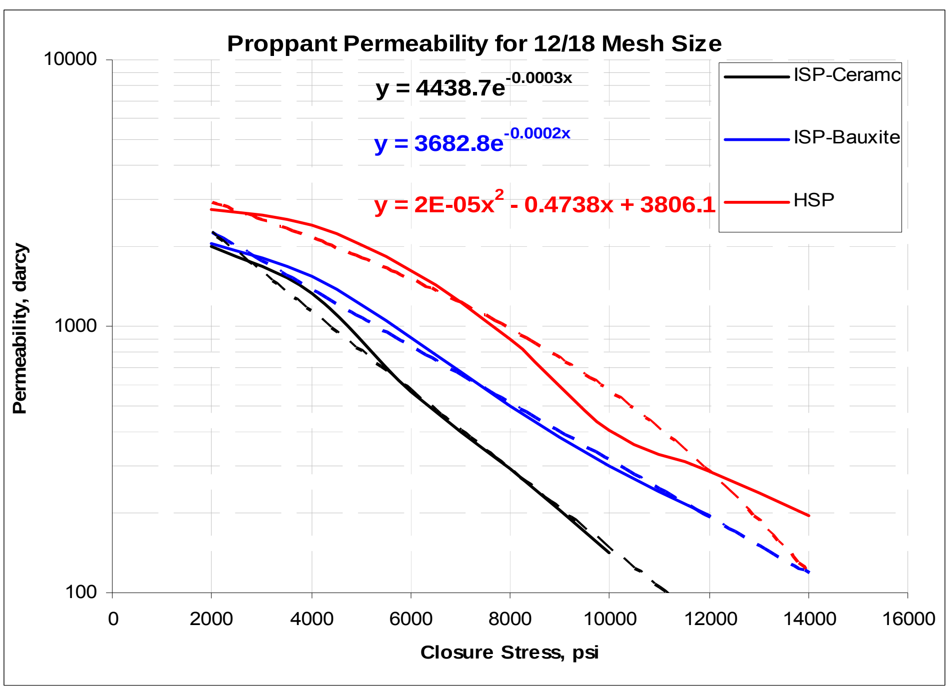


Fig. 4.9—Permeability vs. closure for 12/18 mesh size.

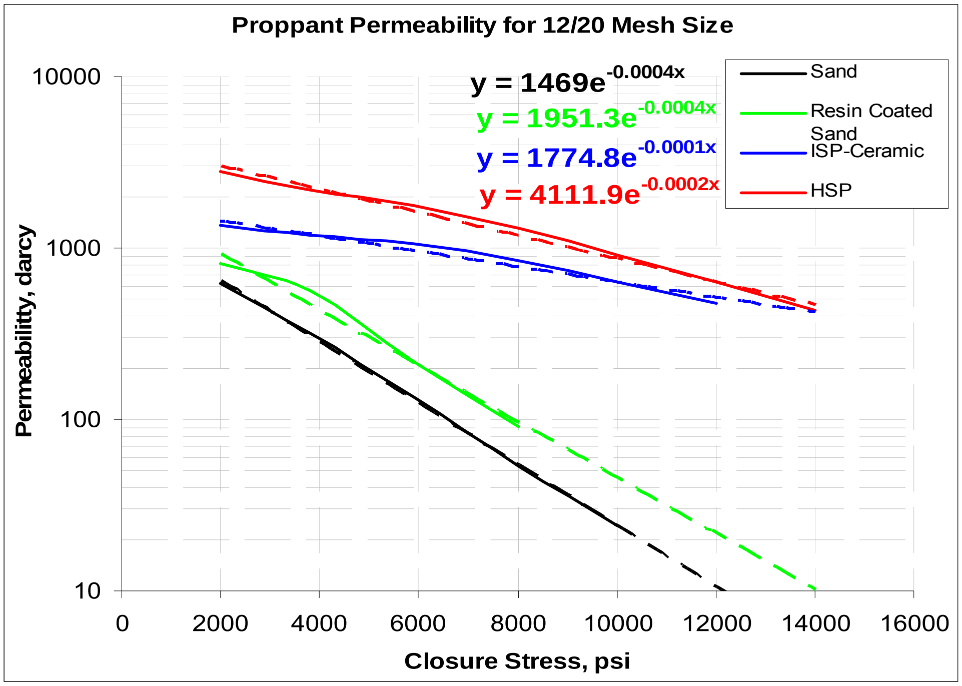


Fig. 4.10—Permeability vs. closure for 12/20 mesh size.

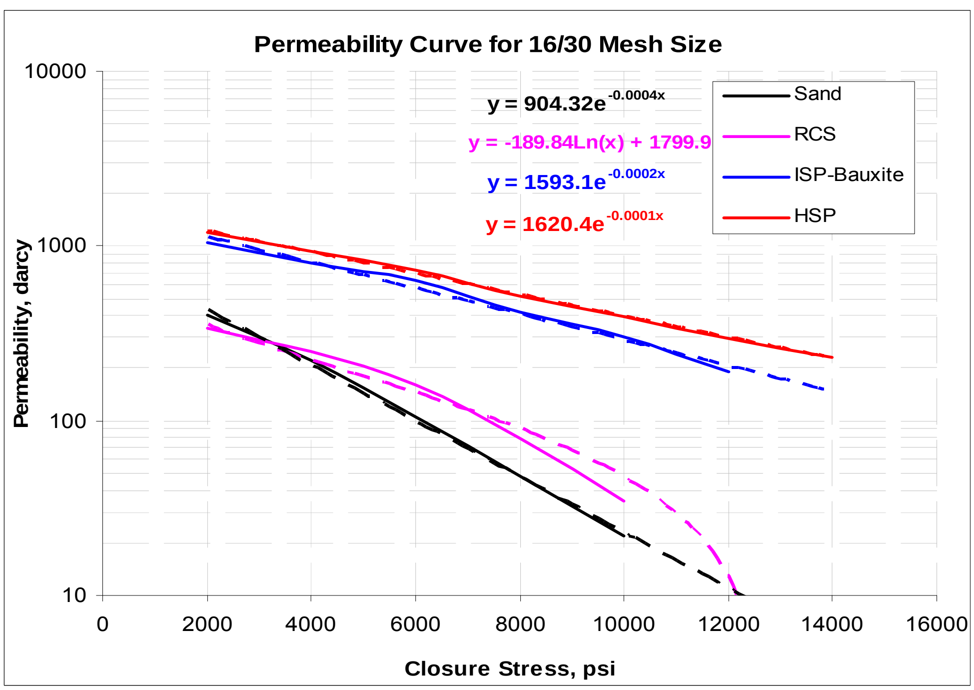


Fig. 4.11—Permeability vs. closure for 16/30 mesh size.

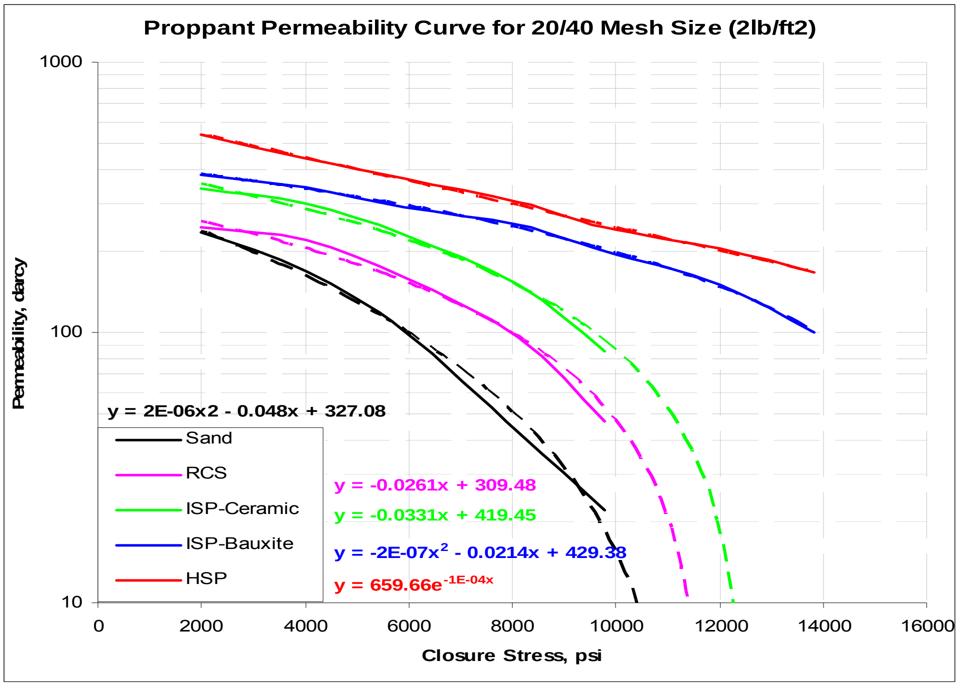


Fig. 4.12—Permeability vs. closure for 20/40 mesh size.

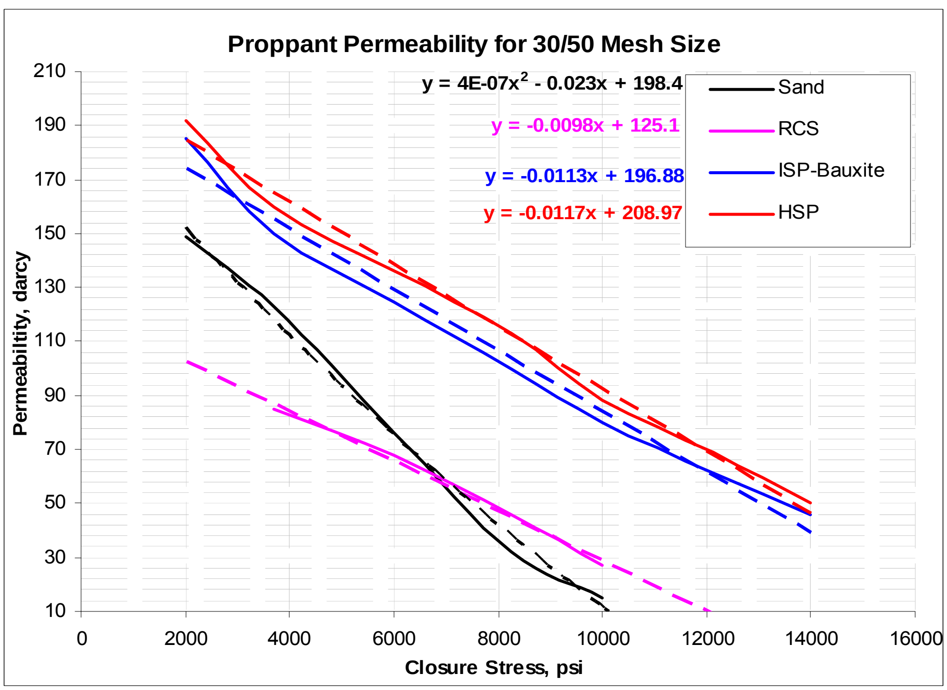


Fig. 4.13—Permeability vs. closure for 30/50 mesh size.

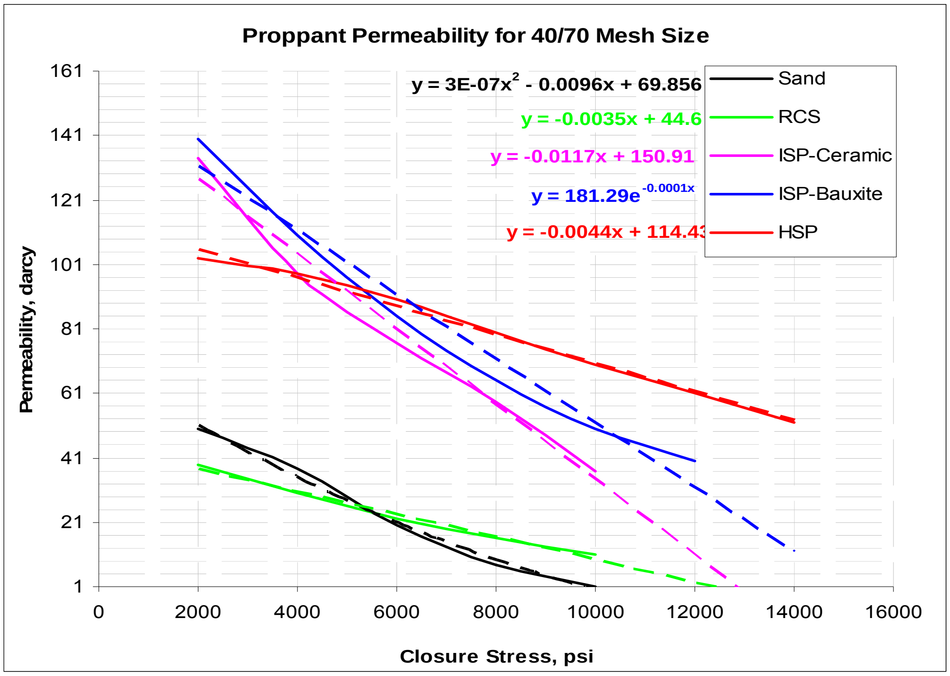


Fig. 4.14—Permeability vs. closure for 40/70 mesh size.

Satisfy the Other Requirements

From the petroleum literature and best practices, Bogatchev (2007) concluded that if formation temperature is greater than 275°F, or formation closure stress is greater 8,000 psi, or well depth is greater 10,000 ft, or a formation produces sand (an unconsolidated formation), then proppant API mesh size should be 20/40 or smaller. Moreover, the maximum proppant diameter should be at least 6 times less than the perforation diameter and 3 times the dynamic fracture width (Bogatchev 2008).

Proppant Selection Logic

In summary, the steps to select proppant are as follows.

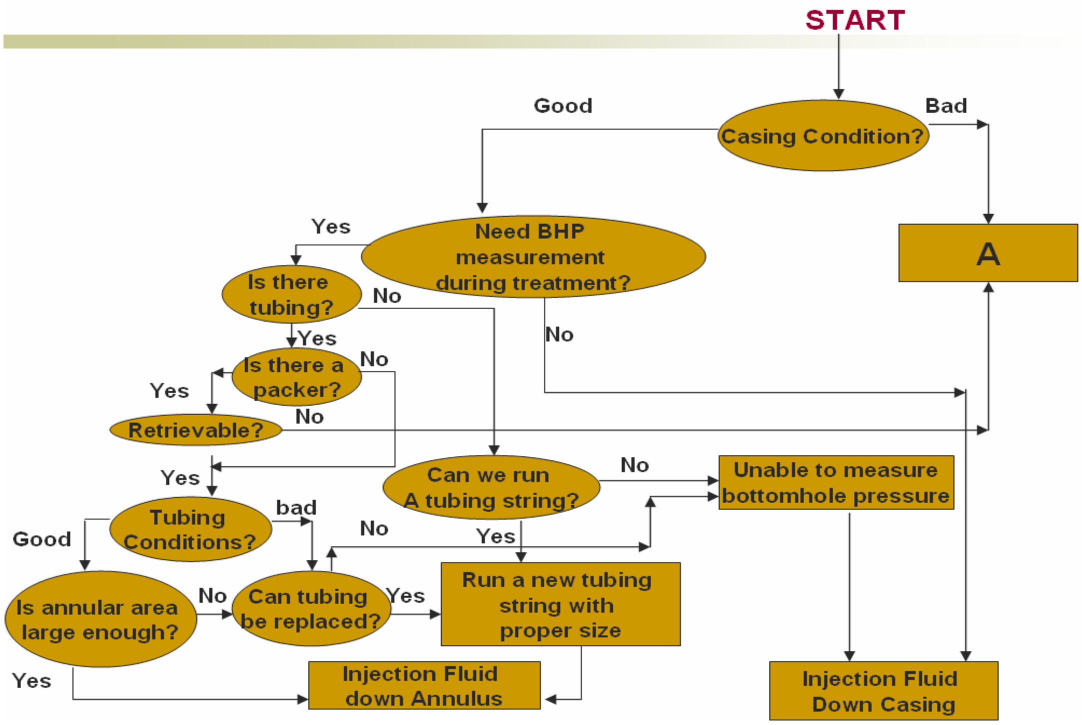
1. Depending on the closure stress of the reservoir, choose appropriate proppant type(s) by using the proppant selection guide shown as Fig. 4.4.

2. Depending on the depth of the reservoir, select the mesh sizes for all the proppant types obtained from Step 1 by using the mesh size selection rules.
3. Use Eq. 4.28 to evaluate all the proppant candidates obtained from Step 2.
4. Check whether the formation temperature is greater than 275°F, or formation closure stress is greater than 8,000 psi, well depth is greater than 10,000 ft, or the formation produces sand (an unconsolidated formation). If any one of these conditions occurs, screen out all the proppants whose mesh size is larger than 20/40.
5. List all the qualified proppants into the results table for the user to choose.

4.4.4 Injection Method

Ogueri (2007) developed a decision chart (Fig. 4.15) to select from three methods to inject fracture fluid and proppant into the reservoir: injecting the treatment fluid down casing, injecting the treatment fluid down tubing, or injecting the treatment fluid down the annulus.

Performing the fracture treatment down casing involves flushing the treatment with a clean, solids-free fluid, and then running in with the packer and tubing before the fracture fluids are produced back. This injection method is quite beneficial because a viscous fluid can be pumped at high injection rates with low surface injection pressures. The high injection rates can be useful to the success of the stimulation treatment. As seen in Fig. 4.15, during the fracture treatment, when there is no need to measure the bottomhole pressure (BHP), the fluids can be injected down the casing.



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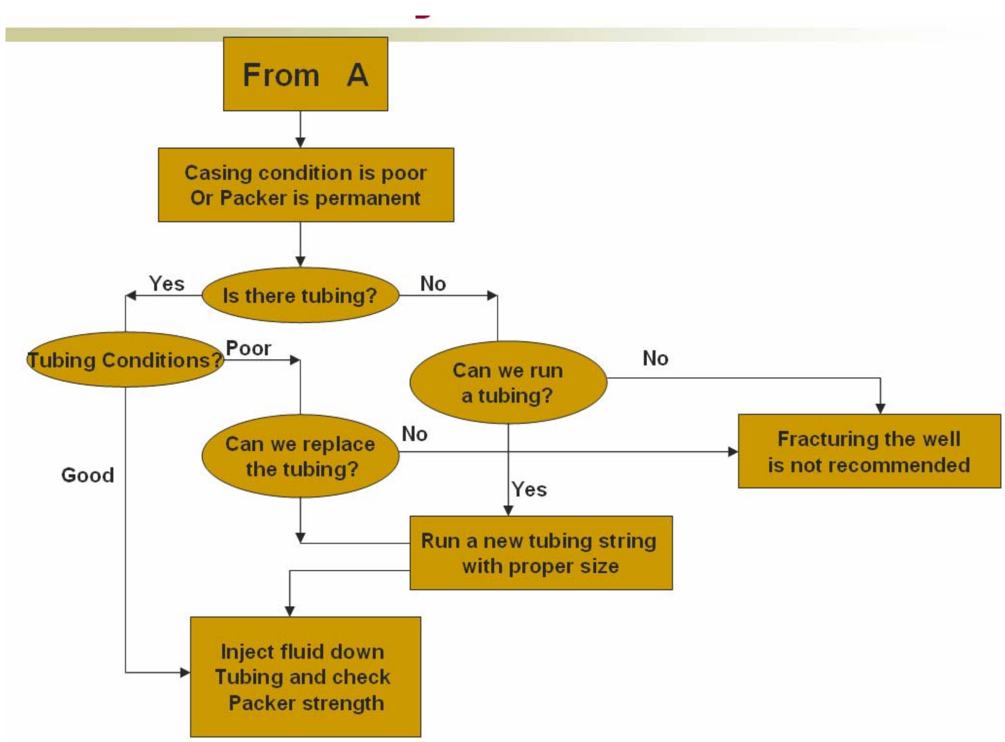


b

Fig. 4.15—Ogueri's (2007) decision chart guides users to choice of appropriate injection method.

Performing the fracture treatment down tubing involves flushing the treatment through tubing with a packer isolating the tubing from the annulus. This method is used especially when the casing condition is bad, such as when corrosion, erosion or a weak liner top have caused weak spots in the casing. Fig. 4.15b shows that when the casing condition is bad, injection down tubing should be the major option. Fig. 4.15b also shows that when the casing condition is bad and the tubing string cannot be replaced or run, fracturing the well is not recommended. Injecting down tubing is also useful in highly overpressured or extremely underpressured formations. Well control can be maintained at all times. This is because the well is produced back after the stimulation treatment and a brief shut-in time, thus minimizing the amount of time the fracture fluid stays in the formation.

Performing the fracture treatment down the annulus involves having a tubing string in the well without a packer to pack off the annulus. This method provides a direct measurement of the fracturing bottomhole pressures (BHPs) that can be used to determine whether fracture containment is being maintained or to foresee possible screenouts before they actually occur. Injecting the treatment down the annulus has numerous advantages over fracturing the well whether down casing or down tubing with a packer in the well.

4.4.5 Pumping Schedule

Xiong (1993) has recommended rules for planning the pumping schedule according to the value of reservoir permeability and fracture fluid viscosity. The basic idea of these rules is that for low permeability, we need more slurry fluid stages, while for high-viscosity fracture fluid, we need high proppant concentration. The rules used to recommend pumping schedule are shown in Tables 4.5, 4.6, and 4.7. First, the total injection stages can be determined by using the value of formation permeability from Table 4.5. With known total stages, the proppant concentration can be determined according to the value of fracture fluid viscosity (fracture fluid with a viscosity higher than 200 cp under reservoir conditions is regarded as high viscosity). Also, the fluid volume distribution can be determined from Table 4.7 with known total stages. If the total fluid volume is given, proppant mass and pad fluid volume can be calculated from the recommended pumping schedule.

Table 4.5—Relationship Between Formation Permeability and Treatment Stages (Xiong 1993)

Formation Permeability	Total Slurry Fluid Stages	Prepad and Afterflush Stages	Pad Stages	Percentage of Pad Volume	Total Stages
>5	3	2	1	50	6
0.1 - 5	4	2	1	45	7
0.001 - 0.1	5	2	1	35	8
<0.001	6	2	1	25	9

Table 4.6—Recommended Proppant Concentration (lbm/gal) in the Slurry Fluid Stages (Xiong 1993)

Slurry Fluid Stages	**3**		**4**		**5**		**6**	
Stage	High viscosity	Low Viscosity	High viscosity	Low Viscosity	High viscosity	Low Viscosity	High viscosity	Low Viscosity
1 (Prepad)	NA	NA	NA	NA	NA	NA	NA	NA
2 (Pad)	*	*	*	*	*	*	*	*
3	6	2	4	1.5	2	0.5	2	0.5
4	8	3	6	2	4	1	4	1
5	10	4	8	2.5	6	1.5	6	1.5
6			10	3	8	2	8	2
7					10	2.5	10	2.5
8							12	3
9 (Afterflush)	NA	NA	NA	NA	NA	NA	NA	NA

Table 4.7—Fluid Volume Distribution (%)

Slurry stages	3	4	5	6
1 (Prepad)	NA	NA	NA	NA
2 (Pad)	50	45	35	25
3	8.33	6.1	4.6	4.2
4	25	12.2	9.3	8.3
5	16.7	24.4	18.6	16.7
6		12.2	23.2	20.8
7			9.3	16.7
8				8.3
9 Afterflush	NA	NA	NA	NA

4.4.6 An Analytical Model to Calculate Fracture Half-Length

The goal of hydraulic fracturing design is to design the optimal fracture length to maximize the profit from the well. As the propped length of a fracture increases, the cumulative gas production will increase, which will lead to an increase in revenue. With the increasing fracture half-length, the incremental benefit decreases in terms of the incremental gas production, ΔG_p, per foot of incremental propped fracture length, ΔL_p. The relationship $\Delta G_p/\Delta L_p$ is a monotonically decreasing function. As the volume of fracture treatment increases, fracture half-length also increases. As the fracture length increases, the incremental cost of each foot of fracture also increases. Because the fracture width is also increasing, the ratio of incremental fracturing fluid, ΔV_{ft}, to increasing fracture length, ΔL_c is an increasing function. In other words, to create additional created fracture length, ΔL_c, larger volumes of fracture fluid, ΔV_{ft}, are required. When the incremental cost of the treatment is compared to the incremental benefit of increasing the treatment volume, an optimal propped fracture length can be found.

To obtain the optimal fracture length, we need to take the following steps.

1. Using available input data, such as reservoir permeability and the viscosity of the fracturing fluid, we use the pumping schedule model (described in Section 4.3.5) to obtain the recommended pumping schedule. (We can also modify the pumping schedule if desired.)

2. If we know the pumping schedule, we also know the proppant mass and pad volume. We can use the proppant selection model (described in Section 4.4.3) to select the appropriate proppant. The proppant selection model will provide the related proppant data such as conductivity, permeability, mesh size, and specific gravity.

3. With a known pumping schedule, proppant properties, and total fluid volume (an input datum), D&C Advisor will use the PKN or GDK fracture propagation model to compute the total fluid volume versus fracture half-length (Fig. 4.16a).

4. We then compute the cumulative gas production versus fracture half-length for a specific time period, such as 5 or 10 years (Fig. 4.16b). (The time period is an input value that the user can control.)

5. From input data such as the proppant price, fracture fluid cost, and workover cost, we compute the correlation between fracture cost and fracture half-length (Fig. 4.16c).

6. Finally, we develop the correlation for revenue to investment ratio (RIR) and fracture half-length and plot them. With the plot, we find the optimal fracture half-length where the RIR reaches the maximum (Fig. 4.16d).

We have discussed the input necessary to complete Steps 1 and 2, but we need additional models to fulfill Steps 3 to 5 and obtain the optimal fracture half-length.

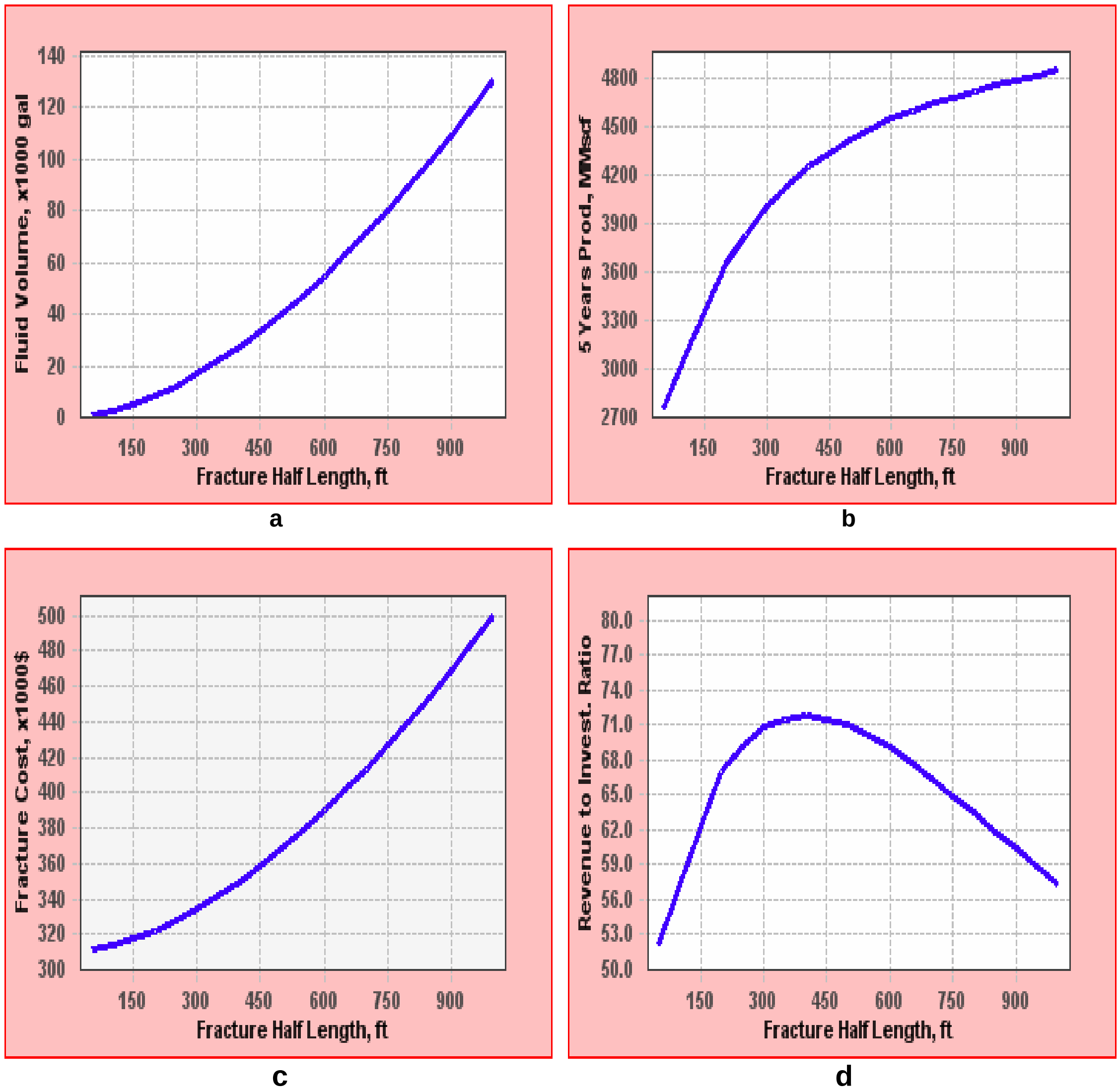


Fig. 4.16—Plotting fracture half-length against total fluid production, cumulative gas, cost, and RIR identifies optimal half-length.

Correlation of Total Fluid Volume and Fracture Half-Length

With the recommended pumping schedule and the input data for the total fracturing fluid volume, we can calculate the mass of proppant, pad volume, and other items required to optimize the treatment. Then by using the PKN or GDK fracture propagation model, we can build the correlation for fracturing fluid and fracture half-length.

An Analytical Model for Production Estimation

Rahman et al. (2002) developed an analytical model to estimate gas production from hydraulically fractured tight gas reservoirs. One of the advantages of this model is that it does not require numerical simulation, so it can be coupled with other programs and repeated many times, as required by the TG Advisor system and the optimization process. Furthermore, this model takes into account both the transient flow period that is important for TG reservoirs and the pseudosteady flow period.

For a TG reservoir, Rahman et al. (2002) suggested Eq. 4.32 to estimate the start time of the pseudosteady-state regime.

$$t_{pss} = \frac{\phi \mu C_t A t_{DA}}{0.000264\, k} \quad , \qquad (4.32)$$

where t_{pss} is the time at which pseudosteady-state begins and C_t is the system compressibility at initial reservoir conditions. t_{DA} is the nondimensional pseudosteady-state time. For a regular shape such as a circle or square with a well in the center, it is about 0.1.

For the period before the start of pseudosteady-state flow ($t < t_{pss}$), the transient model should be applied to calculate gas production.

$$r_w^{'} = r_w e^{-s_f} \qquad (4.33)$$

$$s_f = F - \ln \frac{x_f}{r_w} \qquad (4.34)$$

$$F = \frac{1.65 - 0.328\mu + 0.116\mu^2}{1 + 0.18\mu + 0.064\mu^2 + 0.005\mu^3} \quad \text{......} \quad (4.35)$$

$$\mu = \ln C_{fD} \quad \text{......} \quad (4.36)$$

$$C_{fD} = \frac{w\ k_f}{k\ x_f} \quad \text{......} \quad (4.37)$$

$$D = \frac{6 \times 10^{-5} \gamma\ k^{-0.1} h}{\mu_{g,wf}\ r_w h_{\text{perf}}^2} \quad \text{......} \quad (4.38)$$

$$q_g = \frac{kh(p_{\text{ave}}^2 - p_{wf}^2)}{1637\bar{\mu}_g \bar{Z}_g T}[\log t + \log \frac{k}{\phi\bar{\mu}_g \bar{C}_t (r'_w)^2} - 3.23 + 0.869(s + Dq_g)] \quad \text{......} \quad (4.39)$$

where r'_w is the effective wellbore radius to account for the effect of fracture. The s_f is the pseudoskin to account for the bilinear flow in a finite-conductivity fracture. The $\mu_{g,wf}$ is the gas viscosity, evaluated at bottomhole flowing pressure. The μ_g and Z_g are gas viscosity and gas compressibility factor, both evaluated at the average of reservoir average pressure p_{ave} and wellbore flowing pressure p_{wf}.

For the period after the start of pseudosteady-state ($t > t_{pss}$), the pseudosteady-state production model should be used to calculate gas production.

$$q_g = \frac{kh(p_{\text{avg}}^2 - p_{wf}^2)}{1424\bar{\mu}_g \bar{Z}_g T} \times \frac{1}{\ln\left(\frac{0.472 r_e}{x_f}\right) + \left[s_f + \ln\left(\frac{x_f}{r_w}\right)\right]}, \quad \text{......} \quad (4.40)$$

where the r_e is the reservoir drainage radius.

To use Eq. 4.39 or 4.40, we need to know the value of *Z*-factor under the average reservoir pressure. We can use the Dranchuk Abu-Kassem *Z*-factor correlation to calculate *Z*-factor (Towler 2002). The method is an iteration procedure. First, a possible *Z*-value is assumed. With the assumed *Z*-factor, a new *Z*-factor is calculated by using equations from Eq. 4.41 to Eq. 4.47. Check whether the assumed Z-factor and the calculated Z-factor are close enough. If they are close enough, end the procedure. If not, continue the procedure until the values are close.

$$T_{pc} = 169.2 + 349.5\gamma - 74\gamma^2 \quad \text{(4.41)}$$

$$T_{pr} = \frac{(T + 459.67)}{T_{pc}} \quad \text{(4.42)}$$

$$p_{pc} = 756.8 - 131.07\gamma - 3.6\gamma^2 \quad \text{(4.43)}$$

$$p_{pr} = ZP / p_{pc} \quad \text{(4.44)}$$

$$p_{pr} = \frac{p_{\text{ave}}}{p_{pc}} \quad \text{(4.45)}$$

$$\rho_r = 0.27\frac{p_{pr}}{T_{pr}} \quad \text{(4.46)}$$

$$\begin{aligned} Z = {} & \left(K_1 + \frac{K_2}{T_{pr}} + \frac{K_3}{T_{pr}^3} + \frac{K_4}{T_{pr}^4} + \frac{K_5}{T_{pr}^5}\right)\rho_r \\ & + \left(A_6 + \frac{K_7}{T_{pr}} + \frac{K_8}{T_{pr}^2}\right)\rho_r^2 \text{-} K_9\left(\frac{K_7}{T_{pr}} + \frac{K_8}{T_{pr}^2}\right)\rho_r^5 \quad \text{(4.47)} \\ & + K_{10}\left(1 + K_{11}\rho_r^2\right)\frac{\rho_r^2}{T_{pr}^3}\operatorname{Exp}\left(\text{-}K_{11}\rho_r^2\right) + 1 \end{aligned}$$

where the K_1 to K_{11} are all constants (Table 4.8).

Table 4.8—Constants for Eq. 4.48

Constant	Value
K_1	0.3265
K_2	-1.07
K_3	-0.5339
K_4	0.01569
K_5	-0.01565
K_6	0.5475
K_7	-0.7361
K_8	0.1844
K_9	0.1056
K_{10}	0.6134
K_{11}	0.721

To use Eq. 4.39 or 4.40, we need to know the value of gas viscosity under average reservoir pressure, which we can calculate approximately from Eq. 4.48 (Rahman et al. 2002):

$$(\mu)_i = 4 \times 10^{-6}\left(\frac{\overline{p}_{\text{ave}} + p_{wf}}{2}\right) + 0.0107 \ . \quad \text{..} \quad (4.48)$$

The production rate under constant bottomhole flowing pressure will decline with declining reservoir pressure as a function of cumulative production. To calculate the cumulative production for the total economic life, the total production life is defined as cumulative of small time intervals. If the time interval is small enough, such as several days, we can assume the gas is produced with constant production rate during this small time interval. After each cumulative period, we evaluate the average reservoir pressure and gas properties as functions of cumulative production and use them to estimate production rate for next time interval.

In more detail, we can define the small time interval as Δt and index successive time steps as i = 1, 2, 3, 4, … , n until the end of the economical life. At $i = 1$, all parameters are in initial reservoir conditions and Eq. 4.39 can be used to calculate the production rate for Δt. Then the cumulative production during this period can be calculated by Eq. 4.49 (Lee and Wattenbarger 1996). After the first Δt, the reservoir pressure, which will drop as a function of cumulative production, can be calculated by using Eqs. 4.49 to Eq. 4.51 (Arevalo-Villagran et al. 2001). With the calculated reservoir average pressure, we can calculate the Z-factor and viscosity, which will be used to calculate production rate for the next period.

$$G_i = \frac{7758 A h \phi (1 - S_{wi}) p_i}{5.02 Z_i T} \quad \text{.......} \quad (4.49)$$

$$(G_p)_i = (G_p)_{i-1} + (q_g)_i \times \Delta \mathrm{t} \quad \text{.......} \quad (4.50)$$

$$\frac{\overline{p}}{\overline{\overline{Z}}} = \left(\frac{p_i}{Z_i}\right)\left(1 - \frac{G_p}{G_i}\right) \quad \text{.......} \quad (4.51)$$

In summary, the steps to calculate cumulative production for a specific fracture half-length are as follows.

1. Define the small interval as Δt and index successive time steps as i = 1, 2, 3, 4, … , n until the end of economic life. For the i-th time period, use Eq. 4.33 to determine the flow regime. Then by using the gas properties of z and μ which are obtained from $(i$-1)-th time period, calculate the production rate with Eq. 4.40 or 4.41 according to flow regime.
2. By using Eq. 4.50, calculate cumulative production for i-th period. Obtain the average pressure from Eq. 4.52.
3. With known average pressure, calculate viscosity by using Eq. 4.49 and the Z-factor by using Eq. 4.42 to Eq. 4.48.

4. Go to (i+1)-th period until the end of the economic life.

By using this method, we can build the correlation of cumulative gas production and fracture half-length for a specific economic life. (See Fig. 4.16).

Method to Calculate Fracture Cost

The cost of a fracture treatment comprises the costs of fluid, proppant, workovers, pumping, and fixed expenses. The fluid and proppant costs correlate with fracture half-length. The fixed expenses are mostly charges for equipment. The other items are independent of fracture half-length.

With increasing facture half-length, the amount of proppant and fracture fluid required will increase. Therefore, the cost to generate the increasing fracture half-length will also increase. For a specific fracture half-length, we can calculate the proppant mass and fracture fluid volume with either the PKN or GDK fracture model along with a known pumping schedule. Then with known proppant prices and fracture fluid price, we can calculate the proppant and fracture fluid costs. Because all the other costs are independent of fracture half-length and they are known values, we can compute the correlation between the total cost and fracture half-length by simply summing all the costs (Fig. 4.16).

Find the Optimal Fracture Half-Length

Having computed the correlation between the cumulative gas production and fracture half-length, we can multiply the gas price to compute the correlation between revenue and fracture half-length and the correlation between fracturing cost and fracture half-length. Thus, for a specific fracture half-length, we can easily calculate the revenue to investment (fracturing cost) ratio (Fig. 4.16). We assume that the fracture half-length with the highest RIR is the optimal fracture half-length. UGR Advisor uses the PKN, GDK, UFD, or Holditch (rule-of-thumb) fracture propagation models to generate the optimal fracture half-length.

4.5 Fracture Propagation Models: PKN, GDK, UFD, and Holditch

To produce gas economically from UGRs, each well has to be stimulated, usually by hydraulic fracturing. Therefore, hydraulic fracturing is the most important topic for our UGR Advisor, although our purpose is not to provide detailed designs for fracture treatments but advice on how the wells should be completed and fracture treated. We want to provide the user with advice on the optimal fracture length for a given reservoir. Therefore, simple models that predict fracture half-length and average width at the end of pumping are very useful for our UGR Advisor. We applied the PKN, GDK, and UFD fracture propagation models and Holditch's rule of thumb to calculate the estimated optimal fracture half-length in the stimulation module of UGR Advisor.

4.5.1 PKN Model

Perkins and Kern (1961) published equations to compute fracture length and width for a fixed height. Later Nordgren (1972) improved their model by adding fluid loss to the solution. Thus, one type of model we programmed is called the Perkins-Kern-Nordgren (PKN) model. The PKN model makes the assumption that the fracture has a constant height and an elliptical cross section (Fig. 4.18). It also assumes that the fluid flow and fracture propagation is one dimensional (1D) in a direction orthogonal to the elliptic cross sections. This model is appropriate for modeling a fracture that is constrained to propagate between two stiff layers.

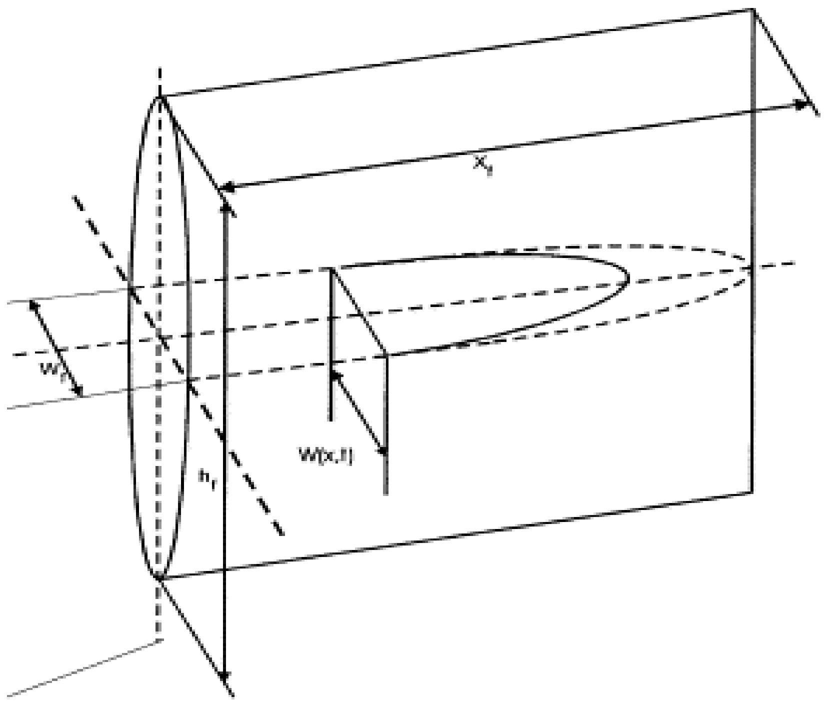


Fig. 4.17—PKN fracture model assumes constant fracture height, elliptical cross section, and 1D propagation and fluid flow.

The PKN fracture is assumed to be of a fixed height, h_f, independent of the distance to which it has propagated away from the well. Thus the problem is reduced to two dimensions (2D) using the plane strain assumption. For the PKN model, plane strain is considered in the vertical direction, and the rock response in each vertical section along the *x*-direction is assumed independent of its neighboring vertical planes. Plane strain implies that the rock strains to open or close along elastic deformations, where the rock may shear along a fracture. The strain is fully concentrated in the vertical cross sections perpendicular to the direction of fracture propagation; outside of these planes, the strains are zero.

The fluid flow problem is considered in 1D, in the *x*-direction in an elliptical channel. The fluid pressure, *p*, is assumed constant in each vertical cross section perpendicular to the direction of propagation. Thus, the maximum width in the elliptical fracture is given by Eq. 4.52 (from Perkins and Kern 1961).

$$W_{(X,t)} = \frac{(1-\nu)h_f(p-\sigma_h)}{G} \quad \text{.......} \quad (4.52)$$

where ν is the Poisson's ratio, σ_h the in-situ normal rock stress perpendicular to the fracture face, and *G* the shear modulus of the rock formation.

The term *X* is the coordinate along the direction of fracture propagation. These cross sections are in fact interconnected without any stiffness. In the direction of fracture propagation, only frictional flow resistance is taken into account. The pressure drop in the *X* direction is determined by the flow resistance in a narrow, elliptical flow channel.

$$\frac{\partial \Delta p}{\partial x} = \frac{-64}{\pi}\frac{q\mu}{w^3 H} \quad \text{.......} \quad (4.53)$$

For the PKN model, the fluid pressure at the propagating edge falls off towards the tip or leading edge. Thus for $x = L$, $p_f = \sigma_h$. This is based on the assumption that the fracture resistance or toughness at the tip is zero. Note that for a crack created and opened by a uniform internal pressure, the tip of the crack experiences infinite high tensile stresses. However, in this model, the stress-concentration problem at the tip is ignored.

Nordgren (1972) wrote the continuity equation:

$$\frac{\partial q}{\partial x} = -\frac{\pi h_f}{4}\frac{\partial w}{\partial t} \quad \text{.......} \quad (4.54)$$

By using Eq. 4.52 to Eq. 4.54, we obtain a nonlinear partial-differential equation, Eq. 4.55, in terms of *w(X,t):*

$$\frac{G}{64(1-\nu)h_f\mu}\frac{\partial^2 w^2}{\partial X^2}-\frac{\partial w}{\partial t}=0 \quad \text{...} \quad (4.55)$$

Eq. 4.55 is subject to the following initial conditions:

$w(X, 0) = 0$

$w(X, t) = 0$ for $X \geq L(t)$

$q(0, t) = q_0$ for a one-sided fracture

or

$q(0, t) = 0.5q_0$ for a two-sided fracture.

Finally, the shape of the fracture takes the form shown in Eq. 4.56.

$$w(X,t)=w(X,0)\left(1-\frac{X}{L}\right)^{0.25} \quad \text{...} \quad (4.56)$$

And the fracture volume is given by Eq. 4.57.

$$V=\frac{\pi}{5}Lh_f w(0,t)\left(1-\frac{X}{L}\right)=q_0 t \quad \text{...} \quad (4.57)$$

4.5.2 GDK Model

The GDK model was developed by Zheltov and Khristianovic (1955) and Geertsma and de Klerk (1969). In this model, the fracture deformation and propagation are assumed to evolve in a situation of plane strain. The model also assumes that the fluid flow and the fracture propagation are 1D.

In a propagating fracture, the fracturing fluid does not pressurize the fracture to the very end (Fig. 4.18).

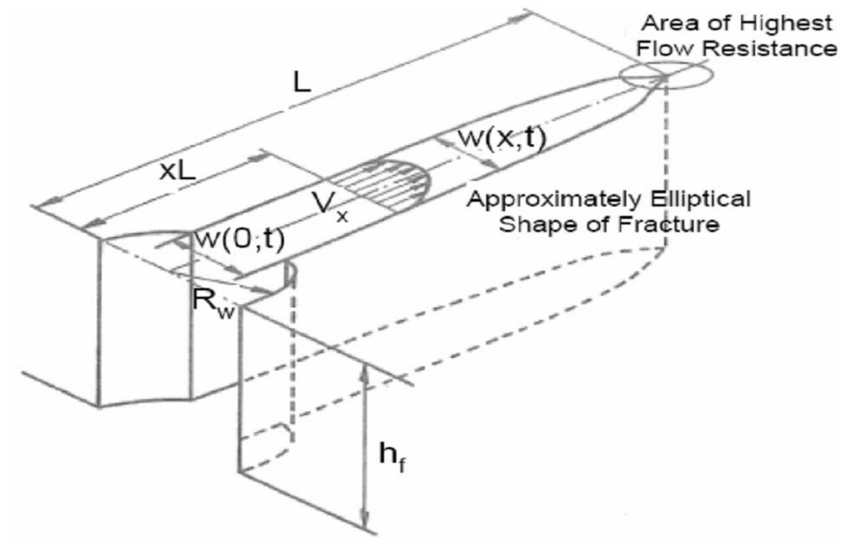


Fig. 4.18—PKN fracture geometry assumes fracturing fluid does not pressurize to end of fracture (Geertsma and de Klerk 1969).

The GDK model makes six assumptions: the fracture has an elliptical cross section in the horizontal plane; each horizontal plane deforms independently; the fracture height, h_f, is constant; the fluid pressure in the propagation direction is determined by the flow resistance in a narrow rectangular, vertical slit of variable width; the fluid does not act on the entire fracture length; and the cross section in the vertical plane is rectangular (fracture width is constant along its height) (Geertsma 1969).

The fluid pressure gradient in the propagation direction is determined by Eq. 4.58.

$$p(0,t) - p(x,t) = p_f - p = \frac{12\mu q_0}{h_f} \int_0^x \frac{1}{w^3(x,t)} dx \quad \text{......................... (4.58)}$$

The equilibrium condition directed by applied mechanics is given by Eq. 4.59.

$$\int_0^L \frac{p(X,t)}{\sqrt{L^2 - x^2}} dx = \frac{\pi}{2}\sigma_h + \frac{K}{\sqrt{2L}} \quad \text{......} \quad (4.59)$$

where σ_h is the in-situ rock stress, perpendicular to the fracture face. K is the cohesion modulus.

Zheltov and Khristianovitch (1955) simplified Eq. 4.59 to Eqs. 4.60 and 4.61, which can be used to calculate the pressure distribution approximately.

$$p_f = p_0 \quad \text{......} \quad (4.60)$$

for $0 < \lambda < L_0/L$, and

$$p_f = 0 \quad \text{......} \quad (4.61)$$

for $L_0/L < \lambda < 1$, where p is the fluid pressure. The $\lambda = X/L$ is the dimensionless fracture coordinate.

Then the condition of "wetted" fracture length can be calculated from Eq. 4.62. This provides a good point to start the calculation, and this approximation is good enough to prevent further refinements.

$$\lambda_0 = \frac{L_0}{L} = \sin\frac{\pi}{2}\left(\frac{\sigma_h}{p_f}\frac{K_c}{p_f\sqrt{L}}\right) \quad \text{......} \quad (4.62)$$

The shape of the fracture in the horizontal plane is elliptical, with maximum width at the wellbore that can be calculated using Eq. 4.63.

$$w(0,t) = \frac{2(1-\nu)L(p_f - \sigma_h)}{G} \quad \text{......} \quad (4.63)$$

A good approximation to determine the fluid flow resistance in the fracture is Eq. 4.64.

$$\int_0^{\lambda_0} \frac{w^3(0,t)}{w^3(X,t)} d\lambda \approx \frac{7}{4}\left(1-\lambda_0^2\right)^{-\frac{1}{2}} \quad \text{......} \quad (4.64)$$

The fracture volume of one-sided fracture amounts can be calculated approximately by Eq. 4.65.

$$V = h_f L w(0,t)\int_0^1 \left(1-\lambda^2\right)^{\frac{1}{2}} d\lambda = \frac{\pi}{4} h_f L w(0,t) = q_0 t \quad \text{......................................} \quad (4.65)$$

After substituting Eq. 4.64 into Eq. 4.58 and linking with Eq. 4.65, we can finally obtain Eqs. 4.66 and 4.67.

$$L(t) = 0.68\left[\frac{G q_0^3}{\mu(1+\nu)h_f^3}\right]^{\frac{1}{6}} t^{\frac{1}{3}} \quad \text{..} \quad (4.66)$$

$$w(0,t) = 1.87\left[\frac{(1+\nu)\mu q_0^3}{G h_f^3}\right] t^{\frac{1}{3}} \quad \text{...} \quad (4.67)$$

4.5.3 UFD Model to Calculate Fracture Half-Length

Economides et al. (2002) developed a physical optimization technique to maximize the productivity index of a hydraulically fractured well in fracture design for a given volume of fluid and proppant mass. This procedure is called unified fracture design (UFD). With the UFD technique, the maximized productivity index can be computed for a given volume of proppant.

One of the advantages of UFD is that the improvement of well performance because of the hydraulic fracture can be estimated immediately during the design stage. Different designs can also be compared readily. For example, we can change the mass of proppant and the proppant type over a large range to determine the optimal proppant mass.

Principles of Unified Fracture Design

In UFD, a very simple and straightforward quantity, the dimensionless pseudosteady-state productivity index, J_D, can be calculated from the treatment size and proppant and reservoir data. With J_D, the improvement in well performance because of fracturing can be evaluated readily. The maximum possible productivity index means that the well outperforms all other possibilities with the same propped volume (Economides 2002). In design, the goal is to maximize the dimensionless productivity index by determining and executing the indicated hydraulic fracture dimensions within allowable constraints.

"The performance of a fractured well is primarily determined by the treatment size and the proppant selection" (Economides 2002). In UFD, the design begins from the treatment size, which is given or can be decided by the design engineer. "Then fracture dimensions (half-length and width) can be selected optimally which means that the resulting optimal fracture conductivity would lead to the maximum pseudosteady-state productivity index" (Economides 2002). In some cases, the optimal dimension has to be modified because of physical constraints or the net pressure limitation. The pumping time and proppant schedule are then determined from the optimal (or modified) dimensions.

Theoretical Basis of Unified Fracture Design

In a fully penetrating vertical fracture in a pay layer of thickness h, the relation between drainage area, A, drainage radius, r_e, and drainage side length, x_e is given by:

$$A = \pi r_e^{2} = x_e^{2} \quad (4.68)$$

The dimensionless fracture conductivity is defined (Economides 2002) as:

$$C_{fD} = \frac{k_f w}{k x_f} \quad (4.69)$$

where x_f is the fracture half-length, x_e is the side length of the square drainage area, k is the formation permeability, k_f is the proppant-pack permeability and w is the average fracture width.

The penetration ratio is defined as:

$$I_x = \frac{2x_f}{x_e} \quad (4.70)$$

Economides et al. (2003) introduced the concept of the dimensionless proppant number, N_{prop}, which is given by:

$$N_{\mathrm{prop}} = I_x^2 C_{fD} = \frac{4k_f x_f w}{k x_e^2} = \frac{4k_f x_f w h_p}{k x_e^2 h_p} = \frac{2k_f V_p}{k V_r} \quad (4.71)$$

where V_r is the reservoir drainage volume and V_p is the volume of the proppant in the pay. The proppant number refers to the weighted ratio of propped fracture volume to reservoir volume. The weighting factor is

$$W_{pn} = 2\frac{V_{pf}}{V_r} \quad (4.72)$$

Thu, the dimensionless productivity index, J_D, is a function of dimensionless fracture conductivity with the proppant number as a parameter.

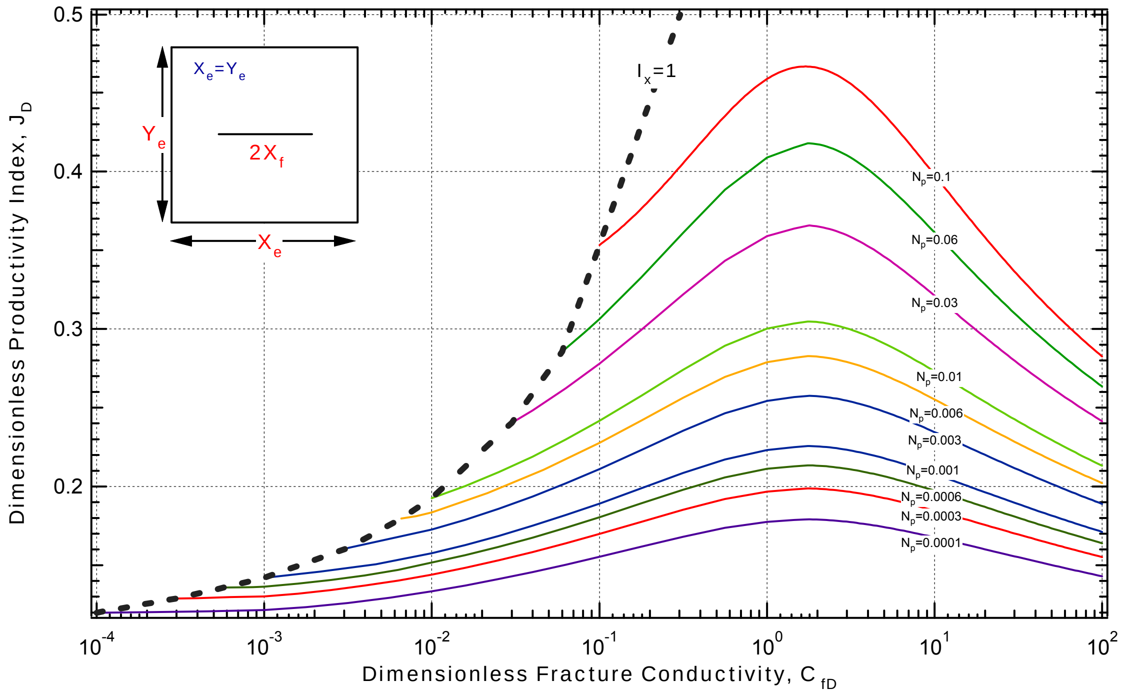


Fig. 4.19—Dimensionless productivity index as a function of dimensionless fracture conductivity and proppant number for *N*prop < 0.1 (Economides 2002).

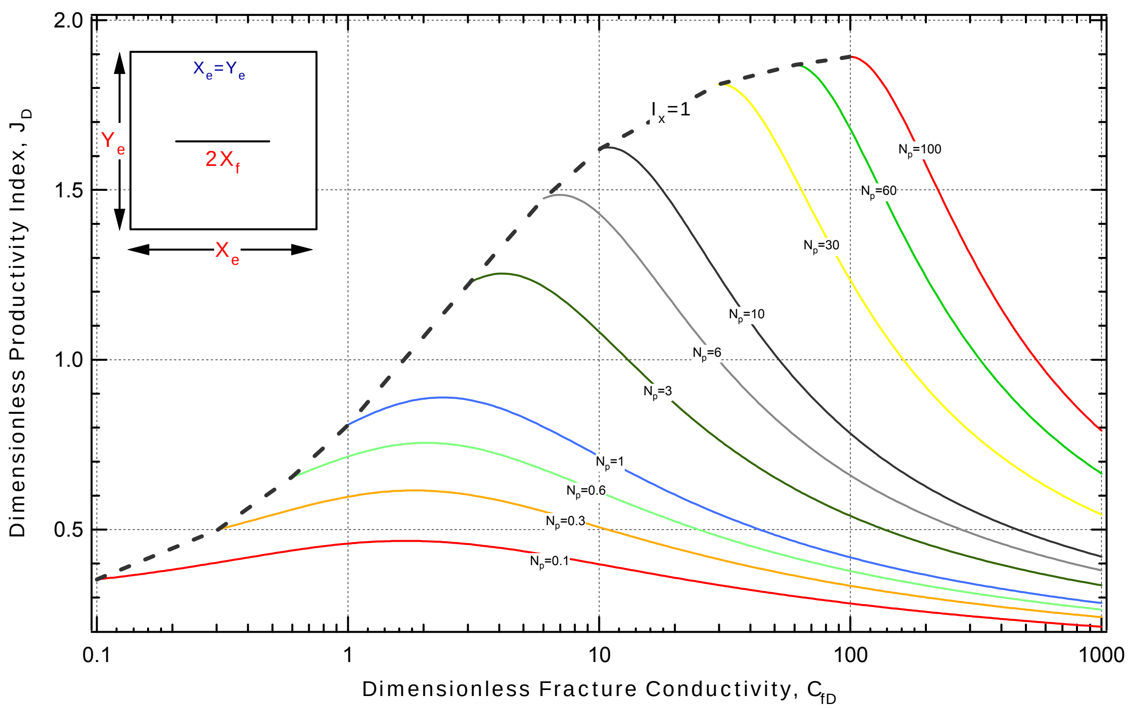


Fig. 4.20—Dimensionless productivity index as a function of dimensionless fracture conductivity and proppant number for N_{prop} > 0.1 (Economides 2002).

As shown in Figs. 4.19 and 4.20 (Economides 2002), at a given value of N_{prop}, there is an optimal dimensionless fracture conductivity at which the productivity index reaches the maximum. In other words, "for a fixed proppant number which represents a fixed amount of proppant, the best compromise between length and width is achieved at the dimensionless fracture conductivity located under the peaks of the individual curves" (Economides 2002). Of course, we want to make the dimensionless productivity index reach the maximum value because of the hydraulic fracture. Thus, our fracture design objective is the optimal dimensionless conductivity identified by the weighted ratio of fracture width and half-length.

From Fig. 4.19, the most important conclusion is that at low proppant numbers (N_{prop} ≤0.1), the optimal conductivity, $C_{fD,opt}$ = 1.6. In UFD, this conclusion is used widely because for most applications, $N_{prop} \leq 0.1$.

As Fig. 4.20 shows, when the propped volume increases or the reservoir permeability is low (in other words, N_{prop} > 0.1), the optimal dimensionless fracture conductivity shifts to a larger value. Another important conclusion from Fig. 4.19 is that the maximum achievable J_D is about 1.9.

Optimal Fracture Dimensions

The pseudosteady-state productivity index is defined by Eq.4-57.

$$J = \frac{kh}{\alpha B \mu} J_D \quad \text{.......} \quad (4.73)$$

The dimensionless productivity, J_D, can be expressed in terms of the formulation given by Cinco-Ley (Economides 2002).

$$J_D = \frac{1}{\ln 0.47F \frac{r_e}{x_f} + F} \quad \text{(4.74)}$$

where F is the function of dimensionless fracture conductivity.

From the definition of dimensionless fracture conductivity, the fracture half-length can be expressed (Economides 2002) as

$$x_f = \left(\frac{k_f V_{pf}}{C_{fD} kh} \right)^{0.5} \quad \text{(4.75)}$$

Substituting Eq. 4.75 into Eq.4.76, the dimensionless productivity index can be expressed (Economides 2002) as

$$J_D = \frac{1}{\ln 0.472 r_e + 0.5 \ln \frac{kh}{V_{pf} k_f} + \left(0.5 \ln C_{fD} + F \right)} \quad \text{(4.76)}$$

From Eq. 4.76, the drainage radius, formation thickness, two permeabilities and propped volume are all constants for a specified reservoir and the given proppant type. Therefore, if the quantity $0.5\ln C_{fD}+ F$ reaches the minimum, J_D reaches the maximum. This appears on the Cinco-Ley et al. (Economides 2002) graph at the optimal value of the dimensionless fracture conductivity, $C_{fD,\text{opt}}$=1.6.

We can understand this conclusion by considering the reservoir and fracture as one system. Because the proppant number is given, a longer length requires a narrower width and vice versa. When the fracture length is larger, which means width is narrower, the flow is restricted by the narrower width. When the fracture width is larger, which means length is shorter, the reservoir cannot feed enough fluid to the fracture and thus the flow is restricted by the short length. "The optimal dimensionless conductivity means the best compromise between the length and the width" (Economides 2002).

Using the more appropriate geometry of a square drainage (and the results shown in Figs. 4.19 and 4.20) for a given proppant number, the optimal fracture dimensions can be obtained from Eq. 4.77:

$$x_{f,\mathrm{opt}} = \left(\frac{k_f V_f}{C_{fD,\mathrm{opt}} kh} \right)^{0.5} \quad \text{and} \quad w_{\mathrm{opt}} = \left(\frac{C_{fD,\mathrm{opt}} k V_f}{k_f h} \right)^{0.5} \qquad \text{..................} \quad (4.77)$$

where $C_{fD,\mathrm{opt}}$ is the optimal dimensionless fracture conductivity.

Design Logic

In UFD, a specified amount of proppant is indicated to be injected and then the design can progress as follows.

1. Assume a volumetric proppant efficiency ($V_f h/h_f$) and calculate the proppant number using Eq. 4.71.
2. From the proppant number, obtain the maximum possible productivity index and calculate the optimal dimensionless fracture conductivity.
3. Then using Eq. 4.77, determine the optimal fracture dimension.

Once the fracture dimension is defined, the next issue is to achieve it, which requires us to design and adjust treatment details such as pumping time and proppant schedules.

In the design of gas well fracturing, the k_f should be reduced by a factor to represent the turbulence effect. This will affect both the proppant number and dimensionless fracture conductivity. To solve this problem, UFD uses an iterative procedure.

Departure from Theoretical Optimal

In UFD, technical limitations may prohibit realization of the theoretical optimization dimensions. In case of conflict, the design has to be modified from theoretical optimal dimensions, but in a reasonable manner and only as much as necessary. We should remember that the more we depart from the theoretical optimal, the lower the dimensionless pseudosteady-state productivity index is.

For example, in low-permeability formations, the theoretical optimal dimension may require a long length and narrow width fracture. In application, the fracture width must be at least three times the maximum proppant diameter to prevent bridging. Therefore, the length should be multiplied by a factor less than 1 to satisfy the minimum required width.

However, in high-permeability formations, the theory may result in a very short length with large width that may be too large to be created. In practice, the fracturing net pressure, which is proportional to the hydraulic width, should be less than 1,000 psi because of technical limitations by both the formation rock and the treatment equipment. Such constraint in the net pressure restricts the inflation of fracture width to the theoretically indicated size. Therefore, the length should be multiplied by a factor larger than 1 to satisfy the constraint of net pressure.

How to Calculate the Treatment Size

In UFD, the proppant mass/treatment size is an input datum. To use this model, we need find a way to calculate the treatment size. Fortunately, Rebbins et al. (1991) found that the job size is optimal at the point where the incremental benefit of the last unit of proppant placed is equal to the cost of placing that unit. By setting the marginal benefit equal to the marginal cost, the optimal size can be calculated by using Eq. 4.78.

$$M_{\mathrm{prop}} = \frac{G_r\, P\, R_r}{25\, H_f\, C_{\mathrm{ave}}\, (kh)^{0.1}} \quad \text{..........} \quad (4.78)$$

where the C_{ave} is the average cost to place the proppant into the formation. G_r is the recoverable gas reserve. The H_f is the gross fracture height and the h is the net pay thickness. The P is the gas price and R_r is the rate of return. They suggested that that job size should not be larger than 2,500 lb/ft since these jobs would be beyond the range of historical correlations.

4.5.4 Holditch's Rule of Thumb Based Fracture Half-Length

Holditch and Bogatchev (2008) simply correlated optimal fracture half-length to drainage area and reservoir permeability (Fig. 4.21). For gas reservoirs, the optimal fracture half-length can be correlated to the permeability and well drainage area (Holditch 2008). As a rule of thumb, the ratio of optimal fracture half-length to drainage radius should be 0.7 for low-permeability reservoirs, 0.4 for medium permeability reservoirs, and 0.2 for high-permeability reservoirs. Holditch and Bogatchev (2008) defined low permeability as permeability lower than 1 md, moderate between 1 md and 100 md, and high permeability greater than 100 md.

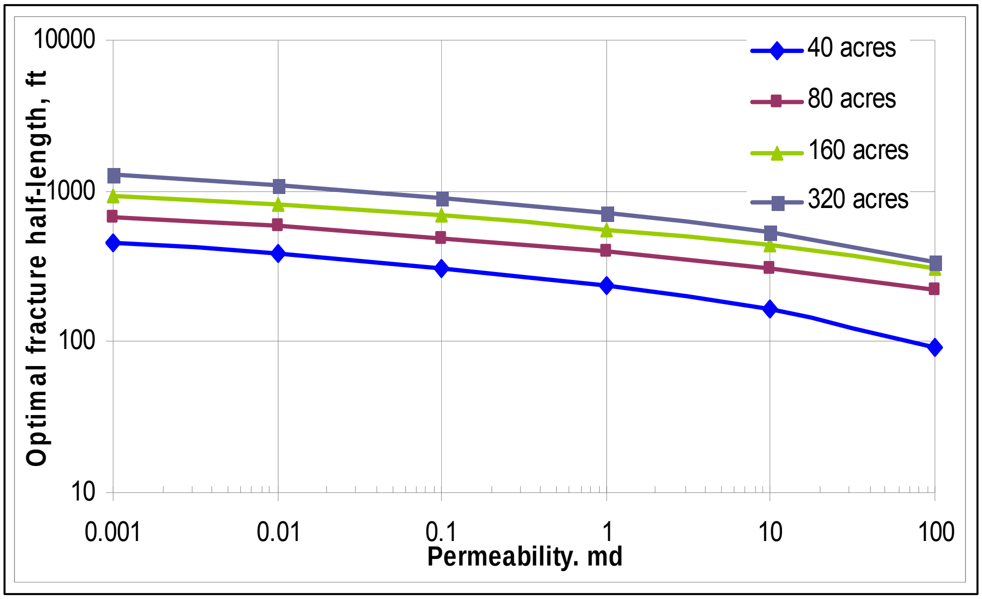


Fig. 4.21—Optimal fracture half-length increases with area and decreases as permeability increases (Holditch and Bogatchev 2007).

Using the relationships in Fig. 4.21, Holditch and Bogatchev developed Eq. 4.79 to express the correlation of optimal fracture half-length and drainage area.

$$X_f = a \cdot \mathrm{Ln}(k) + b \quad (4.79)$$

where X_f is optimal fracture half-length and a and b are the correlation coefficients:

a = -0.1818·A - 24.622

b = 231.23·ln(A) - 615.37

To determine the correctness of this equation, Holditch and Bogatchev (2008) searched the literature compared the results of Eq. 4.62 and the best practice described in some SPE papers. They found that although this method is simple, the results are acceptable. The comparison is shown in Table 4.9.

Table 4.9—Comparison of Calculated Optimal Fracture Half-Length with Best Practice from SPE Literature

SPE Paper	Basin	Formation	Well	Permeability, md	Desired fracture half-length, ft		Deviation, %
					Actual	Rec	
67299	S.Texas	Vickburg	#1	0.090	500	492	2
67299	S.Texas	Frio	#B	0.800	400	407	2
36471	W. Texas	Wolfcamp	Mitchell 6#5	0.010	600	578	4
36471	W. Texas	Wolfcamp	Mitchell 5B#6	0.010	600	578	4
36471	W.Texas	Wolfcamp	Mitchell 5B#7	0.010	600	578	4
36471	W. Texas	Wolfcamp	Mitchell 5a#8	0.010	600	578	4
36471	W. Texas	Wolfcamp	Mitchell 11#6	0.010	600	578	4
67299	S. Texas	Frio	#A	0.150	400	472	18
11600	S. Texas	Wilcox Lobo	1	0.100	750	488	35
30532	Germany	Rotliegendes	Soehlingen Z10	0.010	350	578	65
35196	Permian	Penn	McDonald 15-10	0.023	240	546	128
36735	Permian	Canyon	Couch #7	0.010	200	578	189
36735	Permian	Canyon	Henderson 32-9	0.010	200	578	189
35196	Permian	Canyon	Henderson 6-2	0.054	170	512	201

4.6 D&C Advisor Help and Explanation System

To make our computer program useful and inviting for different users, we made the user interface easy to implement. The interface guides the user through the advisory system to perform the tasks smoothly, easily, and efficiently; for example, once a dataset has been entered into the system, it is available to all parts of the system and need never been entered again. Additionally, UGR Advisor identifies the current module or task the user is working on, and it guides the user to the next task.

In our design, the help and explanation system can be accessed by clicking the help button or the F1 key. If the data are input by a table control, the help system can be accessed by double clicking the mouse. The help and explanation system can provide three kinds of help:

1. Data requirements and information on obtaining that data whenever and wherever required by user
2. Reasons and logic concerning how the advice, recommendations, and best practices are obtained for a specific problem whenever required
3. Background information on specific topics whenever required

The stimulation module of the D&C Advisor is designed to provide advice, recommendations, and best practices for the stimulation design of UGRs. It is composed of submodules such as candidate selection, fracture fluid, fluid additives, proppant selection, injection method selection, and fracture design.

For each of the input data required by UGR Advisor, I have written a help document for that data to provide help information whenever required. For every data item, the help document includes a definition, how the data item is used in the software, how to get the data, rules of thumb, equations to calculate, minimum allowable values, maximum allowable values, and system default values.

We have adopted the HelpProvider control of the Microsoft Visual Studio 2006 software to provide professional help for D&C Advisor. With the HelpProvider control, pressing the F1 key automatically opens the help system with a specific topic, which depends on the location of the mouse when the F1 key is pressed. For example, if the mouse is located on the top of the input textbox of “In-Situ Stress” while the F1 is pressed, the help topic would be “in-situ stress.” Similar help buttons are available for every module of the UGR Advisor. Find and Index functions are also available to find the topic the user wants to read.

5 PROGRAMMING

We built or found the models required for the completion and stimulation design of TGS reservoir. The next steps were to layout and program all the models into the D&C Advisor.

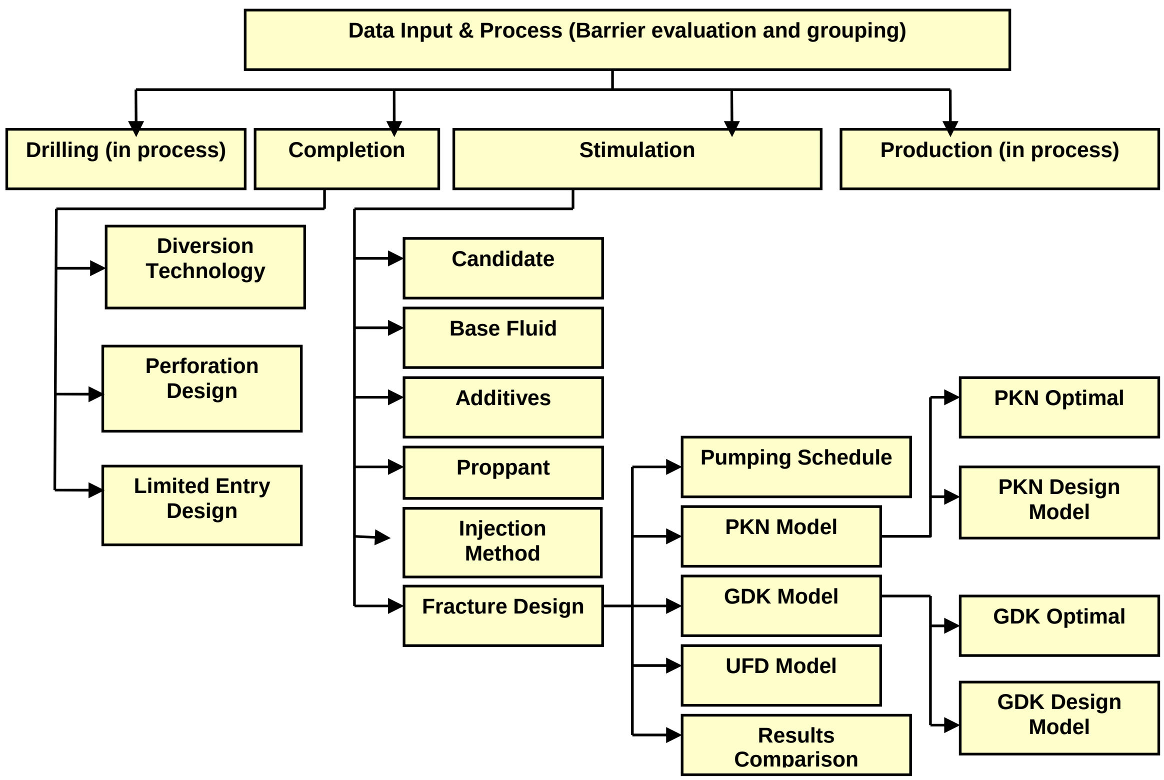


Fig. 5.1—Structure of the D&C Advisor program.

Fig. 5.1 shows the structure of the D&C Advisor. Following this structure greatly simplified the programming of D&C Advisor. Our task was to program each model respectively and then incorporate all the models into the same umbrella of D&C Advisor, based on the structure.

5.1 Input Data Validation of the D&C Advisor

In computer science, data validation is the process of ensuring that a program operates on clean, correct, and useful data. Incorrect data validation can lead to data corruption or vulnerability of the program. Data validation checks that data are valid, sensible, reasonable, and secure before they are processed.

In our D&C Advisor, hundreds of data are required to run the program. Public functions are designed to validate input data for the entire advisory system. For all of the input data, D&C Advisor first checks the data type of the input and gives an error message if the input data does not match with the chosen data type. For example, the permeability input box only accepts numeric data. If the letter *O* was typed instead of a digital number, an error message would appear and the program would ask the user to input an digital number. Second, D&C Advisor checks the range of the input data to ensure the input data lie within a reasonable range of values. For example, the gas price should ranged from USD 0 to USD 20/Mscf; any values out of this range are considered unreasonable. Permeability should not be a negative value. If a negative value was typed, an error message would appear and the program would ask the user to input a proper digital number.

5.2 Communications among Different Models

Because all the models were incorporated into the same umbrella and these models are used to solve problems of the same reservoir, communication among these models is very important. First, it is necessary to transfer the input data to all models. D&C Advisor is a complicated program composed of tens of models. Every model may require different data and some data may be required by several models. We cannot ask the user input the data every time they are used. We designed the system so that once the data are input, they are available for all models. Therefore, the data input must communicate with the process system and models.

Second, the results of some models must transfer to other models. D&C Advisor is composed by tens of models, and some of them use results of others to solve a problem. For example, in the optimal PKN model which is used to calculate the optimal fracture half length, we need to know the pump schedule and proppant information. The pump schedule is the result of the pumping schedule model and the proppant information is the result of the proppant selection model. Therefore, we linked models for optimal communication.

Third, communication is required to generate the report. After the user runs all the desired models, all the results need to be transferred to generate a report. Therefore, all the models must communicate with the report facility.

In our D&C Advisor (and in the whole UGR Advisor system in the future), the communication among different models or facilities is implemented by using public variables. In the Microsoft Visual Studio 2005 system, a public variable means that the variable is shared by all models. Once a public variable is assigned a value or changed, it will be valid to the entire system. By taking advantage of this property of public variable, I made the input data transferrable to all models. Also, taking advantage of this property made the results of all models transferrable to the report facility.

However, it is common sense that using public variables is very dangerous for a program. Public variables make the program difficult to debug. If a mistake is caused by a single public variable, the source of the mistake may be very difficult to find and debug.

Therefore, we strictly restricted the number of public variables in D&C Advisor. We set only the important data that are used by several models or facilities as public variables.

5.3 Flow Charts underlying UGR Advisor

Flow charts are easy-to-understand schematic representation of an algorithm or a stepwise process, showing the steps as boxes of various kinds, and how steps in a process fit together by connecting there boxes with arrows. This makes flow charts useful tools for communicating how processes work, and for clearly documenting how a particular job is done. Furthermore, using flow charts helps to clarify the understanding of the process and helps designers think about where the process can be improved.

In the development of D&C Advisor, we used flow charts to program most of the models. Fig. 5.2 is the flow chart that was used to program the proppant selection model.

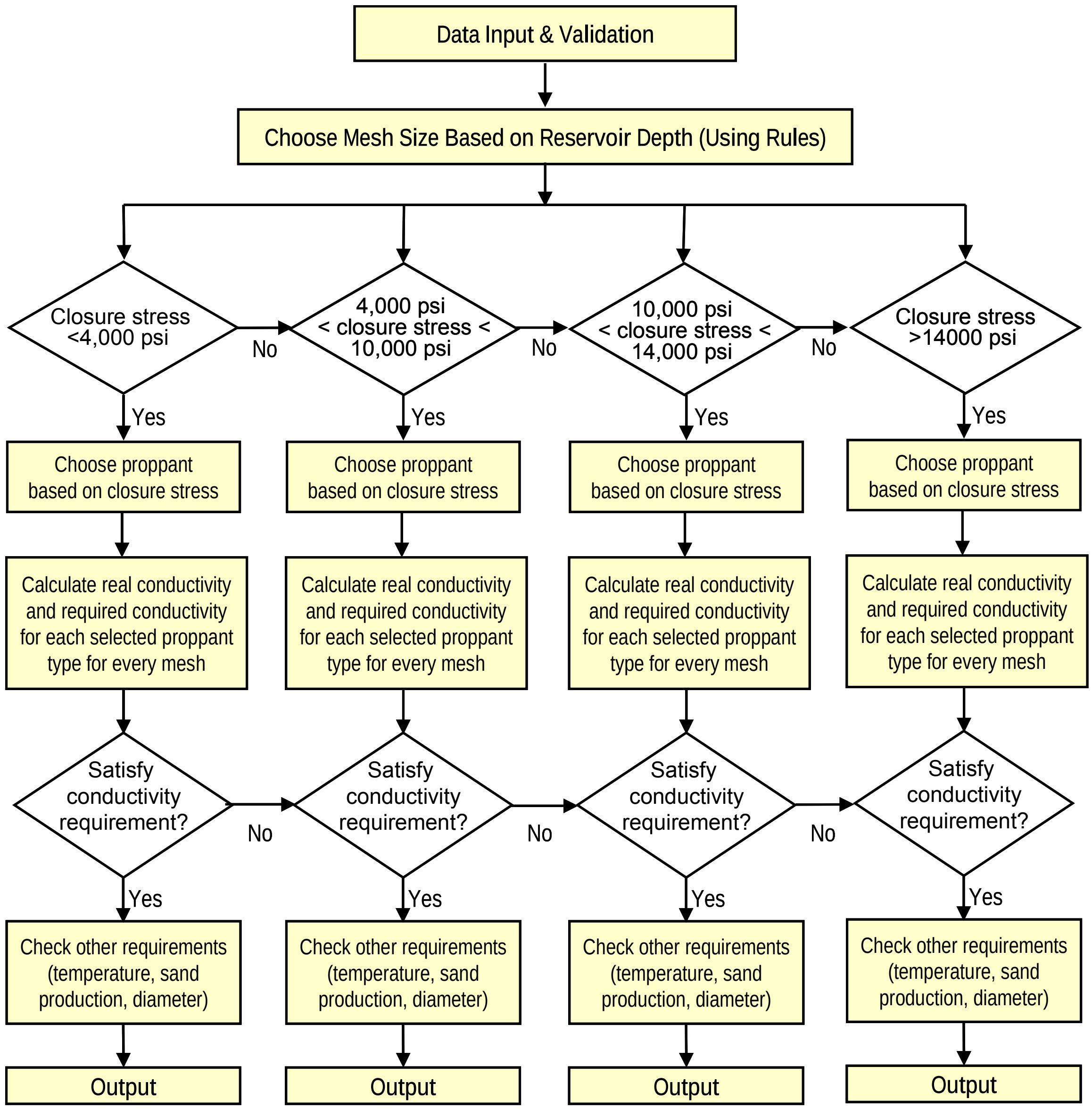


Fig.5.2—Flow chart underlies design of proppant selection model.

6 APPLICATION AND DISCUSSION

This section presents three examples that illustrate the application of D&C Advisor. The first example is a well stimulation class project in the Harold Vance Department of Petroleum Engineering at Texas A&M University. The other two examples are from real data from the industry. In each example, we first present the basic data. Then we compare the recommendations from D&C Advisor to those from the human experts if the data are available.

6.1 Using D&C Advisor for a Class Project

To illustrate the utility of the D&C Advisor, our class used the data from a TG reservoir with a drainage area of 80 acre. The other data are presented in Table 6.1.

Table 6.1—A TG Reservoir Data Set Required as the Input to D&C Advisor

Layer	Depth, ft	Thick, ft	Fluid	Φ, md	k, md	Net Pay	S_w	p_i	T, °F	E	Poisson Ratio	Stress
1	11600	300	NonProd	0.2	1E-05	0	1	6463	250	4000000	0.35	9626
2	11900	100	NonProd	0.1	0.0001	0	1	6573	250	3500000	0.25	8564
3	12000	50	Gas	0.15	0.05	50	0.55	6614	250	3000000	0.22	8310
4	12050	20	NonProd	0.1	0.0001	0	1	6633	250	3500000	0.25	8643
5	12070	30	Gas	0.18	0.1	30	0.5	6647	250	3000000	0.22	8351
6	12100	50	NonProd	0.2	1E-05	0	1	6669	250	4000000	0.35	9933
7	12150	50	Gas	0.2	0.2	50	0.4	6696	250	3000000	0.22	8413
8	12200	100	NonProd	0.1	0.0001	0	1	6738	250	3500000	0.25	8779
9	12300	200	NonProd	0.2	1E-05	0	1	6820	250	4000000	0.35	10158

We could have written a text file and let D&C Advisor read it when we clicked the “Read Data from File” button (Fig. 6.1). Instead, we input the data into D&C Advisor directly through the input interface shown as Fig. 6.1. This way, we could enter the data, then just click the “Read Data from File” button when we were ready to run the program. The data is automatically imported into the UGR Advisor.

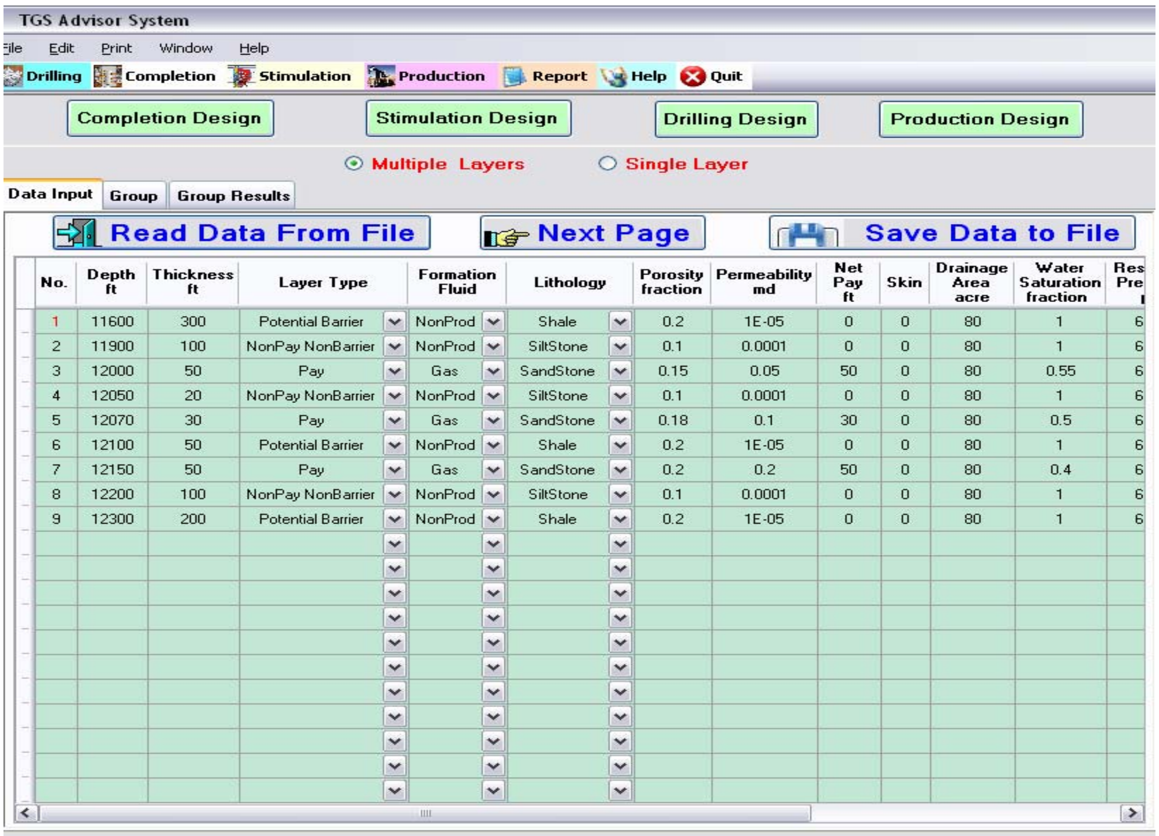
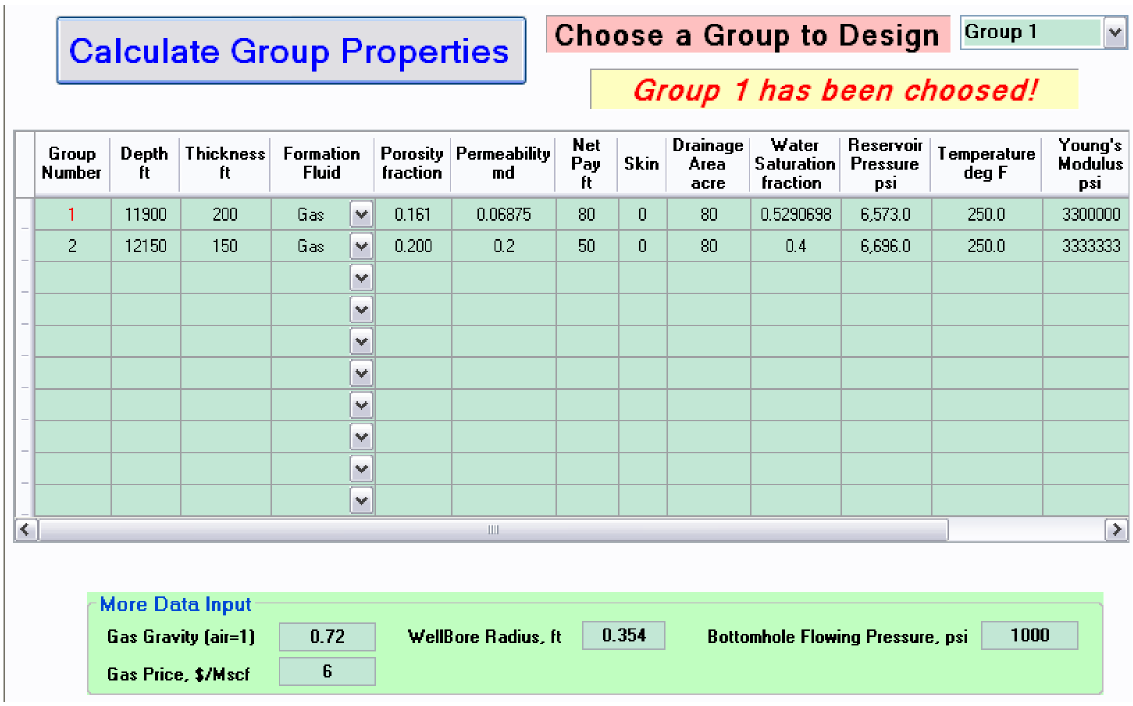


Fig. 6.1—Data input interface of D&C Advisor.

After inputting or importing the data (Table 6.1) into the D&C Advisor, we group the layers by following D&C Advisor’s guides. Fig 6.2 shows that D&C Advisor recommends that we group the nine layers into two groups.

Fig. 6.2—Two groups are recommended by D&C Advisor.

D&C Advisor will also help calculate the average properties of the two groups (Fig. 6.3). At this point, we could have chosen one of the groups to continue with the completion design. Since we did not choose a group, D&C Advisor automatically selected the first group. To make it design a job for Group 2, we would have chosen Group 2 as the working object from the ComboBox (see the upper right of Fig. 6.3). For this example, we selected Group 1 as our design object (Group 2 can be studied with the same procedure, but we did not repeat it).



Group Number	Depth ft	Thickness ft	Formation Fluid	Porosity fraction	Permeability md	Net Pay ft	Skin	Drainage Area acre	Water Saturation fraction	Reservoir Pressure psi	Temperature deg F	Young's Modulus psi
1	11900	200	Gas	0.161	0.06875	80	0	80	0.5290698	6,573.0	250.0	3300000
2	12150	150	Gas	0.200	0.2	50	0	80	0.4	6,696.0	250.0	3333333

Fig. 6.3—Properties of the two groups are calculated by D&C Advisor.

The first step of completion design is to select the diversion technology assuming a two-stage fracture treatment is being contemplated. To run the diversion selection model, we first checked the diversion technology selection data input page; D&C Advisor requires us to check/input a diversion for each layer for the eight diversion technologies. If the data are not available, D&C Advisor has reasonable default values to make the model run (See Fig. 6.4). When we ran the diversion selection model, D&C Advisor recommended the ExCAPE and Flow Thro Composite Frac Plug technologies (See Fig. 6.5).

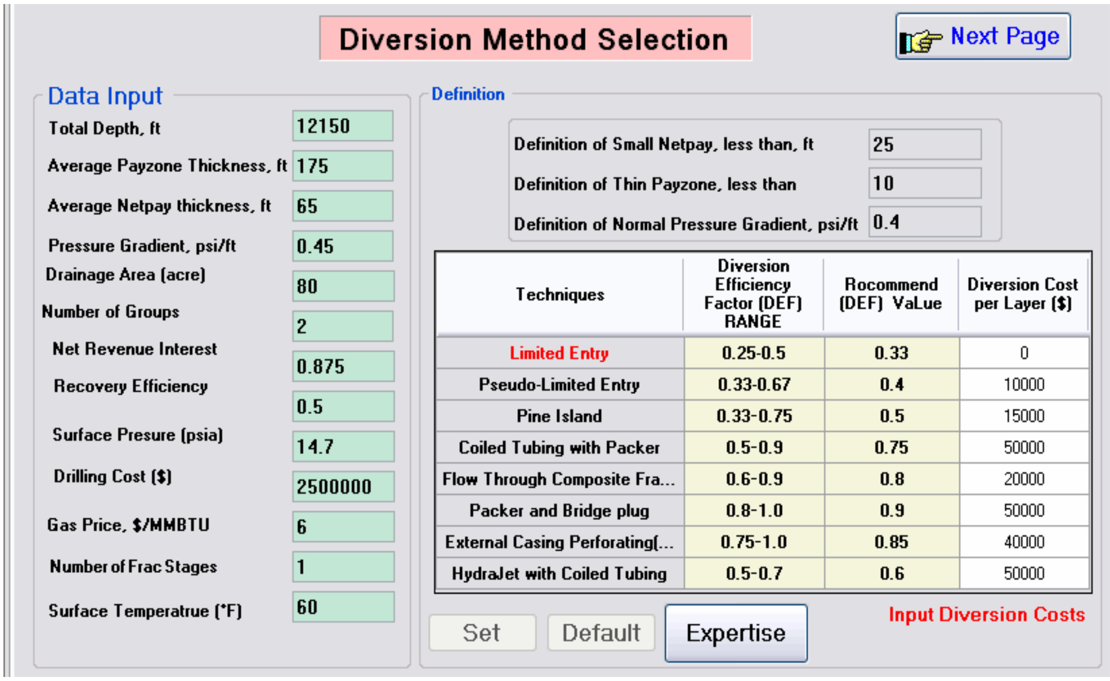


Fig. 6.4—Data input interface of the diversion selection model.

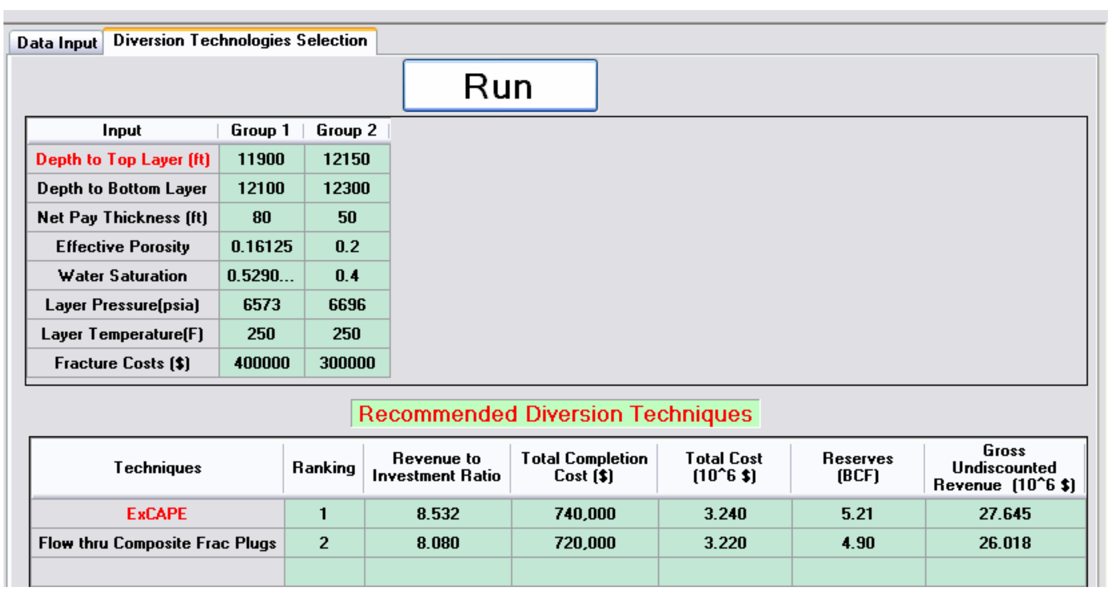


Fig. 6.5—Two diversion technologies are recommended by D&C Advisor.

The next step of the completion design is perforation design. From the perforation design model, D&C Advisor gives advice on perforation phasing, perforation interval, and shot density. For this dataset, D&C Advisor recommended a 60° perforation phasing. The length of perforation is 50 ft, and we should perforate the most porous zone. The shot density is 1 or 2 spf (Fig. 6.6).

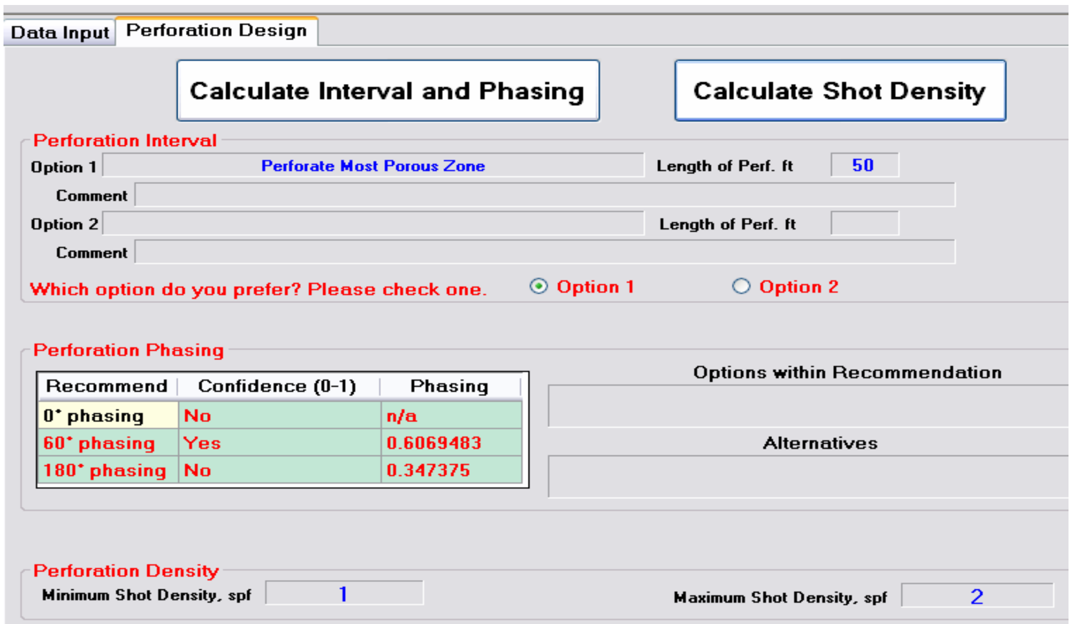


Fig. 6.6—Perforation design model recommends 60º phasing over 50 ft.

Because the recommended diversion technologies do not include the limited entry design diversion technology, we do not need to run the limited entry design model. We can now go to the stimulation module to obtain advice concerning a stimulation design for Group 1.

To begin the fracture design, the first step is to determine whether these reservoirs are good candidates to be fractured. After we ran the candidate model in the stimulation module, D&C Advisor determined that both Group 1 and Group 2 are good candidates for fracture treatment stimulation (see Fig. 6.7).

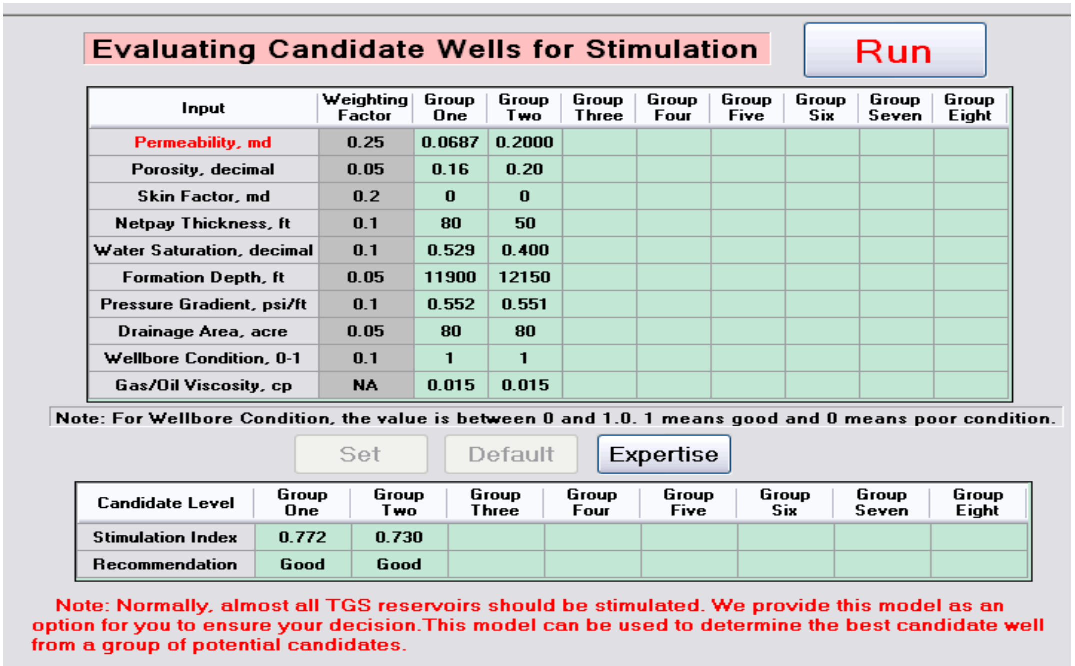


Fig. 6.7—Groups 1 and 2 are good stimulation candidates.

The next step is to obtain advice concerning the fracture fluid that can be considered. From the Fracture Fluid model, D&C Advisor suggested that either a hybrid or a miceller fracture fluid can be used to stimulate this reservoir. The user can choose either fluid to continue the fracture treatment design (Fig. 6.8). In addition, D&C Advisor also recommended the type of fluid for both the pre-flush and after-flush.

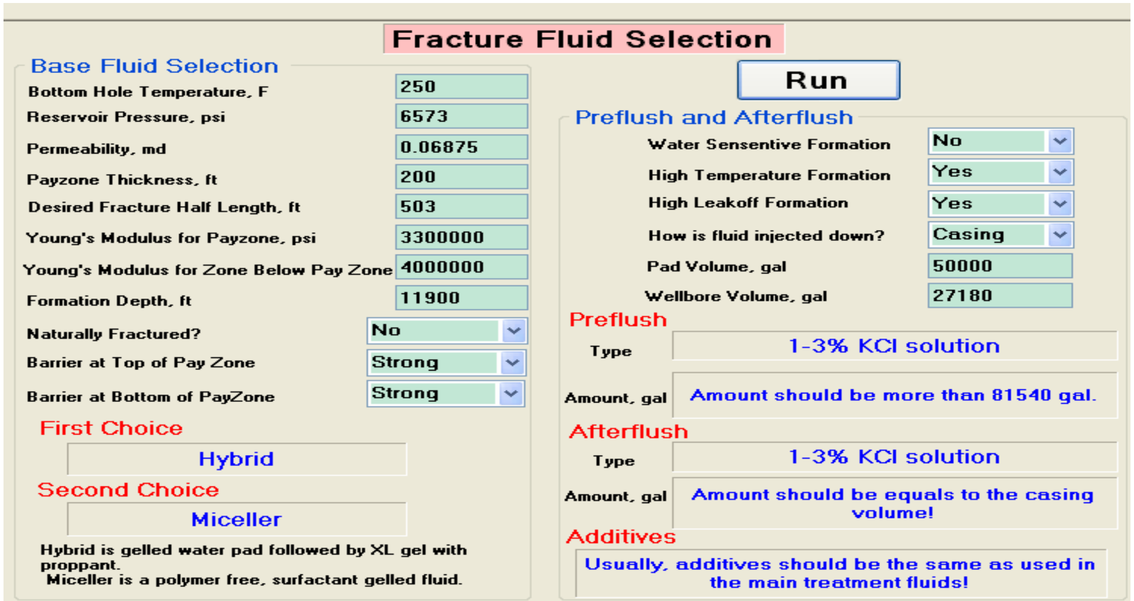


Fig. 6.8—D&C Advisor recommends two fracturing fluids and flushes.

The third step of fracture treatment design is to select additives (Fig. 6.9). In our program, the rules used to select frequently used additives have been built into the additives selection submodule. These rules (published by Xiong in the middle 1990s) need to be updated to conform to the current technology in use by industry.

The fourth step in stimulation design process is to select a propping agent for the treatment. Proppant Selection model of D&C Advisor provides advice in the form of a list of proppants the design engineer should consider. We can select a proppant from the list or input another proppant type; then, D&C Advisor will use the input data of the new proppant for the remaining steps (Fig. 6.10). We can choose a proppant from the ComboBox on the top right.

Fig. 6.9—D&C Advisor recommends granular diverting agent and ball sealers.

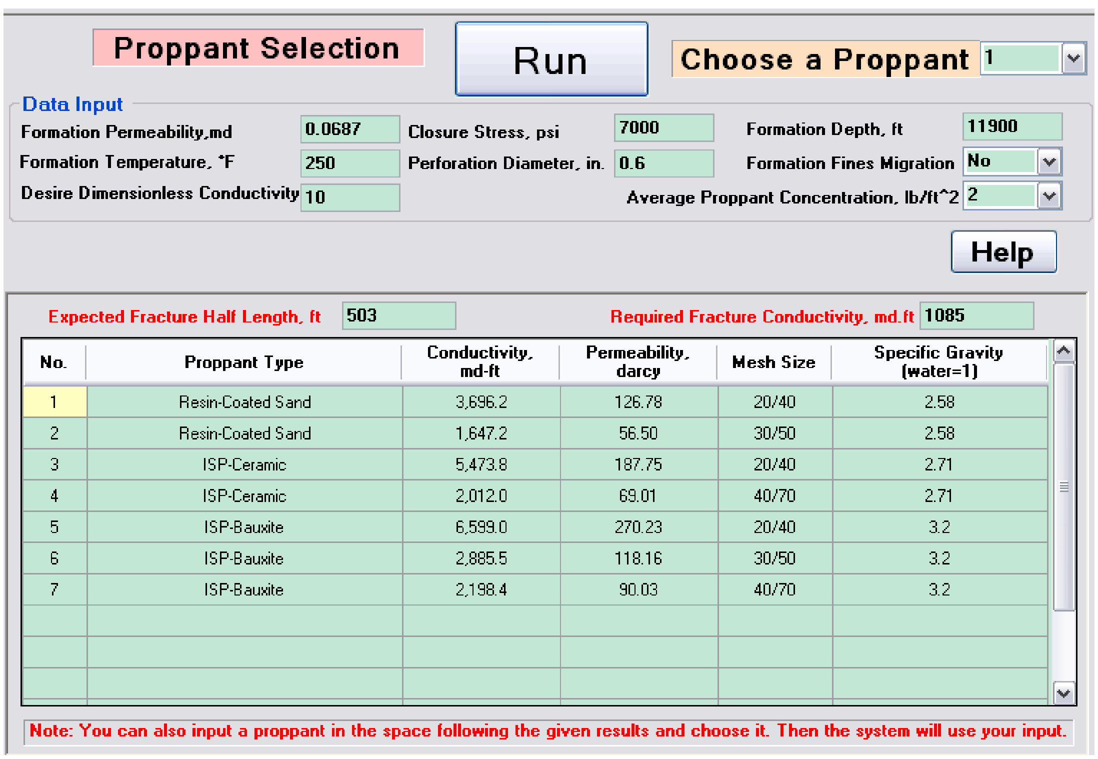


Fig. 6.10—D&C Advisor recommends two proppant types for this field.

The fifth step is to plan the pumping schedule. According to the reservoir data, D&C Advisor recommended a 5-stage slurry injection pumping schedule with fluid volume distributions for every stage. We can accept or make changes in the recommended pumping schedule (Fig. 6.11).

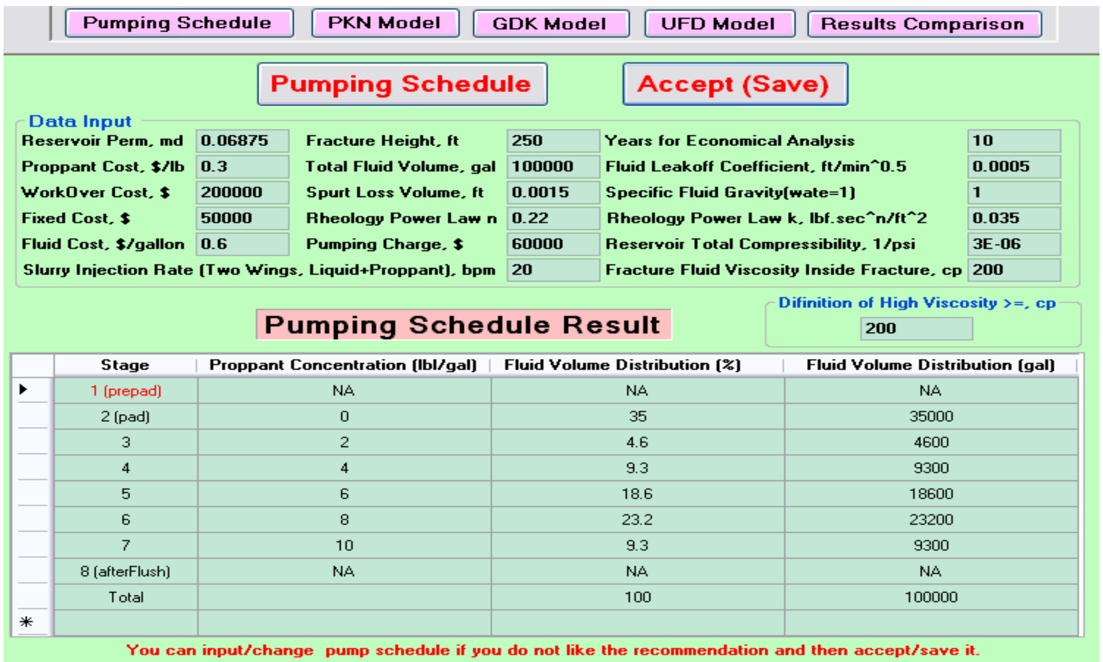


Fig. 6.11—D&C Advisor recommends a five-stage slurry pumping schedule.

The next step in the design is to determine the volume of fluid and proppant required to create the optimal fracture half-length from one of the three available models: GDK, PKN, or UFD. D&C Advisor considers the fracture half-length with maximum RIR as the optimal fracture half-length. Fig. 6.12 shows that the GDK model recommends a 350-ft-long optimal fracture half-length. The PKN model suggests a fracture half-length of about 400 ft (Fig. 6.13).

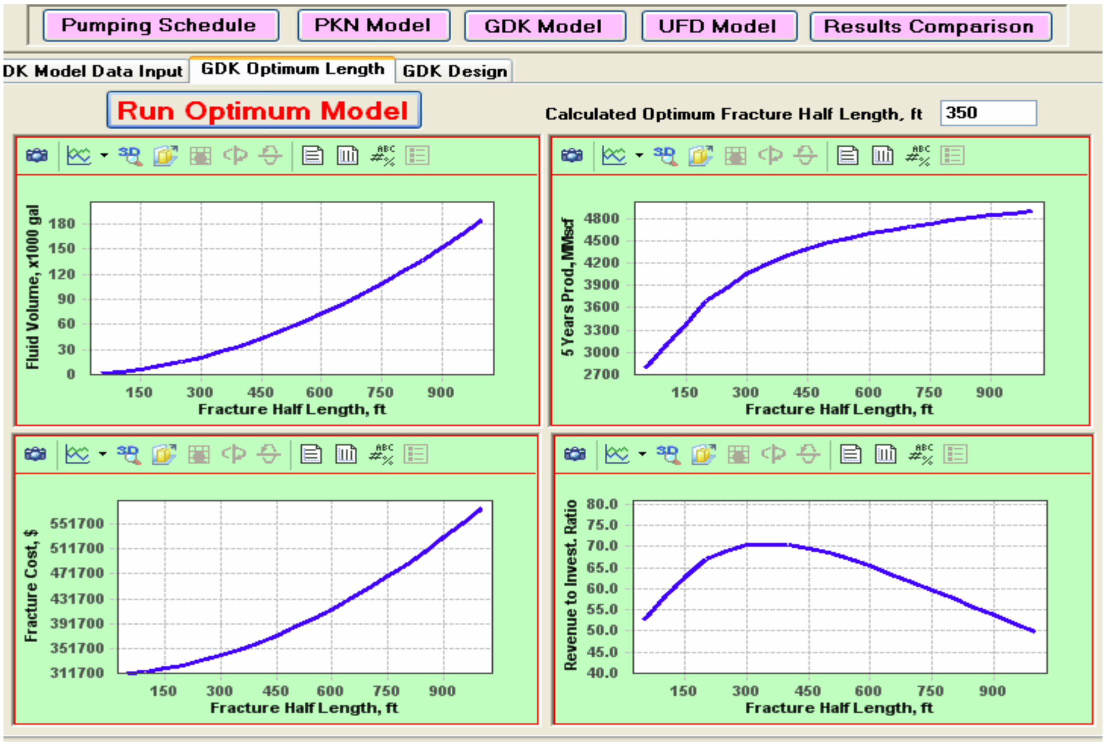


Fig. 6.12—GDK model identifies a 350 ft optimal fracture half-length.

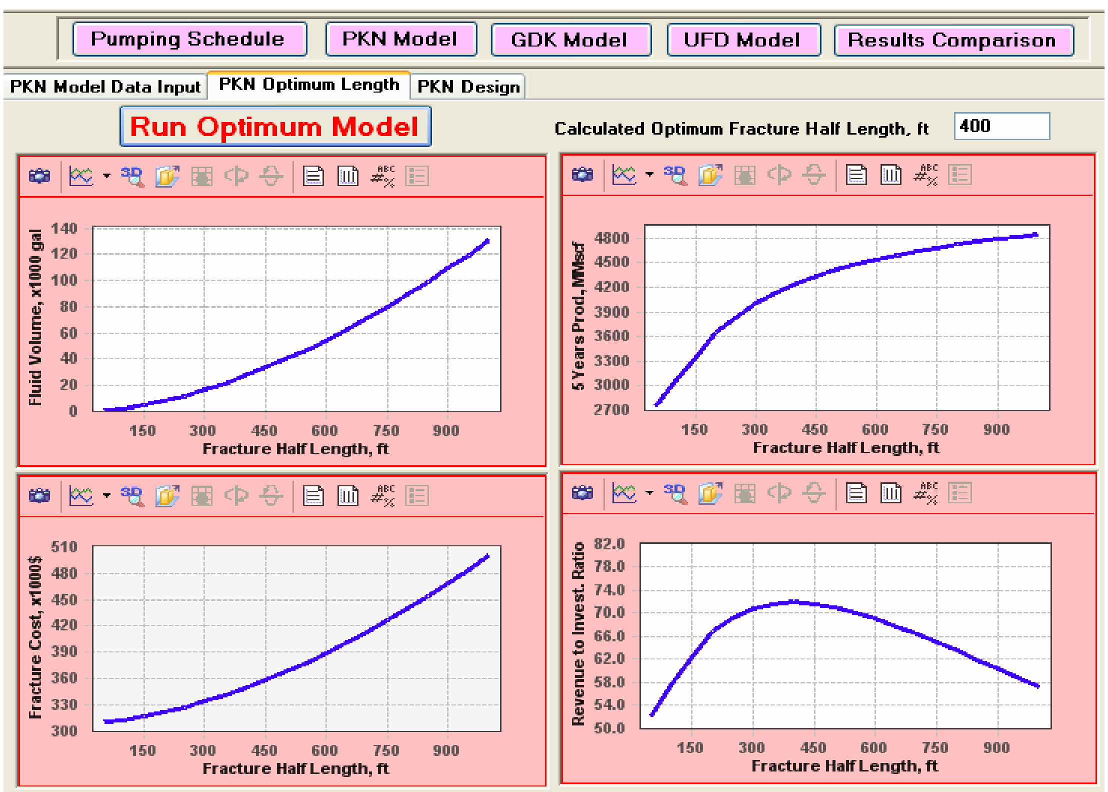


Fig. 6.13—PKN model sets fracture half-length at 400 ft.

D&C Advisor also includes the 2D GDK and PKN fracturing propagation models as tools. Fig. 6.14 shows the GDK model including the correlation of three operations factors—pumping time, suspension, and equilibrium bank—with fracture half-length and width and the plots of pumping time vs. fracture half-length and width.

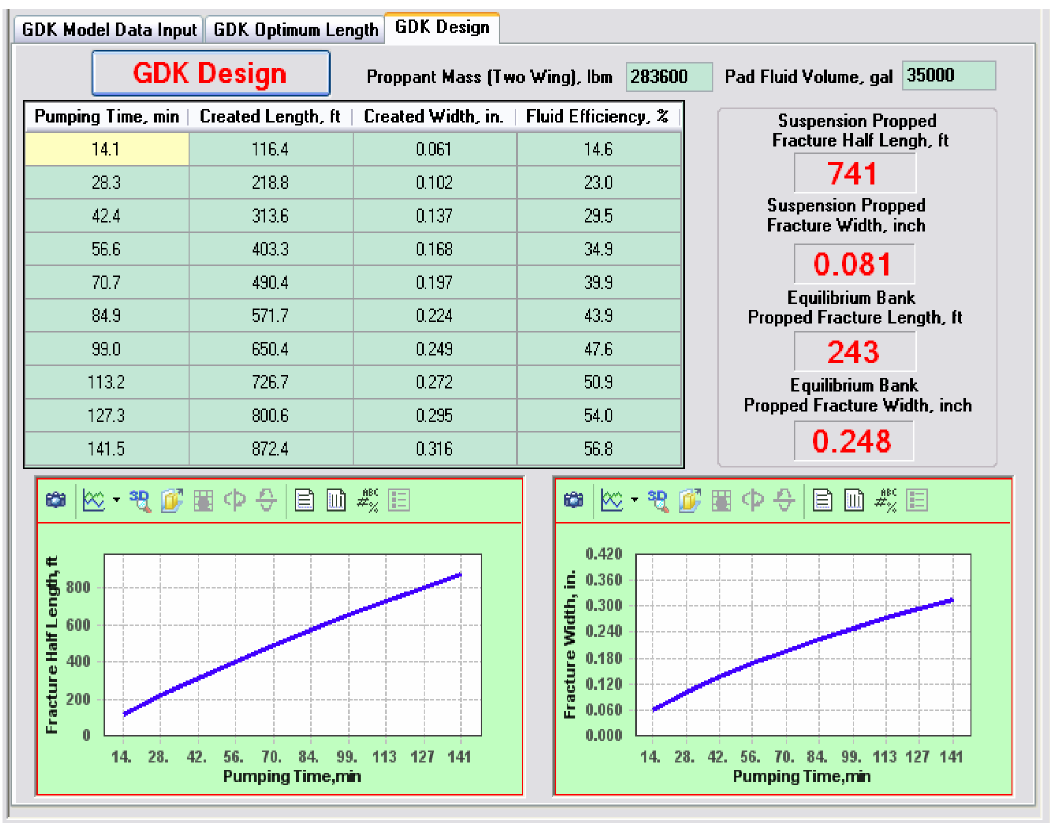


Fig. 6.14—2D GDK model analyzes pumping time, suspension, and equilibrium with fracture length and width.

The third method to find optimal facture half-length is the UFD model. The first step in using the UFD model is to calculate or input the treatment size. As shown in Fig.

6.14, UFD recommends a 640-ft-long optimal fracture half-length and 0.099 in. fracture width for a 300,000 lbm treatment size. Meanwhile, UFD also calculates an expected gas production of 7,475 Mscf/day for the recommended fracture dimension during the pseudosteady-state period.

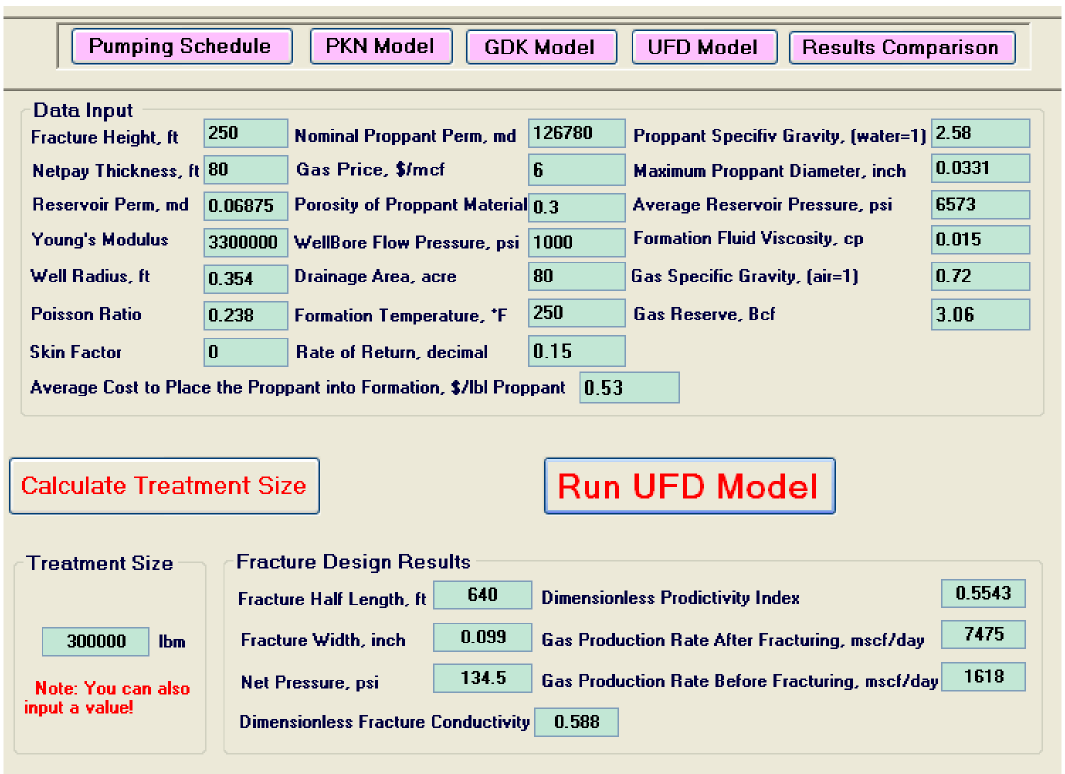
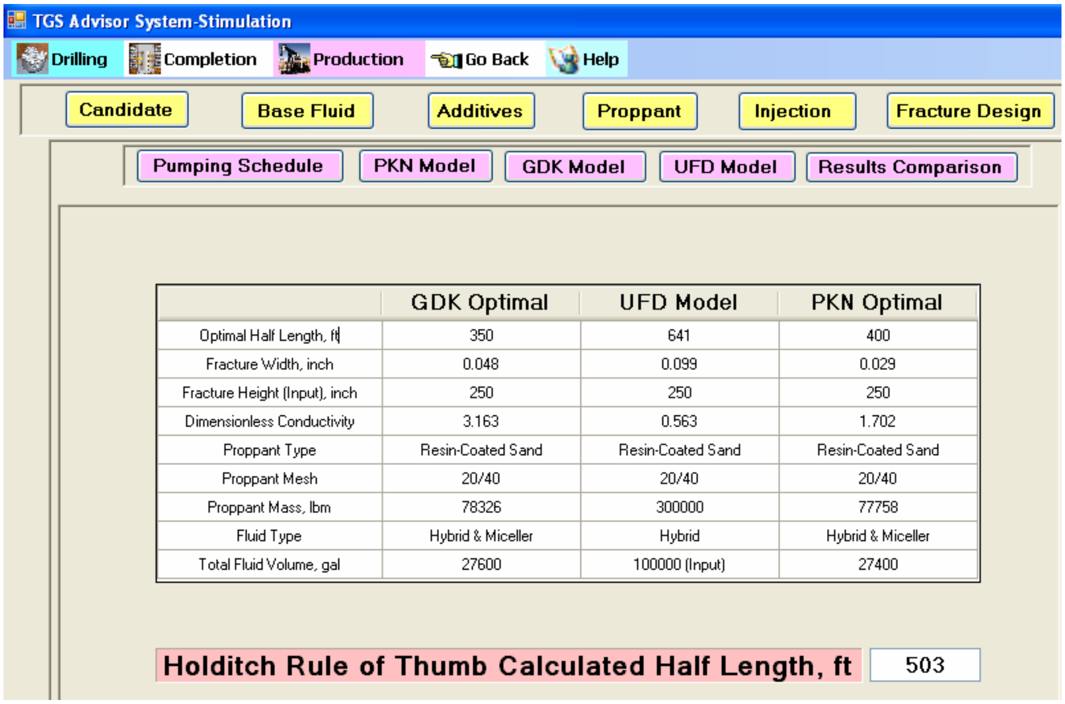


Fig. 6.15—UFD model recommends a 640-ft fracture half-length.

D&C Advisor also provides a simple Holditch rule-of-thumb method to calculate the optimal fracture half-length (Holditch et al. 2007). The method uses the value of formation permeability and expected drainage area. This method recommends a 503-ft fracture half-length (see Fig. 5.16).



	GDK Optimal	UFD Model	PKN Optimal
Optimal Half Length, ft	350	641	400
Fracture Width, inch	0.048	0.099	0.029
Fracture Height (Input), inch	250	250	250
Dimensionless Conductivity	3.163	0.563	1.702
Proppant Type	Resin-Coated Sand	Resin-Coated Sand	Resin-Coated Sand
Proppant Mesh	20/40	20/40	20/40
Proppant Mass, lbm	78326	300000	77758
Fluid Type	Hybrid & Miceller	Hybrid	Hybrid & Miceller
Total Fluid Volume, gal	27600	100000 (Input)	27400

Fig. 6.16—Holditch rule of thumb half-length lies between those of more complicated methods.

In summary, D&C Advisor provides four ways to estimate the optimal fracture half-length for a given data set and provides a summary to compare the results of the four methods (see Fig. 6.16). In our case, the value of optimal fracture half-lengths is in the range of 450 to 640 ft. With this range, operators can determine the facture half-length easily in their real design wok by using a professional 3D or pseudo-3D fracture design software such as Fracade or FracproPT.

6.2 Using D&C Advisor on SFE No.3 Well

We next tested D&C Advisor on data from a fracture treatment performed by a professional consulting firm, S.A Holditch Associates (SAH), Inc., that relied heavily on the best-practices experience of its highly successful staff in designing the project in 1991. We assumed that if our results compared to those of the SAH team, our Advisor was capturing best practices appropriately.

6.2.1 Formation Data

SFE No. 3 is a well in a series of four staged field experiments (SFEs) conducted by the Gas Research Institute (GRI 1991). This well was originally drilled as the Mobil Cargill Unit No.15 in the Waskom field, Harrison County, Texas. It was drilled to a total depth of 9,700 ft and completed in the Lower Cotton Valley Taylor Sand from 9,225 ft to 9,250 ft and from 9,285 to 9,330 ft. The fracture treatment was pumped down the casing/ tubing annulus in March 1989.

From the well logging data, we divided the interval from 9,110 to 9,570 ft into 12 layers, where Layers 4, 5, and 6 are sandstone gas pay zones. We assume that all non-pay zones are tight and 100% saturated with formation water and the drainage area is 80 acre.

Table 6.2—Pay Zones Data for SFE No.3 Well (Xiong 1992)

Items	Layer 4	Layer 5	Layer 6
Permeability, md	0.003	0.023	0.01
Porosity, %	7.9	7.8	8
Temperature, ºF	250	250	250
Reservoir Pressure, psi	4820	4830	4841
Bottomhole Pressure, psi	1000	1000	1000
Fluid Type	Gas	Gas	Gas
Fluid Viscosity, cp	0.01784	0.01784	0.01784

Table 6.3—Basic Data for SFE No.3 Well (Xiong 1992)

Layer	Depth, ft	Thick, ft	Fluid	ϕ, %	k, md	Net Pay	S_w	p_i	T °F,	E	Poisson Ratio	Stress, psi/ft
1	9110	45	NonProd			0			250	6100000	0.31	7600
2	9155	10	NonProd			0			250	6900000	0.28	6750
3	9165	35	NonProd			0			250	8000000	0.25	6000
4	9200	50	Gas	0.079	0.003	25	0.4	4820	250	8300000	0.2	5600
5	9250	60	Gas	0.078	0.023	30	0.35	4830	250	9000000	0.18	5300
6	9310	30	Gas	0.08	0.01	20	0.39	4841	250	7100000	0.2	5900
7	9340	15	NonProd			0			250	6800000	0.24	6590
8	9355	25	NonProd			0			250	5400000	0.26	7300
9	9380	60	NonProd			0			250	7900000	0.2	5800
10	9440	15	NonProd			0			250	6400000	0.21	6400
11	9455	20	NonProd			0			250	4900000	0.28	7500
12	9475	90	NonProd			0			250	3500000	0.3	8300

6.2.2 Comparison of Design Results

We ran the D&C Advisor using available pay zone (Table 6.2) and field (Table 6.3) data. We also had information on the design recommendations made by human experts working for SAH. We compared the recommendations from D&C Advisor with the design generated by SAH to see if D&C advisor can produce best practices of the experts (GRI 1991), as shown in Table 6.4. The recommended pumping schedule by the D&C Advisor was shown in Table 6.5.

Both D&C Advisor and SAH recommended grouping the 12 layers into a single group and both considered the well a candidate for fracturing. The differing advice on fracturing fluid types and additives reflect advances in technology since 1991; the differences in fluid and proppant amounts reflect the differences in recommended fracture half-length. We consider the comparison excellent.

Table 6.4—Recommended Fracture Design Comparison for SPE No. 3 Well

Items	D&C Advisor Recommendations GDK	D&C Advisor Recommendations UFD	D&C Advisor Recommendations PKN	SAH (GRI 1991) Recommendations
Optimal Half-Length, ft	650[1]	435	700	900 to 1000
Fracture Width, inch	0.070	0.142	0.044	
Fracture Height (Input), inch	360	360	360	296 (actual)
Dimensionless Conductivity	10.02	4.771	5.920	
Proppant Type	Sand RCS[2] ISP[3]	Sand RCS ISP	Sand RCS ISP	Sand
Proppant Mesh	16/30 20/40 30/50	16/30 20/40 30/50	16/30 20/40 30/50	20/40
Proppant Mass, lbm	567500	432000	567500	1,197,000
Fluid Type	Hybrid Miceller	Hybrid Miceller	Hybrid Miceller	VERSAGEL-HT1600
Total Fluid Volume (Input), gal	111200	100000 (input)	200000	609,000
Additives	Bactericide, breaker, clay stabilizer, friction reducer, fluid-loss additives			Crosslinker, clay stabilizer, friction reducer
Fluid injection	Run new tubing, inject through annulus			Inject through annulus

[1] Holditch Rule-of-Thumb Calculated Half-Length (D&C only) is 543 ft.
[2] RCS is resin-coated sand.
[3] ISP is intermediate strength proppant.

Table 6.5—D&C Advisor Recommended Pumping Schedule for SPE No. 3

Stage	Proppant Concentration, lbl/gal	Fluid Volume, %	Fluid Volume, gal
1 (prepad)	NA	NA	NA
2 (pad)	0	35	35000
3	2	4.6	4600
4	4	9.3	9300
5	6	18.6	18600
6	8	23.2	23200
7	10	9.3	9300
8 (afterflush)	NA	NA	NA
Total		100	100000

6.3 Using D&C Advisor on SFE No. 2 Well

SFE No. 2 is the second well in the GRI SFE series. SPE No. 2 was drilled to a total depth of 10,163 ft in 1988. Detailed petrologic studies based on core and log data from SFE No. 2 indicate two layers in the Travis Peak formation. The reservoirs at 8,230 to 8,739 ft and 9,480 to 9,942 ft are referred to respectively as the "upper" and "lower" Travis Peak intervals (Robinson 1991).

6.3.1 Fracture Treatment of the Lower Travis Peak

After a mini-frac treatment was performed on the Lower Travis Peak, Robinson et al. (1991) predicted that the height of the fracture might extend from the depth of 9,635 ft to 10,040 ft (405 ft). Data describing the lower Travis Peak are shown in Table 6.6. Because the value of Poisson's ratio is missing, we assumed a 0.2 value. The data of in-situ stress is also missing; we used the value from the upper Travis Peak formation (discussed in our next example).

Table 6.6—Basic Data for the Lower Travis Peak Pay Zones of SFE No. 2 Well (GRI 1990)

Items	Layer 1	Layer 2	Average
Permeability, md	0.008	0.08	0.0387
Porosity, %	4.5	4.9	4.67
Water Saturation, %	35	60	45.7
Gas Saturation,%	65	40	51.4
Bottomhole Pressure, psi	1000	1000	1000
Fluid Type	Gas	Gas	Gas
Fluid Viscosity, cp	0.01784	0.01784	0.1784
Drainage Area, acre	2.57	160	70
Net pay Thickness, ft	55	41	96
Young's Modulus, psi			7.0×10^6
Reservoir Pressure, psi			5,200

A fracture treatment pumped down the casing-tubing annulus into the lower Travis Peak screened out in December 1987. During the treatment, a total of 164,000 gal of gel and only 74,000 lb of proppant were pumped. After the first fracture treatment, the lower Travis Peak was refractured a week later with 171,000 gal crosslinked gel with 114,000 lb mesh ISP proppant. However, this treatment also screened out. Robinson et al. (1991) determined that the fracture shape was roughly circular and was very narrow at the perforations. The created fracture height was about 600 ft and propped fracture length was about 250 ft.

By using the data in Table 6.6, we ran D&C Advisor to provide advice on the stimulation design then compared our design with the design made by human experts SAH (Table 6.7).

Table 6.7—Recommended Fracture Design Comparison for SFE No. 2 Well

Items	D&C Advisor Recommendations GDK	UFD	PKN	SAH Recommendation
Optimal Half-Length, ft	650[1]	620	700	525(GRI 1990)
Fracture Width, inch	0.108	0.100	0.065	
Fracture Height (Input), inch	405	405	405	425 (GRI 1990)
Dimensionless Conductivity	8.206	1.328	4.618	
Proppant Type	RCS ISP	RCS ISP	RCS ISP	ISP
Proppant Mesh	20/40 40/70	20/40 40/70	20/40 40/70	18/20
Proppant Mass, lbm	548282	684000	508552	620,000
Fluid Type	Gelled Water	Gelled Water	Gelled Water	Crosslinked and linear gell
Total Fluid Volume (Input), gal	193200	100000 (Input)	179200	140,000

[1] Holditch Rule of Thumb Calculated Half-Length (D&C Advisor only) is 488 ft.

As shown in Table 5.7, the advice provided by D&C Advisor is similar to the SAH design. The value of D&C optimal fracture half-length is between 488 to 700 ft. The SAH fracture half-length was 525 ft.

6.3.2 Fracture Treatment of the Upper Travis Peak

In the upper Travis Peak, a fracture treatment with proppant was performed in September 1988. For this treatment, a total 235,000 gal of gel and 115,000 lb of 18-20 mesh ISP was pumped. A mini-frac treatment was pumped in order to collect date for analysis of fracture azimuth and fracture height. Based on the mini-frac analysis, the fracture height was estimated to be less than 400 ft and the fracture half length was calculated to be 800 ft. We compared results of this treatment with results from D&C Advisor, again with very good results.

Formation Data

The interest formation is from 8,119 ft to 8,737 ft and the interval was divided into 15 layers based upon the in-situ stress profile. Layers 4, 5, and 6, from 8,238 to 8,327 ft, are sandstones with gas and were perforated. Table 6.8 shows the basic data for each layer.

Table 6.8—Basic Data for the Upper Travis Peak of SFE No. 2 Well (Xiong 1992)

Layer	Depth, ft	Thick, ft	Layer Type	ϕ, %	k, md	Net Pay	S_w	p_i	T, °F	E, psi	Poisson Ratio	Stress, psi/ft
1	8119	31	Potential Barrier							4600000	0.3	6800
2	8150	70	Potential Barrier							5600000	0.25	6500
3	8220	20	Potential Barrier							4800000	0.28	6700
4	8240	50	Pay	0.096	0.01	4	0.391	4000	234	7300000	0.21	6350
5	8290	30	Pay	0.096	0.01	5	0.391	4000	234	5700000	0.27	6700
6	8320	20	Pay	0.096	0.01	4	0.391	4000	234	6600000	0.2	6280
7	8340	50	Potential Barrier							6500000	0.22	6480
8	8390	60	Potential Barrier							6900000	0.2	6300
9	8450	50	Potential Barrier							6600000	0.23	6200
10	8500	40	Potential Barrier							6200000	0.25	6320
11C	8540	20	Potential Barrier							6500000	0.21	6100
12	8560	50	Potential Barrier							6100000	0.25	6360
13	8610	60	Potential Barrier							6800000	0.24	6300
14	8670	50	Potential Barrier							7500000	0.21	6200
15	8720	70	Potential Barrier							7000000	0.22	6350

Comparison of the Design Results

We compared recommendations from D&C Advisor with the design generated by SAH (Table 6.9). Both methods recommended grouping the 15 layers into one group because there are no barriers. Although the stimulation index is only 0.32165 (of a maximum 1.0) and the net pay thickness is only 13 ft, D&C Advisor recommended hydraulic fracturing. The recommended pumping schedule for the upper travis peak of SFE No.2 well was shown in Table 6.10.

The fracture half-length recommended by D&C Advisor ranged from 320 to 736 ft. SAH recommended an 800-ft length (Robinson 1991), but post-fracture analysis revealed that that length was never achieved; the created facture half-length is in the range of 250 to 500 ft.

Table 6.9—Recommended Fracture Design for Upper Travis Peak SFE No. 2 Well

Items	D&C Advisor Recommendations GDK	UFD	PKN	SAH (GRI 1990) Recommendations
Optimal Half-Length, ft	320[1]	436	360	800 (actual 250 to 500 ft)
Fracture Width, inch	0.229	0.142	0.204	N/A
Fracture Height (Input), inch	400	770	400	400 (GRI 1990)
Dimensionless Conductivity	61.49	7.415	48.59	N/A
Proppant Type	Sand	Sand	Sand	ISP
Proppant Mesh	16/30	16/30	16/30	20/40, 18/20
Proppant Mass, lbm	567500	924000	567500	520000
Fluid Type	Hybrid	Hybrid	Hybrid	VERSAGEL-HT1600
Total Fluid Volume (Input), gal	200000	200000	200000	260000

[1]Holditch Rule-of-Thumb Calculated Half-Length (D&C Advisor only) is 736 ft.

Table 6.10—Recommended Pumping Schedule for Upper Travis Peak SFE No. 2

Stage	Proppant Concentration, lbl/gal	Fluid Volume, %	Fluid Volume, gal
1 (prepad)	NA	NA	NA
2 (pad)	0	35	35000
3	2	4.6	4600
4	4	9.3	9300
5	6	18.6	18600
6	8	23.2	23200
7	10	9.3	9300
8 (afterflush)	NA	NA	NA
Total		100	100000

6.4 Using D&C Advisor on SFE No.1 Well

SFE No.1 well is the first well in GRI SFE series. SFE No.1 well was drilled to a total depth of 7,895 ft. The sandstone formation at 6,170 to 6,211 ft, which was named the Travis Peak C1, was selected for fracture treatment. To ensure a successful fracture treatment, a prefracture formation evaluation was performed including log analysis, well test data, and mini-frac test data.

6.4.1 Formation Data

The Travis Peak C1 was completed from 6,189 to 6,211 ft. If we assume 20 ft of net pay, the permeability was 1.5 md and the apparent skin factor was +1. From analysis of the mini-frac treatment, the created fracture length was 160 ft and the fracture height was 275 ft (GRI 1988). The main fracture treatment was pumped in January 1987. The total fluid used was 150,000 gal and total 407,500 lbm proppant of 18/20 ISP was used.

Table 6-11 summaries the data from SPE No.1 well in the Travis Peak C1 sand.

Table 6.11—Basic Data for Pay Zones of SFE No.1 Well (Holditch 1988)

Items	Layer 4
Permeability, md	1.55
Porosity, %	12.9
Net pay,%	20
Reservoir Pressure, psi	1230
Bottomhole Pressure, psi	401
Water Saturation, %	45.4
Fluid Type	Gas
Reservoir Temperature, ºF	202
Fluid Viscosity, cp	0.01392
Drainage Area, acre	320
In-Situ Stress Gradient, psi/ft	0.496
Young's Modulus, psi	6108900
Poisson's Ratio	0.235
Possible Fracture Height (Mini-Frac), ft	275

6.4.2 Comparison of Design Results

Because we have the data about only this single pay zone layer, we ran the single-layer case to design a fracture treatment with D&C Advisor. Comparison of the results from D&C Advisor and human experts (GRI 1988) are shown in Table 6.12.

As shown in Table 6.12, the D&C Advisor design and SAH design do not match the actual treatment result (the design data for fracture half-length, width, and fracture height are missing).

Table 6.12—Recommended Fracture Design Comparison for SFE No. 1 Well

Items	D&C Advisor Recommendations			SAH (GRI 1988) Recommendations
	GDK	UFD	PKN	
Optimal Half-Length, ft	300[1]	158	400	Design Missing, Actual 150 ft
Fracture Width, inch	0.023	0.140	0.014	Design Missing, Actual 0.12 in.
Fracture Height (Input), inch	300	120	300	Upper Height 198 Lower Height 181
Dimensionless Conductivity	0.313	0.671	0.142	
Proppant Type	RCS	RCS	RCS	ISP
Proppant Mesh	16/30 20/40	16/30 20/40	16/30 20/40	18/20
Proppant Mass, lbm	54860	80000	61716	407,500
Fluid Type	Foam Assisted Hybrid; N2 or CO2 Assisted Hybrid	Foam Assisted Hybrid, N2 or CO2 Assisted Hybrid	Foam Assisted Hybrid, N2 or CO2 Assisted Hybrid	Crosslinked gel,
Total Fluid Volume (Input), gal	17600	100000 (Input)	19600	150,000
Pad Volume, %	45%	45%	45%	50%

[1]Holditch Rule-of -Thumb Calculated Half-Length (D&C Advisor only) is 381 ft.

We have identified three reasons for this mismatch:

First of all, the absolute permeability of C1 sand in SFE No.1 well is as high as 8 md and gas permeability is 5 md (GRI 1988). This reservoir can not be classified as unconventional gas reservoir. However, most of the models in Our UGR Advisor are designed for UGR application.

Because of the high permeability, the gas production from this well is also high. From the economics analysis standpoint, high gas production can lead to a long fracture half-length because of the high revenue. This is why the PKN and GDK optimized models computed a longer fracture half-length (300 and 400 ft).

From the fracture treatment standpoint, a high-permeability reservoir requires a short, wide fracture. The UFD model is designed to maximize productivity index. Therefore, the UFD model gives a short, wide fracture dimension (158 ft and 0.14 in.) for this reservoir.

6.5 Using D&C Advisor on Pakenham Field

The Pakenham Field, operated by Chevron, is located in Terrell County, Texas. In the late 1990s, the Wolfcamp A2 and D sands of the Pakenham Field were stimulated in several wells to evaluate and enhance fracture practices. After evaluation of the fracture treatment, Wright et al. (1996) proposed changes on fracture treatment practices. Based on their proposal, a new fracture treatment was performed on a new well in the same field and same formation. The new fracture treatment proved that their proposal was beneficial.

6.5.1 Formation Data

To evaluate the D&C Advisor, I selected the Mitchell 6#5 well from the Wright report to run the D&C Advisor. The results between D&C Advisor and the best practice on this field are compared in the Table 6.13.

Table 6.13—Basic Data of Mitchell 6#5 Well in Pakenham Field (Wright 1996)

Permeability, md	0.1
Porosity, %	9
Net Pay, ft	60
Reservoir Pressure, psi	3800
Bottomhole Pressure, psi	1000 *
Water Saturation, %	0.3*
Fluid Type	Gas
Reservoir Temperature, ºF	200*
Fluid Viscosity, cp	0.015*
Drainage Area, acre	80
In-Situ Stress, psi	7000
Young's Modulus, psi	5000000
Poisson's Ratio	0.16
Depth, ft	8000 (A2 sand)
Pay Zone Thickness (Group Thickness), ft	300 *
Possible Fracture Height (Mini-Frac), ft	340

* Data are missing and the values are assumed to run D&C Advisor.

6.5.2 Comparison of Design Results

The comparison between the result of D&C Advisor and human experts (Wright 1996) are shown in Table 6.14.

Table 6.14—Recommended Fracture Design Comparison for Mitchell 6#5

Items	D&C Advisor Recommendations GDK Optimal	UFD	PKN Optimal	Best Practice (Wright 1996) Recommendations
Optimal Half-Length, ft	300[1]	440	300	Originally 600, optimized to 255
Fracture Width, inch	0.043	0.141	0.030	
Fracture Height (Input), inch	370	370	370	341
Dimensionless Conductivity	4.892	1.231	3.483	
Proppant Type	Sand RCS ISP	Sand RCS ISP	Sand RCS ISP	Originally RCS Optimized to Sand
Proppant Mesh	16/30 20/40 30/50	16/30 20/40 30/50	16/30 20/40 30/50	20/40
Proppant Mass, lbm	91432	444000	91432	299,000
Fluid Type	Gelled Water	Gelled Water	Gelled Water	Originally foam Optimized to crosslinked gel
Total Fluid Volume (Input), gal	40000	100000 (Input)	40000	

[1]Holditch Rule-of-Thumb Calculated Half-Length is 488 ft.

As shown in Table 6.14, the D&C Advisor design and best practice result in a good match. In addition, the D&C Advisor results are closer to the optimized results. For example, the calculated fracture half-length ranges from 488 to 300 ft, which is close to the optimized result of 255 ft. The recommended proppant is sand, which is the same as the optimized proppant.

6.6 Using D&C Advisor on an Indian Tight Gas Well

The Raggesheari Deep gas filed was discovered in 2003 in India. To produce economically, some wells were fracture treated successfully. Most of the treatments are beneficial in this field (Shaoul 2007).

6.6.1 Formation Data

To evaluate the D&C Advisor, I selected Well #1 from their report as an example to run the D&C Advisor. The basic data for Well #1 are shown in Table 6.15.

Table 6.15—Basic Data for Well #1 in India (Shaoul 2007)

Permeability, md	0.13
Porosity, %	9
Net Pay, ft	50
Reservoir Pressure, psi	4900
Bottomhole Pressure, psi	1000*
Water Saturation, %	0.3*
Fluid Type	Gas
Reservoir Temperature, ºF	240
Fluid Viscosity, cp	0.015*
Depth, ft	3000
Drainage Area, acre	200
In-Situ Stress, psi/ft	12372
Young's Modulus, psi	1030000
Poisson's Ratio	0.38
Payzone Thickness (Group Thickness), ft	98.4
Possible Fracture Height (Mini-Frac), ft	210

* Data are missing and the values are assumed to run D&C Advisor.

6.6.2 Comparison of Design Results

The results between the recommendations of D&C Advisor and human experts (Shaoul 2007) match well (Table 6.16). Both select the same proppant, and the recommend fracture half-lengths are very close.

Table 6.16—Recommended Fracture Design Comparison for Well #1 in India

Items	D&C Advisor Recommendations GDK Optimal	UFD	PKN Optimal	Best Practice (Shaoul 2007) Recommendations
Optimal Half-Length, ft	300[1]	301	400	510
Fracture Width, inch	0.043	0.201	0.021	0.095
Fracture Height (Input), inch	210	210	210	210
Dimensionless Conductivity	6.773	9.711	2.555	2.2
Proppant Type	ISP-Ceramic	ISP-Ceramic	ISP-Ceramic	ISP (CarboProp
Proppant Mesh	12/20 20/40 16/30	12/20 20/40 16/30	12/20 20/40 16/30	20/40
Proppant Mass, lbm	53030	252000	50288	166000
Fluid Type	Gelled Water	Gelled Water	Gelled Water	YF140.1HTD
Total Fluid Volume (Input), gal	23200	100000 (Input)	22000	66600

[1] Holditch Rule-of-Thumb Calculated Half-Length is 734 ft.

6.7 Using D&C Advisor on Appalachian Tight Gas Sands

Charles et al. (1983) selected the Medina sand in Crawford County, Pennsylvania to evaluate the stimulation treatment for the early 1980s.

6.7.1 Formation Data

Charles et al. (1983) collected the data from 16 wells and chose one for stimulation treatment evaluation. We call this well Well 1 (Table 6-17).

Table 6.17—Basic Data of Well 1 in Appalachian Tight Gas Sands (Charles 1983)

Permeability, md	0.04
Porosity, %	3.7
Net Pay, ft	48
Reservoir Pressure, psi	1350
Bottomhole Pressure, psi	806
Water Saturation, %	39
Fluid Type	Gas
Reservoir Temperature, °	110
Fluid Viscosity, cp	0.0114
Depth, ft	4900
Drainage Area, acre	100*
In-Situ Stress, psi/ft	3000*
Young's Modulus	7040000
Poisson's Ratio	0.25
Pay Zone Thickness (Group Thickness), ft	100
Possible Fracture Height (Mini-Frac),ft	150*

* Data are missing; values are assumed to run D&C Advisor.

Fortunately, Charles et al.'s analysis provided sufficient data on the design of fracture treatment for this well. These data can be used as best practice to validate our D&C Advisor. I used the data in Table 6.17 to run the D&C Advisor, which compares well with best practice on this well.

6.7.2 Comparison of Design Results

The comparison between the results of D&C Advisor and best practices from human experts are shown in Table 6.18.

Table 6.18—Fracture Design Comparison for Well 1 in Appalachian Tight Gas Sands

Items	D&C Advisor Recommendations GDK Optimal	UFD	PKN Optimal	Best Practice (Charles 1983) Recommendation
Optimal Half Length, ft	450[1]	520	550	510
Fracture Width, inch	0.038	0.099	0.018	
Fracture Height (Input), inch	150	150	150	
Dimensionless Conductivity	21.68	11.55	8.630	
Proppant Type	Sand RCS	Sand RCS	Sand RCS	Sand
Proppant Mesh	12/20 20/40 16/30	12/20 20/40 16/30	12/20 20/40 16/30	20/40
Proppant Mass, lbm	49948	100000	42000	250,000
Fluid Type	Gelled Water	Gelled Water	Gelled Water	Crosslinked water-based gel
Total Fluid Volume (Input), gal	17600	100000 (Input)	14800	100,000

[1] Holditch Rule-of -Thumb Calculated Half-Length (D&C Advisor only) is 587 ft.

As shown in Table 6.18, the fracture half-length design by D&C Advisor and human experts matched very well. D&C Advisor recommended fracture half-length ranging from 450 to 587 ft. The fracture half length for best practice is 540 ft.

6.8 Summary

In our seven examples comparing D&C Advisor recommendations with recommendations by human experts, only one case did not match. That mismatch is probably caused by the reservoir type because D&C Advisor is designed for UGRs. For all the other cases, the results match nicely with each other.

These examples show that the D&C Advisor module of the UGR Advisor can design well stimulation treatments in a manner similar to a team of human experts. The advice provided by D&C Advisor is valuable for the design engineer.

7 SUMMARY AND CONCLUSION

7.1 Summary

In previous sections, we defined objectives and expected features for UGR Advisor. In this section, I address the question, “Does UGR Advisor, in its present form, achieves the objectives and expected features for which is designed?” By addressing each of the expected features separately, I show how each feature has met our objectives and expectations.

7.1.1 Expected Feature 1

For a given target well and target formations, based on the dataset of input, UGR Advisor should first group all the input layers. Based on the groups, it should calculate the properties for all the groups so users can choose any one of the groups to generate completion or stimulation designs.

Response

I built an input system for the UGR Advisor. The input system provides two ways to enter the information of all layers into the UGR Advisor. One way is for UGR Advisor to read the data from a file. The other way is for the user to input the data directly from a table. Based on the input, UGR Advisor evaluates all nonpay zones to find barriers that can stop the fracture growth during a fracture treatment. Based on the barrier evaluation result, UGR Advisor will group all layers into pay zone groups. The properties of each group are calculated automatically by the UGR Advisor. Then, the user can choose the groups to design a completion and/or stimulation treatment.

7.1.2 Expected Feature 2

For the selected group, UGR Advisor should be able to determine which diversion technologies are usable as a function of group properties. Then, from economics analysis, it will rank all the selected diversion technologies.

Response

I programmed the diversion technologies selection model that is located in the Completion module of the D&C Advisor. To develop this model, another team member, selected eight types of the most frequently used diversion technologies in industry as the candidate technologies. From the literature review and expert opinions, he developed a decision chart. I programmed and incorporated the decision chart into the D&C Advisor under the umbrella of UGR Advisor.

7.1.3 Expected Feature 3

For the selected group, UGR Advisor should be able to optimally design perforations including phasing, intervals, and shot density.

Response

I built the perforation design model and located it in the Completion module of the D&C Advisor. To build the perforation model, another team member, reviewed the literature on the best practice of perforation for UGRs. From the literature review, he developed a decision chart and a fuzzy logic model to determine the perforation phasing. Also, he developed a decision chart and a model to determine the perforation interval and shot density. I programmed and incorporated all the decision charts or models into the D&C Advisor under the umbrella of UGR Advisor.

7.1.4 Expected Feature 4

In case limited-entry design technology is selected as the diversion technology, UGR Advisor should be able to help the user design a limited entry including injection rate, fluid distribution, surface injection pressure, and number of hole per group.

Response

Another team member built the limited-entry design model. With this model, users can perform three tasks including calculation of the amount of treatment fluid that would go into the individual zones; calculation of the injection rate per zone; and calculation of the surface injection pressure. I programmed and incorporated this model into the D&C Advisor successfully under the umbrella of UGR Advisor.

7.1.5 Expected Feature 5

For the target well, UGR Advisor should be able to determine whether the reservoir is good candidate to be fractured. In the case of multiple wells, the D&C Advisor can be used to determine the best candidate from multiple wells.

Response

I adopted Xiong's candidate model to perform the task of choosing a reservoir model. This successfully programmed model with its user-friendly interface is located in the Stimulation module of the D&C Advisor under the umbrella of UGR Advisor.

7.1.6 Expected Feature 6

For a selected group, UGR Advisor should be able to help the user select the fracture fluid and additives, proppant, and method to inject the fracture fluid and proppant into the formation.

Response

To solve the fracture fluid selection model, I adopted the flow chart built by Malpani (2006). To solve the problem of fracture fluid additives selection, I applied expert rules developed by Xiong (1993). To solve the proppant selection problem, I built a new model based on one proppant selection guideline, one conductivity analysis model, and some expert rules. To solve the injection model, I applied a decision chart developed by Ogueri (2007). All of these models were programmed and incorporated into the D&C Advisor under the umbrella of UGR Advisor.

7.1.7 Expected Feature 7

For a selected group, UGR Advisor should be able to help the user to make basic decisions concerning fracture design, such as pumping schedule, optimal fracture half-length and width as a function of reservoir properties, and economics input.

Response

To solve the pumping schedule problem, I adopted the expert rule method developed by Xiong (1993a). To solve the most important problem of optimal fracture half-length in fracture treatment design, I used three tools to estimate the value: the PKN or GDK model, UFD model, or the Holditch rule of. I programmed all of the models programmed and incorporated them into the D&C Advisor under the umbrella of UGR Advisor.

7.1.8 Expected Feature 8

UGR Advisor should acquire data using a need-driven model, which means that the advisory system asks the user to input only data that are needed. Furthermore, the advisory system will be able to distinguish reasonable data from unreasonable data input. If the user inputs unreasonable data, UGR Advisor can distinguish it and ask the user to change the input data. If it is necessary, UGR Advisor will give suggestion on how to obtain data. All data for the UGR Advisor need to be input only one time.

Response

UGR Advisor only requires data necessary for a specific model. Once data are input somewhere, they will be available and valid for the whole UGR Advisor system. I designed a data evaluation and validation mechanism. Before running any of the models, UGR Advisor will evaluate and validate all input to avoid unreasonable data input. Help information can be reached anywhere by double clicking the data input table or pressing F1 to open the help information.

7.1.9 Expected Feature 9

UGR Advisor should have a flexible and user-friendly interface and provide good help features. Whenever required by the user, UGR Advisor should provide detailed information on the model, flow chart, or rule of thumb used to obtain the advice, recommendations, or best practices.

Response

I built a user friendly interface for entire UGR Advisor. All of the models can be accessed by clicking a button and run simply by clicking the “Run” button. The explanation of all advice, recommendations, and best practices can be accessed by pressing the F1 key or clicking the Help button to open the help interface.

7.2 Conclusions

On the basis of the research results presented in this dissertation, we offer the following conclusions:

1. An advisory system, UGR Advisor—composed of the BASIN, PRISE and D&C Advisor components—can capture best practices for the drilling, completion, stimulation, and production from UGRs. UGR Advisor also provides a friendly user interface system and a complete help and explanation system.
2. The D&C Advisor module of UGR Advisor can be used to provide advice, recommendations, and/or best practices on the drilling, completion, stimulation, and production of UGRs. The Completion and Stimulation modules of D&C Advisor can be used to help an engineer successfully and optimally design well completion and stimulation treatments.
3. The advisory system created in this project is an effective approach for capturing the best practices for drilling, completion, and stimulation for UGRs. Although the solutions for the development of UGRs are complicated and broad, we can divide the total system into smaller modules or even submodules, where each module is responsible for only a narrow domain and has its own functions that are

different from the other modules. As such, we can easily build modules and integrate them to implement required tasks. This approach has been proved very successful throughout the process of building the D&C Advisor.

4. The approach to develop decision charts to capture the best practices is successful. First, we reviewed the literature on the topic and evaluated and documented the best practices from the review. Combining the results of literature review and consultation with experts in this field, we developed a decision chart that resembles the thought process of the human expert. Then, to validate the decision charts, we compared the decisions obtained from the chart with the best practice from literature review. Depending on the comparison, we modified the decision chart until the decision chart produced the same results as the best practice from literature. The decision chart can be used directly, or but we programmed it into a stand-alone program. In D&C advisor, several models such as the fracture fluid selection, diversion technologies selection, and perforation design were built by using this approach.
5. To build an advisory system effectively and easily, we can use different kinds of programming technologies to solve problems, such as the normal algorithm-based programs, database systems, fuzzy logic methods, numerical simulations, or traditional knowledge-based expert systems.
6. We have run several examples and compared the results of D&C Advisor with the result from human experts. These examples show that D&C Advisor of the UGR Advisor can design well stimulation treatments in a manner similar to a team of

human experts. The advice provided by D&C Advisor is valuable for the design engineer. However, more examples are needed to improve UGR Advisor.

7.3 Recommendations

Development of UGR Advisor is in progress. The drilling module of the D&C Advisor, which is assigned to another graduate student, is still in progress.

All the models are built for tight gas sand. We have not built the models for shale gas and coalbed methane. We should design and layout a D&C Advisor for shale gas and coalbed methane.

After all modules are built, they should be incorporated under the same umbrella of UGR Advisor.

NOMENCLATURE

a and b = correlation coefficients used to calculate Holditch rule-based optimal fracture half-length

a_i = parameter weighting factor for parameter i, as defined

A = drainage area, acres

B = matrix of relative stimulation indices

b_j = relative stimulation indices, j, as defined

c = proppant concentration, lb/ft^2

C = discharge coefficient

C_{ave} = average cost to place proppant into formation

C_{fD} = dimensionless conductivity

$C_{fD,\ \mathrm{opt}}$= optimal dimensionless conductivity

C_r = required dimensionless conductivity

C_t = system compressibility at initial reservoir conditions,

d_{pf} = diameter of perforated hole, in.

D = formation depth, ft

D_{qg} = non-Darcy coefficient for gas production

D_{perf} = perforation diameter, in.

D_r = damage factor

D_{TV} = depth of the packer, in ft

E = Young's modulus

E_b = barrier Young's modulus

E_b/E_p = ratio of barrier Young's modulus to pay zone Young's modulus

E_p = payzone Young's modulus, 106 psi

F = Cinco-Ley and Samaniego *f*-factor as a function of dimensionless fracture conductivity

F_{ij}= member functions of parameter i at level j as defined in matrix

F_x = member functions of x variable as defined

F_b = sum of the contribution of each factor used to evaluation barrier

$F_{60}(x)$ = member function of x parameter for 60° phasing

$F_{180}(x)$ = member function of x parameter for 180° phasing

g_p = formation pressure gradient, psi/ft

G = shear modulus of rock formation (4.53)

G_f = fluid pressure gradient, psi/ft

G_i = original gas in place, Mscf

G_p = cumulative gas production, Mscf

$(G_p)_i$ = cumulative gas production at the i time period, Mscf

$(G_p)_{i\text{-}1}$ = cumulative gas production at the i-1 time period, Mscf

G_{pf} = friction pressure gradient, psi/ft

G_r = recoverable gas reserve, Mscf

h_b = barrier thickness, ft

h = net pay thickness, ft

h_f = fracture height, ft

h_p = payzone thickness, ft

h_{perf} = perforated thickness, ft

H = payzone thickness, ft

H_f = gross fracture height, ft

H C= horizontal stress contrast

i = time-step interval

i_{pf} = the injection rate per zone

I_{cs} = comprehensive stimulation index

I_x = weighting factor of x variable as defined

I_{180} = perforation phasing index for 180°-phased perforations

I_{60} = perforation phasing index for 60°-phased perforations

J = pseudosteady-state productivity index, dimensionless

J_D = dimensionless pseudosteady-state productivity index

k = formation permeability, md

k_f = optimal fracture half-length, ft

k_f = proppant permeability under reservoir conditions, md

k/μ = permeability/viscosity ratio

K = cohesion modulus

K_c = critical stress-intensity factor, psi/in.$^{0.5}$

K_x = constant for determining Z-factor, with x as defined by Table 4.8

L = length, ft

L_0 = length at the wellbore, ft

L_f = optimal fracture half-length, ft

$L_{(t)}$ = fracture half-length at time t, ft

m = squares affected by proximity to a pit

M_{prop} = proppant mass, lb/ft

N = nine-parameter weighting factor for stimulation indices

NF = naturally fractured

N_{perf} = number of perforations

N_{prop} = dimensionless proppant number

p = pressure, psia

p_0 = pressure at the wellbore, psia

p_{ave} = reservoir average pressure, psia

p_{BHT} = bottomhole treatment pressure, psia

p_f = fracture pressure, psia

p_h = fluid pressure at the depth of the packer, psi

p_i= initial pressure

p_{pc} = pseudocritical pressure, psia

p_{pf} = pipe friction

p_{ppf} = perforation friction

p_{pr} = reduced pressure, psia

p_{surf} = surface injection pressure, psia

p_{wf} = bottomhole wellbore flowing pressure, psia

$p(0,t)$ = pressure at the wellbore at time t, psia

$p(X,t)$ = pressure at coordinate X at time t, psia

P = gas price, USD

q = fracturing fluid flow rate, bpm

q_g = gas flow rate, scf

q_0 = injection rate, bbl/min

$q(0,t)$ = injection rate at the wellbore (x=0) at time t

r = pit affecting flow near squares

r_e = reservoir drainage radius, ft

r_w = wellbore radius, ft

r'_w = effective wellbore radius to account for the effect of fracture, ft

r_we= effective wellbore radius, ft

R = relation of functions in matrix

R_r = rate of return on investment

s = skin

s_f = pseudoskin

SP = sand production

S_w = water saturation

S_{wi} = initial water saturation

t = time point during a fracture treatment

t_{DA} = nondimensional pseudosteady-state time, hour

t_{pss} = time at which pseudosteady-state flow begins

T_f = fracture temperature, ºF

T_{pc} = pseudocritical fracture temperature, ºF

T_{pr} = reduced temperature, ºF

V = volume, ft^2

V_p = volume of proppant in pay, ft^2

V_{pf} = volume of propped fracture, ft^2

V_r = reservoir drainage volume, ft^2

w = fracture width, ft

w_j = level weighting factor

wk_f = fracture conductivity, md-ft

w_{opt} = optimal fracture width, ft

W_d = wellbore condition

W_{pn} = weighted proppant number

W_{x} = weighting of factor x as defined

$W_{(x,t)}$ = width in elliptical fracture at time t at location X, ft

x = closure stress, psi (used in proppant selection model)

x_f = fracture half-length, ft

$x_{f\mathrm{iot}}$ = optimal fracture half-length, ft

x_e = drainage side length, ft

X = coordinate along direction of fracture propagation

X_f = optimal fracture half-length, ft

y = proppant permeability, darcy (used in proppant selection model)

$\overline{Z}$ = compressibility factor under the average pressure

Z_i = initial gas compressibility factor

Z_g = gas compressibility factor

γ = gas gravity

Δp = pressure drop, psi

Δp_{perf} = pressure drop across the perforations, psi

$\Delta\sigma$ = in-situ stress differential between the potential barrier and the payzone, psi

λ = dimensionless fracture coordinate

λ_0 = dimensionless fracture coordinate at the wellbore

μ_g = gas viscosity, cp

$\mu_{g, wf}$ = gas viscosity at bottomhole flowing pressure, cp

ν = Poisson's ratio

ρ = density of the fracturing fluid, lbm/gal

ρ_p = proppant density, lb/ft^3

ρ_r = reduced density, lb/ft^3

σ = in-situ stress gradient, psi/ft

σ_h = in-situ normal rock stress perpendicular to fracture face, psi/ft

σ_{fc} = formation closure stress, psi/ft

ϕ = porosity, %

ϕ_p = the proppant porosity, %

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APPENDIX A

VALIDATION OF THE

DIVERSION TECHNOLOGY SELECTION MODEL

Ogueri (2007) validated the Diversion Technology Selection (DTS) model by comparing the results obtained from the model with the best practice from literature. If the actual best practice provided by the case study corresponded with the recommendation provided by the model, the validation was considered successful. The detailed comparisons are shown in Tables A.1 and A.2. The analysis shows that field data and the Diversion Technology Selection Model are in reasonable agreement.

Table A.1—Input Data for the Validation of Diversion Techniques Selection Model (Ogueri 2007)

SPE Paper	Location	Formation	Well	TVD, ft	Net pay thickness, ft	Pay zone thicknes s, ft	Formation pressure gradient
71656	Uinta	Fort Union; Wasatch		3647	175	33	Normally Pressured
60313	Rocky Mountains, Alberta Canada	Viking sands, Wild Cat Hills	3-3-27-5W5M	8200	45	10	Under pressured
90722	Alaska	Beluga sands, Kenai gas Field		7500	175	18	Normally pressured
64526	Oklahoma	Stephens County		7800	262	42	Normally pressured
530	Permian	TXL Tubb field, Ector County		6300	73	18	Under-pressured
6868	East Texas	Cotton Valley		9000	175	76	Normally pressured
59790	Green River	Lance		11000 to 12500	300 to 600	5 to 50	Over-pressured

Table A.2—Diversion Technology Best Practices (Ogueri 2007)

SPE Paper	Best Practice from Literature	Subroutine Options From DTS Model
71656	Coiled Tubing Fracturing	Coiled tubing, ExCAPE, Pine Island, HydraJet
60313	Coiled Tubing Fracturing	Coiled tubing, limited entry, pseudo limited entry, Pine Island, HydraJet
90722	ExCAPE	ExCAPE, coiled tubing, Pine Island, HydraJet
64526	ExCAPE	ExCAPE, coiled tubing, Pine Island, HydraJet
530	Limited Entry	Limited entry, coiled tubing, pseudo limited entry, Pine Island, HydraJet
6868	Packer and Bridge Plug	Packer and bridge plug, ExCAPE, FTCBP, Pine Island
59790	FTCBP*	FTCBP, limited entry, pseudo limited entry, ExCAPE

* Flow through composite frac plug

APPENDIX B

VALIDATION OF THE LIMITED ENTRY DESIGN MODEL

Upon completion of the Limited Entry Design (LED) computer program, Ogueri (2007) checked for accuracy by comparing the results obtained from hand calculations with the results obtained from the program (Tables B.1 through B9).

Verification 1

In Verification 1, Ogueri (2007) modeled injection of 100,000 gal of WF 120 treatment fluid at 30 bbl/min. From the input parameters (Table B.1), the model results (Table B.2) showed that nearly half of the fluid was injected into the second zone, resulting in a surface injection pressure of more than 8,000 psi. Ogueri's hand calculations (Table B.3) returned almost exactly the same values, which may have resulted merely from decimal errors in the hand calculations.

Table B.1—Input Parameters for LED Verification 1 (Ogueri 2007)

Fluid type	WF 120
Fluid density, lb/gal	8.66
Fluid gradient, psi/ft	0.45
Total fluid quantity, gal	100000
Number of zones	3
Perforation diameter, in	0.35
Coefficient of discharge	0.9
In-situ stress, psi/ft	0.8
Depth of packer, ft	9800
Tubing size, in	2.875
Injection rate, bbl/min	20
Friction pressure gradient, psi/ft	0.412

Table B.2—Model Results for LED Variation 1 (Ogueri 2007)

	Input			Output		
Zone	Net Pay thickness per zone, ft	Number of holes per zone	Depth to top of zone, ft	Injection Rate, bbl/min/perf	Fluid Distribution, %	Fluid Distribution, gal
1	10	3	10000	6.3	31.4	31401
2	15	5	10200	9.9	49.8	49772
3	5	2	10400	3.7	18.8	18828

Surface injection pressure = **8272 psi**

Table B.3—Hand Calculation Results for LED Variation 1 (Ogueri 2007)

	Input			Output		
Zone	Net Pay thickness per zone, ft	Number of holes per zone	Depth to top of zone, ft	Injection Rate, bbl/min/perf	Fluid Distribution, %	Fluid Distribution, gal
1	10	3	10000	6.0	31.3	31250
2	15	5	10200	9.6	50.0	50000
3	5	2	10400	3.6	18.8	18750

Surface injection Pressure = **8222 psi**

Verification 2

In the second case, Ogueri (2007) again modeled 100,000 gal of WF 120 fluid, this time at an injection rate of 30 bbl/min. He increased the perforation diameter to 0.375 in. and reduced the in-situ stress to 0.45 psi/ft. The change in injection rate increased the friction pressure gradient to 0.754 (Table B.4). With these changes and a reduction in depths of the zones (Tables B.5 and B.6), the distributions of fluids were still very similar to those in Verification 2, and differences between the model and hand calculations were insignificant. The surface injection pressure was about 300 psi greater in Verification 2 than in Verification 1, but the model and hand calculations still matched closely, confirming “that the equations behind the program were correct and that the program was working effectively” (Ogueri 2007).

Table B.4—Input Parameters for LED Verification 2 (Ogueri 2007)

Fluid type	WF 120
Fluid density, lb/gal	8.66
Fluid gradient, psi/ft	0.45
Total fluid quantity, gal	100000
Number of zones	3
Perforation diameter, in	0.375
Coefficient of discharge	0.9
In-situ stress, psi/ft	0.45
Depth of packer, ft	9800
Tubing size, in	2.875
Injection rate, bbl/min	30
Friction pressure gradient, psi/ft	0.754

Table B.5—Model Results for LED Variation 2 (Ogueri 2007)

	Input				Output	
Zone	Net Pay thickness per zone, ft	Number of holes per zone	Depth to top of zone, ft	Injection Rate, bbl/min/perf	Fluid Distribution, %	Fluid Distribution, gal
1	10	3	8000	9.0	30.0	30001
2	15	5	8500	15.0	49.9	49999
3	5	2	9000	6.0	19.9	19999

Surface injection pressure = **8536 psi**

Table B.6—Hand Calculation Results for LED Variation 2 (Ogueri 2007)

	Input				Output	
Zone	Net Pay thickness per zone, ft	Number of holes per zone	Depth to top of zone, ft	Injection Rate, bbl/min/perf	Fluid Distribution, %	Fluid Distribution, gal
1	10	3	8000	9.0	30.0	30000
2	15	5	8500	15.0	50.0	50000
3	5	2	9000	6.0	20.0	20000

Surface injection Pressure = **8542 psi**

Verification 3

Ogueri's (2007) third verification of the LED model increased the fluid amount to 150,000 gal WF 240 treatment fluid, pumped at an injection rate of 40 bbl/min. He changed in-situ stress to 0.8 psi/ft and interpolated between two rates and two pressure gradients (Table B.10) for WF 240 fluids to compute a new friction pressure gradient of 0.491 psi/ft.

The results of these changes again showed about half the fluid going into the second zone, with the remainder split to about 30% in the upper zone and 20% in the lower zone, much as they did in the first two verifications, and the hand calculations again closely matched the modeled ones; differences were insignificant. In fact, although the surface injection pressure increased to around 9,800 psi, the difference between the model value (9,810 psi) and the hand calculation (9,813 psi) was moot.

Table B.7—Input Parameters for LED Verification 3 (Ogueri 2007)

Fluid type	WF 240
Fluid density, lb/gal	8.66
Fluid gradient, psi/ft	0.45
Total fluid quantity, gal	150000
Number of zones	3
Perforation diameter, in	0.375
Coefficient of discharge	0.9
In-situ stress, psi/ft	0.8
Depth of packer, ft	9800
Tubing size, in	2.875
Injection rate, bbl/min	40
Friction pressure gradient, psi/ft	0.491

Table B.8—Model Results for LED Variation 3 (Ogueri 2007)

	Input				Output	
Zone	Net Pay thickness per zone, ft	Number of holes per zone	Depth to top of zone, ft	Injection Rate, bbl/min/perf	Fluid Distribution, %	Fluid Distribution, gal
1	10	3	8000	12.4	31.2	46725
2	15	5	8500	19.9	49.8	74712
3	5	2	9000	7.6	19.0	28563

Surface injection Pressure = 9813 **psi**

Table B.9—Hand calculation results for LED Variation 3 (Ogueri 2007)

	Input				Output	
Zone	Net Pay thickness per zone, ft	Number of holes per zone	Depth to top of zone, ft	Injection Rate, bbl/min/perf	Fluid Distribution, %	Fluid Distribution, gal
1	10	3	10000	12.4	31.2	46727
2	15	5	10200	19.9	49.8	74680
3	5	2	10400	7.6	19.1	28593

Surface injection Pressure = **9810 psi**

Table B10—Friction Pressure vs. Rate Data for WF 240 (Ogueri 2007)

	Rate, bbl/min	**Friction Pressure, psi/1000 ft**
Low	1.6	10.8
Pivot	5.8	32
High	77.9	1000

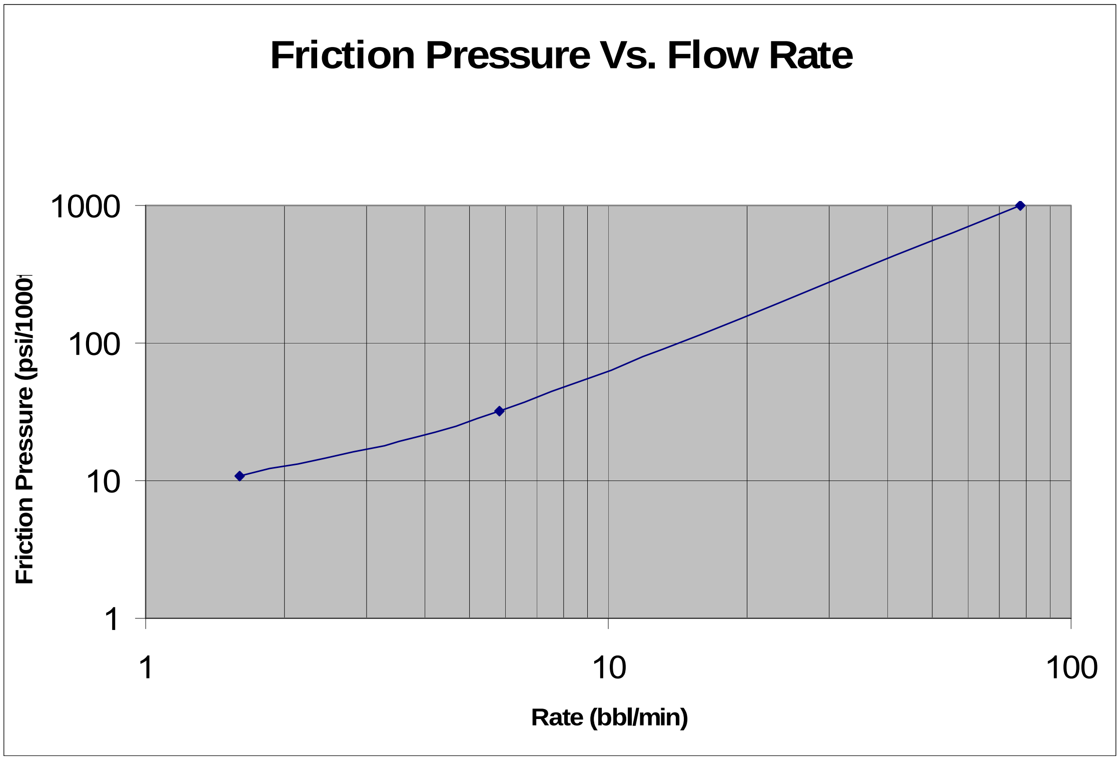

Fig. B.1—Friction pressure increases log-normally with rate for WF 240. (Ogueri 2007)

APPENDIX C

VALIDATION OF THE PERFORATION DESIGN MODEL

Upon completion of the perforation design model, Bogatchev (2007) validated the model by comparing the results obtained from the model with the best practice from literature. If the actual best practice provided by the case study matched the recommendation provided by the perforation design model, the validation was considered successful. The detailed comparisons are shown in Tables C.1 to C.4.

Table C.1—Validation of the PPS Model (Bogatchev 2007)

SPE Paper	Basin	Formation	Well	Perforation phasing, ° Actual	Rec I(60°)	I(180°)	TVD, ft	Perm, md	Young's mod, MM psi	Natural fracs	Formation sand prod	Horiz stress contrast
94002	S. Texas	Vicksburg	1	60	0.67	0.20	9310	0.100	3.3	low	no	moderate
95337	Permian	Canyon	A	60	0.51	0.27	5834	0.010	5.5	low	no	moderate
95337	Permian	Canyon	B	60	0.51	0.27	5930	0.010	5.5	low	no	moderate
39951	S. Texas	Vicksburg	B	60	0.58	0.35	9900	0.010	3.5	low	no	moderate
76812	S. Texas	Wilcox Lobo	B	60	0.61	0.33	7800	0.010	2.5	low	no	moderate
50610	Illizi Algeria	Tin Fouye	1	60	0.56	0.26	4500	10.000	5.0	low	no	moderate
77678	Japan	Minami-Nagaoka	MHF#1-1	60	0.49	0.40	14000	0.100	5.0	moderate	no	moderate
36471	W. Texas	Wolfcamp	Mitchell 6#5	90	0.47	0.40	7700	0.010	5.0	moderate	no	moderate
36471	W. Texas	Wolfcamp	Mitchell 5B#6	90	0.47	0.40	7950	0.010	5.0	moderate	no	moderate
36471	W. Texas	Wolfcamp	Mitchell 5B#7	90	0.47	0.40	7850	0.010	5.0	moderate	no	moderate
36471	W. Texas	Wolfcamp	Mitchell 5a#8	90	0.47	0.40	7950	0.010	5.0	moderate	no	moderate
36471	W. Texas	Wolfcamp	Mitchell 11#6	90	0.47	0.40	9800	0.010	5.0	moderate	no	moderate
36735	Permian	Canyon	Henderson 32-9	120	0.51	0.27	6400	0.010	5.5	low	no	moderate
36735	Permian	Canyon	Couch #7	120	0.51	0.27	6500	0.010	5.5	low	no	moderate
21495	E. Texas	Upper Travis Peak	SFE #2	180	0.35	0.47	8300	0.006	7.0	moderate	no	moderate

Table C.2—Validation of the Shot Density Model for Conventional Hydraulic Fracturing (Bogatchev 2007)

SPE Paper	Basin	Formation	Well	Total perfo-rated interval, ft	Shot density, SPF Actual	Shot density, SPF Recom-mended Min	Shot density, SPF Recom-mended Max	Perf phasing,°	Number of perf intervals	Perf diameter, in.	Average slurry rate, bpm	TVD, ft	Perm, md
36471	W.Texas	Wolfcamp	Mitchell 11#6	38	2.0	1.8	3.6	90	3	0.38	35	9800	0.01
39951	S.Texas	Vicksburg	B	25	4.0	3.3	6.6	60	1	0.25	18	10000	0.10
11600	S.Texas	Wilcox Lobo	1	50	1.0	1.0	2.0	60		0.25	20	10000	0.10
94002	S.Texas	Vicksburg	1	26	2.0	1.5	3.0	60		0.25	20	9310	0.10
76812	S.Texas	Wilcox Lobo	B	5	8.0	8.0	12.0	60		0.32	23	7800	0.10
36471	W.Texas	Wolfcamp	Mitchell 6#5	36	2.0	1.6	3.3	90	1	0.38	30	7700	0.01
77678	Japan	Minami-Nagaoka	MHF#1-1	12	6.0	10.0	12.0	60	1	0.26	15	1400	0.10
36471	W.Texas	Wolfcamp	Mitchell 5B#6	20	2.0	3.0	6.0	90	2	0.43	30	7950	0.01
36471	W.Texas	Wolfcamp	Mitchell 5B#7	46	1.0	1.3	2.6	90	2	0.43	30	7850	0.01
36471	W.Texas	Wolfcamp	Mitchell 5a#8	20	2.0	3.5	7.0	90	1	0.43	35	7950	0.01

Table C.3—Validation of the Shot Density Model for Limited-Entry Hydraulic Fracturing (Bogatchev 2007)

SPE Paper #	Basin	Formation	Well	Total perf interval, ft	Number of shots Actual	Number of shots Rec Min	Number of shots Rec Max	Perf phasing, °	Number of perf intervals	Perf diameter, in.	Average slurry rate, bpm	Perm, md
95337	Permian	Canyon	A-zone3	115	24	23	46	60	1	0.32	48	0.01
95337	Permian	Canyon	A-zone4	91	24	24	48	60	1	0.32	49	0.01
95337	Permian	Canyon	B-zone4	126	28	25	49	60	1	0.32	49	0.01
95337	Permian	Canyon	B-zone5	140	24	24	48	60	1	0.32	48	0.01
95337	Permian	Canyon	B-zone6	104	18	19	37	60	1	0.32	38	0.01
53923	Texas	Mesaverde		100	25	22	45	60	2	0.32	45	1.00
95337	Permian	Canyon	A	723	101	72	145	60	6	0.32	46	0.01
95337	Permian	Canyon	B-zone2	30	13	8	15	60	1	0.32	16	0.01
5337	Permian	Canyon	A-zone2	174	30	16	33	60	1	0.32	33	0.01
95337	Permian	Canyon	B-zone3	122	17	22	44	60	1	0.32	45	0.01
95337	Permian	Canyon	B-zone1	84	13	19	39	60	1	0.32	38	0.01
95337	Permian	Canyon	A-zone6	271	16	24	49	60	1	0.32	51	0.01
95337	Permian	Canyon	A-zone1	130	14	22	46	60	1	0.32	46	0.01
95337	Permian	Canyon	B-zone7	116	13	26	51	60	1	0.32	52	0.01
95337	Permian	Canyon	A-zone5	128	14	36	46	60	1	0.32	47	0.01

Table C.4 Validation of the Perforation Interval Selection Model (Bogatchev 2007)

SPE Paper #	Basin	Formation	Well	Pay-zone thick-ness, ft	Net-pay thick-ness, ft	Total length of perforated interval, ft		Number of perf intervals	Sand/Shale closure stress contrast gradient, psi/ft	TVD, ft	Perm, md	Young's modulus, MMpsi	Natu-ral frac-tures
						Actual	Recom-mended						
Most Porous Zone													
36471	W.Texas	Wolfcamp	Mitchell 5B#6	90	70	20	20	1	0.03	7950	0.01	5.0	low
39951	S.Texas	Vicksburg	B	149	60	25	20	1	moderate	10000	0.10	3.5	low
36471	W.Texas	Wolfcamp	Mitchell 5a#8	80	79	20	20	1	0.11	7950	0.01	5.0	low
94002	S.Texas	Vicksburg	1	149	70	26	20	1	moderate	9310	0.10	3.3	low
36471	W.Texas	Wolfcamp	Mitchell 11#6	90	81	38	60	3	0.1	9800	0.01	5.0	low
36471	W.Texas	Wolfcamp	Mitchell 6#5	80	60	36	20	1	0.1	7700	0.01	5.0	low
107827	Neuduen, Argentina	Cupen Mahida	1	150	130	6	6	1	moderate	11000	0.10	2.5	high
77678	Japan	Minami-Nagaoka	MHF#1-1	150	120	12	12	2	moderate	14000	0.10	4.9	mode-rate
Entire Interval													
36471	W.Texas	Wolfcamp	Mitchell 5B#7	100	46	46	46	2	0.12	7850	0.01	5.0	low
11600	S.Texas	Wilcox Lobo	1	149	50	50	50	1	moderate	10000	0.10	2.5	low
Limited-Entry													
95337	Permian	Canyon	A	1000	909	909	909	6	0.15	5834	0.01	5.5	low
95337	Permian	Canyon	B	1000	722	722	722	7	0.15	5929	0.01	5.5	low
53923	Texas	Mesaverde		400	100	100	100	2	moderate	5500	1.00		low
Point-Source													
76812	S.Texas	Wilcox Lobo	B	140	96	5	5	1	low	7800	0.1	2.5	low

APPENDIX D

MEMBERSHIP FUNCTIONS FOR

FRACTURE CANDIDATE MODELS

(1) Level 1 " Excellent Candidate"

$$F_1(\phi)\begin{cases} \text{Exp}\left[-\left(\dfrac{\phi-2.5}{-9.6089}\right)^2\right] & (6 \le \phi < 22) \\ 1-\text{Exp}\left[-\left(\dfrac{\phi-5}{-1.20112}\right)^2\right] & (5 \le \phi < 6) \\ 1-\text{Exp}\left[-\left(\dfrac{\phi-26}{-4.8045}\right)^2\right] & (22 \le \phi < 26) \\ 0 & (\text{otherwise}) \end{cases}$$

(2) Level 2 - " Good Candidate"

$$F_2(\phi)\begin{cases} 1-\text{Exp}\left[-\left(\dfrac{\phi-32.5}{-3.0028}\right)^2\right] & (30 \le \phi < 32.5) \\ \text{Exp}\left[-\left(\dfrac{\phi-26}{-4.8045}\right)^2\right] & (22 \le \phi < 30) \\ 1-\text{Exp}\left[-\left(\dfrac{\phi-14}{-9.6089}\right)^2\right] & (6 \le \phi < 22) \\ \text{Exp}\left[-\left(\dfrac{\phi-5}{-1.20112}\right)^2\right] & (4 \le \phi < 6) \\ 1-\text{Exp}\left[-\left(\dfrac{\phi-3}{-1.20112}\right)^2\right] & (3 \le \phi < 4) \\ 0 & (\text{otherwise}) \end{cases}$$

(3) Level 3 -" Possible Candidate"

$$F_3(\phi)\begin{cases} \text{Exp}\left[-\left(\dfrac{\phi-32.5}{-3.0028}\right)^2\right] & (30 \le \phi) \\ 1-\text{Exp}\left[-\left(\dfrac{\phi-26}{-4.8045}\right)^2\right] & (26 \le \phi < 30) \\ 0 & (5 \le \phi < 26) \\ 1-\text{Exp}\left[-\left(\dfrac{\phi-5}{-1.20112}\right)^2\right] & (4 \le \phi < 5) \\ \text{Exp}\left[-\left(\dfrac{\phi-3}{-1.20112}\right)^2\right] & (\phi < 4) \end{cases}$$

(4) Level 4 - " Not a Candidate"

$$F_4(\phi)\begin{cases} 1-\text{Exp}\left[-\left(\dfrac{\phi-32.5}{-3.0028}\right)^2\right] & (30 \le \phi) \\ 0 & (4 \le \phi < 30) \\ 1-\text{Exp}\left[-\left(\dfrac{\phi-5}{-1.20112}\right)^2\right] & (\phi < 4) \end{cases}$$

.... (D.1)

(1) Level 1 " Excellent Candidate"

$$F_1\left(\frac{k}{\mu}\right)\begin{cases} \mathrm{Exp}\left\{-\left[\dfrac{\log\left(\frac{k}{\mu}\right)-0.5}{-1.80168}\right]^2\right\} & (0.1 \le \frac{k}{\mu} < 100) \\ 1-\mathrm{Exp}\left\{-\left[\dfrac{\log\left(\frac{k}{\mu}\right)+1.5}{-0.60056}\right]^2\right\} & (0.032 \le \frac{k}{\mu} < 0.1) \\ 1-\mathrm{Exp}\left\{-\left[\dfrac{\log\left(\frac{k}{\mu}\right)-2.5}{-0.60056}\right]^2\right\} & (100 \le \frac{k}{\mu} < 320) \\ 0 & (\text{otherwise}) \end{cases}$$

(2) Level 2 - " Good Candidate"

$$F_2\left(\frac{k}{\mu}\right)\begin{cases} 1-\mathrm{Exp}\left\{-\left[\dfrac{\log\left(\frac{k}{\mu}\right)-3.349}{-0.42}\right]^2\right\} & (1000 \le \frac{k}{\mu} < 2250) \\ \mathrm{Exp}\left\{-\left[\dfrac{\log\left(\frac{k}{\mu}\right)+2.5}{-0.6}\right]^2\right\} & (100 \le \frac{k}{\mu} < 1000) \\ 1-\mathrm{Exp}\left\{-\left[\dfrac{\log\left(\frac{k}{\mu}\right)-0.5}{-1.8}\right]^2\right\} & (0.1 \le \frac{k}{\mu} < 100) \\ \mathrm{Exp}\left\{-\left[\dfrac{\log\left(\frac{k}{\mu}\right)+1.5}{-0.6}\right]^2\right\} & (0.01 \le \frac{k}{\mu} < 0.1) \\ 1-\mathrm{Exp}\left\{-\left[\dfrac{\log\left(\frac{k}{\mu}\right)+2.5}{-0.6}\right]^2\right\} & (0.032 \le \frac{k}{\mu} < 0.01) \\ 0 & (\text{otherwise}) \end{cases}$$

(3) Level 3 -" Possible Candidate"

$$F_3\left(\frac{k}{\mu}\right)\begin{cases} \mathrm{Exp}\left\{-\left[\dfrac{\log\left(\frac{k}{\mu}\right)-3.349}{-0.41977}\right]^2\right\} & (1000 \le \frac{k}{\mu}) \\ 1-\mathrm{Exp}\left\{-\left[\dfrac{\log\left(\frac{k}{\mu}\right)-2.5}{-0.60056}\right]^2\right\} & (320 \le \frac{k}{\mu} < 1000) \\ 0 & (0.1 \le \frac{k}{\mu} < 320) \\ 1-\mathrm{Exp}\left\{-\left[\dfrac{\log(\left(\frac{k}{\mu}\right)+1.5}{-60056}\right]^2\right\} & (0.032 \le \frac{k}{\mu} < 0.1) \\ \mathrm{Exp}\left\{-\left[\dfrac{\log\left(\frac{k}{\mu}\right)+1.5}{-0.60056}\right]^2\right\} & (0\ \frac{k}{\mu} < 0.032) \end{cases}$$

(4) Level 4 - " Not a Candidate"

$$F_4\left(\frac{k}{\mu}\right)\begin{cases} 1-\mathrm{Exp}\left\{-\left[\dfrac{\log\left(\frac{k}{\mu}\right)-3.3495}{-0.41977}\right]^2\right\} & (2250 \le \frac{k}{\mu}) \\ 0 & (0.0032 \le \frac{\mathrm{k}}{\mu} < 2250) \\ 1-\mathrm{Exp}\left\{-\left[\dfrac{\log\left(\frac{k}{\mu}\right)+2.5}{-0.60056}\right]^2\right\}) & (\frac{k}{\mu} < 0.0032) \end{cases}$$

.... (D.2)

(1) Level 1 " Excellent Candidate"

$$F_1(s)\begin{cases} 1 & (s > 15) \\ 1 - \text{Exp}\left(-\dfrac{s - 5.5}{-5.40506}\right) & (5.5 \le s < 15) \\ 0 & (s < 5.5) \end{cases}$$

(2) Level 2 - " Good Candidate"

$$F_2(s)\begin{cases} \text{Exp}\left[-\left(\dfrac{s+1}{-2.40224}\right)^2\right] & (1 \le s < 10) \\ 1 - \text{Exp}\left[-\left(\dfrac{s+2.5}{-4.20393}\right)^2\right] & (-6 \le s < 1) \\ 0 & (\text{otherwise}) \end{cases}$$

(3) Level 3 -" Possible Candidate"

$$F_3(s)\begin{cases} 1 - \text{Exp}\left[-\left(\dfrac{s-5.5}{-5.40505}\right)^2\right] & (1 \le s < 5.5) \\ \text{Exp}\left[-\left(\dfrac{s+2.5}{-4.20393}\right)^2\right] & (-6 \le s < 1) \\ 0 & (\text{otherwise}) \end{cases}$$

(4) Level 4 - " Not a Candidate"

$$F_4(s)\begin{cases} 1 - Exp\left[-\left(-\dfrac{s+2.5}{-4.20393}\right)^2\right] & (s \le -2.5) \\ 0 & (s > -2.5) \end{cases}$$

$$\text{.. (D.3)}$$

(1) Level 1 " Excellent Candidate"

$$\text{F}_1(h)\begin{cases} 1 - \text{Exp}\left[-\left(\dfrac{h-100}{-60.56}\right)^2\right] & (100 < h) \\ 0 & (h \ge 100) \end{cases}$$

(2) Level 2 - " Good Candidate"

$$F_2(h)\begin{cases} \text{Exp}\left[-\left(\dfrac{h-100}{-60.56}\right)^2\right] & (50 < h) \\ 0 & (h < 35) \\ 1 - \text{Exp}\left[-\left(\dfrac{h-35}{-18.017}\right)^2\right] & (35 < h \le 50) \end{cases}$$

(3) Level 3 -" Possible Candidate"

$$\text{F}_3(h)\begin{cases} 1 - \text{Exp}(-(\dfrac{h-100}{-60.56})^2) & (35 < h < 100) \\ 0 & (h \ge 100) \\ \text{ExpExp}\left[-\left(\dfrac{h-35}{-18.017}\right)^2\right] & (h \le 35) \end{cases}$$

(4) Level 4 - " Not a Candidate"

$$F_4(h)\begin{cases} 1 - \text{Exp}\left[-\left(\dfrac{h-35}{-18.017}\right)^2\right] & (h < 35) \\ 0 & (h \ge 35) \end{cases}$$

$$\text{.. (D.4)}$$

(1) Level 1 "Excellent Candidate"

$$F_1(S_w)\begin{cases} 1 - \text{Exp}\left[-\left(\dfrac{S_w - 37.5}{-15.014}\right)^2\right] & (S_w < 37.5) \\ 0 & (S_w \geq 37.5) \end{cases}$$

(2) Level 2 - "Good Candidate"

$$F_2(S_w)\begin{cases} 1 - \text{Exp}\left[-\left(\dfrac{S_w - 60}{-12.0112}\right)^2\right] & (50 < S_w \leq 60) \\ 0 & (S_w > 60) \\ 1 - \text{Exp}\left[-\left(\dfrac{S_w - 37.5}{-15.014}\right)^2\right] & (S_w \leq 50) \end{cases}$$

(3) Level 3 -"Possible Candidate"

$$F_3(S_w)\begin{cases} \text{Exp}\left[-\left(\dfrac{S_w - 60}{-12.0112}\right)^2\right] & (50 < S_w) \\ 0 & (S_w < 37.5) \\ 1 - \text{Exp}\left[-\left(\dfrac{S_w - 37.5}{-15.014}\right)^2\right]) & (37.5 \leq S_w \leq 50) \end{cases}$$

(4) Level 4 - "Not a Candidate"

$$F_1(S_w)\begin{cases} 1 - \text{Exp}\left[-\left(\dfrac{S_w - 60}{-12.0112}\right)^2\right] & (S_w > 60) \\ 0 & (S_w < 60) \end{cases}$$

.... (D.5)

(1) Level 1 "Excellent Candidate"

$$F_1(D)\begin{cases} 1 - \text{Exp}\left[-\left(\dfrac{D - 10000}{-2402.25}\right)^2\right] & (D < 10000) \\ 0 & (D \geq 10000) \end{cases}$$

(2) Level 2 - "Good Candidate"

$$F_2(D)\begin{cases} 1 - \text{Exp}\left[-\left(\dfrac{D - 16000}{-4804.5}\right)^2\right] & (12000 < D \leq 16000) \\ 0 & (D > 16000) \\ \text{Exp}\left[-\left(\dfrac{D - 10000}{-2402.25}\right)^2\right] & (D \leq 12000) \end{cases}$$

(3) Level 3 -"Possible Candidate"

$$F_3(D)\begin{cases} \text{Exp}\left[-\left(\dfrac{D - 16000}{-4804.5}\right)\right]^2 & (12000 < D) \\ 0 & (D \leq 10000) \\ 1 - \text{Exp}\left[-\left(\dfrac{D - 10000}{-2402.25}\right)^2\right] & (10000 < D \leq 12000) \end{cases}$$

(4) Level 4 - "Not a Candidate"

$$F_4(D)\begin{cases} 1 - \text{Exp}\left[-\left(\dfrac{D - 16000}{-4804.5}\right)^2\right] & (16000 < \mathrm{D}) \\ 0 & (D \leq 16000) \end{cases}$$

.... (D.6)

(1) Level 1 " Excellent Candidate"

$$F_1(g_p)\begin{cases} 1 - \mathrm{Exp}\left[-\left(\dfrac{g_p - 0.5}{-0.12011}\right)^2\right] & (g_p > 0.5) \\ 0 & (g_p \le 0.5) \end{cases}$$

(2) Level 2 - " Good Candidate"

$$F_2(g_p)\begin{cases} \mathrm{Exp}\left[-\left(\dfrac{g_p - 0.5}{-0.12011}\right)^2\right] & (g_p > 0.4) \\ 0 & (g_p \le 0.3) \\ 1 - \mathrm{Exp}\left[-\left(\dfrac{g_p - 0.3}{-0.12011}\right)^2\right] & (0.3 < g_p \le 0.4) \end{cases}$$

(3) Level 3 -" Possible Candidate"

$$F_3(g_p)\begin{cases} 1 - \mathrm{Exp}\left[-\left(\dfrac{g_p - 0.5}{-0.12011}\right)^2\right] & (0.4 < g_p \le 0.5) \\ 0 & (g_p > 0.5) \\ \mathrm{Exp}\left[-\left(\dfrac{g_p - 0.3}{-0.12011}\right)^2\right] & (g_p \le 0.4) \end{cases}$$

(4) Level 4 - " Not a Candidate"

$$F_4(g_p)\begin{cases} 1 - \mathrm{Exp}\left[-\left(\dfrac{g_p - 0.3}{-0.12011}\right)^2\right] & (g_p < 0.4) \\ 0 & (g_p \ge 0.4) \end{cases}$$

.... (D.7)

(1) Level 1 " Excellent Candidate"

$$F_1(A)\begin{cases} 1 - \mathrm{Exp}\left[-\left(\dfrac{A - 110}{-60.056}\right)^2\right] & (A > 110) \\ 0 & (A \le 110) \end{cases}$$

(2) Level 2 - " Good Candidate"

$$F_2(A)\begin{cases} \mathrm{Exp}\left[-\left(\dfrac{A - 110}{-60.056}\right)^2\right] & (A > 60) \\ 0 & (A \le 40) \\ 1 - \mathrm{Exp}\left[-\left(\dfrac{A - 110}{-24.0224}\right)^2\right] & (40 < A \le 60) \end{cases}$$

(3) Level 3 -" Possible Candidate"

$$F_2(A)\begin{cases} 1 - \mathrm{Exp}\left[-A\left(\dfrac{A - 110}{-60.056}\right)^2\right] & (60 < A < 110) \\ 0 & (A \ge 110) \\ \mathrm{Exp}\left[-\left(\dfrac{A - 40}{-24.0224}\right)^2\right] & (A \le 60) \end{cases}$$

(4) Level 4 - " Not a Candidate"

$$F_4(\mathrm{A})\begin{cases} 1\mathrm{Exp}\left[-\left(\dfrac{A - 40}{-24.0224}\right)^2\right] & (A \le 40) \\ 0 & (A > 40) \end{cases}$$

.... (D.8)

(1) Level 1 " Excellent Candidate"

$$F_1(W_D)\begin{cases} 1 - \text{Exp}\left[-\left(\dfrac{W_D - 0.75}{- 0.12011}\right)^2\right] & (W_D > 0.75) \\ 0 & (W_D \leq 0.75) \end{cases}$$

(2) Level 2 - " Good Candidate"

$$F_2(W_D)\begin{cases} \text{Exp}\left[-\left(\dfrac{W_D - 0.75}{- 0.12011}\right)^2\right] & (W_D > 0.6) \\ 0 & (W_D \leq 0.55) \\ 1 - \text{Exp}\left[-\left(\dfrac{W_D - 0.55}{- 0.12011}\right)^2\right] & (0.55 < W_D \leq 0.6) \end{cases}$$

(3) Level 3 -" Possible Candidate"

$$F_3(W_D)\begin{cases} \text{Exp}\left[-\left(\dfrac{W_D - 0.75}{- 0.12011}\right)^2\right] & (0.75 \geq W_D > 0.6) \\ 0 & (W_D > 0.75) \\ \text{Exp}\left[-\left(\dfrac{W_D - 0.55}{- 0.12011}\right)^2\right] & (W_D \leq 0.6) \end{cases}$$

(4) Level 4 - " Not a Candidate"

$$F_4(W_D)\begin{cases} 1 - \text{Exp}\left[-\left(\dfrac{W_D - 0.55}{- 0.12011}\right)^2\right] & (W_D < 0.55) \\ 0 & (W_D \geq 0.55) \end{cases}$$

.... (D.9)

APPENDIX E

ADDITIVES

Choosing additives for a fracture treatment is a complex problem because of the multiple fluid factors they must control. Xiong's (1993) simple rules to determine for choosing additives (Tables E.1 through E.7) allow designers to narrow the choices by following rules of thumb for the bactericides, breakers, clay stabilizers, temperature (gel) stabilizers, fluid loss additives, friction reducers, iron controllers, surfactants, and diverting agents that may contribute to the success of the fracturing fluid.

Table E.1—Bactericides and Breakers

Additive	Purpose/Types	Selection and Use Guidelines	Concentration
Bactericides	**Purpose** Prevent viscosity loss from bacterial degradation Protect formation from anaerobic bacterial growth **Types** Glutaraldehyde Chlorophenates Quaternary amines Isothiazoline	**Not for oil-based fluids** Add before adding water Add to water-based fluids Select newest available; use after appropriate water testing	Depends on the material Default is 0.3 lbm/1000 gal
Breakers	**Purpose** Degrade viscous fracture fluid to thin fluids (e.g., μ<3 cp) that can be produced out of the fracture Enhance proppant distribution; Facilitate fracture closure **Types** Acid breaker Enzyme breaker Oxidizing breaker	**Not for use** if T> 300ºF or μ < 10 cp For **water-based** fluids only: Enzymes for guar/guar derivatives, cellulose derivatives, 70 ≤T≤130 ºF Oxidizers for guar/guar derivatives, cellulose derivatives, 120 ≤T≤ 280 ºF High-temp oxidizers for guar/guar derivatives, cellulose derivatives, 160 ≤T≤ 230 ºF Acid (weak carbolic acid) for guar/guar derivatives, cellulose derivatives, T>200 ºF Catalyed oxidizer for high-pH fluids, 70 ≤T≤120 ºF For **oil-based** fluids only: Low-temperature organic compound (LTOC) (hydrolyzes to form a weak organic acid) for aluminum octoate gels LTOC to control soap created from reaction of caustic and fatty acids Granular (weak organic acid) for aluminum phosphate ester Alternative (sodium bicarbonate or lime) for aluminum phosphate ester ≥ 100ºF Liquid (amine-type compound) for aluminum phosphate ester; requires presence of water	See Tables E.2, E.3

Table E.2—Breaker Concentrations: Base Fluid 1% KCl Water

Gel Concentration, lbm/1,000 gal	**20 lbm**			**30 lbm**			**40 lbm**			**50 lbm**			**60 lbm**		
T, ºF	**E**	**O**	**H**	**E**	**O**	**H**	**E**	**O**	**H**	**E**	**O**	**H**	**E**	**O**	**H**
80	0.5			0.75			1			4			<4.0		
100	0.3			0.4			0.6			<2.0			<2.5		
120	0.25			0.35			0.5			0.5			2		
140		0.3		0.3			0.15	0.5			0.5		1	1	
160		0.15			<0.2			0.3			0.5			0.6	
180		0.05			0.1			0.1			0.2			<0.2	
200		<0.05			0.05			0.05			0.1			0.15	
220						<0.4			<0.5			<0.5			0.75
240									0.25			<.25			<0.2
260									0.2			0.15			<0.1

E=enzymer breaker; O= oxidizer breaker; H= high-temperature oxidizer breaker

Table E.3—Breaker Concentrations: Base Fluid 20% Methanol in 1% KCl Water

Gel Concentration, lbm/1,000 gal	**20 lbm**			**30 lbm**			**40 lbm**			**50 lbm**			**60 lbm**		
T, ºF	**E**	**O**	**H**	**E**	**O**	**H**	**E**	**O**	**H**	**E**	**O**	**H**	**E**	**O**	**H**
80	<1.5			<1.5			2			<2.25			<4		
100	1.15			<1			1.85			<2			<3		
120	<1.25	<3		0.75	5		<.75	<7		1.75	5		<3	<6	
140	<1.25	<2		<.75	<3		1.0	5		<1.75	<5		<3	<5	
160		2			<2			3			3.5			3	
180		.85	<3		1.0	<4		2.5			2.5			1.5	
200			<1			<1			<7			<7			<7
220			.75			.75			<1.5			<4			<2
240									<1			<1.25			<1.5
260									<0.3			<0.5			<0.6

E=enzymer breaker; O= oxidizer breaker; H= high-temperature oxidizer breaker

Table E.4—Clay Stabilizers and Temperature (Gel) Stabilizers

Additive	Purpose/Types	Selection and Use Guidelines	Concentration
Clay Stabilizers	**Purpose** Prevent fines migration (prevent clay swelling Prevent disaggregation of clay/sand matrix **Types** KCL Cationic Cationic polymeric (typical with acrylic backbone chain) Nh4Cl	**Not for oil-based fluids** 1% to 3% KCL recommended in all fluids **Use when** Formation permeability > 0.01 md, clay content ≥ 10% **Not needed when** Carbonate formation Formation permeability ≤ 0.01 md	Depends on clay content in formation; determined by lab test
Temperature (Gel) Stabilizer	**Purpose** Protect the fracturing fluid from degradation at high bottomhole temperature by removing free oxygen from the system **Types** Liquid stabilizer (methanol at 5 to 10% concentration, sodium ethorbate) Powdered stabilizer for high temperature	Formation temperature > 200ºF	See Table E.5

Table E.5—Recommended Temperature (Gel) Stabilizer Concentration, lbm/1,000 gal

T, ºF	1 Hour	2 Hour	3 Hour	4 Hour	5 Hour	6 Hour
150	0	0	0	0	0	0
200	0	0	0	0	0	10
250	0	10	10	10	10	20
300	10	10	10	20	20	20
350	20	20	20	20	20	20

Example values for thiosulphate

Table E.6—Fluid Loss Additives and Friction Reducers

Additive	Purpose/Types	Selection and Use Guidelines	Concentration
Fluid Loss Additives	**Purpose** Improve the fracturing fluid efficiency by preventing leakoff into the formation **Types** Diesel or hydrocarbon fluid-loss additives Silica flour 100- to 200-mesh sand Starch-based fluid-loss additives Oil-soluble resins	**Not for foam or polyemulsion fluids** k_{gas} < 0.01 md or k_{oil} < 0.1 md: none needed 0.01 < k_{gas} < 1 md or 0.1 < k_{oil} < 10 md ▪ 5% diesel or hydrocarbon ▪ Starch or silica flour k_{gas} > 1 md or k_{oil} > 10 md: 50 to 60 lbm/1000 gal silica flour Natural fractures in the formation: < 50μ wide: 200-mesh sand ≥ 50μ wide: 100-mesh sand Silica starch Flour Difference between fracture pressure and reservoir pressure > 2,000 psi, use additional amounts (k_{gas} = permeability to gas; k_{oil} = permeability to oil)	Depends on circumstances
Friction Reducer	**Purpose** Reduce resistance caused by fluid flowing in pipes **Types** Liquid (preferred) Powdered	**Always recommended**	
		Fresh water	
		Highly anionic polyacrylamide	0.25 to 1 gal/1000 gal
		Powered anionic polyacrylamide	0.25 to 3 lbm /1000 gal
		Fersh water or acid	
		Liquid anionic copolymer	0.5 to 2 gal/1000 gal
		Fresh water, acid,or brine	
		Liquid cationic polyacrylamide	0.25-2 gal/1000 gal
		Powdered anionic	2-5 lbm/1000 gal
		Powdered cationic	2-5 lbm /1000 gal
		Oil	
		Liquid	7 to 10 gal /1000 gal

Table E.7—Iron Controllers and Surfactants

Additive	Purpose/Types	Selection and Use Guidelines	Concentration
Iron Controllers	**Purpose** Keep subsurface iron ion products in solution Formation damage from iron ion products **Types** Acetic acid Citric acid Proprietary and nonproprietary blends Enthylendiametertraacetic acid (EDTA) NTA	**Always recommended** except soon after acidation **Always** recommended if formation contains iron ions **Recommended** if formation contains iron and pH < 3	Depends on circumstances
Surfactant	**Purpose** Assistant in fluid cleanup by lowering surface tension Minimize emulsion problems Help maintain relative permeability to formation fluid **Types** Non-ionic (preferred) Anionic Cationic (for oil-wet sandstones or water-wet carbonates Fluorocarbon	**None needed** if pressure gradient (g_p) > 0.6 psi/ft Gas well: $g_p < 0.4$: use surfactant $0.4 < g_p < 0.6$, $T \geq 200$ºF, no surfactant $0.4 < g_p < 0.6$, $T < 200$ºF, use surfactant Oil well: $g_p < 0.6$: use surfactant Ensure that surfactant is compatible with other additives. Never mix cationic surfactants with anionic surfactants.	Default value: 1 gal/1,000 gal Run emulsion test with recommended blend of chemical and the reservoir fluid

Table E.7—Diverting Agents

Additive	Purpose/Types	Selection and Use Guidelines	Concentration
Diverting Agents	**Purpose** Divert the flow of fracturing fluid to a different perforated interval by plugging off either the perforations or some part of the formation **Types** Oil-soluble resin in aqueous solution Graded rock salt Flake benzoic acid Alcohol solution of n-benzoic acid Wide range of graded oil-soluble resins, used for temperature up to 350 F Unibends Polymer-coated sand that swells upon contact with water Oil-soluble graded naphthalene Ball sealers	**Use if** formation thickness ≥ 300 ft or has numerous perforation zones For oil-based fluids, use oil-soluble wax polymers For water-based fluids, use oil-soluble resins In saturated brine fluids, use only rock salt In openhole completions, use granular diverters To seal perforations, use ball sealers For fracture treatments, use only ▪ Ball sealer ▪ Sand plug ▪ Bridge plug **Do not use** benzoic acid flakes.	Depends on type of diverter and number of perforations

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