Fracture Acidizing

Introduction

The main objective of a stimulation treatment is to increase the rate at which the formation delivers hydrocarbons naturally. When a customer decides to stimulate a particular well, as much information as possible about that formation and wellbore configuration must be obtained. This information will aid in candidate selection, and may indicate whether a matrix of fracturing treatment will best stimulate the formation.

A matrix treatment is defined as treating a formation below fracturing rates and pressures. In certain places throughout the world, a matrix rate is 40 to 60 bbl/min because the fluid pumped is flowing through the formation matrix according to Darcy's Law.

A fracturing treatment is defined as treating a formation above matrix rate and pressure above the limits dictated by Darcy's Law. Under this condition, the rock cannot take the fluid according to Darcy's Law and is `split' or fractured to accept the fluid at the delivery rate. The pressure and rate needed to initiate a fracture may be determined by using the Step Rate Test of a Minifrac treatment.

This Best Practices document provides information about treatments using fracturing acidizing techniques. For information about matrix acidizing treatments, see the Matrix Acidizing Best Practices.

Well and Formation Data

Before designing a fracture acidizing procedure, the job designer collects well and formation data. Along with this information, a brief description about how the information will be used in the fracturing design process is included. If some necessary information is unavailable, a value for the data must be assumed. Any assumption made should be noted, and all parties should agree on the value. If necessary, a sensitivity study should be conducted.

Well Data

Perforations
Knowing the number, size, shot density, and phasing of the perforation is important under different conditions. When the expected wellhead pressure is calculated, the number and size (diameter) of the perforations must be known to calculate whether a pressure drop might occur across the perforations that would increase the expected wellhead pressure. In long formation intervals, the treatment may have to be diverted with ball sealers or granular diverting agents.

The size and shot density of the perforations will help job designers determine the number of ball sealers or the amount of granular diverting agent needed per foot of formation to divert the next portion of the treatment.

**Spacing**

In some areas, regulatory bodies control oil and gas production. These bodies assign well spacing depending on the type of well (oil or gas) and the well operator's assessment of reservoir conditions (the amount of reserves and the formation's ability to drain the reservoir).

Some fracturing models use the spacing value to determine the production increase value for a given stimulation treatment. If the spacing value is unknown, 80-or 160-acre spacing should be used for oil wells and 640-acre spacing should be used for gas wells.

**Wellbore Deviation**

Wellbore deviation information might not be needed as input into some simulators, but the information is very important to the treatment designer. When a wellbore transverses a formation at an angle, and the formation section has been perforated over long intervals, multiple fractures might be generated, each competing for the fluid pumped. With multiple fractures, no single dominant fracture exists, and the wellhead pressure might be higher than would be calculated under nondeviated conditions because of complex rock and fluid mechanics.

**Tubing/Casing Size and Weight**

The size, weight, depth, and grade of tubing and casing also influence treatment design. This information will determine the maximum allowable surface pressure. In addition, these parameters allow engineers to predict whether the tubing will elongate or contract as a result of the bottomhole static temperature (BHST) and the volume and temperature of the treating fluid. This information is required input to many fracture simulators and to tubing contraction programs. The Halliburton Energy Services, Inc. (Halliburton) tubing contraction program is the Tubing Mechanics Program (TMP), which is a part of the
Drilling Mud

When treatment designers are determining fluid compatibility, they must know the type of drilling mud used or lost to the formation. Many water-and oil-based muds are incompatible with many treating and completion fluids that have been treating standards. Therefore, designers may need to obtain a sample of the last mud used before the last production casing or liner was cemented. With this sample, they can conduct compatibility tests to determine the correct fluids and additives to stimulate the formation without creating more damage. Generally, preventing damage is easier than cleaning it up.

Maximum Wellhead Pressure

As mentioned earlier, the maximum wellhead pressure depends on the size, weight, and grade of tubulars as well as the maximum working pressure of the surface wellhead equipment. The maximum wellhead pressure value might be set by the well operator; if not, the treatment designer should use 80% of the tubing internal yield pressures ratings published in the Halliburton Cementing Tables (Dimensions and Strengths). The well operator must verify the maximum acceptable limit. This value can be reduced further, depending on the well history before the completion of a particular formation.

Well Type

When determining the type of granular diverting agent to use, treatment designers must know the type of well (oil, gas, water, injector, or disposal). For example, it would be inappropriate to use an oil-soluble resin for diversion when the formation is a water, water injector, or water disposal well. Knowing the bottomhole temperature (BHT) is another factor in determining the type of diverters to use. Many diverters have an upper temperature usage limit at which the diverter starts to melt or soften.

Packer Type and Depth

Packer type and depth also influence treatment design. When treating deep, hot wells, treatment designers must consider the effects of temperature and hydraulics on the tubing string. Knowing the packer type generally determines the conditions under which the TMP program is run. The tubing might be tied or latched into the packer or free to move inside a sealbore with a seal assembly. If the tubing is latched into a packer, designers must determine the maximum load on the top joint. This calculation determines whether

1. the load will exceed the tubing's internal yield strength, resulting in failure, or
2. the load will exceed the elastic limit of the steel and be permanently deformed or corkscrewed.

If the tubing is free to move in the sealbore, designers must know the OD of the seal assembly, the length of the sealing elements, and the amount of slack-off set on the packer when the tubing was landed. This information is all necessary input to the TMP.

**Formation Data**

**Bottomhole Temperature**

The design of the treating fluid system is based on bottomhole temperature (BHT). Depending on the BHT, a cooldown prepad may be necessary. The BHT also influences the selection of such typical treatment fluids as gelled fluid systems, acids, corrosion inhibitors, acid gelling agents, and other additives (surfactants, mutual solvents, crosslinkers, granular diverting agents, and alcohols). The BHT is also a necessary input to the fracture simulator and TMP.

**Bottomhole Pressure and Bottomhole Flowing Pressure**

Bottomhole pressure (BHP) is also used as an input to fracture simulators. The BHP is used to determine the closure stress that will be exerted on the fracture conductivity, whether conductivity is provided by proppant or a differentially etched fracture face. To determine the stress that will be on the fracture conductivity for the life of the well, the abandonment bottomhole flowing pressure (BHFP) must be estimated. When the design closure stress is estimated, the abandonment BHFP is subtracted from the bottomhole treating pressure (BHTP). If the BHFP is not available, it can be estimated as 40 to 60% of the BHP for oil wells or 30 to 50% of the BHP for gas wells.

**Bottomhole Treating Pressure and Fracturing Gradient**

Bottomhole treating pressure is a value needed for input into the fracture stimulator (TMP), for calculating the wellhead treating pressure, and for estimating the closure stress. To calculate the BHTP, multiply the fracture gradient by the depth. BHTP is equal to the instantaneous shut-in pressure (ISIP) plus the hydrostatic pressure. If no previous treatments have been performed on the formation, use a fracture gradient from a nearby well in the same field or assume a value.

**Permeability and Porosity**

Permeability and porosity are values required for input in fracture simulators and many other programs. Values determined by core analysis are generally to a gas (nitrogen or helium). To determine permeability, pump liquid (water or oil) through a core plug drilled
Permeability or porosity values determined from cores are specific to the place sampled within the cored section. Although these values can be used, the permeabilities calculated from pressure buildup tests are preferable. Permeability values from these tests provide the "effective permeability" because the value is determined over the entire interval exposed during the buildup test, and the calculated permeability value would be influenced by the presence of natural fractures.

Although most formations have some degree of natural fractures present; these fractures may not always be present in the recovered cores. Therefore, if available, porosity values from logs or averaged porosities over a logged interval can be used. If the effective permeability and porosity are available, they should be used as input to the fracture simulators; otherwise, the values from core testing should be used. Permeability and porosity values are used in the fracture simulator to calculate the filter-cake portion ($C_w$) of the total fluid-loss coefficient, spurt loss, and fluid efficiency. These values are very critical in determining the fracture conductivity and final fracture geometry, which consists of height, length, and width for 3D simulators, and length and width for 2D simulators.

**Reservoir Fluid Compressibility and Viscosity**

Reservoir fluid compressibility and viscosity values are also input into the fracture simulator. These values are the other two components used to calculate the total fluid-loss coefficient. They are generally set for any given formation based on the type of hydrocarbon present and the BHT. Therefore, changes to the total fluid-loss coefficient may only be made if the filter-cake portion is modified with a fluid-loss additive in the fluid system.

Input default values for gas wells are $8.5 \times 10^{-5}$ Δv/v/psi for fluid compressibility and 0.02 cp for viscosity. Input default values for oil wells are $2.5 \times 10^{-5}$ Δv/v/psi for fluid compressibility and 0.3 to 5 cp for viscosity.

**Rock Properties**

The rock properties of a formation are the Young's modulus and Poisson's ratio. These values are also input into a fracture simulator. These values influence the calculated fracture height in 3D simulator models, which influences the final fracture geometry. Many simulators have default rock property values, but the values can also be changed when core testing is performed.

**Mineralogy**
A formation's mineralogy is an important key in determining a fracture acidizing candidate. Mineralogy can be determined by an X-ray diffraction analysis of a formation sample. Formation cuttings can be used as a sample, but they should only be used if no other options are available for determining mineralogy. Shot or drilled sidewalls can also be used for formation sampling, but using whole cores is the preferred method. With the whole core, X-ray analysis, hydrochloric acid (HCl) solubility, acid-etch flow capacity tests, and rotating disc tests can be performed.

X-ray analysis reveals the relative amounts of minerals within a core. HCl solubility indicates the amount of fines that may be released. Rotating disc tests, reaction rate constant, order of reaction, and activation energy are important values for input parameters for fracture simulators. Table 1 shows the fines that can be produced from 1,000 gal of 15% HCl completely spent on a carbonate formation for a given acid solubility. For an 85% acid-soluble formation, 325 lb of fines can be produced for each 1,000 gal of 15% HCl spent.

Table 1: Produced Fines Per 1,000 gal of Acid Spent

<table>
<thead>
<tr>
<th>Acid Solubility</th>
<th>7.5% HCl</th>
<th>15% HCl</th>
<th>20% HCl</th>
<th>28% HCl</th>
</tr>
</thead>
<tbody>
<tr>
<td>40</td>
<td>1,330</td>
<td>2,765</td>
<td>3,768</td>
<td>5,475</td>
</tr>
<tr>
<td>50</td>
<td>888</td>
<td>1,843</td>
<td>2,512</td>
<td>3,650</td>
</tr>
<tr>
<td>60</td>
<td>592</td>
<td>1,229</td>
<td>1,675</td>
<td>2,433</td>
</tr>
<tr>
<td>70</td>
<td>381</td>
<td>790</td>
<td>1,107</td>
<td>1,564</td>
</tr>
<tr>
<td>80</td>
<td>222</td>
<td>461</td>
<td>628</td>
<td>913</td>
</tr>
<tr>
<td>85</td>
<td>158</td>
<td>325</td>
<td>443</td>
<td>644</td>
</tr>
<tr>
<td>90</td>
<td>99</td>
<td>205</td>
<td>279</td>
<td>406</td>
</tr>
<tr>
<td>96</td>
<td>37</td>
<td>77</td>
<td>105</td>
<td>152</td>
</tr>
<tr>
<td>98</td>
<td>18</td>
<td>38</td>
<td>51</td>
<td>74</td>
</tr>
</tbody>
</table>

Because of the potential amount of fines produced from a low-solubility formation, treatment designers must determine a minimum acid solubility at which the fracture-treatment should be performed. When cores are unavailable for acid etch fracture flow capacity testing, the lowest acid solubility that should be considered for fracture acidizing should be 85%. When cores are available, formations can be tested that have acid solubilities less than 85% to determine if adequate flow capacities can be generated even with the higher amounts of produced fines.

If a formation has an acid solubility of less than 75%, proppant fracture treatments
should be performed. If acid solubilities are between 75 and 85% and cores are available, special lab tests can be used to determine whether to use fracture acidizing or proppant fracture treatments by analyzing the differential etching and flow capacity values generated in these tests. If flow capacities from a proppant fracture treatment would be greater than flow capacities generated from a fracture acidizing treatment, design engineers should recommend a proppant fracture treatment.

If no cores are available for acid-etch testing, fracture-acidizing treatments should be used on formations with acid solubilities greater than 85%.

**Treatment Techniques**

For an effective stimulation treatment, use one of four main fracture-acidizing techniques:

- SUPRA FLC (Sustained Production Acidizing) (Fluid-Loss Control)
- SUPRA CE (Conductivity Enhancement)
- SUPRA EHC (Etched Height Control)
- tailored treatment

Table 2 lists the Carbonate 20/20 fluid systems commonly used with each SUPRA system.

<table>
<thead>
<tr>
<th>SUPRA FLC</th>
<th>SUPRA CE</th>
<th>SUPRA EHC</th>
</tr>
</thead>
<tbody>
<tr>
<td>CSA</td>
<td>CSA</td>
<td>CSA</td>
</tr>
<tr>
<td>CEA</td>
<td>HRA</td>
<td>FRA</td>
</tr>
<tr>
<td>HRA</td>
<td>HRA</td>
<td></td>
</tr>
</tbody>
</table>

**SUPRA FLC (Fluid-Loss Control)**

*Purpose*

SUPRA FLC controls acid fluid-in induced and natural fractures. In rock matrix or natural fracture systems, acid leakoff must be controlled so that live acid will remain within the fracture and generate effective etched fracture length. Under some conditions, Carbonate 20/20 treating fluids provide fluid-loss control; under excessive fluid-loss conditions, some additional fluid-loss material may be required in addition to alternating phases of acid and nonacid fluids. The acid provides conductivity, and the nonacid fluid (containing fluid-loss additive) establishes or reestablishes fluid-loss control. The nonacid phase also acts as an acid extender, allowing a sufficient volume of acid to penetrate the required distance.
while reducing the volume of acid necessary for that distance. Phases can be alternated at any time, depending on the treating conditions. The acid leaks off and forms wormholes or goes into natural fracture systems. The nonacid phase (containing fluid-loss additives) sands off and seals up wormholes or natural fractures, and fluid-loss control is reestablished.

**Benefits**

The SUPRA FLC technique provides the following benefits:

- The acid is in laminar flow in the fracture because of the physical surface retarding effect.
- Gelled or emulsified acid exhibits some fluid-loss control.
- The technique produces good friction reduction unless the acid system is an emulsion.
- All fluid systems have good fines-carrying capabilities.

**SUPRA CE (Conductivity Enhancement)**

**SUPRA CE Technique**

SUPRA CE can be used in standard or limited-entry conditions. When using the SUPRA CE technique, service operators pump a viscous pad fluid ahead of the acid and behind an optional nonviscous, cooldown prepad.

As the viscous pad is pumped, it generates fracture geometry (Figure 1). Because the acid that follows it is less viscous, it "fingers" through the viscous pad. This fingering process limits the acid contact to the formation face, which creates etched and nonetched areas. This process results in longer acid penetration distance and possibly more effective conductivity at a greater distance along the induced fracture. Table 3 lists advantages and potential disadvantages of using the SUPRA CE system.

**Figure 1: SUPRA CE technique**
Table 3: Advantages and Disadvantages of the SUPRA CE System

<table>
<thead>
<tr>
<th>Advantages</th>
<th>Disadvantages</th>
</tr>
</thead>
<tbody>
<tr>
<td>The overall nature of the treatment provides an excellent retarded system.</td>
<td>The treatment is more complicated to design.</td>
</tr>
<tr>
<td>The technique provides good fluid-loss control with the gelled pad and additional fluid-loss additive can be used when necessary.</td>
<td>The technique is more expensive because more materials are required for the treatment.</td>
</tr>
<tr>
<td>Uneven etching is achieved mechanically.</td>
<td>The technique generally requires larger volumes of acid.</td>
</tr>
<tr>
<td>Nonetched areas support the etched areas, allowing the formation to withstand higher closure stresses.</td>
<td></td>
</tr>
<tr>
<td>Live acid can penetrate more deeply into the formation.</td>
<td></td>
</tr>
</tbody>
</table>
Limited-Entry SUPRA CE Technique

When used as a limited-entry treatment, the fluid composition of SUPRA CE is the same, but large intervals are perforated with only a few holes. These holes are spread out over the entire interval (Figure 2).

The design of the treatment and the perforating must be coordinated according to well limitations of pressure, rate, and conducting tubulars. All perforated sections should be broken down individually before the major stimulation.

When used for limited-entry applications, SUPRA CE provides the following benefits:

- Etched areas are forced at a required location because of perforations placed at some predetermined point.
- Treatment can be directed to the best part of a large interval.
- All of the required interval can be treated depending on the limitations of the limited-entry design.
- The operator and the treatment designer can maintain close interaction.

Figure 2: Limited-entry SUPRA CE technique
UPRA EHC (Etched Height Control)

The SUPRA EHC technique uses fluid density differences to control fluid placement in certain sections of an induced vertical fracture. This technique can place acid in areas of a fracture that do not contain water or possibly a gas cap. Figure 3 shows the fracture-acidizing process including SUPRA EHC.

Advantages of the SUPRA EHC system are that it prevents the acid treatment from entering unwanted zones such as water-producing intervals and gas caps, and that it uses less acid.

With the aid of nitrogen, many heavier fluids can be lightened by foaming (gas content greater than 55%) or commingling (gas content less than 55%) gas in the fluid; even with the best engineering and design, this treatment may not always work.

Figure 3: Limited-entry SUPRA CE technique
Tailored Treatments

Tailored treatments may consist of foamed acids, heated acids, zonal coverage acid (ZCA), and closed-fracture acidizing (CFA) treatments.

Foamed Acids

Foamed acids usually consist of acid and 65- to 70-quality nitrogen (N₂), but under certain conditions, acid can also be foamed with carbon dioxide (CO₂). This technique is generally used when the reservoir has a low BHP and load water recovery would require extensive swabbing time. The flush can also be foamed to aid in fluid recovery. Table 4 lists the advantages and possible disadvantages of using foamed acids.

Table 4: Advantages and Disadvantages of Foamed Acid Methods
The heated acid treatment technique is useful when the reservoir has a low BHT. The heated acid increases the acid reaction rate. The acid may be heated mechanically (hot oiler or steamer) or chemically. Table 5 lists the advantages and possible disadvantages of using heated acids.

**Table 5: Advantages and Disadvantages of Foamed Acid Methods**

<table>
<thead>
<tr>
<th>Advantages</th>
<th>Disadvantages</th>
</tr>
</thead>
<tbody>
<tr>
<td>The heated acid has an increased reaction rate on cold formations, particularly dolomites, and also aids in removing hydrocarbon deposits such as heavy oil, paraffins, or asphaltenes.</td>
<td>The heating process (either mechanical or chemical) is more expensive than other treating methods, and if heated chemically, some acid is spent to generate the heat.</td>
</tr>
<tr>
<td>The removal of hydrocarbon deposits allows for better acid-formation contact, which results in better acid-etch conductivity.</td>
<td>Chemical heating requires a higher initial acid concentration so the designed acid strength will be available on the formation.</td>
</tr>
<tr>
<td>The heated acids technique is helpful in preventing thermal shock to the formation and the precipitation of paraffins and asphaltenes.</td>
<td>Heated acid treatments cause accelerated tubular corrosion.</td>
</tr>
<tr>
<td>The technique also limits tubing contraction.</td>
<td></td>
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</tbody>
</table>

**Heated Acids**

ZCA is a gelled acid system that helps control fluid loss in fracture acidizing by in-situ crosslinking. As the acid leaks off through wormholes, the fluid crosslinks to plug the
wormhole, stopping fluid loss. By maintaining more live acid in the fracture, a longer fracture of higher conductivity is achieved. As the reaction continues, the crosslink breaks, allowing easy cleanup.

In the past, the use of crosslinked acidizing fluids was limited. The high fluid viscosity required during pumping increased frictional pressures, which required greater pumping horsepower. In addition, obtaining a live-acid, crosslinked fluid was an expensive process, with a major portion of acid lost as a result of leakoff through wormholes. When the ZCA system is used, fluid loss can be controlled as the acid leaks off through wormholes and spends. Once the acid is nearly spent, the system crosslinks, blocking wormholes and preventing further loss of acid from the fracture face. The system will not break until the acid is completely spent. The viscosity of the fluid before crosslinking and after breaking is approximately 25 cp (as measured with a Fann 35A viscometer at 300 rev/min).

Because the ZCA crosslinks when nearly spent, it can also be used as a diverting agent when treating fluid may be lost to a natural fracture system. When the ZCA fluid system is lost to a natural fracture, the acid spends, then crosslinks and diverts the treatment down the fracture. ZCA can be staged with neat acid or other Carbonate 20/20 acid fluid systems to promote increased fracture lengths.

**Closed-Fracture Acidizing (CFA)**

The closed-fracture acidizing (CFA) technique reopens previously created fracture systems with a prepad fluid pumped at high rates. The fractures are then allowed to close naturally, or part of the prepad is flowed back to force the fractures to close. Next, acid and any necessary additives and diverters are pumped below fracturing pressure.

This technique can also be used immediately after a fracture acidizing treatment performed for enhanced etched conductivity. The process is similar to the one previously described, except that rather than a prepad, the Carbonate 20/20 fluid used for the initial acidizing procedure is partially flowed back to force the fractures to close. CFA acid and any necessary additives and agents are then pumped below the fracturing pressure.

Note: CFA treatments can be used on wells years after they have been fracture-acidized. However, special attention to additional fluid-loss additives might be necessary.

**Treating Fluids**

After choosing a treating technique, treatment designers must choose the fluid system(s) best suited for that technique. For example, for a SUPRA treatment, a viscous gel pad fluid is necessary for the acid to finger through the formation to create the differential etching. Under these conditions, high-pH crosslinker fluids (borate systems) should
generally not be used. In most borate-crosslinked fluid systems, the crosslinking occurs at pH 8.5 or higher. When acid is introduced into this fluid system, lowering the pH would quickly uncrosslink the fluid.

Acid will break any natural polymer-crosslinked fluid system, but using the low-pH crosslinked systems delays this break. Most low-pH crosslinked fluid systems have higher gel loading than the borate-crosslinked fluid systems; therefore, there should be a higher viscosity for the acid to finger through, even though the crosslinker may have been broken by the acid. If the polymer loading of a borate-crosslinked fluid system is increased, the crosslinked gel viscosity may be so high that increased friction may occur. If a delayed crosslinker is used, the fluid may never reach the correct pH for crosslinking to occur.

After determining the acid and nonacid fluid systems for the fracture acidizing treatment, treatment designers must enter fluid parameters into a fracture simulator. Some fracture simulators contain a fluids database within the program; if a simulator does not contain a fluids database, the user must enter fluid parameters into the system.

**Fluid Parameters**

The following sections explain two fluid parameters: the behavior and consistency index (\(n'\) and \(k'\)) and spurt and \(C_w\).

**Behavior and Consistency Index (\(n'\) and \(k'\))**

Pseudoplastic fluids exhibit no yield value. A logarithmic plot of shear stress and shear rate is linear with a slope \(n'\) between zero and 1, which is a measure of the degree of non-Newtonian behavior of the fluid. The \(k'\) is a constant and a measure of a fluid's consistency.

For more information regarding theory and equations, see the Halliburton *Fracturing Theory* manual and the SPE Monograph Volume 12 "Recent Advances in Hydraulic Fracturing."

If the fracture simulator does not have access to a fluids database, treatment designers may use the StimWin program to find values for \(n'\) and \(k'\). The data are generally shown as a function of time at BHT at a given shear rate. If these data must be entered into the program, the treatment designer should enter values for \(n'\) and \(k'\) that represent (1) the gel viscosity at about half of the treatment pumping time and (2) a shear rate equal to that which would occur as the fluid flowed down the created fracture. For example, if the
total treatment time will probably be 4 hours, the designer would enter (1) the n' and k' values for a gelled fluid that has been at BHT for 2 hours and (2) a shear rate of around 80 sec−1.

**Spurt and \( C_w \)**

Spurt is the fluid that is lost to the formation face before the fluid-loss coefficient (\( C_w \)) starts controlling fluid leakoff. The fluid-loss coefficient is the wall-building characteristic for a particular fluid. Adding fluid-loss material to the fluid system will reduce this value. If the fracture stimulation program has a fluids database, the fluid-loss coefficient for the fluid system will be stored in this database. If fluid-loss additive is added to the fluid system, the treatment designer must change the \( C_w \) value to account for the fluid-loss additive.

**Fluid-Loss Control**

The most critical aspect for achieving a good fracture acidizing treatment is fluid-loss control. Fluid-loss control is a function of porosity and permeability. When a fracture is initiated, the fluid must remain in the induced fracture to propagate fracture geometry. Once fluid leaks off into the matrix or down a natural fracture, it can no longer extend the fracture. Leakoff can be partially controlled if fluid-loss additives are used in the treatment fluid.

The classic view of fluid leakoff in proppant fracturing is fluid leaking through pore throats and down natural fractures. Crosslinked gelled fluids containing silica flour or other particulate materials are used in an attempt to achieve fluid-loss control efficiencies ranging from 30 to 40%. Acid further complicates the design of effective fluid-loss control. The acid that leaks off into a pore throat suddenly turns the pore throat into a wormhole. If 70% of the acid is leaking into the matrix, then most of the acid is spent making wormholes instead of making fracture-face conductivity.

The following steps can be performed to help control acid leakoff during an acidizing treatment:

1. **Viscosify the acid.**

2. **Add solid particulates.**

3. **Use alternating stages of acid and nonacid fluids.**

**Viscosifying the Acid**

Many methods of thickening the acid exist, including the use of emulsified acid (Carbonate
Emulsion Acid), foamed acid, synthetic polymer gelled acid (SGA-II, SGA-III, SGA-HT, ZCA), and surfactant gelled acid (SGA-1). The BHT and rock composition of the formation, along with the conductivity development on the rock sample (as determined by laboratory tests) will dictate the appropriate method to use.

Adding Solid Particulates

In proppant fracturing, fluid leakoff generally occurs through a pore throat. Fluid-loss particles effective on pore throats are usually less than 1 micron in diameter. Silica flour contains many submicron particles and is considered to be very effective at minimizing spurt loss during proppant treatments. When acid leaks through the pore throat, the pore throat quickly enlarges to a hole at least 1 mm in diameter, and a wormhole forms. Therefore, solid particles for acid fluid-loss control should be relatively large.

Halliburton research indicates that 60- to 80-mesh solids are often necessary for controlling acid fluid loss once the acid has been viscosified. This research indicates that particulate material such as 100-mesh sand should be used at a starting concentration of 0.25 lb/gal and possibly reaching a concentration of 1 lb/gal. Along with the 100-mesh sand, 25 to 40 lb/ Mgal silica flour might need to be added to control the small pore throats of the 100-mesh sand. The 100-mesh sand and silica flour can limit fluid loss to enlarging wormholes and open natural fracture systems.

Using Alternating Stages

If alternating phases are used, acid fluid-loss control may be recovered. Acid leakoff can be so severe that it becomes necessary to switch to a nonacid fluid to fill the wormhole and/or open natural fractures and regain fluid-loss control. The nonacid fluid should be a crosslinked, gelled water that has some tolerance to a low-pH environment. The nonacid stage will displace the acid out of the wormholes and natural fracture network and then form a filter cake. With the fluid-loss additive(s) and crosslinked nonreactive fluid filling the wormholes and natural fractures, the acid remains in the fracture longer and increases the amount of rock removal along the induced fracture face, thus creating fracture-face conductivity.

Diverting

In a fracture acidizing treatment, sometimes the potential producing interval covers several hundred feet. When this condition exists, the design engineer has to consider some method of diversion; otherwise, the total treatment may be placed in the first section that breaks down at the lowest fracture initiation pressure. The following sections
explain the three types of diverting techniques: packers and bridge plugs, Perfpac balls, and granular diversion.

Packers and Bridge Plugs

Several conditions affect whether packers and bridge plugs can be used for diversion. First, determine how the wellbore was perforated. Was the formation section perforated from top to bottom continuously, or were perforations grouped in two or more sections with several feet of blank pipe between them? If blank pipe exists between the sections, a retrievable packer and bridge plug can be set in the blank pipe sections for individual fracturing treatments on each section. Other determining factors include how high the fracture growth can extend, and the rig time necessary to run the tools and perform each fracturing treatment before the final production string is run.

Perfpac Balls

Perfpac balls divert fluid flow and pressure from one perforation to another. This procedure allows more than one fracture to be initiated during a single treatment without halting the flow of the treating fluid. Perfpac balls are transported in the treating fluid to those perforations taking fluid, seating and sealing off the perforation. This action diverts the flow and pressure of the treating fluid to another perforation, where another fracture may be initiated, if conditions are suitable. When pumping stops and/or the flow reverses, the balls are disengaged from the perforations; they then either fall to the bottom of the well or are recovered mechanically. Perfpac balls can be used with all fracturing or acidizing methods.

Design considerations include (1) the volume of treating fluid to be pumped, (2) the pump rate, (3) number of perforations, (4) number of balls to be dropped, (5) fluid density, and (6) ball density. When balls are used, an appropriate pump rate must be maintained. If the pump rate is too slow, and the ball density is greater than the fluid density, the balls will fall faster than the fluid can be displaced. If the ball density is less than the fluid density, then, at a low pump rate, the balls could float to the surface.

After the treatment, the balls either float to the surface, or fall into the rathole. If the balls float to the surface, they should be removed from the fluid stream before they hit the flowback valve or choke. If the well has to be swabbed, the balls should be allowed to fall to the bottom to prevent sticking the swabbing tools. Recovering stuck swabbing tools could be very expensive.

When designing a treatment that will include Perfpac balls for diversion, treatment
designers

must consider the following:

- If balls will be dropped in clusters, the pipe ID must be greater than three ball diameters so that bridging will not occur. If balls are dropped individually, pipe ID is not a concern.
- Balls should be used in proper temperature and differential pressure ranges.
  - In moderate temperatures and pressures, a solid rubber ball can be used.
  - At higher temperatures and pressures, rubber-covered nylon (RCN) can be used.
  - At the highest temperatures (~350°F), RCP (rubber-covered phenolic) balls must be used.
- The larger the diameter of the pipe, the higher the pump rate must be for the ball to seat.
- The greater the specific gravity difference between the ball and fluid, the higher the pump rate must be for the ball to seat.
- The greater the viscosity of the fluid, the easier the ball will seat.
- The smaller the ball, the easier it is to seat, but the ball must fit the perforations.

The core of a ball should never be smaller than the perforations; balls should be $\frac{1}{4}$ in larger than the perforations.

**Granular Diverting**

When Perfpac balls can no longer divert properly, granular diverting agents can be used. As the treating fluid is pumped into the first initiated fracture, the particles can bridge on the perforations (or the wellbore in an openhole completion). When enough of these particles accumulate, they initiate a fracture in other sections of the formation.

Granular diverting agents include rock salt, graded rock salt, benzoic acid flakes, wax beads, wax buttons, or oil-soluble resin material. In all cases, each product has a limiting factor or factors in its application. Temperature and solubility are the main limiting factors in designing a diversion treatment with a particulate material.

**Temperature.** Each treatment material has an upper temperature limit at which it can either go into solution with the treating fluid, melt, or become ineffective as a diverting agent. If the BHT of the formation is too low, the solubility of the material in the producing fluids can be low. Therefore, cleaning up the diverting material can be slow and costly, resulting in lost production time.

The softening point of the bridging agent should be high enough that it does not soften before diversion is complete. In many treating operations, the treating fluid pumped ahead of the diverting material will cool the formation. Therefore, effective diversion can
occur, even when the BHT is at or slightly above the diverting agent's melting point.

**Solubility.** A diverting agent must be soluble in the formation fluid. Therefore, oil-soluble resins are not used in water injection or disposal wells, and water-soluble diverting agents are not used in oil or gas wells that do not simultaneously produce some water. The producing fluids must dissolve the diverting agent at the BHT for efficient cleanup. If the well is a "dry" gas well (no liquid hydrocarbons), the diverting material could sublime or become soluble in the dry gas.

The fluid that carries the particulate must be dense and viscous enough to keep the particles uniformly dispersed. When a slightly viscous carrier is used, the particulate can be pumped more smoothly, for a more professional appearance on location.

Like a fluid-loss additive, the effectiveness of a diverting agent depends on its particle size distribution. Most bridging agents contain particles ranging in diameter from about 0.25 to 0.002 in. The larger particles bridge on the zone, and the smaller particles bridge on the large particles to form a low-permeability bridge.

Many Halliburton diverting agents and their solubilities, temperature limits, and recommended concentrations are listed in the *Chemical Services Manual*. Table 6 describes some commonly used diverting agents.

**Table 6: Commonly Used Diverting Agents**

<table>
<thead>
<tr>
<th>Diverting Agent</th>
<th>Generic Name</th>
</tr>
</thead>
<tbody>
<tr>
<td>TBA-110</td>
<td>Graded rock salt</td>
</tr>
<tr>
<td>TBA-350</td>
<td>Graded oil-soluble resin</td>
</tr>
<tr>
<td>TLC-80</td>
<td>Benzoic acid flakes</td>
</tr>
<tr>
<td>TLC-15</td>
<td>Graded naphthalene</td>
</tr>
</tbody>
</table>

**Initial Treatment Design**

Once the materials and equipment for fracture acidizing have been selected, the total treatment volume must be considered. The total perforated interval can be helpful in determining the total volume. Each foot of perforated interval can be multiplied by some factor to give a total treatment volume. Many times, this factor can range from 1,000 to 2,000 gal/ft of perforated interval. Even when using this starting point, the design engineer must use some common sense and logic to ensure the economic feasibility of the treatment. After determining a total volume, the engineer must determine how much of
the volume will be nonviscous pad, viscous pad, acid treatment, and overflush.

For example, a well has 100 ft of perforated interval and the total carbonate section is 180 ft. Based on the factors above, the initial total treatment volume would be 100,000 to 200,000 gal. Considering that the treatment rate may be 20 to 40 bbl/min down casing, the total pumping time would range from 1 to 4 hours.

The next step would be to divide the total treatment volume into the separate fluid volume for each of the four types of fluids. Although dividing the total volume by four might be the easiest method, it may not be the most effective. In this case, since the acid is the fluid that will give the differential etching and conductivity, the total volume could be broken up by pumping 20,000 gal of nonviscous pad. This fluid would be used to initiate the fracture, cool down the reservoir, and place some initial fluid-loss additive in the generated fracture and any connected natural fractures. That step would possibly be followed by 25,000 gal of viscous pad that would also help cool down the reservoir, help control fluid loss with additional fluid-loss additive, and generate a wider fracture.

This step could be followed by 30,000 gal of acid. The acid would dissolve rock from the fracture faces and finger through the viscous pad fluid, creating differential etching. The acid would be overflushed with 25,000 gal of nonviscous fluid. This stage would displace the acid out into the fracture, allowing the acid to completely spend, creating additional etched-fracture length and flow capacity as long as the acid can dissolve rock. If a viscous pad is not pumped, then the additional 25,000 gal in the example would have to be added to the other treatment stages.

Since this example well has 100 ft of interval perforated out of 180 ft of zone, the treatment should be broken into two stages with a diverting agent between them. With only 15,000 gal of acid used per stage, the treatment designer must consider the penetration depth of the acid and the amount of conductivity generated. When these points are considered, the 200,000-gal treatment does not look excessively large with the pumping time of 2 to 4 hours, depending on the proposed treating rate of 40 or 20 bbl/min. Once some estimated volumes are determined, the design engineer enters the information into a fracture simulator to approximate the fracture geometry and etched conductivity.

**Computer Simulators**

Many 2D and 3D computer simulators can be used for fracture acidizing design. Not all simulators generate the acid reaction, spending, and etched conductivity similarly.
Once results are obtained from the initial input, one must consider how to optimize the acid fracturing treatment. Fracture acidizing treatments can be optimized based on one or more of the following factors: production increase value, dimensionless fracture conductivity ($F_{CD}$), acid-etch conductivity (md-ft), acid-etched length (or effective acid-etched length), or production simulators.

**Production Increase Value**

The production increase value allows designers to optimize the fracture design. The production increase value is an index to compare one treatment design to another—not a multiplier for determining the amount of oil or gas that will be produced, given a production rate before treatment. When one treatment is compared to another, the greater the value, the better the treatment design based on the amount of conductivity generated, and the etched-fracture length.

**Dimensionless Fracture Conductivity ($F_{CD}$)**

The dimensionless fracture conductivity ($F_{CD}$) value can be used similarly to the production increase value. The $F_{CD}$ is also an index comparing one treatment to another. The $F_{CD}$ is equal to the etched conductivity divided by the permeability of the formation and the etched fracture length.

**Acid-Etched Conductivity**

The etched conductivity is generated by uneven rock removal along the fracture faces. This value is expressed in MD-ft, just like the conductivity generated when proppant is placed in a fracture. Since acid can dissolve large amounts of rock, the conductivity generated by acid can be many times greater than that generated by proppant in a sandstone formation. A minimum conductivity value can also be used for determining the effective acid-etched fracture length. The effective fracture length refers to a conductivity value equal to or greater than the value that can be achieved by the use of proppant, at some distance away from the wellbore and under the same closure stress. Generally, the fracture simulator may output a longer acid-etched fracture length, but the conductivity in this region of the fracture should be compared to the conductivity that would be generated by proppant.

**Production Simulators**

Several fracture design programs contain production simulators. Therefore, the treatment designer can easily move from one module to another without needing to input the fracture conductivity and geometry. In the production simulator module, additional input
is required.

These inputs include such items as the lease operation cost, the price of the produced hydrocarbon, the maximum/minimum production rate, production time (the total number of days, months, or years, for production to be calculated), maximum/minimum pressure drawdown, and other inputs.

Production simulation is a very powerful tool for stimulation treatment designers, but if much of the requested input information is unavailable, they may have to make assumptions, which in turn can lead to many hypothetical questions. These questions can then lead to many hours spent generating comparisons of the possibilities. When using a production simulator for treatment design, all parties will benefit by obtaining as much of the critical input information as possible. Figure 4 shows a decision tree for an acid fracture treatment design.

Figure 4: Fracture acidizing decision tree