Abstract

Production from naturally fractured reservoirs can be greatly enhanced by stimulation with acid. When pumping the treatment from the surface (a bullhead treatment), the acid tends to enter the reservoir at the most permeable interval (conductive natural fractures). Without any other injectivity control, the acid will not likely divert from this path. Mechanical diversion techniques using swab cups or inflatable packers on jointed pipe or coiled tubing (CT) can ensure injection into the various intervals.

With these methods, surface pressure can be monitored to assess fluid placement effectiveness for each zone treated, but uncertainty of the friction pressure in the pipe while pumping can result in an incorrect interpretation of fluid entry. These mechanical isolation techniques are typically more costly and time consuming than bullhead jobs. Diversion techniques for bullhead stimulation treatments using chemical or foam diverters are more efficient, but lack the confirmation that all the zones received acid because of uncertainty of interpreting downhole behavior from surface pressure. A new technique using fiber-optic distributed temperature sensing (DTS) measurements offers a solution when bullheading by providing an indication of where the acid has been injected into the fractured reservoir.

A system has been developed consisting of a fiber-optic element encased in an acid-resistant slickline (commonly referred to as SL-DTS) that can be deployed in wells to monitor acid treatments in real time. The entire length of the fiber-optic strand functions as a temperature sensor with a vertical resolution of approximately 3.5 ft. The SL-DTS is gravity deployed or can be pumped into highly deviated or horizontal wells prior to the stimulation treatment. Once in place, the fiber is interrogated with pulsed laser energy to record temperature profiles versus time over the entire fiber length. These time-based data allow easy observation of thermal events due to fluid injections as well as any exothermic reaction of the acid system with the formation. Surface-temperature fluid pumped into perforations provides a cooling effect along the flow path. Interaction of the acid system with carbonate-containing minerals in the formation generates heat. Temperature profiles observed during and after pumping can be used to detect and quantify the distribution of the fluid system into the various intervals.

This method was used to successfully delineate acid placement in several deviated wells during bullhead stimulations. The data illustrate zones successfully treated as well as zones that may be targeted...
for remedial treatment. SL-DTS offers a unique opportunity to optimize stimulation placement in fractured reservoirs or any reservoir with variable injectivity.

**Introduction**

Naturally fractured reservoirs are known for their heterogeneity. The Monterey shale in California exhibits heterogeneity in both lithology and fracture distribution (Fig. 1). Fracture density can vary greatly throughout the reservoir, typically controlled by in-situ and tectonic stresses in conjunction with rock properties. Identification of, and completion in, zones of high fracture density can result in highly prolific producing wells. The high fluid conductivity of these fracture sweet spots often allows invasion of whole mud during drilling. Specially formulated treating fluids, including acid-based systems, are commonly used to remove the drilling mud in an attempt to return the fractures to their undamaged condition. Acid-stimulation of the natural fractures can also significantly increase the production of the unstimulated fractures. Different techniques have been developed in the attempt to achieve uniformity of acid distribution to all the fractures in a well. However, variability of fracture density and aperture along with fluid conductivity pose challenges to this goal. The optimum technique would allow effective treatment of all the fractures, be operationally efficient, and facilitate the determination of treatment effectiveness in real time.

![Figure 1—Resistivity images used to identify and characterize natural fractures.](image)

Diversion of the treatment fluid helps ensure that the entire interval is stimulated effectively based upon the design objectives. When diversion is not considered, there is a significant reduction in the assurance of complete zonal coverage. In the past, the rule-of-thumb has been that when attempting matrix stimulation of more than 20 ft of zone, diversion should be recommended.

Diversers can be separated into two broad categories—mechanical and chemical.
Mechanical diversion is the category that comprises devices such as staged completion systems, bridge plugs and packers, straddle packers, balls and baffles, sliding sleeves, etc. Ball sealers can also fall into this category, because no chemical reaction takes place, but recently developed dissolvable ball sealers have characteristics of both mechanical and chemical techniques.

Chemical diversion relies on the ability to perform an action to reduce fluid injection into the zones taking most of the early-time injection fluid and redistributing the injection to other areas of the formation that also need to be stimulated. This occurs because the diverter reduces the injectivity of the zone of highest permeability by blocking and/or bridging across the perforations, the pore throats of the matrix, and/or the natural fractures, thus creating a more even injection profile. Since chemical diverters introduce barriers to flow in the most permeable zones, it is an important consideration that this effect can be reversed once the treatment is finished and the well is returned to production.

Mechanical diversion is the most certain option for ensuring the treatment fluid is pumped into the intended zone. This is achieved by the positive isolation within the wellbore and the requirement of hydraulic zonal isolation on the outside of the pipe for cased and cemented wells.

A straddle packer that can be set/unset multiple times or opposing swab cups (that flare to provide seal when pumping) are very effective when run on coiled tubing. They can also be run on jointed pipe with a workover rig, but there is a significant additional complexity and safety consideration.

Ball sealers have been used for many years and can be effective under certain conditions. The fluid properties (density, viscosity), pumping rate/casing internal diameter (velocity), ball sealer properties (specific gravity, diameter), perforation entrance hole diameter, wellbore trajectory, etc. are all factors to be considered to determine if ball sealers are likely to be effective. It is also an important consideration that if shutdown of pumping (planned or unplanned) occurs, the balls can unseat from the perforations as they primarily rely on pressure-differential to keep them in place. Simple diagrams illustrating the diversion process for a straddle packers and ball sealers can be seen in Fig. 2.

Chemical diversion is the most commonly used diverter type. This is mostly due to the fact that it carries less risk and does not require having to run packers, plugs, and other mechanical equipment into the wellbore that can become stuck, lost in the wellbore, etc. Chemical diversion can be performed during bullhead treatments and, therefore, does not require the use of coiled tubing or a workover rig.
Natural Fracture Heterogeneity

Natural fractures are created when fracturable rock is stressed past its breaking point. Variations in stress magnitudes over time cause natural fracture occurrences to be difficult to predict. Fracture density is quite varied in the Miocene-age Monterey shale in California. Wireline resistivity images are typically used for identification of natural or drilling-induced fractures and orientation. Resistivity imaging tools use arrays of microresistivity buttons to record the texture of the rock via the variations in current flow into formation. When the tool encounters an open fracture filled with water-base drilling mud, the sharp resistivity contrast with the surrounding rock matrix allows easy identification of the fracture trace in the image. Images are typically color scaled so that open fractures are dark events compared to the surrounding brighter-colored matrix. Images are often presented in 3D (Fig. 3) to aid in the understanding of fracture orientation, spacing, and relationship to structural geologic events. (Grayson et. al., 2006). Fracture intensity is typically higher near folding or faulting as a result of the increased stress associated with these features. Software programs are available for the image interpreter to identify, orient, and catalog fractures to understand their distribution along the wellbore (Fig. 4). Fracture characterization using resistivity images provides the data for reservoir modeling, completion design and stimulation optimization.

Figure 3—3D visualization of natural fractures and other structural features allows a better understanding of fracture intensity variations.
Open fractures provide high fluid conductivity pathways for petroleum production under optimum conditions. However, open fractures are also a source of fluid loss during the drilling process, which must be addressed for safety reasons. Various techniques have been developed to successfully control fluid loss in fractured reservoirs, but the typical result is a reduction in fluid conductivity due to a concentration of drilling solids in the fractures. This is often referred to as drilling damage. In cemented-casing completions, perforating with deep-penetrating charges can get past some drilling damage, but stimulation of the perforations with acid usually shows a production increase in the fractured Monterey formation.

Figure 4—Fracture distribution displays provide the foundation for optimization of completion and stimulation programs.
Acid Treatment Considerations

Though the Monterey shale can be thought of as a diatomaceous shale/mudstone, cherty (opaline silica), and dolomitic shale, it comprises many layers that are generally less than 1.64 ft thick, which can include marl, chalk, limestone, and dolostone. Adding to this complexity are the calcite-filled fracture networks that are a result of localized folding.

Various acid systems have been tried in the Monterey. The primary design factor is the amount of carbonate in the form of calcite or dolomite in each individual well. Operators with formation containing over 20% carbonates have seen good results pumping 15% HCl, and tailing in with just very small amounts of a blend of HCl and HF, commonly referred to in the industry as mud acid (MA). Other operators, with formation containing less than 20% carbonate, tend to pump MA treatments with the MA containing 12% HCl/3% HF (12-3 MA). Treatments with higher HF concentrations (up to 6%) have been performed, but the economics/effectiveness of the treatments did not warrant continuing this trend (Patton et al. 2003).

Due to the complexity of the Monterey formation mineralogy, along with long production intervals without external isolation, the treatment of choice is 12-3 MA jobs pumped at high rate with the goal of stimulating as much formation as possible. The acid treatment volumes are in the range of 40 to 60 gal/ft of 15% HCl, 60 to 90 gal/ft of 12-3 MA, and 100 to 200 gal/ft of 2% NH₄Cl. Where asphaltenes are present, it may be necessary to add an aromatic solvent as a preflush or blend it with the HCl. Volumes are determined by economics and the logistics of operating in an offshore environment.

Typical Monterey completions are either very long (500 to 1,500 ft) openhole slotted liners or cased, cemented, and perforated completions. Recently, external swell packers with sliding sleeves have been used to isolate different producing intervals. Bullheading the acid has been the primary initial treatment method for initially stimulating the Monterey. Other methods include coiled tubing (CT) straddle packers, rotating head wash tools run with CT, and perforating wash techniques. Bullheading acid treatments are usually preferred for cost effectiveness. Foam diversion using nitrogen and 2% NH₄Cl with surfactants is also heavily utilized. However, analysis of surface pressure readings made interpretation of foam diversion effectiveness very difficult.

The Slickline DTS System

The distributed temperature survey (DTS) measurement is built by launching 10-nsec bursts of light down the optical fiber. During the passage of each packet of light, a small amount is backscattered from molecules in the fiber. This backscattered light can be analyzed to measure the temperature along the fiber. Because the speed of light is constant, a spectrum of the backscattered light can be generated for each meter of the fiber using time sampling; allowing a continuous log of spectra along the fiber to be generated (Fig. 5).
A physical property of each spectrum of backscattered light is that the ratio of the Stokes Raman to the Anti-Stokes Raman bands is directly proportional to the temperature of the length of fiber from which it is generated. Consequently, a log of temperature can be calculated every meter along the whole length of the fiber using only the laser source, analyzer, and a reference temperature in the surface system. There is no need for any calibration points along the fiber or to calibrate the fiber before installation. Spectrum acquisition times can be varied from as little as 2 sec to hours, and this defines the accuracy and resolution of the measured temperature log. Typically, a resolution of 0.05°C is required for reservoir surveillance, but observing transient thermal events such as water injection require fast acquisition times of 5 sec, and these will have reduced statistical resolution. (Gonzalez et al. 2008).

The slickline DTS (SL-DTS) employs a standard mobile slickline unit and drum with slickline pressure-control equipment. The fiber itself is a 125-μm-diameter fiber, located in a 0.033-in.-diameter tube, surrounded by carbon weaves inside a 1/8-in.-diameter Inconel 825 tube (Fig. 6). The slickline is 18,500 ft long and H₂S-corrosion resistant, with a working load of 1,000 lbf, and a maximum temperature rating of 248°F. The line looks and feels like a regular 0.125-in. slickline and is deployed in much the same manner with the exception of running a drum and sheaves with a 20-in. outside diameter (OD). The toolstring consists of slickline weight bars, rollers, and possibly a swab mandrel to get pumped into place. Memory gauges for recording downhole pressures should be used as well and run on the bottom. However, because the line is not as strong in tension as a conventional slickline, it cannot be used for operations such as jarring.
Field Operations

Running slickline distributed temperature surveys (SL-DTS) in the California wells presented operational challenges. Several of the wells are highly deviated and some sections are almost horizontal, making it not feasible to run the slickline into the well in the traditional manner using weight bars to pull the wire to bottom. Pumping SL-DTS to bottom was the obvious choice to get the fiber optic into the well to the desired depth. Rollers were used for friction reduction and were selected with a large enough outside diameter (OD) to provide a surface area that can be pumped against to push the toolstring in, but still get back up the well without getting hydraulically stuck in any small restrictions.

For the field case studies discussed in this paper, the SL-DTS was pumped in with the cleanout stage the day before the stimulation treatment injection was to begin. The water pushed slowly and the acid had too low of a viscosity to push the tools, but the foam stage with higher viscosity pushed the toolstring in the well at a pace almost to the maximum running speed of the SL-DTS. During pumping of the toolstring in the well, the line tension must be watched closely and the drum speed set so there is always tension holding the line avoiding any shock loading or overpulling of the line that would cause premature line failure.

Use of high-pressure, hostile environment wellhead equipment (WHE) and a stuffing box is a must for this type of logging (Fig. 7). The WHE wireline valve blowout preventer (BOP) must be secured during the acid injection to prevent rotation during the N₂ foam injection. An injection line on the top of the WHE is also needed to inject a chemical to cut or dilute the wellbore crude oil fluids as they will harden on the line causing the slickline stuffing box to plug and tighten around the line, which can lead to the line getting stuck in the stuffing box without the ability to move up or down.
Once the line is on bottom, ensure the line is past the bottommost perforation in the well as far as possible to be able to monitor the temperature changes of the fluid entering and reacting with the formation and the subsequent warmback overnight. A deep-enough toolstring depth will also ensure the toolstring line is not going to be affected by or affect the downward flow and injection of the fluids into the formation. It should be known that during the pumping process, the line is so small that as long as it is held under tension, the pressures and pumping process will not add tension or stress to the SL-DTS. The WHE will shake and attempt to rotate and the Martin-Decker line-tension measurement device attached to the well will also flutter; therefore, the line tension can be monitored by taking the mean average of the dial gauge movement.

**Thermal Behavior in Acidized Reservoirs**

In naturally fractured formations, effective acid stimulation is critical to enhance well productivity. It is expected that the acid interactions significantly minimize the near-wellbore formation skin by removing drilling damage. In addition, the acid will dissolve carbonate rock, generating wormholes out from the wellbore to efficiently connect the near-wellbore area to the completion. McDuff et al. (2010), discuss the distribution of acid-created wormholes around a wellbore (Fig. 8). The acid reaction with carbonate results in an exothermal generation of heat, which is recorded using the slickline distributed temperature survey (SL-DTS). During acid injection into the formation, when the acid is creating the wormholes, the exothermal heat is generated at the tip of the wormhole. During this injection period, the temperature measured in the borehole will be the injection temperature of the acid without exothermal effects. When the acid injection is stopped, the live acid remaining in the wormhole system surrounding the borehole will
react with the carbonate rock to create a heated “donut” around the wellbore, and this will then heat the liquid in the wellbore, which can be observed using SL-DTS (Gonzalez et al 2012).

Fig. 9 shows SL-DTS measurements in a vertical well with multiple reservoir zones (224 ft of perforated intervals) and drilled depth of 5,210 ft. The stimulation treatment design involved the “acid bullhead” technique in which in a single stage, 15% HCl was pumped at 15 bbl/min over the entire reservoir zone. In addition, ball sealers were used as a diversion method. The use of SL-DTS was to determine in real time a qualitative analysis of the acidized reservoir zones.

The SL-DTS was run into the wellbore to monitor the distributed temperature traces before, during, and after the acid treatment and then use the temperature warm-back interpretation technique to determine the fluid placement over the open reservoir intervals. The warm-back technique consists of analyzing the
temperature behavior after the acid stimulation has been completed. The warm-back response in a fractured reservoir containing carbonate will contain two components superimposed: normal and acid exothermic. During injection of fluids from the surface, the reservoir is cooled at a rate that is proportional to the pore volume of fluid entry. Zones of high fluid conductivity see maximum cooling while nonreservoir zones show less impact. During a “normal” temperature warm-back, the temperature at the reservoir zones stay cold and closer to the injected fluid, and the temperature at the nonreservoir zones will move towards the geothermal gradient. Acid reaction with carbonate in the reservoir contacted by injected fluid is exothermic, causing the reservoir zones to heat-up faster than the normal warm-back in the rock above the reservoir as shut-in time increases.

The baseline geothermal temperature profile (green curve in Fig. 9) will enable comparison of the subsequent temperature profiles during the acid injection and post-treatment warm-back time. The acid injection trace curve (blue curve in Fig. 9) shows significant temperature drops across the reservoir intervals. Note that the injection temperature into the two lower zones is slightly higher than the injection temperature into the upper zones, suggesting a lower flow rate into these intervals.

Once the acid injection stops, the yellow and then red curves in Fig. 9 show sequential temperatures associated with the rate of warm-back. Normal warm-back can be observed above the reservoir (4,200 ft to 4,300 ft) and can be compared to the rate of warm-back in the orange, pink, and green reservoir intervals. Clearly, these intervals warm-back much quicker than the normal warm-back in the rock above the reservoir. This is a result of exothermal heating by the acid as it reacts with the carbonate in the formation. The results of the SL-DTS data indicate that all the reservoir intervals have been successfully stimulated by the acid, with the upper reservoir interval showing the best exothermal acid response. Fig. 10 shows the complete temperature dataset from this acid stimulation presented versus depth and versus time in a 3D display. This type of display is helpful for diagnostic assessment of the job, but contains both normal and acid exothermic data superimposed.

Removing the contribution of normal rock warm-back from the dataset leaves only the acid response. This is shown in the 3D display in Fig. 11. Note how the top zone (orange) takes longer to warm up, and that it stays warmer much longer than the lower pink and green zones. The rapid heating and quicker cool-off of the lower zones is likely indicative of a less well-developed set of wormholes and/or less carbonate-containing minerals than in the upper (orange) zone (Gonzalez et al. 2012).
Understanding the effect of temperature transients during acid spending provides important insights on the stimulation effectiveness during pumping or post-treatment. Acid spending and wormhole growth is a dynamic process that involves competition between physical and chemical processes, including acid–mineral reaction and mass transport. For a given type of carbonate, the acid reaction rate is a function of acid concentration and temperature. Acid mass transport depends on the injection flux and the molecular diffusion rate. The nature of rock heterogeneity, including pore structure and pore size distribution, can significantly affect wormhole propagation during carbonate matrix acidizing (Abou-Sayed et al. 2005). Depending on the reaction kinetics for a given fluid and formation, the effect of temperature on acid spending and wormhole formation varies. For instance, for HCl acid pumped into a limestone formation, the acid volume required to achieve a given permeability increase or skin decrease has been shown to increase as the temperature is increased. Conversely, for HCl acid pumped into a dolomite formation, the effect of temperature is more complex and depends in the injection rate (Nikita et al. 2010).

This DTS data presented in this paper shows how continuous and accurate temperature measurements along the wellbore provided a method to qualitatively infer the acid distribution during pumping or post-acid treatment.

**Case Studies**

Slickline distributed temperature survey (SL-DTS) measurements have been used in naturally fractured Monterey shale wells in California. The wells had many feet of open perforations over several zones and were acid stimulated using a bullhead pumping treatment with multiple foam diverter stages. The SL-DTS was first deployed into the well and obtained a baseline temperature profile. Then a multistage aromatic solvent treatment was pumped to remove asphaltenes from the wellbore and any clogged perforations. Subsequently, the multiple-stage, diverted acid treatment was pumped. Temperature monitoring continued after pumping was concluded to observe the formation heating (warm-back) response from the temperature perturbation created by the injected treatment fluids. In one well, the DTS data showed that the majority of the stimulation fluid was injected in the lowermost section of the perforated intervals. The warm-back after the acid treatment was pumped showed a strong heating that extended below the lowest perforation. A smaller heating anomaly was seen in one of the upper zones later in time, possibly indicating upward acid movement (wormholing) through the formation. The uppermost zones showed no indication of having received fluid while pumping the treatment. Another well had numerous perforation
zones within a large gross interval. The DTS data showed the upper zones received the majority of the treatments.

Fig. 12 shows a thermal 3D map of the temperature dataset from the entire stimulation treatment. Fig. 13 shows the result of the normalization process in which the contribution of normal rock warm-back is removed from the DTS data. This illustrates where acid reacted exothermically with carbonate in the reservoir.

Figure 12—3D display of temperature monitoring during a multistage acid stimulation using SL-DTS.
Another dataset showed a progression of deepening temperature responses associated with successful nitrogen diversion stages. However, downward progression ceased above the lowest perforation, likely due to a highly conductive fracture sweet spot that the nitrogen diversion could not overcome. After solvent and acid pumping ceased, the warm-backs were monitored. Acid responses were observed at several locations in the upper portion of the perforated interval (Fig. 14 and Fig. 15).

Figure 13—Normalized response of temperature monitoring of an acid stimulation in a fractured reservoir. The warmer colors indicate the exothermic heating due to acid reaction with carbonate rock.

Another dataset showed a progression of deepening temperature responses associated with successful nitrogen diversion stages. However, downward progression ceased above the lowest perforation, likely due to a highly conductive fracture sweet spot that the nitrogen diversion could not overcome. After solvent and acid pumping ceased, the warm-backs were monitored. Acid responses were observed at several locations in the upper portion of the perforated interval (Fig. 14 and Fig. 15).

Figure 13—Normalized response of temperature monitoring of an acid stimulation in a fractured reservoir. The warmer colors indicate the exothermic heating due to acid reaction with carbonate rock.
Figure 14—3D display of temperature monitoring during a multistage acid stimulation using SL-DTS.

Figure 15—Normalized response of temperature monitoring of an acid stimulation in a fractured reservoir. The warmer colors indicate the exothermic heating due to acid reaction with carbonate rock.
Evidence of a leaking gas lift valve was also observed with the DTS data. A cooling anomaly was observed at the gas lift mandrel due to expansion of the gas entering the tubing string (Gonzalez et al. 2008).

Conclusions
This was the first real-time monitoring of a naturally fractured, stimulation treatment in California. The deployment of the fiber-optic slickline (SL) system was straightforward. Valuable feedback from the distributed temperature survey (DTS) evaluation of the stimulation procedure will be used to modify future acid jobs. Alternative diversion strategies are planned for future treatments. The SL-DTS system will allow evaluation of their effectiveness and a fine tuning of the techniques. DTS monitoring using SL-DTS combined with pressure measurements provides valuable reservoir data as well as stimulation optimization. Highly conductive natural fractures show a larger response than less-conductive fractures. This can be tied back to fracture identification logs for an enhanced fractured reservoir model. And the ability to monitor the placement of stimulation fluids provides an environmentally robust solution in today’s increasingly scrutinized operating environment.

Acknowledgments
The authors would like to express appreciation to Schlumberger management for permission to publish the results of this work.

CONVERSION FACTORS

<table>
<thead>
<tr>
<th>Unit Conversion</th>
<th>Formula</th>
</tr>
</thead>
<tbody>
<tr>
<td>bbl / H11003</td>
<td>$1.58973 \times 10^{-1}$ m³</td>
</tr>
<tr>
<td>°F / H11003</td>
<td>$(\text{°}F - 32)/1.8$ °C</td>
</tr>
<tr>
<td>°C / H11003</td>
<td>$(\text{°}C \times 1.8) + 32$ °F</td>
</tr>
<tr>
<td>gal / H11003</td>
<td>$3.785412 \times 10^{-3}$ m³</td>
</tr>
<tr>
<td>in / H11003</td>
<td>$2.54 \times 10^{0}$ cm</td>
</tr>
<tr>
<td>lbf / H11003</td>
<td>$4.448222 \times 10^{0}$ N</td>
</tr>
<tr>
<td>psi / H11003</td>
<td>$6.894757 \times 10^{0}$ kPa</td>
</tr>
</tbody>
</table>

References


