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APPLICATION FOR CLASSIFICATION AS HARDSHIP GAS WELLS
Dinero Operating Company
Dublin Ranch Morrow Wells,
Eddy County, New Mexico

ITEM NO. I

1. In July of 1980, El Paso Natural Gas Company (Pipeline Company) shut in our Big Chief Comm. No. 3 Well due to the Market demand of the July 4th. weekend. This well had consistently been flowing over one million standard cubic foot of gas per day from the Morrow formation prior to this period. Subsequent to the five day shut in period, the well produced no significant amount of gas relative to its past history, and a great deal of time and money was spent in an attempt to return production to normal. All of this work was to no avail, and the well was eventually plugged in the Morrow formation and recompleted in the Atoka formation.

   The Big Chief Comm. No. 2 Well was originally completed in the Morrow in late 1978. It tested for 2.6 million SCFPD. It was necessary to shut this well in following the acid treatment and subsequent cleanup due to an incomplete pipeline connection. When the line was finally completed over 30 days later, the well could sustain a rate of only 300 MSCFPD. This well was later plugged back in the Morrow formation and recompleted in the Atoka formation.

   The estimated loss of production from just these two wells because they had been shut in is over 1500 MMSCF.

   We believe that the Morrow production was lost due to the quality of sandstone and associated bentonitie clay material present in the Morrow and Atoka formation in this area. Studies of the Pennsylvanian sandstones in this area indicate an average composition of 85% fine grained quartz, 10% total clay minerals, and 5% other minerals. It is the 10% clay content that exposes these wells to the danger of lost production. This clay is composed of 95% chlorite and 5% illite. Chlorite is a very water sensitive mineral, and it occupies some of the pore space in the sandstone matrix. It has a high irreducible water saturation, and fluid retention of the chlorite during drilling, completion, or as in this case, temporary shut in periods, can lower the relative gas permeability.

   These wells produce very little water, but as in the case of the Big Chief Comm No. 3 Well, enough water entered the wellbore to cover the perforations. A swabbing unit was placed on the well and 6 days were spent trying to swab back the well. All the water was recovered from the wellbore, but the damage had been done.

   Therefore, we ask that the following wells be classified as HARDSHIP GAS WELLS, so that we will avoid the possibility of losing another Morrow gas well to formation damage.

   BIG CHIEF COMM. NO. 1 WELL, BIG CHIEF COMM. NO. 4 WELL, LITTLE SQUAW COMM. NO. 1 WELL, and DINERO STATE COMM. NO. 1 WELL.

APPLICATION FOR CLASSIFICATION AS HARDSHIP GAS WELLS
Dinero Operating Company
Dublin Ranch Morrow Wells
Eddy County, New Mexico

ITEM NO. 2

2. Attached are the well histories showing the attempts to rectify production problems in the Morrow zones of the Big Chief No. 2 and Big Chief No. 3 wells. Since the wells which we are applying for hardship gas well status have not as yet been damaged by being shut-in, we are using these two wells to justify our case for the remaining four Morrow wells in this field.

   Attached are well hisitories of the Big Chief Comm No. 2 Well and the Big Chief Comm. No. 3 Well. Also attached are wellbore sketches of the Big Chief Comm. No. 1 Well, Big Chief Comm. No. 4 Well, Little Squaw No. 1 Well, and the Dinero State Comm. No. 1 Well.

COMPLETION HISTORY ON THE BIG CHIEF #2

January 15, 1979

Rigged D.A. & S. Well Service. Prep to run Gamma Correlation Log.

January 15, 1979

Rigged up Schlumberger and ran Gamma Ray Corr. Log from plug back total depth of 12,655-10,800. Unloaded 404 jts. of tub. on rack, ran 100 jts. of tub. in hole open ended.

January 17, 1979

Ran 401 jts. of tub. in hole open ended. Displaced fresh water with 275 bbls of 2% KCL waer. Pulled 2" tub. Perf. Lower Morrow formation: 12,455-464' 9 shots, 12,360-68' 8 shots, 12,346-56' 10 shots.

January 18, 1979

Ran Tub. with disc. and Otis Packer set @ 12,288'. Dropped bar @ 3:45 p.m. well kicked off, was flowing @ 300,000 cf/day. Shut well in last night. Will flow today and check with swab for fluid and give it acid wash.

January 19, 1979

SITP 2250, flowed well to pit and ran swab to bottom of tubing. No fluid in hole. Well stabilized on 3/4" choke @ 20 PSI , rate 500 MCF/day. Acidized Morrow form. with 3000 gal. MS acid & 5000 SCS of Nitro. Break down press. 9100. Treated @ 6700 PSI @ 5 bbls/min. ISIP 5000 15 min SIP 4300. Flowed well to pit , rate increased to 1.5 MMCF/Day. Still making water.

January 20, 1979

Flowed and cleaned up.

January 21, 1979

Flowed and cleaned up.

January 22, 1979

NB

Will run Otis Plug in Packer set @12,288'. Prep to perf. upper Morrow Zones.

January 23, 1979

SITP 3400 PSI, flowed to pit and ran Otis Blanking Plug and set in packer @ 12,280. Released on-off tool and pulled tubing out of hole. Perf. upper Morrow formation from 12,232-42 12,170-75 12,160-64' total of 19 shots.

COMPLETION HISTORY ON BIG CHIEF #2

January 24, 1979

Ran Otis Perma Latch Packer and on-off tool in hole with 387 jts. of 2" tub. Bottom of Packer 12,255'. Spotted 200 gal of 7½% MS acid over perfs. Pulled 8 jts. of tub. and set Packer @ 12,021'. Acidized formation with 200 gal. acid. Break down press. 4900. Pumped into pay @ 4800 @ 2/bbls min. ISIP 3800, 5 min SIP 2200. Swabbed load and acid water to pit for 2 hours, fluid level 7200. Well kicked off and flowed gas and water to pit. Stabilized on 3/4" choke @ 100 psi, rate 1.6 MMCF/day.

January 25, 1979

SITP 3000#, flowed well to pit. unloaded water and stabilized @ 200 psi on 3/4" choke, rate 3 MMCF/day. Flowed well on 7/16" choke @ 550 psi, rate 2.6 MMCF/day. Rigged up Otis and attempted to pull blanking plug out of bottom of packer but have not.

January 26, 1979

Otis cont fishing for blanking plug, retreived plug @ 10:30 PM. Flowed well to pit on 3/8" choke, flowed water and gas. No rate.

January 27, 1979

Waiting on Tie in.

January 28, 1979

Waiting on Tie in.

January 29, 1979

Waiting on Tie in.

January 30, 1979

Waiting on gas line connection (El Paso Nat. Gas.)

January 31, 1979

Waiting on Gas Line Connection.

February 1, 1979

Waiting on Gas Line Connection.

COMPLETION HISTORY ON THE BIG CHIEF #2

February 2 thru March 24, 1979

Waiting on ElPaso Gas Line connection.

March 24, 1979

Tied in well to ElPaso Line @ 12:00 noon 3500# Shut In press. @ time well was turned on. Flowing 1.871 MMCF.

March 26, 1979

Tied in & flowing.

March 27, 1979

Flowing to ElPaso Line, will have rate later today. Unloading water and waiting on well to stabilize to start 4 point test.

March 28, 1979

Flowing into ElPaso line. Start 4 pt. test if well is stabilized.

March 29, 1979

Open up and flow on larger choke and attempt to unload water.

March 30, 1979

Flow TP 600#, 950 MCF. Crew lay to blow down well. Lease operator will attempt to unload water.

April 1, 1979

Flowing no report

April 2, 1979

Flowing no report.

April 3, 1979

Closed in for pressure buildup and attempting to unload water.

April 4, 1979

TP 450#, Gas 320 MCF. Opened well to atomsphere & blow down for 2 hours & rec. an est. 3 bbl of water. Closed well in for press. build up.

April 5, 1979

Closed in 24 hrs. press. built up to 1300# in 24 hrs. Lease operator left closed for cont. press build up.

COMPLETION HISTORY ON THE BIG CHIEF #2

April 6, 1979

Left well closed for 48 hrs. Built up to 1500#. Opened well to pit and blow down, recovering 0 water. well will probably have to be swabbed off.

April 7, 1979

Shut In.

April 8, 1979

Shut In.

April 9, 1979

Shut In.

April 10, 1979

West Texas Consulting Service ran BHP. Surface press 1777# BHP @ 12,300' 2299#, no fluid.

April 11, 1979

SI BHP 2229# surface tub. press. 1777# Western Co. making up recommendation for treatment.

April 12, 1979

Prep. to acidize well.

April 13, 1979

Re-treat upper zone 6000 gal. 7½% Gelled acid 9000 Cu. ft. Nit. 72 balls Av. treat press. 8500# , 8.4 BPM. Good ball action - ISDP 4800# FST 10 min. 4250# flow to pit, well died, rig up to swabb. Shut Down.

April 14, 1979

Swabbing load back, released unit, well not coming back.

April 15, 1979

Attempting to flow well back.

April 16, 1979

T.P. 2060# flow to pit, unload very little water. Stabilized on ½" choke, 160# TP, Rate 850 MCF.

April 17, 1979

Shut In.

COMPLETION HISTORY ON THE BIG CHIEF #2

April 18, 1979

Shut In, tie back into ElPaso line this AM.

April 19, 1979

TP 2210# , open well to sales line, press came down to 500#, open to 3/4" Choke.

April 20, 1979

On line, flowing 583 MCF.

April 21, 1979

Flowing.

April 22, 1979

509 MCF 6 bbls. of fluid, TP 500#.

April 23, 1979

501 MCF 6 bbls. of fluid, TP 450#.

April 24, 1979

On Line.

April 25, 1979

Flow to line, est. 371 MCF.

April 26, 1979

Flowing to sales line.

April 27, 1979

Flowing 401 MCF.

April 28, 1979

Flowing into line.

April 29, 1979

Flowing into line.

May 1, 1979

Flowing ElPaso to run 4 pt. test as soon as possible start 24 hrs. Shut In. 5/1/79 28th - 29th 376 MCF.

COMPLETION HISTORY ON THE BIG CHIEF #2

May 2, 1979

Starting 4 pt. test @ 9:30 am.

May 3 1979

Run 4 pt. test by ElPaso .

COMPLETION HISTORY BIG CHIEF NO. 3

June 1, 1980

Produced and sold 34,000 MSCF gas, approx. 1130 MCF/day.

July 4, 1980

ElPaso Pipeline called to inform us Bug Chief #3 had to be shut in.

July 5, 1980

Shut In.

July 6, 1980

Shut In.

July 7, 1980

Shut In.

July 8, 1980

Shut In.

July 9, 1980

Shut In.

July 10, 1980

Well back on line.

July 11, 1980

No Production.

July 12, 1980

No Production.

July 13, 1980

No Production.

July 14, 1980

No Production.

COMPLETION HISTORY ON THE BIG CHIEF #3

July 15, 1980

No Production.

July 16, 1980

No Production.

July 17, 1980

RU Mack Chase Swab Unit. Ru blow down line and started swabbing.

July 18, 1980

Bled well down. Run swab to 11,500'. Fluid level approx. 9000'. Swabbed dry, then made one swab run every hour. Shut Down.

July 19, 1980

Bled well down, ran swabb, swabbed well dry and shut down.

July 20, 1980

Shut Down.

July 21, 1980

Bled well down. Started swabbing.

July 22, 1980

Bled well down, swabbed well dry, shut down.

July 23, 1980

Bled well down, swabbed well dry. Acidized with 3500 gallons 7.5% MS acid. with corrosion inhibitor and clay stabilizers. Maximum pressure 7000 psig. Min. pressure 3400 psig. Avg. pressure 5000 psig. Average rate 3.0 BPM. ISIP 2200# 15 min. SIP 500##. 134 bbls. of load to recover. Good ball action indicated. Start swabbing, recovered, 30 bbls load. 104 bbls to recover.

July 24, 1980

Swabbing initial fluid level 7700'. Recovered 66 bbls. some gas. Final fluid level 11,800'. Rec. 66 bbls. 38 bbls to recover.

July 25, 1980

450 psig on tubing. Bled well down. Swabbed dry.

COMPLETION HISTORY ON THE BIG CHIEF #3

July 26, 1980

Tubing pressure 750 psig. Bled well down. Initial fluid level at 6000'. Swabbed dry.

July 28, 1980

Bled well down. Swabbed dry. Total load recovered/ Put on line at 300#. Tubing pressure up to 900# 2 hours later, decreasing to 350# . Zero sales that night.

July 29, 1980

Tubing pressure 400 psig. Bled well down in 10 min. Initial fluid level at 6000'. Fluid level stayed around 7500' all day.

July 30, 1980

Tubing pressure 1400 psig. Bled well down. Initial fluid level at 6000' Swabbed all day with fluid level around 7500'. Shut Down.

July 31, 1980

Swab all day. Shut Down.

August 1, 1980

Swab all day. Shut Down.

August 2, 1980

Bled well down, swabbed well dry. put well on line, Shut Down.

August 3, 1980

Well on line.

August 4, 1980

Tub. pressure 400 psi. Bled well down. Initial fluid level 6000'. Swabbed well dry. Shut down. Rig down.

August 5, 1980

Tubing pressure 1500 psig. Bled well down. Made two swab runs. Shut Down.

August 6, 1980

Tub. press. 400 psi. Bled well down. Swabbed well dry. Rig Down, Cleaned location. Put well back on line.

REVIEW OF THE COMPLETION PRACTICES IN THE MORROW FORMATION OF SOUTHEAST NEW MEXICO

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ABSTRACT

The Morrow Formation is one of the main targets of the drilling activity in Southeast, New Mexico. The paper presents background information including formation lithology derived from X-ray diffraction data and scanning electron micrographs. Formation rock characteristics such as frac and temperature gradient, Young's modulus, permeability, porosity and formation water properties are also presented. Completion techniques such as cementing practices, casing programs and perforating programs are reviewed in detail. The stimulation fluids, volumes, injection rates and types of proppant used are presented to provide an optimum completion program.

INTRODUCTION

Morrow sands of Pennsylvanian age are deposited erratically on the Northwestern shelf of the Delaware Basin. The most prolific zones are found in the Southeastern part of New Mexico, more specifically in the Southeastern part of Chaves County, the Western one-third of Lea County, and almost all of Eddy County, New Mexico. (See Map Fig. 1).

Reserves in the Morrow in S. E. New Mexico which cover about 3.5 million acres, have been estimated at up to 10 trillion cubic feet of gas and 100 million bbl. of oil. Completion success has been high in recent years and proven reserves are rapidly accumulating for many operators.

The search for Morrow pay increased dramatically after prices were allowed to rise under the Natural Gas Policy Act of 1978. Partial price deregulation for gas at depths between 10,000 and 15,000 feet would be attractive in most instances. Although the size and location of the sands are unpredictable, they often lie in multiple layers and success ratios have been high. An additional incentive is oil and gas production from the Atoka, Strawn, Wolfcamp and Bone Springs Formations.

Although over the years the Morrow sand has been an object of considerable drilling activity, completion difficulties encountered in the Morrow have forced abandonment of several promising prospects. Improper completion practices have yielded production tests inferior to results indicated from DST information.

Up to and including the late 1960's, the only Morrow production in Southeast New Mexico was from wells that were completed natural due to well developed native permeability. Stimulation attempts during that period consisted of hydraulic fracturing with oil based gels or saturated NaCl brines which yielded poor results.[1] In many instances, the production after stimulation was lower than that indicated by DST. The first successful stimulation consisted of weak HCl acid gelled with a synthetic polymer that contained copious quantities of low surface tension surfactants, iron sequestering agents and clay stabilizers. CO_2 was used to enhance load recovery. The proppants used in these treatments were 40-60 mesh sand, 20-40 mesh sand and a tail-in of 20-40 mesh glass beads.

In the late 1970's some operators used crosslinked aqueous gels with varying degrees of success. With improved gelling technology and pumping equipment it became possible to increase proppant concentrations up to and above 3 pounds per gallon of gel. In the late 1970's and early 1980's a few foam fracs were attempted, however, mechanical problems related to excessive surface treating pressures were experienced.

Wellbore damage cleanout and perforation breakdown with the conventional 15% HCl acid generally resulted in severe production decline. Specially designed weak HCl acid (7 1/2%) systems with iron sequesterant, clay stabilizers and surfactants pumped with N_2 gas have yielded the best results and are usually sufficient to trigger commercial production.

Of several hundred Morrow treatments the authors have been involved with, only about 25% have been fracture treatments. It should be noted that fracture treatments have yielded 3 to 5 fold production increases in over 50% of the wells.

Several fields have been developed in S. E. New Mexico. Some of the fields selected for the purpose of this study are: Antelope Ridge, Big Eddy, Buffalo Valley, Burton Flats, Carlsbad, Catclaw Draw, Cemetary, Hat Mesa, Lusk, Vacuum, and Washington Ranch.

In Central Eddy County well depths average between 7,000' to 8,500'. In deeper areas of South-Eastern Eddy and Western Lea Counties well depths range 11,000' to 15,000'. The formations South of the Huapache fault generally are 4,000' shallower than those of central Eddy County.

FORMATION DEPOSITIONAL & ROCK CHARACTERISTICS

The Morrow depositional environment is regarded as a general marine regression during which streams laden with clastics prograded to the South and Southeast depositing pro-delta, delta and stream sediments.[2,3] This marine regression can be divided into three depositional units. Each unit consists of a clastic progradation which is interrupted by brief marine incursions. These marine incursions show up on logs as highly radioactive shales.[3]

The lower most Morrow unit is considered to be a delta-plain evnironment with major sands trending NW-SE direction between interdistributary backlevee deposits.

The middle Morrow unit distributions indicate pro-delta and distributary systems associated with a restricted marginal marine environment.

Although Morrow sedimentation consists mainly of clastic deposition, limestone is found in some areas.[4] The clastics comprise of coarse to fine grained quartz sands and gray to black silty shales. These sands are deposited in discontinuous lenses aligned roughly parallel to ancient shorelines which border the depositional basin to the Northwest. These lenses vary in thickness, occurence and lateral extent.

Morrow sands can be adequately described as well consolidated, white angular to sub-angular, coarse grained bodies containing traces of calcareous and glauconitic materials. Generally, with some exceptions, the Morrow productive interval consists of several producing stringers covering between 100 to 400 feet. Average individual sand thickness varies from 15 to 20 feet. In certain areas, such as the Burton Flats field in Eddy County, it is not unusual to find a sand thickness of 20 to 30 feet. The gross interval, however, varies from 10 to 75 feet. Porosities range from a low of 6% to a high of near 20%, with lower porosity numbers being more common. Permeability studies have reported values ranging from 10 to 100 md. based on core studies, however, pressure buildup studies indicate permeabilities ranging from 0.1 to 1 md.

Morrow sands can be divided into two major rock types:

1. A poorly sorted coarse grained to conglomeritic kaolinite-rich quartz sandstone.

2. A moderately sorted fine grained chlorite and mixed layer clay rich quartz sandstone.

Several cores from the Morrow in the area under investigation have been available for mineralogical studies such as, X-Ray Diffraction, Petrographic studies and SEM analysis. Figures 2 through 7 are a presentation of Scanning Electron Micrographs at various degrees of magnification. X-Ray Diffraction analysis data taken from several cores are summarized in Table 1. These analyses show that the cores studied had no more than a trace of montmorillonite, indicating little or no water sensitivity. However, the amount of kaolinite present in these cores is higher than that found in most formations, which explains the observed water sensitivity of the formation. When contacted by aqueous systems, kaolinite disassociates, leading to particle migration and subsequent permeability damage. Sample studies have also shown presence of HCl acid soluble material. Solubility varies from 2 to 6%.

In many instances, investigations revealed unusually large concentrations of iron bearing minerals. These minerals (pyrite, chlorite) are HCl acid sensitive and contribute to the formation of $Fe(OH)_3$ (Ferric hydroxide), which may precipitate during the shut-in period of the acid treatment. To minimize these potential problems special fluid additives are employed in stimulation fluids, and shut-in times are minimized.

Many of the samples studied can be classified as conglomeritic sandstone. Others are fine grained, shale laminated sandstone. The well consolidated frame works are composed mainly of quartz with an abundance of both thick and thin laminae. Secondary dolomite crystallization and anhydrite occur in minor quantities.

Pyritized organic debris is evident within the shale laminae. Petrographic studies show clay minerals, chlorite, kaolinite and mixed-layer illite-smectite are dispersed within intragranular pore spaces. The result is very poor visual permeability and porosity as seen in Figures 7a and 7b.

The clay minerals, in conjunction with formation fines and precipitating iron compounds, can affect the formations petrophysical properties by behaving as migrating fines within a pore system. Both these problems can drastically reduce productivity.

Scanning Electron Micrographs reveal that most of the clays present are in the form of a thin coating on the pore walls. Thus, the permeabilities are sometimes below one millidarcy, although the porosity may be in excess of 15 to 20%. The clay coatings are usually very porous and will calculate higher residual water saturation due to this microporosity.

Matrix flow through tests were performed on core plugs. The results of the tests are presented in Figures 8 and 9. Note, MS Acid, a special blend of 7.5% HCl and surfactants, introduced very little formation damage and showed considerable improvement in permeability.

Table 2 is a summary of water analysis from several well-known Morrow fields. Note, the pH of the waters ranged from 5 - 7.1. The sodium and potassium, and calcium concentrations ranged from 17,100 - 22,600 and 1,400 - 11,600 ppm respectively. The chloride concentration varied from 30,000 to 48,000 ppm. Fluid densities were remarkably similar 1.036 - 1.05 at 75° F.

COMPLETION PRACTICES

The characteristics that typify the Morrow formation in S. E. New Mexico are:

1 Limited areal extent
2. Wide variations in permeability
3. Very high skin damage
4. Poor response to conventional stimulation treatments

The factors that must be considered to have overall optimum completion of the Morrow formation are:

1. Drilling fluids and practices
2. Perforating program
3. Casing and tubing programs
4. Stimulation treatment

Drilling and Drilling Fluids

Morrow drilling has employed conventional rotary drilling. The shallow beds in this area are highly cavernous with large vugular porosity and valuable fresh aquifers.[3] A typical casing program is presented in Fig. 10. A conductor pipe is set between 40' to 80'. The surface pipe, usually 13 3/8" is set between 500' to 650' to protect the fresh water aquifers. The intermediate casing is usually 9-5/8" and is run from about 1200' to 5500'. Its main function is to protect fresh water zones and prevent fracturing of incompetent beds by the required med weight. Loss circulation is a common occurrence in drilling the intermediate hole.

Circulation of cement to the surface or into the surface casing is a state of New Mexico requirement in the water basins and in the abnormally pressured areas. It is suggested that the entire intermediate casing string be supported with cement.

In areas of the basin where abnormal pressures occur, well design should be modified to provide a protective casing or liner to case off the weaker formation above the Wolfcamp. In most areas a 5-1/2" production casing is run to TD and cemented back to the intermediate string. The 5-1/2" production string is cemented with Class C or Class H cement containing 5 to 7 lbs. of salt per sack and a fluid loss additive to control hydration. The mix water should contain 2% KCl to prevent formation damage by the filtrate. The pipe should be rotated and centralizers should be run in the completion interval.

Drilling from intermediate casing point to the top of the Wolfcamp section makes maximum use of fresh water. Near the top of the Wolfcamp the drilling fluid is changed to cut brine or ±5% KCl water to prevent shale sloughing and to maintain good hole conditions. In the Morrow clastics, the mud system is usually changed to a KCl based starch-viscosifier system. The KCl water provides a mud filtrate designed to minimize clay swelling in the productive interval and greatly reduces skin damage and washouts.

The selection of drilling fluids in the water sensitive Morrow sands is of paramount importance in the drilling and completion of Morrow gas wells. Figure 10 presents a typical mud program. The most commonly used mud systems are composed of water based systems such as Ben-ex or Gelex, Lignosulfonate (dispersed) system, starch viscosifier and KCl polymer. The KCl polymer system prevents shale sloughing, provides hole stability protection from formation damage, and improves penetration rates. This system contains 2 to 5% KCl and polymers which provide viscosity and water loss control.[5] Wells drilled with muds that provided stable hole conditions tend to have better cement jobs as indicated by cement bond logs. Good cement jobs prevent communication behind the pipe during stimulation treatments, and therefore play an important role in the overall completion program. Since fresh water muds might affect the clays present in the Morrow pay section it is recommended that a KCl brine based system be used during drilling through the Morrow pay section.

Recently some operators have used oil based muds in the Morrow Sands. Early reports indicated better penetration rates and more stable hole conditions. From a completion standpoint the use of oil based muds is not recommended, as oil invasion in a dry gas zone could damage the native permeability, and irreversibly impair its productivity.

About 80% of the wells are drill stem tested.[5] The DST data, formation damage factor and open hole logs are used in making the decision to run pipe or abandon. A damage factor of 2 to 10 is common.

erforating Program

When perforating, it is desirable to attain large deeply penetrating holes that will facilitate hydrocarbon communication to the wellbore. It is also necessary to prevent either partial or complete blockage of the perfs with mud, cement and perforating debris. To achieve these ends the operators have used the following methods.[5]

1. Perforating through casing with a casing gun
2. Through tubing with differential into the wellbore
3. Perforating with a tubing conveyed gun
4. Seal or disc method

Perforating Through Casing Method

A few operators in S. E. New Mexico use the conventional through casing method of perforating. This method uses an overbalanced hydrostatic head and the perforating occurs in a mud or an acid environment. Although the use of a large gun produces deep penetrating perforations, the overbalance does not allow the debris and the damage to clean-up.

Through Tubing Method

Most of the wells in the Morrow are perforated through tubing and below a packer. To provide for larger diameter and deeper penetrating perforating guns it becomes necessary to run 2-7/8" or 3-1/2" tubing in the hole. It is recommended that the fluid level in the tubing be swabbed down to provide a significant pressure differential into the wellbore. This keeps the completion fluid off the formation and blows off any invading drilling fluids and perforation debris blocking off the perforations. It should be noted that the tubing gun produces smaller diameter holes with less penetration.

Tubing-Conveyed Perforating

When perforating with a tubing conveyed deep penetrating casing gun (Fig. 11), formation pressure is instantly released into the wellbore at maximum differential. The maximum differential pressure pushes fluids into the tubing carrying with it mud filtrate, cement contamination and perforating debris. This cleaning action allows the formation to produce at its natural capacity.

This system provides deeply penetrating perforations, however, higher costs and loss in operating flexibility may result. The perforating gun must be tailormade for a particular formation thickness and perforation density, thus increasing perforating costs, and reducing stimulation flexibility. Furthermore, the gun is released into the rathole, and sufficient rathole depth is necessary to drop the spent carrier.

Disc Method

The disc method combines the advantages of perforating with a casing gun and the enhanced clean-up achieved with a tubing conveyed gun. First, the well is perforated with differential pressure into the formation using a deep penetrating casing gun. Tubing is then run dry into the wellbore with a sub and shear tested disc assembly installed in the tubing near the packer. With the tubing and packer set, a surface weight is dropped to rupture the disc, thus creating an instantaneous surge into the wellbore. Filtrate and debris is forced into the wellbore as the formation pressure is exposed to near atmospheric conditions. This system allows for maximum size and penetration of shots. Once the disc is ruptured the tubing remains open full gauge for stimulation operations. Overall this system is more efficient and less costly than the three previously mentioned methods.

Perforating Procedure

As mentioned earlier the Morrow pay zone may be found as several layers each 8' to 10' thick and separated by shale stringers spread over 200 feet. To effectively treat the entire zone careful consideration should be given to engineering the perforating program, i.e. selecting the type of gun, pressure differential, number, and size of perforation.

Prior to perforating, the wellbore should be displaced with clean 2% KCl water containing appropriate surfactants and packer fluid. Weak organic acid (10% acetic acid) should be spotted opposite the Morrow pay interval to be perforated.

The authors suggest that the Morrow be shot selectively with either a tubing conveyed casing gun or a conventional casing gun to achieve maximum penetration (±19") and have perforation diameters in excess of 0.4". The well should be perforated underbalanced so as to have a positive differential into the wellbore, or perforated overbalanced via casing, and the tubing run dry.

The number of perforations should range from 20 to 40 to provide sufficient control during treatment and afford fluid selectivity by the use of Limited Entry or the modified Limited Entry Technique. The number of perforations will depend on zone thickness, vertical separation between pay zones and the treatment hydraulics (injection rates and pressures).

CASING & TUBING PROGRAMS

When planning casing programs for the Morrow formation one should consider the type of stimulation (i.e. hydraulic fracturing) that may be required. To effectively fracture two or more stringers spread over 100' or more it is necessary to achieve high injection rates during treatment. High injection rate improves selectivity and considerably enhances the probability of treating the entire zone.

High bottom hole frac pressures coupled with reduced hydrostatic head by addition of gas such as N_2 or CO_2 makes high injection rates difficult to obtain via smaller size tubing (2-3/8"). Therefore, it is necessary to use 2-7/8" or 3-1/2" tubing (see Fig. 12) to obtain high rates required for successful fracturing. To run the larger diameter tubing (2-7/8" or 3-1/2") it becomes necessary to run 5-1/2" casing. The economics of using 2-7/8" vs 2-3/8" becomes obvious at higher injection rates by reviewing horsepower costs presented in Table 3.

High injection rates are necessary to carry the proppant in the gel and reduce the probability of a premature screenout during fracturing. The authors recommend fracturing injection rates be maintained between 8 to 15 BPM. The Morrow fracturing gradients for various fields are presented in Table 4.

Wells are usually not treated down the casing for two reasons: 1) high surface treating pressures are encountered, and 2) the potential danger of damaging the zone during "killing" operation when tubing is run into the hole.

STIMULATION CONSIDERATIONS

The general philosophy in Morrow stimulation is:

1. Perforate in weak acetic acid underbalanced and attempt a natural completion.

2. Acidize to breakdown perforations and clean-up any damage around the wellbore.

3. If step 2 is unsuccessful, fracture stimulate the well.

In the late sixties nearly 70% of the wells were natural completions.[4] Today, nearly 90% of the wells need some sort of stimulation, of which 25% or more need hydraulic fracturing.

In the early days of Morrow development, response to any type of stimulation treatment was poor. The most significantly observed characteristic was very poor load recovery. This fluid retention characteristic was attributed to presence of clay minerals. However, later studies showed that fluid retention occurs as a result of three factors.[4]

1. Abnormally large capillary forces
2. Undersaturated condition of the formation
3. Presence of migrating clay particles

Fluid retention problems have been significantly reduced by employing ultra low surface tension fluorosurfactants that water wet sandstones in conjunction with large volumes of gas, such as nitrogen (N_2) or carbon dioxide (CO_2). The addition of gas provides energy to enhance fluid recovery and decreases the volume of liquid required to stimulate, thus reducing the amount of liquid to be recovered. The use of foaming surfactants should be avoided in reservoirs which tend to make significant amounts of condensate. In fact, where reservoirs make large amounts of condensates an emulsion test should be run to determine the best surfactant application.

Productivity as related to fluid retention is a function of shut-in period after treatment. There is sufficient field data to suggest a substantial impairment in productivity if the well is shut-in after stimulation for long periods of time. If for some reason the well has to be left shut-in, it should be stimulated just prior to opening.

In order to expedite clean-up the well should be opened within 30 minutes after an acid treatment and within approximately 2-4 hours after a frac treatment. Frac treatments should be left shut-in longer to allow for the gel to break and the fracture to heal. Excessively long shut-in times lead to dissipation of stimulation gas into the formation leading to a substantial loss in pressure (energy) that would be used in fluid recovery.

The Morrow's virgin static reservoir pressure varies between 4000 psi to 7000 psi, and the flowing bottom hole pressure in the new wells varies from 3200 psi to 5000 psi. The bottom hole fracturing pressure varies between 6000 psi to 13,000 psi. This translates to an overburden pressure ranging from ±3500 to ±9000 psi in new wells. Most new Morrow wells exhibit an average overburden pressure in excess of 6000 psi. Since the crushing strength of 20-40 sand is around 6000 psi, it becomes necessary to use a high strength proppant such as glass beads or bauxite. Most operators run bauxite only in the last 10-25% of the treatment in an effort to minimize job costs. This technique provides a bauxite pack around the immediate vicinity of the wellbore where the pressure draw down is maximum.

A new, less expensive ceramic type proppant is now available which crushes at stresses greater than 9000 psi. Table 6 compares the properties of this new proppant to 20-40 sand. The cost of this new proppant is approximately 60% of bauxite. Thus, larger proppant volumes may be pumped at similar costs when overburden pressures exceed 6000 psi, thus reducing production decline rates and improving the volumes of hydrocarbons produced.

STIMULATION DESIGN

The Morrow wells should be acidized with 7 1/2% HCl acid containing clay stabilizers, low surface tension surfactants, iron sequesterants and 1000 to 1500 SCF N2 per bbl. The acid volumes should range from 150 to 200 gal. per net foot. If 2-3/8" tubing is the conductor, a friction reducer should be added to the acid to reduce the surface treating pressure. Average injection rates vary from 3 to 4 BPM of acid and 3000 to 6000 SCF N_2/min. Surface treating pressures vary from 7000 psi to 10,000 psi depending on the fracturing pressure and the tubing size. Normally 50% excess ball sealers are spaced evenly in the acid to achieve a ball out and to ensure that all the perforations are opened. The well should be opened in approximately 30 minutes.

A wide range of parameters must be considered in designing the fracture stimulation treatment, such as: well mechanical considerations, reservoir properties, stimulation fluid properties, and productivity increase desired. Mechanical considerations include; the internal yield of the casing and tubing, wellhead pressure specifications, and packer specifications. Accurately measured reservoir properties are important in achieving an optimum stimulation design. The properties required to design the stimulation program are presented in Table 5. DST information is used to determine the reser-

›ir pressure, flow capacity, skin damage, flow efficienty and fluid :covery.

Fracturing fluid properties that are critical to overall success ˜e:

1. Wettability: The fluid should leave the formation water wet. This is accomplished by addition of surfactants.

2. Viscosity: The fluid should have sufficient viscosity to carry sand at low injection rates, and control leak off, at high (180-200° F) temperatures.

3. Low pH: The fluid should provide a low pH environment to prevent clay swelling.

4. Quick Break: The gel should break rapidly to allow the well to be opened in approximately 2-4 hrs.

5. Low Residue: The gel should leave behind a minimum amount of insoluble residue.

The example design shown meets all the above criteria.

]MPUTER AIDED STIMULATION DESIGN

Ideally, stimulation design should be a blend of computer simula-ion tempered with field experience. As previously discussed, tubing ıd casing design will have a large influence over treatment rates and ressures, which in turn influence the prop concentration the Morrow ill accept. At treating rates in the 8-15 BPM range, maximum proppant ɔncentrations of 3-4 lbs/gal. may be pumped successfully. With this estriction in mind a computer study was conducted to determine the luid volumes required to optimize the productivity increase contrast J/Jo). The formation properties and frac fluid data employed in the tudy are given in Table 5. Fracture heights for this study represent nd average pay section of 15' with gross vertical growth of 40'. esults of the computer study are given on Figures 13-15. Note, that alculated frac lengths between 40 and 60% of the drainage radius give he most cost effective increases in productivity contrast (J/Jo).

Initially, a pre-pad of ±15,000 gal. gelled weak (3-5%) hydro-loric acid and 5000 gal. CO_2 containing surfactants and clay abilizer is pumped to: 1) cool down the formation to minimize scosity loss in proppant laden fluid, 2) condition the formation e. create a low pH environment to minimize clay swelling and slough-g, 3) establish a filter cake on the fracture face and minimize the osslinked fluids leak-off thus reducing the tendency for screenout nditions, and 4) reduce clean-up time by the addition of CO_2.

The proppant laden fluid used in this stimulation design was a lb. titanate crosslinked hydroxypropyl guar (HPG) and CO_2 system. tanate crosslinked HPG systems are extremely efficient fluids that e not shear sensitive. These crosslinked HPG fluids develop high scosities that exhibit several advantages over non-croslinked systems: 1) extremely good fluid leak-off control, 2) high viscosity fluids yield wider fractures that accept higher sand concentrations, 3) exhibit perfect proppant transport properties, and 4) better temperature stability. The frac fluid should be prepared in 2% KCl water and contain the following additives: a clay control agent, a low surface tension surfactant and a gel breaker. The 2% KCl water in combination with the clay stabilizer should render the frac fluid non-damaging, i.e. control particle sloughing and migration. The surfactant should reduce surface tension at the formation and frac fluid interface to facilitate treatment clean-up after the gel's viscosity is reduced below 20 cps by the breaker. Finally, the CO_2 is added to the fluid to improve recovery rate and the total volume of fluid recovered. The Morrow formation has historically been sensitive to stimulation fluids. The less time a foreign fluid is in contact with the Morrow the better. Thus, the improved clean-up rate should reduce formation damage and swabbing costs.

STIMULATION MECHANICAL CONSIDERATIONS

In Morrow wells it is prudent to design casing and tubing strings with fracturing pressure in mind. From Figure 12 we see that Morrow wells, typically, are fractured with surface pressures ranging from 8,500 to 12,000 psi.

During fracturing the following precautions must be exercised:

1. A wellhead isolation tool should be used to protect the tree from excessive pressure.

2. The annulus should be loaded with clean 2% KCl water containing packer fluid and pressured up to approximately 3000 psi during treatment.

3. Wherever possible treatment should be designed to maintain surface pressures below 10,000 psi. If 2-7/8" or 3-1/2" tubing is used, pressures higher than 10,000 psi will hardly ever be encountered at average treating rates.

4. The production tubing string should be landed in compression (at least 10,000 lbs.).

5. Surface treating pressure should be less than the internal yield by at least 1000 psi to allow for a "ball-out" or a sudden premature "screen-out".

6. N_2 or CO_2 should be used in all fluids.

NOMENCLATURE

J - The productivity index after fracturing.

Jo - The productivity index before fracturing.

Petrographic study - Figures 7a and 7b were originally color photographs and will be presented in color at the short course. They appear in black and white in printed copy of the paper.

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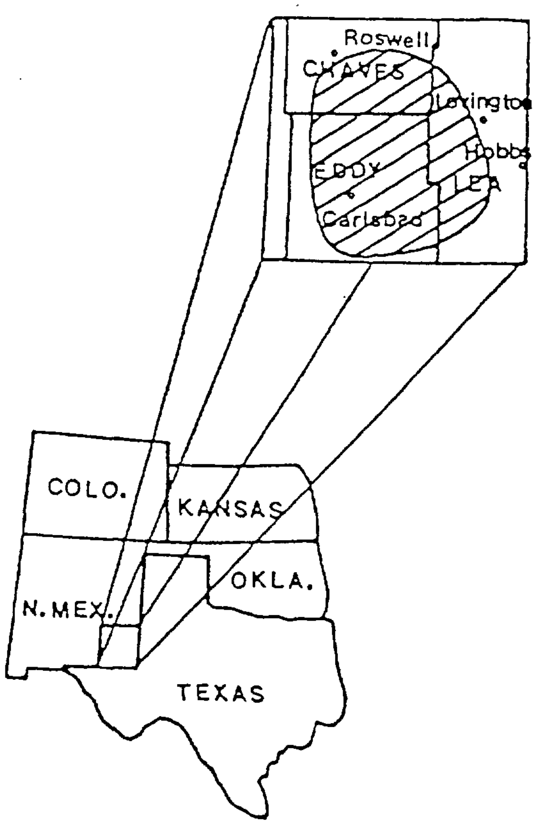

FIGURE 1 — LOCATION OF MORROW SAND EXPLORATION

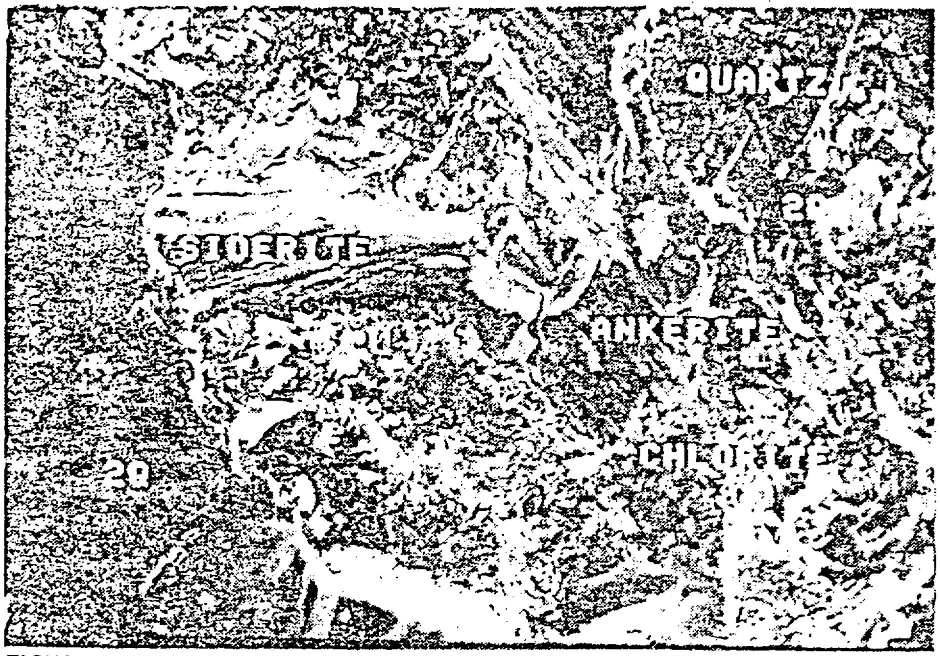

FIGURE 2 — 1000X · THE IRON BEARING MINERALS ANKERITE AND SIDERIATE CAN BE SEEN AT THE EDGE OF A SECONDARY QUARTZ (2Q) CRYSTAL. CHLORIT CLAY, WHICH WAS ABUNDANT THROUGHOUT THE SAMPLE, IS ALSO PRESENT.

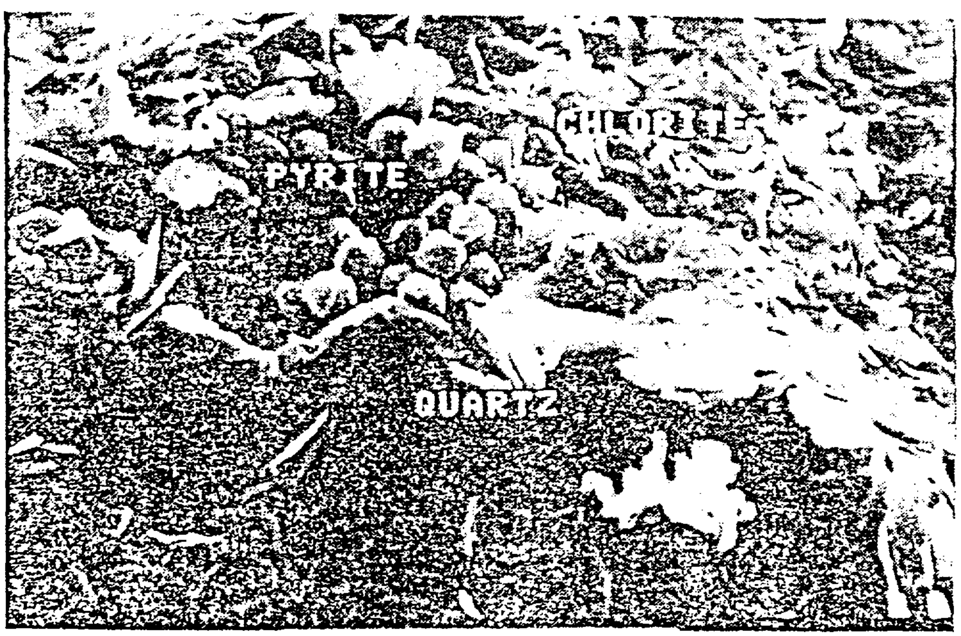

FIGURE 3 — 5100X · THIS IMAGE SHOWS A SMALL POCKET OF PYRITE CRYSTALS AND CHLORITE CLAY EMBEDDED IN A SECONDARY QUARTZ OVERGROWTH.

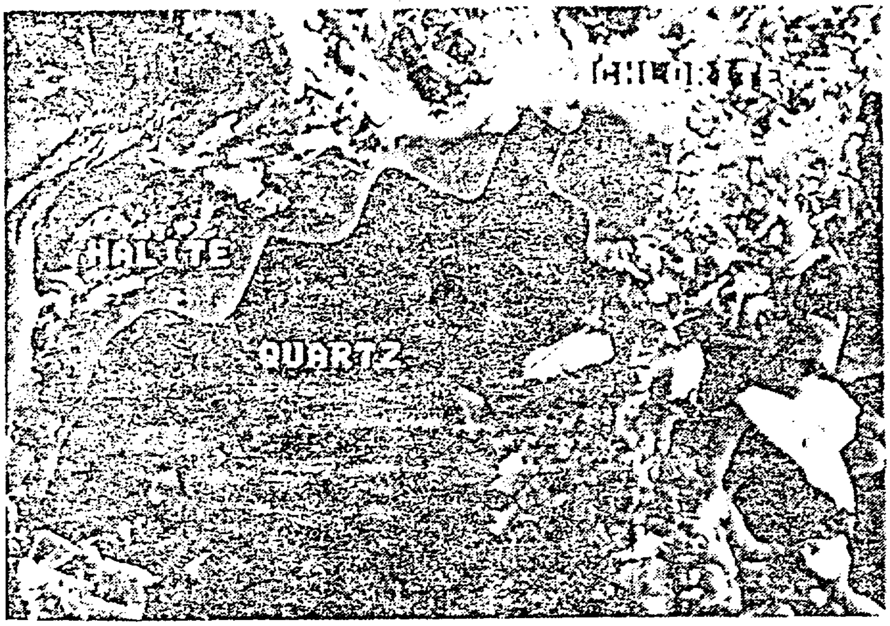

FIGURE 4 — 2000X · WEATHERED HALITE CRYSTALS ARE SHOWN PARTIALLY COVERING A QUARTZ CRYSTAL. EVERPRESENT CHLORITE CLAY IS ALSO EVIDENT.

FIGURE 5 — 2600X · PYRITE IS SEEN HERE EXHIBITING TWO SEPARATE MORPHOLOGIES. THE ROSETTE MORPHOLOGY APPEARS JAGGED (FOREGROUND). THE FRAMBORDAL MORPHOLOGY APPEARS TO HAVE SPHERICAL COMPONENTS (POINTER). CHLORITE CLAY IS AGAIN PRESENT.

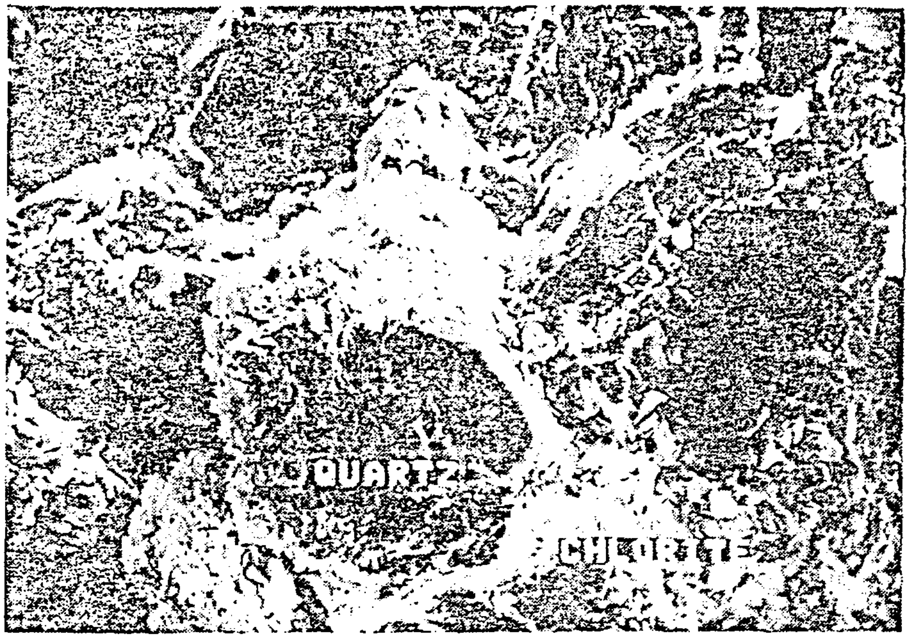

FIGURE 6 — 1000X - CHLORITE CLAY IS SHOWN HERE SITUATED BETWEEN TWO QUARTZ GRAINS IN AN AREA WHICH COULD CONSTITUTE POTENTIAL POROSITY.

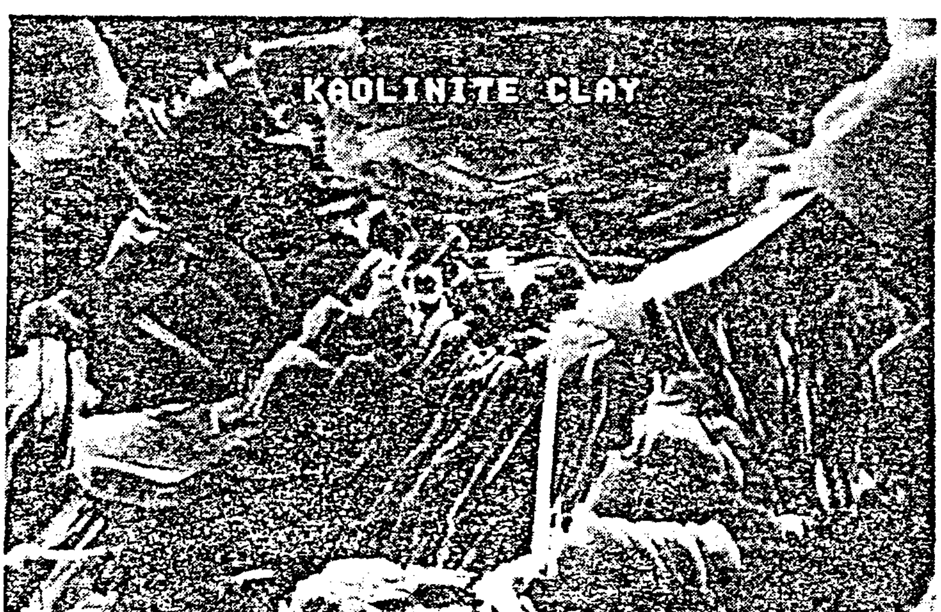

FIGURE 7 — 14500X-THIS IMAGE SHOWS A PLATE-LIKE MORPHOLOGY CHARACTERISTIC OF KAOLONITE CLAY.

FIGURE 7a — 100X CROSS POLARIZED LIGHT. IN THIS PHOTO THE QUARTZ GRAINS APPEAR WHITE, GRAY OR BLACK. DOLOMITE APPEARS AS GRAINLY-BLACK AREAS. THE INTER-PENETRATING NATURE OF SOME OF CONTACTS SUGGEST THAT COMPACTION BY SOLUTION HAS OCCURRED.

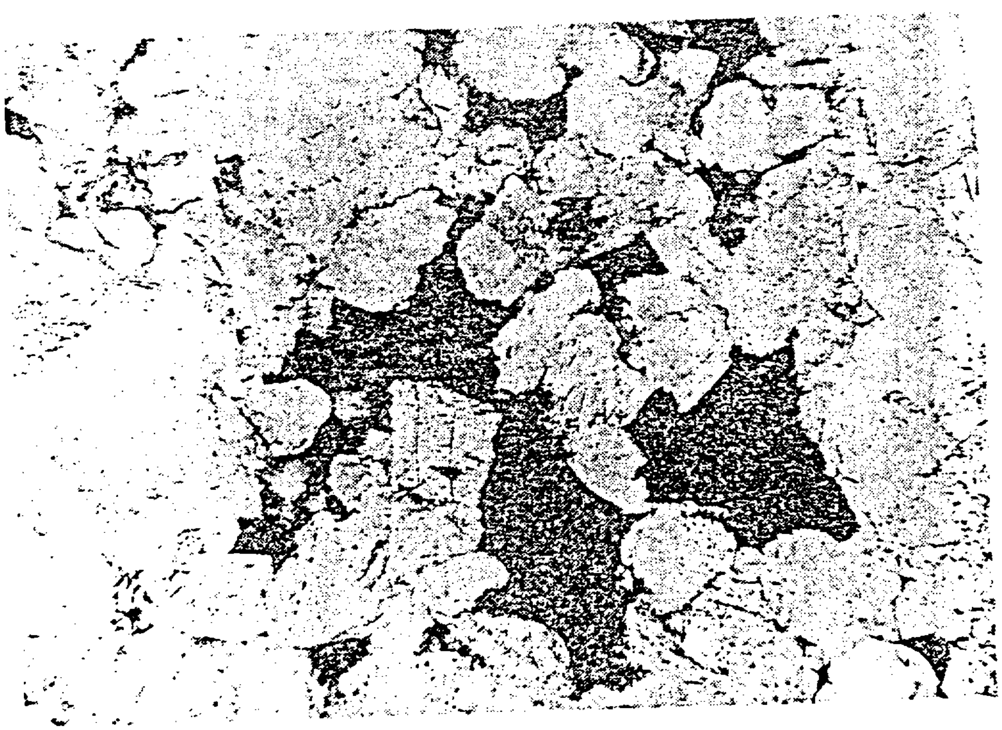

FIGURE 7b — 50X BOTH CLAY AND DOLOMITE (DARK AREAS) INCLUDE MUCH OF THE POROSITY. ALSO NOTE THAT THE LARGE QUARTZ GRAINS ARE TIGHTLY CEMENTED BY SECONDARY QUARTZ OVERGROWTHS.

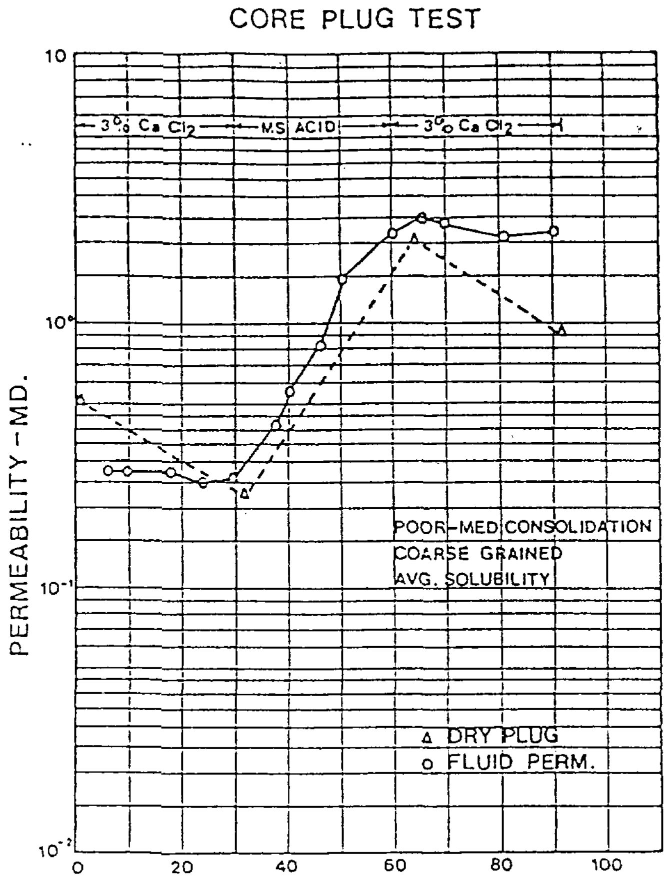

FIGURE 8 — CUMULATIVE EFFLUENT—ML.

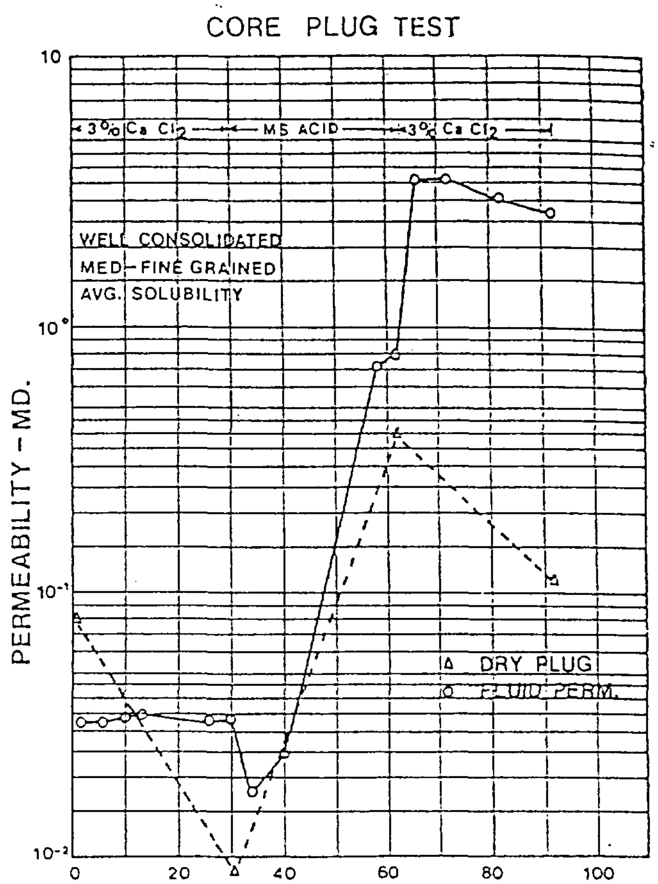

FIGURE 9 — CUMULATIVE EFFLUENT—ML.

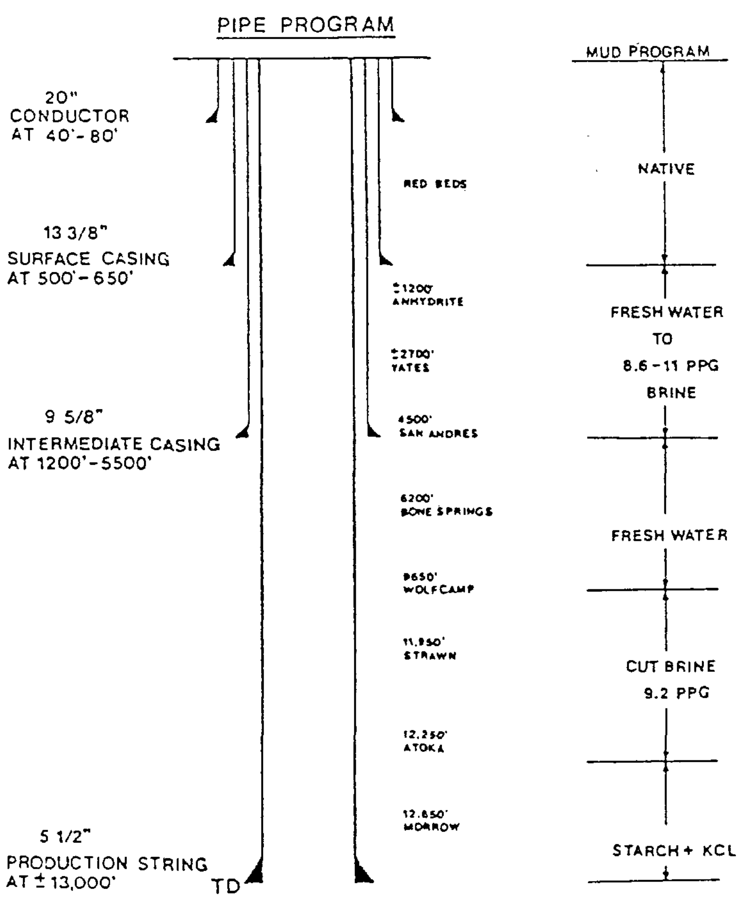

FIGURE 10 — TYPICAL MORROW CASING PROGRAM

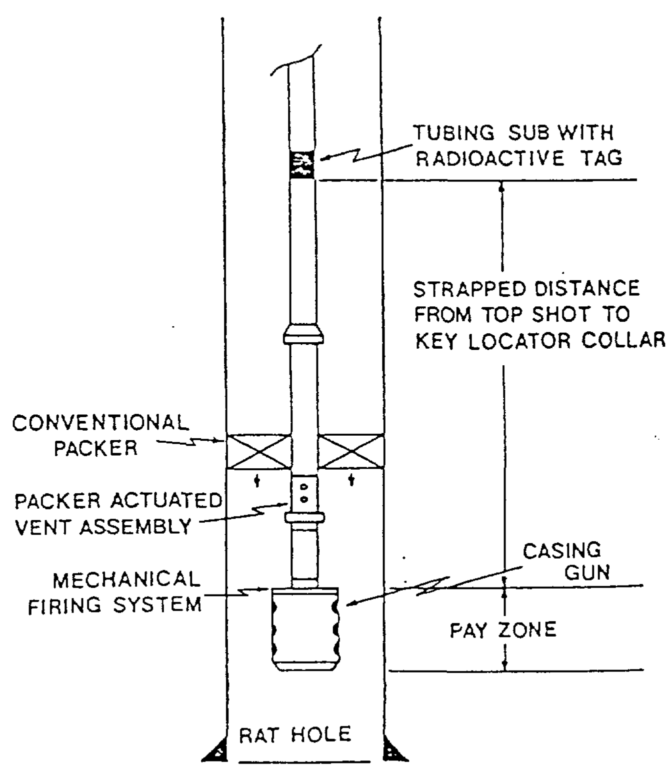

FIGURE 11 — TUBING CONVEYED PERFORATING ASSEMBLY

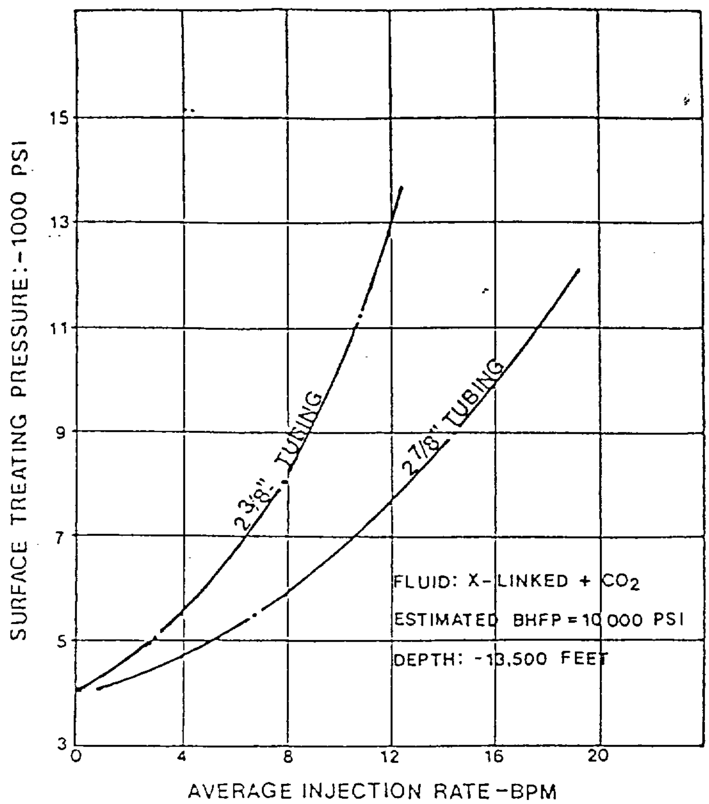

FIGURE 12 — RATE VS PRESSURE CURVE

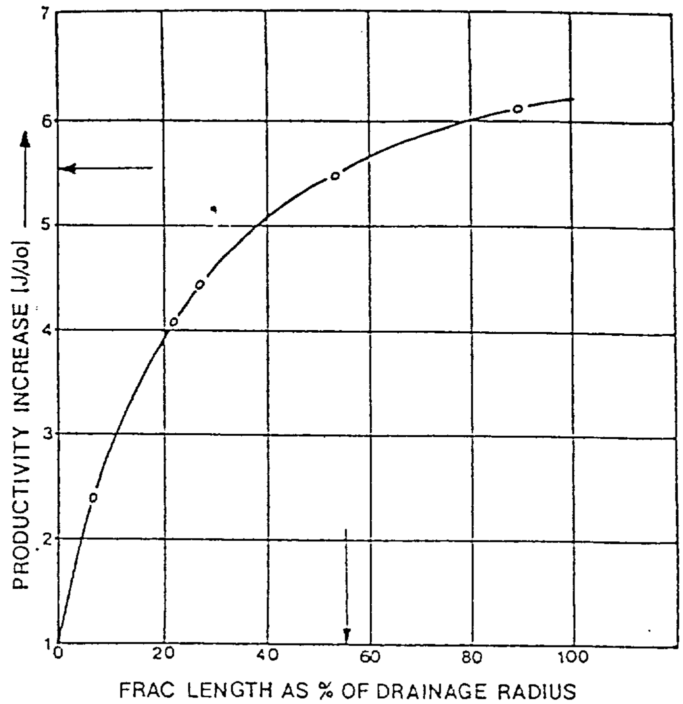

FIGURE 14 — CALCULATED PI VS FRAC LENGTH

WESTERN PETROLEUM SERVICES
PROPPANT PROFILE STUDY
PERFECT SUPPORT FLUIDS

FLUID STUDIED - CROSSLINKED HPG
TOTAL VOLUME - 73440 GAL
FLUID PENETRATION - 1161 FT

PERM. TO STIMULATION FLUID - 0.3 MD	FRAC. PRESSURE - 10000 PSI
PERM. TO RESERVOIR FLUID - 0.5 MD	RES. PRESSURE - 4000 PSI
LEAK-OFF FLUID VISCOSITY - 1 CP	N PRIME - 0.52
RESERVOIR FLUID VISCOSITY - 0.02 CP	K PRIME - 0.23
RESERVOIR FLUID COMP. - 4.0E-04 1/PSI	YOUNGS MODULUS - 1.0E-07 PSI
STIM. FLUID C-III - 3.20E-03 FT/SQRT(MIN)	WIDTH - 0.453 IN
FRACTURE HEIGHT - 40 FT	INJECTION RATE - 12 BPM
COMBINED C - 1.99E-03 FT/SQRT(MIN)	

WESTERN PETROLEUM SERVICES
PROPPANT PROFILE STUDY
PERFECT SUPPORT FLUIDS

FLUID VOLUME (GAL)	SURFACE PROPPANT CONC (LB/GAL)	LOCATION IN FRACTURE (FT)	FRACTURE PROPPANT CONC (LB/FT**2)	CUMULATIVE PROPPANT (LB)
20000	0.00	1025 TO 1161	0.000	0
10000	0.50	929 TO 1025	0.656	5000
15000	1.00	728 TO 929	0.931	20000
15000	2.00	388 TO 728	1.104	50000
5000	3.00	214 TO 388	1.077	65000
5000	3.00	0 TO 214	0.875	80000

TOTAL FRAC FLUID VOLUME - 70000 GAL
TAILING GALLONS CONTAINING BAUXITE - 5000 GAL

FIGURE 13 —

SUGGESTED PROCEDURE

1. Rig up safety wellhead protector.
2. Rig up to frac via tubing (2-7/8" or 3-1/2").
3. Apply and hold 3000 psi on annulus.
4. Frac in a single stage at 8 to 15 BPM as follows:
   a. Pump 15,000 gal. gelled weak acid & CO_2 pre pad.
   b. Pump 20,000 gal. Crosslinked gelled water & CO_2 pad.
   c. Pump 10,000 gal. Crosslinked gelled water & CO_2 with 0.5 ppg. 20-40 sand.
   d. Pump 15,000 gal. Crosslinked gelled water and CO_2 with 1 ppg. 20-40 sand.
   e. Pump 15,000 gal. Crosslinked gelled water & CO_2 with 2 ppg. 20-40 sand.
   f. Pump 5,000 gal. Crosslinked gelled water & CO_2 with 3 ppg. 20-40 sand.
   g. Pump 5,000 gal. Crosslinked gelled water & CO_2 with 3 ppg. 20-40 bauxite.
5. Flush to perforations with slick 2% KCl water and CO_2.
6. Shut-in 3 hours; open to recover load.

FIGURE 15 —

TABLE 1
TYPICAL X-RAY DIFFRACTION ANALYSIS MINERAL COMPOSITION %

	DEPTH IN FEET					
Mineral	6,750'	7,600'	10,400'	11,750'	12,900'	13,600'
Quartz	96-97	80-85	85-90	86-93	90-97	80-85
Feldspar	Trace	-	Trace	Trace	0-2	Trace
Dolomite	3	-	1-3	-	-	15-20
Siderite	-	-	2-5	-	-	1-2
Anhydrite	-	-		1	-	-
Pyrite	-	-	Tr-1	Trace	Trace	Trace
Kaolinite	Tr-1	2-10	1-3	Trace	Trace	Trace
Illite	Trace	Trace	-	Trace	Trace	-
Chlorite	-	1-8	5	4.7	-	-
Montmorillonite	Trace	-	Trace	-	-	
Mixed Layer	-	Trace	Trace	Trace	-	Trace
Acid Solubility	4	5.4	7.3	5.2	1.71	25.07
Soluble Iron	0.6	1.37	1.37	1.6	0.13	2.88

TABLE 2
FORMATION WATERS - MORROW FORMATION - SOUTHEASTERN NEW MEXICO

LOCATION	FIELD	COUNTY	DENSITY 75° F	IRON	SODIUM & POTASSIUM	CALCIUM	MAGNESIUM	CHLORIDE	pH	HYDROGEN SULFIDE	BICAR-BONATES	SULFATES
T19S R29E	Turkey Track	Eddy	1.035	Strong tr.	17,457	1,400	365	30,000	6.5	None	793	None
T20S R28E	Burton Flats	Eddy	1.04	Good tr.	17,500	1,600	730	32,000	6.4	None	925	None
T21S R25E	Catclaw Draw	Eddy	1.05	Strong tr.	17,411	2,400	486	32,000	6.5	None	915	None
T21S R32E	Hat Mesa	Lea	1.04	Very str. tr.	18,264	1,600	729	32,000	6.4	None	549	1,090
T22S R27E	Carlsbad	Eddy	1.04	Strong tr.	22,600	2,000	608	36,000	5.0	None	366	None
T25S R32E	Red Tank	Lea	1.036	Strong tr.	17,100	2,050	505	30,400	6.5	None	655	140
T23S R30E	James Ranch	Eddy	1.05	Strong tr.	22,400	2,560	535	36,000	6.4	None	387	5,400
T21S R26E	Big Eddy	Eddy	1.05	Strong tr.	17,889	1,960	510	32,314	7.1	None	305	72
T20S R25E	Cemetary	Eddy	1.03	Strong tr.	17,506	11,600	515	48,000	7.0	None	305	None

TABLE 3
HHP COST ANALYSIS FOR 2-3/8" & 2-7/8" TUBING

BASIS: (assumed) - BHFP = 10,000 psi (Fg = 0.74 psi/ft)

DEPTH = 13,500'

Assume $\Delta P_{perf} = 0$

VG. INJ. TE (bpm)	STP (psi) 2-3/8"	STP (psi) 2-7/8"	HHP 2-3/8"	HHP 2-7/8"	COST $ 2-3/8"	COST $ 2-7/8"
5	6000	4800	735	588	2610	1911
8	8200	5800	1608	1138	8442	4039
10	10,100	6700	2475	1642	19,428	6814
11	11,100	7200	2993	1941	29,181	8055
12	12,200	7600	3588	2235	41,800	11,733
13	13,400	8300	4269	2645	58,058	13,886
14	—	9000	—	3088	—	20,072
15	—	9500	—	3493	—	27,420

TABLE 4
MORROW FORMATION PROPERTIES AND STIMULATION HISTORY LISTED BY FIELD

FIELD	PERFORATIONS	FORMATION DATA & LITHOLOGY	TREATMENT TYPE & SIZE	ISOP (psi)	FRAC GRAD (psi/ft)
Antelope Ridge	12,806-14,272	Medium to coarse grained, angular to subangular quartz	1000-6000 gal. 7.5% HCl & N_2 16,000 gal. gelled weak acid & CO_2 17,500 lb. 20-40 sand	5100-7700	0.82-1.03
Big Eddy	11,630-13,098	Medium to coarse grained, angular to subangular quartz T21S-R28E Eddy Co., N. Mexico	1000-2500 gal. 7.5% HCl 10,000 gal. gelled weak acid &20-40 sand	3600-5300	0.71-0.87
Buffalo	7,962-9,070	Medium to coarse grained, angular to subangular quartz T15S-R28E Chaves Co., N. Mexico	500-3500 gal. 7.5% HCl & N_2	3000-4200	0.72-0.83
Burton Flats	11,044-11,449	Medium to coarse grained, angular to subangular quartz T20-R28E Eddy Co., N. Mexico	1500-4000 gal. 7.5% HCl & N_2 10,000 gal. gelled weak acid 7000 lb. 20-40 sand & CO_2	2000-5350	0.62-0.82
Carlsbad	11,112-11,926	Medium to coarse grained, angular to subangular quartz T27S-R28E Eddy Co., New Mexico	1500-4000 7.5% HCl	4400-6200	0.77-0.94
Catclaw Draw	10,570'-11,218	Poorly cemented coarse grained angular to subangular quartz 9-17% Porosity BHT-178° F, Gas expansion drive T21S-R25 & 26E Eddy Co., N.M.	500-7000 gal. 7.5% HCl & N_2	2400-4000	0.6-0.81
Cemetary	9,166-9,700	Clear to white medium to coarse grained angular to subangular quartz: 7-20% Porosity: 10-60 md Per BHT-208° F: Gas expansion drive T20S-R25E Eddy Co., N. Mexico	1000-3000 gal. 7.5% HCl & N_2 12,000-40,000 gal. gelled weak acid 20-40 sand & CO_2	3250-3800	0.79-0.88

TABLE 4 (CONTINUED)
MORROW FORMATION PROPERTIES AND STIMULATION HISTORY LISTED BY FIELD

FIELD	PERFORATIONS	FORMATION DATA & LITHOLOGY	TREATMENT TYPE & SIZE	ISOP (psi)	FRAC GRAD (psi/ft)
Hat Mesa	11,830-14,493	Medium to coarse grained, angular to subangular quartz T21S-R32E Lea Co., N. Mexico	3000-6500 gal. 7.5% HCl & N_2	6300-8000	0.84-0.93
Lusk	12,114-13,538	Medium to coarse grained, angular to subangular quartz T18S-R23E Lea Co., N. Mexico	1500-4000 gal. 7.5% HCl & N_2	4800-7500	0.80-0.97
Vacuum	11,465-12,212	Gray to white sandstone, angular to very coarse-grained to conglomeratic gas expansion drive T17S-R34,35E Lea Co., N. Mexico	Predominantly Natural	NA	NA
Washington	6921-7052	White to gray medium to coarse grained angular poorly sorted quartz gas expansion drive T24,25S-R24E Eddy Co., N. Mexico	Predominantly Natural	2800-3300	0.85-0.93

TABLE 5
RESERVOIR & FRAC FLUID PROPERTIES

Average Bottom Hole Temperature	180° F
Net Frac Height	15 ft.
Gross Frac Height	40 ft.
Average Formation Permeability	0.5 md
Average Formation Porosity	8%
Average Bottom Hole Pressure	4000 psi
Average Bottom Hole Frac Pressure	10,000 psi
Rock Young's Modulus	1×10^{7}
Reservoir Fluid Viscosity	0.02 cps
Average Frac Gradient	0.85 psi/ft
Drainage Radius	1867'
Formation Permeability to Frac Fluid	0.3 md
Frac Fluid Leak-off Viscosity	1 cps
Spurt Loss	0
N'	0.52
K'	0.22
Specific Gravity	1.02
Frac Fluid Leak-off Coefficient (CIII)	3.2×10^{-3}
Frac Fluid Type	50 lbs. X-linked HPG

TABLE 6
COMPARISON OF API PROPERTIES FOR 20-40 SAND & NEW CERAMIC PROPPANT

API PROPERTY	API SPEC.	FRAC SAND RANGE	CERAMIC PROPPANT
Krumbein Shape			
Roundness	0.6 min.	0.6-0.8	0.7-0.9
Sphericity	0.6 min.	0.7-0.9	0.7-0.9
Crush Resistance			
Fines Generated	14 max.	5.5-9	6
% @ stress (psi)	at 4000	4000	10,000
Acid Solubility			
12/3 HCl/HF @ 150°F, %	2	0.5-1.5	3
Silt & Fine Content			
Turbidity FTU	250 max.	50-90	100
Density			
Bulk, lb/ft^3	100	100	114
Particle SpGr	2.65	2.65	3.1
X-Ray Analysis	2 quartz	2 quartz	Mullite/ Corundum
% between 20 and 40 screens			
Sieve Analysis	90 min.	90-95	94

TREATMENT HISTORY

Initial Stimulation

As stated in the introduction, there were only about 100 Morrow wells completed through 1971. The primary factors contributing to this low number were probably inadequate stimulation techniques and low gas prices. Prior to 1971, completion efforts in the Morrow were most discouraging. In most instances when stimulation programs were attempted, production results were almost never as good as was indicated from drill stem testing.

Through the years, various types of initial breakdown treatments have been utilized. The more common treatments consisted of "Mud Acid" employing hydrofluoric acid (3 to 12 percent strength) with HCl, solutions of hydrofluoric acid, mixtures of mud acid or regular HCl with alcohol, alcohol-CO_2 mixtures, specially prepared brine waters, and others. The selection of fracturing fluids has been equally varied, ranging from assorted, modififed brine waters to distillate and kerosene or diesel. Most of the fluid systems tried met with limited success. The modified brine water system did; however, provide some of the more encouraging results.

With the anticipation of increased drilling in early 1972, The Western Company began an intensive research program for a better fluid to more effectively stimulate the Morrow formation. Frac these efforts, MS Acid was developed. This product proved to be so successful that more than 280 treatments (including fracture types) have been performed to date.

The development of MS Acid for use in the Morrow involved a close observance of previous treatments. The unusually poor load recovery characteristic was the single most significant reoccurrence noted. Initially, this condition was attributed almost entirely to the presence of clay minerals. Based largely on field findings and now more or less verified by results, the basic problem was believed to be the result of abnormal capillary forces and a basically undersaturated formation. The end result when most fluids are lost to or injected

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into the Morrow is fluid "loading" or an unbalanced fluid saturation-relative permeability condition with greatly reduced flow capacity. Dispersion and movement of formation fines are also likely to contribute to the problem.

Research efforts were directed toward the rock "wetting" characteristics of various fluid systems. Of particular interest was the potential effect on fluid retention-relative permeability and movement of formation fines. A study of surfactant behavior was made, including the effects of preferential adsorption onto rock surfaces from the fluid system (Table V). Laboratory investigations have established that a specific combination of surfactants significantly altered the "wetting" characteristics of formation materials. The bulk of the testing involved here employed the use of a specialized flow apparatus and formation core plugs. The resulting MS Acid system is effective in controlling fluid retention, thus aiding greatly in load recovery and formation clean-up. Field testing has proven that it is compatible with the Morrow Sandstone. (See Figures 4, 5, 6, & 7.)

As previously stated, initial breakdown treatments are designed primarily to clean-up the well bore vicinity through removal of filter cake and fluids lost to the formation during drilling operations. Western utilized 7 1/2% MS Acid with a friction reducer (FR-14 or FR-16) containing Nitrogen (1000 SCF/bbl.). Volumes range from 1,000 to 5,000 gallons, depending upon the thickness of zone to be treated. As a rule-of-thumb, 100 to 150 gallons per foot of net pay is utilized. Average formation penetration will range from 100 to 150 feet. See Table VI for a list of acid treatments performed by The Western Company. See attached Stimulation Bulletin for a description of MS Acid.

Subsequent Stimulation

Since MS Acid has proven effective in cleaning up the well bore vicinity, it was modified slightly for use as a fracturing fluid. MS Frac is a specially formulated weak acid system usually (5%) with viscosity and fluid loss controls. Fracture volumes in a range of from 10,000 to 30,000 gallons are normally conducted