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Creating Fractures Past Damage More Effectively With Less Environmental Damage

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Sean Hollis (Author)
Research Engineer
CSI Technologies
2202 Oil Center Court
Houston, Texas 77073

Steven R. Wann (Principle Investigator)
Chief Technology Officer
DaniMer Scientific, LLC
1301 Colquitt Highway
Bainbridge, GA 39819

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Principal Investigator



Steven R. Wann
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Abstract

A novel method for creating short, highly conductive fractures in wells to bypass formation damage has been developed. When operational, the method uses comparatively small material volumes, low horsepower and pump rate, produces minimal environment effect, and leaves the formation face and proppant pack residue free. Function and application of the method present significant variations in treatment design and execution compared to traditional hydraulic fracturing past damage. This report presents the results and conclusions for the Novel Fracturing Treatment (NFT) determined from polymer chemistry, laboratory testing, and candidate well selection. An array of simulations and tests were completed in order to determine the feasibility and to assess the performance of the Environmentally Friendly Fracturing (EFF) polymer that is the basis of the NFT.

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Executive Summary

The goal of the NFT is to create an inexpensive, environmentally benign alternative to conventional fracturing systems that are otherwise cost prohibitive on marginal and “stripper” wells. This system is specifically designed for smaller volume fracture treatments intended to create fractures past wellbore damage and is not designed for large frac jobs. The fluid system used in the NFT is markedly different from conventional fracturing fluids. It uses an Environmentally Friendly Fracturing polymer, (EFF polymer) as the fracture fluid. The EFF is formed into small, solid pellets that are suitable for placement in an aqueous wellbore environment. The EFF polymer degrades by hydrolysis to first yield a viscous liquid. It is the viscous liquid produced by hydrolysis of the solid EFF polymer that serves as the fracture fluid. This unique fracture fluid has the characteristics needed to suspend and transport proppant. After the fluid carries the proppant into the formation, hydrolysis of the EFF polymer continues to completion the fluid becomes increasingly less viscous and eventually only water soluble monomeric components remain. The validity of the NFT process was confirmed in large-scale laboratory trials involving several hundred of pounds of proppant-containing EFF and is now ready for field testing.

The degradable polymers that formed the basis of the NFT were synthesized from lactic acid, lactide and other comonomers designed to produce polymers of varying molecular weight, crystallinity and phase change during hydrolytic degradation (e.g., hydrolysis to monomer via a solid or a liquid pathway). By adjusting the monomer composition, a family of EFF polymers were produced that will hydrolyze at approximately at constant rate (e.g., days) over a range of reservoir temperatures (130-176°F) and remain a liquid throughout the entire course of hydrolysis. The current range in bottom hole temperatures covered by the EFF polymers represent about 80% of the wells in the United States for which the NFT is applicable. Developing additional polymers for use in wells outside this temperature range is work anticipated for the future.

The success of the NFT depends on the performance of the fracturing fluid. The fluid must provide all of the qualities required for the application. One of the most important qualities of the fluid is its performance during hydrolytic degradation. This performance was determined through testing and research. The results were used to optimize the polymer chemistry to provide the ideal degradation profile. Determining the degradation of the EFF polymer also

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helped determine the pumping rheologies and pressures as well as its proppant transport and settling properties. This report discusses the testing and data involved with this development.

Proppant was incorporated into EFF polymer pellets at concentrations up to 40% by weight. Pellets without proppant can be utilized as a pad stage during a fracture treatment. A typical frac job might have 25-35% of the total material weight as proppant-less EFF polymer. The pellets can be pumped, dropped into, or dump bailed into the wellbore, subject to the wellbore conditions. The most likely wellbore loading method would be to pump the pellets into the well and either circulate to the bottom or allow them to fall.

Manufacturing options for EFF delivery systems were explored including pastillation, extruder-based pelletization, and depositing. Of the methods tested, pastillation appears to show the greatest promise for large scale production of EFF polymer. Production rates for 40% proppant-containing polymer were 225 lb/hr. Options for increasing pastille production rates several fold are discussed.

To facilitate the evaluation of wells as candidates for the NFT, a well selection software tool utilizing Microsoft Excel was developed. The program uses well temperature, formation permeability and treatment volume along with other criteria as inputs for determining well suitability for the NFT. Preliminary results of the software development effort are included in this report.

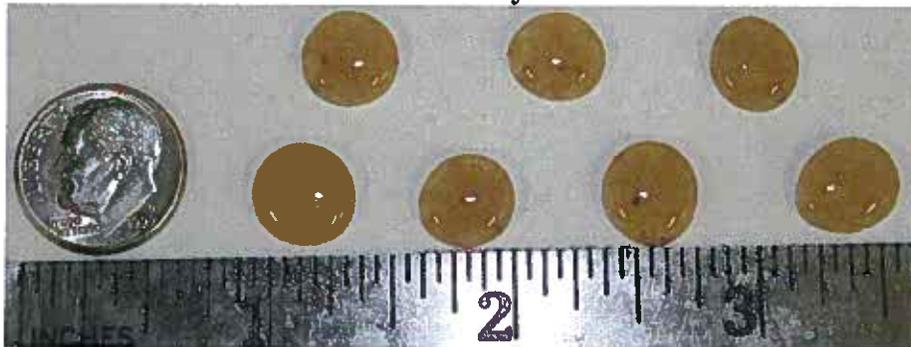
As supported by the results in these report, the NFT is a viable technology ready for the next step of development. Small- and large-scale laboratory performance of the EFF polymer was confirmed and manufacturing methods have been established for ton quantities of material. The NFT has been proven in the laboratory and now it is ready for a field trial.

Introduction

The use of degradable, thermoplastic polymers as a hydraulic fracture fluid has been anticipated and some its benefits over conventional fracture fluids have been described (Cooke, 2005). Until now, the types of degradable polymers that could serve this purpose in a commercially feasible process had not been fully characterized. The reservoir temperature and wellbore temperature profile governs the polymer composition and molecular weight, which were chosen to produce a specific degradation profile that encompassed a viscous liquid stage for a proscribed time interval. The time interval during which the polymer viscosity was sufficiently fluid to inject into the perforations to create a fracture, but not yet sufficiently degraded to allow proppant settling is termed the “pumping window”. Field-applicable polymers can be formulated to create suitable pumping windows to cover a temperature range of 10-40°F, for example. A few standardized polymer formulations may be established for use in wells in reservoirs having a range of temperatures. The chemistry can be tailored for each individual well.

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Picture 1: EFF Polymer Pellets



The degradable polymer, produced in pellet form, (see **Picture 1**) may be introduced into the well by circulation down the tubing or by bullheading from the surface with a water carrier fluid. Alternatively, the pellets can be poured or injected into the top of the well and allowed to settle to a column at total depth. The only requirements for the well fluid are that it must contain water and be solids-free. Brine also works equally well as degradation media as degradation products are also soluble in salt water.

It is in the wellbore environment where the EFF polymer degradation takes place. After a specific amount of time (See Results and Discussion Section), the polymer degradation proceeds to the pumping window. At some point during the pumping window, the polymer is injected into the perforations, creating a hydraulic fracture. Once placed in the fracture, the polymer continues to degrade and the fracture closes. The product of the polymer degradation process is a water-soluble organic acid that is compatible with formation water and that can be transported out of the proppant pack leaving the pack and formation face residue free. This complete degradation of the polymer into soluble components that leave no residue to damage the fracture conductivity is an important technical benefit of this innovation.

Experimental Methods

NFT polymers are polyesters that were synthesized by: (1) polycondensation reactions of various enantiomers of lactic acids (L-, D-, or D,L-) and glycolic acid and (2) ring opening polymerization of lactides of varying enantiomeric purity. In both polymerizations reactions, small amounts of organic alcohols were included in the reaction mixture as initiators to control the molecular weight and tin (II) octoate was employed as a catalyst. The synthesis of NFT polymers has been previously described (Wann, 2011) but the procedures shown are illustrative. (Note: During the course of the project, the polymer synthesis reactions shown below were scaled up to produce several hundred pounds of product at a time.)

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1. L-Lactic Acid/Glycolic Acid Polymers by Polycondensation Reaction.

A two liter pear-shaped flask was charged with 971 gm L-lactic acid, (9.5 mole; PURAC; 88% solution) 381 gm glycolic acid, (3.5 mole; DuPont; 70% solution) 4.4 gm pentaerythritol (0.03 mole; Perstorp) and 1.36 gm tin (II) octoate (Alfa Aesar). The flask was placed on a rotating evaporator and heated to 180°C at 50-75 rpm and atmospheric pressure. When the reaction mixture reached about 160°C water began to distill from the reaction mixture and was collected in the receiving flask of the rotating evaporator.

After about 2-3 hrs, about 40% of the total water was collected. At this time, a vacuum was applied to the reaction mixture. The pressure was reduced in a stepwise fashion (~ 50 torr every 30 min) over a 2-3 hour period. When a vacuum of 50-75 torr was reached, and the reaction mixture produced no more water, the temperature was raised to 190°C. The flask was heated for an additional 8-10 hours (approximately 12-16 hours total reaction time). During this period, traces of lactide (about 2% of the total yield) accumulated in the condenser and the reaction mixture increased in viscosity. The reaction was considered complete when: (1) the viscosity of a sample measured 4,000-10,000 cps @ 127°C and (2) the content of volatile materials in the product (as determine by gravimetric loss of a sample heated to 180°C for 3 min) was < 0.18%. The polymer was brownish red, brittle solid and had a ring and ball softening point of 70°C.

2. D, L Lactide Polymers by Ring Opening Polymerization.

A one liter pear-shaped flask was charged with 68.4 gm L-lactide, (PURAC) and 3.6 gm D-lactide (PURAC). The flask was placed on a rotating evaporator fitted with a gas inlet tube and rotated at about 50 rpm. Dry nitrogen gas was slowly bubbled through the mixture at ~ 0.01 ft³/min and the temperature was raised to 120°C. After about 0.5 hr, the lactide mixture had melted and 1.13 gm 1, 4-butandiol (BASF) and 34 mg tin (II) octoate (Alfa Aesar) were added. The temperature of the reaction mixture was increased to 170°C and the flask was rotated at 75-100 rpm. Soon after the diol and tin catalyst were added, the viscosity of the mixture increased markedly. Heating was continued for about an additional hour or until samples subjected to infrared spectroscopy showed that disappearance of peaks associated with lactide (1,240 cm⁻¹ C-C-O stretch; 1,055 cm⁻¹ C-O-C stretch; 935 cm⁻¹ C-O stretch). The polymer was a clear, brittle solid with a melting point of 97°C.

3. Polymer Degradation Studies.

Polymer degradation (i.e., hydrolysis) at various temperatures was conducted under aqueous conditions using 250 mL beakers. To 50 gm polymer in a tared beaker was added about 200 mL deionized water and afterward the beaker was covered with aluminum foil and incubated in a controlled temperature water bath. During the course of the degradation, the weight loss of the polymer was determined by carefully decanting the aqueous phase and weighing the polymer + beaker. When it became evident during the course of the degradation that the polymer was beginning to viscosify at the incubation temperature, polymer melt viscosity was also measured.

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Viscosity was determined using a DVII + Pro Viscometer (Brookfield Engineering Laboratories) fitted with a Thermosel™ constant temperature chamber set to the degradation temperature. 16-17 gm of polymer were transferred to a Thermosel™ sample tube and after the viscosity was measured the material in the sample tube was returned to the beaker, the original incubation water was poured back into the beaker, and the polymer, beaker and original solution were returned to the water bath for continued degradation. Triplicate samples were used for each degradation temperature tested.

4. Laboratory Simulations (Small Scale Tests)

Laboratory simulations consisted of small scale and large scale tests. These tests used the EFF polymer pellets (see **Picture 1**) loaded into specific test setups to determine the behavior and properties of the fluid. The rheological data, proppant transport properties, degradation, and pumping friction pressures were determined.

For small scale tests, EFF polymer pellets were placed in a graduated cylinder as shown in **Picture 2**. The first 30% of the graduated cylinder was filled with EFF polymer without proppant. This simulated the pad fluid used to create the fractures in the rock during the initial stages of a NFT. The remaining 70% of the graduated cylinder was filled with proppant laden polymer pellets.

Picture 2:
EFF Polymer Pellets Loaded
into a Graduated Cylinder
for Small Scale Test



Picture 3:
Proppant Settling at
the Completion of a
Small Scale Test



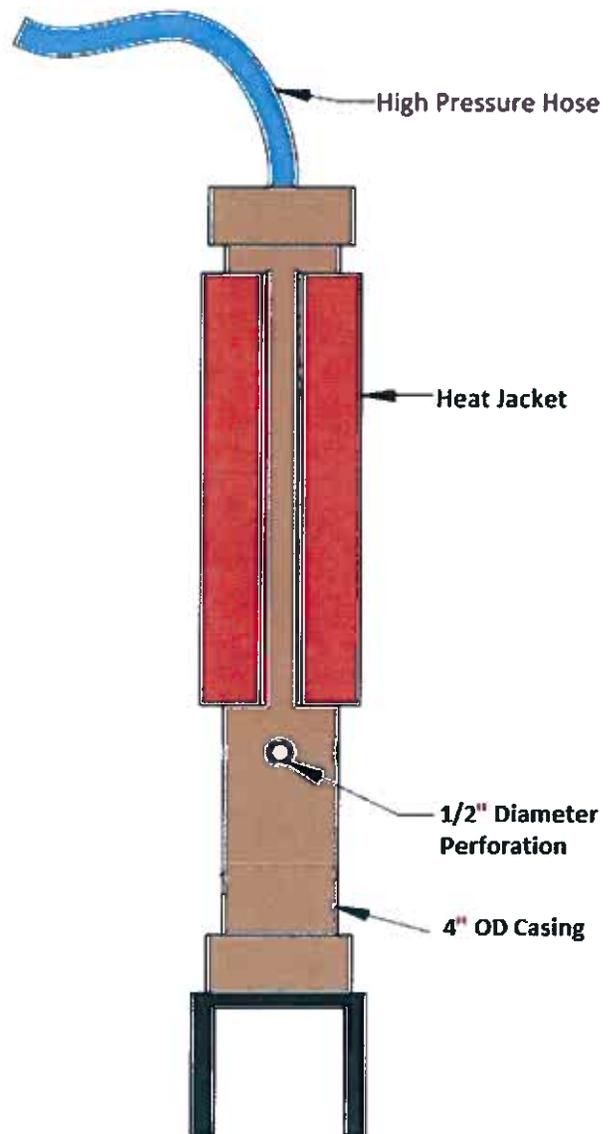
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With the EFF polymer in the graduated cylinder, the cylinder was filled with water sufficient to fill all of void space between the pellets. A plastic sleeve was placed over the top of the graduated cylinder to prevent evaporation during the test. Next, the graduated cylinder was photographed to document its initial condition before it was placed in a water bath at room temperature. The water bath temperature was ramped up to the desired temperature to simulate insertion conditions into a well. At various intervals (typically each hour), the graduated cylinder was removed from the water bath and the changes in the EFF polymer were recorded and photographed. Periodically the plastic cover was removed from the graduated cylinder and a glass stirring rod was used as a probe to determine if the polymer had viscosified to an extent suitable for pumping. Testing continued until the polymer could no longer support the proppant and it settled to the bottom of the cylinder (see **Picture 3**). Typically, this occurred when the polymer viscosity reached about 17,000 cP at any given testing temperature.

5. Laboratory Simulations (Large Scale Testing)

The large scale test was a scaled up version of the small scale test. The test setup, shown in **Figure 1**, used different equipment due to the increase in size. The setup consists of a pipe 12 feet in length and 4 inches in diameter mounted vertically. Each end of the pipe was sealed so that it could be pressurized. Compressed air (120 psi maximum pressure) was attached to the top of the pipe. A 1/2 inch port with a valve attached was located near the bottom of the pipe. This port simulated a well perforation through which the EFF polymer was squeezed during the test. **Picture 4** displays the squeeze port. A differential pressure transducer was attached between the top and bottom of the pipe to measure the differential pressure across the pipe during the squeeze. Heating elements were attached to the outside of the pipe to heat the pipe to the desired temperature. Three controllers, shown in **Picture 5**, regulate the heating elements to ensure a consistent temperature throughout the pipe.

Figure 1:
Basic Large Scale Test Setup



Picture 4: Perforation Nipple



Picture 5: Large Scale Temperature Controllers



EFF pellets were loaded in a similar fashion as the small scale tests. A pad made up of neat (i.e., no proppant) EFF polymer pellets was loaded into the pipe first (30% total material weight) followed by proppant-containing pellets (70% total material weight). Finally, the pore space between the pellets was filled with water. The pipe was sealed and pressure tested before starting the test. The pipe was heated to the desired temperature and the test was monitored until the time the polymer reached the viscosity corresponding to the pumping window as determined by the small scale test.

Once in the pumping window, constant pressure was maintained on the apparatus by means of compressed air. A set schedule of pressures were applied and tested over the course of the simulation. The valve on the 1/2" port located at the bottom of the pipe was opened to allow the NFT fluid to be squeezed through. **Picture 6** shows the fluid as it was squeezed through the perforation port. As the EFF polymer was expressed through the port, the volume, differential pressure, and time the valve was open were recorded. The volume and time were used to calculate the pumping rate and the differential pressure and applied pressure were used to calculate the friction pressure of the NFT fluid.

Picture 6: Squeezing the NFT Fluid through the Perforation



6. Polymer Manufacture

Three methods for large scale manufacture of the EFF polymer were examined. Methods included pastillation, deposition, and pelletizing. Pastillation was accomplished on a Sandvik Rotoform Pastillator. The polymer contained in a 55 gallon drum was heated to a temperature of about 160°C and then pumped as a melt using a Nordson Drum Melter to an auger system. Proppant was also gravimetrically fed to the auger. Two types of proppant were used: (1) classified sand, 20 to 40 mesh screen (0.45-0.48 mm diameter) and (2) sintered clay (ECONOPROP 20/40; CarboCeramics). Proppants were mixed with the polymer in the auger at a target loading of about 27 to about 45 weight percent. The polymer/proppant mixture was then pumped to the rotoform head of the pastillator. Pastillator head temperature was set at 177°C and the head rotated at 22 rpm.

The pastilles were expressed from the rotoform head onto a moving stainless steel belt that was cooled by means of chilled water from below the belt to about 16°C. The belt speed was about 30 feet per minute (fpm), and the pastilles were doctored off the end of the belt into containers and stored in fiber drums. The average diameter of the pastilles formed was about 0.25 to 0.375”.

Deposition was accomplished with a custom-built depositor. This device used an air solenoid to drive two air actuated pistons. The pistons operated in a heated reservoir to keep the polymer and proppant molten and at a viscosity that did not allow the proppant to settle (typically > 17,000 cP). By adjusting timing and stroke length of the pistons, pastille of varying sizes could be produced.

Pelletization on an extruder was carried out on only one material - polymer E2411 lacking proppant. An Entec model 40 mm diameter barrel twin screw extruder (L/D = 40) with a Gala Corp. underwater pelletizer was used. Polymer was melted in the front section at 360°F and then progressively cooled down the length of the barrel to be extruded and pelletized at 250°F.

Results and Discussion

1. EFF Polymers

Polymer structure and chemistry are the keys to controlling degradation kinetics, rheology, and preventing damage to the formation. Not all degradable polymers will perform the intended functions. Performance criteria that were optimized for the NFT included:

1. Degradability (e.g., hydrolyzable) in hot water at a rate coincident with well completion and hydrocarbon production schedules
2. Degradation must proceed through a viscous liquid stage (to facilitate the hydraulic fracture operation)
3. Minimal amounts of solid residue should be left after degradation (for no interference with the permeability of the fracture or formation)

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Commercially available, high molecular weight (e.g., > 100,000 gm/mol) polylactic acid (PLA) was considered for the NFT, but it hydrolyzes too slowly (see **Figure 2**) at common well temperatures (130-180°F). Further, high molecular weight PLA does not proceed through a viscous liquid stage as it degrades to oligomeric and ultimately monomeric components. To a significant degree, the unsuitability of commercially available PLA is due to its: (1) high molecular weight and (2) enantiomeric purity (i.e., high L (+)-lactic acid content) that leads to a degree of crystallinity. Lower molecular weight polylactides in which the crystallinity has been reduced or disrupted are better suited for this application. **Figure 2** depicts the rate of degradation for a high molecular weight, amorphous PLA compared to that of EFF polymer E2411. Depending on temperature, hydrolysis of high molecular weight PLA to soluble components can take months to complete. Conversely, the EFF polymers can be tailored to meet specific performance criteria for a NFT treatment and take just a couple of days to degrade.

Figure 2: Degradation Rate of High (Commercial) & Low Molecular Weight PLA (82°C)

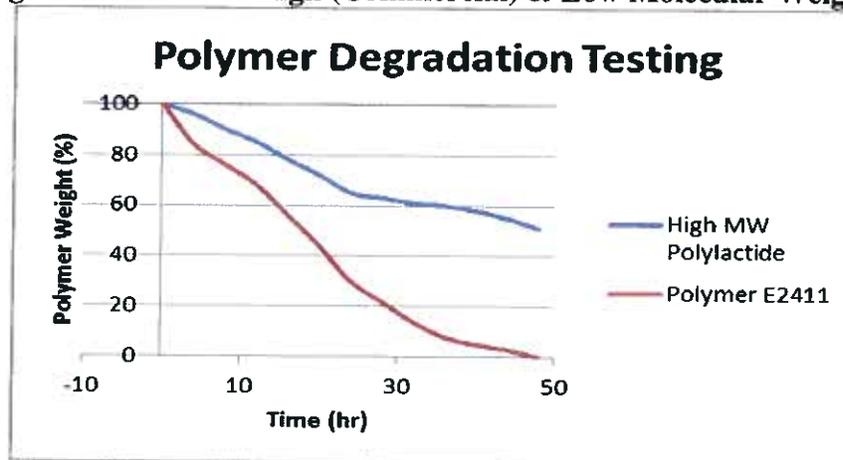


Table 1 shows the properties of representative EFF polymers that have been used in laboratory simulations of the NFT process. K0309 and K0309PM were synthesized by polycondensation of L-lactic and glycolic acid with pentaerythritol as an initiator and E2411 was made by ring opening polymerization of a racemic lactide. These three polymers are suitable for NFT application for wells with bottom hole temperatures spanning the range shown.

Table 1: Physical Properties of Three EFF Polymers

Polymer Designation	Application Temp Range	Ring & Ball Softening Point, °F	Melt Viscosity, cP @ °F	Mn	Mw
K0309	130-140°F	161	4,400 @ 260	4,500	11,000
K0309PM	140-150°F	176	15,000 @ 260	N.D.	N.D.
E2411	150-176°F	195	41,000 @ 338	57,600	88,700

Co-polymerization of small amounts of glycolic acid or D-lactic acid with L-lactic acid is an effective way to disrupt the crystallinity of L-poly(lactic acid) polymers and produce a polymer

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that degrades through a viscous liquid stage and does not leave a solid residue after complete degradation. Presumably, the production of a solid during degradation is due to hydrolysis of the amorphous regions of the polymer leaving behind the more hydrolysis-resistant crystalline regions. The production of a solid residue during the course of degradation is undesirable because: (1) it does not have the necessary rheology to function as a fracture fluid and (2) it could plug up the formation or prolong well completion due to its inherently slower degradation rate.

Table 2 depicts the amount of glycolic acid substitution needed to produce a low molecular weight poly(lactic acid) that degrades to monomer exclusively through a liquid pathway in 140°F water. A series of polymers were synthesized with the mole percentages of L-lactic and glycolic acid shown. The course of aqueous degradation in water at 140°F was followed and the physical state of the residue immediately after 50% hydrolysis (based on the initial mass) was recorded.

Table 2: Effect of Polymer Composition on the Pathway of Hydrolytic Degradation

Component Mole %		Residue After Hydrolytic Degradation, 140°F
L-Lactic Acid	Glycolic Acid	
100	0	Solid
85	15	Solid
80	20	Solid
78	22	Solid
75	25	Liquid
73	27	Liquid
70	30	Liquid

In **Table 2** it can be seen that more than 22% substitution of glycolic acid for L-lactic acid in the polymer was needed before the degradation produces exclusively liquid oligomeric components in the appropriate time frame. Nearly identical results were obtained when D-lactic acid was used in place of glycolic acid to disrupt crystallinity. In that case, a polymer made in the same way that was 30 mol % D-lactic acid and 70 mol % L-lactic acid degraded exclusively through a liquid pathway at 140°F.

The course of the aqueous hydrolysis of K0309 at 190°F is illustrative of EFF polymers and shown in **Figure 3**. The loss in molecular weight (as reflected in the decline in viscosity) occurs early in the degradation – well before any detectable loss in mass. Polymer mass, on the other hand, increases slightly at first (as the polymer initially absorbs some water) but then mass is gradual until the polymer is completely hydrolyzed to monomer components after about 3 days. These observations are consistent with the known mechanism of polylactic acid hydrolysis in which random chain cleavage results in a rapid reduction of molecular weight but water soluble oligomers are not produced until the molecular weight is quite low (Sodergard and Stolt, 2002).

Figure 3: Aqueous Degradation of Polymer K0309 at 190°F

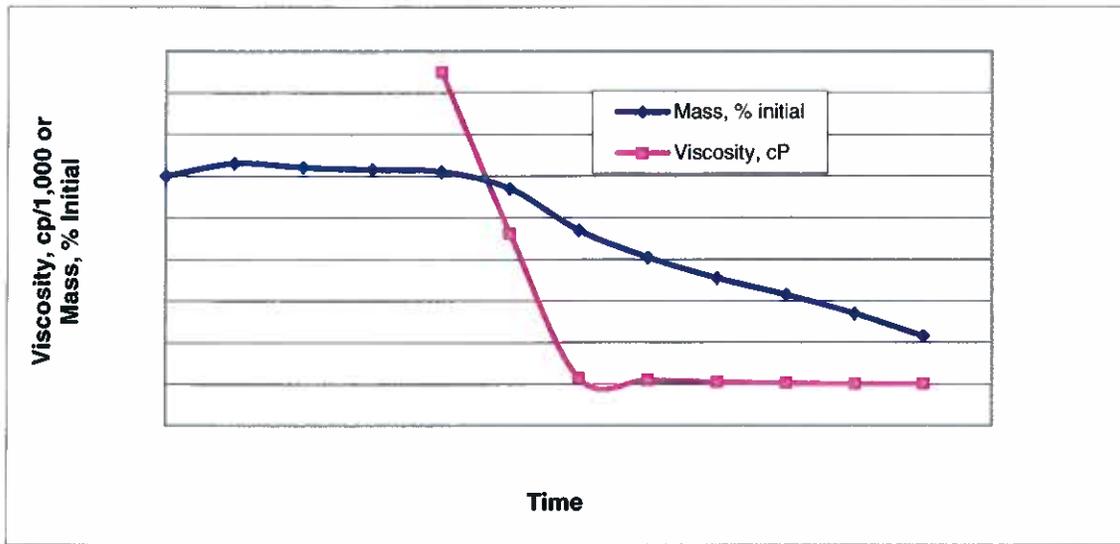
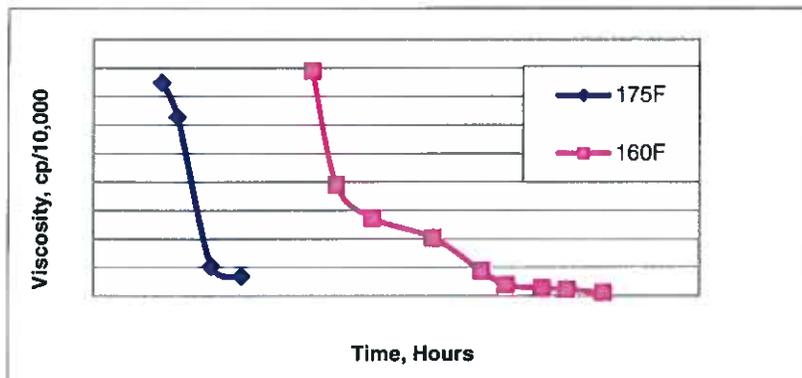


Figure 4 shows how well temperature and polymer degradation rate can be combined to tailor polymer composition for an NFT application. For example, at 175°F, polymer E2411 would have a narrow pumping window, indicated by the steep slope of the viscosity vs. time curve. On the other hand, E2411 would provide a wide pumping window at a well temperature of 160°F with a long time period for proppant suspension and fluidity.

Figure 4: Viscosity vs. Time for the Aqueous Degradation of E2411 at Two Temperatures



Over 20 different copolymers were synthesized and their degradation pattern determined during the search to define polymer compositions that would cover a broad range of well temperatures. At present polymers have been synthesized that could be used in the NFT for well temperatures 130-176°F (55-80°C). The types of polymers used for this purpose include: (1) L-lactic acid condensation polymers (with 25-30 mol % glycolic or D-lactic acid added to disrupt crystallinity) for the low end of the temperature range; (2) chain extended (via reaction with dianhydrides, diisocyanates or diepoxides, see Wann, 2011) versions of (1) for the middle

temperature range; and (3) ring opening polymerization of racemic lactides for the high end of the temperature range.

It is possible to produce polymers that degrade at temperature $< 130^{\circ}\text{F}$ (55°C), but these materials are cumbersome to handle at present due to their low softening points. The use of coatings made from low melting waxes could make handling low temperature EFF polymers practical. Developing EFF polymers for low temperature wells is seen as an important need for hydraulic fracture in shale oil and gas fields, many of which around 50°C and would not be amenable to the materials developed here.

High temperature ($> 175^{\circ}\text{F}$) EFF polymers pose another challenge in that they must be a polymer other than polylactide or employ a polylactide that has a significant degree of crystallinity. This modification is necessary to provide a measure of heat tolerance. Blends of low molecular weight crystalline polylactide with amorphous polylactide are an option. This is possible because polylactide can exhibit crystallinity even at very low molecular weights. Such blends have to be precisely crafted to maintain the degradation pathway through the viscous liquid phase while balancing the solid component that forms by degradation of the crystalline portion of the blend. Viscous liquids in these cases take on a putty-like appearance. Future work will be needed to determine if these materials exhibit the necessary rheology to form the novel fracture fluid.

2. Small Scale Testing Results

Small scale tests were used to determine the pumping window by measuring the degradation and proppant transport (or proppant settling) properties of different EFF polymer formulations at various temperatures. Small scale tests were a convenient screening tool for determining the best polymer formulations to be carried forward in the large scale tests.

The small scale tests were used to determine the proper EFF polymer composition for specific temperatures. Degradation of the polymer is dependent on its formula, temperature, and time. Tests were conducted at 130°F , 140°F , 150°F , 160°F , 170°F and 180°F with different polymer formulations. **Table 3** depicts time lapse photographs of polymer K0309 degraded at 130°F . The first picture shows the polymer pellets loaded into the graduated cylinder and filled with water just before the temperature was ramped up to 130°F . The next picture, taken after 1:15 hr:min shows K0309 starting to soften as it begins to degrade after it has reached. By 3:00 hr:min the pore space between the pellets is nearly gone as the polymer formed a single mass. The next pictures at 15:00 and 23:00 hr:min indicate the minimum and maximum times of the pumping window. Beyond 73:00 hr:min the proppant settling was nearly complete (see the last picture in **Table 3**).

Table 3: Time Lapse of Small Scale Test of K0309, 130°F

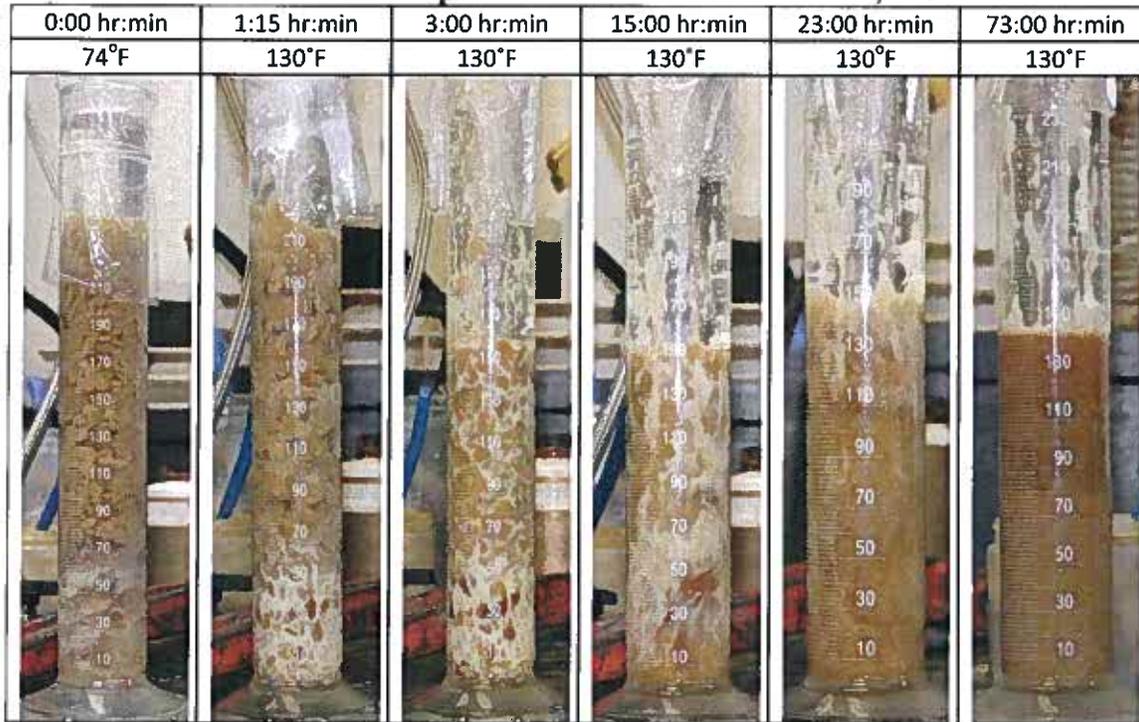
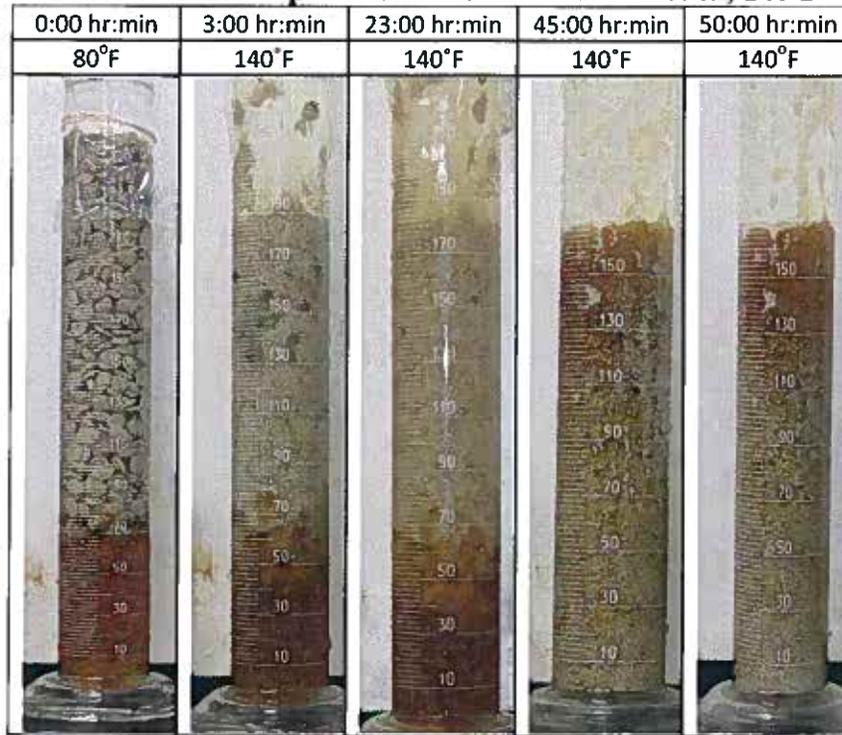


Table 4 shows select photographs of the progression of the small scale test of K0309 performed at 140°F. This stage is shown in the photograph taken at 0:00 hr:min. The individual pellets are clearly visible, with the proppant laden pellets on top. The temperature is then increased to the desired 140°F. By 3:00 hr:min, K0309 pellets have degraded to form a solid mass and the individual pellets are no longer visible. The polymer is deformable at this point and easily supports the proppant.

Table 4: Time Lapse of Small Scale Test of K0309, 140°F



During the testing of EFF polymers the transition from pellets into a homogenous substance, the point at which the polymer is pumpable, ability to hold proppant, the transition into being too thin to hold proppant, and the time to complete hydrolysis to water soluble components were measured. Test results for EFF polymers between 130°F and 180°F and the results are displayed in **Tables 5, 6, and 7.**

Table 5: 130°F Small Scale Test Results

	130 F				
EFF Polymer Sample	R1367-A	R1380-A	R1409-A & R1367-A	R1500-A	R1576-A&B
Pumpable	71 Hours	-	48 Hours	165 Hours	50 Hours
Holds Proppant	71 Hours	23 Hours	48 Hours	-	-
Won't Hold Proppant	144 Hours	73 Hours	168 Hours	-	50 Hours
Hydrolyzed	268 Hours	-	-	-	-

Table 6: 140°F Small Scale Test Results

	140 F						
EFF Polymer Sample	R1330-A	R1367-A	R1380-A	R1409-A & R1367-A	R1409-A	R1476-B & R1367-A	R1576-A&B
Pumpable	18 Hours	53 Hours	-	23 Hours	23 Hours	30 Hours	118 Hours
Holds Proppant	-	53 Hours	-	23 Hours	23 Hours	30 Hours	-
Won't Hold Proppant	-	93 Hours	19 Hours	45 Hours	45 Hours	46 Hours	118 Hours
Hydrolyzed	-	214 Hours	-	-	-	-	-

Table 7: 150°F-180°F Small Scale Test Results

	150 F		160 F	170 F		180 F
EFF Polymer Sample	R1330-A	R1367-A	R1341-A	R1341-A	R1367-A	R1367-A
Pumpable	7 Hours	53 Hours	24 Hours	25 Hours	19 Hours	22 Hours
Holds Proppant	-	53 Hours	-	-	19 Hours	-
Won't Hold Proppant	-	93 Hours	-	-	26 Hours	22 Hours
Hydrolyzed	140 Hours	214 Hours	173 Hours	97 Hours	71 Hours	70 Hours

3. Large Scale Testing Results

Based on the results of small scale tests, four large scale tests were conducted at 140°F. The data collected from the large scale tests helped determine if the NFT could be successful in the field. Once the EFF polymer degraded to the viscosity corresponding to the pumping window, 10-70 psi pressure was applied at the top of the pipe to squeeze the polymer out of the perforation at the bottom. Differential pressure, calculated friction pressure, flow duration, fluid volume expressed and flow rate of the EFF polymer squeezed through the perforation are listed in **Table 8**.

Table 8: Large Scale Test Results

Pressure (psi)	Run #	ΔP (psi)		Friction Pressure (psi/ft)		Duration (sec)	Volume (mL)	Pumping Rate (gpm)	
		Initial	During	Per Run	Average			Per Run	Average
10	1	2.7	0.8	0.08	0.07	30	145	0.08	0.10
	2	2.5	0.5	0.05		20	165	0.13	
30	1	15	3.7	0.37	0.42	18	210	0.18	0.18
	2	11	4.6	0.46		20	215	0.17	
50	1	29	3.9	0.39	0.92	8	180	0.36	0.29
	2	19	14.5	1.45		9	130	0.23	
70	1	40	2.5	0.25	1.40	6	205	0.54	0.42
	2	30	25.4	2.54		9	165	0.29	

Although the test pressures were low due to the pressure limitations of the test equipment, the results showed a very reasonable amount of friction pressure compared to the pumping rate. This confirms that the NFT process is ready for a field trial.

Partially degraded EFF polymer samples captured from the large scale squeeze were loaded into a high temperature Brookfield viscometer to measure the fluid viscosity. The rheology results are listed in **Table 9**. It shows the NFT fluid has very favorable viscosities for its intended purpose.

Table 9: Viscosity vs. Shear Rate for EFF Fluid From Large Scale Tests

Test #	Viscosity (cP)		
	10 s ⁻¹	20 s ⁻¹	40 s ⁻¹
1	3004	2939	2919
2	3111	3110	3086
3	3324	2610	2671
4	1138	1118	1114
5	1849	1911	1875
6	3022	2966	2936
7	5084	4579	3546
8	1209	1054	1092

4. Polymer Manufacturing

Pastillation: Pastillation is a process in which molten material is injected into a horizontal rotating drum that contains a pattern of holes of a regular diameter. **Picture 7** shows the pastillator drum and conveyor belt. **Picture 8** shows the drilled holes in the pastillator head where pastilles are expressed onto the moving belt. As the drum rotates, molten material drips from the holes onto a moving belt where it cools and hardens into tiny hemispheres, or “pastilles”, of approximately ¼” diameter. A well-known example of a pastille is the chocolate chip. At the end of the belt the pastilles are doctored from the belt with a blade and classified using screens of appropriate diameter.

Picture 7: Pastillator Drum and Conveyor Belt

Note: Pastilles on stainless steel belt moving away from the operator (kneeling) as they are being deposited from the holes in the pastillator head (see **Picture 8** for close up of pastillator head).



Picture 8: Close-up of Pastillator Head



Pastillation is best suited for materials with low strength, low melting/softening points, moderate viscosity and materials that cannot tolerate the quenching of process heat with cold liquids. Pastillation is well suited for incorporating hard, abrasive particulates such as proppant because the clearance between the particulates dispersed in the polymer and the machinery parts are quite large. This prevents the abrasive particulates from eroding the machined surfaces of the equipment, thereby reducing wear on expensive metal parts. These characteristics makes pastillation ideally suited for processing low temperature range EFF polymers with and without proppant.

As noted, pastillation tends to be limited to low viscosity materials, typically 1,000 to 30,000 cP. This is due to limitations in the rate at which molten material can be pumped by commercially available drum melter equipment. Proppant incorporation into the molten polymer increases the viscosity of the mixture making it difficult to achieve a concentration greater than 40% (by weight).

Pastillation rates with a 48" width rotating head were as high as 225 lb/hr without proppant and approximately 100 lb/hr for 40% proppant-loaded pastilles. These production rates are possible using a belt speed that allows for sufficient cooling time before the pastilles are collected. Higher production rates are feasible with larger pastillation heads and higher pumping rates for molten polymer. Higher pumping rates would be best achieved by using multiple drum melters.

Deposition: Depositors are devices well known in the confectionary and pharmaceutical industry (see **Picture 9**). Depositors are especially useful for highly viscous materials. The viscosity of the material and the size of the orifice are controlled such that the material does not drip under the influence of gravity. In the context of EFF polymers, highly viscous materials might be those polymers used for NFT at higher temperatures than those examined in this work or for proppant

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loading in excess of 40% by weight. A conveyor belt of sufficient length is used so the “deposits” cool by the time they reach the end and are collected in a manner similar to that used on the pastillator. Based on the clearance between the orifice and piston, wear due to proppant abrading against metal parts was minimized but not eliminated entirely. By increasing the size of the clearance, proppant loadings higher than that possible with pastillation (i.e., > 40% by weight) might be achieved.

Picture 9: Close-up of a Two Piston Depositor

(Note chute for loading and two pistons in the heated polymer/proppant reservoir)



The custom depositor was operated at a maximum speed of 3.5 lb/hr or 1.75 lb/piston/hr to produce several hundred pounds of EFF polymer loaded with proppant. During the run, some wear was observed on the parts associated with the orifice. Periodic adjustment to the timing and length of the piston stroke was required to keep the product uniform.

If high viscosity EFF polymers were needed for hotter well temperatures, a depositor might be an attractive option for scale-up. However, based on experience, a depositor will always have an inherently slower production rate and will always pose a maintenance challenge owing to the large number of moving parts. Nevertheless, the capital cost and machinery size was similar to that of a pastillator.

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Pelletization (Extruder): A twin screw extruder with an underwater pelletizer was used to produce pellets of polymer E2411. Only higher molecular weight EFF polymers (e.g., polylactides) could be pelletized as the lower molecular weight lactic acid based polymers (e.g., K0309) shattered in the pelletized do their low strength. EFF polymer E2411 was pelletized without proppant at 250°F at a rate of about 200 lb/hr. The Entec extruder can produce pellets with diameters smaller than ¼” perhaps as low as 500 um . This is smaller than both the pastillator and the depositor can achieve and could be very useful for some applications.

EFF polymer containing proppant could not be pelletized in an extruder as the proppant quickly eroded the pelletizer cutting blades and dieface. In an extruder, the clearance between metal parts and the diameter of the abrasive proppant is so small that the equipment was rapidly eroded. This eliminates the extruder as a production option for producing proppant loaded EFF polymer pellets.

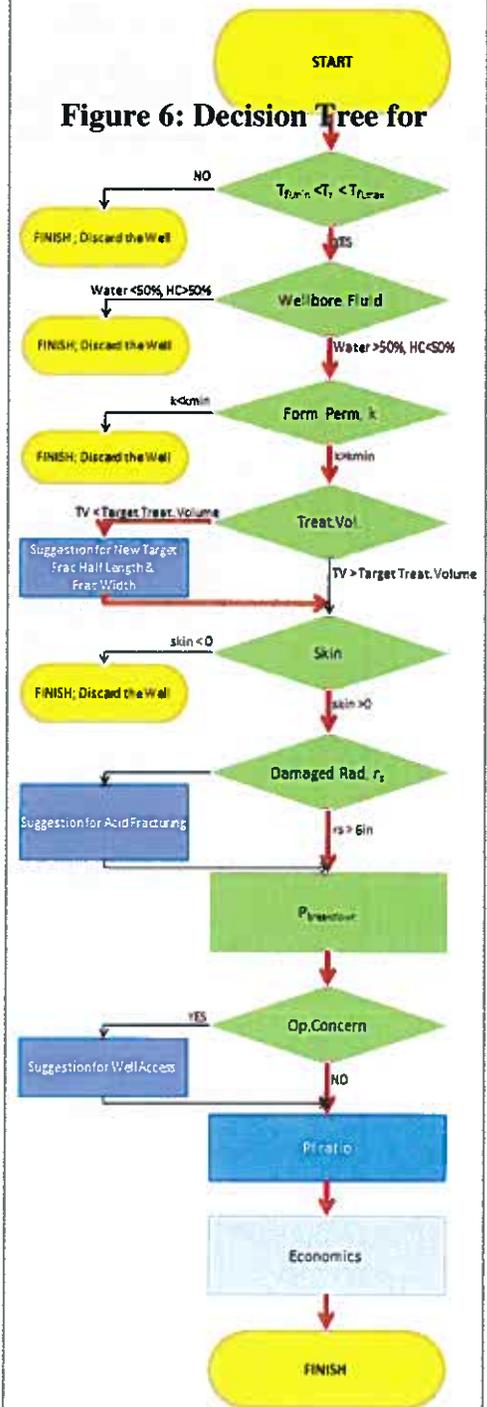
Candidate Well Selection

The NFT process is applicable to specific types of wells. Many parameters will affect the results of the application, so proper selection of candidate wells is critical for successful application. It was determined that a flowchart to help select candidate wells or determine feasibility of this NFT process would be highly useful to small producers in particular. **Figure 6** shows the decision tree developed for preliminary candidate well selection. These parameters were incorporated into a spreadsheet-based well selection software program to verify a particular candidate’s applicability. The parameters are discussed below.

A. Reservoir Temperature

Polymer degradation rate is governed by temperature. This degradation rate defines the pumping window and resulting proppant suspension. The first criterion of candidate well selection is, therefore, the wellbore temperature profile. For the polymers discussed here, the reservoir temperature is preferably between 130°F and 250°F. Actual temperature profile vs. depth, well geometry, and treatment volume will govern polymer composition to achieve a selected pumping window.

Figure 6. Decision Tree for Candidate Well Selection



B. Formation Permeability

Usually a conventional hydraulic fracturing treatment is more effective in low permeability reservoirs. Though the degradable biopolymer can be used for any permeability formation, it only creates short fractures to bypass formation damage and will not be effective for stimulating very low-permeability reservoirs. Application modeling performed to date suggests that reservoir permeability greater than 0.1 md will be suitable. Therefore, wells in reservoirs with permeability higher than 0.1 md qualify as candidate wells for damage-removal treatments. For lower permeability formations, conventional fracturing is recommended. It can also be applied to previously fractured wells to bypass near wellbore damage that has accumulated during its production of oil and gas.

C. Treatment Volume

The maximum treatment volume is determined by the space available in the wellbore, which is the sum of the inside tubing volume and the casing volume between the packer and the bottom perforation. The treatment volume is calculated and the target fracture half-length is determined based on an expected width. If the maximum treatment volume is too small and the resulting fracture length does not exceed the estimated damage depth, a conventional fracture treatment will be recommended. Otherwise the well will continue as a candidate.

D. Damage Assessment

An estimate of a candidate well's skin factor is calculated using Hawkins' formula (1956).

Equation 1: Hawkin's Formula

$$s = \left(\frac{k}{k_s} - 1 \right) \ln \left(\frac{r_s}{r_w} \right)$$

At the same skin factor value, the wells with deeper damage are better candidates for the technology, especially for a sandstone formation. For a carbonate formation with shallow damage zone, acidizing may be effective enough to remove the damage, but an acid fracture with the polymer may provide deeper penetration. The skin factor is also used to evaluate the treatment result by comparing productivity index before and after the treatment.

E. Operational Check-points : Accessibility, HSE Issues, Restrictions by Law

Since most operations are conducted in remote areas, accessibility and size of the location must be assessed. Health, Safety and Environment (HSE) concerns such as the contamination of ground water, air pollution, migration of gases or chemicals to the surface and mishandling of waste must also be addressed. For hydraulic fractures, state and local regulations for protection of drinking water sources and for safe operation require evaluation. Any issues identified will be flagged and trigger attention regarding the regulation. However, the fracturing fluid discussed

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here is benign and contains no ingredient that is harmful to the environment or to operating personnel.

1. Candidate Selection Software

A software program was developed for candidate well selection. It also provides a tool to show the potential benefits a well could expect to realize after an NFT application. The program determines if the candidate well meets the required criteria discussed in the previous section. If these requirements are fulfilled then the software was also able to estimate the anticipated production increase after the treatment.

Previous information about the well such as tubing size, casing size, fluid level, packer depth, etc. is required by the program in order to evaluate the needed decision criteria. The program was developed using Microsoft-Excel VBA for ease of application. The program is composed of input and output sections. The input section has 3 different parts: Part 1 - the basic screening to determine suitability for the NFT; Part 2 - the productivity index; Part 3 - the economic analysis. The output section also consists of 3 main parts. First, the various input data and the results of evaluation for each session are summarized. Second, for effective visualization, the evaluated results are presented on the decision tree. Finally, several graphs are presented for given input data to show the sensitivity analysis. Inflow Performance Relationship (IPR) curves are determined according to the various skin factors, productivity index versus skin factor, and optimum fracture geometry for a given proppant mass.

2. Decision Criteria of the Candidate Well Selection Program

A. Reservoir Temperature

To achieve sufficient viscosity to transport the proppant but not so low that proppant settles out prematurely, the temperature needs to be set from 130 to 176°F, a range identified from the laboratory test. Therefore wells with reservoir temperatures within of this range will be considered as candidate wells.

B. Wellbore Fluid Type

The degradable biopolymer reacts with the water inside the tubing/casing and breaks down into viscous liquid to transport proppant. Laboratory testing has indicated the water content inside the tubing/casing needs to be more than 50% of the total fluid volume. Therefore wells with water content > 50% of total volume will continue as candidate wells.

C. Formation Permeability

The degradable biopolymer can be used for all the ranges of permeability. However, there exists a range for optimum successful reaction in the formation. From laboratory testing, it was characterized that the degradable biopolymer works successfully in reservoirs of permeability > 0.1 md. Therefore, wells with permeability higher than 0.1 md will be selected as candidate wells.

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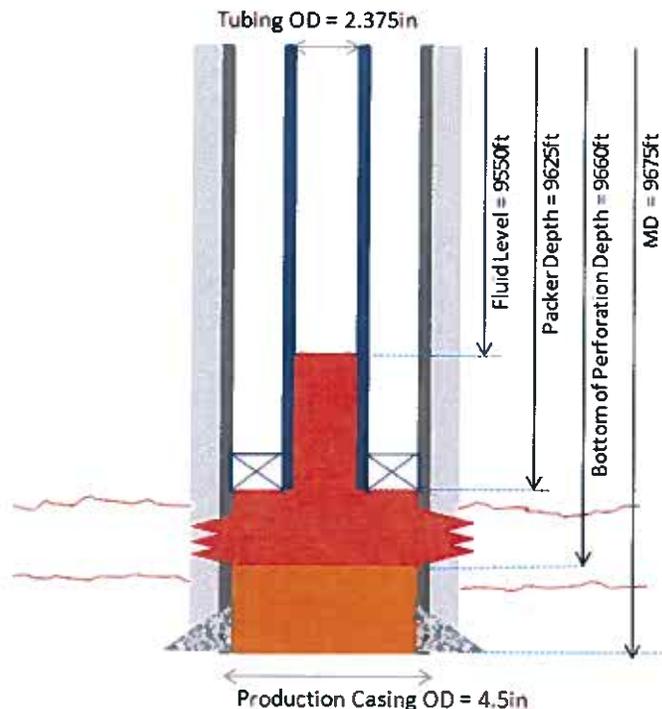
D. Treatment Volume

The treatment volume is calculated and target fracture half-length and target width are adjusted if necessary. The fracture volume is determined by the space available in the wellbore, the possible treatment volume (i.e., the inside tubing volume between fluid level and packer depth plus the inside casing volume between packer depth and bottom of perforation depth).

Equation 2: Allowable Treatment Volume in Cubic Feet

$$V_{creat} = 0.005454 \times ID_{tubing}^2 \times (\text{Packer Measure Depth} - \text{Measured Fluid Level}) + 0.005454 \times ID_{prod.casing}^2 \times (\text{Bottom Perforation Measured Depth} - \text{Packer Measured Depth})$$

Figure 7: Example Diagram for the Calculation of Allowable Treatment Volume



After calculating the possible treatment volume, the penetrable height of fracture is calculated from target fracture half-length and target width.

Equation 3: Penetrable Height of Fracture

$$h_{penetrable} = \frac{V_{poss.treat.}}{2 \times l_{f.target} \times w_{target}}$$

Equation 4: Ratio of Penetrable Height of Fracture to Payzone Thickness

$$\text{ratio} = \frac{\text{penetrable height}}{\text{payzone thickness}}$$

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When the penetrable height is smaller than payzone thickness, the possible treatment volume is not enough to achieve target fracture geometry. Therefore, the target fracture half-length and target width are modified based on the ratio of penetrable height and payzone thickness. Since achieving a wide fracture width is more important than having a long fracture length, fracture width was modified to half of the original target width and fracture half-length was modified using the ratio of payzone thickness and penetrable height.

Equation 5: Modified Target Fracture Width

$$w_{new} = 0.5 * w_{old\ target}$$

Equation 6: Modified Target Fracture Half-Length

$$x_{f,new} = \frac{\text{ratio}}{0.5} * x_{f,old\ target}$$

When the penetrable height is greater than payzone thickness, which is enough to achieve target fracture half-length and target fracture width, the original target values were used in subsequent calculations. The optimum fracture half-length and optimum fracture width are calculated using following equations developed by Economides et al. (2002) using Unified Fracture Design concept for the reference.

Equation 7: Optimum Fracture Half-Length

$$x_{f,opt} = \left(\frac{k_f V_p}{2C_{fD,opt} kh} \right)^{0.5}$$

Equation 8: Optimum Fracture Width

$$w_{opt} = \left(\frac{C_{fD,opt} k V_p}{2k_f h} \right)^{0.5}$$

E. Damage Assessment

The candidate well should be one in need of production increase due to the near wellbore damage. The skin was calculated using Hawkins' formula (1956) based on known damaged permeability and damaged radius. If the skin is positive and the damaged zone radius is long enough for hydraulic fracturing, the well is considered as candidate well. This is determined by using **Equation 1**.

F. Pressure

This section determines breakdown pressure and is not used to screen candidate wells. Breakdown pressure is the pressure required to initiate a fracture from the wellbore. Due to the effect of the stress induced by the wellbore, the breakdown pressure is usually

greater than the fracturing pressure. An expression for the breakdown pressure has been given by Terzaghi as far back as 1923 and for a vertical well this pressure, p_{bd} , is expressed as follows (Economides et al. 1994).

Equation 9: Breakdown Pressure for a Vertical Well

$$p_{bd} = 3\sigma_{H,\min} - \sigma_{H,\max} + T_0 - p_p$$

where, $\sigma_{H,\min}$ and $\sigma_{H,\max}$ are the minimum and maximum horizontal stresses, respectively, T_0 is the tensile stress of the rock, and p_p is the reservoir pressure.

G. Operational Check-points: Accessibility, HSE Issues, Restrictions by Law

During the treatment, large amounts of proppant and fluid additives are used. Therefore, the well should be located and accessible at least by a full-size heavy-duty truck and provide enough room on location for the truck. As hydraulic fracturing becomes increasingly widespread in shale gas production, Health, Safety and Environment (HSE) concerns such as the contamination of ground water, air pollution, the migration of gases and chemicals to the surface and the mishandling of waste are increasing. Many states or cities have comprehensive laws and regulations for hydraulic fracturing to protect drinking water sources and for safe operation. Upon evaluation, if the well has one of these issues the well is still considered as candidate well; however, the program gives the user the message that special attention is needed regarding that matter.

H. Calculation of Productivity Index

The productivity index for an unstimulated well is given by (Economides et al. 1994).

Equation 10: Productivity Index for an Unstimulated Well

$$J = \frac{q}{\Delta p} = \frac{kh}{141.2B\mu \left[\ln \left(\frac{0.472r_e}{r_w} \right) + s \right]}$$

For a fractured well, the stimulation effect can be incorporated into several ways, but the f-factor by Cinco-Ley and Sameniog (1981) was used the program.

Equation 11: Productivity Index for a Stimulated Well

$$J = \frac{q}{\Delta p} = \frac{kh}{141.2B\mu \left[\ln \left(\frac{0.472r_e}{x_f} \right) + f \right]}$$

The f-factor is calculated starting from the dimensionless fracture conductivity, which is expressed by

Equation 12: f-factor Calculation

$$C_{fD} = \frac{k_f w}{k x_f}$$

where k is the reservoir permeability, x_f is the fracture half-length, k_f is the permeability of proppant and w is the average fracture width.

The relationship between f-factor and dimensionless fracture conductivity is obtained from the following equation.

Equation 13: Relationship of the f-factor to Dimensionless Fracture Conductivity

$$f(C_{fD}) = \frac{1.65 - 0.328u + 0.116u^2}{1 + 0.18u + 0.064u^2 + 0.005u^3}$$

where, $u = \ln(C_{fD})$

Productivity index can also be calculated from a pseudo-skin factor, which can be easily converted into f-factor in Cinco-Ley's model and effective wellbore radius in Prats (1961).

Equation 14: Pseudo-skin Factor

$$J = \frac{q}{\Delta p} = \frac{kh}{141.2B\mu \left[\ln\left(\frac{0.472 r_e}{r_w}\right) + s_f \right]} = \frac{kh}{141.2B\mu \left[\ln\left(\frac{0.472 r_e}{r_w}\right) \right]}$$

$$f = s_f + \ln\left(\frac{x_f}{r_w}\right)$$

The effect of treatment on productivity is obtained by calculating productivity index ratio and comparing it between wells. Productivity index ratio indicates how much the productivity increased as a result of the treatment by comparing the productivity before and after the treatment. The higher the productivity index, the bigger the effect of the treatment. The productivity ratio is calculated by

Equation 15: Productivity Index

$$PI \text{ ratio} = \frac{J_{\text{after frac}}}{J_{\text{before frac}}} = \frac{\ln\left(\frac{0.472 r_e}{r_w}\right) + s}{\ln\left(\frac{0.472 r_e}{x_f}\right) + f} = \frac{\ln\left(\frac{0.472 r_e}{r_w}\right) + s}{\ln\left(\frac{0.472 r_e}{r_w}\right) + s_f}$$

I. Economic Analysis

For a simple economic analysis, additional expected daily revenue from hydraulic fracture treatment is determined from the productivity index, which does not consider the time value of money and assumes constant pressure drawdown. Payback period is

obtained using the expected revenue and the treatment cost. These numbers are not exact values but can be used for the comparison between the wells.

Equation 16: Expected Additional Revenue

$$\text{Additional Expected Revenue} = (J_{\text{after frac}} - J_{\text{before frac}}) \times \text{Pressure Drawdown} \times \text{Oil Price}$$

Equation 17: Pay Back Period

$$\text{Pay Back Period} = \frac{\text{Treatment Cost}}{\text{Additional Expected Revenue}}$$

Impact to Small Producers

The NFT will provide small producers with a simple, effective, low cost, and environmentally friendly tool for enhanced hydrocarbon recovery. It will allow zones which were previously considered to be economically unproductive to be tapped by small producers that have limited resources and smaller budgets. This increases the ultimate gas recovery and production from the available reserves in the U.S. It increases the reserves that can be recovered economically.

This technology can be especially beneficial when used on marginal wells known as stripper wells. These are wells that produce 10 barrels or 60 thousand cubic feet of natural gas per day or less. The oil and gas zones are typically only a few feet thick and would benefit greatly from a small fracture treatment. Since the fluid volume of an NFT application is restricted by the pipe volume, it is ideal for small treatments such as this. It could even be used to restimulate stripper wells to increase end of life production. As of 2008, there were 375,000 stripper wells producing 262 million barrels of oil per day – 20% of the nation total production (See National Stripper Well Association’s website, 2013) If this technology could increase stripper well production by just 0.2%, that would add another 600,000 bpd to the domestic supply.

The NFT has many operational advantages for small producers. Advantages include the reduced requirement of expensive high hydraulic horsepower pumps. Fracture initiation with EFF polymer is achieved at lower pump rates due to its high viscosity and also due to the pad and proppant already being located at the perforations prior to pumping. It completely eliminates the need for complicated and costly blenders, chemical additives, frac tanks, and proppant delivery equipment. This in turn reduces cost and the equipment footprint on location.

The unique characteristics of the EFF polymer also provide many fluid advantages. It is a non-damaging fluid that will not leave behind any formation clogging polymer. Typical fracturing fluids that are commercially available leave a residue of polymer in the formation that greatly reduces the permeability. The final products of complete EFF hydrolysis are soluble organic acids, which may further stimulate the formation, especially in carbonaceous rock. It also achieves a very high viscosity while providing low friction pressures during pumping.

The bio-based polyesters utilized are degradable and environmentally friendly. The degradable nature eliminates the need for breakers and other chemical additives, therefore reducing the

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health risks and hazards associated with these chemicals. The NFT polymer is transported in a solid form which eliminates the potential for liquid spills. The reduced fluid volume and required equipment drastically reduces the equipment footprint. The need for frac tanks, blenders, hydration units and chemical additive units is eliminated. This in turn reduces the fuel consumption and air emissions of the fracturing operations. The less equipment also reduces the heavy truck traffic on small county and lease roads leading to the well site. This also reduces noise emissions in urban and environmentally sensitive areas.

Technology Transfer Efforts

The technology presented by the NFT will need to be properly shared with the industry. The Society of Petroleum Engineers (SPE) provides a well-known and respected platform for presenting new technology in the oilfield through their published papers. A paper describing the technology was presented at the SPE Hydraulic Fracturing Conference (Cooke et al., 2012) and also at the RPSEA Onshore Production Conference (Midland, TX April 10, 2012). A new company, Ener-Pol (www.ener-pol.com) has been formed by one of the project's subcontractors to commercialize this technology and on their website there is a description of the process. A number of other technology transfer activities are still being pursued. One activity is the submission of an article to World Oil. We may also consider submission of articles to other trade magazines such as American Oil and Gas Reporter, Hart's E&P and others.

One of most effective technology transfer organizations is the Petroleum Technology Transfer Council (PTTC). This is particularly the case for this technology which lends itself to independent producers which the PTTC reaches throughout the U.S. The PTTC has been contacted in order to provide materials and speakers at appropriate workshops and publications. It is planned to transfer the NFT through participation in industry organizations on a regional and national level.

Conclusions and Recommendations

The data and results presented in this report support the following conclusions for the NFT:

1. Viability of the NFT process has been confirmed and is ready for field trial.
2. Degradable polymers suitable for application under reservoir temperatures ranging from 130-176°F have been developed.
3. Design data and performance properties required for treatment design have been developed.
4. Manufacturing methods as well as techniques for incorporating proppant into the polymer and forming field-usable material have been developed.
5. Large-scale laboratory process simulations indicate that the materials and process can be applied in a well.
6. A well candidate selection software program was developed for the NFT method.

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Recommendation: Based on the results of large-scale laboratory testing, it is recommended that the NFT process be tested in the field on at least 6-10 wells of differing temperatures, permeabilities, etc. to assess and quantify the commercial potential of the NFT. If field testing proves successful, additional development work required to implement the NFT into routine operations should include:

- Measurement of fluid rheology throughout the pumping window,
- Establish maximum proppant loading
- Develop EFF polymers for higher (>180°F) and lower (<130°F) well temperatures
- Development of a design simulator specifically for the process
- Optimizing the technique of placing the NFT material into a compatible wellbore. This activity may include development of coatings that will prevent pastilles from bridging in well casings during some types of insertion techniques.
- Improve the utility of the well selection software tool by incorporation of data from field tests

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Acronyms and Abbreviations

B	formation volume factor, res bbl/STB
C_{fD}	dimensionless fracture conductivity
$C_{fD,opt}$	optimum dimensionless fracture conductivity
f	f-factor
h	payzone thickness, ft
ID	inner diameter, in
J	productivity index
k	formation permeability, md
k_f	proppant permeability, md
k_s	damaged permeability, md
q	flow rate, STB/d
p	pressure, psi
p_{bd}	breakdown pressure, psi
p_p	reservoir pressure, psi
r_e	drainage radius, ft
r_w	wellbore radius, ft
r_w'	effective wellbore radius, ft
r_s	damaged zone radius, ft
s	skin factor (before treatment)
s_f	skin factor (after treatment)
T_o	tensile stress of the rock
MD	measured depth, ft
TVD	true vertical depth, ft
V_p	propped fracture volume contain within the payzone (2-wing)
w	fracture width, in
w_{opt}	optimum fracture width, in
x_f	fracture half length, ft
$x_{f,opt}$	optimum fracture half length, ft
μ	viscosity, cp
ν	Poisson's ratio

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$\sigma_{H,max}$ maximum horizontal stress, psi

$\sigma_{H,min}$ minimum horizontal stress, psi