Evaluation of Frac-and-Pack Completions in the Eugene Island

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Abstract
This paper presents a systematic evaluation of frac&pack completions conducted in the Eugene Island region of the Gulf of Mexico. Reservoir, treatment and production data are analyzed from a unified viewpoint. First a completion design strategy is described which is centered around the dual goals of optimal stimulation and sufficient sand control. Then a method is presented to evaluate the technical success of the completion using 3-D reservoir/fracture simulators and the recently developed Slopes Analysis method. Finally, a simple but practical frac&pack treatment design and optimization procedure is presented for improving the performance of frac&pack completions. An example of frac&pack treatment design using the new design philosophy is provided in details showing how to achieve the stimulation goals in a theoretically optimum manner and why often the actual treatment has to depart from the theoretical optimum.

Introduction
Sand production associated with relatively permeable and unconsolidated formations is a recurrent problem. The options for completion of these formations are conventional gravel packing, recently emerged high-rate water packing, and frac&pack. Several statistical studies from field operations indicate that gravel packing inherently results in reduced well performance manifested by a large positive skin.1,2 In the Gulf of Mexico, a skin factor of +5 to +10 is considered excellent but skin factors of +40 or higher are not uncommon either for gravel pack completions. High-rate water packing results in smaller skin factors than gravel packing because proppant can be placed outside the perforation. However, this technique is limited in its ability to transport sufficient proppant into deep formations.3

Frac&pack provides a simultaneous solution for formation stimulation and sand control. The stimulation is achieved by creating a high-conductivity flow path to bypass the damaged zone and changing the streamline structure in the near wellbore area. The sand control aspects of frac&pack include but are not restricted to the same mechanism as gravel packing. Additional sand control is achieved by exertion of compressive stress on the wellbore-formation interface and reduction in the influx per unit area at the interface.4

Despite undoubted success, frac&pack technology is still lacking to achieve optimum completion efficiency and to deliver reliably the production as designed. Many studies have shown that frac&pack is significantly different from low-perm fracturing regarding completion fluids,5,6 rock mechanics,7,8 pressure analysis,9-12 treatment design and execution,13-16 Unfortunately, current practices do not always pay attention to these differences and sometimes copy the techniques and operational procedures originally developed for traditional fracturing.

This paper describes a comprehensive approach for the design and evaluation of frac&pack completions. Several analysis tools are applied to treatment and production data in order to answer the basic question: how the completion realized the design goals. As a result of the comprehensive analysis a new design philosophy is presented for frac&pack treatments. It is based on the dual concept of theoretically optimum fracture dimensions and minimum necessary departure from the theoretical optimum due to technical constraints.

Reservoir Background
Eugene Island Block 354, located approximately 160 miles Southwest of New Orleans in the central Gulf of Mexico in 280’ of water, was originally developed by Mobil Oil Corp. in the mid 1980’s. Numerous problems, primarily fines migration, combined to cause high drawdown and a rapid decline. Mobil eventually abandoned the property in 1987. The block was finally acquired by Texaco Exploration and Production, Inc. as a farm in from Shell Offshore in 1994. Two wells were drilled in 1994 and identified several sands as
potential production horizons. A platform was constructed and placed over the two discovery wells which were completed and placed on production in September, 1995. Eventually, a total of 17 wellbores produced from the platform, many completed as duals.

Most of the sands at Eugene Island Block 354 are over-pressured, highly laminated channel sands running generally in a north to south direction. The productive sands were deposited in the Plio-Pleistocene Period. The inter-bedded shales are primarily mixed layer. Natural formation permeabilities range from a few millidarcies up to two darcies in some laminations. The primary hydrocarbon produced is oil of approximately 30° API.

Because of the fines problems experienced by Mobil, it was necessary to employ a completion method that would minimize drawdown and thereby reduce the fines migration problem. Although horizontal completions had been successful at reducing drawdown in other areas of the Gulf of Mexico, the highly laminated sands at Eugene Island Block 354 would limit the vertical permeability within the sands and reduce a horizontal well’s effectiveness. Therefore, frac-packing became attractive as a method to overcome the limited vertical permeability and minimize the fines migration problems.

After the fracture treatments were pumped, the tubing was run, the Xmas trees installed and the wells gaslifted on production. Pressure-transient analysis indicated initial skins ranging from zero to ten. Eventually, many Eugene Island Block 354 frac-packed completions would produce sand-free with up to 2500 psi drawdown. Several of the wells are presently over or approaching 1 MM bbls total production. Although their skins have increased slightly with time, now ranging from ten to twenty, this is a good indication that the fines migration problems have been largely mitigated and the reservoirs have been adequately drained. Fig. 1 shows a production history after treatment. Production increased gradually as per the completion schedule reaching a maximum rate of approximately 12 MBOPD and 24.6 MMCFG. It is important to note that during the entire 32 months of production history shown, there were no sand production problems from any of the wells. The experience that we learned from development of Eugene Island is that completion techniques, reservoir management and sand control methods should be integrated into one consistent operation strategy at the early stage of the reservoir development.

Methods of Study

Treatment Evaluation. Reservoir, treatment and production data from Eugene Island 354 were gathered for this study. Three different approaches are employed to conduct independent analyses, focused on fracture dimensions, proppant placed in pay zones and productivity index. First the minifrac data including step rate and gel calibration tests are analyzed using a fracture simulator and the software package VirtuWell to determine fracture closure, leakoff parameters and possible fracture geometry. Then the main treatment data are evaluated using pressure match process and the Slopes Analysis method. Both methods determine propped fracture dimensions, areal proppant concentration, fracture conductivity and proppant number, which in turn determines the productivity index. The actual jobs are compared with treatment design in terms of pumping parameters, final fracture dimensions, and dimensionless productivity index. Finally, a three-phase, 3D reservoir simulator with a hydraulic fracture option is used to conduct a sensitivity study based on known reservoir characteristics and production history.

Performance of Frac&Packed Well.
The pseudo-steady state productivity index relates production rate to pressure drawdown:

\[ J = \frac{q}{p - p_{wf}} = \frac{2\pi kh}{\alpha_B \mu} J_D \]  \hspace{1cm} (1)

where \( J_D \) is the dimensionless productivity index, \( k \) is the formation permeability, \( h \) is the pay thickness, \( B \) is the formation volume factor, \( \mu \) is the fluid viscosity and \( \alpha_1 \) is a conversion constant (one for a coherent system).

In the case of a propped fracture there are several ways to incorporate the stimulation effect into the productivity index. One can use the pseudo-skin concept:

\[ J_D = \frac{1}{\ln \frac{r_e}{r_w} - \frac{3}{4} + s_f} \]  \hspace{1cm} (2)

or the equivalent wellbore radius concept:

\[ J_D = \frac{1}{\ln \frac{r_e}{r_w'} - \frac{3}{4}} \]  \hspace{1cm} (3)

or one can just provide the dimensionless productivity index as a function of the drainage-volume geometry and fracture parameters. All three options give exactly the same results although the last option is the most convenient, especially if we wish to consider fractured wells in a rectangular drainage area. Many authors have provided charts and correlations in one or another form for special geometries and reservoir types. Unfortunately, most of the results are less obvious to apply in high permeability environments. In the follows, we will present a fresh look at the partly known results based on a new dimensionless variable called proppant number, \( N_{prop} \).

For a vertical well intersecting a rectangular vertical fracture that penetrates fully from the bottom to the top of the drainage volume the performance is known to depend on the x-directional penetration ratio:

\[ I_x = \frac{2x_f}{x_e} \]  \hspace{1cm} (4)
and on the dimensionless fracture conductivity:

\[ C_{fD} = \frac{k_f V_w}{k x_f} \]  

\[ N_{prop} = I_f^2 C_{fD} = \frac{2k_f V_p}{k V_r} \]  

where \( V_p \) is propped volume of the two-wing fracture and \( V_r \) is drainage area multiplied by pay thickness. The dimensionless proppant number, \( N_{prop} \), is nothing else but the ratio of two volumes: the propped volume in the pay divided by the reservoir volume in the pay, both volumes weighted by their permeability, respectively. (In addition, a factor of two is used in front of the propped volume.) As we will see, the proppant number is the most important parameter in fracture design.

Similar to previous work, Fra&pack treatments have dimensionless productivity index vs. dimensionless fracture conductivity at a fixed value of the proppant number. As seen from Figs. 2 and 3, for a given value of \( N_{prop} \), that is for a fixed amount of available proppant, there is an optimal dimensionless fracture conductivity, representing the optimal compromise between the ability of the formation to provide flow into the fracture and the ability of the fracture to conduct the flow into the wellbore. For frac&pack in medium to high permeability formations, typical proppant numbers range between 0.0001 and 0.01. For that range, the optimum dimensionless fracture conductivity is 1.6. When the propped volume increases, the optimal compromise happens at larger dimensionless fracture conductivities because the penetration cannot exceed unity. The behavior at large \( N_{prop} \) is as anticipated because we know that the absolute maximum for \( J_D \) is \( 6/\pi \) corresponding to perfect linear flow.

Frac&pack treatments have \( N_{prop} \) less than 0.1. For that region the dimensionless productivity index is given by:

\[ J_D = \frac{1}{-0.629 + 0.5\ln \frac{C_{fD}}{N_{prop}} + f(C_{fD})} \]  

where

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

\[ u = \ln C_{fD} \]

The maximum dimensionless productivity index, \( J_{D,max} \), can be obtained substituting \( C_{fD} = 1.6 \) into Eq.7:

\[ J_{D,max} = \frac{1}{0.990 - 0.5\ln N_{prop}} \]

The above correlations serve as a basis for designing technically optimum fractures.

For frac&pack, when \( N_{prop} > 0.1 \) is not relevant, but for sake of completeness we present a correlation for the maximum dimensionless PI for that range too:

\[ J_{D,max} = \frac{6}{\pi} \exp \left[ -\frac{0.423 - 0.311 N_{prop} - 0.089 (N_{prop})^2}{1 + 0.667 N_{prop} + 0.015 (N_{prop})^2} \right] \]

The optimum dimensionless fracture conductivity is given by

\[ C_{fD, opt} = 1.6 + \exp \left[ -\frac{0.583 + 1.48 \ln N_{prop}}{1 + 0.142 \ln N_{prop}} \right] \]

for \( 0.1 \leq N_{prop} \leq 10 \), and

\[ C_{fD, opt} = N_{prop} \]

for \( N_{prop} > 10 \).

**Treatment Design, Implementation, and Evaluation**

**Treatment procedures.** All of the frac packs were pumped from stimulation boats with the gravel pack screen and packer in place. The jobs involved pumping an injection test and a step rate test and then re-designing the frac treatment. The frac objectives were to achieve as wide of a fracture as possible with about a 50’ half-length. Due to the low strength contrast between sand and shale, the fractures encountered no boundaries while pumping. For this reason, the perf intervals were relatively short and picked near the middle of the sand in an attempt to position the most conductive portion of the fracture in the most productive portion of the sand. The proppant used was 20/40 Econoprop and the carrier fluids were borate crosslinked, low guar systems. The major properties of the selected candidates in EI 354 are presented in Table 1, including rock mechanics, formation data and producing intervals.

Fig. 4 shows a typical treatment procedure, where the step rate test using 2% KCl is conducted for determining breakdown rate, fracture extension and closure pressures (in some cases, a few hundred gallons of 10% hydrochloric acid...
is pumped prior to the step rate test to remove the near-wellbore damage due to completion operations). This is followed by an injection test to quantify the fluid leakoff parameters and possible fracture geometry. The main treatment is pumped after the calibration test to realize the design goals. It is shown in Fig. 4 that a screenout was experienced when 9 ppa stage was in the formation. After the tip screenout, continuous pumping results in net pressure buildup. The maximum surface screenout pressure is set as 9300 psi. (Usually, the pump pop-off valves are set at 10,000 psi in an attempt to protect the treating iron such as coflexip and chucksans.) At this point the service tool is shifted to reverse position and the excess slurry was reversed out with the rig pumps.

**Minifrac Analyses.** Software packages, FracCade and VirtuWell, are used to conduct independent analyses for the step rate and injection tests. Except for leakoff coefficient, the parameters obtained from FracCade analysis are well agreed with VirtuWell analysis. The leakoff coefficient calculated from VirtuWell is larger than that obtained from FracCade because the leakoff is assumed to be zero outside the pay layer in VirtuWell. Table 2 presents results of minifrac tests, including fracture closure pressure and fluid efficiency. It is found that interpretation of minifrac pressure data in the soft and high-permeability formations are more complex than for low-permeability hard rocks because of characters of high fluid leakoff and soft formation. The 2% KCl brine may not be an appropriate fluid for step rate test due to the tremendous leakoff. More viscous fluid such as gel is recommended in order to obtain stable pressure data for each rate step. The analysis procedure seems still valid for determining fracture closure pressure in the soft and high-permeable formations. Fig. 5 shows plots of pressure and pressure derivative vs. square root of shut-in time. However, the formation may have multiple fracture closure pressures as shown in Fig. 6. It is important to conduct different types of analyses (plots) to obtain the consistent results. Fig. 7 shows a Nolte-Smith plot for diagnosis of possible fracture geometry. The negative slope on the Nolte-Smith plot indicates the radial fracture created. The important observations we had from pressure analysis are:

- Step rate and injection tests, if necessary, should be conducted mainly for the purpose of checking treatment reliability prior to the main job, including issues of pumping equipment, pipe lines, perforation and cementing. The only useful information obtained from the tests is fracture closure pressure. This pressure, similar to the function of bottomhole flowing pressure in well testing, serves as a basis for computing fluid efficiency, conducting pressure match analysis, and generating Nolte-Smith plot. In addition, the closure pressure is also used to estimate maximum surface treating pressure and hydraulic horse power required.
- Attempt to determine fluid leakoff parameters in high-permeability formations using the minifrac procedures, originally developed for low-permeability fracturing, may result in misinterpreting pressure data. In many cases, for example, there is no straight line section in the G-function plot. In high permeability formations, fluid leakoff is pressure dependent. The leakoff coefficient determined from the minifrac cannot be used for the main treatment because of variation in fracture pressures. Recent study also indicates that fluid efficiency in the minifrac is much different from that in the subsequent main treatment. More importantly, the proppant schedule that is based on the fluid efficiency, once again developed for low-perm fracturing to prevent premature screenout, is not applicable for frac&pack treatment where the tip screenout is intentionally required at an early stage.

**Treatment Design.** The stimulation proposal for each candidate well was prepared by the service company, including information on wellbore configuration, formation properties, and detailed pumping schedules. A fracture simulator was then used to predict the fracture dimensions, average conductivity and well productivity. Table 3 presents the design parameters that have significant effects on the treatment outcomes, including fluid volume, proppant mass, computed fracture dimensions and well PI. The detailed pumping schedules are not provided in this paper.

**Pressure Match Process.** The bottomhole pressure measured during the treatment is analyzed using the fracture simulator. The process involves an iterative procedure of tuning formation and fluid properties to match simulated net pressure with measurement. When the net pressure is matched, the simulated fracture dimensions are regarded as what occurred underground. Fig. 8 shows the result of a typical pressure match for the tip screenout treatment. Because of the complex nature of pressure-dependent leakoff and fracture inflation after the tip screenout, the pressure match for the frac&pack treatment in the high-perm and soft formation is more difficult than that in traditional fracturing. Reasonable results can be obtained when we have good knowledge about the rock mechanics properties and fluid leakoff behavior. Table 4 presents summary of treatment evaluation for the selected wells, including information on fluid and proppant pumped, fracture dimensions created, average proppant concentration, average fracture dimensionless conductivity, computed dimensionless productivity index and the pseudo skin factor. It should be noted that although widely used in the industry, the pressure matching process is subjective and does not yield a unique solution for the created fracture dimensions and conductivity. Treatment evaluation using this process needs extensive experience and good understanding of treated formations and used fluids.

**Slopes Analysis.** Slope analysis provides another option to determine packed fracture radius, areal proppant distribution and productivity index from the treatment pressure. Unlike the pressure match process, this method uses simple linear
elasticity and material balance principles to analyze change of the pressure slopes. Fig. 9 shows the obtained evolution of fracture radius (both hydraulic and packed) with injection time for Well B. In this case, the tip screenout occurs after 3.6 min when the fracture radius reaches about 70 ft. Continuous pumping after the tip screenout results in proppant packing back from the fracture tip. The results also indicate that the tip screenout is not a single event. Rather, frac&packs consist of multiple proppant bridging and then breaking processes, resulting in alternating fracture width inflation and fracture area extension. The distribution of proppant and propped fracture width for Well B are shown in Fig. 10. Although the packed radius is about 70 ft, the most proppant is placed within the 45-ft radius. Beyond the 45 ft, the areal proppant concentration is almost negligible. The evaluation of treatment pressure using the Slopes Analysis method is presented in Table 5 for the selected wells. It is interesting to note in Table 5 that the percentage of proppant placement in pay zone ranges from 46% to 66% for the selected wells. The remainder is placed into the non-productive layers, which will not directly contribute to the production increase. There are two scenarios responsible for the loss of proppant. One is shale streaks laminated in the pay intervals and the other is fracture growth out of the pay zone. Technically, there is no effective means to avoid the proppant loss if the pay intervals are embedded with non-productive streaks. If the loss of proppant is due to significant growth of fracture height, proper modification of the treatment design would be useful to mitigate the waste.

Reservoir Simulation. Attempts to post-evaluate fracture treatments through production history are also made using a three-phase, 3D simulator package that has a hydraulic fracture option. The models were built assuming single-well cases and establishing the earth model based on known reservoir characteristics. For the short fracture and highly permeable formations investigated, it seems difficult to reliably quantify the fracture dimensions by matching the production data because the flow transition from the linear region to the radial is too short. Therefore, the reservoir simulation in this study is directed towards examining the effects of fracture geometry on the well performance in terms of daily production rate of three fluid phases. First, production history matches were completed in order to substantiate the parameters. Then, the designed fracture geometry was introduced into the model and projections were conducted to determine productivity. Parametric studies were done on fracture geometry to evaluate impact on well productivity. The fracture length was varied by a 25% margin, both larger and smaller. The fracture height and width were adjusted accordingly and the projections were rerun. A comparison of projections shows essentially no change in performance for the first 245 days and only minor differences between all three cases for the remainder of the simulation. Fracture geometry has little or no impact on well/reservoir performance in areas with relatively high permeability. This conclusion is in agreement with the earlier statement we drew from the semi-analytical solution.

Comparison and Evaluation. The treated cases are compared against treatment designs and theoretical optimization in terms of PI folds of increase (FIO) and pseudo skin factors ($S$). Fig. 11 shows the FIO based on the fracture dimensions and conductivity created for the selected wells. The pseudo skin factors for each case are shown in Fig. 12. It is found for the cases studied that folds of increase is in the range of 1.6 to 2.2 if careful optimization is carried out as suggested in this paper, 1.3 to 2.1 for stimulation designs provided by the service company, and 1.3 to 1.8 if calculated from actual treatment data. The treatments can be claimed as successful in terms of production increase, but are not yet optimal. In particular, the actual jobs further depart from the already less than optimal treatment designs, often without explicit reasons. It is also not clear how the minifrac data are used to assist the design of the subsequent main treatment. We found that the lack of a clear design philosophy resulted in a somewhat incidental design for some cases. Oftentimes the most important economic issue of treatment size was not addressed at all, the proppant schedule was perhaps copied from a previous treatment. On the other hand, unnecessary burden was placed on the operator by requiring detailed layer by layer rock mechanics data, even though they cannot be acquired with sufficient accuracy and it is not clear whether they have any relevant economic implication at all.

Philosophy for Improved Frac&Pack Design
Frac&pack treatment design is regarded as a relatively complex process because the design procedure is oriented by completion goals and influenced by economical and technical constraints. In the following, we describe a simple but practical engineering procedure for frac&pack design. Our design philosophy is based on the concept of the maximum possible production increase, while balancing the competition between fracture length and width for the fixed amount of proppant.

1. Dimensionless PI
Specify the goal of the treatment in the form of amount of proppant reaching the target layer. Calculate the proppant number, which in turn determines the maximum possible productivity index. The target proppant number has to be at least 0.0001, otherwise there is no stimulation effect. It seems reasonable to select $N_{prop} = 0.0005 - 0.001$ as a target for many high permeability formations, because that would provide a $J_0$ of about 0.2. To increase the $J_0$ significantly one would need an order of magnitude larger proppant number that is economically (and sometimes even technically) not feasible. Determining the amount of proppant should consider a whole range of proppant numbers including cost-benefit (NPV) analysis. Determine the optimum dimensionless fracture conductivity from the proppant number, $J_{Opte}$.

2. Optimum Fracture Dimensions

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Compute optimum length and width according to

\[ x_f = \left( \frac{V_i k_f}{C_{D, opt} \eta h k} \right)^{1/2} \] .................................(14)

\[ w = \left( \frac{C_{D, opt} V_i k}{\eta h k_f} \right)^{1/2} \] .................................(15)

where \( V_i = V_p/2 \) is the volume of proppant in one fracture wing placed into the pay. These fracture dimensions will realize the previously determined maximum possible productivity index.

3. Pumping Schedule

Determine the injection time, the necessary maximum added proppant concentration and the detailed proppant schedule realizing the optimum dimensions. (At this point a simple TSO criterion has to be postulated and then continuously improved using e.g. the Slopes Analyses of already conducted treatments in the area.) If technical constraint does not allow the realization of the “optimum placement”, make departure from it only to the extent that is really necessary. There might be several such technical constraints. In the case of frac&pack most likely a limitation has to be considered for the minimum fracture extent (“to get behind damage”, “to cover the full gross pay”) and another for the maximum allowed net pressure during the treatment (to avoid damaging the structural integrity of the well).

It is important to notice that

- There is no theoretical difference between low and high permeability fracturing. In both cases there exists a technically optimal fracture, and in both cases it should have dimensionless fracture conductivity depending solely on the proppant number. While in a low permeability formation this requirement results in a long and narrow fracture, in high permeability formations, a short and wide fracture will provide the same dimensionless conductivity.
- Increasing either the volume of proppant or the permeability of the proppant pack by a given factor has exactly the same effect on the productivity if otherwise the proppant is placed optimally. To achieve the same post-treatment skin factor in a low and a high permeability formation the volume of proppant placed to the pay layer should be increased by the ratio of the formation permeabilities, provided all the other formation and proppant parameters are the same.
- Since not all proppant will be placed into the permeable layer, the optimum length and width should be calculated with the effective volume, subtracting the proppant placed in the non-productive layers. In high permeability formations, the indicated fracture length might not be enough to bypass the damaged zone, therefore a minimum length should be applied.
- Considerable fracture width can be lost because of proppant embedment into soft formations. For gas wells, non-Darcy effects may create a dependence of the apparent permeability of the proppant pack on the production rate itself. These issues are best handled by using proper effective permeabilities in the conductivity expression.

For the TSO fracture design of high permeability formations, one has to consider how to timely terminate the fracture length growth and then inflate the fracture width to achieve sufficient fracture conductivity. The TSO is caused by fluid dehydration and/or proppant bridging. Therefore good knowledge about fluid leakoff behavior is essential for proper design of pad volume, injection rate and proppant concentration. In the period of width inflation, it is possible that the technical constraints such as net pressure at the end of the treatment may not allow optimal placement. In practice, the treating pressure should be monitored in real time. If no TSO event occurs at the designed fracture length the pumping rate should be moderately reduced in order to induce a TSO event and arrest fracture growth. Because of the difficulty in predicting fluid leakoff, a pumping schedule should be flexible. The concept of real-time treatment modification used in massive fracturing for low-perm formations can be extended to frac&packs in high-perm formations.

When comparing actual practices with the suggested methodology one of the important lessons we learned is that copying the frac&pack design from one treatment to the other may lead to unnecessary treatment failures. Because of the qualitative nature of engineering involved in the current design practice (“we need conductivity, not length”) often a too aggressive TSO schedule is proposed, leading to near wellbore screenout and premature ending of the treatment. Our calculations show that in several cases a more conservative proppant schedule would lead to only marginal loss of productivity with respect to the optimal one while the risks associated with premature near-wellbore screenout could be reduced.

Conclusions

1. Reservoir, treatment and production data are analyzed using different methods for evaluation of technical success of frac&pack treatments conducted in the Eugene Island of Gulf of Mexico. The post-treatment pressure analysis using 3D fracture simulator provides fracture dimensions and conductivity created, which are in reasonable agreement with the results from the Slopes Analysis. The treatments of the selected wells were successful in terms of production increase, but are not yet optimal. The actual jobs are often very different from the treatment design with no explicit reasons.
2. A method to predict fractured well performance is presented based on proppant number and dimensionless fracture conductivity. For most frac&pack candidates, the op-
timum dimensionless fracture conductivity is 1.6. The target
propped fracture conductivity should be at least 0.0001 in order
to achieve well stimulation. The realistic production in-
crease for medium to high permeability frac&packs is in
the range of 20% to 150%. This observation agrees with
the analysis conducted using a three-phase, 3-D reservoir
model. Fracture dimensions have little impact on well perfor-
ance in relatively high permeability formations for a
fixed amount of proppant placed into the pay.

3. Interpretation of minifrac data collected in the soft and high
permeability formations is much more complex than for
low-perm hard rocks because of multiple fracture closures
and pressure-dependent leakoff. Copying the test procedure
and analysis methodology developed for low-perm frac-
turing may lead to an improper design of frac&pack treat-
ments. Nevertheless, some kind of minifrac procedure
should be practiced mainly for the purpose of completion
reliability, particularly for the offshore well. Most jobs
analyzed in this study have achieved tip screenout as de-
signated. The tip screenout fracturing appears to be a mature
procedure for completion of unconsolidated and high-perm
formations. However, the tip screenout is not achieved and
completed in a single process. Most often the frac&pack
treatment consists of a series of proppant bridging-and-
then-breaking processes, subsequently resulting in alter-
nating fracture width inflation and fracture area extension.
Therefore, it is important to monitor the downhole pressure
and set up flexible pumping schedule in real time.

4. A simple but practical procedure for frac&pack design has
been developed to achieve the maximum productivity in-
crease for the fixed amount of proppant. Regardless of the
formation permeability, there exists a technically optimal
fracture depending solely on the proppant number. In low
permeability formations, this requirement results in a long
and narrow fracture. For frac&pack candidates, the opti-
mum dimensionless conductivity is obtained creating a
short and wide fracture. Although the detailed pumping
schedules may vary with different fracture simulators and
company practices the logical thinking and procedure de-
scribed is universal for both low-perm and high-perm
formations. The Appendix an example design of a frac&pack treatment is provided to illustrate the new
design philosophy and the incorporation of technical con-
straints.

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Acknowledgement
The authors wish to thank Texaco Inc. for the support and permission to publish this work. One of the authors, P.V., acknowledges the support of GRI (contract No 32559-31120).

Appendix – An Example of Frac&Pack Design
In this Appendix, a treatment design for Well A of Eugene Island 354 is provided.

Initial Design Considerations. The significant reservoir properties for Well A are given in Table 2. The formation has 44 ft of net pay that is distributed in 67 ft of gross pay (from 7,377 – 7,444 ft TVD). Embedded in the net pay are shale layers. The average permeability of the net pay is 712 md. The well drainage radius is 1000 ft and the wellbore radius is 0.3 ft. The closure stress is about 6000 psi. The proppant is 20/40 Econoprop with effective permeability of about 100 Darcies under the closure stress, temperature and flow conditions.

The fracture should have at least 67 ft in height in order to cover the entire production interval, which, in turn, requires fracture half length to be about 45 ft. Because of shale streak distributed in the gross pay, only 2/3 of the proppant can reach the net pay even in the best case (1/3 will be placed into the embedded shales, and will provide mostly only vertical communication). Therefore, even in the best case only 2/3 of the proppant injected can be taken into account when calculating the proppant number.

Treatment Design.
1. Select Amount of Proppant to Calculate Maximum PI.
Three targets of proppant numbers, 0.0005, 0.00075 and 0.001 are chosen initially. According to Fig. 2 or Eq. (10), the maximum dimensionless productivity index and pseudo skin factor are obtained as follows.

<table>
<thead>
<tr>
<th>N_{prop}</th>
<th>V_t</th>
<th>M_{prop}</th>
<th>J_{D, max}</th>
<th>s_t</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.00050</td>
<td>244</td>
<td>40,000</td>
<td>0.209</td>
<td>-2.60</td>
</tr>
<tr>
<td>0.00075</td>
<td>366</td>
<td>60,000</td>
<td>0.218</td>
<td>-2.81</td>
</tr>
<tr>
<td>0.00100</td>
<td>488</td>
<td>80,000</td>
<td>0.225</td>
<td>-2.95</td>
</tr>
</tbody>
</table>

It is seen that the maximum realizable productivity index varies only mildly with increasing proppant number. This is true for most of the high permeability fracturing situations.

From Eqs. 14 and 15, the optimum fracture dimensions are obtained as follows:

<table>
<thead>
<tr>
<th>N_{prop}</th>
<th>C_{D, opt}</th>
<th>x_t</th>
<th>w_{prop}</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.00050</td>
<td>1.6</td>
<td>15.6</td>
<td>2.1</td>
</tr>
<tr>
<td>0.00075</td>
<td>1.6</td>
<td>19.2</td>
<td>2.6</td>
</tr>
<tr>
<td>0.00100</td>
<td>1.6</td>
<td>22.1</td>
<td>3.5</td>
</tr>
</tbody>
</table>

3. Modify the Optimum Fracture Dimensions Because of Constraints
For this case, two constraints are applied. One is the vertical coverage and the other is maximum allowable net pressure (stemming from the upper limit on BHP). In order to cover the entire production interval (67 ft), the fracture half length has to be about 44 ft (ratio of height over length is 1.5). In practice, a limit has to be set on net pressure because of operation safety and pumping equipment capability. For simplicity, we consider an upper limit of the net pressure is 1000 psi. With these limitations in mind we have to depart from the theoretical optimum by increasing length and decreasing width (but keeping the proppant number fixed). In this example, the fracture length is increased by a factor of 2-3 and upper limit of the net pressure is 1000 psi. Below shown are the modified fracture dimensions.

Two observations are made from the results. First, a 44 ft fracture is long enough to bypass the damaged zone and also allows for vertical penetration to cover the entire production interval. The net pressure at the end of treatment also meets the constraint requirement, except for the third case where there is a need to further depart from the theoretical optimum. Second, some economic analyses should be made to determine if gaining an additional -0.34 skin units at the price of placing 60,000 lb proppant has better economic returns than placing
40,000 lb proppant, or if the -0.49 skin units increase is justifiable for a 100% increase in treatment size. In this case, it is appropriate to select the target proppant number to be 0.0005. The designed fracture length is 44 ft with net pressure limit of 1000 psi.

4. Determination of the Pumping Schedule
For given fracture dimensions a design spreadsheet is used to generate the detailed pumping schedule. The major outputs of the treatment design in this case are shown as follows:

**Output 1**

Optimum placement without constraints

- Proppant number, Nprop: 0.00050
- Dimensionless PI, Jdopt: 0.209
- Optimal dimensionless fracture cond, CfDopt: 1.6
- Optimal half length, xf, ft: 15.6
- Optimal propped width, wopt, inch: 2.1
- Post treatment pseudo skin factor, sf: -2.60
- Folds of increase of PI: 1.54

**Output 2**

Suboptimal placement with modified length

- Actual placement
- Proppant mass placed (2 wing) lbm: 40000
- Proppant number, Nprop: 0.00050
- Dimensionless PI, Jdact: 0.191
- Dimensionless fracture cond, CfD: 0.20
- Half length, xf, ft: 43.7
- Propped width, w, inch: 0.76
- Post treatment pseudo skin factor, sf: -2.15
- Folds of increase of PI: 1.41

Table 1 – Major formation properties of frac&pack candidates of EI 354.

<table>
<thead>
<tr>
<th>Well</th>
<th>Reservoir type</th>
<th>Drainage radius (ft)</th>
<th>Gross pay (ft)</th>
<th>Net pay (ft)</th>
<th>Perforation interval (ft)</th>
<th>Perm (md)</th>
<th>Porosity</th>
<th>Young’s modulus (psi)</th>
<th>Poisson’s ratio</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>Oil</td>
<td>1000</td>
<td>67</td>
<td>44</td>
<td>15</td>
<td>712</td>
<td>0.28</td>
<td>5.4e5</td>
<td>0.35</td>
</tr>
<tr>
<td>B</td>
<td>Oil</td>
<td>1000</td>
<td>61</td>
<td>38</td>
<td>5</td>
<td>300</td>
<td>0.30</td>
<td>6.0e5</td>
<td>0.32</td>
</tr>
<tr>
<td>C</td>
<td>Oil</td>
<td>1000</td>
<td>90</td>
<td>41</td>
<td>10</td>
<td>80</td>
<td>0.30</td>
<td>5.0e5</td>
<td>0.30</td>
</tr>
<tr>
<td>D</td>
<td>Oil</td>
<td>1000</td>
<td>71</td>
<td>35</td>
<td>14</td>
<td>80</td>
<td>0.29</td>
<td>7e5</td>
<td>0.32</td>
</tr>
</tbody>
</table>

Although different fracture simulators may give different pumping schedules, the logical thinking and procedure described above is universal.
Table 2 – Results of Minifrac analyses.

<table>
<thead>
<tr>
<th>Well</th>
<th>Bkd rate (bbl/min)</th>
<th>P_{Ext} (psi)</th>
<th>P_c (psi)</th>
<th>T_c (min)</th>
<th>FG (psi/ft)</th>
<th>FE (%)</th>
<th>CL (ft/min^{0.5})</th>
<th>Radius (ft)</th>
<th>Minifrac (YF120L)</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>*</td>
<td>6207</td>
<td>16.3</td>
<td>0.84</td>
<td>55</td>
<td>0.0099</td>
<td>61</td>
<td>4703</td>
<td>4970 gals, 5.9 min</td>
</tr>
<tr>
<td>B</td>
<td>3.4</td>
<td>4378</td>
<td>3966</td>
<td>5.2</td>
<td>0.72</td>
<td>45</td>
<td>0.013</td>
<td>50</td>
<td>2966 gals, 4.2 min</td>
</tr>
<tr>
<td>C</td>
<td>*</td>
<td>4861</td>
<td>4.3</td>
<td>0.86</td>
<td>37</td>
<td>0.015</td>
<td>56</td>
<td>3898</td>
<td>4.6 min</td>
</tr>
<tr>
<td>D</td>
<td>*</td>
<td>6020</td>
<td>2.7</td>
<td>0.87</td>
<td>27</td>
<td>0.017</td>
<td>81</td>
<td>4911</td>
<td>5.8 min</td>
</tr>
</tbody>
</table>

* No stable pressure data are obtained from step rate test due to high fluid leakoff.

Table 3 – Stimulation design by service company.

<table>
<thead>
<tr>
<th>Well</th>
<th>Pump rate (bbl/min)</th>
<th>Pad volume (gals)</th>
<th>Total fluid (bbl)</th>
<th>Proppant mass (1000 lb)</th>
<th>Fracture length (ft)</th>
<th>Max width (in)</th>
<th>Total height (ft)</th>
<th>Proppant conc (lb/ft^3)</th>
<th>CID</th>
<th>Designed J_{D}</th>
<th>Pseudo skin S_r</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>20</td>
<td>4000</td>
<td>476</td>
<td>108</td>
<td>88</td>
<td>1.3</td>
<td>162</td>
<td>4.76</td>
<td>0.05</td>
<td>0.178</td>
<td>-1.76</td>
</tr>
<tr>
<td>B</td>
<td>18</td>
<td>1500</td>
<td>189</td>
<td>28.6</td>
<td>30</td>
<td>3.6</td>
<td>57</td>
<td>10.5</td>
<td>1.4</td>
<td>0.220</td>
<td>-2.95</td>
</tr>
<tr>
<td>C</td>
<td>20</td>
<td>6500</td>
<td>627</td>
<td>136</td>
<td>53</td>
<td>3.0</td>
<td>108</td>
<td>14.7</td>
<td>4.0</td>
<td>0.281</td>
<td>-3.84</td>
</tr>
<tr>
<td>D</td>
<td>20</td>
<td>8058</td>
<td>527</td>
<td>93</td>
<td>51</td>
<td>1.7</td>
<td>106</td>
<td>10.9</td>
<td>2.2</td>
<td>0.284</td>
<td>-3.88</td>
</tr>
</tbody>
</table>

Table 4 – Evaluation of treatment pressure match by using 3D fracture simulator.

<table>
<thead>
<tr>
<th>Well</th>
<th>Total fluid (bbl)</th>
<th>Proppant pumped (1000 lb)</th>
<th>Fracture length (ft)</th>
<th>Max width (in)</th>
<th>Total height (ft)</th>
<th>Proppant conc (lb/ft^3)</th>
<th>CID</th>
<th>After treated J_{D}</th>
<th>Pseudo skin S_r</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>380</td>
<td>57</td>
<td>75</td>
<td>0.78</td>
<td>132</td>
<td>3.6</td>
<td>0.03</td>
<td>0.170</td>
<td>-1.51</td>
</tr>
<tr>
<td>B</td>
<td>137</td>
<td>15</td>
<td>47</td>
<td>0.58</td>
<td>51</td>
<td>3.2</td>
<td>0.17</td>
<td>0.194</td>
<td>-2.23</td>
</tr>
<tr>
<td>C</td>
<td>703</td>
<td>58</td>
<td>42</td>
<td>1.3</td>
<td>149</td>
<td>5.9</td>
<td>2.0</td>
<td>0.255</td>
<td>-3.47</td>
</tr>
<tr>
<td>D</td>
<td>276</td>
<td>24</td>
<td>45</td>
<td>0.51</td>
<td>98</td>
<td>3.4</td>
<td>0.75</td>
<td>0.236</td>
<td>-3.16</td>
</tr>
</tbody>
</table>

Table 5 – Evaluation of treatment pressure slope analyses.

<table>
<thead>
<tr>
<th>Well</th>
<th>Proppant pumped (1000 lb)</th>
<th>Fracture extent (ft)</th>
<th>Average width (in)</th>
<th>Average APC (lb/ft^3)</th>
<th>Proppant in pay (%)</th>
<th>Nprop *</th>
<th>Penetration, Ix</th>
<th>CID</th>
<th>After treated J_{D}</th>
<th>After treated S_r</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>75.2</td>
<td>60</td>
<td>0.74</td>
<td>6.7</td>
<td>66</td>
<td>0.00093</td>
<td>0.0677</td>
<td>0.20</td>
<td>0.203</td>
<td>-2.4</td>
</tr>
<tr>
<td>B</td>
<td>14</td>
<td>35</td>
<td>0.41</td>
<td>3.6</td>
<td>62</td>
<td>0.00045</td>
<td>0.0395</td>
<td>0.29</td>
<td>0.193</td>
<td>-2.2</td>
</tr>
<tr>
<td>C</td>
<td>58</td>
<td>56</td>
<td>0.20</td>
<td>1.8</td>
<td>46</td>
<td>0.00048</td>
<td>0.0632</td>
<td>1.19</td>
<td>0.27</td>
<td>-3.7</td>
</tr>
<tr>
<td>D</td>
<td>17.7</td>
<td>13</td>
<td>3.72</td>
<td>33.3</td>
<td>49</td>
<td>0.0018</td>
<td>0.0147</td>
<td>8.57</td>
<td>0.224</td>
<td>-2.9</td>
</tr>
</tbody>
</table>

* Assuming frac height equals gross thickness
Fig. 1 – Production history for the studied area.

Fig. 2 – Dimensionless productivity index as a function of dimensionless fracture conductivity and proppant number (for $N_{prop} < 0.1$). Note that $N_{prop}$ is abbreviated as $N_p$ in the figure. The line $I_x=1$ corresponds to a fracture extending from boundary to boundary in the x-direction.
Fig. 3 – Dimensionless productivity index as a function of dimensionless fracture conductivity and proppant number (for \( N_{\text{prop}} > 0.1 \)). Note that \( N_{\text{prop}} \) is abbreviated as \( N_p \) in the figure. The line \( I_x = 1 \) corresponds to a fracture extending from boundary to boundary in the \( x \)-direction.

Fig. 4 – A typical frac\&pack treatment for EI area (well B).
Fig. 5 – The falloff test using 2% KCl brine for well B.

Fig. 6 – The falloff test using fracturing fluid for well B.

Fig. 7 – The Nolte-Smith plot for well B.

Fig. 8 – The pressure match using 3D fracture simulator for well B.
Fig. 9 – The fracture packed radius for well B.

Fig. 10 – The proppant and fracture width distribution for well B.

Fig. 11 – Folds of PI increase for the studied wells.

Fig. 12 – The pseudo skin effects for the studied wells.