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A Novel Approach to Identifying Refracturing Candidates and Executing Refracture Treatments in Multiple Zone Reservoirs

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Abstract

Refracture candidate selection and treatment execution has always presented four main challenges to the industry when multiple pay zones are involved. The first challenge is determining the underlying cause of the poor production performance (poor reservoir quality, an ineffective original stimulation treatment, or both). The second challenge is the identification of the specific zones with significant remaining reserves that have been poorly stimulated. The third challenge is determining the current reservoir pressure in all of the prospective refracture candidate zones. The fourth major challenge is selectively stimulating the target zones in the wellbore when there are existing perforations above the target zones.

The first and second challenges are addressed using the “Completion Efficiency” (CE) or “Recovery Factor” (RF) techniques discussed in SPE 90483.[1] These techniques use an integrated petrophysical, reservoir, and completion model to evaluate well and zone performance. The techniques has been employed on over 3000 zones to date in a wide variety of reservoirs with excellent results. The CE and RF analysis can be supplemented by rate-transient production decline analysis if adequate producing time has elapsed. The third challenge is addressed using selective zone buildup and/or injection tests to obtain reservoir pressure and permeability. The recommended technique uses a service rig and a low rate pump truck, tubing, packer, bridge plug, and a surface readout pressure gauge with downhole shutin. This technique has recently been employed on over 60 zones in the last two years in the Hugoton field in Kansas with excellent results. The fourth challenge is selectively isolating individual perforated intervals for the refracture treatments. The most efficient technique involves the use of openhole packer hardware set inside the cased hole. The openhole packer technology has been primarily deployed in horizontal openhole wellbores to date, however the hardware is readily adaptable to cased holes and has been used on a number of vertical cased holes to date (Table 1). The integration of these proven techniques (CE, RF, downhole shutin surface readout testing, and openhole packer hardware) provides the means to meet all of the main challenges of refracturing multiple zone wells. Field examples are provided to demonstrate the viability of the concept, and a methodology is proposed for “best practices” in the implementation of the techniques.

Introduction

Refracture treatments have been routinely used to improve well productivity in the oil and gas industry in a wide variety of reservoirs worldwide. A literature search on the topic yields numerous papers that discuss mostly successful applications of refracturing technology.[2,3] In almost all of these studies the prior treatments that were applied involved outdated technology such as low strength proppant selection in high closure stress reservoirs, low proppant volumes where higher conductivity was needed, slickwater treatments where conventional gelled treatments damaged the reservoir and didn’t create fracture complexity, etc. In most of these cases the application of more modern “best practices” proppant type and proppant volumes for a field resulted in improved productivity. Very few studies addressed the situation where “best practices” fluids and proppants were applied and the result was still a low CE or RF. The CE studies done to date have identified significant remaining mobile hydrocarbons in numerous zones in a wide variety of reservoirs even with the application of “best practices” fluids and proppants-low recovery factors and completion efficiencies are the rule and not the exception. Three recent projects were done on fields where the productive areas of the field were fully drilled up on 40 acre spacing (and the operators had no plans to file for 20 acre spacing). Field 1 had an average recovery factor (EUR/Current Gas in Place) of 31%, with estimated ultimate recovery of 19.2 BCF in a field with 62.1 BCF gas in place. Field 2 had the same development status (no additional proration units available without downspacing) and the estimated ultimate recovery was estimated at 41 BCF. The volumetric analysis of the developed area indicated 136.6 BCF gas in place or a 30% expected recovery factor.

Field 3 was an example of “best practices” vs recovery factors. The operator had changed their fluid program three times and suspected the new program was not performing as well as the old ones were. The CE study indicated that this was indeed correct, as the new program using polymer free surfactants averaged 15% CE and a 35% recovery factor. As this was only a 10 well subset this would not have been bad in itself since there were 56 wells in the study. The bad news was that the second most recent fluid system (Borate XLG) had identical performance metrics to the surfactant systems and there were 28 wells fraced with that fluid. The highest performing group of wells used CO2 foams or CO2 assists and had average recovery factors close to 100%. The average gas left in the ground by the last two fluid systems was over 0.5 BCF per well. Without refracturing or downspacing these reserves and the reserves left behind in the first two fields will most likely not be recovered.

Completion Efficiency and Recovery Factor Models

The “Completion Efficiency” concept (SPE 90483) has been applied on over 3000 zones in a wide variety of reservoirs since 2003. In these studies numerous zones have been identified with low completion efficiency, low recovery factors, and extremely short effective producing propped fracture lengths. Development of a CE model involves a detailed analysis of pre-frac flow tests to calibrate the log derived permeability to flow test permeability (Figs. 1 and 2). Reservoir pressure is estimated from pre-frac pump-in test data tied to measured reservoir pressure (Figs. 3 and 4). With reasonable permeability and pressure data estimates of flow rate with a range of effective propped fracture lengths is relatively straightforward (Fig. 5). The CE value is the ratio of actual flow rate to an estimate of flow rate from the minimum acceptable fracture geometry for the given proration unit to adequate to drain the proration unit. Numerous simulations have been done using the Net Present Value concept to determine the optimum frac half length, however in virtually all cases where permeability is less than 0.1 md the length equals at least 90% of the distance to the drainage unit boundary. For a 40 acre proration unit the minimum acceptable propped fracture length is 600 ft, and if infinite conductivity is desired the conductivity should be at least 200 md-ft. If permeability is higher a negative skin target replaces the 90% rule. An apparent effective propped fracture length can also be estimated from the process as well if the effective length conductivity is assumed to be infinite.

If sufficient time has elapsed following the original completion decline curve analysis can be done to estimate effective frac length, permeability, and drainage area.[4] In two large completion efficiency projects decline curve analysis was done in parallel with the completion efficiency analysis. In both projects the two techniques identified the same wells as poor performers and effective producing frac lengths were very similar when the decline curve analysis assumed a permeability similar to the well test calibrated permeability from the CE process. The CE process log derived permeability has agreed very well with pre-frac well test permeability in all studies to date. If the decline curve analysis assumed permeability is constrained by the CE model permeability a higher confidence factor can be assigned to the decline curve effective producing fracture half length.

A third technique that supplements the CE analysis is a comparison of estimated ultimate recovery to volumetric reserves (recovery factor) (Fig. 6). In all studies to date high completion efficiencies correlated to high recovery factors and the inverse was true for low completion efficiencies (Fig 7). The exceptions were most likely due to geological anomalies or mechanical problems during production. EUR can be estimated from decline curve analysis, with rate-cumulative analysis most frequently used technique. P/Z analysis can be used as well, however the majority of wells in the studies done to date have only one bottomhole pressure measurement. This is most often taken when the wells are initially completed. A key component of the CE process is developing a correlation between measured reservoir pressure and fracture closure stress (Figs. 3 and 4). In many cases an excellent correlation can be obtained between fracture gradient and reservoir pressure as well. If a calibrated reservoir pressure to fracture treatment pressure model is available the pre-frac pump-in test from the refracture treatment can be used to obtain the second reservoir pressure for the P/Z analysis.

Completion Efficiency Study Results

In one South Texas Wilcox and Vicksburg study the average completion efficiency was only 30% with average effective fracture lengths of less than 70 feet. In all of the frac stages evaluated the operator used either Bauxite, resin coated Bauxite, or high strength ceramic proppants and pumped adequate volumes to create 600 to 900 ft of propped fracture length. The majority of the low performing zones were cases where multiple zones were fracture treated in single frac stages and the fracture treatments did not effectively treat all zones that were perforated. The operator assumed the fracture treatments were “reserve seeking missiles” instead of fluids and proppants with rather limited intelligence that seek the path of least resistance. Most of these poor performing frac stages used the correct proppant types and volumes, with the poor performance related primarily to the treatment not effectively stimulating all of the zones in the frac stage. The average CE for single perforated interval frac stages was 69%, while multiple perforated intervals averaged 35%. This corresponds to an effective propped length of 259 ft for single perforated interval frac stages and 99 ft for multiple perforated interval frac stages. Within the multiple perforated interval stages the average CE for the highest flow rate perforation set was 67% (249 ft effective frac half length) or very similar to the single perforated interval stage. The lower performing perforation sets in the multiple perforated interval stages averaged 14% (1 ft effective frac length or skin removal). A summary of this analysis can be seen in Figs. 8 and 9.

If the well is refractured with the same multiple entry points the second treatment will most likely follow the path of the original treatment. If higher pressure zones were not treated effectively in the original treatment they will almost certainly not be treated the second time as the pressures in the lower pressure zones should be even lower due to depletion. Both treatments went where the gas "was" rather than where the gas "is." In most cases the results of the studies have been to improve productivity on future completions with revised "best practices." The original zones with short effective frac lengths have largely been ignored as re-completion targets for a variety of reasons, with the main reason being the mechanical isolation of zones among existing perforations. . This paper will demonstrate that poor performing zones in multiple zone completions can be identified, isolated, and effectively treated to improve well productivity.

While ineffective stimulation of multiple perforated intervals is the "low hanging fruit" for refracturing opportunities, there were several other causes of poor performance observed in the CE process that can result in equally attractive refracturing opportunities. Zones with long perforated intervals (over 15-20 ft) had lower completion efficiencies once the wellbore deviation exceeded 2 degrees. Zones with drawdown over 50% of reservoir pressure had lower completion efficiencies than zones with less drawdown. Zones that flowed gas between stages and were subsequently shut in to frac subsequent stages had significantly lower completion efficiencies than zones with no flowback between frac stages. Lastly, when zones that have aqueous phase trapping tendencies are fracced with water based fluids the CE averaged 15%. In all of these cases the fluid and proppant selection was in accordance with current "best practices," with Bauxite or ISP pumped with Zirconium or Borate crosslinked fluids and proppant volumes were sufficient to achieve at least an 800 ft propped fracture (average of 14,000 lb/ft of pay and 550,000 lb of proppant per stage in one field with a 39% CE average (113 ft effective propped frac length). The completion efficiency studies to date strongly suggest that current completion practices have resulted in numerous opportunities for improving production through refracturing. A systematic methodology is proposed to validate the presence of remaining mobile hydrocarbons in refrac candidate wells and to economically recover these hydrocarbons.

Refracture Candidate Well Identification

The CE and RF techniques are recommended to identify potential refracturing candidate wells and zones from flow rate and production log data. The recommended work flow for candidate evaluation and refrac treatment execution is:

1. Collect all available data for candidate wells (openhole log data, completion diagrams, production logs, production data)
2. If no calibrated CE model is available develop model using procedures in SPE 90483 (tie basic log data to core (Porosity, Vclay, and Sw), tie log derived permeability to flow tests, pre-frac pump-in test data to measured reservoir pressures)
3. Estimate initital reservoir pressure for each frac stage from pre-frac pump-in test data
4. Estimate net pay thickness, porosity, Sw, and effective permeability for completed intervals
5. Estimate volumetric reserves for proration unit and estimate RF from EUR from decline or rate/cumulative analysis
6. Estimate flow rate for minimum acceptable frac geometry for each frac stage using petrophysical model outputs, reservoir pressure, and observed drawdown.
7. Compare actual production to estimated production from minimum acceptable frac geometry (CE)
8. If well has low CE and RF either analyze existing production log data or run new production log
9. Run in hole with tubing, packer, bridge plug, and downhole SI surface readout gauges and test all prospective zones.
10. Determine refrac target zones from petrophysical analysis and updated pressure data
11. Design wellbore configuration for openhole packer and frac port placement
12. RIH with openhole packer assembly, fracture treat each target zone

Refracture Candidate Zone Pressure Measurements

Once the candidate zones are identified using the completion efficiency process, an estimate of current reservoir pressure is needed to validate the remaining gas in place if significant volumes of gas have been produced. For zones with extremely low initial completion efficiency and low cumulative production this step is optional unless a limited reservoir is suspected. A technique that has been used successfully on over 60 zones to date uses a combination of a bridge plug, packer, and downhole shutin surface readout gauge assembly. Each zone is isolated with the packer and bridge plug and the wellbore between the two is isolated with a downhole shutin tool placed in a nipple in the tubing below the bridge plug (Fig. 10). A static buildup can then be obtained by dropping the gauge and probe into the nipple and shutting in the wellbore between the packer and bridge plug (Fig. 11). Following the stabilized pressure measurement, the zone can be tested with an injection/falloff test to obtain closure stress, a second estimate of reservoir pressure, and in some cases permeability. The second reservoir pressure estimate can be obtained from three sources. The first is an extrapolated pressure from a Horner analysis (Fig. 12). The second is an extrapolated pressure from a Nolte FR analysis that also provides an estimate of permeability-thickness (Fig. 13). In both the Horner and Nolte FR analysis the diagnostic plot should indicate that the zone is in radial flow (Fig 14). A clear indication of this is not always available, especially when large fluid volumes are injected or shutin times are limited. A third technique that is available is an empirical correlation between closure stress and reservoir pressure developed from zones where both are available (Figures 3 and 4). This correlation generally has a 90 percent or better correlation coefficient since most pay zones in a reservoir have a similar Poisson's ratio, overburden gradient, and tectonic components. The primary driver in this case for differences in closure stress is reservoir pressure. This technique is the most common means of determining initial reservoir pressure for the completion efficiency and recovery factor techniques discussed above. It can be used to estimate current reservoir pressures as well using the downhole shutin tool.

A second mechanical configuration for the static pressure measurement involves the use of a memory gauge suspended between two bridge plugs. A limitation of this technique is there is no indication that the static pressure is stabilized prior to pulling the gauge. A second limitation is that the real time surface readout injection testing discussed in the previous paragraph cannot be done. The primary advantage of the memory gauge technique is lower cost as the surface readout technique requires an electric line truck, tubing, and a pulling unit. A second advantage is for cases when the reservoir pressure is significantly below hydrostatic pressure and the zone is relatively deep. The current downhole shutin tool has been used primarily on wells less than 5000 ft deep where the differential between the full fluid column above the gauge and reservoir pressure is within the limits of the wireline pull capability. Two options that are under consideration are an equalization mechanism that can release the hydrostatic column prior to pulling the gauge out of the nipple. A second is a gauge probe with a smaller cross sectional area that would reduce the differential as well. These are still on the drawing board, however, so a memory based system may be required for deeper wells.

Refracture Candidate Zone Isolation

Once the target zones have been identified there may be open intervals above test zones. Industry experience fracturing below packers with tubing in the hole has not been positive, with numerous instances of mechanical problems from proppant re-entering the wellbore through perforations above the packer and packers becoming stuck. In two major refracturing projects in the Hugoton field operators tried refracturing below packers with open perforations above the packer and the practice was discontinued early in the program. Over 200 wells were refractured in the two programs all but a select few had open perforations above packers.

If the target zone is below existing perforations and the perforations cannot be sealed off effectively coiled tubing can be used to fracture treat the zone. The treatment must be done inside the tubing, however, and in relatively deep tight gas wells the treatment rate may be limited due to excessive tubular friction pressures. In several of the completion efficiency studies done to date “best practices” have involved treating a single relatively short perforated interval in each frac stage. An example is the study presented in SPE 90483 where the best performing zones had single entry points with less than 15 feet of perforated interval. In many cases high treatment rates are required to provide adequate rate per interval in multiple perforated interval frac stages. If there is only one interval to treat the rate requirements may be reduced and coil may be an option even in reservoirs that have historically been treated with higher rates.

In many cases the most effective way to refracture zones below existing perforation is to mechanically isolate the open perforations and re-perforate the zones to be refractured. The two primary techniques recommended to accomplish this are openhole packer hardware run outside of tubing and inside the existing casing and metal liners inside the existing casing that effectively results in a new wellbore.

Openhole Packer Hardware

These were initially developed for treating multiple zones in horizontal open holes, with the first systems commercially deployed in 2002.[6,7,8] The published advantages of the system was lower overall cost from eliminating the cost of casing, cementing, and perforations and reducing total completion rig time. While the applications to date have been primarily in open holes, the systems can be run in cased hole as well. One of the major vendors for the openhole packer systems ran 750 jobs in 2008, and ten (10) of these were in cased hole for refrac treatments. Since 2005 they have run 22 cased hole refracs with the system. A list of formations that have been treated with their system is found in Table 1, along with a list from Vendor B. The advantage of the technology in the refracturing process is the ability to isolate multiple perforated intervals, fracture treat each interval, then commingle the intervals. Previously stimulated zones that were not refractured can be re-accessed using ports that can be opened and closed with slickline or coiled tubing. A complete discussion of the technology is found in refs 6 and 7. Diagrams of commercially available systems are shown in Figs. 15 and 21. Fig. 15 is a system that has mechanical packers and Fig. 21 uses swellable packers.

In addition to the refracturing of producing wells, the openhole packer technology has potential applications in new wells. All of the potential pay zones could be perforated in advance and tested using the packer, bridge plug, and downhole shutin tool assembly discussed earlier. Once the testing is done the fracture treatment stages can be determined from the integration of the log derived net pay and the pressure test data. If a perforated interval is depleted the openhole packer assembly can be set to avoid stimulating the depleted interval. The stages that are selected for completion can often be completed in a single day depending on the number of stages to be treated (up to 7 stages in 4.5 inch casing and more stages for larger tubular sizes). A plot of number of stages per job from Vendor A is shown in Fig. 17, with the formations deployed in shown in Fig. 18. While these are primarily horizontal well deployments, there is virtually no difference between the horizontal openhole system and the vertical cased hole system. The plot shows that operators are going to more stages with these systems and that these systems have the potential to maximize the number of single perforated interval frac stages (a universally consistent “best practice” from all of the Completion Efficiency studies to date. The implications for refracs are significant-nine stages or more pumped in one to two days with existing perforations isolated is a quantum leap from the packer and bridge plug operations in the past that were used to frac below existing perfs (with mixed success).

Metal Liners Inside Existing Casing

Several systems are available to isolate existing perforations so selected perforations can be isolated or new perforations can be added for the refracturing treatment.[9,10,11] The latest versions of liners involve the use of swellable or expandable packers on the outside of the liner or a metal to metal seal at the ends of the liner segments to isolate existing perforations. The completion can then be done conventionally with perforations, composite plugs, or proppant plugs in the target zones for refracturing. Diagrams of commercially available hardware are provided in Figs. 22 and 23. The advantage of the metal liners is a larger inside diameter to treat through. In a request for proposal for a 4.5 inch 11.6 lb P110 casing refrac the maximum tubular size for Vendors A and B with mechanical openhole packers was 2 7/8 OD tubing (2.441 ID). The metal liner vendors can provide a 2.992 inch ID with one system (Ref 10) and 2.93 inch ID with the second system evaluated (Ref. 11).

Economic Evaluation

The vendors discussed above were all asked for proposals to use their systems on a two stage refracture treatment on a 10800 ft tight gas well. The well had 46 sets of perforations open over a 3350 ft gross interval inside 4.5 inch 11.6 lb P-110 casing. There were two sets of perforations proposed for refracs in the lower portion of the well. All submitted approximate cost estimates to help determine the overall economics of the refrac process. The operator also worked up an approximate cost for the service rig, surface rentals, frac stimulation costs, etc. to complete the comparison. Vendor A proposed the openhole packer hardware in Fig. 15 with the specific line items shown in Fig. 16. Vendor B proposed the openhole packer hardware detailed in Figs. 19 and 20. Vendor C proposed the swellable packer hardware shown in Fig.21, vendor D proposed the metal liner option in Fig. 22, and Vendor E proposed the metal liner option shown in Fig. 23. The total estimated costs for the refracs using the mechanical packer systems are $276,800, the swellable packer system $307,000, and the lowest cost liner system was $267,000. There were several options for the liner systems that were more expensive, and in other applications these may be of benefit. The details for these systems can be obtained from the vendors listed in the references.

With the costs in hand, the overall completion efficiency process can provide the basic inputs to estimate expected flow rates by zone and recoverable reserves. If there are analog completions in the field with a range of recovery factors and completion efficiencies this range can provide the expected production results from a refracture treatment executed using “best practices.” The CE model results can provide an estimate of potential cash flows. The costs of the procedure can be compared to the expected cash flows to determine if the refracturing project is viable. An example from a recent refracturing study is shown in Table 2. The previous operator utilized a “shotgun” perforating strategy that had 42 entry points over three frac stages. The new operator commissioned a CE study to determine “best practices” and evaluate potential refracturing candidates. The CE study indicated two major zones had low completion efficiencies, with one 639 MMCF volumetric reserve zone with a 7% CE and a second 1.13 BCF zone with a 2% CE. Apparent frac lengths in the two zones were less than 10 ft. A two stage refracture treatment focusing on these two zones was proposed and an economic analysis was requested by the operator.

To forecast the results a range of possible outcomes is recommended. For Stage 1 with the current CE of 7% the average CE from the study was 36% for all wells in the study, with a range of 4% to 98%. The previous operator perforated nine separate intervals in three groups of perforations for the original stage. A distribution of volumetric reserves and completion efficiencies for Zone A is shown in Table 3. Zone A Upper received the best stimulation, producing 78 MCFD with a CE of over 100% from volumetric reserves of 16.8 MMCF. Zone A Middle received the second best stimulation with a CE of 32% from volumetric reserves of 229 MMCF. Zone A Lower received the poorest stimulation with a CE of 7% from volumetric reserves of 639 MMCF. The target for the refrac is Zone A Lower. The average CE of 36% is the P50 case for the treatment, even though several improvements have been made in “best practices” as a result of the study and better than average results are expected. A CE of 100% with a 600 ft effective propped fracture length should result in a 1057 MCFD initial producing rate, and 36% of this is 412 MCFD.

For Zone B, the reservoir properties are shown in Table 3. For Stage 2 the average CE from the study was 20% for all wells completed in Zone B lower alone in the study, with a range of 2% to 39%. The 20% CE was used as the P50 for the analysis even though better results are expected due to the “best practices” developments. A 100% CE would result in a 1912 MCFD initial rate, and 20% of that would be 382 MCFD. This would result in a total expected initial flow rate of 795 MCFD from the refrac treatment. The proposed openhole packer configuration is shown in Figures 15 and 16. There are five ports recommended for the packer system, with one inbetween the stages across from Zone A middle that would be opened after both fracs and two above the second stage top packer to capture oil and gas from the original perforations. The current rate from all zones is 37 MCFD and 1.3 BOPD, however these are not included in the economic analysis.

Figures 24 and 25 have comparisons of the economics for the refracturing project. Since the costs were so similar a $300,000 cost was estimated for all three options. For the decline rate an average was taken for the first year decline in the field followed by a 2% monthly decline after the first year (see spreadsheet column 2). Two passes were made at $3.00 and $4.00 gas to cover the variable with the greatest concern. At $4.00 gas the refrac should pay out in 10 months, have a payout ratio of 3.21 to 1, and an IRR of 94%. At $3.00 gas the payout goes out to 18 months with a payout ratio of 2.26 to 1 and an

IRR of 53%. The offset completion efficiency benchmark is rather conservative as it does not incorporate any “best practices” learnings from the CE study. The 36% CE for the first stage and 20% CE for the second stage should increase with the proposed changes to the treatment design. In SPE 90483 the zones that used “best practices” completion designs averaged 67% completion efficiency. If that analog is used the initial rate would increase to 1989 MCFD. At $3.00 gas and this initial rate payout occurs in 4 months and there is a 6.25 to 1 payout multiple and IRR of 252%. If the operator adds frac stages and upgrades the proppant to a higher conductivity premium ISP and well cost increases to $500,000 with this scenario payout is 8 months and the multiple is 3.75 to 1 with a 115% IRR. All of these potential scenarios should provide acceptable economics even in the current low gas price environment.

Conclusions

A flow chart to summarize the process is shown in Fig. 26. The completion efficiency technique is a powerful tool to evaluate potential wells and zones for refracturing. Once the zones are identified, selective zonal pressure tests can be run to refine the estimate of recoverable gas reserves. The target zones can be isolated with commercially available openhole packers or expandable liners and the treatments executed normally. The completion efficiency technique provides a solid basis for economic analysis of the treatment to determine if the project is viable. The technique provides reasonable estimates of potential deliverability that reduces the risk of selecting a poor candidate for refracturing. In the current economic environment of low natural gas prices the refracturing optimization process described in this paper has the potential to provide superior rates of return to new well drilling with minimal risk.

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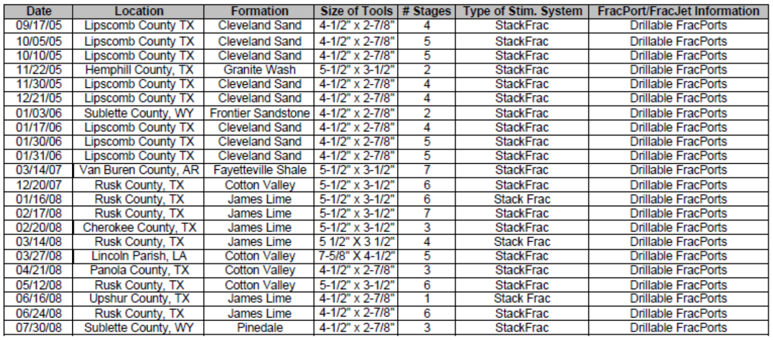
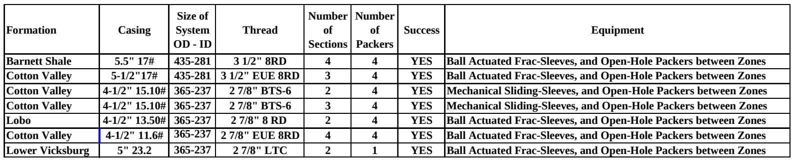


Date	Location	Formation	Size of Tools	# Stages	Type of Stim. System	FracPort/FracJet Information
09/17/05	Lipscomb County TX	Cleveland Sand	4-1/2" x 2-7/8"	4	StackFrac	Drillable FracPorts
10/05/05	Lipscomb County TX	Cleveland Sand	4-1/2" x 2-7/8"	5	StackFrac	Drillable FracPorts
10/10/05	Lipscomb County TX	Cleveland Sand	4-1/2" x 2-7/8"	5	StackFrac	Drillable FracPorts
11/22/05	Hemphill County, TX	Granite Wash	5-1/2" x 3-1/2"	2	StackFrac	Drillable FracPorts
11/30/05	Lipscomb County TX	Cleveland Sand	4-1/2" x 2-7/8"	4	StackFrac	Drillable FracPorts
12/21/05	Lipscomb County TX	Cleveland Sand	4-1/2" x 2-7/8"	4	StackFrac	Drillable FracPorts
01/03/06	Sublette County, WY	Frontier Sandstone	4-1/2" x 2-7/8"	2	StackFrac	Drillable FracPorts
01/17/06	Lipscomb County TX	Cleveland Sand	4-1/2" x 2-7/8"	4	StackFrac	Drillable FracPorts
01/30/06	Lipscomb County TX	Cleveland Sand	4-1/2" x 2-7/8"	5	StackFrac	Drillable FracPorts
01/31/06	Lipscomb County TX	Cleveland Sand	4-1/2" x 2-7/8"	5	StackFrac	Drillable FracPorts
03/14/07	Van Buren County, AR	Fayetteville Shale	5-1/2" x 3-1/2"	7	StackFrac	Drillable FracPorts
12/20/07	Rusk County, TX	Cotton Valley	5-1/2" x 3-1/2"	6	StackFrac	Drillable FracPorts
01/16/08	Rusk County, TX	James Lime	5-1/2" x 3-1/2"	6	Stack Frac	Drillable FracPorts
02/17/08	Rusk County, TX	James Lime	5-1/2" x 3-1/2"	7	StackFrac	Drillable FracPorts
02/20/08	Cherokee County, TX	James Lime	5-1/2" x 3-1/2"	3	StackFrac	Drillable FracPorts
03/14/08	Rusk County, TX	James Lime	5 1/2" X 3 1/2"	4	Stack Frac	Drillable FracPorts
03/27/08	Lincoln Parish, LA	Cotton Valley	7-5/8" X 4-1/2"	5	StackFrac	Drillable FracPorts
04/21/08	Panola County, TX	Cotton Valley	4-1/2" x 2-7/8"	3	StackFrac	Drillable FracPorts
05/12/08	Rusk County, TX	Cotton Valley	5-1/2" x 3-1/2"	6	StackFrac	Drillable FracPorts
06/16/08	Upshur County, TX	James Lime	4-1/2" x 2-7/8"	1	Stack Frac	Drillable FracPorts
06/24/08	Rusk County, TX	James Lime	4-1/2" x 2-7/8"	6	StackFrac	Drillable FracPorts
07/30/08	Sublette County, WY	Pinedale	4-1/2" x 2-7/8"	3	StackFrac	Drillable FracPorts

Vendor A



Formation	Casing	Size of System OD - ID	Thread	Number of Sections	Number of Packers	Success	Equipment
Barnett Shale	5.5" 17#	435-281	3 1/2" 8RD	4	4	YES	Ball Actuated Frac-Sleeves, and Open-Hole Packers between Zones
Cotton Valley	5-1/2"17#	435-281	3 1/2" EUE 8RD	3	4	YES	Ball Actuated Frac-Sleeves, and Open-Hole Packers between Zones
Cotton Valley	4-1/2" 15.10#	365-237	2 7/8" BTS-6	2	4	YES	Mechanical Sliding-Sleeves, and Open-Hole Packers between Zones
Cotton Valley	4-1/2" 15.10#	365-237	2 7/8" BTS-6	3	4	YES	Mechanical Sliding-Sleeves, and Open-Hole Packers between Zones
Lobo	4-1/2" 13.50#	365-237	2 7/8" 8 RD	2	4	YES	Ball Actuated Frac-Sleeves, and Open-Hole Packers between Zones
Cotton Valley	4-1/2" 11.6#	365-237	2 7/8" EUE 8RD	4	4	YES	Ball Actuated Frac-Sleeves, and Open-Hole Packers between Zones
Lower Vicksburg	5" 23.2	365-237	2 7/8" LTC	2	1	YES	Ball Actuated Frac-Sleeves, and Open-Hole Packers between Zones

Vendor B

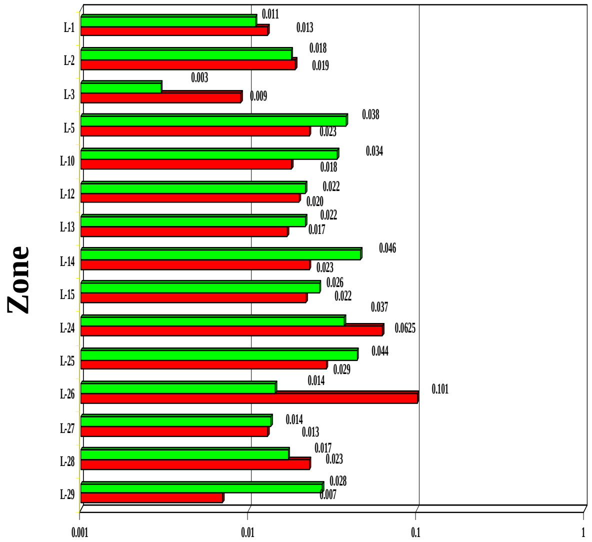
Table 1: Openhole Packer Vertical Well Refracturing Treatments through 7/08-Two Major Vendors

							FG	Res	Flow	0 Skin	600 XF	PLT	PLT		App	40	
Zone	Top	Base	H	Porosity	Sw	Perm	PPG	psi	Days	MCFD	MCFD	Gas	Water	CE	Xf	Ac GIP	% GIP
A Upper	10324.5	10333	2	0.061	0.522	0.001	0.406	4191	30	1	12	78	0	650%	600	16,831	2%
A Middle	10410	10434	16	0.050	0.261	0.007	0.406	4229	30	24	326	105	13	32%	130	228,661	26%
A Lower	10508.5	10570.5	33.5	0.073	0.376	0.013	0.45	4729	30	91	1057	69	13	7%	0	639,234	72%
										116	1395	252	26	18%		884,727	100%

Table 2: Reservoir Properties Refracturing Candidate Well Zone A

							FG	Res	Flow	0 Skin	600 XF	PLT	PLT		App	40	
Zone	Top	Base	H	Porosity	Sw	Perm	PPG	psi	Days	MCFD	MCFD	Gas	Water	CE	Xf	Ac GIP	% GIP
B Upper	9920.5	10069	14.5	0.045	0.309	0.003	0.325	4464	30	10	191	4	0	2%	0	178,819	14%
B Lower	10125.5	10243	62.5	0.068	0.344	0.017	0.325	4556	30	203	1912	32	0	2%	0	1,135,189	86%
										213	2103	36	0	2%		1,314,009	100%

Table 3: Reservoir Properties Refracturing Candidate Well Zone B



CE Model Perm Red
Well Test Perm Green

Median Value Comparison
CE Model 0.020 md
Well Test 0.022 md

Fig. 1: Permeability from CE Model vs Well Tests (Wilcox)

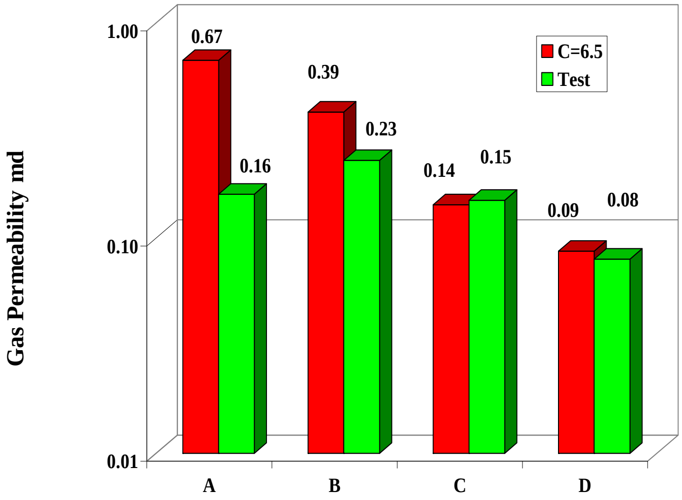


Fig. 2: Permeability from CE Model vs Well Tests (Vicksburg)
Well A was a multiple zone well test

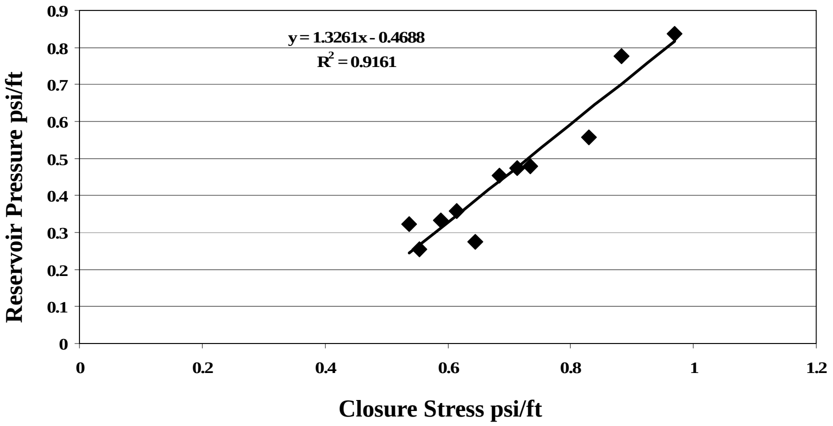


Fig. 3: Measured Reservoir Pressure vs Frac Closure Pressure

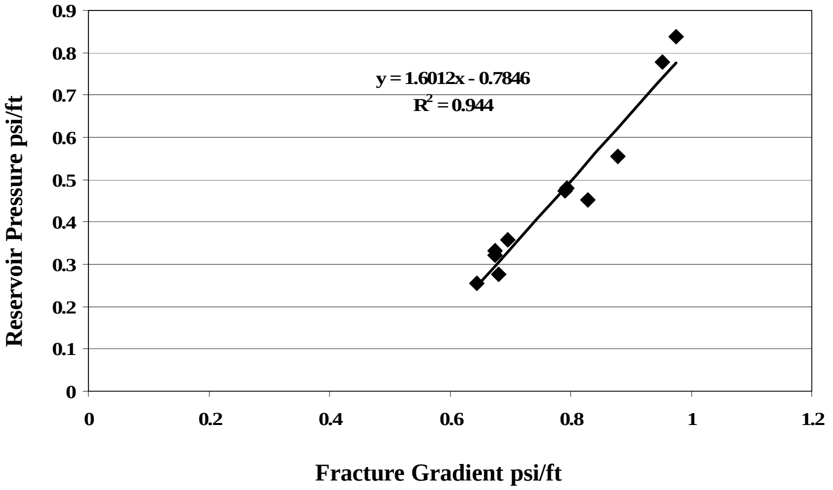


Fig. 4: Measured Reservoir Pressure vs Frac Gradient

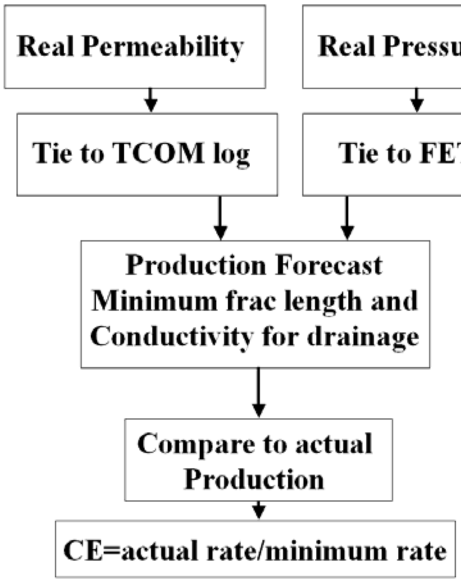


Fig. 5: CE Process Flow Chart

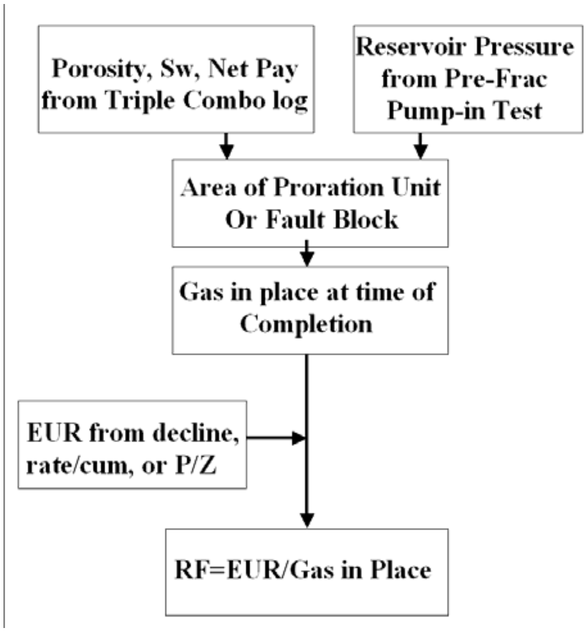


Fig. 6: Recovery Factor Process Flow Chart

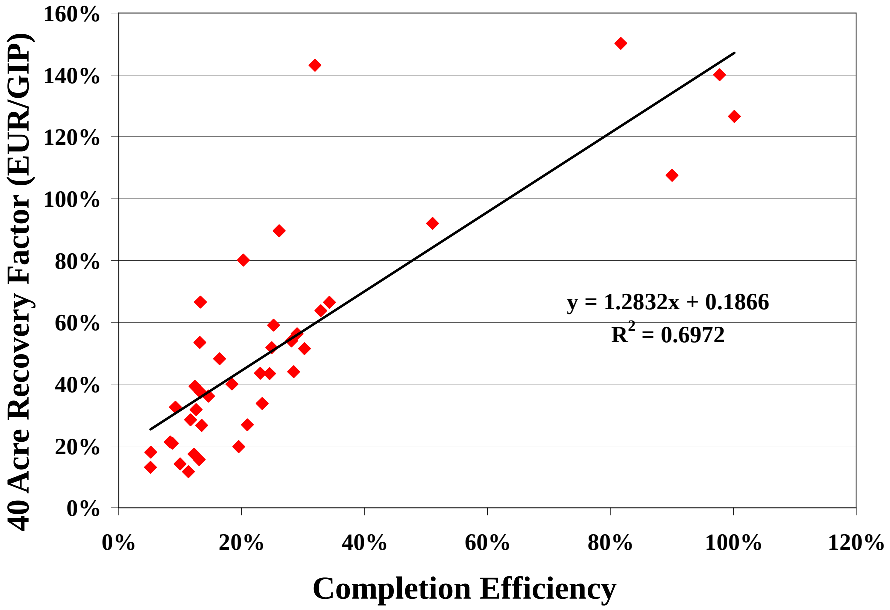


Fig. 7: CE vs Recovery Factor Example

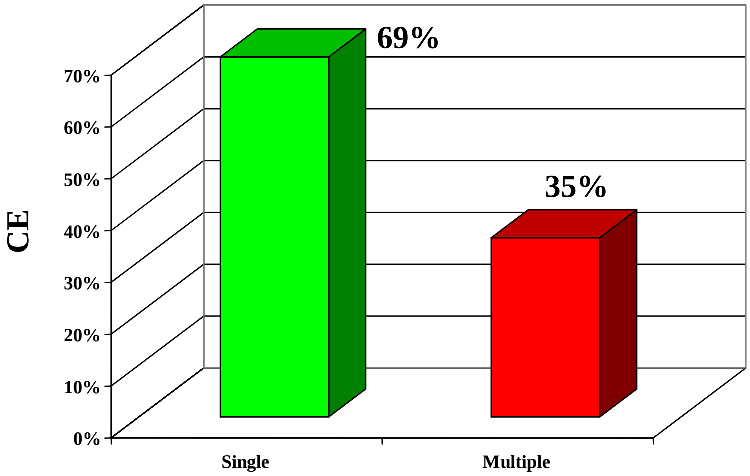


Fig. 8: Single Perforated Interval Stage CE vs Multiple Intervals

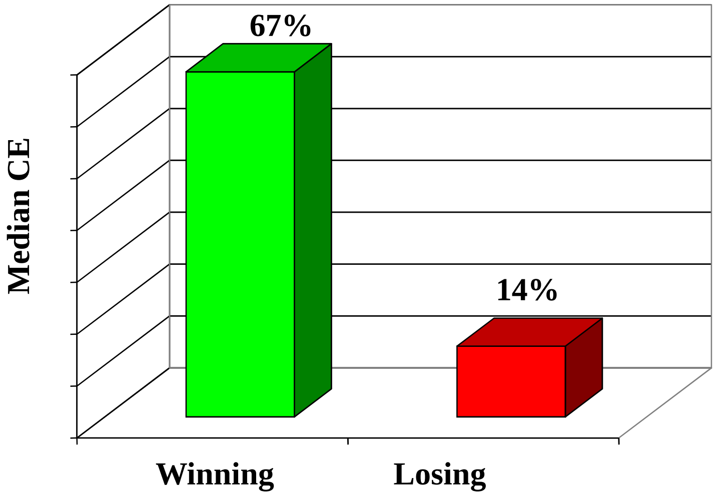


Fig. 9: Top flow rate zone vs remaining zones CE One zone behaves like single perforated interval Remaining zones skin removal only

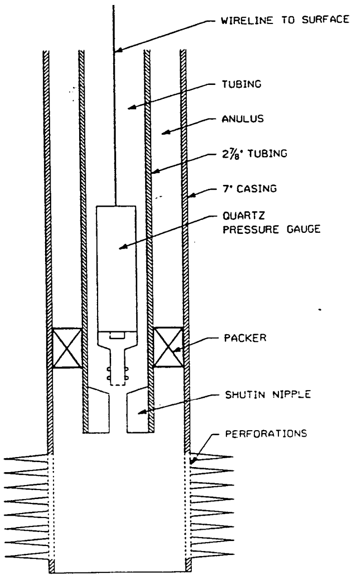


Fig. 10: Downhole shutin surface readout hardware

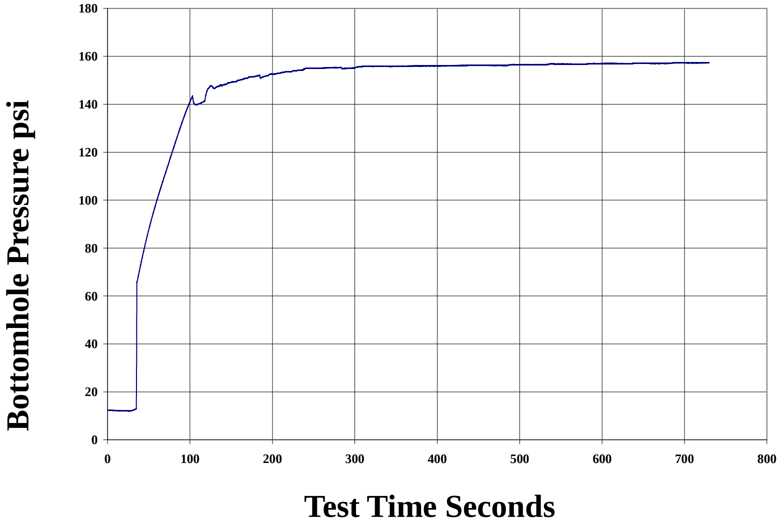


Fig. 11: Static buildup pressure using downhole shutin

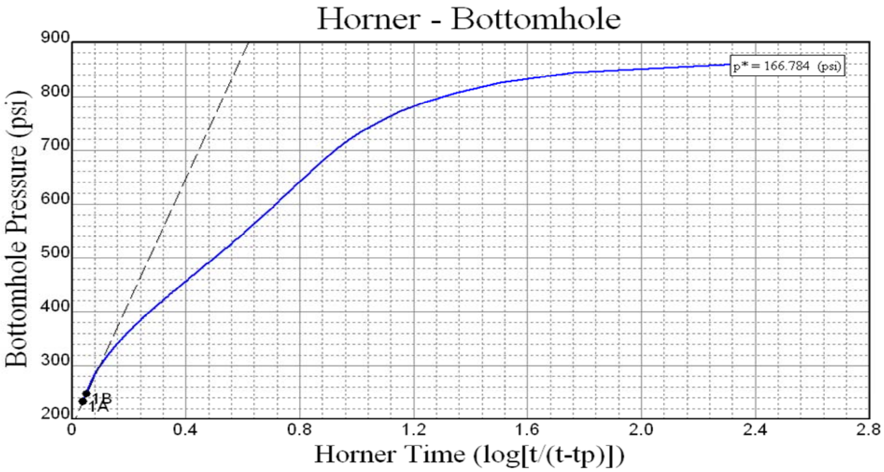


Fig. 12: Horner Extrapolated Reservoir Pressure

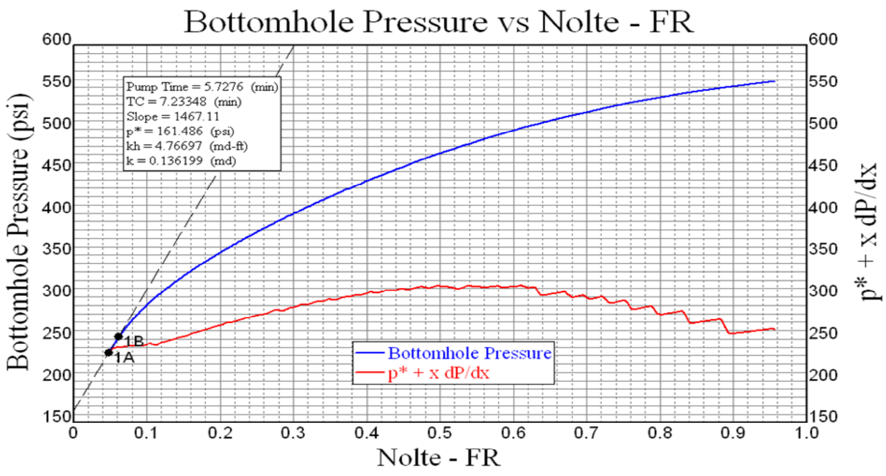


Fig. 13: After Closure Reservoir Pressure and Permeability

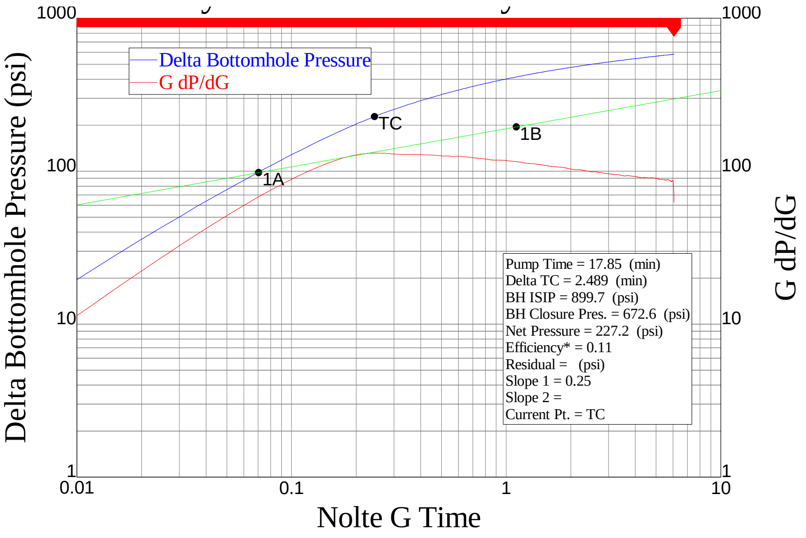


Fig. 14: Log-log diagnostic plot

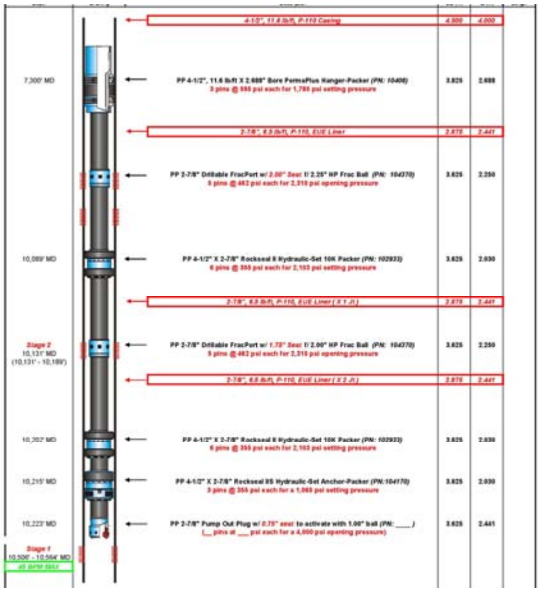
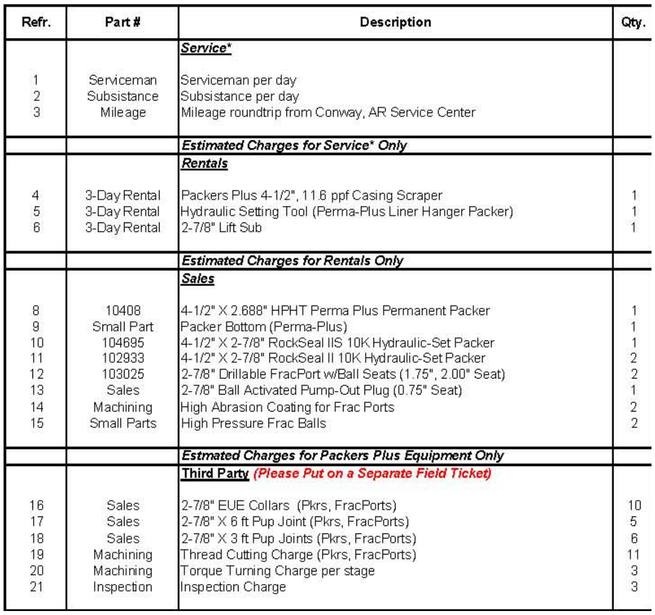
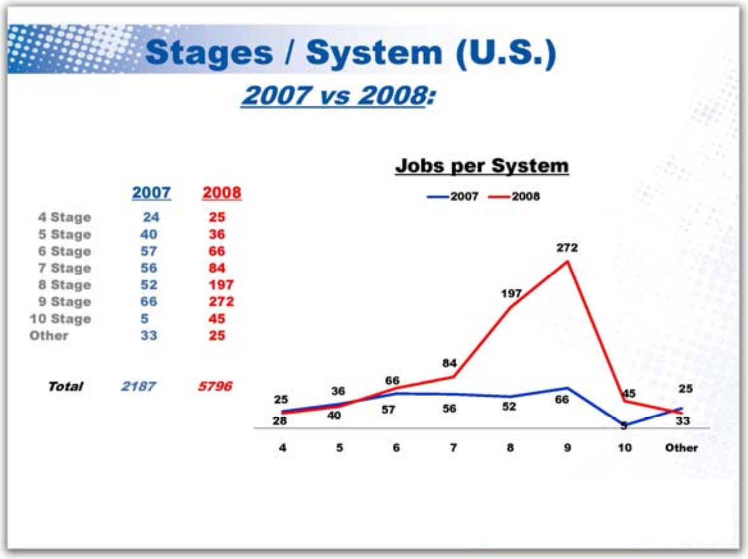


Fig. 15: Mechanical packer assembly for two stage refrac Vendor A



Refr.	Part #	Description	Qty.
		Service*	
1	Serviceman	Serviceman per day	
2	Subsistance	Subsistance per day	
3	Mileage	Mileage roundtrip from Conway, AR Service Center	
		Estimated Charges for Service* Only	
		Rentals	
4	3-Day Rental	Packers Plus 4-1/2", 11.6 ppf Casing Scraper	1
5	3-Day Rental	Hydraulic Setting Tool (Perma-Plus Liner Hanger Packer)	1
6	3-Day Rental	2-7/8" Lift Sub	1
		Estimated Charges for Rentals Only	
		Sales	
8	10408	4-1/2" X 2.688" HPHT Perma Plus Permanent Packer	1
9	Small Part	Packer Bottom (Perma-Plus)	1
10	104695	4-1/2" X 2-7/8" RockSeal IIS 10K Hydraulic-Set Packer	1
11	102933	4-1/2" X 2-7/8" RockSeal II 10K Hydraulic-Set Packer	2
12	103025	2-7/8" Drillable FracPort w/Ball Seats (1.75", 2.00" Seat)	2
13	Sales	2-7/8" Ball Activated Pump-Out Plug (0.75" Seat)	1
14	Machining	High Abrasion Coating for Frac Ports	2
15	Small Parts	High Pressure Frac Balls	2
		Estmated Charges for Packers Plus Equipment Only	
		Third Party ***(Please Put on a Separate Field Ticket)***	
16	Sales	2-7/8" EUE Collars (Pkrs, FracPorts)	10
17	Sales	2-7/8" X 6 ft Pup Joint (Pkrs, FracPorts)	5
18	Sales	2-7/8" X 3 ft Pup Joints (Pkrs, FracPorts)	6
19	Machining	Thread Cutting Charge (Pkrs, FracPorts)	11
20	Machining	Torque Turning Charge per stage	3
21	Inspection	Inspection Charge	3

Fig. 16: Mechanical packer assembly details Vendor A

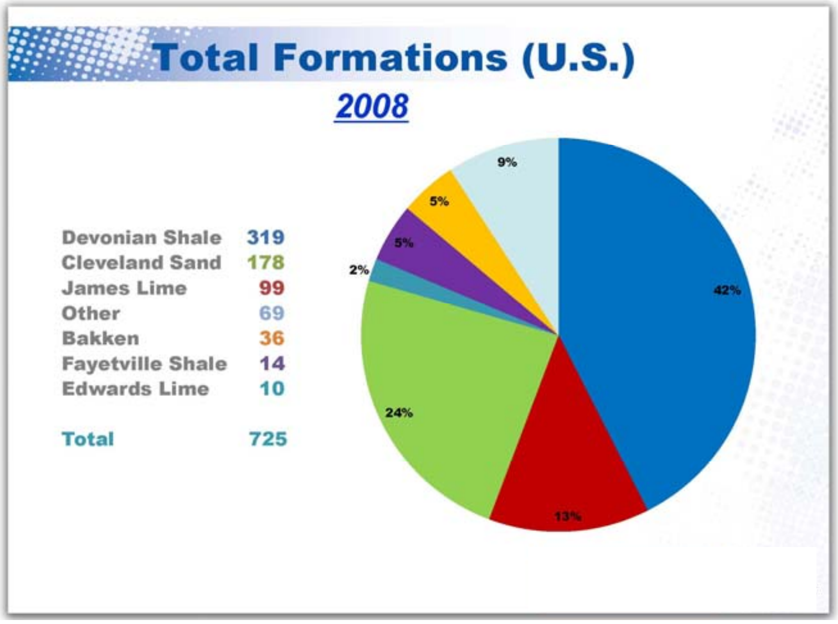


Stages / System (U.S.)

2007 vs 2008:

	2007	2008
4 Stage	24	25
5 Stage	40	36
6 Stage	57	66
7 Stage	56	84
8 Stage	52	197
9 Stage	66	272
10 Stage	5	45
Other	33	25
Total	*2187*	*5796*

Fig. 17: Openhole Packer Stage Distribution Vendor A

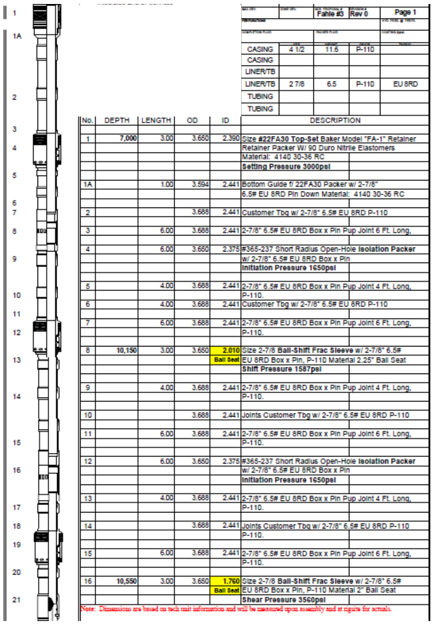


Total Formations (U.S.)

2008

Devonian Shale	319
Cleveland Sand	178
James Lime	99
Other	69
Bakken	36
Fayetville Shale	14
Edwards Lime	10
Total	725

Fig. 18: Openhole Packer Jobs by Reservoir Vendor A

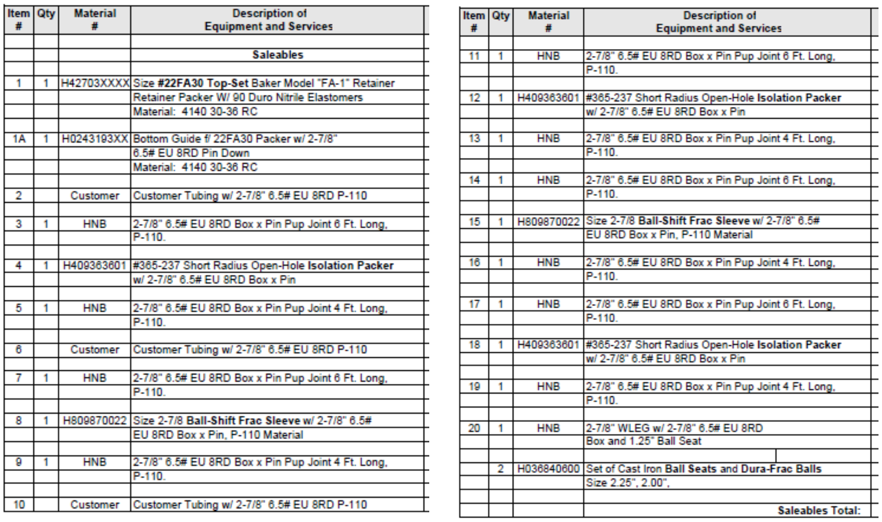


		Fahle #3	Rev 0	Page 1
CASING	4 1/2	11.6	P-110	
CASING				
LINER/TB				
LINER/TB	2 7/8	6.5	P-110	EU 8RD
TUBING				
TUBING				

No.	DEPTH	LENGTH	OD	ID	DESCRIPTION
1	7,000	3.00	3.650	2.390	Size **#22FA30 Top-Set** Baker Model "FA-1" Retainer Retainer Packer W/ 90 Duro Nitrile Elastomers Material: 4140 30-36 RC **Setting Pressure 3000psi**
1A		1.00	3.594	2.441	Bottom Guide f/ 22FA30 Packer w/ 2-7/8" 6.5# EU 8RD Pin Down Material: 4140 30-36 RC
2			3.688	2.441	Customer Tbg w/ 2-7/8" 6.5# EU 8RD P-110
3		6.00	3.688	2.441	2-7/8" 6.5# EU 8RD Box x Pin Pup Joint 6 Ft. Long,
4		6.00	3.650	2.375	#365-237 Short Radius Open-Hole **Isolation Packer** w/ 2-7/8" 6.5# EU 8RD Box x Pin **Initiation Pressure 1650psi**
5		4.00	3.688	2.441	2-7/8" 6.5# EU 8RD Box x Pin Pup Joint 4 Ft. Long, P-110.
6		4.00	3.688	2.441	Customer Tbg w/ 2-7/8" 6.5# EU 8RD P-110
7		6.00	3.688	2.441	2-7/8" 6.5# EU 8RD Box x Pin Pup Joint 6 Ft. Long, P-110.
8	10,150	3.00	3.650	2.010 Ball Seat	Size 2-7/8 **Ball-Shift Frac Sleeve** w/ 2-7/8" 6.5# EU 8RD Box x Pin, P-110 Material 2.25" Ball Seat **Shift Pressure 1587psi**
9		4.00	3.688	2.441	2-7/8" 6.5# EU 8RD Box x Pin Pup Joint 4 Ft. Long, P-110.
10			3.688	2.441	Joints Customer Tbg w/ 2-7/8" 6.5# EU 8RD P-110
11		6.00	3.688	2.441	2-7/8" 6.5# EU 8RD Box x Pin Pup Joint 6 Ft. Long, P-110.
12		6.00	3.650	2.375	#365-237 Short Radius Open-Hole **Isolation Packer** w/ 2-7/8" 6.5# EU 8RD Box x Pin **Initiation Pressure 1650psi**
13		4.00	3.688	2.441	2-7/8" 6.5# EU 8RD Box x Pin Pup Joint 4 Ft. Long, P-110.
14			3.688	2.441	Joints Customer Tbg w/ 2-7/8" 6.5# EU 8RD P-110 P-110.
15		6.00	3.688	2.441	2-7/8" 6.5# EU 8RD Box x Pin Pup Joint 6 Ft. Long, P-110.
16	10,550	3.00	3.650	1.760 Ball Seat	Size 2-7/8 **Ball-Shift Frac Sleeve** w/ 2-7/8" 6.5# EU 8RD Box x Pin, P-110 Material 2" Ball Seat **Shear Pressure 3560psi**

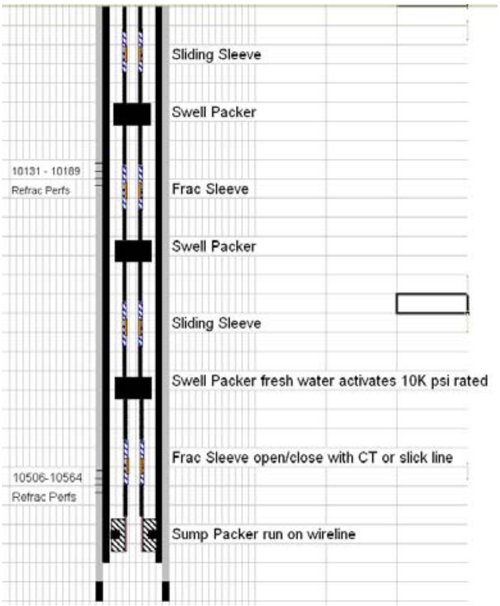
Note: Dimensions are based on tech unit information and will be measured upon assembly and at rigsite for actuals.

Fig. 19: Mechanical packer assembly details Vendor B



Item #	Qty	Material #	Description of Equipment and Services
			Saleables
1	1	H42703XXXX	Size **#22FA30 Top-Set** Baker Model "FA-1" Retainer Retainer Packer W/ 90 Duro Nitrile Elastomers Material: 4140 30-36 RC
1A	1	H0243193XX	Bottom Guide f/ 22FA30 Packer w/ 2-7/8" 6.5# EU 8RD Pin Down Material: 4140 30-36 RC
2		Customer	Customer Tubing w/ 2-7/8" 6.5# EU 8RD P-110
3	1	HNB	2-7/8" 6.5# EU 8RD Box x Pin Pup Joint 6 Ft. Long, P-110.
4	1	H409363601	#365-237 Short Radius Open-Hole **Isolation Packer** w/ 2-7/8" 6.5# EU 8RD Box x Pin
5	1	HNB	2-7/8" 6.5# EU 8RD Box x Pin Pup Joint 4 Ft. Long, P-110.
6		Customer	Customer Tubing w/ 2-7/8" 6.5# EU 8RD P-110
7	1	HNB	2-7/8" 6.5# EU 8RD Box x Pin Pup Joint 6 Ft. Long, P-110.
8	1	H809870022	Size 2-7/8 **Ball-Shift Frac Sleeve** w/ 2-7/8" 6.5# EU 8RD Box x Pin, P-110 Material
9	1	HNB	2-7/8" 6.5# EU 8RD Box x Pin Pup Joint 4 Ft. Long, P-110.
10		Customer	Customer Tubing w/ 2-7/8" 6.5# EU 8RD P-110
11	1	HNB	2-7/8" 6.5# EU 8RD Box x Pin Pup Joint 6 Ft. Long, P-110.
12	1	H409363601	#365-237 Short Radius Open-Hole **Isolation Packer** w/ 2-7/8" 6.5# EU 8RD Box x Pin
13	1	HNB	2-7/8" 6.5# EU 8RD Box x Pin Pup Joint 4 Ft. Long, P-110.
14	1	HNB	2-7/8" 6.5# EU 8RD Box x Pin Pup Joint 6 Ft. Long, P-110.
15	1	H809870022	Size 2-7/8 **Ball-Shift Frac Sleeve** w/ 2-7/8" 6.5# EU 8RD Box x Pin, P-110 Material
16	1	HNB	2-7/8" 6.5# EU 8RD Box x Pin Pup Joint 4 Ft. Long, P-110.
17	1	HNB	2-7/8" 6.5# EU 8RD Box x Pin Pup Joint 6 Ft. Long, P-110.
18	1	H409363601	#365-237 Short Radius Open-Hole **Isolation Packer** w/ 2-7/8" 6.5# EU 8RD Box x Pin
19	1	HNB	2-7/8" 6.5# EU 8RD Box x Pin Pup Joint 4 Ft. Long, P-110.
20	1	HNB	2-7/8" WLEG w/ 2-7/8" 6.5# EU 8RD Box and 1.25" Ball Seat
	2	H036840600	Set of Cast Iron **Ball Seats** and **Dura-Frac Balls** Size 2.25", 2.00",
			Saleables Total:

Fig. 20: Mechanical packer assembly details Vendor B



Qty	Description
1	4-1/2" 11.60# 10k Sump Packer, including setting adapter rental
2	2-7/8" Frac Sliding Sleeves
3	2-7/8" Production Sliding Sleeves
3	Swellfix Water Swell Packers 2-7/8" 10k psi rating
1	4-1/2" X 2-7/8" Liner Hanger Packer, 10k psi rating
1	2-7/8" Liner Running Assembly Rental Cost
1	Sleeve Shifting Tool Rental

Fig. 21: Swell packer assembly for two stage refrac Vendor C

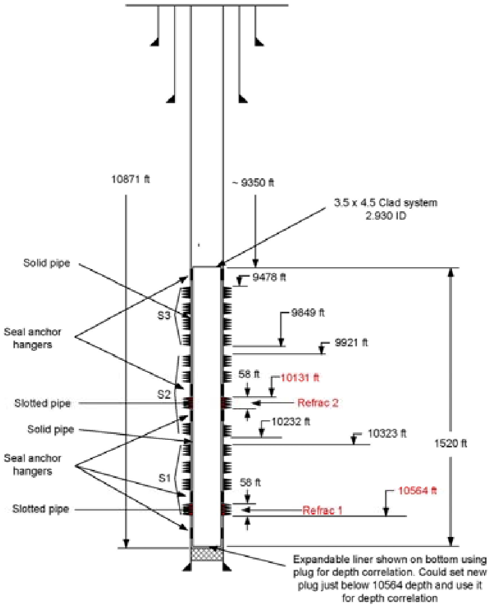


Fig. 22: Expandable liner option Vendor C

APPLICATIONS INCLUDE:

Water Shut-off / Zonal Isolation

FRAC Thru / Zonal Protection

Liner Lap Sealing

Velocity Strings

Open Hole Completion System Repair

Casing / Tubing Repair

Hanger Systems for Gravel Packing

Large ID PBR's

Can incorporate Profile Nipples, Sliding Sleeves, Sandscreens and Sump Packer

Fig. 23: Expandable liner option Vendor D

Base Case Economics

Refrac Project Economics												6/30/09
Decline based on composite of offset wells in field												
Initial rate estimated from Completion Efficiency model												
									Tristone Bank Survey Q2 09			
						UNIT	Total			Henry Hub		
Gross gas price							$ 4.00		2009	$4.36		
Transportation costs							$ 0.24		2010	$5.13		
Less severance						7.533%	$ 0.28		2011	$5.64		
Net price after severance							$ 3.48		2012	$5.82		
Monthly LOE						$ 1,000	$ 1,000					
Total Well Cost							$ 300,000		$4.00 flat price assumed here			
Discount Rate						IRR	94%					
						NPV	$0					
				Cum		PV10	$ 462,571					
				404349		Total rev	$ 962,480					
						Payout mult	3.21					
						Payout Mos	10					
Month	Monthly Decline	Avg MCFD	Monthly MCF	Cum MCF	Rev after severance	Working Interest	Revenue Interest	Gross LOE	Net LOE	Net Cash Flow	CUM CF	PAYOUT
1	0.75	795	24200	24200	$ 84,137	100.0%	77.00%	$ 1,000	$ 1,000	$ 63,785	$ 63,785	21%
2	0.78	596	18150	42350	$ 63,102	100.0%	77.00%	$ 1,000	$ 1,000	$ 47,589	$ 111,374	37%
3	0.82	465	14157	56507	$ 49,220	100.0%	77.00%	$ 1,000	$ 1,000	$ 36,899	$ 148,273	49%
4	0.86	381	11609	68115	$ 40,360	100.0%	77.00%	$ 1,000	$ 1,000	$ 30,077	$ 178,351	59%
5	0.89	328	9983	78099	$ 34,710	100.0%	77.00%	$ 1,000	$ 1,000	$ 25,727	$ 204,077	68%
6	0.92	292	8885	86984	$ 30,892	100.0%	77.00%	$ 1,000	$ 1,000	$ 22,787	$ 226,864	76%
7	0.93	269	8174	95158	$ 28,420	100.0%	77.00%	$ 1,000	$ 1,000	$ 20,884	$ 247,748	83%
8	0.94	250	7602	102761	$ 26,431	100.0%	77.00%	$ 1,000	$ 1,000	$ 19,352	$ 267,100	89%
9	0.95	235	7146	109907	$ 24,845	100.0%	77.00%	$ 1,000	$ 1,000	$ 18,131	$ 285,231	95%
10	0.96	223	6789	116695	$ 23,603	100.0%	77.00%	$ 1,000	$ 1,000	$ 17,174	$ 302,405	101%

Fig. 24: Base Case Economics 36% CE and $4.00 gas

Low Case Economics

Refrac Project Economics												6/30/09
Decline based on composite of offset wells in field												
Initial rate estimated from Completion Efficiency model												
									Tristone Bank Survey Q2 09			
						UNIT	Total			Henry Hub		
Gross gas price							$ 3.00		2009	$4.36		
Transportation costs							$ 0.23		2010	$5.13		
Less severance						7.533%	$ 0.21		2011	$5.64		
Net price after severance							$ 2.56		2012	$5.82		
Monthly LOE						$ 1,000	$ 1,000					
Total Well Cost							$ 300,000		$4.00 flat price assumed here			
Discount Rate						IRR	53%					
						NPV	($0)					
				Cum		PV10	$ 241,864					
				404349		Total rev	$ 677,465					
						Payout mult	2.26					
						Payout Mos	18					
	Monthly	Avg	Monthly	Cum	Rev after	Working	Revenue	Gross	Net	Net		
Month	Decline	MCFD	MCF	MCF	severance	Interest	Interest	LOE	LOE	Cash Flow	CUM CF	PAYOUT
1	0.75	795	24200	24200	$ 61,984	100.0%	77.00%	$ 1,000	$ 1,000	$ 46,727	$ 46,727	16%
2	0.78	596	18150	42350	$ 46,488	100.0%	77.00%	$ 1,000	$ 1,000	$ 34,796	$ 81,523	27%
3	0.82	465	14157	56507	$ 36,260	100.0%	77.00%	$ 1,000	$ 1,000	$ 26,921	$ 108,443	36%
4	0.86	381	11609	68115	$ 29,734	100.0%	77.00%	$ 1,000	$ 1,000	$ 21,895	$ 130,338	43%
5	0.89	328	9983	78099	$ 25,571	100.0%	77.00%	$ 1,000	$ 1,000	$ 18,690	$ 149,028	50%
6	0.92	292	8885	86984	$ 22,758	100.0%	77.00%	$ 1,000	$ 1,000	$ 16,524	$ 165,552	55%
7	0.93	269	8174	95158	$ 20,937	100.0%	77.00%	$ 1,000	$ 1,000	$ 15,122	$ 180,673	60%
8	0.94	250	7602	102761	$ 19,472	100.0%	77.00%	$ 1,000	$ 1,000	$ 13,993	$ 194,667	65%
9	0.95	235	7146	109907	$ 18,303	100.0%	77.00%	$ 1,000	$ 1,000	$ 13,094	$ 207,760	69%
10	0.96	223	6789	116695	$ 17,388	100.0%	77.00%	$ 1,000	$ 1,000	$ 12,389	$ 220,149	73%
11	0.97	214	6517	123213	$ 16,693	100.0%	77.00%	$ 1,000	$ 1,000	$ 11,853	$ 232,003	77%

Fig. 25: Low Case Economics 36% CE and $3.00 gas

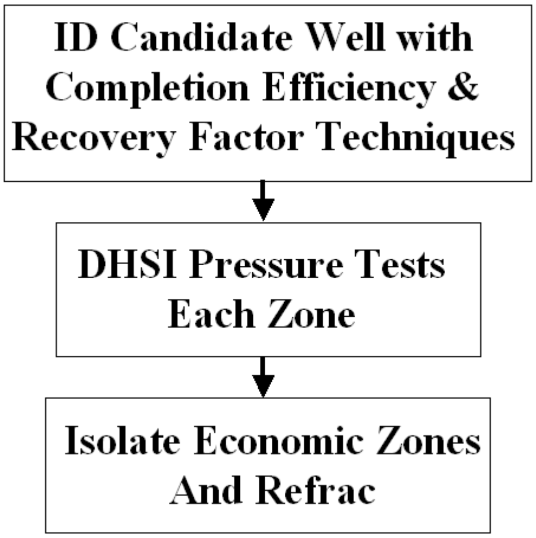


Fig. 26: Refracture Treatment Optimization Flow Chart