FRACTURING PREVIOUSLY BYPASSED HIGHLY LAMINATED TIGHT GAS SANDS: A PRODUCTION OPTIMIZATION CASE STUDY IN SOUTH TEXAS


Abstract
Highly laminated tight gas sand sequences remain prolific targets worldwide and have often been bypassed using standard petrophysical analysis and simple porosity cut-off technique. The problem becomes more acute in marginal tight gas reservoirs. The high cost of hydraulic fracturing increases the need for an effective and useable petrophysical model for an accurate productivity indication of the target interval. The pressure to avoid non-economical completions continues to leave hydrocarbons bypassed. Using recent advances in logging technology and production optimization modeling, the thinly laminated gas bearing permeable sands can be discerned from clay dispersed in silt and sand. A true net height can now be obtained. Through production optimization modeling, it is possible to assess the economic viability of completing and stimulating highly laminated interval. In this paper, we will show a case study from a South Texas tight gas sand field. Several wells were evaluated using micro-resistivity imaging. From this an enhanced high-resolution petrophysical analysis was created. This image-enhanced evaluation of reservoir properties was combined with production modeling. The production performance was simulated for each interval and used for recommendations on completion strategies. Additional pay intervals, normally bypassed, were perforated and hydraulically stimulated. We compared production data from offset wells that used standard petrophysical analysis to the results of the newer wells with the high-resolution analysis. The results indicated that actual field production increased and paid out the increased fracture stimulation cost. Production logs acquired across entire intervals confirmed that portions of the field produced from horizons that were previously bypassed. This process is useful for any highly laminated tight gas sand sequence and is of widespread applicability. Previously bypassed intervals can now be assessed and completed effectively and economically. This process will further add to the reserve base of tight gas.

Introduction
Identification of low resistivity from highly laminated sand/shale sequences has been an exploitive success in recent years. Many proposals are put forth showing offset production that seem to defy standard log analysis and cut-offs. They show water production from saturation calculation that may be in the 70 or 80 percentile ranges. On top of this, these laminated sequences may be found in what are considered marginal reservoir rock even by today’s standard and higher anticipated natural gas prices. These are the pay sands that are still only partially exploited and bypassed on an ongoing basis.

In tight, clay laminated gas sand basins, one technique that the completion engineer often uses to assess whether a zone should be attempted for stimulation is to perforate and flow the well. This luxury does not exist for the tight marginal gas sands discussed here. The risk associated with stimulating a non-flowing zone results in bypassed pay of unknown potential. Presented here is a proven technique for quantifying the non-flowing zone results in bypassed pay of unknown potential. Presented here is a proven technique for quantifying pay and sizing hydraulic fracture design options. The net height of laminated sand evaluated is compared with post-frac well production data to determine if the additional perforated intervals and larger stimulation treatments result in additional value. The methodology to compare production forecasts using a laminated sand analysis and stimulation designs is a useful tool for exploiting bypassed tight gas.

Geographical and Geological Background
The geographical setting for this case study is LaSalle County in South Texas. The area is known for the Olmos sand which has been exploited for tight gas primarily since the 1970’s but initially since the 1920’s.1 Another sand existing in parts of the Olmos play is known as the Escondido sand. There are a few nearby stand alone Escondido fields for comparison; Mesquite, Clark and Encinal. Kundert and Smink described recompletion stimulation techniques for the Mesquite field at a total depth of 5600 ft.2 The wells were natural producers in 1976 and stimulation efforts in 1977 led to substantially higher initial production rate and an estimated two-fold increase in cumulative production.
The Escondido formation is considered part of three Upper Cretaceous clastic wedges deposited in the Maverick basin of the Rio Grande embayment. These depositional units are in order of youngest to oldest: the Escondido, Olmos, and San Miguel formations. In the study area the Escondido formation is mainly a gas bearing sandstone. The sands generally are thinly laminated and very heterogeneous with permeabilities in the range of 0.005 md to 0.1 md. The sands also vary widely in terms of net height, water saturation and porosity. The combination of laminated sand intervals, low permeability and intermingled wet zones makes it challenging to make an optimized recommendation for completion strategies. The geographical trend of Escondido and Olmos discussed here is in southwest Texas (Fig. 1).

![South Texas Tight Gas Olmos/Escondido](image)

**Fig. 1 — Geographical location of well study area.**

Both the Olmos and Escondido sands are late Cretaceous near-shore depositional environments. Whether a shoal, a channel or a deltaic splay, these formations are laminated sand/shale sequences with varying bed thickness. The Escondido sands tend to be silty and more laminated than the Olmos. Standard local net pay cut-off values result in Escondido thicknesses between 10 and 30 feet.

Discussed here is the northern portion of the trend in La Salle County (Fig. 2).

![Well Study Area](image)

**Fig. 2 — Field location of study wells.**

The Process: Identification of Bypassed Pay

**Reservoir Evaluation/Petrophysical Analysis:**

The standard log analysis for this field has resulted in a resistivity cut-off of about 12 ohmmeters and 9 porosity units (p.u.). Most of the wells in the area have been successfully completed using these simple guidelines. The methodology here is to incorporate image log data with the log derived effective porosity and provide additional information for quantitative use in fracture design.

Qualitative use of electrical image logs to discern bypassed pay in highly laminated sand/shale sequences has been used at least since the early 1990’s. The electrical image log quickly provides an image of sand/shale laminations as thin as 0.1 inches. Economically viable low contrast pays were found in turbidite deepwater sands with contrast resistivity as low as 1 ohmmeter. The actual resistivities of the sand laminations were found to be much higher. These sequences could be qualitatively reviewed and economically completed. The quantitative process requires using an average resistivity from all button sensors from one pad of the micro-imaging device. A second derivative technique, indicating bed boundaries, is described by Ramamoorthy et al. These bed boundaries are then used in a mathematical modeling process to reconstruct the induction, density, neutron and gamma ray logs as if they had the same vertical resolution of the micro-imaging tool.

In the Olmos and Escondido sands described here, the porosity cut-off for the density tool was adjusted from the previous standard of 9 p.u. to 6 p.u. Mathematical modeling, based on the image log, results primarily in adjustment to the gamma and induction curves. The adjustment to porosity is less pronounced. The modeling does not increase the porosity in highly resistive very fine grain sands. The density and neutron porosities will read very low in these cases and only a small adjustment is made. The result is added pay calculation where the criteria of adjusted resistivity and porosity are met for total water saturation and irreducible water saturation. The image-enhanced high-resolution process will not add pay in dispersed clay sands but, in the case of laminated sequences, can add as much as 100% as is shown in the following study. This high-resolution petrophysical model can be used to justify adding perforations, fine-tuning the rock properties model and adjusting the stimulation design parameters.

The use of image logs for production optimization has been described for the Oligocene Vicksburg formation in South Texas. Bypassed low resistivity pay sands of 2 MMcf/d were discovered in this field study. In the following case study, the pay sands are much more marginal and the cost of stimulation can be prohibitive. The need for an accurate quantitative process is essential but often not utilized because of the added cost and time. In this marginal reservoir the set-pipe decision based on thin bed analysis requires critical time efficiency. The time between set-pipe and stimulation can be as short as a couple of days. Image-enhanced high-resolution log analysis can now be completely processed in less than 4 hours. This is down from several days processing just 10 years ago. The streamlined process is illustrated in Fig. 3.
Stimulation Considerations:
Wells within the scope of this project were stimulated with 20/40 Ottawa sand, linear gel fluids and a resin coated tail for sand containment. All jobs were performed with a carbon dioxide (CO₂) assist for fracture cleanup purposes and formation sensitivity. The primary consideration for stimulation design has been the job size and the economical return of the treatment. While other fluids have been tested and pumped, they are outside the scope of this discussion.

Stimulation design is based on a rock property model that is derived from the petrophysical analysis. Dipole sonic data acquired in a base well are used to create synthetic rock properties for outlying wells. This rock model uses consistent parameters in the field that are checked and possibly recalibrated when offset dipole data is acquired. The stimulation model is a pseudo three-dimensional (3D) design. For purposes of this discussion the model is adequate. Fully three-dimensional modeling has been compared but is still in test phase.

The stimulation design can vary greatly even when using a consistent model. The design engineer is usually given a set of perforations, the rock/stress model and sometimes an anticipated job size. The job size may be based on offset results or on an anticipated economical return. The design engineer is often faced with suggesting the correct size and may vary the job size based on permeability and known pore pressure gradients. The differentiating factor shown here is added net height and added intervals. The design engineer uses the high-resolution petrophysical model to add perforations and increase the size of the treatment. With a bigger job size the question becomes economics. Just how big should the job be to go in the ground and still make the required return? The question can be better answered with accurate height information. Actual production results in this study were compared to the production forecasts. The added perforations and increased job size produced economical results in some cases but not in all. The optimization process is ongoing and refinements continue to be made.

Production Modeling:
Evaluating the laminated sequences for production forecasting requires the same techniques used with standard log resolution. In order to validate the forecast the actual production data is compared and evaluated. The process of forecasting & evaluating production data has been described by Poe et al. Further work by Poe et al., resulted in a comprehensive technique to uniquely estimate fracture half-length, fracture conductivity and effective reservoir permeability. The process/technique had been validated and confirmed by England et al. The method of distinguishing between multiple completion intervals is performed as described by Poe et al. A field study in South Texas by Larkin et al. has verified this methodology. These techniques and processes provide the production data analyst with a consistent tool to calibrate log permeability estimates, fracture property estimates and get a closer match between production forecast vs. actual. This process is used for the following case study and compares both high-resolution petrophysical data sets and standard resolution data sets.

Case Study—Well A
This well was drilled in the southern portion of the study area. Most of the typical sand bodies were not evident due to faulting or stratigraphy. The sand encountered was of poor quality, only 10 ft of net pay using the standard resolution logs. The well would normally be plugged and abandoned. A high-resolution image device was being run for fault and bed dip information analysis. From this electrical image, a resistive sand-count was derived and indicated 23 ft of net pay (Fig. 4).

A stimulation design recommendation was considered for both cases using the 10 ft of net pay as well as the sand count result of 23 ft. A 103,000 lbm treatment was designed for the standard resolution analysis. A proppant concentration cut-off of 1.1 lbm/ft² results in a fracture height of 50 ft and a half-length of 450 ft (Fig. 5). A 206,000 lbm treatment design was made based on the 23 ft sand-count (Fig. 6). Using the same
proppant concentration of 1.1 lbm/ft² cut-off, the fracture height is 150 ft and the half-length is 550 ft. The height and length comparisons were used for production forecasting and the larger 206,000 lbm treatment was pumped.

**Well A Standard Resolution Based Design**

Treating Pressure: 3,300 psi, Frac Gradient: 0.77 psi/ft
103,000 lbm, Fluid: 33,587gal, 97 tons CO₂, Pad: 16.7%

**Well A Sand Count Based Design**

Treating Pressure: 3,300 psi, Frac Gradient: 0.77 psi/ft
206,000 lbm, Fluid: 67,174gal, 97 tons CO₂, Pad: 16.7%

Production results confirmed the zone’s ability to produce but did not match forecast (Fig. 7). The underperformance was approximately 30% and led to investigation of the net height used from the sand count alone. Data matching showed the producing height to be closer to 15 ft than 23 ft The conclusion was that the sand count alone provides a visual picture to work with but the petrophysical properties need to be included to more accurately determine effective sand intervals. Specific high-resolution log responses with high resistivity and low effective porosity were determined to be fine grained tight sands, silts and calcite. These intervals will not add to net effective height. The other conclusion however, was that this type of sand could be attempted in offset drilling if combined with other intervals.

**Well A Production Forecast and Actual**

![Well A Production Forecast and Actual](image)

**Fig. 7**—Well A production compared to forecast.

**Case Study—Well B**

The second example is a well with multiple zones potential. The high-resolution petrophysical log increases net height in the lower section from 13 to 24 ft The net height change is shown in Fig. 8.

**Well B Enhanced Resolution Petrophysics**

![Well B Enhanced Resolution Petrophysics](image)

**Fig. 8**—Net height of Well B is increases by double.

Fracture stimulation designs for the section were modeled based on both the 13 ft and the 24 ft net height of pay. The same proppant cut-off technique described in Case A was used with well B treatment designs. The standard resolution design with 147,000 lbm proppant with only 13 ft of perforated interval resulted in a fracture height of 100 ft and half-length of 350 ft (Fig. 9). The high-resolution petrophysical analysis identified an extra 11 ft of pay over a 40 ft interval. The size of the treatment was therefore increased to 294,000 lbm. The added volume treatment resulted in a fracture height of 130 ft and half-length of 550 ft (Fig. 10). These were the parameters used to compare job size and anticipated economics. The decision was to add perforations as indicated on the high-resolution log and to pump the larger job of 294,000 lbm. The forecasted production closely matched the actual production (Fig. 11).
The conclusion drawn from well example B is that the high-resolution net height provides a much more accurate technique for stimulation design and production optimization. The incremental difference for the larger pump design was $28,000, for an incremental increase of 150 Mcf/d. Incremental increase in revenue at 200 days is $91,000, making the cost justifiable.

Case Study—Well C

This well contained two laminated sand intervals that were completed and commingled. Shown here is the upper section only. Throughout the general area, only the obvious sand in the upper section is perforated and stimulated. In this well however, the design engineer recommended perforating all of the highly laminated sections of the entire upper sand. The perforations were based on the image-enhanced high-resolution petrophysics. A stimulation treatment of twice the normal size was recommended and pumped. The production from the laminated sequence was verified by running production logs (Fig. 12). The highest increase in production was from the obvious sand but all of the laminated sands contributed as indicated by the flowmeter and temperature profile.

The treatment design for the upper and obvious sand alone without including the laminations would have required 130,000 lbm of proppant resulting in a fracture height of 100 ft and a half-length of 350 ft. This is again based on a 1.1 lbm/ft² cut-off (Fig. 13). The treatment design based on the high-resolution petrophysics, adding 60 ft of perforated interval, specified a job size of 265,000 lbm of proppant. This resulted in a fracture height of 165 ft and a half-length of 600 ft using the 1.1 lbm/ft² proppant cut-off (Fig. 14). The production log confirmed the entry of gas from the laminated and normally bypassed sands. The production log also indicated that the entire upper zone contributed about 30-40% of the total flow rate. The production log when coupled with the production data indicated that the laminated sequences contributed significantly to the total production of the well.
The initial lower section (Olmos formation) of the well was completed and flow tested for 30 days before the upper section (Escondido formation) described in this case study was completed and commingled. During the flow testing, the lower section of the well produced gas and light oil. Production data analysis was complex due to significantly different completion timing (around 30 days) and gas and light oil from commingled production. Significant assumptions needed to be changed in order to verify and quantify the contribution from the highly laminated sand in the Escondido formation that was uncovered from the high resolution analysis. Honoring the actual gas production and the production log information (30-40% gas contribution comes from the Escondido formation), production analysis was attempted. The modeling matches the overall rate and the laminated sequences can be quantified for contribution. The difference in production performance from the standard analysis vs. the high resolution analysis in this highly laminated formation is an incremental initial production of 280 Mcf/D (Fig. 15).

In this particular field, where Well C is located, similar wells with previously bypassed zones were uncovered following this third case. In some of these wells the same technique was applied with complete high-resolution petrophysical analysis. With other wells the image log was used visually by the stimulation design engineer to add perforation intervals and suggest increased stimulation designs. In this field there are 8 newer wells (group 1) with date of first production (DOFP) later than 2003 that used the high resolution petrophysical analysis techniques. There are also 4 older wells (group 2) with DOFP from 1980 – 1995 that used the standard petrophysical analysis in the completion design strategy. We compared the average production performance of these two groups using time-zero production plot comparison. The result indicated that the newer wells production rates significantly outperformed the older wells (Fig. 16).

The production performance of the group 1 in this particular field is also compared to the wells’ production performance from a nearby offset field with similar reservoir quality (group 3). Group 3 wells did not use the high resolution petrophysical analysis techniques.
resolution petrophysical analysis in their completion strategy. However, some of the wells in group 3 had a bigger size fracture treatment (>250,000 lbm proppant with the same fracturing fluid). The production performance of group 1 wells is still outperforming the production performance of the group 3 wells (Fig. 17).

![Offset Field Decline Rate Comparison](image_url)  
**Fig. 17**—Decline rate analysis field comparison.

**Effect on Reserve Base**
From Fig. 16 and Fig. 17, it appears clear that the high-resolution petrophysical analysis gives the potential to adjust the completion strategy of the wells and which resulted in a production optimization of a well. From a big picture standpoint, a comparison of volumetric and decline based reserves analysis was made. The contributions of the zones identified by the high-resolution petrophysical log which are not identified as pay by conventional analysis have been confirmed by decline curve analysis. As an example, a 400 acre area containing 14 wells was evaluated by volumetric and decline curve analysis methods. Decline curve analysis yields a total estimated ultimate recovery for this area of 12.9 Bcf. Conventional log analysis yielded volumetric reserves of 9.6 Bcf. High-resolution volumetric analysis of wells in the area yield approximately 37% higher reserves as compared to conventional analysis. This increase results in total reserves for the 14 wells of 13.2 Bcf which is within 2% of decline curve analysis.

The existence of the laminated low permeability pay sands is apparent by looking at the production history of wells drilled in the early 1980’s. Several of these wells had initial production rates from 200 to 400 Mcf/d but declined quickly to 50 to 150 Mcf/d and have produced 75% of their current cumulative production with declines rates of less than 5% per year. This type of decline is consistent with laminated sequences being drained from inadequate perforation and stimulation. Some of these wells became refrac candidates after identifying the nature of the reservoir. While increasing net pay in both the highly laminated sections of the Escondido and Olmos formations, the high-resolution technique actually decreased the net pay in some of the apparently blocky Olmos sands. This is because of thin laminations of shale within the sand section.

**Conclusion**
Image logs, like cores, often show a much more complex reservoir environment than conventional logging tools. These high-resolution measurements can be used quantitatively to increase the accuracy of log based volumetric evaluation in laminated tight gas sands. Multi-zone completion methods are costly and are often avoided in marginal reservoirs where only the most obvious pay zones are completed and stimulated. Resolution of conventional petrophysical logs can be refined with image-enhanced high-resolution logs to delineate finely laminated sand, silt and shale laminated intervals. This high-resolution petrophysical analysis is used in production modeling software to predict the contribution of the various intervals. A pseudo three-dimensional fracture design model is used in conjunction with the production model to optimize the stimulation treatment and provide job design parameters. This process results in an optimized completion and stimulation strategy and led to identification of additional pay and development of previously bypassed resources. These new-found resources have been turned into reserves 20 or 30 years after the first wells encountered them. This combination of pay identification and quantification incorporated into improved completion and stimulation design has created significant opportunities for those in the hunt for tight gas resource plays.

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**References**


**SI Metric Conversion Factors**

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