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Restimulation Technology for Tight Gas Sand Wells

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Abstract

In 1996, the Gas Research Institute (GRI) performed a scoping study to investigate the potential for natural gas production enhancement via restimulation in the United States (lower-48 onshore). The results indicated that the potential was substantial (over a Tcf in five years), particularly in tight sand formations of the Rocky Mountain, Mid-Continent and South Texas regions. However, it was also determined that industry's current experience with restimulation is mixed, and that considerable effort is required in candidate selection, problem diagnosis, and treatment selection/design/ implementation for a restimulation program to be successful. Given a general lack of both specialized (restimulation) technology and "spare" engineering manpower to focus on restimulation, GRI initiated a subsequent R&D project in 1998 with several objectives. Those objectives are to 1) develop efficient, cost-effective, reliable methodologies to identify wells with high restimulation potential, 2) identify and classify various mechanisms leading to well underperformance, 3) develop and test non-fracturing restimulation techniques tailored to selected causes of well underperformance and, 4) demonstrate that, with improved technologies in these key areas, restimulation is a viable and attractive approach to improve well recoveries and economics.

The approach adopted for the R&D program is a combination of candidate selection methodology development, conceptual well underperformance/problem classification, laboratory studies, and actual field experiments and demonstrations of restimulation treatments. At this time, a multi-process candidate selection methodology has been developed, consisting of production comparisons, engineering based performance assessments, and pattern recognition technology. Also incorporated into the overall methodology are individual well reviews, economic analysis, and a new short-term field test for candidate verification. Laboratory studies have also identified new procedures for effective clean-up of unbroken gel in propped and natural fractures.

In total, twenty actual restimulation treatments are planned at four separate test sites. Currently active sites are in the Rocky Mountain and Mid-Continent regions. One site is located in the Big-Piney/LaBarge Producing Complex in the northern Moxa Arch area of the Green River Basin. As of this writing, three restimulation treatments have been performed at this location.

The second site is the combined Rulison, Parachute and Grand Valley fields in the Piceance Basin. Candidate selection has been completed, and actual field-testing and restimulation activities are expected to begin in July 1999. The third site is the Carthage field in East Texas. Candidate selections are complete at this site also, with field activities also scheduled to begin in July. The fourth test site, not yet active, is in the Wilcox Lobo Trend of South Texas.

This paper is the first comprehensive publication of results from this recent GRI initiative. It provides detailed descriptions of the candidate selection and restimulation methods employed, the results obtained, and should prove to be of value to operators seeking a production enhancement from tight gas sand wells throughout the United States and internationally.

Introduction

In 1996, the Gas Research Institute (GRI) began investigating the potential for natural gas production enhancement via restimulation in the United States (lower-48 onshore)[1,2]. The initial results indicated that the potential was substantial (over one Tcf of reserves in five years), particularly in the tight gas sands of the Rocky Mountain, Mid-Continent and South Texas regions. Further, when successful, restimulation was found to be an attractive investment, providing incremental reserves at costs of $0.10 to $0.20 per Mcf. However it was also determined that industry's historical experience with restimulation is mixed, and that considerable effort is required in candidate selection, problem diagnosis, and treatment selection/design/implementation for a restimulation program to be successful. Given an overall lack of both specialized (restimulation) technology and "spare" engineering manpower within the industry today to focus on restimulation, GRI initiated a two-year R&D project in 1998, currently underway, with several objectives. Those objectives are to 1) develop efficient, cost-effective, and reliable methodologies to identify wells with restimulation potential, 2) identify and classify various mechanisms leading to well underperformance, 3) develop and test new (non-fracturing) restimulation techniques tailored to selected causes of well underperformance, and 4) demonstrate that, with these new approaches, restimulation is a viable and attractive approach to improve well recoveries and economics. It is believed that with new technologies in these key areas, industry can more effectively capture the incremental reserves that exist via restimulation, and the handsome financial benefits they represent, particularly in today's challenging business climate. This paper discusses the progress, results, and conclusions to date from that project.

Description of Candidate Selection Methodology

Considerable effort in the project has been (and continues to be) focused on the development of the candidate selection methodology itself; it is believed that this is where a technology advancement will provide the greatest industry benefit[3]. In the earlier GRI work, an important finding was what has been termed the "85/15" rule. Specifically, this "rule" states that 85% of the restimulation potential for a field exists in 15% of the wells; the key to any successful restimulation program is therefore being able to correctly and reliably identify that 15% of wells representing the high-potential restimulation candidates. The economics of a restimulation program are highly sensitive to proper candidate selection, and relatively minor miscalculations in this regard can turn what could otherwise be a highly profitable project into an unprofitable one. Inadequate candidate selection procedures seem to be the reason that many restimulation projects today do not meet expectations.

With this understanding, two concepts formed the foundation of the candidate selection methodology. The first is that a series of sequential analyses would be used to gradually reduce the total well population to the plus or minus 15% that are actually high-potential candidates. The first analytic level, for example, might be for rapid screening and be low in cost, perhaps eliminating 50% of the wells. Subsequent analytic levels would be incrementally more detailed, labor-intensive and expectedly higher in (per well) cost. Further, a heavy reliance on existing data is essential, hence, avoiding the need for collecting additional, expensive test data. The objective is to develop a methodology that is affordable and efficient to implement on large well populations.

The second concept is that to accurately select candidates, well performance must be separated into its respective reservoir quality and completion efficiency components (i.e., permeability and skin). High-potential candidates, those that should provide the greatest level of incremental production and reserves, are likely to be wells exhibiting both high permeability and high (positive) skin. The implication is that the better performing wells in a field may actually be the most attractive restimulation candidates, not those that are underperforming the field or offset well averages. While the practice of restimulating highly productive wells is understandably performed reluctantly (if at all) by most companies, not doing so may be the very reason many restimulation projects are less successful than originally envisioned.

A multi-process candidate selection methodology was therefore conceived. Brief summaries of the (three) analytic methods adopted are provided below:

Production Type-Curve Matching (Process III)

The ideal approach to selecting restimulation candidates is to directly understand the relative impact of reservoir and completion properties on the performance of each individual well (i.e., permeability and skin), and select the high-permeability/high-skin wells for restimulation. Unfortunately, obtaining such information can be expensive if approached via conventional pressure transient testing. An alternative approach is to use production type-curves. Such curves have been specifically developed for hydraulically-fractured tight sand wells and can provide estimates of the permeability, skin and drainage area with relatively limited data[4]. The problems with this approach are severalfold however; first, models of this type are developed for single-layered reservoirs, and the multi-layered nature of most tight sand plays can compromise the validity of the results. Second, the noise-level of the production data normally available, plus the inherent interdependencies of the output parameters, makes the ability to achieve a unique result difficult. Finally, since these methods also require values of net pay for each well, considerable interpretive and labor-intensive petrophysical evaluation is required, increasing both cost and interpretation bias on the part of the evaluator. However, with an understanding these limitations, such approaches can be used in a relative manner to identify potential restimulation candidates.

Production Performance Comparison (Process I)

In an effort to bypass the interpretive and cost issues using production type curves or other similar methods, a non-analytic production comparison evaluation was also adopted as a potential screening tool. In the most simple terms, this process essentially compares the production performance of each well in the subject area to its offsets, and identifies underperforming wells that could be restimulation candidates. However, the process is quite advanced in that it compares life-cycle production, including early-time performance and most-recent performance, to provide insights into why a well may be underperforming[5]. The method also accounts for depletion associated with infill drilling and attempts to identify the production "signature" associated with high-permeability/high-skin wells. The drawback of this technique is that it does not explicitly identify those "superior" wells (i.e., those in high permeability fairways) that could be improved, and that could be the source of the most favorable restimulation economics. This is most important where reservoir heterogeneity is high, as is the case with many tight, naturally fractured plays. Hence, production comparisons alone cannot distinguish between reservoir variability and completion effectiveness. While production comparisons are "localized" in this analysis to minimize the potential effects of reservoir heterogeneity, superior wells are still not selected. Nevertheless, the selection of underperforming wells, particularly where reservoir properties and completion/stimulation practices are more uniform, is a valuable candidate recognition approach.

Pattern Recognition Technology (Process II)

While the first two processes strictly attempt to identify underperforming wells regardless of why, a third approach was incorporated to better replicate the procedure an engineer might follow to select restimulation candidates. Specifically, this involves examining well records to identify activities that may have led to an inefficient completion. Examples might be the use of a single, small fracture treatment to stimulate a large, multi-interval pay section, a frequent occurrence of well workovers with damaging kill-fluids, among many other possibilities.

This analytic process therefore utilizes artificial neural nets and genetic algorithms to identify potential restimulation candidates[6]. Artificial neural nets are utilized to recognize complex patterns in how various input parameters (e.g., location, geologic, drilling, completion, stimulation and workover data) impact the output (i.e., production). Such an approach was selected due to the complex system being evaluated, and the inability of uni- or multi-variate analysis to achieve the same result.

This approach serves several useful purposes. First, the relative contribution of geologic/reservoir parameters (i.e., uncontrollable) can be separated from drilling, completion, stimulation parameters (i.e., controllable). This in effect is the separation of the reservoir and completion components (i.e., permeability and skin). Then, by understanding which of the controllable parameters have the greatest impact on production response (i.e., the "performance drivers"), patterns can be identified to infer "best" (or "worst") practices, and flags raised for wells with restimulation potential (i.e., those where "less than best" practices were used). Also, insights can be obtained on the causes of well underperformance and how to treat it. For example, if the use of heavy mud is identified as a "bad" practice, then mud damage may a problem with well performance, and treatments can be designed specifically to remedy that problem.

Genetic algorithms are then used to "optimize" the input parameters for any given well, and those wells where the greatest discrepancies exist between actual well performance and optimized performance are identified as restimulation candidates. The difficulty with this overall approach is that frequently the amount, type, and quality of data available are insufficient to perform a thorough analysis; all technical data used for an analysis must be available for all wells. In addition, some judgement is required on the selection of data to utilize. As a result, this approach can be compromised by the lack of important well performance information such as reservoir properties. Nevertheless, this approach is believed to hold great potential for evaluating restimulation opportunities in tight gas fields.

Hence, the processes (from I to III) proceed from minimal data requirements to comprehensive data sets with interpretation bias (Table I). This is also shown graphically in Figure 1. This diagram illustrates that both Process II and III are more costly than Process I, either requiring more data or more interpretation. Note that no judgement is made on which process does the best job at selecting candidates, but clearly an incentive exists to utilize process I as an initial low-cost screening tool. Also, reducing the cost of process II by reducing the data requirements, and the cost of process III by reducing the amount of interpretation required, would improve overall efficiency. Automation of each process should provide additional cost savings, yet the ability to incorporate some customization for each specific area being evaluated must be preserved.

After processes I, II, and III are completed, individual well reviews are performed on the top 15-20% of the candidates. The purpose of the reviews is to determine the mechanical suitability of a well for restimulation, the specific horizons within a multi-zone well that appear to hold restimulation potential, and the likrly cause of well underperformance. Part of this process can, but may not necessarily, include laboratory studies into fluid/formation compatibilities and site-specific damage mechanisms. It is based on these reviews that specific restimulation procedures and designs are prepared. Once the restimulation horizons are identified and the treatments designed, restimulation costs are assembled and incremental production forecasts made. These are used to evaluate the economic viability of each proposed restimulation candidate.

As a final step, the methodology includes a well testing component to verify the current stimulation effectiveness of the remaining candidates. New and novel testing methods specifically designed to address the problems associated with testing low permeability gas wells, such as multi-layered environments, long test times, etc., are being developed. The objective of the new testing method is not a quantitative analysis of a well, but a qualitative determination of the current effectiveness of the stimulation in the well. Also, the testing procedure itself must be simple, inexpensive and of short duration.

Considering the objective of the new testing method, research was focussed on developing techniques that quantified the stimulation of the well from the shape of the data. Unfortunately, the initial techniques developed for this task had problems similar to conventional tests in low permeability environments, such as non-uniqueness when wellbore storage dominates most of the test. In order to obtain a unique solution using this method, it was found that the method required unacceptably long shut-in times.

As a result, a second approach is now being investigated[7]. This approach utilizes certain key points in time during a pressure buildup to place bounds on the likely values for permeability and skin. For example, if the point in time in which wellbore storage ends (i.e., end of unit slope line) is reached, by knowing the mechanical configuration of the well and upper and lower-bound estimates of reservoir pressure (i.e., cannot be greater than original pressure or lower than measured pressure at that point in time), then upper and lower bounds on permeability and skin can be estimated. The degree of accuracy would obviously increase with longer shut-in times, however, even with short term data, the accuracy should be sufficient for restimulation candidate verification purposes (i.e., is the well/zone stimulated or not?) Validation and testing of this procedure is currently underway.

A schematic illustration of the overall process is provided in Figure 2. Note that each initial process (I, II, and III) are shown to be performed in parallel; this was designed in such a manner for research purposes. The ability of each process to replicate the well selections of previous processes was key to the sequential nature of the analytic methodology proposed, and testing the validity of that assumption was therefore required. Hence, parallel evaluations were performed to compare the candidate selections from each process.

Potential Causes of Well Underperformance

While the proper selection of candidate wells is a critical success factor for restimulation, understanding the cause of well underperformance, and how to treat it, is also crucial. As described above, the methodology currently incorporates artificial neural nets to provide initial insights into these issues by the identification of production "performance drivers". Specific problems for selected wells are then further understood via individual well reviews. To aid in this overall problem diagnosis procedure, a framework has been established to classify potential causes of well underperformance. At the highest level, three broad well underperformance categories have been identified (Figure 3). These are:

Problematic or Ineffective Initial Completion. Some examples of problems in this category would include poor quality control on an initial fracture treatment, gel damage, inappropriate proppant selection, treatment screenout, poor design (e.g., too small, damaging fluid, etc.), attempting to stimulate too many horizons with a single treatment (and leaving some untreated), among many others. These are the most common types of problems identified by the methodology.

Gradual Damage During Production. Examples of these problems would include deterioration of the fracture conductivity due to embedment and/or fines plugging, plugging in the formation due to fines mobilization and/or scale deposition, proppant flowback from the near-well area, among others. Due to the fact that little information is typically collected that can provide insights into these mechanisms; they are rarely specifically identified. In fact, a bias may exist against the selection of wells with this problem, since the quality of the initial completion, which seems to be the typical focus problem diagnosis, is not considered. Yet, this problem may be the most widespread and hold the greatest potential.

Technology Evolution. Finally, where significant advancements in completion and/or stimulation technology have taken place, an opportunity may exist to restimulate wells that originally utilized "old" technology. In some sense this could be a subset of the first two causes cited above in that "old" technology may be synonymous with a "less effective" initial completion, and "older" wells may be those where more production damage has taken place.

The implications of these problem diagnosis categories, particularly with respect to candidate selection, are severalfold. In the first instance (problematic or ineffective initial completion), by understanding well performance drivers via sophisticated pattern recognition technology and individual well reviews, problems can be diagnosed and wells selected for restimulation. The important question is what types of problems correlate to the high-potential restimulation candidates. Three specific problem types have been identified for tight gas sand wells, and ranked in order of perceived restimulation potential. These three are:

Unstimulated Horizons. This would typically result from fracturing with (for example) the limited-entry approach, or any time multiple pay horizons were the target of a single fracture treatment. This condition is believed to hold the greatest restimulation potential because 1) most tight sand or other emerging gas resources are frequently completed in a multiple-zone environment, and there exists a strong tendency to treat multiple intervals with fewer treatments for economic reasons, and 2) the incremental production via restimulation is almost assuredly an incremental reserve and not rate acceleration. Indicators of this condition would include a low ratio of fracture treatments (and proppant volume) to the number (and distribution) of net pay intervals.

Insufficient Fracture Conductivity. Insufficient fracture conductivity is believed to hold the second greatest potential from a restimulation standpoint, although the distinction between rate acceleration and a true incremental reserve becomes more blurred (except in extreme cases). Examples would include insufficient proppant strength for the reservoir depth, proppant settling, low proppant concentrations, and gel damage (i.e., by unbroken gel) to the proppant pack. Diagnosing these conditions requires review of fracturing and flowback records.

Insufficient Fracture Length. It is believed that capturing an incremental reserve via improving fracture length is the most difficult to achieve, and hence the least attractive. This is because, unless the initial treatment was extremely small, achieving a greater fracture length is likely to come only at considerable expense, and for an incremental reserve at the outer margin of the drainage area. However, if additional length can be achieved, and expand the drainage area of a well, then the incremental production should also be a true reserve addition. The restimulation opportunity via fracture length extension is probably limited to those cases where the initial fracture length is very short, and would be diagnosed by a small treatment relative to the net pay thickness.

The three problems discussed above, and indicators of their existence, relate to the first classification of well underperformance (problematic or ineffective initial completion). For the second and third classifications, specifically gradual damage during production and technology evolution, well age may be the best indicator of their potential existence. In the case of technology evolution, review of the completion and stimulation records should provide the information needed to make that assessment. In the case of gradual production damage however, diagnosis is more difficult. Some of the potential indicators of this condition would be evidence of fines or scale deposition from production records, perhaps catalyzed by the onset of multi-phase flow, proppant flowback, and a high frequency of workovers (indicating potential damage from kill-fluids). One important aspect of these second two well underperformance problems is the role of reservoir pressure. While older wells may have a higher probability of exhibiting the problems discussed, sufficient remaining reservoir pressure must also exist to justify a restimulation treatment, both in terms of an available incremental reserve base, and for adequate treatment flowback.

Laboratory Studies

The success of hydraulic fracturing when originally completing tight gas wells depends upon creating a fracture with sufficient permeability contrast to produce gas. The effectiveness of the fracture is therefore affected by the clean-up of the fracturing fluid, which when ineffective, tends to retard actual in-situ fracture conductivity achieved. Even though a variety of improved breaker systems are available to mitigate this problem, there is ample field evidence demonstrating that less than optimum clean-up is achieved.

To investigate this, in 1996, GRI conducted a study to evaluate the nature and impact that damage mechanisms resulting from hydraulic fracturing had on gas well productivity[8]. The results of that work suggested that the two primary damage mechanisms associated with hydraulic fracturing are 1) damage to the proppant pack, and 2) damage to natural fractures.

In a proppant pack, gel concentrates at the rock interface due to the deposition of filter cake during fluid leak-off. Gel also becomes more concentrated within the center of the pack by means of static leak-off during closure. The conductivity of proppant packs is even further reduced by multiphase flow. The pressure drop required to initiate gas flow through the proppant pack is extremely high when the pack is filled with highly concentrated unbroken gelled fluids. Examination of factors affecting clean-up in hydraulic fractures has shown that there is a minimum differential pressure required to achieve fracture clean-up. In lower rate/lower pressure gas wells, the fracture simply cannot clean up. The end result is that effective fracture lengths are much shorter than were expected or created.

During hydraulic fracturing, natural fracture apertures dilate above a critical treating pressure. This dilation increases fluid loss and allows the natural fractures to accept whole gel (unfiltered) and fluid loss control materials. The acceptance of whole gel greatly reduces the permeability of the natural fractures, which is exacerbated at low drawdown pressures when they also tend to close.

Because of the damage potential to the hydraulic fracture and natural fracture systems, the ability to remediate damage caused by unbroken gelled fluids would be invaluable in restoring or improving gas productivity in fracture-treated wells. The objectives of the laboratory work are therefore to look at the various options available for remediation of fracturing fluid damage, to identify mechanisms of clean-up and, finally, to select conditions to optimize fracturing fluid clean-up.

While the studies conducted are too extensive to fully describe here, their results are provided elsewhere in the literature[9]. The key findings as they relate to the restimulation procedures are summarized below:

- For effective clean-up of a proppant pack, it needs to be "fluidized" (i.e., proppant mobilized). Fluidization is primarily rate dependent with higher rates providing greater depth of penetration. While the potential benefits of gel-breaking chemicals cannot be discounted in the field, in the laboratory untreated water provided as effective clean-up as treated water provided fluidization was achieved. Further, while practical concerns over high-rate injection are warranted (i.e., flushing proppant away from the perforations, proppant settling below the perforations), the improved clean-up achieved in the laboratory is compelling and deserving of field testing.
- Similarly, for the natural fractures, dilation (opening) and flushing of the natural fractures appears to be a critical success factor for effective clean-up. While the utility of gel-breaking chemicals must be considered to break the gel that is flushed further back into the formation (perhaps not dissimilar to the proppant pack case), premature "spending" of these chemicals on the minerals within the rock can present a risk to treatment effectiveness.
- In both propped and natural fractures, the existence of a gas saturation seemed to improve the effectiveness of the clean-up treatment. While the specific mechanism for this effect could not be identified, one might speculate that fluid diversion due to relative permeability effects may play a role.

Field Testing

The final objective of this project is to demonstrate the application of the candidate selection methodology and its benefits in the field. Four test sites are being utilized for this purpose, located in the Green River, Piceance, East Texas and South Texas Basins (Figure 4), and each in cooperation with an active operator in the area. Each test site consists of 200-300 wells to which the candidate selection methodology is applied. Ultimately, five wells at each site are selected for restimulation. As of this writing, three test sites are active

(Green River, Piceance and East Texas), with the fourth (South Texas) pending results of the first three. To date, three restimulation treatments have actually been performed, all in the Green River Basin.

Geologic type sections for each site are provided in Figures 5 to 8, and selected reservoir properties in Table II. One can easily envision the challenge being faced in this project when considering the development of a single, general purpose methodology that will work in such diverse geologic and reservoir environments. The most common challenge has to do with the multi-pay nature common to all sites; i.e., "Where is the gas currently coming from and which zones are not contributing due to an ineffective stimulation?" Beyond that, reservoir discontinuity and compartmentalization are problematic. Differential depletion and the potential for crossflow after restimulation must also be considered. With that backdrop, summaries of the activities and results from each site are presented below.

Field Site 1, Green River Basin

The first site is the Big-Piney/LaBarge producing complex in the northern Moxa Arch of the Green River Basin. The cooperative research partner, Enron Oil and Gas, operates close to 300 wells in the area that produce solely from the Frontier Formation. The multi-process candidate selection methodology was applied to all wells at the site. What was observed was the coincidence of candidates from one process (I, II, or III) to the next was inconsistent. Further, the top candidates from each process were unique to that process, and were not replicated in the other processes. The implication is that since each process seems to focus on different indicators of restimulation potential, each selects different candidate wells. For example, process I selects wells that are underperforming their offsets. Process II selects wells where "less-than-best" practices were employed, and process III selects wells with the greatest estimated upside potential, albeit using non-unique engineering methods. Hence, the potential to use process I as a preliminary screening tool has become uncertain. Further information on the candidate selection process at this site can be found elsewhere in the literature[10].

Ultimately, five wells were selected for restimulation, which are listed in Table III. Note that these wells do not represent the best candidates from the methodology, but represent a compromise between the methodology selections and various factors such as mechanical integrity, operator preference, etc. Close examination of this list reveals two important observations. First, even with the short-list of five wells (ranked in order of estimated 5-year incremental production), the first well targets an unstimulated horizon, the next two aim to improve fracture conductivity, and the last two aim to extend fracture length. This order is consistent with the hypothesized restimulation potential by well underperformance category presented earlier. Secondly, the last well, GRB 45-12, was selected by the operator as a "control" well, and was not selected by the methodology (and hence does not have an associated incremental reserve estimate). Based on their extensive experience in the area, Enron believed this well was a strong restimulation candidate.

Restimulation treatments have now been performed on three of the five wells, the GRB 45-12, the GRB 27-14, and the NLB 57-33. The first two treatments were pumped, with minor exceptions, as originally designed. Both treatments were tagged with radioactive material. The GRB 45-12 was designed to treat four intervals simultaneously, each with eight perforations. While the rate was limited to 48 bpm in the pad due to wellhead pressure limitations, the pressures were close to expected. The post-stimulation radioactive tracer log indicated only the two middle sets of perforations took fluid (Figure 9). Thus, the Kf2-1b and 5b interval were not treated while the Kf2-2b and 3b intervals were. Despite this, the GRB 45-12 treatment is considered successful, with post-restimulation production nearly double the pre-restimulation rate (Figure 10).

The GRB 27-14 treatment was pumped through the Kf2-1b and 2b perforations with a bridge plug isolating the Kf2-3b and 5b perforations. Modeling predicted that the Kf2-3b interval should be treated through the Kf2-2b perforations. The post-stimulation radioactive tracer log verified this (Figure 11). The well has not cleaned up however and continues to produce water without the ability to sustain flow. It is anticipated that, once the water is recovered, improved production will be realized (Figure 12).

The NLB 57-33 well was treated to clean-up gel damage believed to exist in the proppant pack. Based upon the results of the laboratory studies, a fluid containing various gel-breaker, penetration aids and diverting agents was proposed. While the objective was to pump at high rates, wellhead pressure rating constraints limited the rate that could actually be pumped, compromising treatment effectiveness. As of this writing post-treatment production was showing continued improvement, but not yet reaching the pre-stimulation rate (Figure 13).

Field Site 2, Piceance Basin

The second field test site is the combined Rulison, Parachute and Grand Valley fields located in the eastern portion of the Piceance Basin. The cooperative research partner, Barrett Resources, operates close to 300 Williams Fork Formation wells in the area. Due to the uncertainty in candidate selection from the first test site, it was decided to perform each analytic process on all wells at this site also. The purpose was to provide further insights into the uniqueness of selections for each level, and if they could be made more consistent from one level to the next. While refinements and improvements in each analytic level were made, the inconsistencies in selections remained. Nevertheless, a list of five candidate wells has been prepared, following individual well reviews, problem diagnosis, treatment design and economic forecasts (Table IV). Combined candidate verification testing and restimulation treatments are scheduled to begin in July.

Field Site 3, East Texas Basin

The third active test site is the Carthage Field in the East Texas Basin. The cooperative research partner, Union Pacific Resources, operates over 300 Cotton Valley wells in the specific project area. At this time, processes I, II, and III have been completed, and the individual well reviews are currently underway. Field activities are expected to commence in July.

Conclusions

The results to date from this project show why methodologies to accurately select "high – potential" restimulation candidates have eluded previous investigators. Each of the analytic procedures utilized thus far is providing a different list of candidates, each based upon different criteria and with uncertainty as to the validity (or lack thereof) of each. While the situations being addressed in this project are understandably complex, specifically multi-layered, heterogeneous reservoirs that are completed and stimulated in a wide variety of ways, the project experience to date supports that no acceptable methodology currently exists to universally select restimulation candidates across different geologic settings.

What is clear is that restimulation potential does appear to exist, as evidenced from the restimulation treatments performed to-date, but that some degree of site-specific knowledge and methodology customization is required. This is supported by the findings from the individual well reviews and laboratory studies. Clearly, more results from this project are needed to better understand the methodologies being investigated, and how they should be integrated to develop the efficient yet robust methodology sought.

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Nomenclature

μd	= microdarcies
%	= percent
$	= United States dollars
Bcf	= billions of cubic feet
bpm	= barrels per minute
ft	= feet
Mcf	= thousands of cubic feet
mlbs	= thousands of pounds
psi	= pounds per square inch
R&D	= research and development
Tcf	= trillions of cubic feet

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TABLE 1 - Data Requirements for Each Process

Process	Description	Data Requirements	Source
I	Prediction Performance Comparison	• Well locations • Production vs time data	• Public database
II	Pattern Recognition Technology	• Geologic/reservoir • Drilling/completion • Stimulation • Workover	• Operator well files
III	Production Type-Curve Matching	• Petrophysics • Reservoir properties	• Interpreted well logs • Well tests

TABLE 2 - Typical Reservoir Properties at Each Test Site *

Basin	Green River	Piceance	East Texas
Test Site	Big-Piney/ LaBarge	Rulison, Parachute, Grand Valley	Carthage
Formation	Frontier	Williams Fork	Cotton Valley
Average Depth to Top	6,300 – 7,400 ft	4,600 – 5,400 ft	8,800 – 9,100 ft.
Original Pressure	4,200 – 4,600 psi	2,800 – 4,200 psi	4,800 – 5,000 psi
Thickness (Gross/Net)	90 – 450 ft / 30 – 80 ft	400 – 1,200 ft / 30 – 300 ft	600 – 1000 ft / 40 – 220 ft
Permeability	10 – 250 µd	5 – 50 µd	5 – 40 µd
Typical Recovery	0.2 – 4.8 Bcf/well	0.3 – 2.3 Bcf/well	0.9 – 4.6 Bcf/well

* 10 – 90 percentile

TABLE 3 - Selected Restimulation Candidates, Green River Basin

(after individual well reviews, problem diagnosis, treatment design, economics, candidate verification tests)

Well No.	Completion	Top “50" List Rank			Restimulation		Estimated 5-Year Incremental	Restimulation Cost		Restimulation Status
		I	II	III	Problem	Treatment Objective	(Bcf)	$1,000	$/Mcf	
CBU 5-14	F21,F22, F23,F24,F25	25	_	15	Unfrac'd in F24/F25	Refrac (unstimulated)	0.24	$140	$0.58	Pending
NLB 66-04	F1	17	7	17	Proppant Settling	Refrac (conductivity)	0.23	$70	$0.30	Pending
NLB 57-33	F1	4	6	20	Gel Damage	Gel Cleanup (conductivity)	0.20	$10	$0.05	Performed 4/8/99
GRB 27-14	F21,F22, F23,F25	_	10	32	Small Fracs	Refrac (length)	0.15	$87	$0.58	Performed 1/6/99
GRB 45-12	F21,F22, F23,F25	_	_	_	Small Fracs	Refrac (length)	_	$87	_	Performed 1/6/99

Notes: 1) “Average” candidates from “Top 50” lists selected; “best” wells reserved until after restimulation success demonstrated.
2) GRB 45-12 selected as “control” candidate independently by Enron.

TABLE 4 - Selected Restimulation Candidates, Piceance Basin
(after individual well reviews, problem diagnosis, treatment design, economics)

Well No.	Field	Top "50" List Rank			Restimulation Type	Estimated 5-Year Incremental	Restimulation Cost	
		I	II	III		(Bcf)	$1,000	$/Mcf
GR 31-2	Grand Valley	49	45	42	Gel Cleanup	0.97	$101	$0.10
RMV 55-20	Rulison	43	-	1	Refracture	0.386	$152	$0.41
RMV 29-27	Rulison	5	-	-	Gel Cleanup	0.34	$79	$0.23
RMV 64-20	Rulison	22	-	45	Refracture	0.31	$151	$0.48
Langstaff #1	Rulison	1	-	-	Refracture	0.316	$163	$0.53

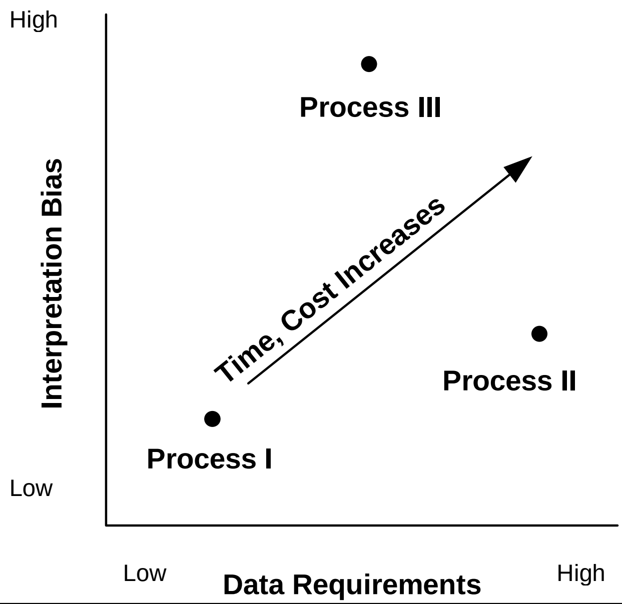

Figure 1: Data Interpretation Requirements for Each Process

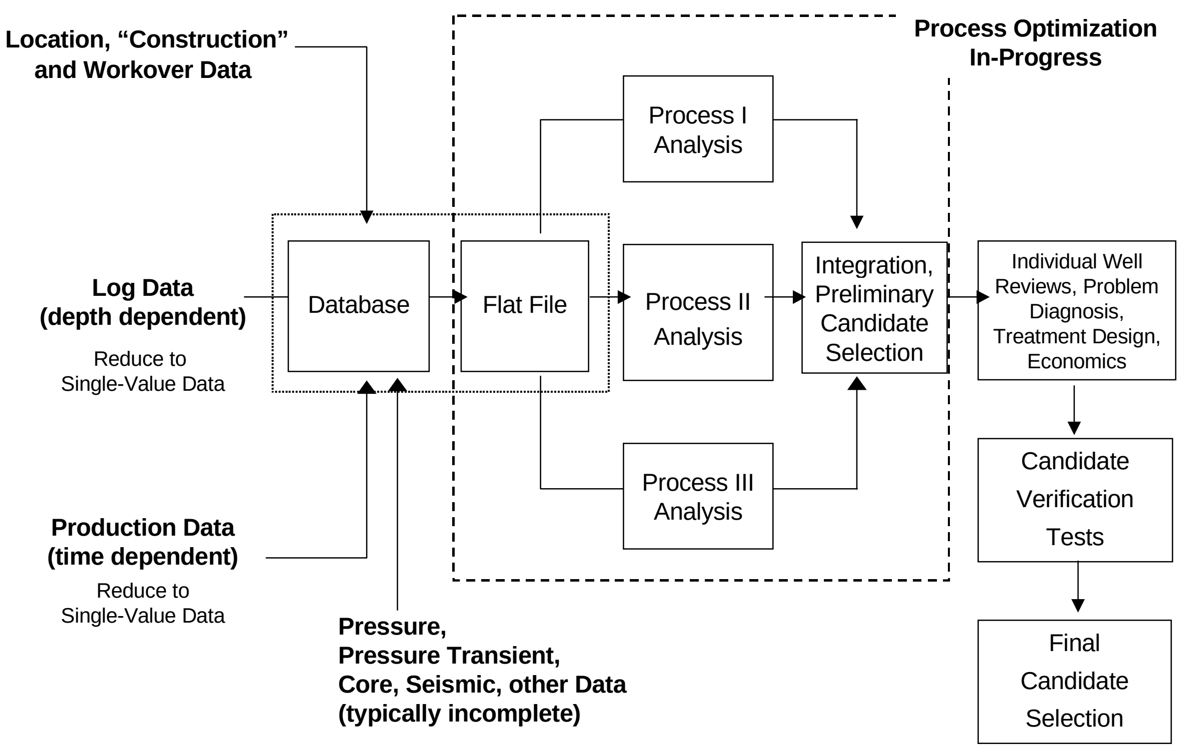

Figure 2: Prototype Candidate Selection Methodology

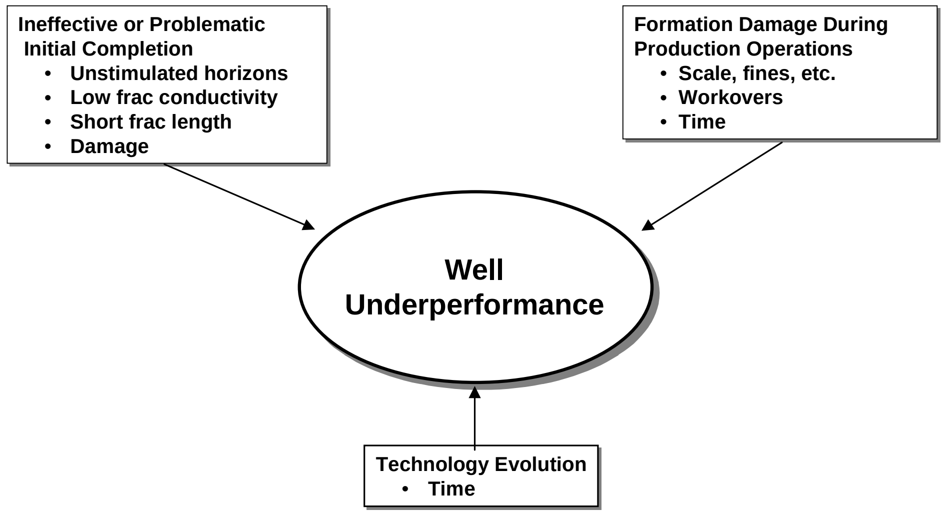

Figure 3: Potential Sources of Well Underperformance

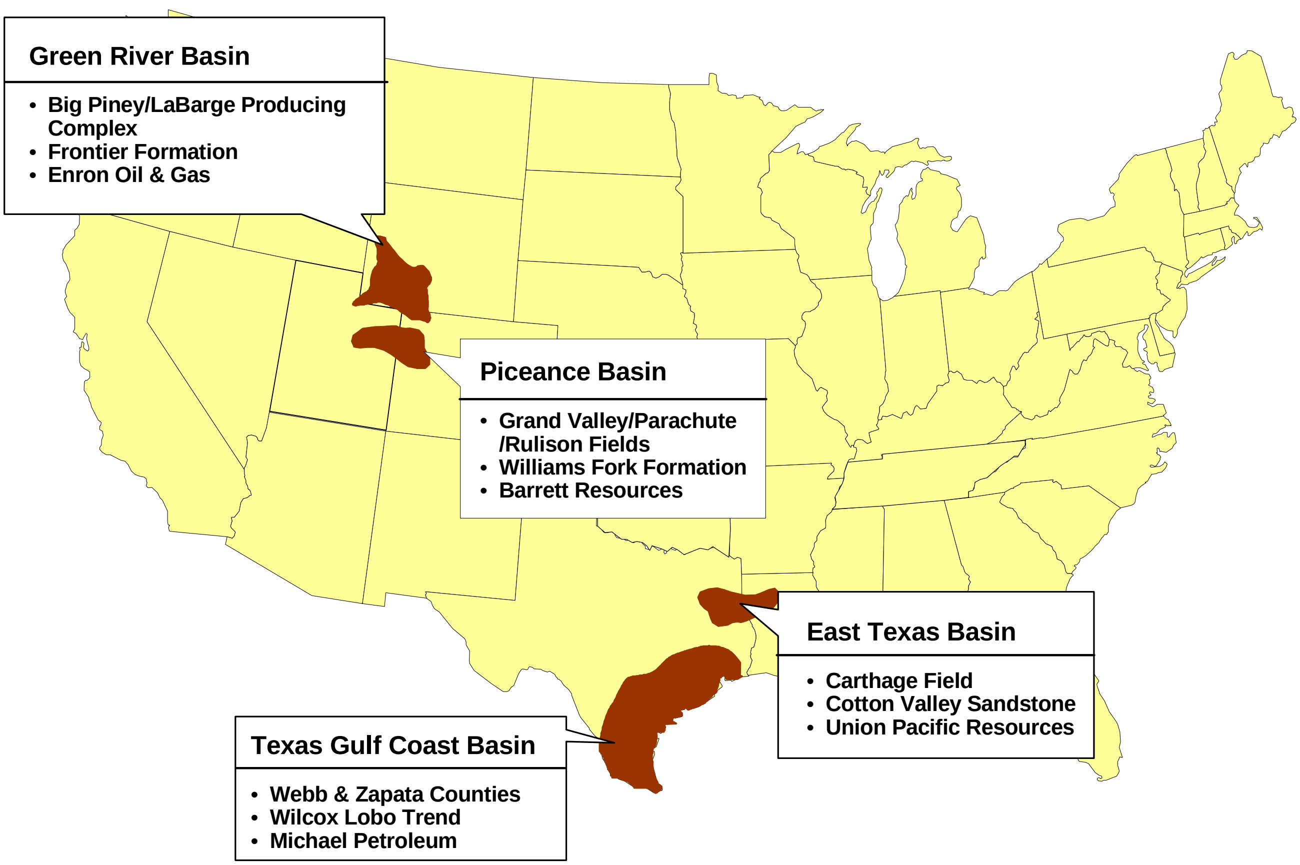

Figure 4: Location of Restimulation Project Test Sites

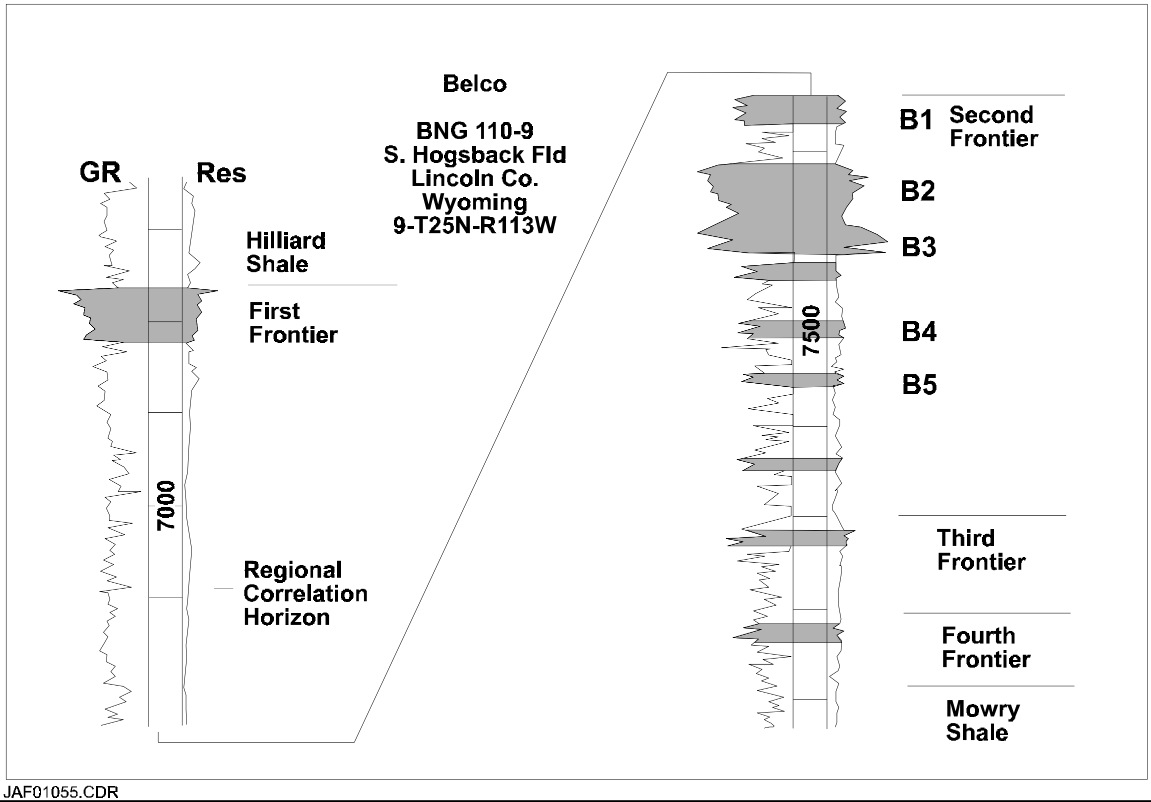

Figure 5: Type Log of the Frontier Formation, Northern Moxa Arch, Green River Basin

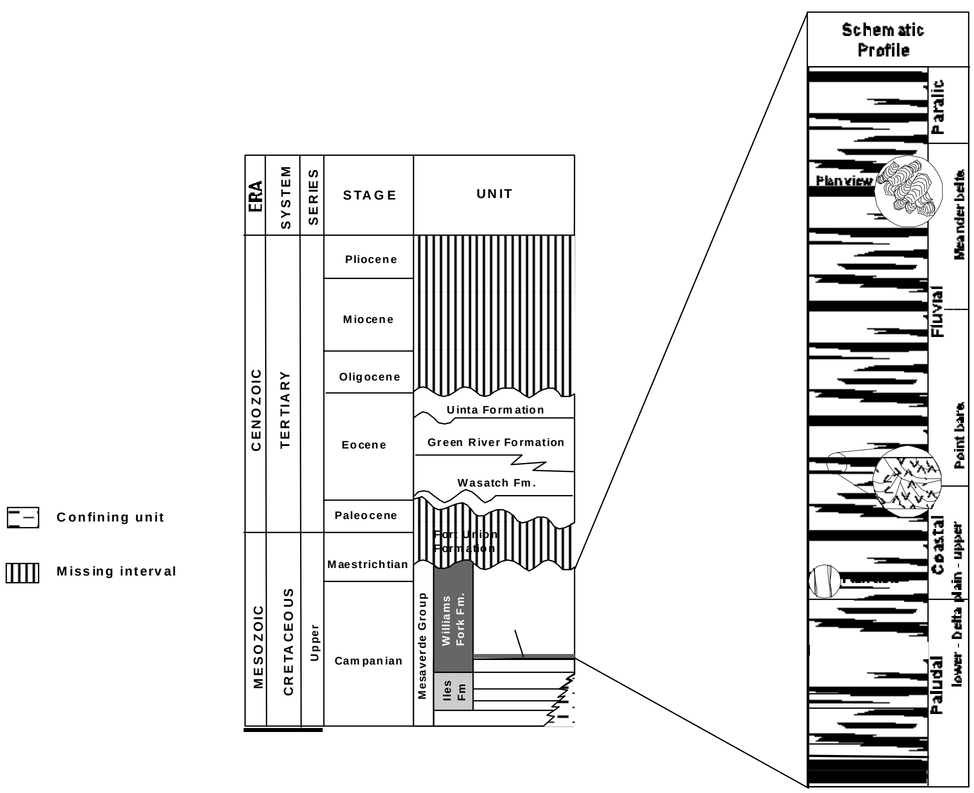

Figure 6: Stratigraphic Column, Eastern Piceance Basin

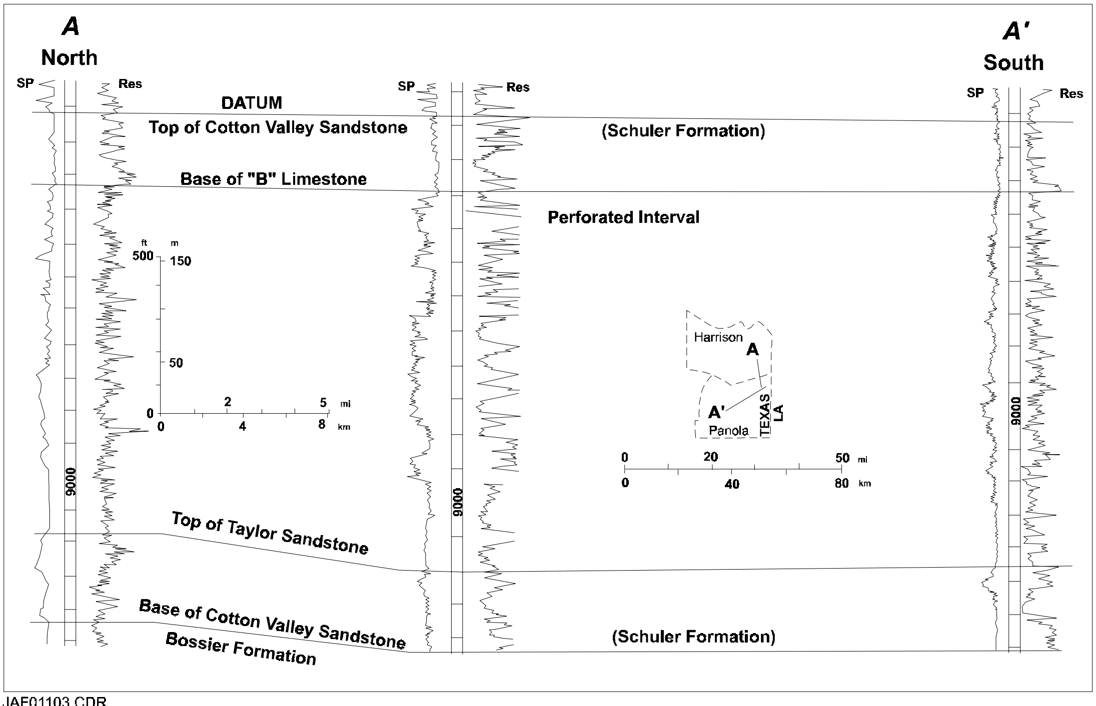

Figure 7: Cross-Section of the Carthage Field, East Texas Basin

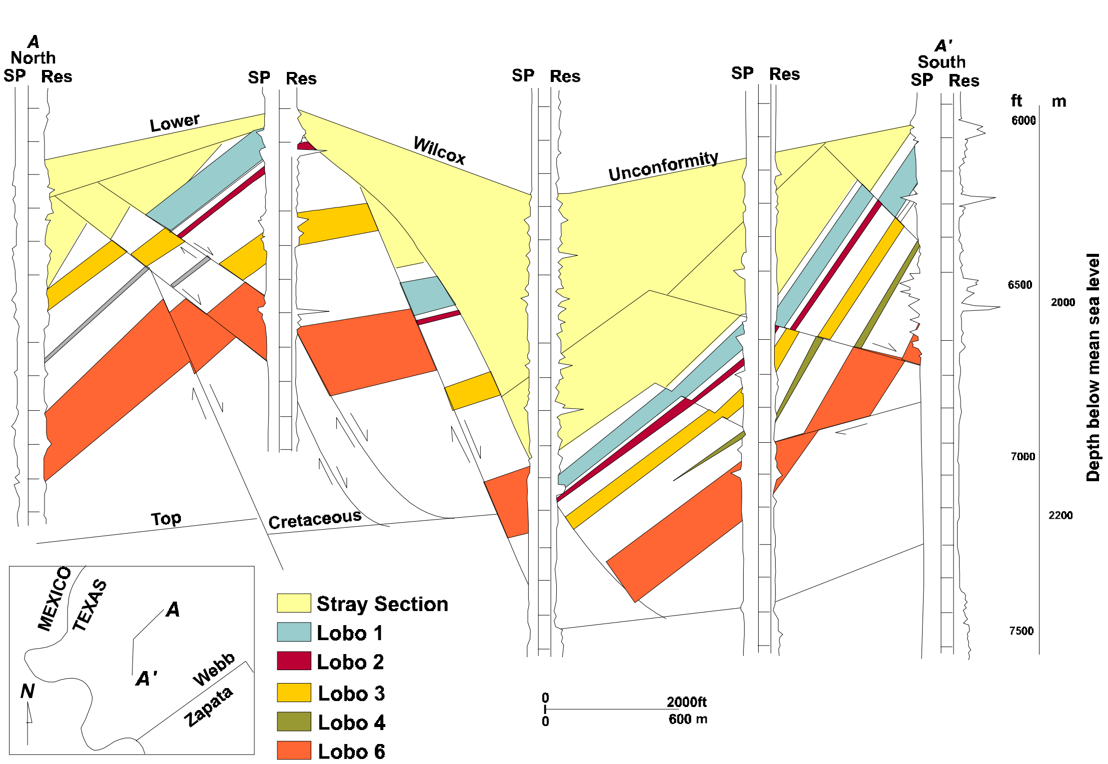

Figure 8: Cross Section of Laredo (Lobo) Field, South Texas Basin

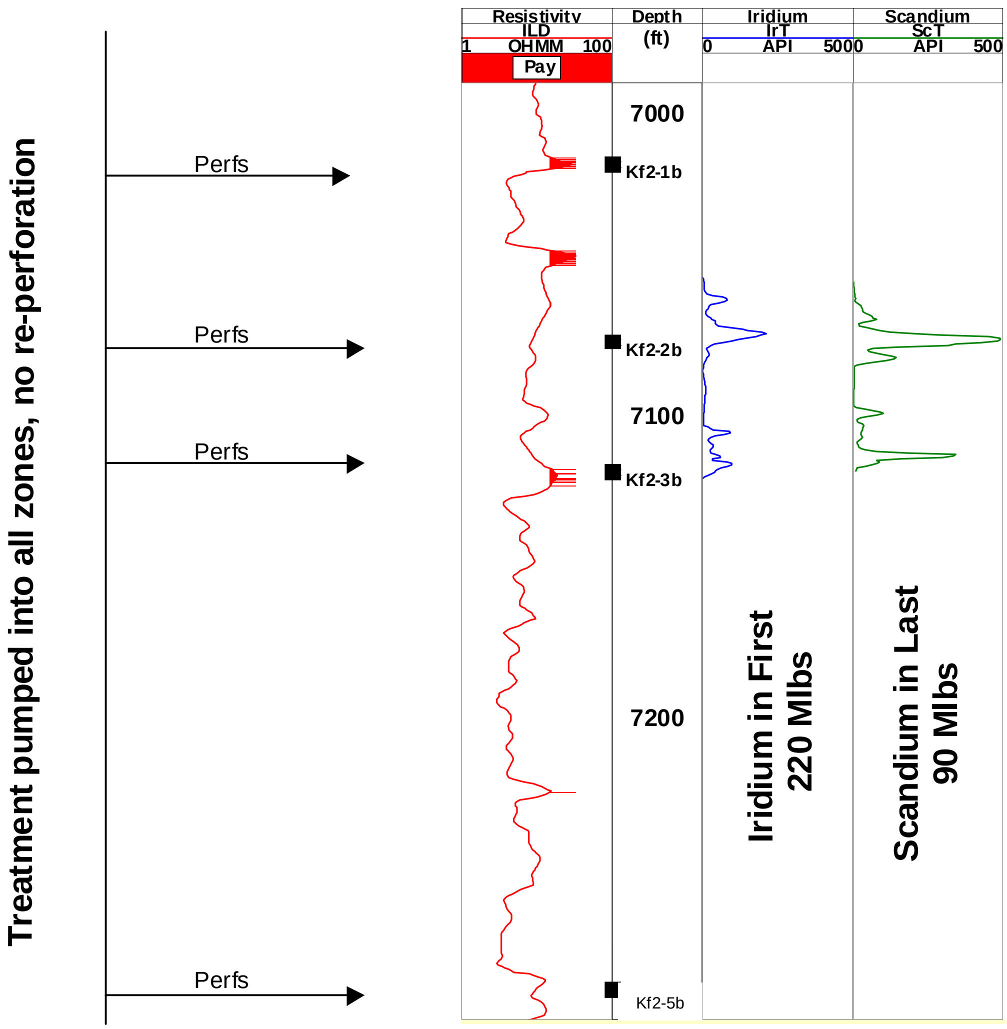

Figure 9: Post-Treatment Radioactive Tracer Survey, GRB 45-12

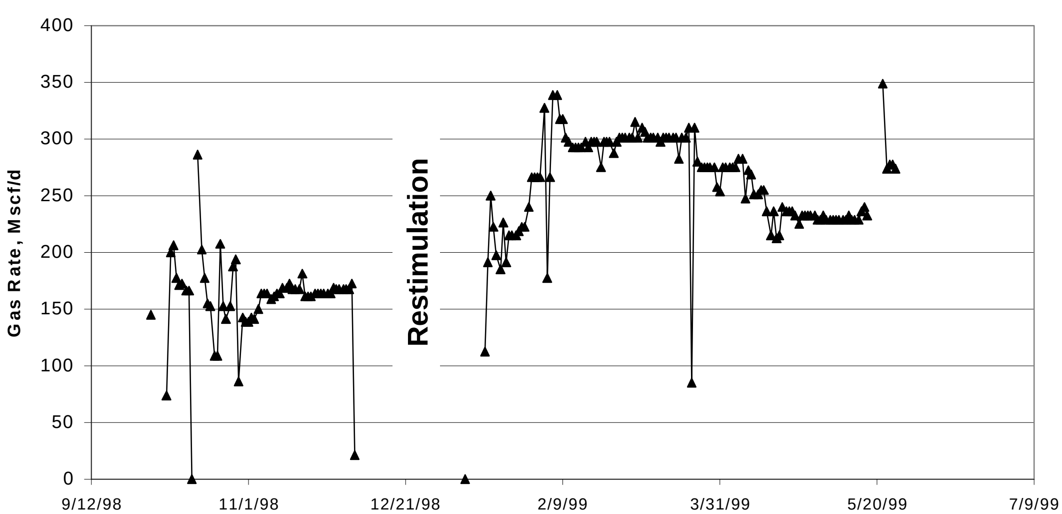

Figure 10: GRB 45-12 Restimulation Results

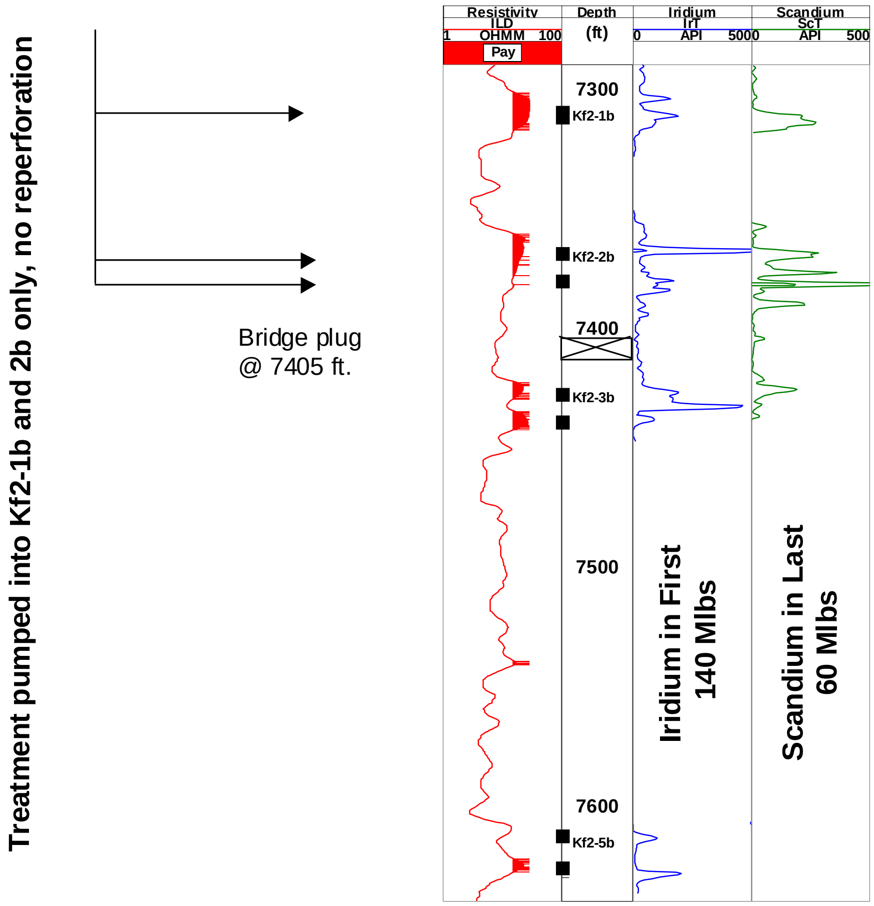

Figure 11: Post-Treatment RA Tracer Survey (GRB 27-14)

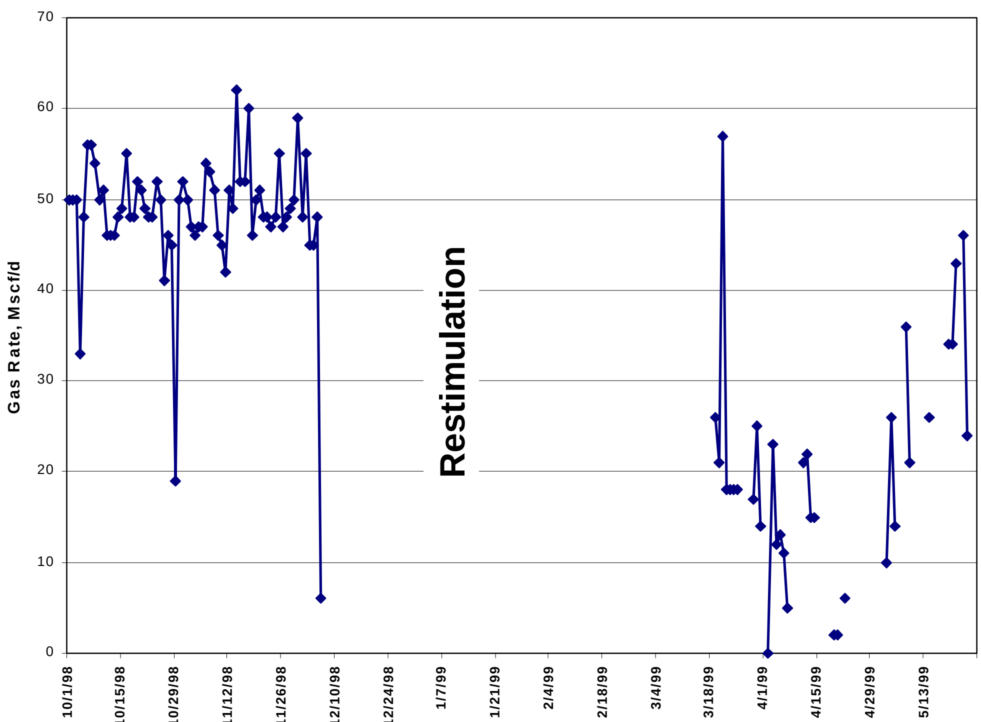

Figure 12: GRB 27-14 Restimulation Results

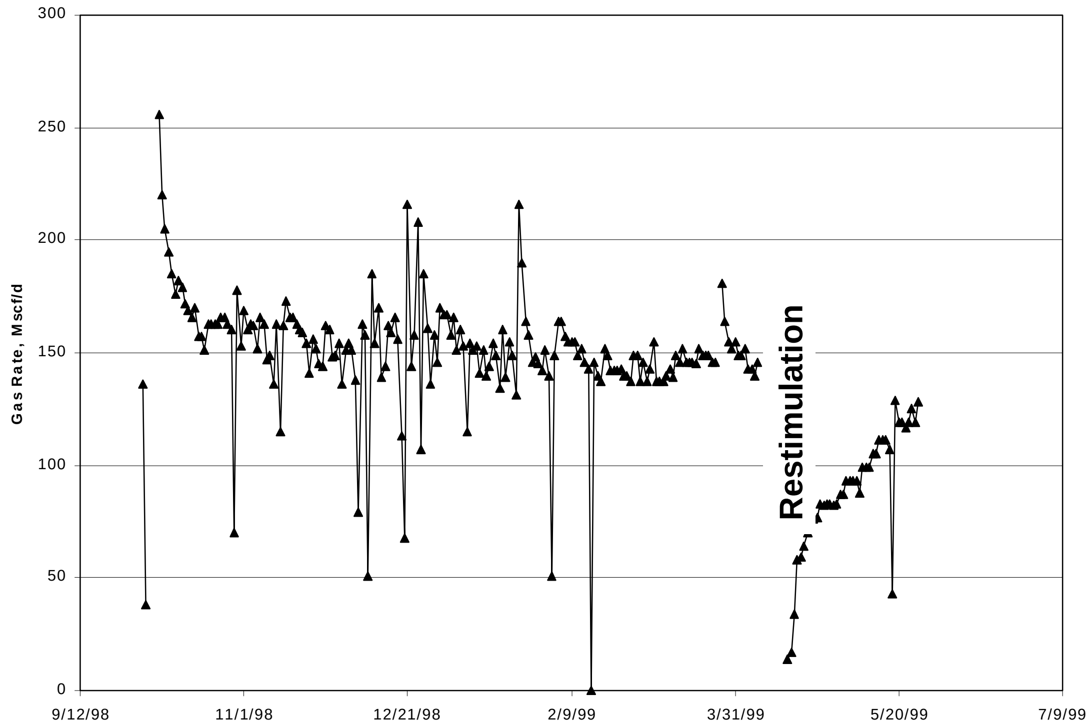

Figure 13: NLB 57-33 Restimulation Results