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Restimulation of Tight Gas Sand Wells in the Rocky Mountain Region

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Abstract

Introduction

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).[1, 2] The results indicated that the potential was substantial (over one Tcf of reserves in five years), particularly in the tight 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 subsequent 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, and 3) develop and test various restimulation techniques tailored to different causes of well underperformance. 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 financial benefits they represent, particularly in today's challenging economic climate.

The approach adopted for the R&D program is a combination of conceptual methodology development, laboratory studies, and actual field testing of restimulation treatments in tight gas sand reservoirs. In total, four test sites are planned for the project; each site consists of about 300 total wells in a contiguous area and completed in a consistent producing horizon, out of which five are selected for actual restimulation. The locations of the selected sites are presented in Figure 1. The first two sites are in the Rocky Mountain region, the first being in the Big-Piney/LaBarge Producing Complex of the northern Moxa Arch in the Green River Basin (Frontier Formation), and the second being the combined Rulison, Parachute and Grand Valley fields of the eastern Piceance Basin (Williams Fork Formation). At present, restimulation candidates have been selected, verification testing completed, and two restimulations performed at the first site; preliminary candidate selections have been made at the second site. The East Texas and South Texas test sites are currently in the earliest stages of data collection and analysis. This paper presents the candidate selection methodology as it currently exists (it is under continuous improvement), and the results-to-date from the two Rocky Mountain test sites.

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. In the previously cited GRI study, an important finding was what is referred to as the "85/15" rule. 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 the total well population that represents the high-potential restimulation candidates. Project economics are highly sensitive to accurate candidate recognition and selection. Poor candidate selection procedures seem to be the reason that many restimulation projects are unsuccessful.

With this understanding, two concepts formed the foundation of the candidate selection methodology. The first concept 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 cost.

The second concept is that to accurately select candidates, well performance must be separated into the reservoir quality and completion efficiency components (i.e., permeability and skin). High-potential candidates, those that would provide the greatest level of incremental production and reserves, are likely to be wells exhibiting both high permeability and high 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 the more productive wells in a field is understandably performed reluctantly, not doing so may be the very reason many restimulation projects do not reach expectations. A candidate selection methodology was therefore prepared with these two concepts in mind, and subsequently field-tested as will be described in the next section. Brief summaries of the methods used for each analytic level are provided below:

Level I Rapid Screening: Statistical Production Data Analysis. In the most simple terms, Level I essentially compares the production performance of each well to its offsets, and identifies underperforming wells that could be restimulation candidates. The process is quite advanced however in that it compares life-cycle production, early-time performance and most-recent performance each separately to provide insights into why a well may be underperforming, and accounts for depletion associated with infill drilling. The drawback of this technique is that it does not identify those "superior" wells that could be improved, and that could be the source of the most favorable restimulation economics. Nevertheless, the selection of underperforming wells, particularly where reservoir properties and completion/stimulation practices are more uniform, is a valid candidate recognition approach[3].

Level II Advanced Screening: Artificial Neural Nets and Genetic Algorithms. The second analytic level utilizes artificial neural nets and genetic algorithms to identify potential restimulation candidates. Artificial neural nets are utilized to recognize patterns in how various input parameters (e.g., location, geology, drilling, completion, stimulation and workover data, etc.) impact the well output (i.e., production). This information serves several useful purposes. First, the relative contribution of geologic/reservoir parameters can be separated from drilling, completion, and stimulation parameters. 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 "worst" 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 (select those “controllable” input parameters that yield the highest predicted production response) and those wells where the greatest discrepancies exist between actual well performance and predicted optimized performance are identified as restimulation candidates. The difficulty with this approach is that frequently the amount, type and quality of data available is insufficient to perform a meaningful and insightful analysis; all technical data used for an analysis must be available for all wells. One piece of missing information for one well requires that either that well or that piece of data (for all wells) be eliminated. Nevertheless, this approach is believed to hold great potential for evaluating restimulation opportunities in tight gas fields[4].

Level III Candidate Identification: Production Type-Curve Matching. 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 pressure transient testing. An alternative approach is to use production type-curves. Such curves have been specifically developed for hydraulically fractured tight sand wells in the western U.S., and can provide estimates of the permeability, skin and drainage area with relatively limited data[5]. The problems with this approach are several-fold however; first, the models are developed for single-layered reservoirs, and the multi-layered nature of most tight sand plays render the results suspect. 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 require values of net pay for each well, some interpretive and potentially labor-intensive petrophysical evaluation may also be required. With an understanding these limitations, however, such approaches can be used in a relative sense to identify potential restimulation candidates.

Field Test 1: Green River Basin

Site Description. The first field test site is the Big-Piney/LaBarge Producing Complex located in the northern Moxa Arch area of the Green River Basin (Figure 2). The cooperative research partner, Enron Oil & Gas, operates close to 300 Frontier Formation (not commingled with production from other horizons) wells in the area. A type-log of the Upper Cretaceous Frontier Formation is shown in Figure 3; the productive horizons in the area include the First Frontier, and benches one through five of the Second Frontier. The Second (and Third) benches of the Second Frontier are the most prolific gas reservoirs, and are marine sandstones. Benches 1, 4 and 5 are primarily fluvial, with the First Frontier being a deposited in a distal shoreface environment. Reservoir properties can vary considerably for each horizon, but each reservoir is relatively continuous and can be distinctly correlated throughout the project area. Table 1 provides selected reservoir information for the field.

Well vintages in the study area range from the late 1950's through to the present, representing an interesting blend of completion/stimulation technologies used, stages of infill drilling, depletion and mechanical (wellbore) issues to consider. The completion intervals for each well are typically based upon log-derived net pays, and hence vary from well to well. Wells can be completed in only one or up to six different pay horizons, and production from multiple pays is commingled.

Candidate Selection and Problem Diagnosis. Being the first field test of the methodology, the three levels of analysis for candidate selection were each performed on all wells at the site. This was to ensure that each analytic level captured all the potential candidates from the subsequent levels (i.e., the preliminary levels did not eliminate candidates that would likely be selected by subsequent, more detailed levels). Once completed, the top 50 candidate wells from each level were compared. That comparison is illustrated in Figure 4. What can be observed from this figure is that the coincidence of candidates from one level to the next is inconsistent; further, the top candidates from each level were unique to that level, and are not replicated in the other levels. The implication is that since each level seems to focus on different indicators of restimulation potential, each selects different candidate wells. For example, Level I selects wells that are underperforming their offsets, Level II selects wells where "less-than-best" practices were employed, and Level III selects wells with the greatest estimated upside potential, albeit using non-unique engineering methods.

Without a clear indication of which process was truly providing the best candidates, or if they were each providing high-potential candidates with different characteristics, those candidates that appeared on more than one "top 50" list, plus the top 5 wells that were unique to each list, were selected for further, detailed individual well reviews. Together these wells added up to a short list of about 50 wells for detailed consideration as restimulation candidates.

The candidate wells were then individually evaluated to choose those with the greatest chance of restimulation success. This involved detailed study of all information in the well files as well as interviews with personnel that had direct expenses with the well being considered. Information considered included:

- The mechanical integrity and condition of the wellbore, such as pipe size, weight, and grade, perforations or holes in the casing, cement squeeze treatments, primary cement volume and expected top of cement, primary cement results, wellbore deviation, perforation intervals, number of perforations, production packers, production tubing, sliding sleeves, scaling problems, stuck tubing, the existence and location of any fish, the production method, i.e., plunger lift, intermitted, siphon string, etc.
- The original completion and stimulation data procedures including perforating for limited entry, treating pressures, treating rates, fluid volume, fluid type, proppant volume, proppant type, fluid details such as polymer type, breakers, clay stabilizers, crosslinker type, surfactants, etc., screen-outs, ISIP's, and anything else noted in the files.
- The flowback procedure, such as shut-in time, forced closure, the amount of fluid recovered, and any noted problems such as gel observed for extended periods of time.
- Production history, such as initial production, production decline, production by intervals, water onset, amount of condensate produced, etc.
- Pressures, such as initial pressure, pressure buildups, DST's, pressures during shut-in periods, etc.
- Any workovers such as new perforations, acid for scale removal, squeeze of perforations, setting of bridge plugs, etc.
- Many of the wells were drilled and completed about 40 years ago. There were no indications of severe pipe deterioration from production fluids and gases, and age therefore was not considered as a factor by itself.

Those wells with mechanical problems, such as squeeze-cement holes above the perforations, stuck tubing or packers, very small primary cement volumes (or those squeeze cemented to increase cement height), those wells which would create perforation or zonal isolation problems, and wells completed with low-grade, low-weight casing, were essentially eliminated from further consideration. While these wells may indeed be good restimulation candidates, they possessed a high risk of mechanical failure and/or cost. Similarly, deviated wells with large numbers of perforations across several feet would require squeeze-cementing and reperforating, which would increase the risk and cost of the treatments, and were therefore also downgraded as candidates.

Reservoir pressure was a major uncertainty for these wells. The initial pressure, cumulative production, latest pressure information and the rate of production since that time were considered in an effort to evaluate present-day pressures in the short list of wells. Wells with an expected BHP of 1500 psi or less were downgraded on the candidate list. Those wells which were considered to have gel, fluid, and/or scale damage were rated fairly high (if justified by other considerations) as the cost for restimulation would be lower than for wells needing refracturing.

The top 20 candidates following this stage of analysis were submitted to the operator, Enron Oil & Gas, for review. Wells were then further eliminated for various reasons, including uncertainty in the accuracy of the production data, uncertainty on the cause of well under performance, and production levels being "too high" to risk. Out of this, 7 wells were chosen as restimulation test wells. Note that, in general, these wells ranked in the middle to lower and of the "top 50" list from each analysis level.

The original stimulation treatments for these seven wells were then modeled using an industry standard hydraulic-fracturing model. Many early treatments utilized ungelled diesel, while later treatments used various crosslinked fluids, foams, and emulsions. In general, the results indicated the existence of low conductivity fractures, and that proppant settling was probable. This was especially obvious in the Kf1 and Kf2-2b (Figure 3) intervals, where downward fracture growth appears likely.

Pressure Transient Testing. The overall methodology also included a testing component to verify the stimulation effectiveness of the ranked candidates. In addition to applying conventional well testing methods to restimulation candidates, new or novel methods specifically designed to address the problems associated with testing low permeability gas wells were studied. The objective outcome of the new testing method is not a quantitative analysis, but rather a qualitative determination of the current stimulation effectiveness existing in the well. In addition, the testing procedure itself had to be simple, inexpensive and of short duration, to be practical.

For this test site, different testing procedures were designed to handle the various mechanical configurations of the wells, including conventional shut-in tests and a multi-rate test for wells on either plunger lift or intermittent operation. As part of the objective to develop inexpensive testing procedures, the test designs included both bottomhole and surface pressure measurements to determine if surface measurements could be used instead of the more costly and difficult bottomhole pressure measurements.

A total of seven wells were tested; these seven tests were analyzed using conventional methods as well as the newer, novel technique developed to qualitatively determine the stimulation effectiveness of the wells. Table 2 presents a summary of results for the conventional analyses, compared to various production analysis (Level III) methods.

These results show that the interpreted values of permeability are very low, with a wide range of fracture lengths. Unfortunately, the data were often too noisy to apply the newly developed technique, and hence the results were very non-unique. This applied to both the surface and bottomhole data. The conclusion was that it was relatively difficult to assess the degree of stimulation in the wells using the new method, especially with surface-acquired data. A new approach has subsequently been developed for the next site. Using the conventional analysis results, two wells were eliminated from further consideration; the Larson 1-17 was dropped because of the well-test derived long fracture length and low permeability, and the SHB 12-04 was dropped due to a lack of results (plus the long fracture lengths as determined by Level III).

Treatment Design, Incremental Production and Economic Forecasts. The key questions to be answered regarding the restimulation treatments were, 1) what intervals to treat and 2) how to treat them. For the seven-selected test wells, the following appraches were adopted:

- The GRB 45-12 and GRB 27-14 wells were both originally treated with small proppant volumes and hence larger treatments to create greater length were designed. In the GRB 45-12 well, the original intervals of Kf2-1b, 2b, 3b and 5b each had 8 perforations, which could all possibly be retreated simultaneously using limited entry. In the GRB 27-14 well, a decision was made to treat only the Kf2-1b and 2b perfs, with a bridge plug set over the 3b perfs. The 3b interval would probably be treated through the 2b perfs as no fracture barrier existed between them. The 4b was nonexistent and the 5b was of small net height hence not targeted for restimulation.
- The CBU 5-14 well was originally treated over a large interval; it is not believed that the lower benches were effectivively stimulated. This well was therefore selected for two treatments since the net pay height was widely distributed throughout the Kf2 interval.
- The NLB wells were completed in the Kf1 bench only and with a tubingless completion technique. The NLB 57-33 was deemed to have polymer damage and a fracture clean up treatment was designed for this well. That treatment design for the NLB 57-33 well contains large concentrations of oxidative and enzyme breakers and pH modifiers to break the borate crosslinked and guar gel. The NLB 66-4 was to be refractured to re-establish conductivity as the initial treatment utilized a larger pad with proppant settling a high probability.

The treatments were designed for ±250 feet of fracture length. The addition of more length appeared uneconomical and could also create water recovery problems due to fluid volumes in the depleted pressure environment. Modeling of the restimulation treatments utilized a reduced stress gradient value for the sandstone intervals, but the original stress gradient (1 psi/ft) in the bounding shale layers. The refracs were therefore much more bounded than the original treatments.

The refracturing treatment designs included using a 35lb/Mgal guar gel crosslinked with borate. Nitrogen was not utilized for a flow-back assist at the request of the operator; this simplified and reduced treatment cost, and if needed, could still be utilized to unload the well at a later date. Proppant consisted of 20/40 mesh Ottawa sand that should have sufficient conductivity for the depleted formations.

Laboratory data was also used to aid in the restimulation design process in two ways. The first involved developing general guidelines for conducting remediation treatments that do not involve the use of additional proppant. The second was to address specific issues regarding additives to be used in the stimulation treatments.

X-ray results showed that both the fluvial and marine sequences in the Frontier Formation contain similar clays that line the pores (Table 3). Both swelling and non-swelling clays are present; a typical example of a pore is shown in Figure 5. Fibrous illite is on top of the more general coating of illite/smectite. Some quartz overgrowth is also visible.

The principal stimulation fluid currently in use in this area is a borate crosslinked gel system. Because of the presence of swelling clays, there was concern about the type of clay protection that was required to maximize the compatibility of water based stimulation fluids with the reservoir. The laboratory data presemted in Figure 6 shows that 2% KCl is required for maximum clay protection. The KCl substitutes provide some improvement over fresh water but clearly suffer leading edge depletion as the limited amount of clay stabilizer is plated out on the clays. For these reasons, the stimulation fluids used in the refracturing operations contained 2% KCl.

Once the treatments were designed, restimulation costs were estimated. Incremental production predictions were also made using type-curve models; an example is shown in Figure 7. Restimulation economics were then computed, as provided in Table 4. For these wells, 5-year incremental estimate ranged from 0.15 to 0.24 Bcf, with recovery costs ranging from $0.05 to $0.58 per Mcf. Again, note that these wells were not the top picks from any of the analytic levels, but were considered average candidates. The GRB 45-12 was not selected by the methodology at all, but rather was selected by the operator, and represents a control case. An incremental production estimate was therefore not available for this well.

Treatment Execution and Results. Restimulation treatments have now been performed on two of the five wells, the GRB 45-12 and the GRB 27-14. These 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 8 perforations. While the rate was limited to 48 bpm in the pad due to wellhead pressure limitations, the pressures were close to expected. The well was flowed back immediately, utilizing the forced closure technique. The flush volume was recovered and the well continued to flow for several hours. Tubing was run and the well cleaned up rather quickly. The post-stimulation radioactive tracer log indicated only the two middle sets of perforations took fluid (Figure 8). Thus the Kf2-1b and 5b perfs were not treated while the Kf2-2b and 3b perfs were treated. Despite this, the GRB 45-12 treatment is considered successful, with post-restimulation production nearly double the pre-restim rate (Figure 9).

The GRB 27-14 treatment was pumped through the Kf2-1b and 2b perfs with a bridge plug isolating the Kf2-3b and 5b perfs. Modeling predicted that the Kf2-3b interval would be treated through the Kf2-2b perfs. The post-stimulation radioactive tracer log verified this (Figure 10). Once again, the well flowed back for several hours using the forced closure technique. However, the well has not cleaned up 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.

Next Steps. The remaining tasks to be completed at this site include the restimulation of the final three test wells, and post-restimulation pressure transient testing on all five-test wells to evaluate treatment effectiveness.

Field Test 2: Piceance Basin

Site Description. The second field test site is the combined Rulison, Parachute and Grand Valley fields located in the eastern portion of the Piceance Basin (Figure 11). The cooperative research partner, Barrett Resources, operates close to 300 Williams Fork Formation wells in the area. A stratographic column of the Upper Cretaceous Williams Fork Formation is shown in Figure 12; unlike the Frontier Formation in the LaBarge Platform, the productive horizons in the area are discontinuous, massively stacked lenticular sands. This is a basin-centered gas play, with the potential for water production increasing in the upper portions of the gross interval. The lowermost Cameo section is paludal sandstone, which is overlain by coastal sandstones that transgress into fluvial sands. There can be as many as 40 discreet net pay intervals in the several thousand feet of gross interval, but typically they cannot be correlated from one well to the next, even on close spacing. Table 1 provides selected reservoir information for the field.

Development of the area began in 1980, but the most intensive drilling has occurred since 1990. Development strategies have evolved, including infill drilling from an original spacing of 160 acres to as little as 20 acres per well recently in some areas of the Rulison and Grand Valley field. Fracturing and completion strategies have also evolved, including the move to limited entry fracturing and crosslinked gel fluids (up to 4 fracture treatments per well, each targeting several hundred feet of gross interval), and attempting to capture additional pay by more aggressive uphole, completions (nearer to the water-wet intervals). Similar to the first site, production from all completed horizons in a well is commingled.

Candidate Selection Results. 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 more made, the inconsistencies in selections remained (Figure 13). A similar process for candidate selection, now underway and encompassing both coincidental candidates and the top candidates from each level, is being performed. This is the extent of progress at this time for this site.

Conclusions

Acknowledgements

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Nomenclature

º F	=	degrees Farenheit
µd	=	microdarcies
$	=	United States dollars
BHP	=	bottom-hole pressure
BPM	=	barrels per minute
DI	=	distilled and ionized
DST	=	drill-stem test
ft	=	feet
gal	=	gallons
lbs	=	pounds
lkCl	=	potassium choloride
ISIP	=	instantaneous shut-in pressure
Mcf	=	thousands of cubic feet
Mgal	=	thousands of gallons
md	=	millidarcies
min	=	minutes
ml	=	milliliters
psi	=	pounds per square inch
R&D	=	research and development
SEM	=	scanning electron microscope
Tcf	=	trillions of cubic feet

References

1 – restim topical report
2 – GasTips article
3 – moving domain paper
4 . Mohaghegh, S., Arefi, R., Ameri, S. “Petroleum Reservoir Characters
5 – Cox type-curve paper

Table 1
Typical Reservoir Properties at Each Test Site

Basin	Green River	Piceance
Test Site	Big-Piney/ LaBarge	Rulison, Parachute, Grand Valley
Formation	Frontier	Williams Fork
Average Depth to top	6,300 – 7,000 ft	4,800 – 5,400 ft
Original Pressure	4,200 – 4,600 psi	3,800 – 4,200 psi
Thickness (Gross/Net)	100 – 400 ft / 15 – 90 ft	1,700 – 2,400 ft / 150 – 300 ft
Permeability	10 – 150µ	5 - 100µ
Typical Recovery	1 – 2 Bcf/well	1 –2 Bcf/well

Table 2 - Well Test Results Comapared to Level III Analytic Results, Green River Basin

	Permeability (md)				Fracture Length (ft)				Drainage Area (acres)			
Well Name	**ARIType[1]**	**Promat[2]**	**RPI[3]**	**Well Test**	**ARIType[1]**	**Promat[2]**	**RPI[3]**	**Well Test**	**ARIType[1]**	**Promat[2]**	**RPI[3]**	**Well Test**
Larson 1-17	**<0.01**	**0.02 – 0.03**	**0.02**	**<0.01**	**193**	**1**	**6**	**162**	**42**	**-**	**20**	**-**
GRB 45-12	**0.02**	**0.02 – 0.11**	**0.1**	**0.02 – 0.05**	**280**	**1 – 3**	**<1**	**50**	**258**	**-**	**>350**	**-**
NLB 66-04	**0.02**	**-**	**-**	**-**	**248**	**80 – 104**	**-**	**123**	**23**	**-**	**>25**	**-**
SHB 12-04	**0.02**	**-**	**0.05**	**-**	**341**	**-**	**-**		**54**	**-**	**-**	**-**
GRB 27-14	**0.01**	**0.01 – 0.03**	**0.02**	**-**	**200**	**1**	**-**	**-**	**45**	**-**	**-**	**-**
CBU 5 –14	**<0.01**	**<0.01**	**0.01**	**<0.01**	**130**	**63 – 68**	**52**	**50**	**56**	**-**	**60**	**-**
NLB 57-33	**0.01**	**0.02 – 0.05**	**0.06**	**0.06**	**234**	**1**	**1**	**166**	**45**	**-**	**100**	**-**

[1] Fractured, tight grs sand type-curve
[2] Multi-purpose type-curve
[3] Recipricol productivity index method

Table 3
X-Ray Diffraction Analysis
Frontier Formation

Well	GRB 137-4	ELB 55-32
Bench	Kf2-2b	Kf2-2b
Type	Fluvial	Marine
Depth	7262.3 feet	6955.3 feet
Qaurtz	68	64
Plagioclase	19	12
Pyrite	Trace	Trace
Calcite	2	-
Apatite	Trace	-
Total Clay	11	24*
I/S Mixed Layer	6	13
Illite	3	5
Chorite	2	4
Kaolinite	-	2

* Mica was not determined

Table 4 – Restimulation Economics, Green River Basin

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

Figure 1 - Location of Test Sites

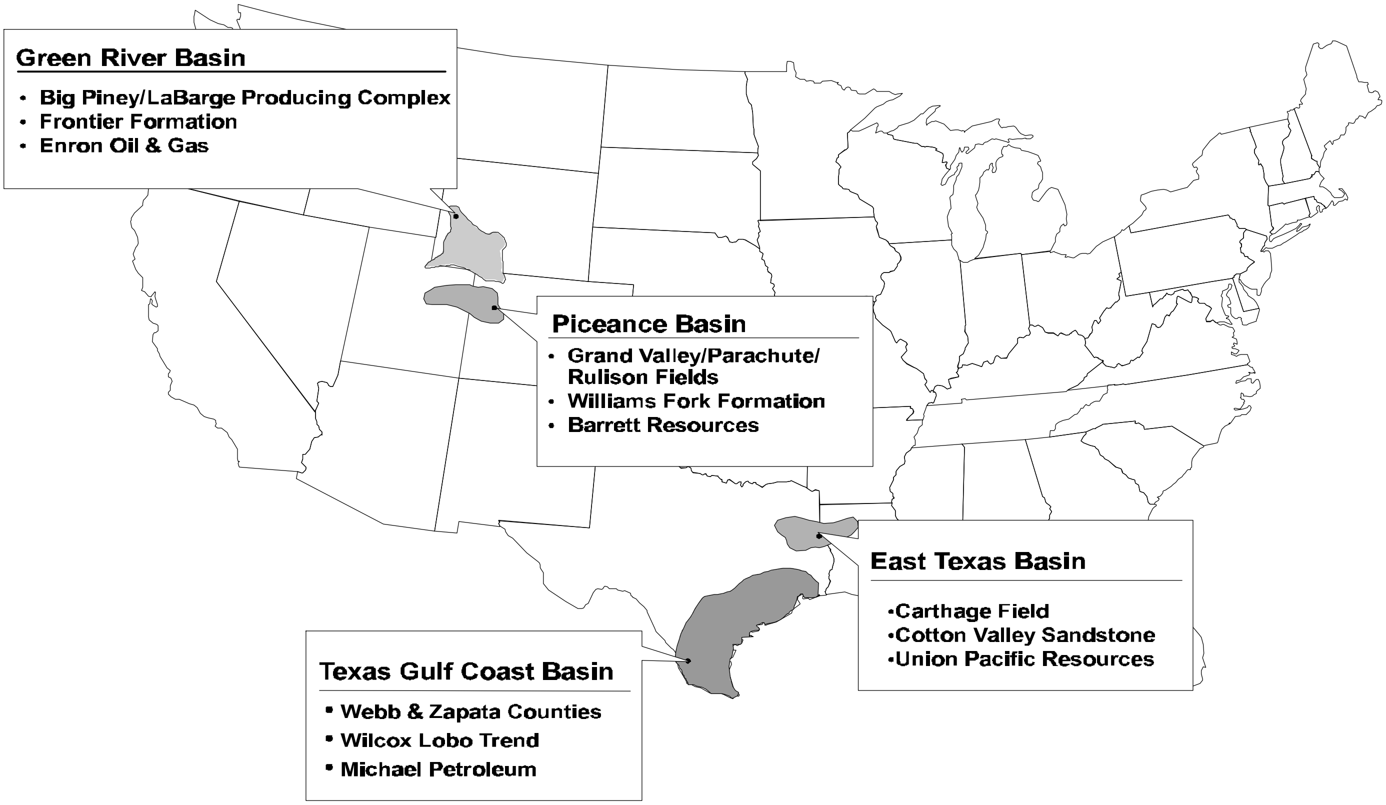

Figure 2 - Green River Basin Study Area

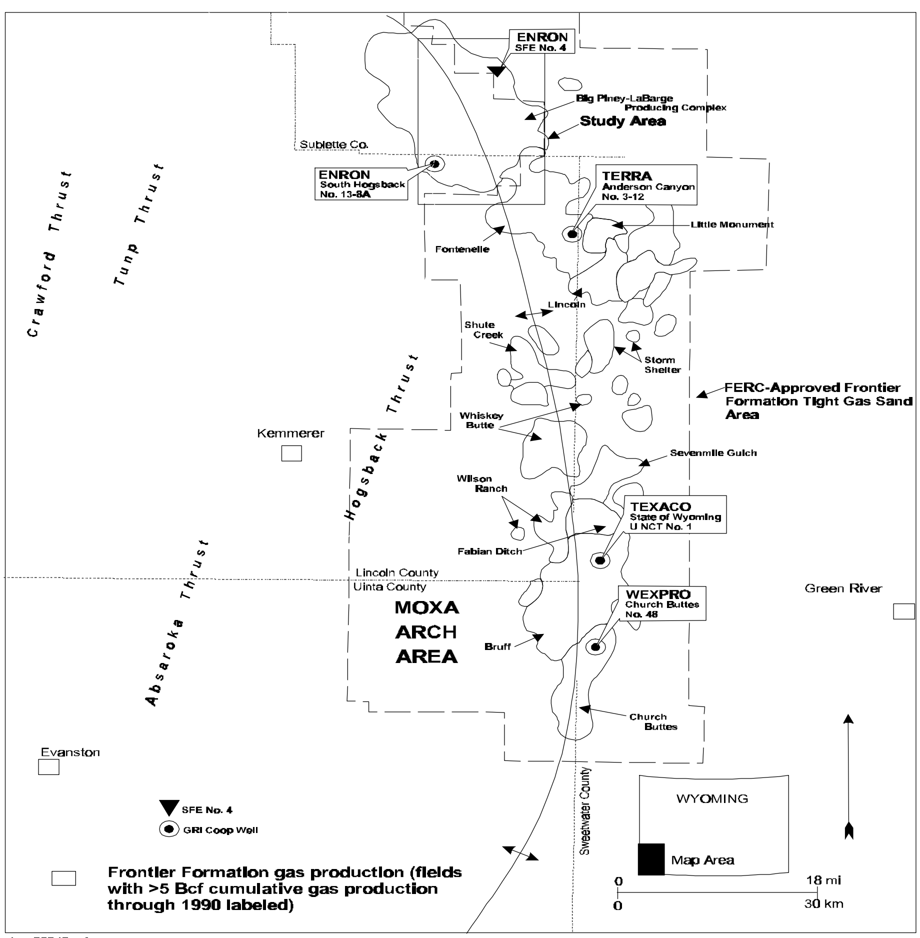

Figure 3 – Type Log of the Frontier Formation, Northern Moxa Arch, Green River Basin

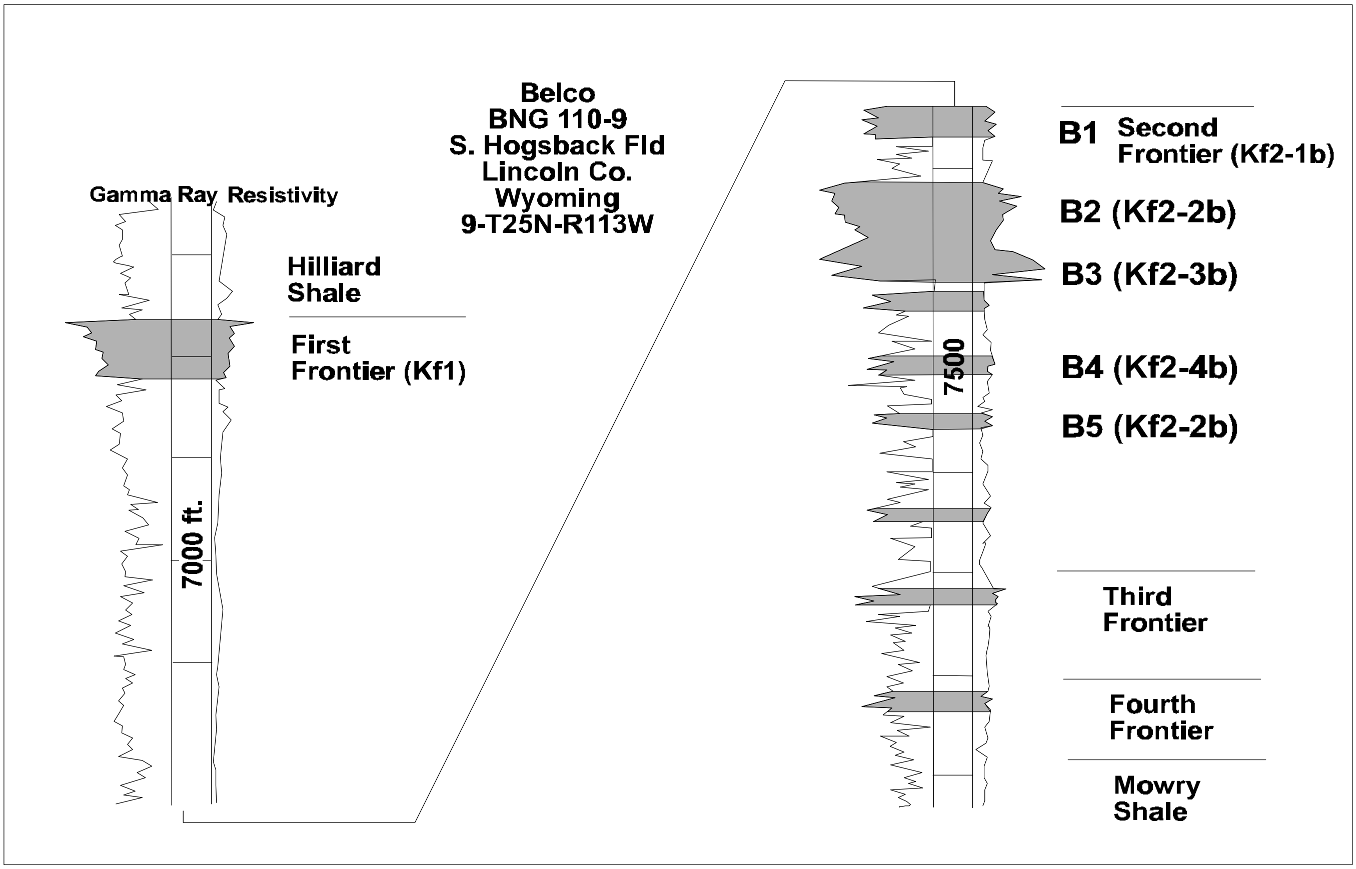

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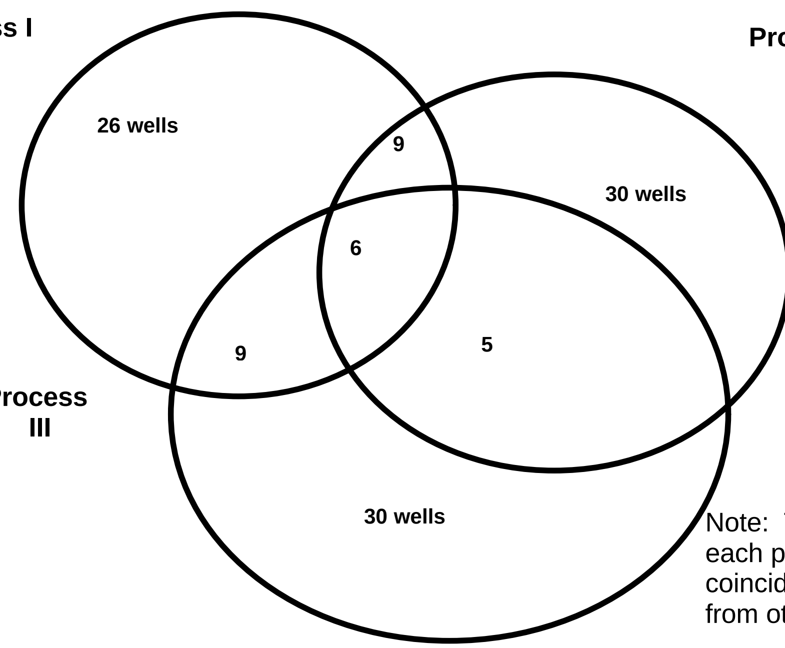
Figure 4 - COINCIDENCE OF“TOP 50” CANDIDATE SELECTIONS from each Level, Green River Basin



Note: Top Candidates from each process do not necessarily coincide with top candidates from other processes.

Figure 5
SEM Photograph of Frontier Formation Core
GRB 134-7, Kf2-5b, 1262.7 ft, 800x magnification

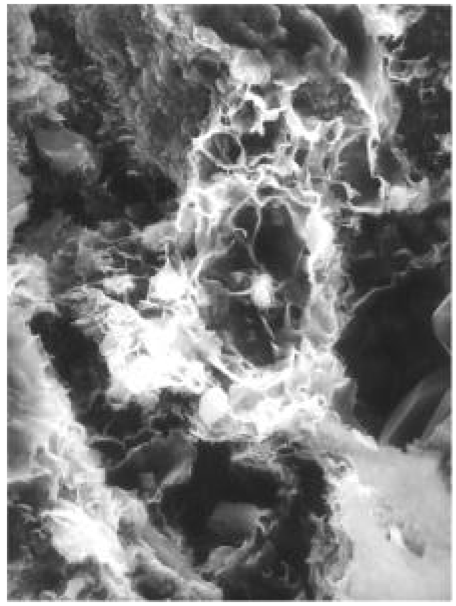


Figure 6
Effect of 2 gal/1000 gal Clayfix II, KCl Substitute on Permeability of
Frontier Kf2-5b, Well GBR 134-7, Depth 7262.7 ft.

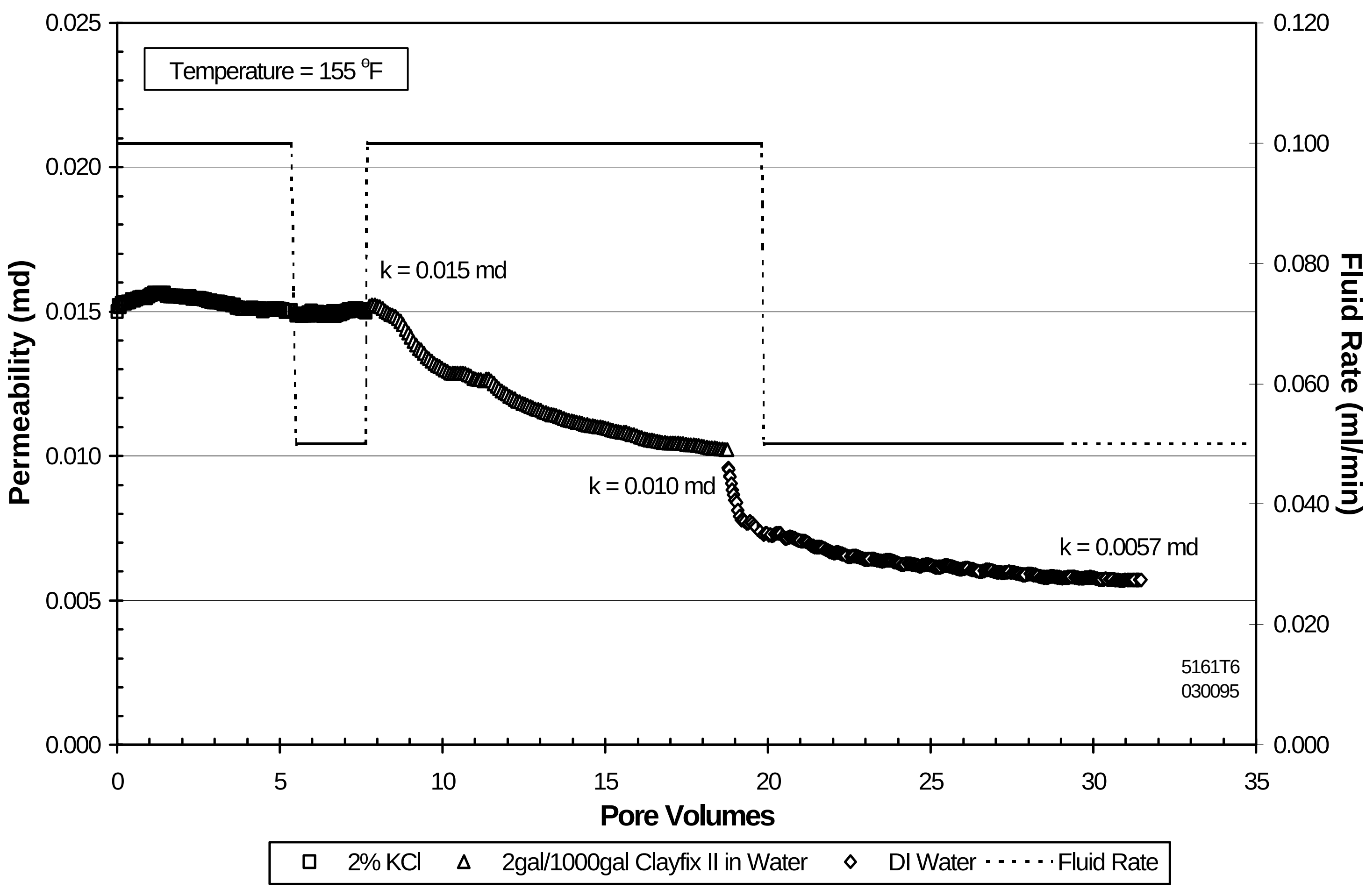


Figure 7 - INCREMENTAL PRODUCTION FORECAST, GRB 27-14

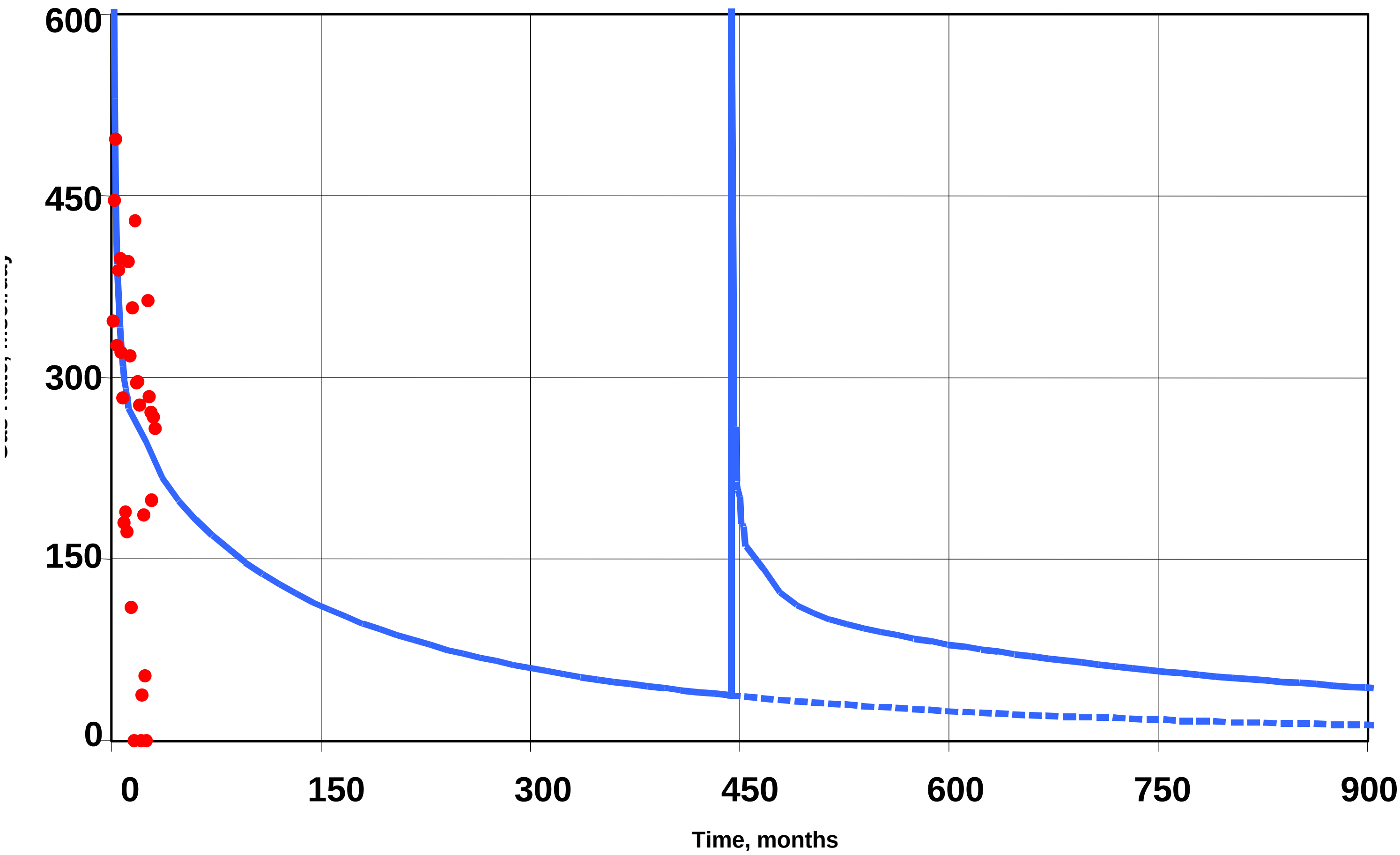


Figure 8 - POST-TREATMENT RADIOACTIVE TRACER SURVEY, GRBU 45-12

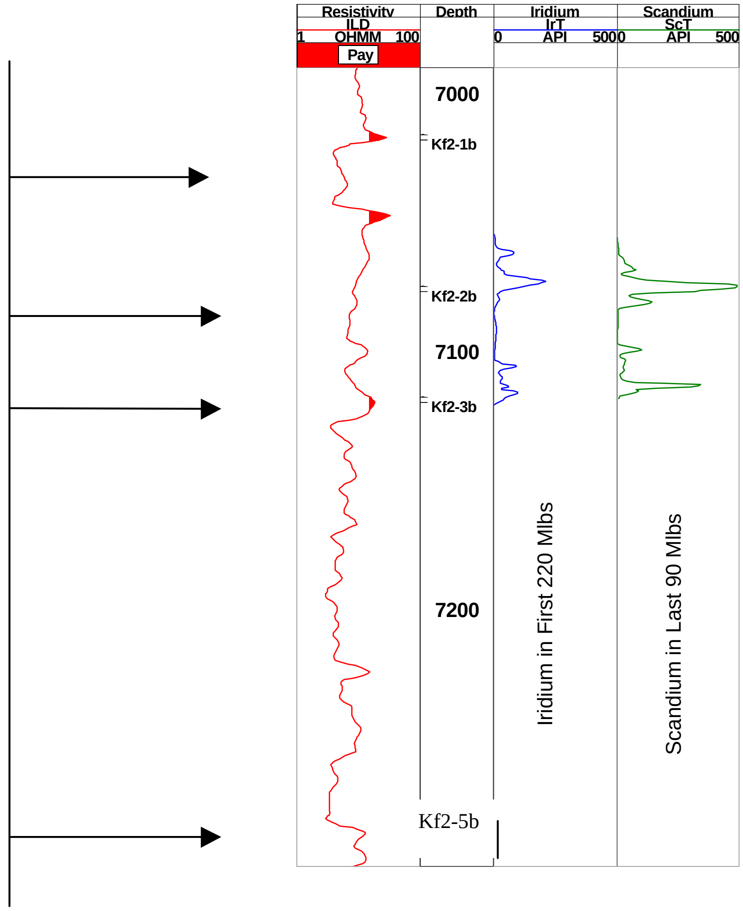
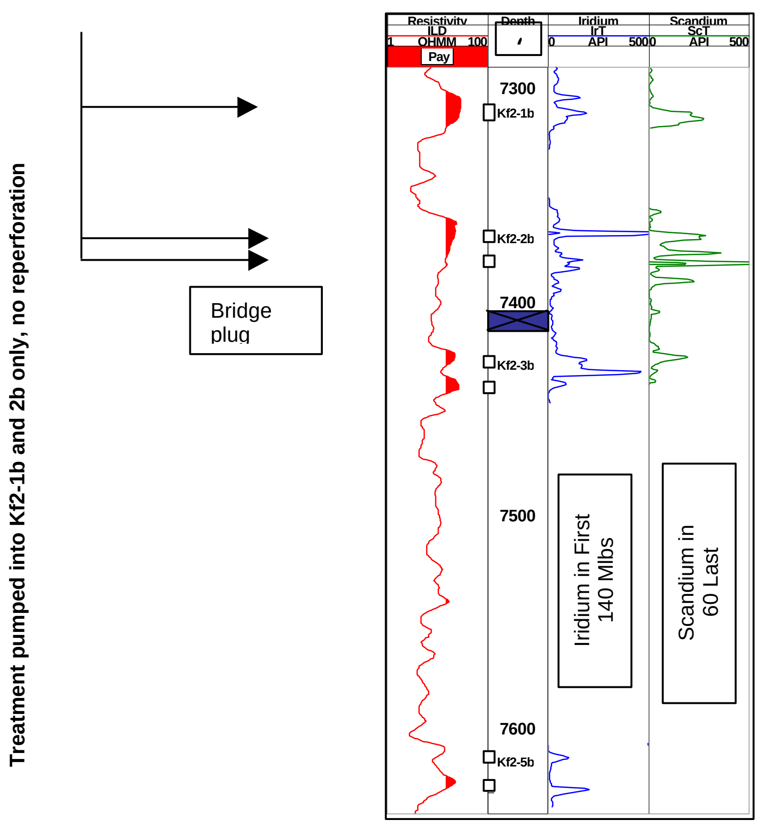


Figure 9 - POST-TREATMENT RADIOACTIVE TRACER SURVEY, GRBU 27-14



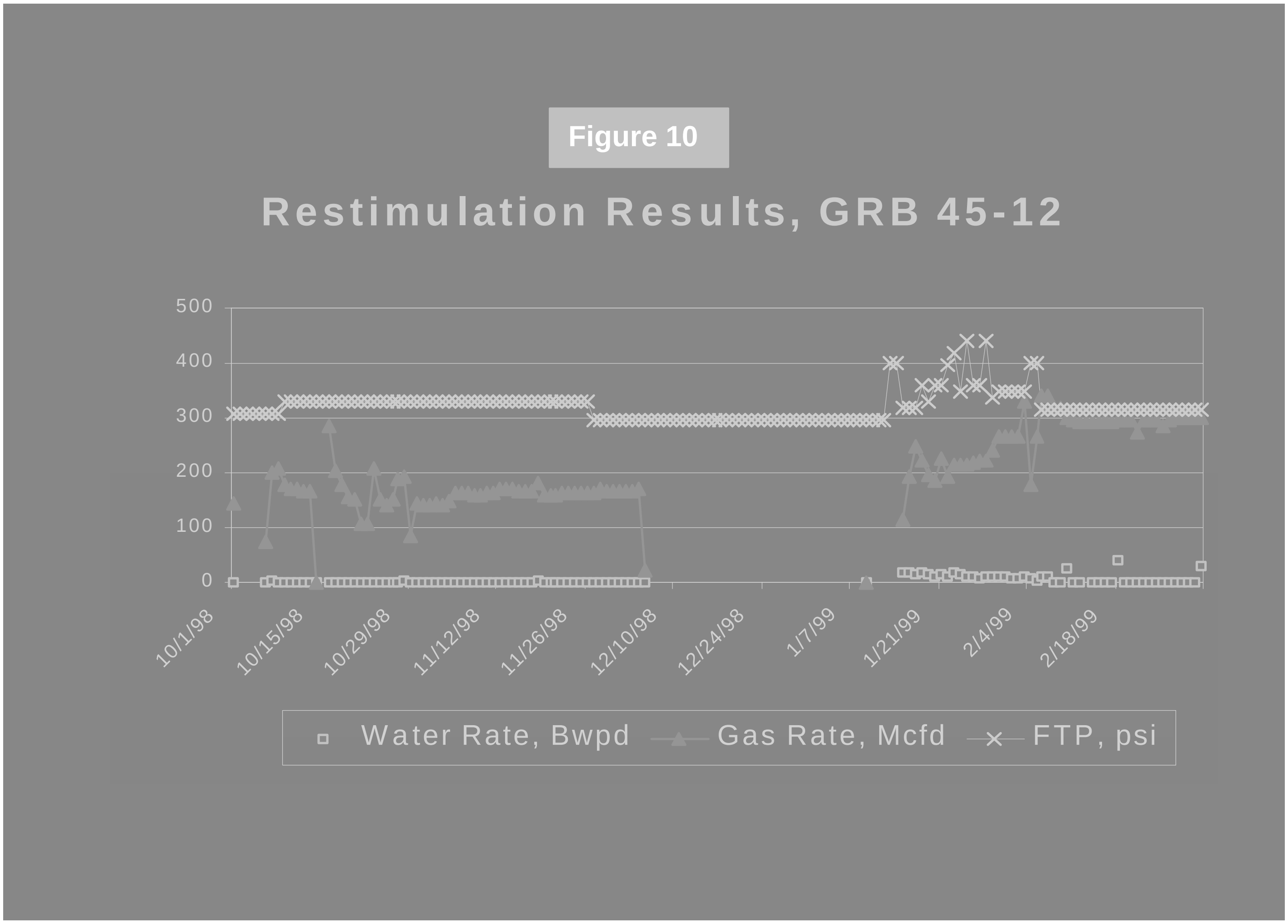


Figure 11 - Piceance Basin Study

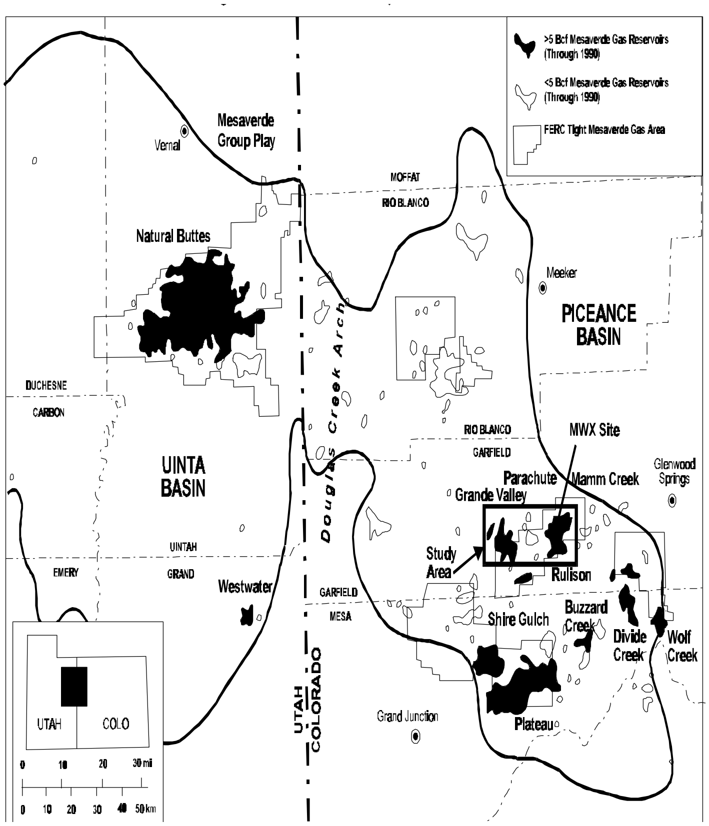


Figure 12 - STRATIGRAPHIC COLUMN, PICEANCE BASIN

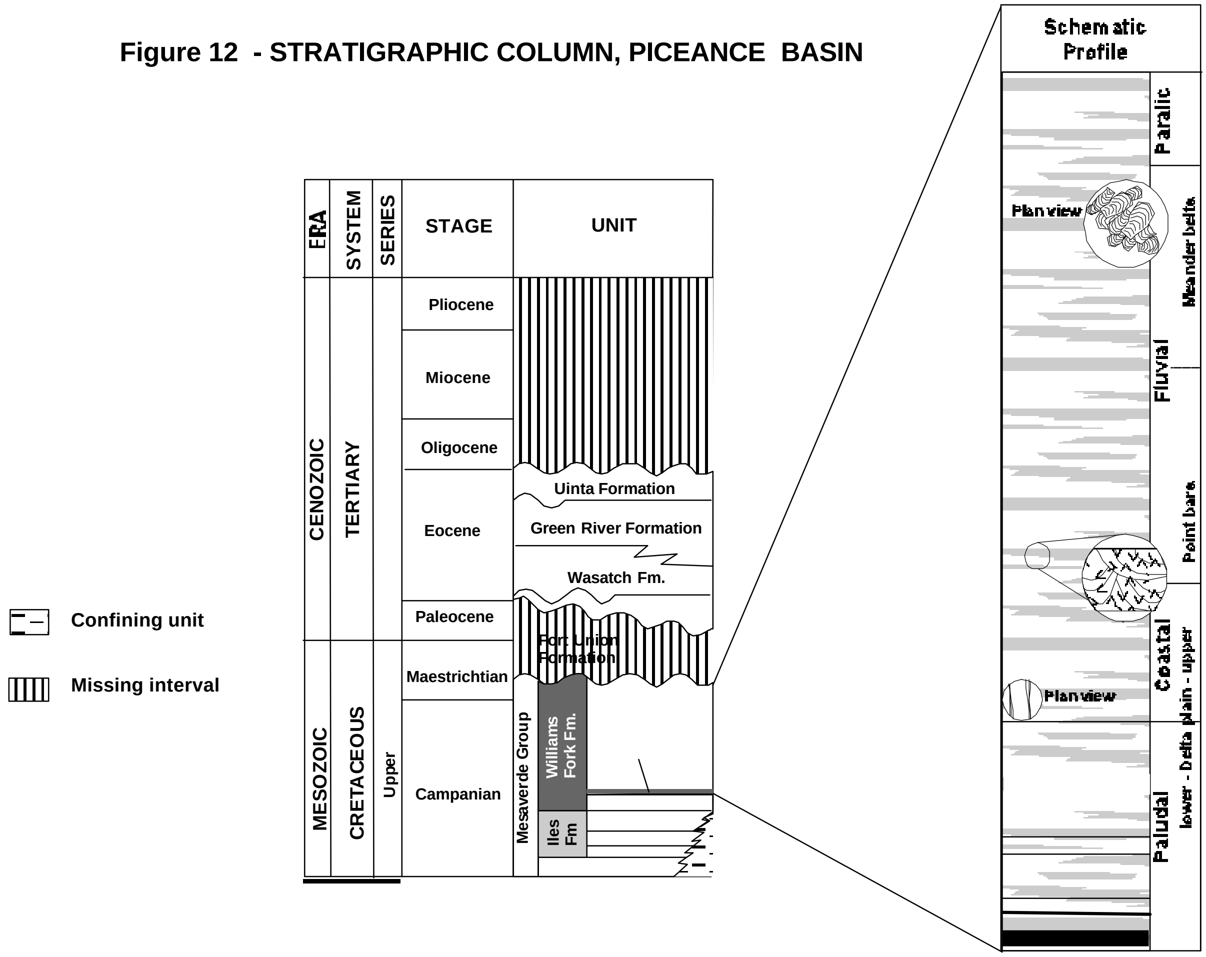


Figure 13 - Coincidence of "Top 50" Candidate Selections from each Level, Piceance Basin