Selection and Treatment of Stripper Gas Wells for Production Enhancement, Mocane-Laverne Field, Oklahoma

Final Report

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Executive Summary

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1.0 Introduction

In 1996, Advanced Resources International (ARI) began performing R&D targeted at enhancing production and reserves from natural gas fields. The impetus for the effort was a series of field R&D projects in the early-to-mid 1990's, in eastern coalbed methane and gas shales plays, where well remediation and production enhancement had been successfully demonstrated[1,2,3]. As a first step in the subsequent R&D effort, an assessment was made of potential for restimulation to provide meaningful reserve additions to the U.S. resource base, and what technologies were needed to do so. That work concluded that[4]:

- A significant resource base did exist via restimulation (multiples of Tcf).
- The greatest opportunities existed in non-conventional plays where completion practices were (relatively) complex and technology advancement was rapid.
- Accurate candidate selection is the greatest single factor that contributes to a successful restimulation program.

With these findings, a field-oriented program targeted at tight sand formations was initiated to develop and demonstrate successful candidate recognition technology. In that program, which concluded in 2001, nine wells were restimulated in the Green River, Piceance and East Texas basins, which in total added 2.9 Bcf of reserves at an average cost of $0.26/Mcf[5]. In addition, it was found that in complex and heterogeneous reservoirs (such as tight sand formations), candidate selection procedures should involve a combination of fundamental engineering and advanced pattern recognition approaches, and that simple statistical methods for identifying candidate wells are not effective[6].

In mid-2000, the U.S. Department of Energy (DOE) awarded ARI an R&D contract to determine if the methods employed in that project could also be applied to stripper gas wells. In addition, the ability of those approaches to identify more general production enhancement opportunities (beyond only restimulation), such as via artificial lift and compression, was also sought. A key challenge in this effort was that whereas the earlier work suggested that better (producing) wells tended to be better restimulation candidates, stripper wells are by definition low-volume producers (either due to low pressure, low permeability, or both). Nevertheless, the potential application of this technology was believed to hold promise for enhancing production for the thousands of stripper gas wells that exist in the U.S. today.

The overall procedure for the project was to select a field test site, apply the candidate recognition methodology to select wells for remediation, remediate them, and gauge project success based on the field results. This report summarizes the activities and results of that project.

2.0 Test Site Description and Preliminary Data Exploration

The site selected for the project was the Mocane-Laverne field in Oklahoma's central Anadarko basin (Figure 1)[7]. It is one of the largest gas fields in the Anadarko basin and hence an excellent opportunity for reserve enhancement. The field produces from four main horizons, the Hoover and Tonkawa (Upper Pennsylvanian), the Morrow (Lower Pennsylvanian), and the Chester (Upper Mississippian) (in order of increasing depth). The uppermost three horizons are sandstones, and the lowermost (Chester) is a limestone. A summary of reservoir properties are presented in Table 1.

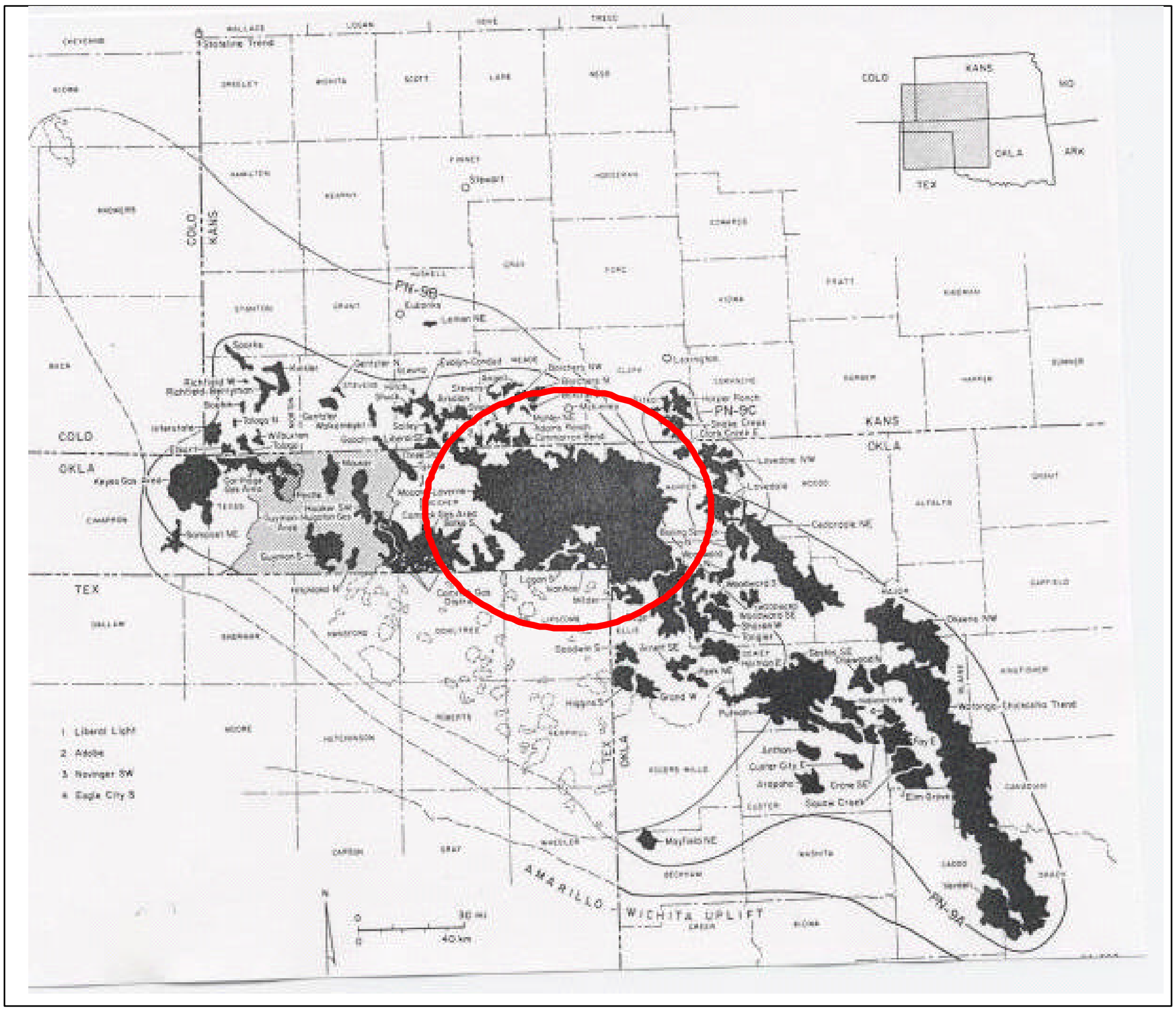


Figure 1: Location of Mocane-Laverne Field, Anadarko Basin

Table 1: Summary of Reservoir Properties

	Hoover	Tonkawa	Morrow	Chester
Depth	4283 ft	5558 ft	7000 ft	7050 ft
Pressure	1525 psi	1865 psi	2200 psi	2192 psi
Temperature	112°F	130°F	150°F	154°F
Pay	----	15ft	20 ft	18 ft
Porosity	18%	18%	12%	8%
Water Saturation	----	----	38%	30%
Permeability	60 md	40 md	25 md	1 md
Gas Gravity	0.67	0.73	0.75	0.64

The industry partner for the project was Oneok Resources, who operates over 100 wells in the field. An illustration of the locations of those wells included in the study (limited to the four horizons mentioned above) is provided in Figure 2. A breakdown of those wells in terms of completions and well vintages are provided in Figures 3 and 4. About 75% of the wells are completed in either the Morrow and Chester, and the wells can date back as far as the 1950's to as recently as the 1990's, representing a broad cross-section well ages and completion practices.

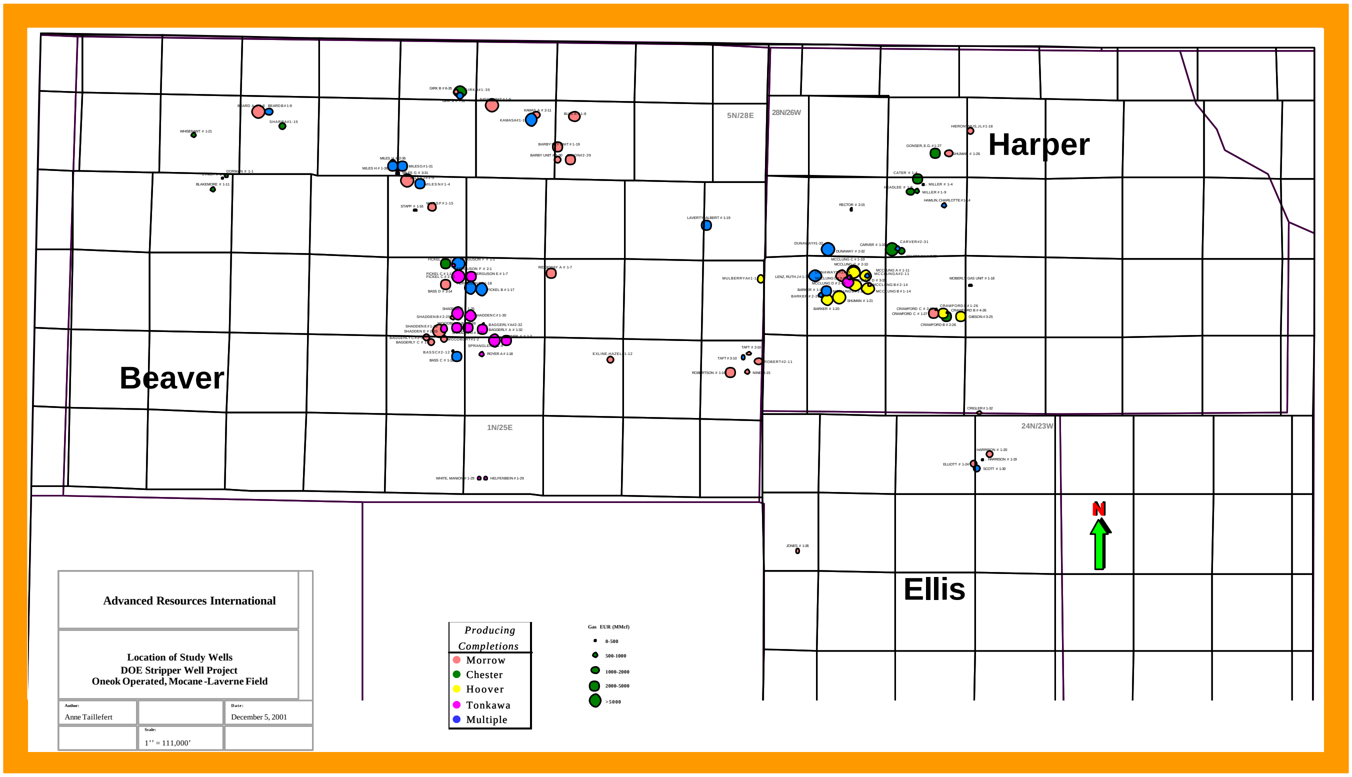


Figure 2: Location of Study Wells

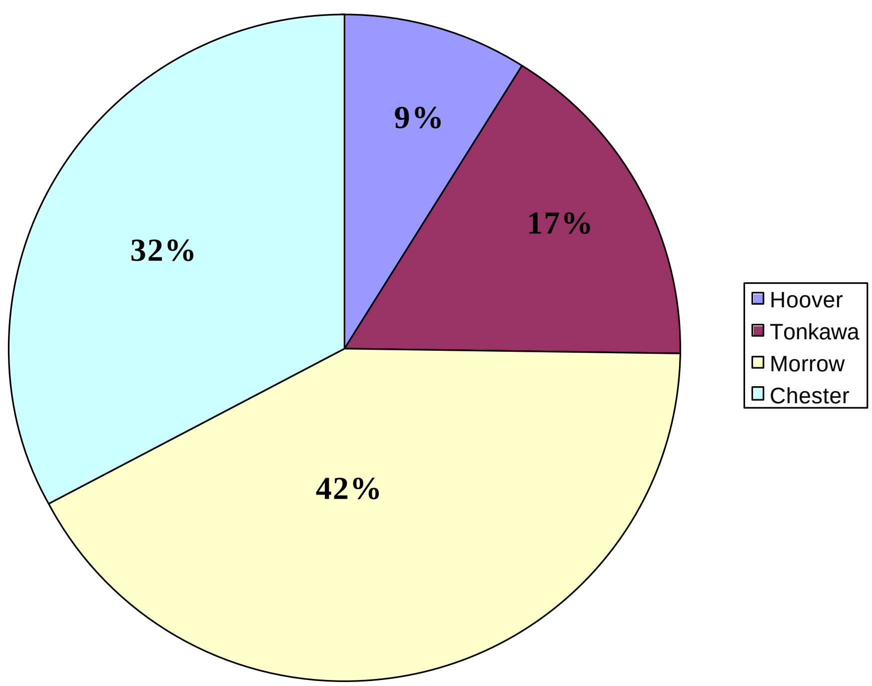


Figure 3: Well Completions Summary

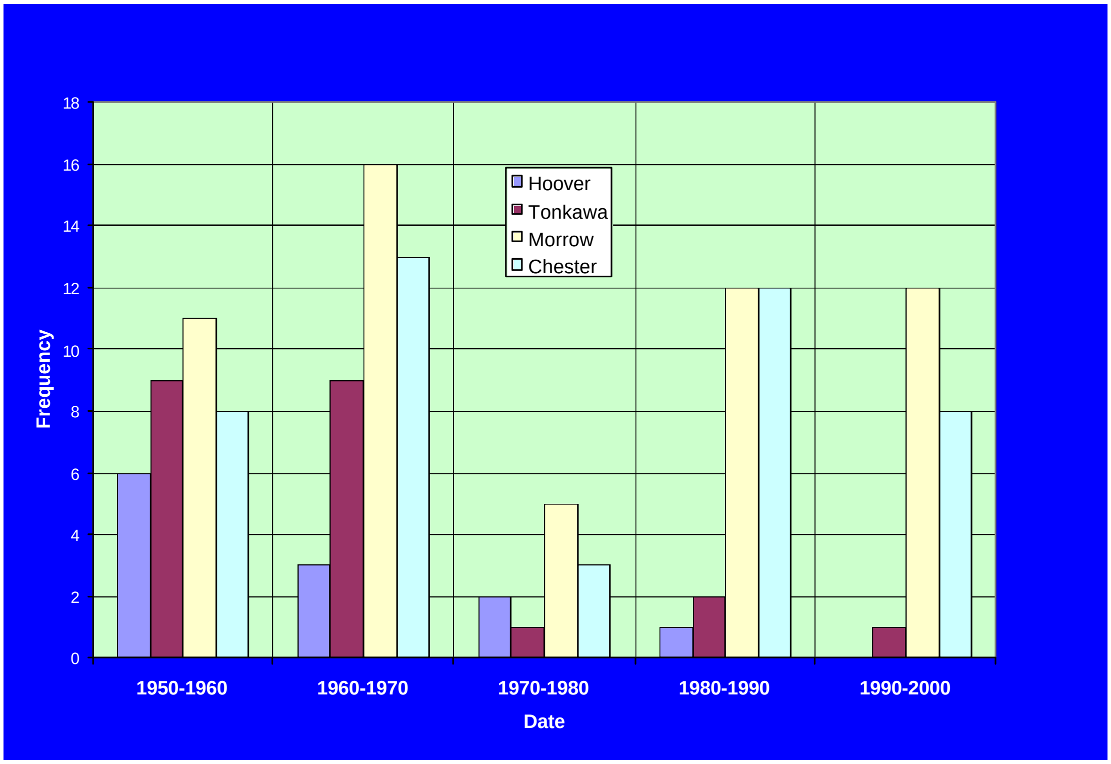


Figure 4: Well Vintage Summary

Further insights into that cross-section of well types are provided in the following series of figures. Figure 5 shows that most stimulation treatments performed on the wells were hydraulic fracture treatments. Those that were matrix (acid) stimulation treatments tended to be in the Chester horizon. Some completions never did receive a stimulation treatment, and represent potential restimulation opportunities.

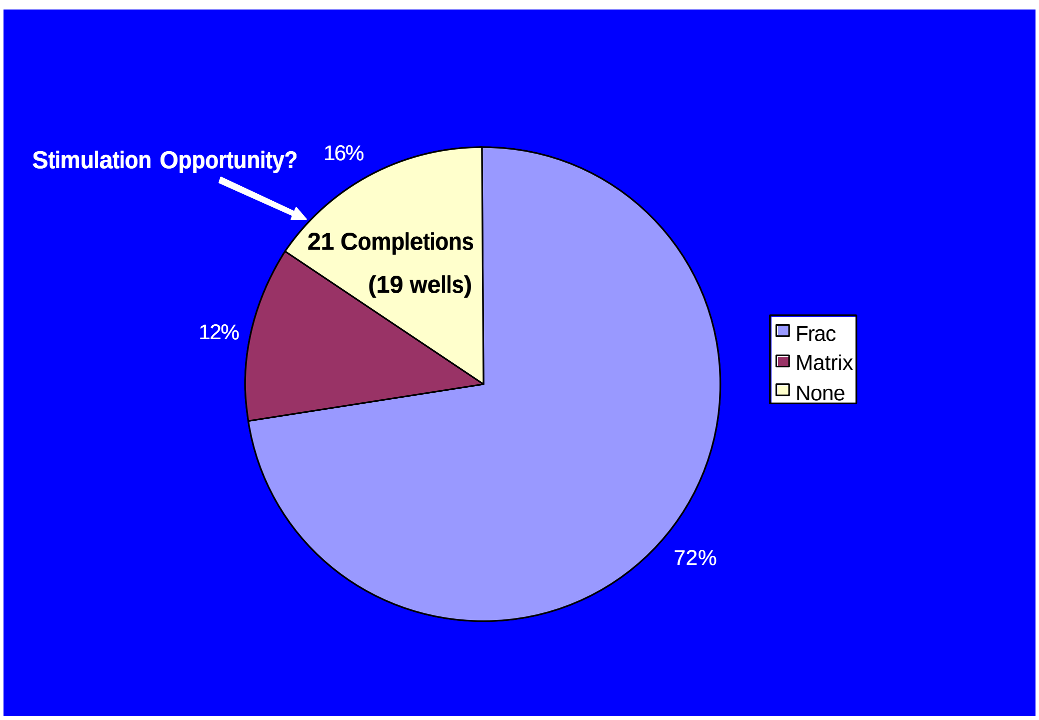


Figure 5: Breakdown on Stimulation Type

In general, the base (hydraulic fracturing) fluid was either acid, diesel/oil, or water, which was used in various forms – untreated, foamed or gelled (Figure 6). The proppant volumes used were generally quite small – less than 25,000 lbs per treatment (Figure 7). These cases too may represent Restimulation opportunities.

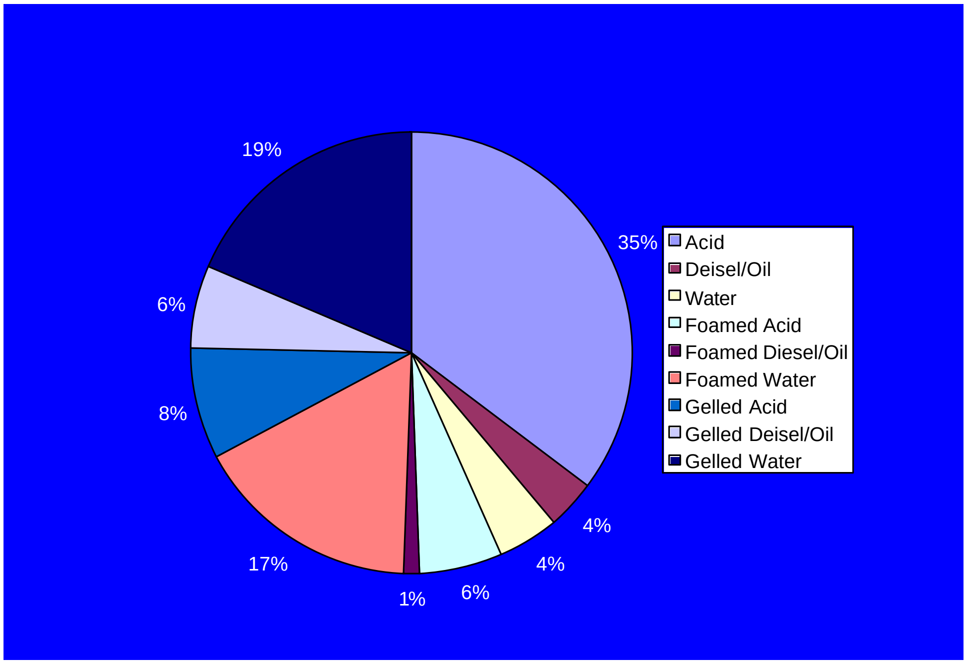


Figure 6: Stimulation Fluids

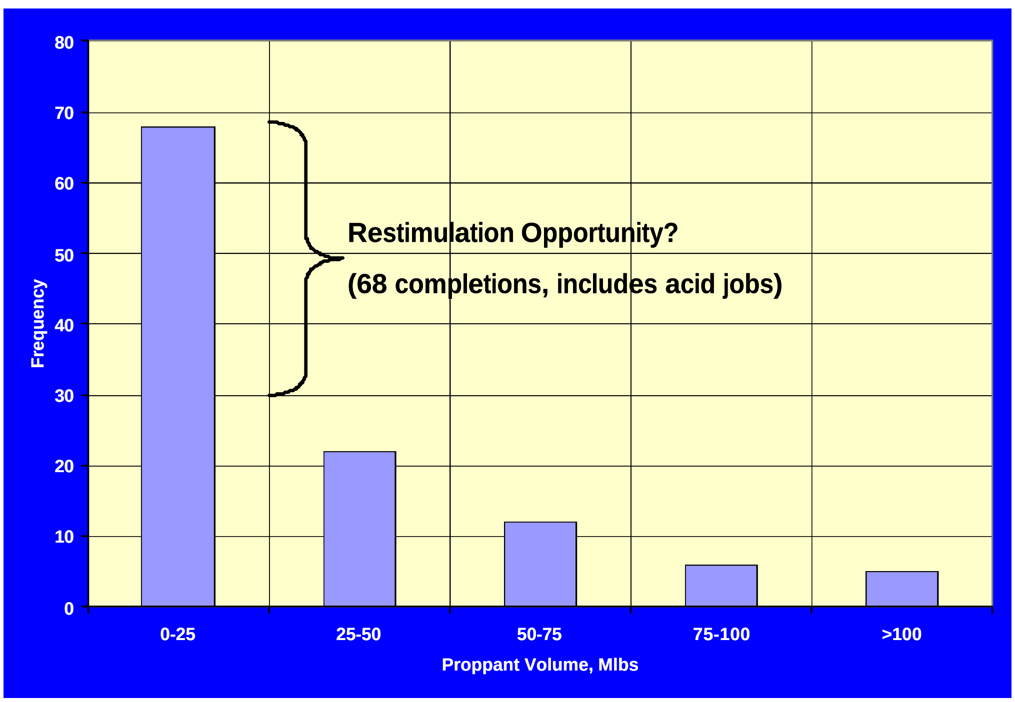


Figure 7: Proppant Volumes

The wells tend to produce small volumes of either oil or water (or both), Figure 8, but not all wells were equipped with artificial lift systems (Figure 9). These too might represent production enhancement opportunities.

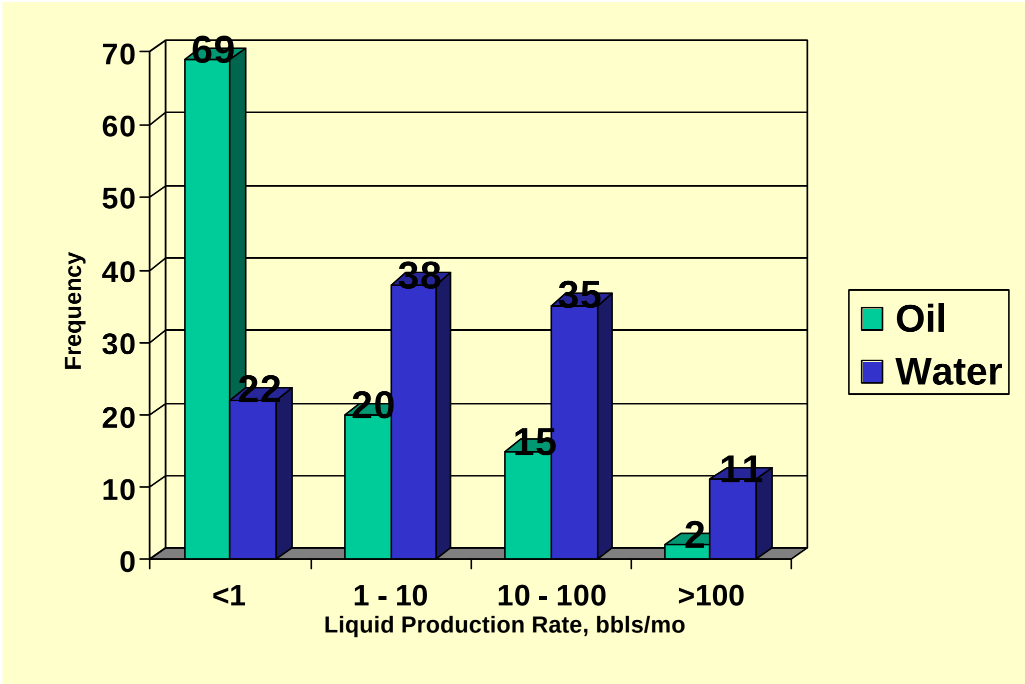


Figure 8: Liquids Production

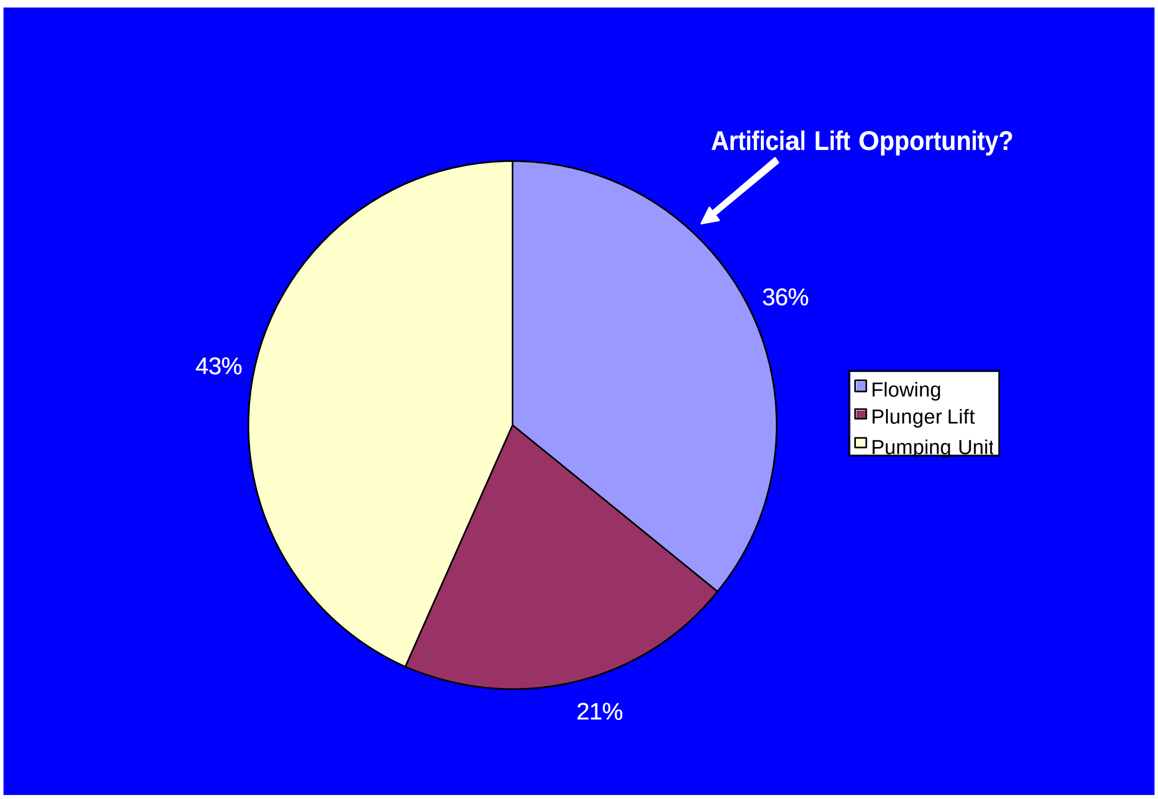


Figure 9: Liquid Producing Configurations

The estimated current reservoir pressures for each horizon, based on annual 24-hour shut-in tests, are provided in Table 2. For comparison, the distribution of flowing pressures for the wells are presented in Figure 10. Combining the information presented in these two figures, Figure 11 presents the distribution of pressure drawdowns being achieved in the wells; however only about one-third of the wells are on some form of compression (Figure 12). This may represent yet another production enhancement opportunity.

Table 2: Reservoir Pressures

Horizon	Pressure (psi)	
	Range	Average
Hoover	40 – 170	90
Tonkawa	90 – 390	190
Morrow	20 – 400	140
Chester	40 – 780	180

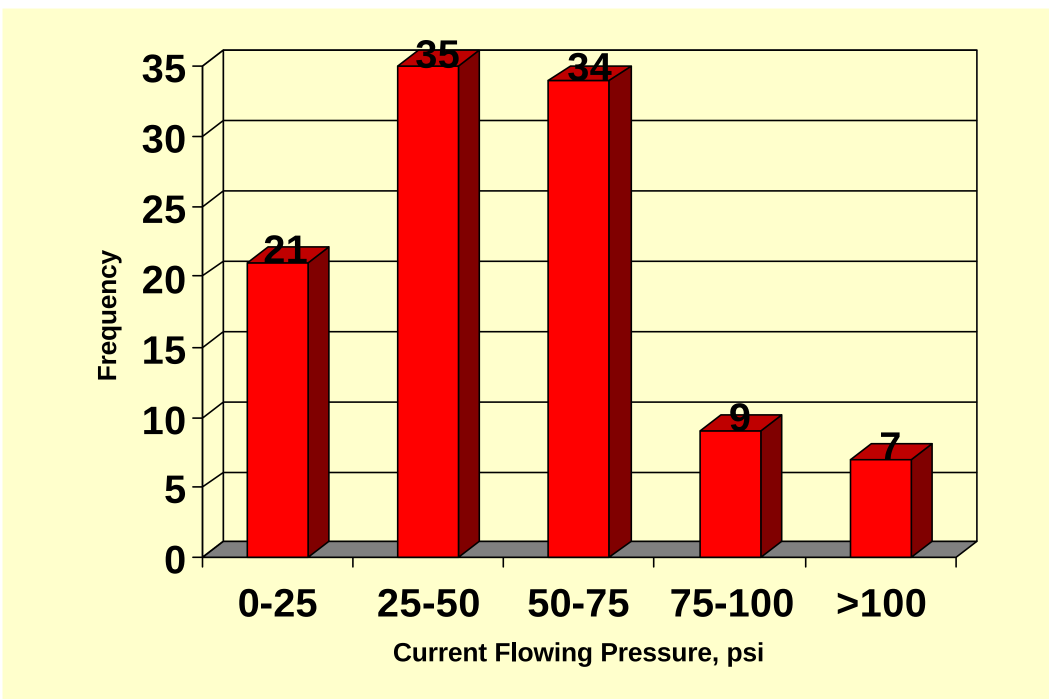


Figure 10: Distribution of Flowing Pressures

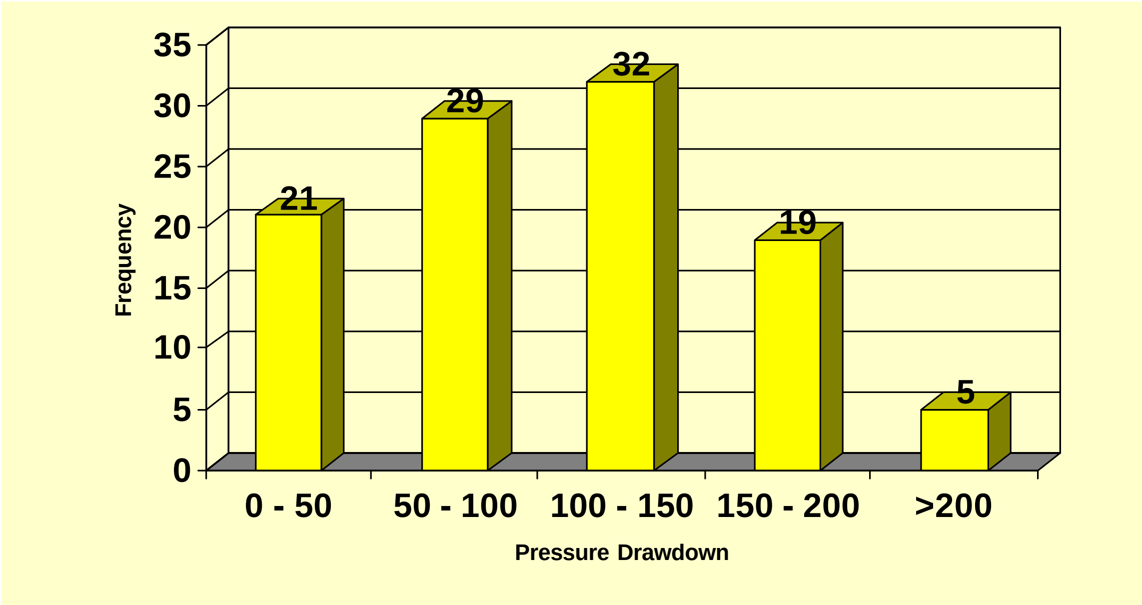


Figure 11: Distribution of Pressure Drawdowns

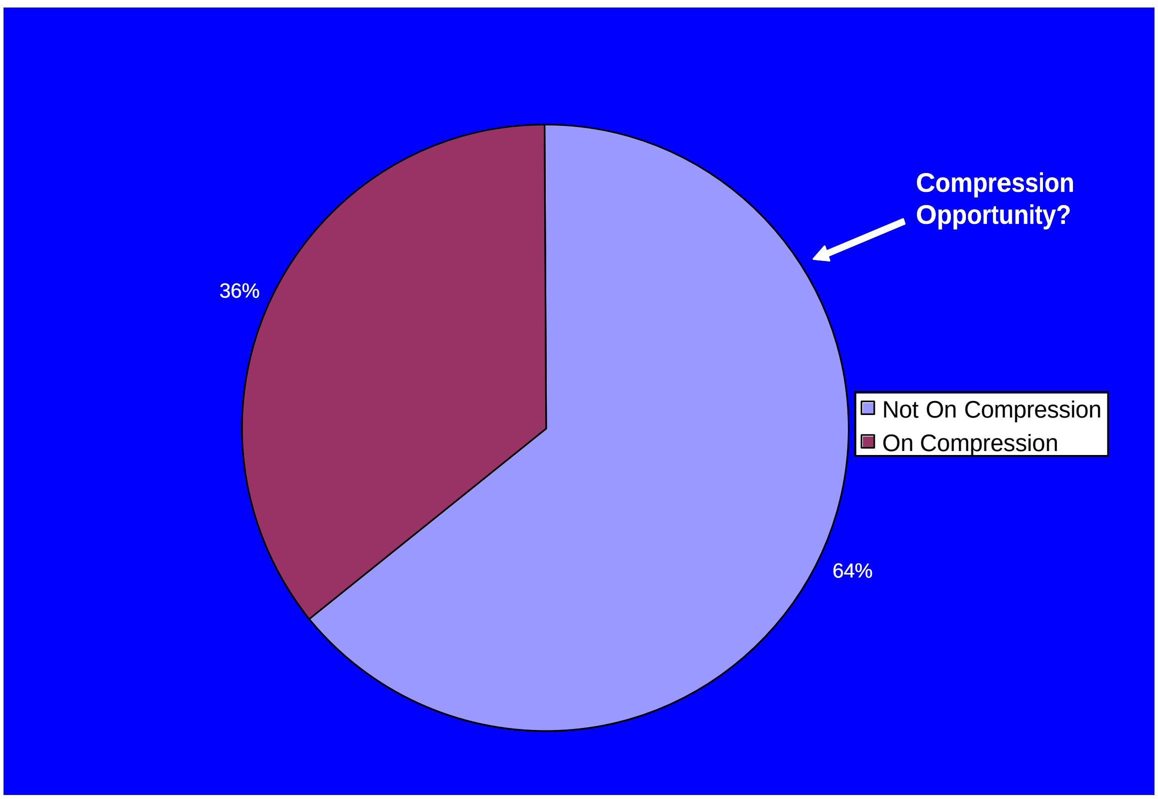


Figure 12: Utility of Compression

A review of well performances by completion interval are presented in Figure 13. Noteworthy is that the Morrow appears to be the best performing overall interval, and that the average completion yields an impressive 3.8 Bcf of reserves. Current well performances are, however, quite low (hence the stripper well status). Figure 14 demonstrates that the majority of all completions currently produce less than 2,000 Mcf/month (66 Mcf/d).

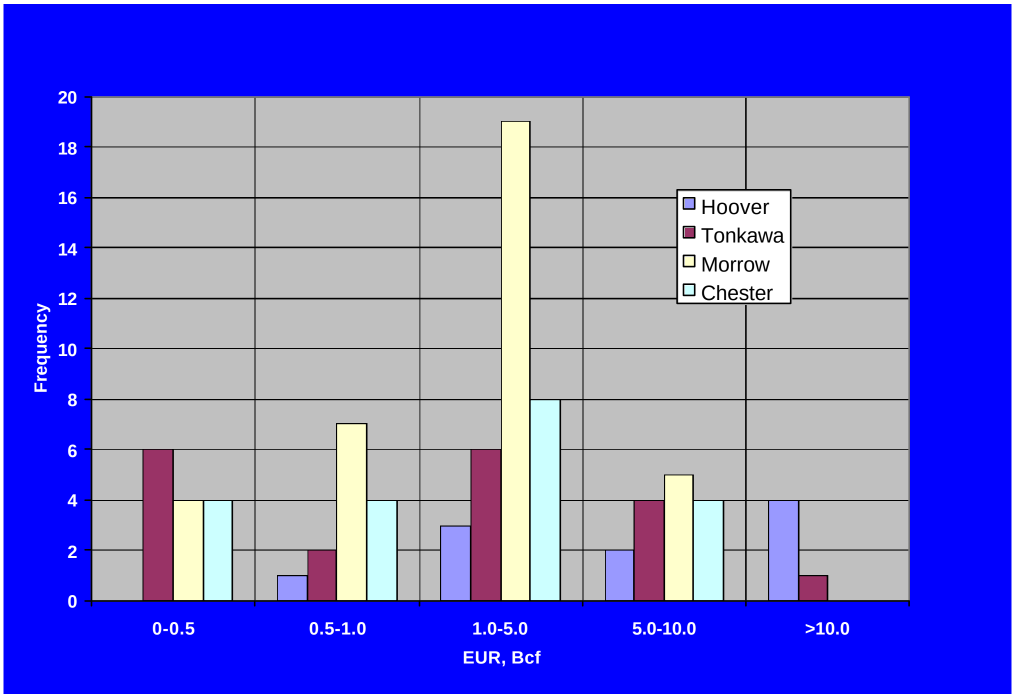


Figure 13: Overall Completion Performance

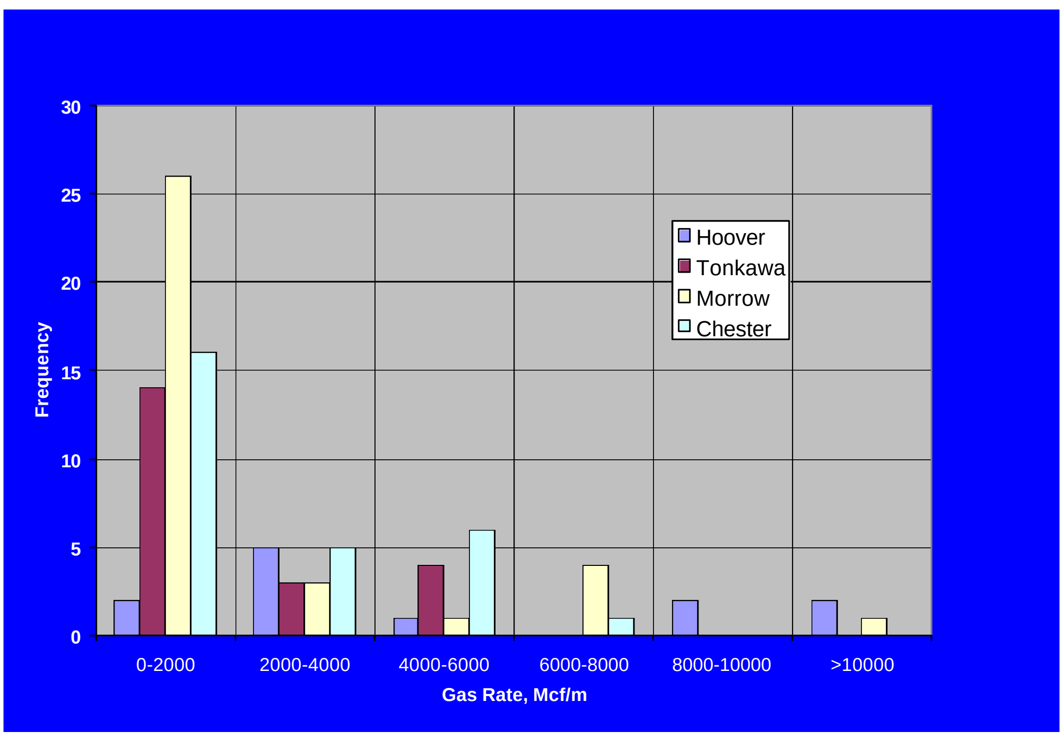


Figure 14: Current Completion Performance

In summary, the study wells represent historically good-performing, yet now older wells that have become depleted. The wells now also suffer from liquid production, which can inhibit gas flow. But, small-sized or no stimulation in some cases, the absence of artificial lift, and limited compression installation suggests that production enhancement opportunities may exist. The key objective of the project is to identify and rank those opportunities with more clarity and precision.

3.0 Remediation Candidate Selection

Building upon the findings from the earlier R&D, the candidate selection procedure involved a combination of engineering, pattern recognition, and heuristic approaches. The specific procedure was:

- Perform engineering (type-curve) analysis to identify potential candidates.

- Perform artificial neural network (ANN) and genetic algorithm (GA) analyses to identify potential candidates.

- Combine the results of the first two steps, plus the findings from the data exploration presented in Section 2.0, in a heuristic candidate selection process.

The procedures followed and results for each of these three steps is presented below.

3.1 Type-Curve Analysis

The ideal approach for selecting production enhancement candidates is to understand the relative impact of reservoir properties and completion/production practices on the performance of each individual well, and select the wells with high upside potential for remediation. An approach to accomplish this is through the use of production type-curves. Type curves can provide estimates of reservoir permeability, skin and drainage area from relatively limited (production) data. There are several limitations with this technique, however. First, the typical models are for single-layer 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 achieving a unique result difficult. Finally, because this method requires values of net pay, porosity, fluid saturation and other reservoir parameters for each well, some interpretive and potentially labor-intensive petrophysicial evaluation is required, and the errors associated with such interpretations are introduced into the process (especially problematic in tight formations). Recognizing these limitations however, such approaches have been shown useful in a relative sense to identify production enhancement candidates.

The first step in the type-curve matching process for this project was to assemble the input data required for an analysis on each well. Such data included producing history (volumes and pressures), and reservoir properties (i.e., net pay thickness, initial pressure and temperature, porosity, water saturation, and fluid properties, among others). That data was obtained from both well files and public data sources, and is listed in Table 3.

Table 3: Parameters for Type Curve Matching

	Hoover	Tonkawa	Morrow	Chester
Initial Pressure	Actual pressure if available, from correlation if not.			
Net Pay	18 ft.			
Porosity[1]	18%	18%	12%	8%
Water Saturation[2]	65%	30%	34%	37%
Temperature[1]	112°F	130°F	150°F	154°F
Gas Gravity	0.68			
Producing Pressure	Last measure value			

[1] – Gas Atlas value (reference 7)
[2] – Well data value (from well files)

One particularly noteworthy parameter each well was the initial reservoir pressure. Since the wells were drilled over a large time period, during which time active development occurred, the initial reservoir pressures could be very different depending upon when a particular well was drilled. Therefore, a correlation of reservoir pressure versus time was prepared using the annual 24-hour pressure surveys. The results of that correlation, by formation, are presented in Figure 15.

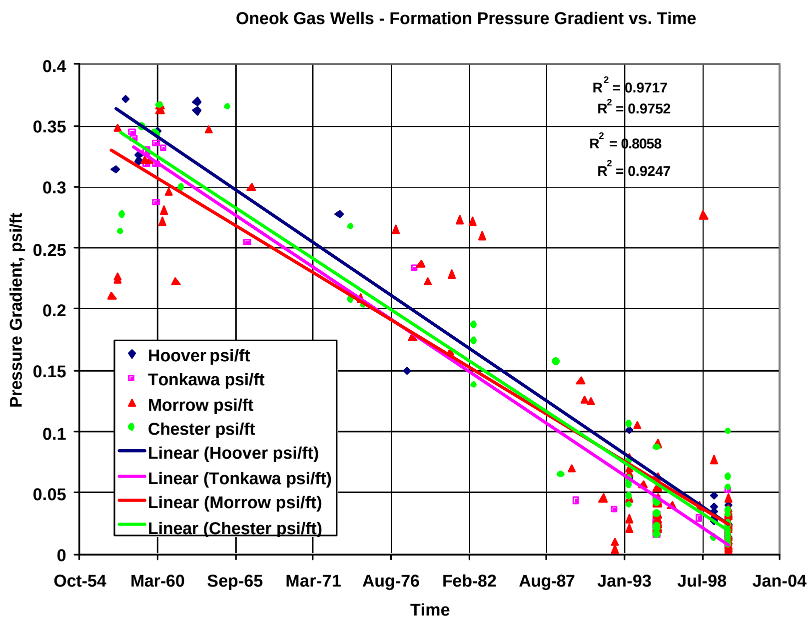
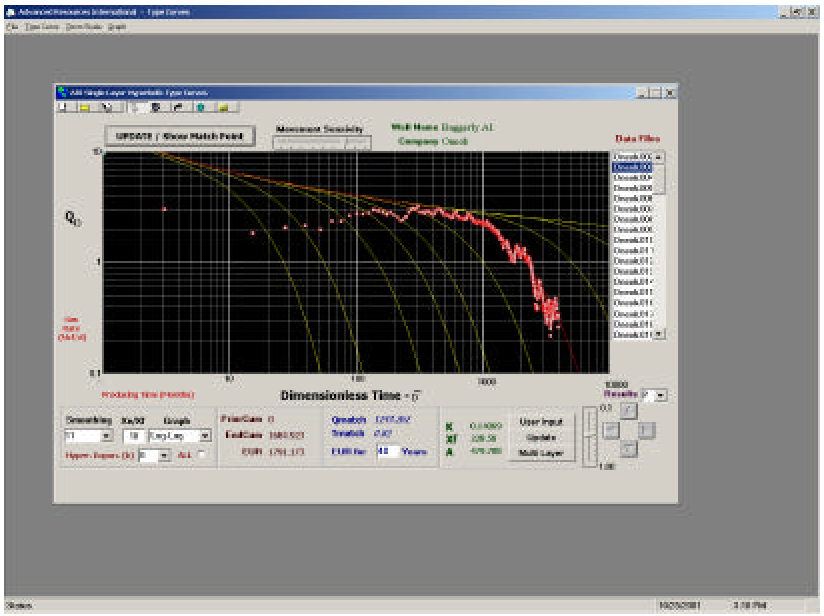


Figure 15: Reservoir Pressure Correlation

Using these data, type curve matches for each completion in the dataset were generated. As mentioned earlier, due to quality of production data in general (which can be very noisy), type curve matching involves a high degree of interpretation. As an example, Figure 16 presents what would be considered an “excellent-good” and a “fair-poor” match in terms of quality. One can easily envision that other interpretations could also result from the same data. When all matches were complete, a summary of match quality was prepared (Figure 17). Clearly, the overall quality of the results was less than preferred.

Excellent-Good



Fair-Poor

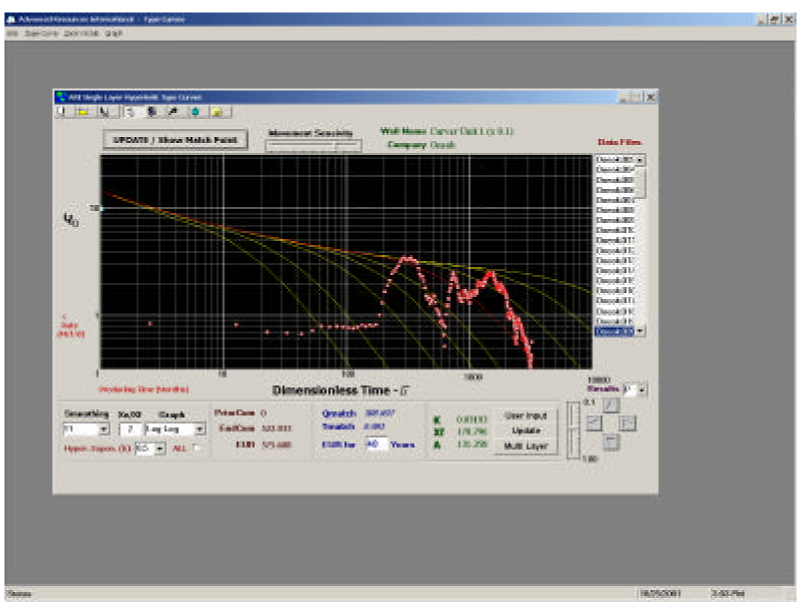


Figure 16: Example Type Curve Matches

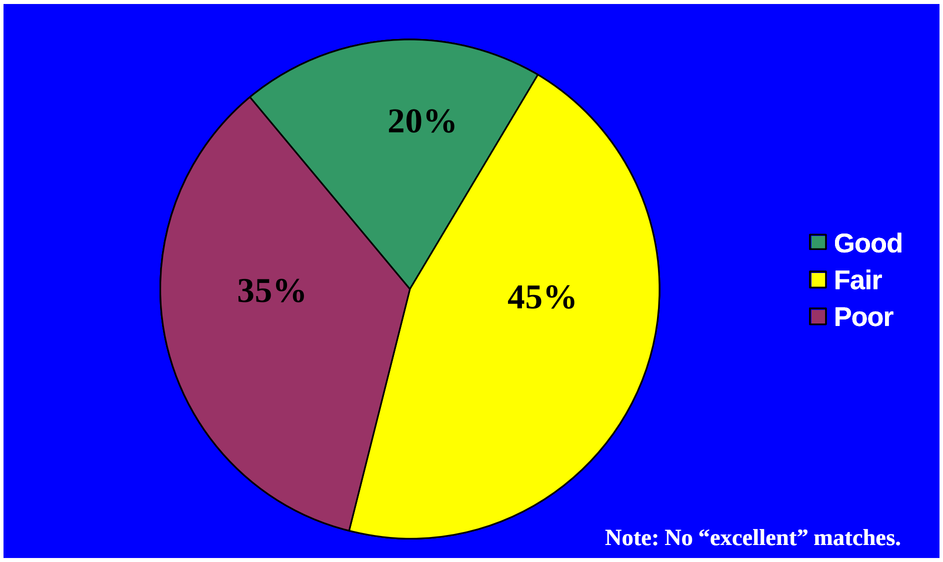


Figure 17: Summary of Match Quality – All Study Wells

The results of the type curve matches are presented in Figures 18 through 20. Note that these results are on a production stream basis, not necessarily an individual completion or horizon basis, as many wells had commingled completions. Figure 18 provides the permeability-thickness results, and indicates an average value of 28 md-ft. Figure 19 provides the thickness-drainage area results (i.e., effective reservoir volume), and indicates an average value of 31,000 acre-ft per well. Finally, Figure 20 provides the effective fracture penetration results (assuming an infinite conductivity fracture), indicating an average ratio of drainage area to fracture penetration of about 8 (i.e., the average fracture penetrated 10-15% of the distance to the drainage boundary.

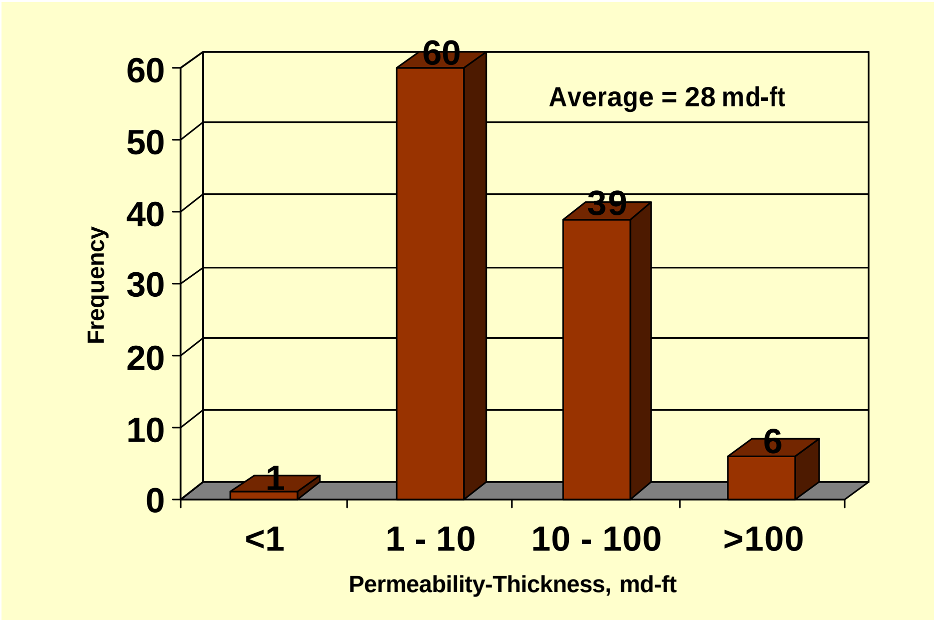


Figure 18: Permeability-Thickness Results

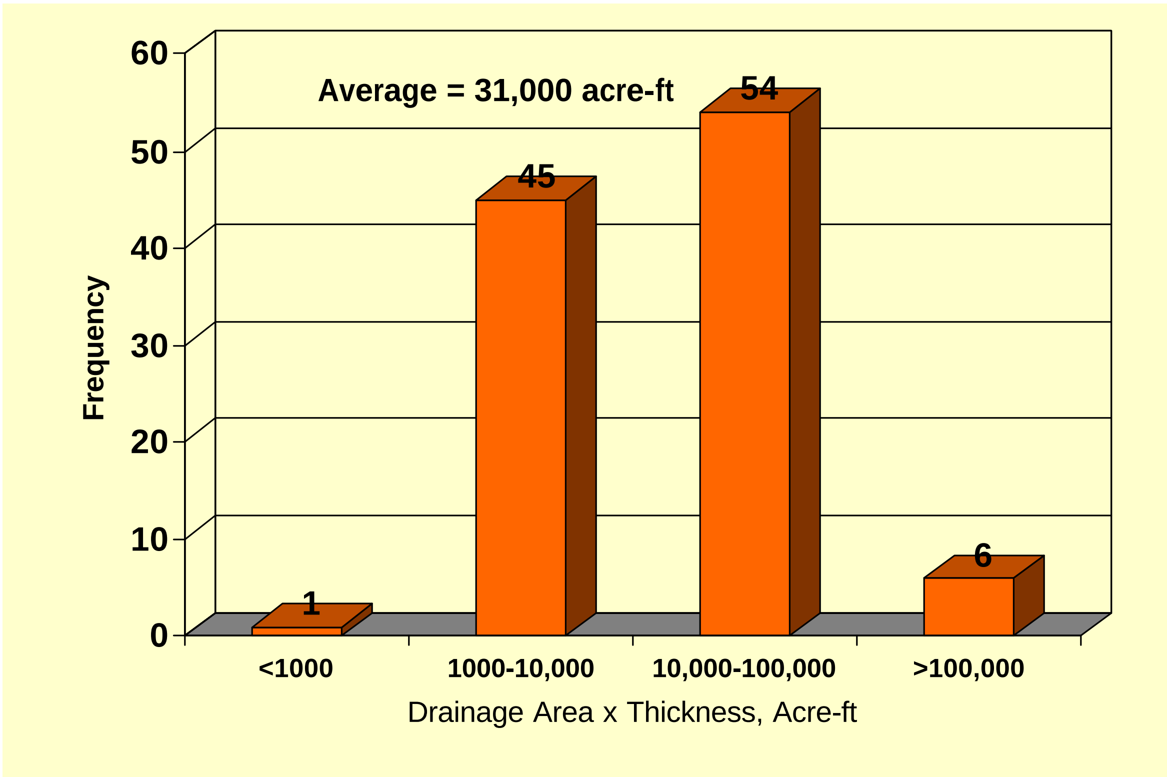


Figure 19: Thickness-Drainage Area Results

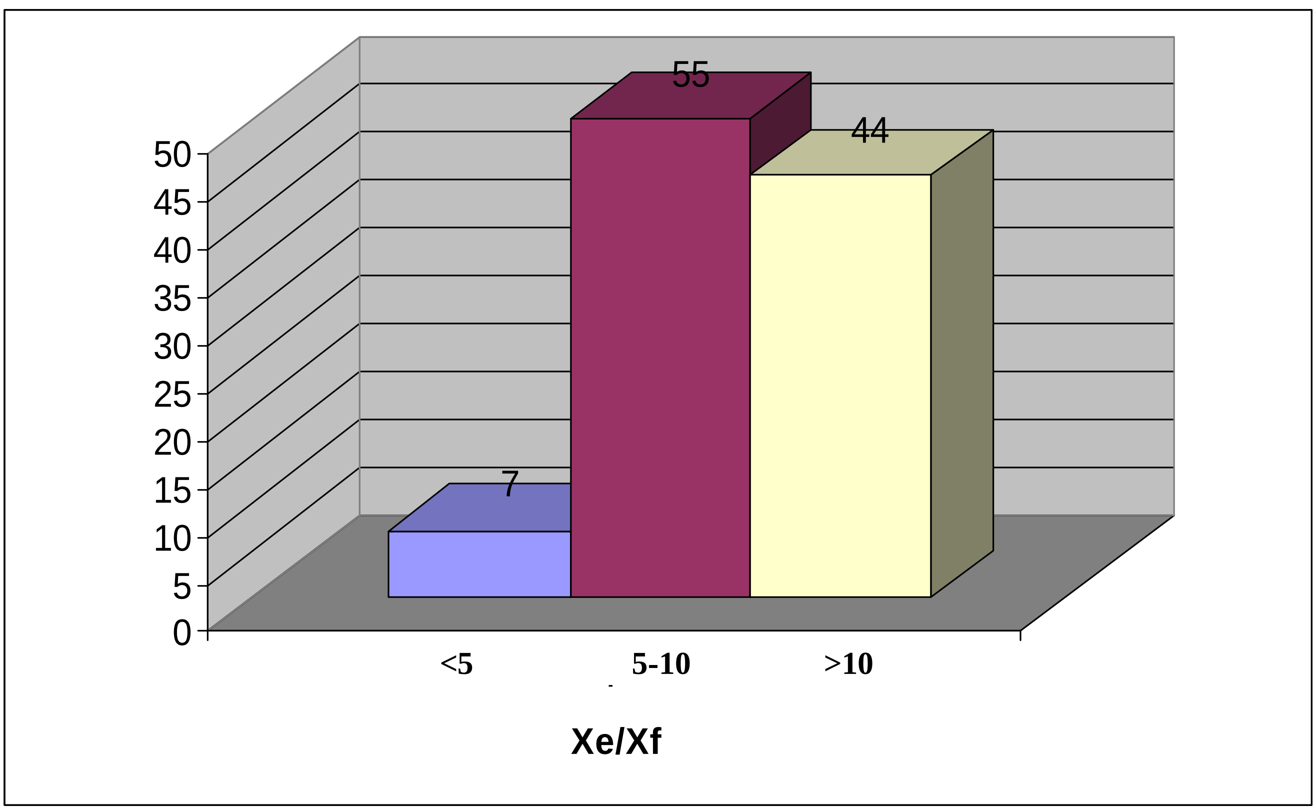


Figure 20: Fracture Penetration Results

To compute production enhancement potential, a well performance cross-plot was created (Figure 21). Here, a normalized well performance indicator – in this case the estimated ultimate recovery divided by the reservoir drawdown – was plotted against a reservoir volume & transmissibility function – specifically the product of effective reservoir volume and permeability. The result is a simple, yet reasonably representative model of well performance for the +/-100 wells in the dataset. Wells with performances that fell short of the model expectations (i.e., those that fall below the trend line) were identified as production enhancement opportunities. The ranking of those opportunities are based on the absolute magnitude of the deviation from the trend line (note that the well performance indicator is plotted on a logarithmic scale). This approach essentially "lumps" all three categories of production enhancement – restimulation, artificial lift, and compression – into one assessment, and does not distinguish which type of enhancement opportunity each well represents.

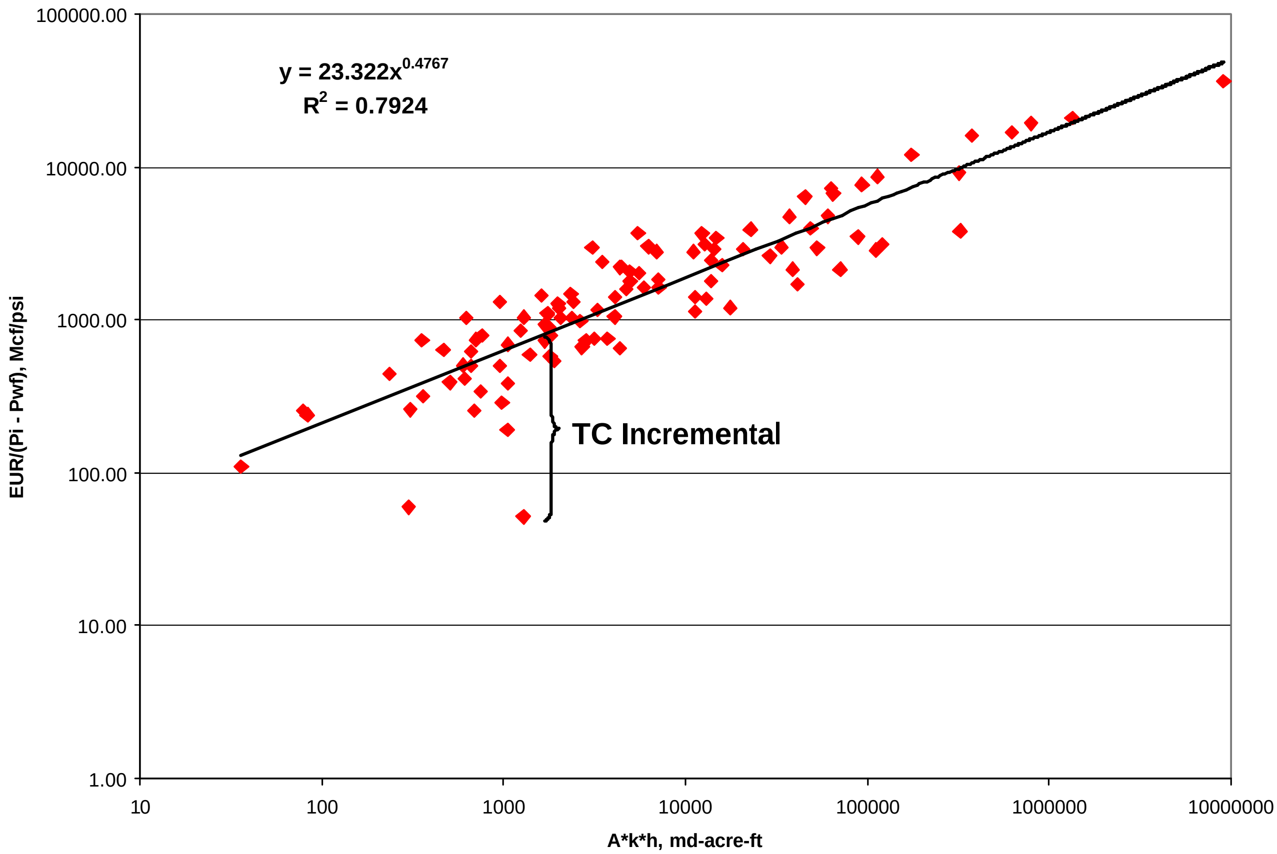


Figure 21: Well Performance Cross-Plot

3.2 Artificial Intelligence Analysis

The second analytic technique utilizes artificial intelligence, specifically artificial neural networks and genetic algorithms, to identify production enhancement candidates. Artificial neural networks are utilized to recognize highly complex patterns in how various input parameters (e.g., geologic, drilling, completion, stimulation, and workover data) impact the output (i.e., production). The relative contribution of "uncontrollable" geologic/reservoir parameters can thus be separated from "controllable" drilling, completion, and stimulation parameters. This in effect is the separation of reservoir and completion components (i.e., permeability and skin). Genetic algorithms are then used to "optimize" the "controllable" input parameters for any given well, and those wells where the greatest discrepancies exist between actual well performance and optimized performance are identified as production enhancement opportunities.

In this case, the input parameters selected for the ANN model are listed in Table 4; the output (dependent) variable was the estimated ultimate recovery (EUR). Two models were actually constructed; one for wells that had been previously stimulated, and one for wells that had not been previously stimulated. Both models were fully-connected, feed-forward/back-propogation models with three layers (input, hidden, output). For the first model, 93 wells existed, of which 61 were used for training the model and 31 were used to test it. For the second model, only 13 wells existed – 9 were used for model training and 4 for testing.

Table 4: Input Parameters for ANN Model

Space & Time	Completion/Stimulation
? X (Long) ? Y (Lat) ? Perf Depth for each Horizon ? Date of First Production	? Treatment Interval ? Treatment Type ? Fluid Type ? Fluid Volume ? Proppant Volume ? No. Stages
Reservoir	**Production Practices**
? Zone ? Net Perf Thickness	? Producing Method ? Flowing Pressures ? Last Rate
Output (dependent) parameter – EUR (gas).	

The model predictions versus actual well performance for the first model (stimulated wells) is presented in Figure 22. The correlation coefficients indicate that a reasonably good match to actual results are achieved by the model.

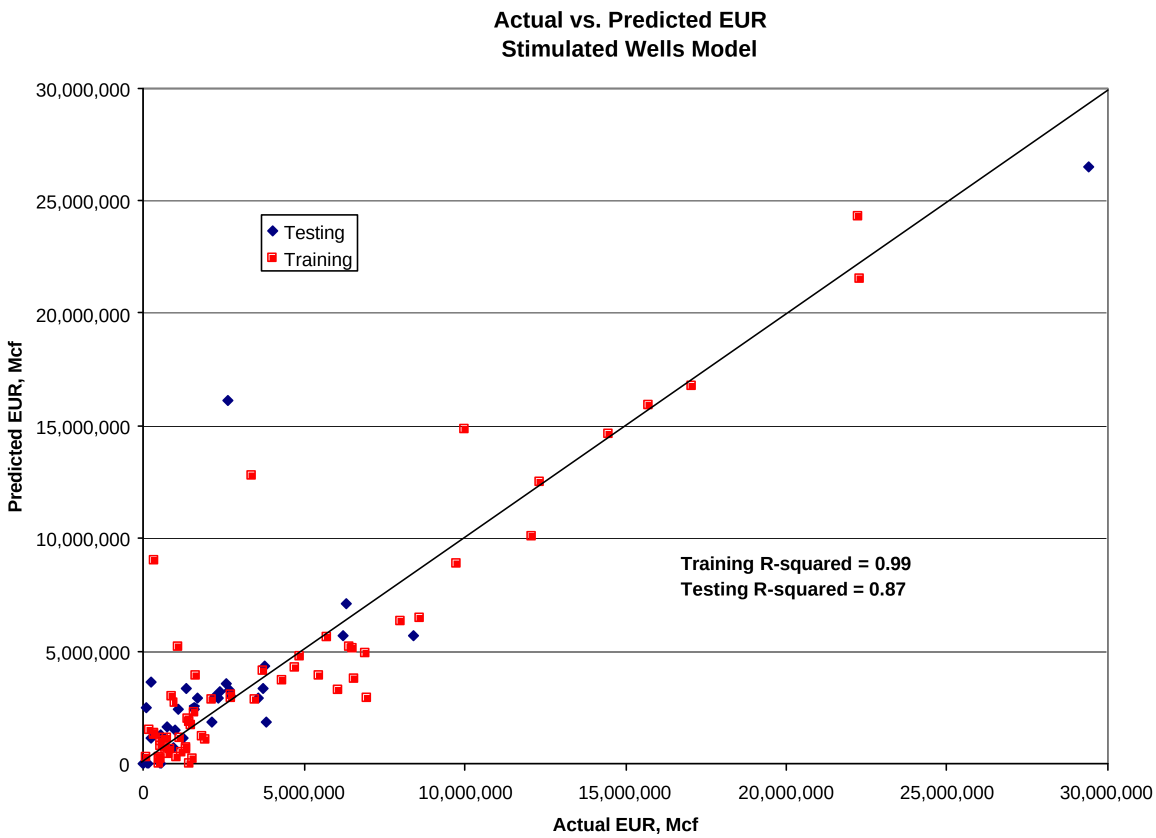


Figure 22: Predicted versus Actual Well Performance, Stimulated Wells Model

The genetic algorithm analysis was then performed to determine restimulation potential for the wells. Specifically, for each well, the following stimulation parameters were optimized:

- Stimulated (Y/N)
- Stimulation Fluid
- Fluid Volume
- Proppant Volume

The magnitude of any differences between actual well performance (EUR) and predicted performance with optimized stimulation parameters was the ranking criteria for restimulation opportunity. To estimate the production opportunity represented by artificial lift and compression, the performance of each well was modeled assuming the installation of a pumping unit, and reducing the flowing pressure to 28 psi (the average value for wells on compression). The total incremental potential was then summed and ranked on that basis. Note that in this case, the total incremental could be allocated between the three production enhancement categories.

3.3 Candidate Screening Process

A heuristic approach to the selection of candidate wells was then applied. The criteria for selection included the results of the data exploration, the type-curve analysis, the artificial intelligence analysis, and also the most recent producing rate (prior R&D indicated that the better the most recent rate, the better the candidate a well is for production enhancement). These criteria are listed in Table 5.

Table 5: Candidate Screening Criteria

- **Data Exploration**
  - **Unstimulated (21 completions, 19 wells)**
  - **Flowing >100 bbls/mo (3 production streams)**
  - **Not Compressed with <50 psi current drawdown (18 production streams)**
- **TC Incremental (top 30 wells)**
- **GA Incremental (top 30 wells)**
  - **Stimulation**
  - **Artificial lift**
  - **Compression**
- **Current Producing Rate (top 30 wells)**

Based on these criteria, two lists (“A” and “B”) were created. The “A” list represented wells that had at least four “hits” of the above criteria, and the “B” list were wells with at least three “hits” each. Those wells are presented in Tables 6 and 7.

Table 6: Group "A" Candidate List

	Data Exploration Opportunities			Top 45 Rank		
Well	Stimulation	Artificial Lift	Compression	TC Incremental	GA Incremental*	Last Rate
Girk B 1-35	N	Y	N	10	28(95,0,5)	31
McClung A 1-11	Y	N	N	1	23(100,0,0)	1
Miles H 2-36	Y	N	N	5	41(97,0,3)	38
Schonlau 2-32	N	N	Y	4	31(87,0,13)	44
Taft 2-10	N	Y	N	30	16(83,7,10)	3

*Breakdown = % Stim, % pump, % compr.

Top Candidate

Table 7: Group "B" Candidate List

	Data Exploration Opportunities			Top 45 Rank		
Well	Stimulation	Artificial Lift	Compression	TC Incremental	GA Incremental	Last Rate
Barker 1-17	N	N	N	43	43(100,0,0)	23
Cater 1-4	N	N	N	3	13(100,0,0)	32
Crawford B 1-26	Y	N	N	N	30(100,0,0)	28
Crawford B 2-26	Y	N	N	N	15(100,0,0)	35
Fickel B 1-17	Y	N	N	N	5 (92,0,8)	6
Fickel C 2-12	Y	N	N	37	36(83,0,17)	N
Hieronymus 1-18	N	N	Y	32	7(58,1,40)	N
Jones 1-26	N	Y	N	33	N	24
Judy B 1-5	Y	N	N	N	3(81,6,13)	22
Kamas A 2-11	Y	N	N	7	45(57,43,0)	N
McClung B 1-14	Y	N	N	N	40(100,0,0)	39
McClung C 1-10	Y	N	N	N	8(100,0,0)	33
Miles G 1-31	Y	N	N	N	42(96,0,4)	34
Moberly Unit 1-18	Y	N	N	11	25(100,0,0)	N
Rector 2-15	Y	N	N	22	14(89,0,11)	N
Scott 1-30	Y	N	N	45	1(88,0,12)	N
Shuman 1-21	Y	N	N	N	33(100,0,0)	2

Interestingly, from the breakdown of production enhancement opportunity by type, based on the artificial intelligence analysis, the bulk of the opportunity in this case lies with restimulation, not with artificial lift or compression. With this understanding, within each candidate group the wells were further prioritized according to the following “rules”:

- Has an unstimulated horizon in the well.
- Ranks in the top 45 based on *both* artificial intelligence and last rate.
- Is in the top 30 ranking for at least one of the above criteria.

Using these rules, certain wells were highlighted as candidates in each of the two groups, and are indicated by boxes. These represent the top priority candidates for production enhancement, based on the analysis performed, for the dataset of study wells evaluated.

4.0 Field Implementation Results

Complete when field results are available.

5.0 Conclusions

Complete when field results are available.

6.0 Acknowledgements

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