# Unconventional Resource Recovery Improvement Using Conventional Reservoir Engineering Strategies*

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## Abstract

Conventional resources follow a very different reservoir development process than do most unconventional resource plays. In the case of the numerous tight gas and shale gas plays in North America, maximizing the profitability of the individual well being drilled dominates the development strategy compared to maximizing overall resource recovery. Most conventional resources utilize a workflow that incorporates optimizing the overall reservoir recovery and rolls the field-wide economics into the decision-making process.

Unconventional resources usually require stimulation. Often, the biggest challenge is not finding the productive zones as much as finding the zones that are most conducive to effective stimulation. Optimizing hydraulic fracture treatment characteristics, zone-by-zone, often determines the degree to which the available resource is recovered. In practice, however, fracture treatment parameters are often selected that produce profitable wells but leave behind considerable hydrocarbon resources.

In low-permeability reservoirs well placement decisions can have dramatic effects on field-wide reservoir drainage if stimulation patterns are not well understood. Unconventional resources often begin development with a low-drilling density and are down-spaced as reservoir understanding increases. Utilizing development drilling strategies that conform to the plethora of technical constraints while maintaining the option of efficient down-spaced drilling options in the future is particularly challenging. Often, resources are stranded and become impossible to economically recover at some future date.

This article shows, via models and actual field results, how unconventional resource developments, while pursing profitable wells, often do so at the expense of leaving considerable bypassed resources behind that will never be economic to recover. These decisions can result in sub-par overall economic performance for the operators utilizing this strategy. Some emerging technologies and workflows are discussed that enable more efficient exploitation of unconventional tight gas and shale plays and maximize the ability to improve the recovery factors of most unconventional resource plays.

## General Statement

The role of unconventional hydrocarbon exploration and development has grown exponentially over the past decade, especially in North America. As this portion of the world hydrocarbon portfolio matures, it is worth while to learn from the much richer accumulation of best practices we have developed over the last century in developing conventional hydrocarbon deposits. By their very nature, unconventional reservoirs are different from conventional ones, and they require different technologies and strategies to make economic exploitation possible. However, unconventional resource plays are often marginally economic. Incumbent upon unconventional resource managers is the pragmatic use of any engineering practices from the conventional resource development world that can bring positive economic results to the unconventional world.

By definition, unconventional resources require stimulation for the well to flow hydrocarbons economically. In contrast with conventional deposits, where much of the effort can be in simply finding the petroleum accumulation, unconventional resources have what is often termed *continuous reservoirs* by the USGS. Certainly, spatial changes in reservoir quality due to deposition, diagenesis, and deformation still occur, but are secondary effects for most unconventional plays. Likewise, with most unconventional resource plays covering thousands of square kilometers, for all practical purposes, the "edge" of the reservoir is simply the boundary of the operator's mineral rights.

The conventional oil and gas development process can be summarized as the 5D process (Figure 1). First *Discovery* of the field must occur, followed by *Delineation* of its extent, then *Description* of the physical properties of the rock and fluids which then leads to a *Development* plan for optimal extraction, and finally the *Divestiture* of the asset once it has reached the end of its economic life. This sequence of activities forms the best practices that have evolved over many years of exploiting, and learning from our mistakes in, conventional resource development. As we march though this series of tasks we are initially refining the architecture of the petroleum trap. Once we have a framework we begin to focus on the properties of both the fluids in the trap but also the geomechanical rock properties of the reservoir and the overburden we must drill through to get to it. This forms the basis for an early, and evolving, model of the reservoir. Once we have a model we can begin to simulate how fluids will flow through this model over time. Actual flow characteristics versus modeled ones provide one mechanism to refine and improve the model. Managing all of these aspects over time not only allows us to optimize the recovery of hydrocarbons from the reservoir but by constantly updating our model we get an ever improving representation of the petroleum accumulation we are trying to responsibly develop.

All petroleum development projects are assessed and ranked prior to making the substantial investments required for the extraction and sale of the resource. Each operator and investor may use their own set of business metrics for these critical go – no go decisions. An informal poll was taken among several operators working both conventional and unconventional resource plays, and the top seven economic business metrics were ranked in order of importance driving the decisions for development (Table 1). One can see that, while many of the same measures of economic success are used, they tend to be flipped in order of importance between conventional and unconventional resource opportunities. This fundamental difference in mind set drives much of the different behavior seen in the two approaches.

## Unconventional Resource Recovery

While the process for developing conventional resources is fairly well developed, that for unconventional resources is widely different between different operators and different basins. This has been further complicated by the shift from tight gas and coal bed methane deposits to the recent surge in shale plays throughout North America. Many of the geologic, petrochemical, and engineering analyses used for normal petroleum deposits are substantially difference for shales. The role and importance in shale development cannot be understated, as shown in Figure 2, where the sudden uptick in reserves is almost totally due to new shale gas reservoirs.

Some of the important factors in successful shale resource plays are: 1) gain early and substantial land position in established high Total Organic Content (TOC) shale, 2) utilize accumulated knowledge of the best drilling, completion, and stimulation practices in the basin, 3) militantly focus on cost control and economies of scale in all engineering services, and 4) find a way to make each well profitable. This formula for success has driven a tremendous amount of incremental resource for extraction. This success has, however, come at the cost of leaving more recoverable resource in the ground that, in most cases, is effectively stranded and can never be exploited in the future. This fact is evidenced by the relative priority of recovery factor in Table 1.

No wells can be drilled and completed if sufficient average production does not offset average fully burdened well costs. It is worthwhile to remember what factors are in our control to enhance the flow of hydrocarbons from the well. Figure 3 is the equation for pseudo-steady state flow from an oil reservoir, but similar equations exist for all flow regimes and petroleum fluids for our purposes.

With all the parameters available in Figure 3, there are realistically only have two variables that can be altered to enhance the flow from the well: 1) increase the length of the wellbore contacting the reservoir by turning the wellbore sideways and creating long horizontal wellbores (h), and 2) reduce the skin damage (sd) through hydraulic fracturing. Both of these strategies are now common place in most unconventional resource development plays. Hydraulic fracturing has probably been the most important factor in the reserves growth from unconventional resources to the overall portfolio of hydrocarbon resources in North America. Over time this is likely to extend to most of the other petroleum provinces of the world.

Several previously uneconomic unconventional plays have been ‘unlocked’ through a series of cost reductions similar to those pioneered in the automobile manufacturing optimization processes launched in the 1970’s in Japan. Some examples of these efficiency gains and corresponding cost reductions are pad drilling up to 20 directional wellbores from one location, and round robin-fracturing of multiple stages in multiple well bores, all from one pad over a series of days to months and never moving the equipment. Perhaps the epitome of field completion optimization is not only fracturing numerous stages and wells on one pad but physically connecting several pads several miles apart to the pumping equipment on a centralized location. In one case study done by Encana on the Pinedale Anticline in Wyoming, 406 stages in 40 wells across 10 interconnected pads were hydraulically fractured in 2 weeks (Figure 4). This has the potential for driving down costs tremendously.

The focus on making economic wells tends to take precedence over asset level economics and hydrocarbon recovery in unconventional plays. Minimizing well cost, at the expense of hydrocarbon recovery, can be detrimental to project return. Too much focus on making each individual well maximally profitable can detract from the overall goal of extracting the maximum amount of hydrocarbons from the reservoir profitably. To pursue the broader goal, one must truly understand how the wells are being drained and what part of the reservoir has been stimulated.

Many parameters go into the hydraulic fracture models, and some of these parameters are often poorly understood. Perhaps the most significant problem is that the petroleum industry still does not have a reliable complex fracture model (more than a simple bi-wing fracture). Independent evidence suggests that, especially in the new shale plays, complex fractures are more the rule than the exception. Until we get better at modeling complex fractures, their optimized design will require heuristic experimentation and validation through some external fracture diagnostic method.

Several fracture diagnostic methods have evolved over the years starting with surface tilt meter surveys and downhole tracer and production logs. Today we have both surface and downhole tilt meters, surface and downhole microseismic, distributed temperature sensing along the wellbore, tracers, and production logs. All of these techniques have their own strengths and weaknesses. For far-field investigation of hydraulic fracture geometry, the downhole microseismic method is currently the most reliable measure we have. As it is currently practiced, downhole microseismic provides a good
qualitative assessment of vertical fracture growth, horizontal fracture growth, fracture azimuth, and an approximation of the complexity of the fracture system (Figure 5). Over the coming year, quantitative methods will start to become common in assessing the degree to which the intended zones were stimulated, where excessive treatment out-of-zone growth occurred and to what degree the pumping schedule achieved uniform half-length fractures as intended.

Studies have shown that well production correlates well with both the area in map view of the stimulated region from microseismic as well as the volume of the stimulated area in 3D (Figure 6). Any part of the intended reservoir that does not get effectively stimulated correlates to lost production and lost revenue. Utilizing fracture diagnostic methods to assess the effectiveness of the treatment programs and design is critical to achieving the optimum production from the well, at least until predictable fracture designs are dialed-in for a particular basin.

Figure 7 shows an actual example where five wells and 28 fracture stages were done from one pad yet 17% of the intended zones to be stimulated were missed. Much of the treatment slurry went into zones that were not candidate reservoirs, or they restimulated a zone that already had adequate coverage from a former stage.

Even more important on overall production is the consistent and planned fracture length between wells and stages. It is common practice for vertical wells to display all stages and determine the fracture length. This masks the differences in fracture length between stages. In Figure 8 the result for the same wells analyzed in Figure 7 shows that 28% of the intended reservoir was not stimulated due to inconsistent fracture lengths between stages and wells. To achieve truly consistent fracture growth may be impossible to design a priori but may be quite achievable with real-time monitoring of the fracture as it is being pumped. In this case, the primary ‘stop pumping’ decision would be driven more by the actual physical geometry of the fracture, as indicated by the microseismic than by the step in the pumping treatment or when the intended volumes have been pumped.

As the stimulated reservoir volume of the reservoir is the primary contributor to overall production, errors of 17% in height and 28% in length give an error in volume of their product, or a loss of 40% of the intended reservoir to be stimulated and its potential production. Clearly there is ample headroom in increasing well cost, if getting more of the reservoir stimulated could result in higher well production and better recovery of the in-place hydrocarbons.

The final factor that is usually the primary justification for conducting microseismic mapping surveys in the first place is to accurately determine the azimuth and complexity (shape - in this case length/width aspect ratio) of the hydraulic fracture. This guides the development drilling location planning to optimally drain the reservoir and minimize well-to-well interference. Figure 9 demonstrates a typical elliptical drainage pattern common in tight gas sands where strong horizontal stress anisotropy exists. One can see that rows of wells are laid out with separations between the wells and skews between the rows so as to minimize the pressure interference between the wells while minimizing the untreated reservoir between the ellipses. This model is somewhat idealized but quite realistic for planning the development well bottomhole locations. The areas between the ellipses (stranded reserves) will never be economically produced due to the marginal economics of most unconventional plays as well as drilling density restrictions in most of those areas. The area of stranded reserves is a function of the error between the actual fracture azimuth orientations and the planned development drilling orientations. In Figure 9 one can see that a not-unheard-of error of 30° in the planned versus actual fracture azimuth would result in stranding about 15% of the reserves of the reservoir. This has negative implications for both the operators' revenue stream but also in the recovery factor of the hydrocarbons present in the reservoir. Not only does leaving this gas behind negatively affect the profitability for the operator but it also is detrimental to the tax revenues the government realizes for public lands leased for oil and gas production.

## Conclusion

Any unconventional resource development strategy that places undue focus on well cost reduction at the expense of good engineering practices, that have evolved over many years in the conventional resource development world, could result in sub-optimal economics for the project. Horizontal drilling rigs have sustained a 20% higher utilization rate than vertical drilling rigs through this recent downturn of the industry. As shown above, significant well productivity enhancements are possible with careful stimulation of the reservoir. We now have the tools to determine the reservoir stimulation effectiveness and tune the treatment procedures accordingly. Adopting some of these historical metrics of oil and gas business opportunities (like recovery factor) has the potential of driving better returns in marginal unconventional resource plays. A balance of cost reduction and production optimization will result in the most prudent engineering and business practices being implemented for maximal economic recovery of these unconventional resources that are proving to be so abundant in North America, and likely elsewhere.

## Reference

Potential Gas Agency, 2009, Potential Supply of Natural Gas in the United States: Report of the Potential Gas Committee (December 31, 2008) Washington, D.C., June 18, 2009 (accessed April 17, 2010).

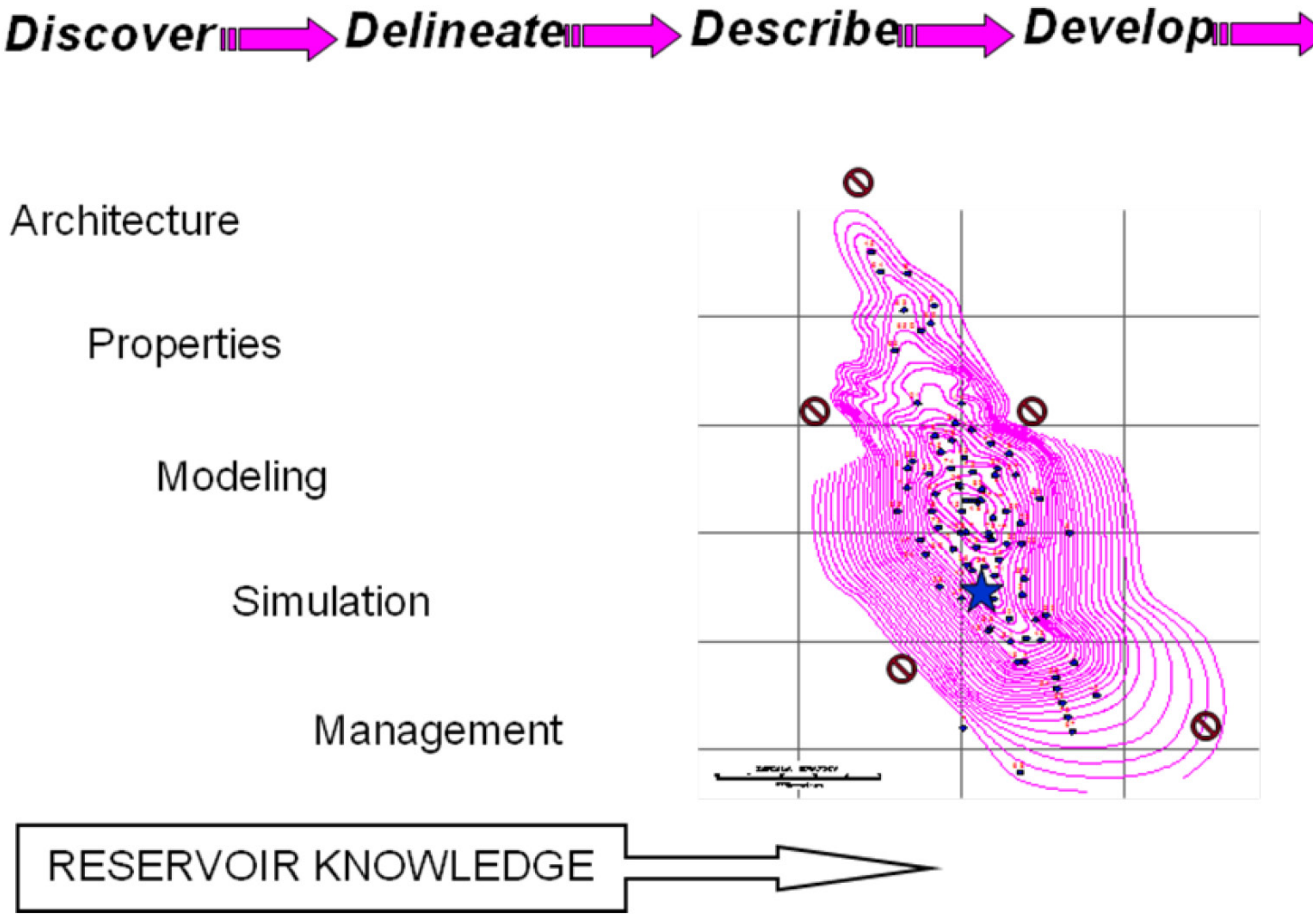



Figure 1. Conventional hydrocarbon field development process.

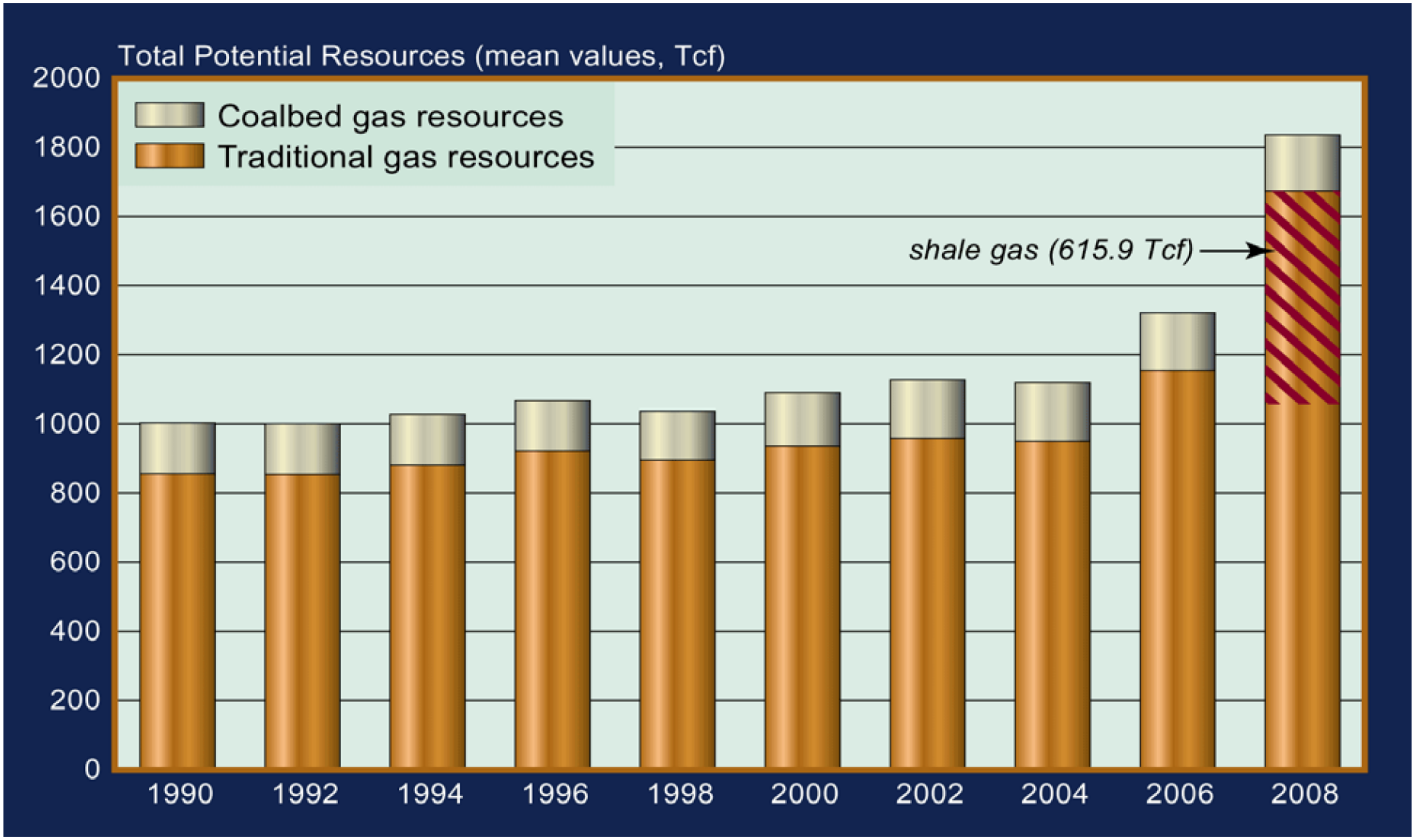



Figure 2. US gas resource estimates (Potential Gas Agency, 2009).

$$q_{sc} = \frac{[p_e - p_w]kh}{141.2\mu B_0[\ln \frac{r_e}{r_w} + s_d]}$$

$q_{sc}$ = flow rate
$p_e$ = reservoir pressure
$p_w$ = wellbore pressure
$\mu$ = viscosity
$r_e$ = radius of reservoir
$r_w$ = wellbore radius
$s_d$ = skin damage

Figure 3. Flow equation for pseudo-steady state oil.

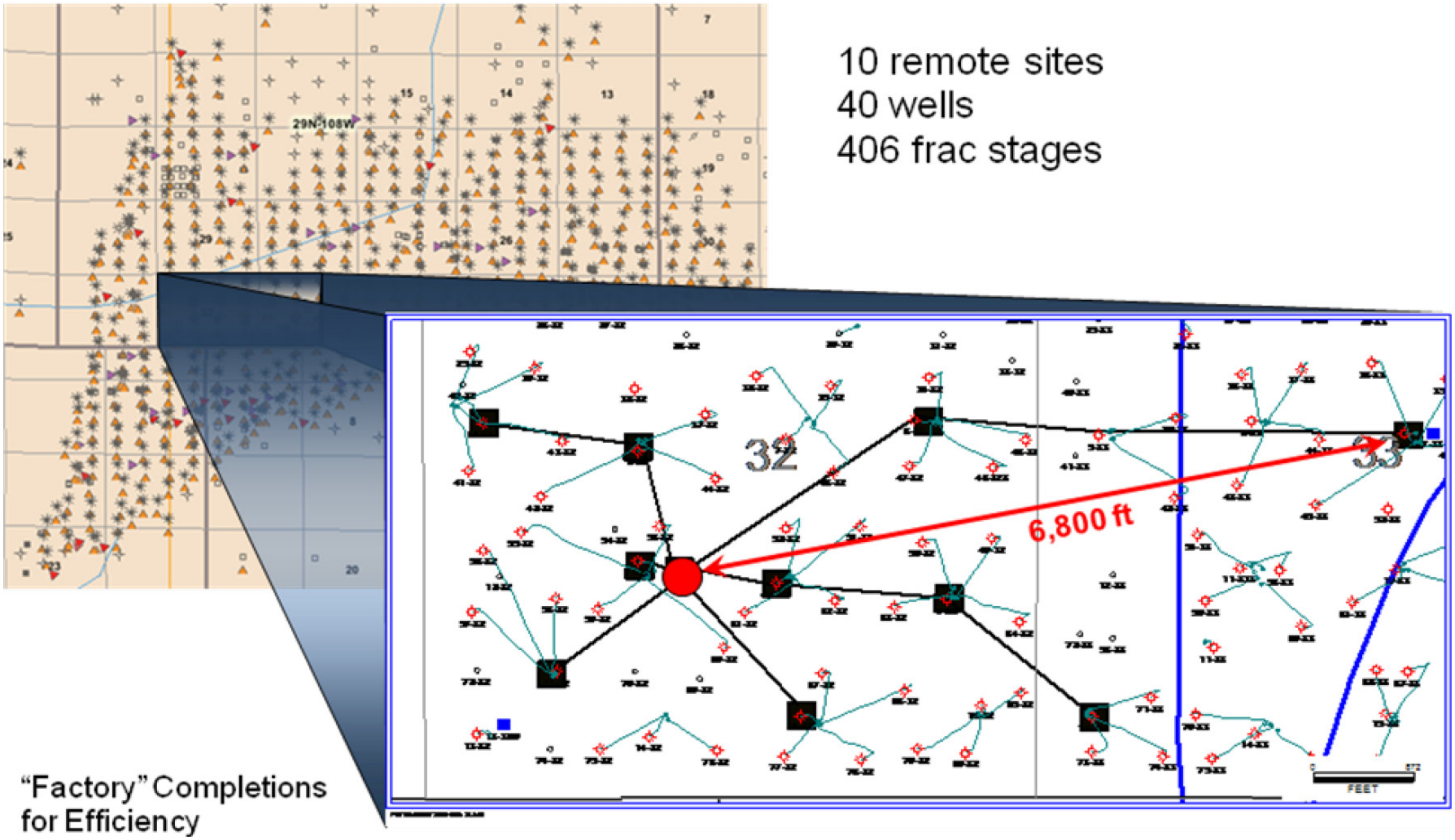



Figure 4. Example of highly efficient hydraulic fracturing processes.

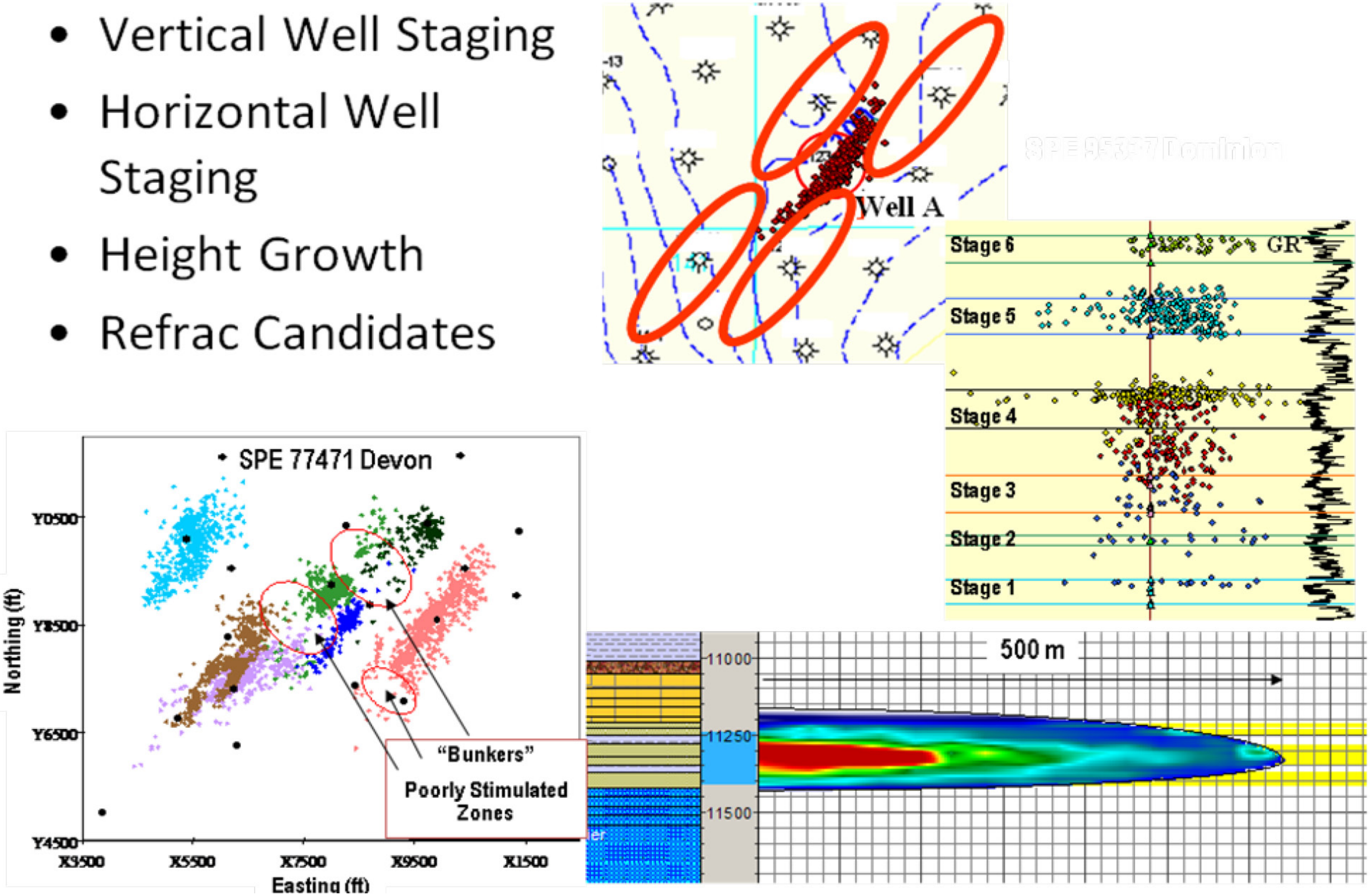



Figure 5. Fracture diagnostic information to assess fracturing success.

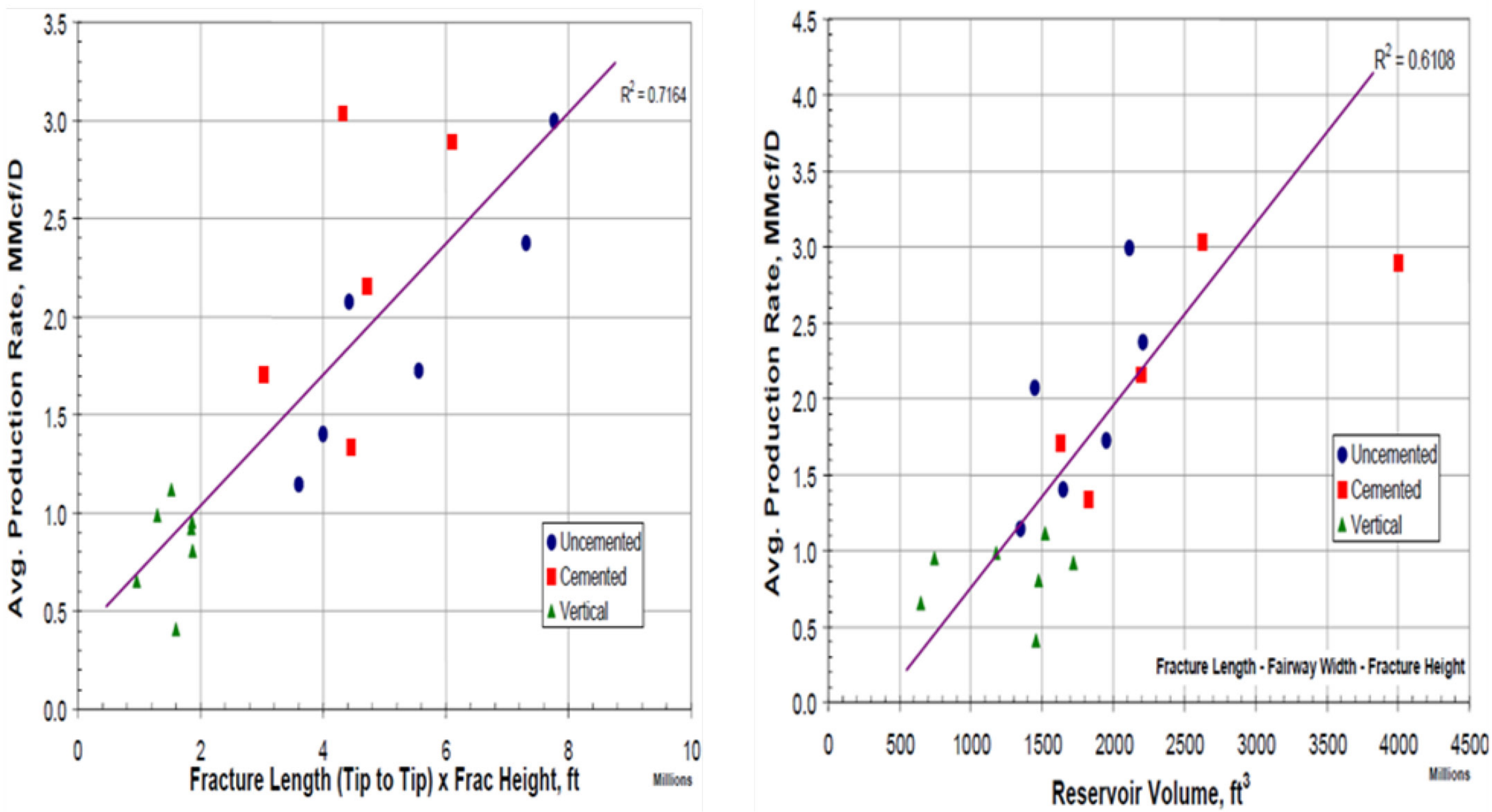
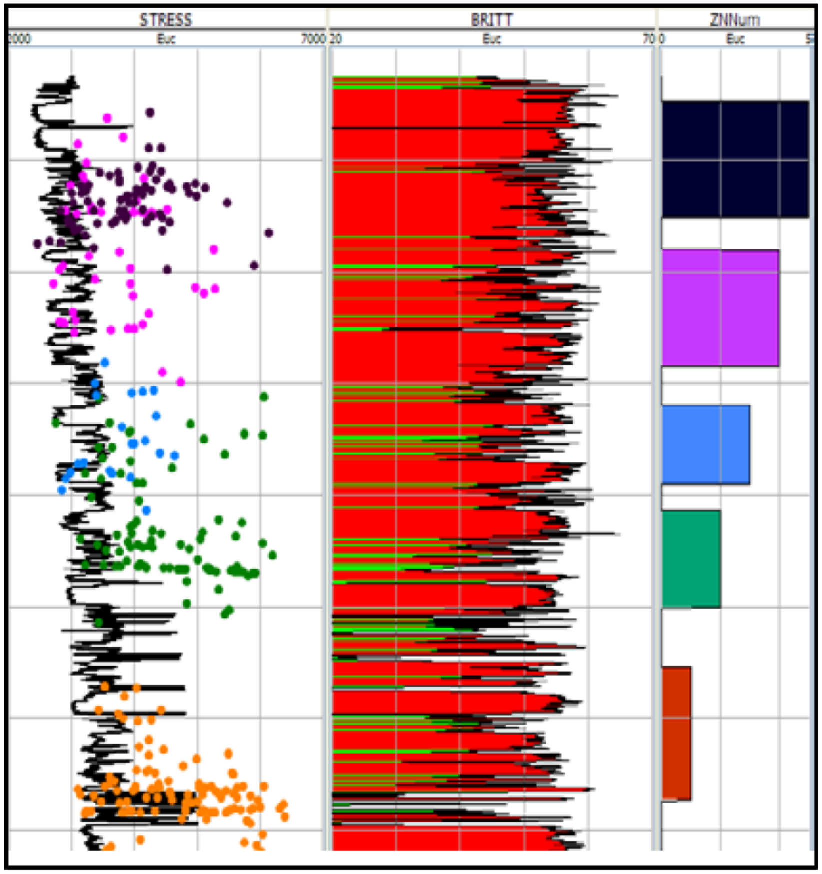
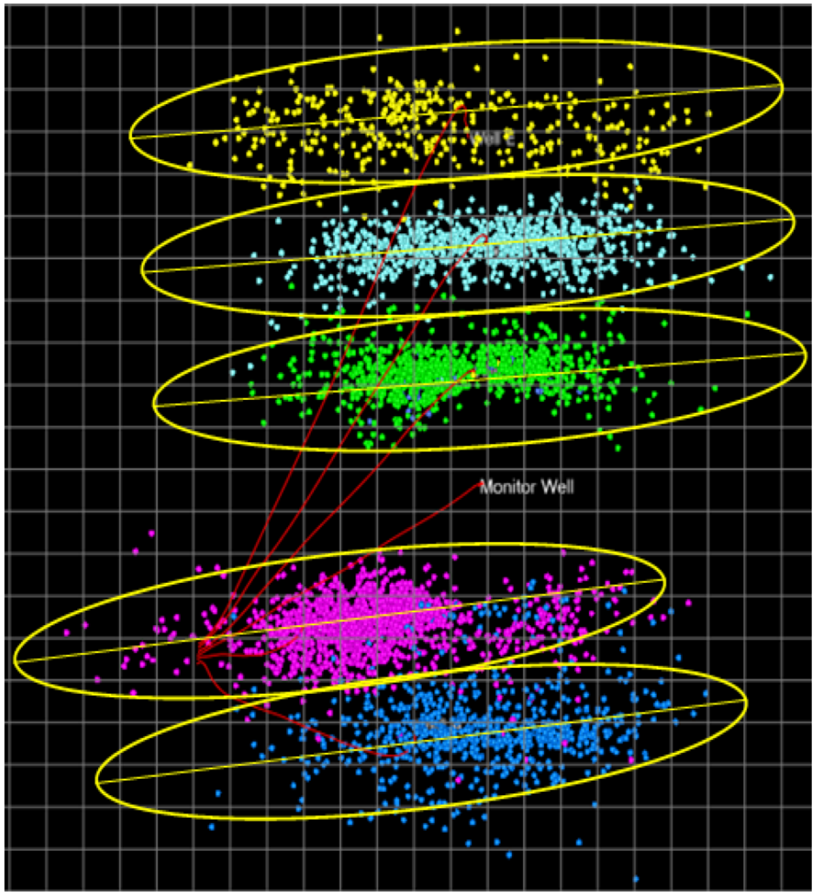



Figure 6. Production correlation with stimulated area and volume.




| Well ID | Height | Pay | Covered | Missed |
|---|---|---|---|---|
| Well A | 2047 | 1132 | 877 | 23% |
| Well B | 1559 | 1074 | 1046 | 3% |
| Well C | 1561 | 1067 | 834 | 22% |
| Well D | 1129 | 992 | 803 | 19% |
| Well E | 1204 | 1011 | 795 | 21% |
| Average | 1500 | 1055 | 871 | 17% |

Figure 7. Hydraulic fracture vertical treatment effectiveness.




| Well ID | Length | Shortage |
|---|---|---|
| Well A | 834 | 33% |
| Well B | 904 | 27% |
| Well C | 837 | 32% |
| Well D | 882 | 29% |
| Well E | 1022 | 17% |
| Average | 896 | 28% |

Figure 8. Hydraulic fracture treatment length consistency.

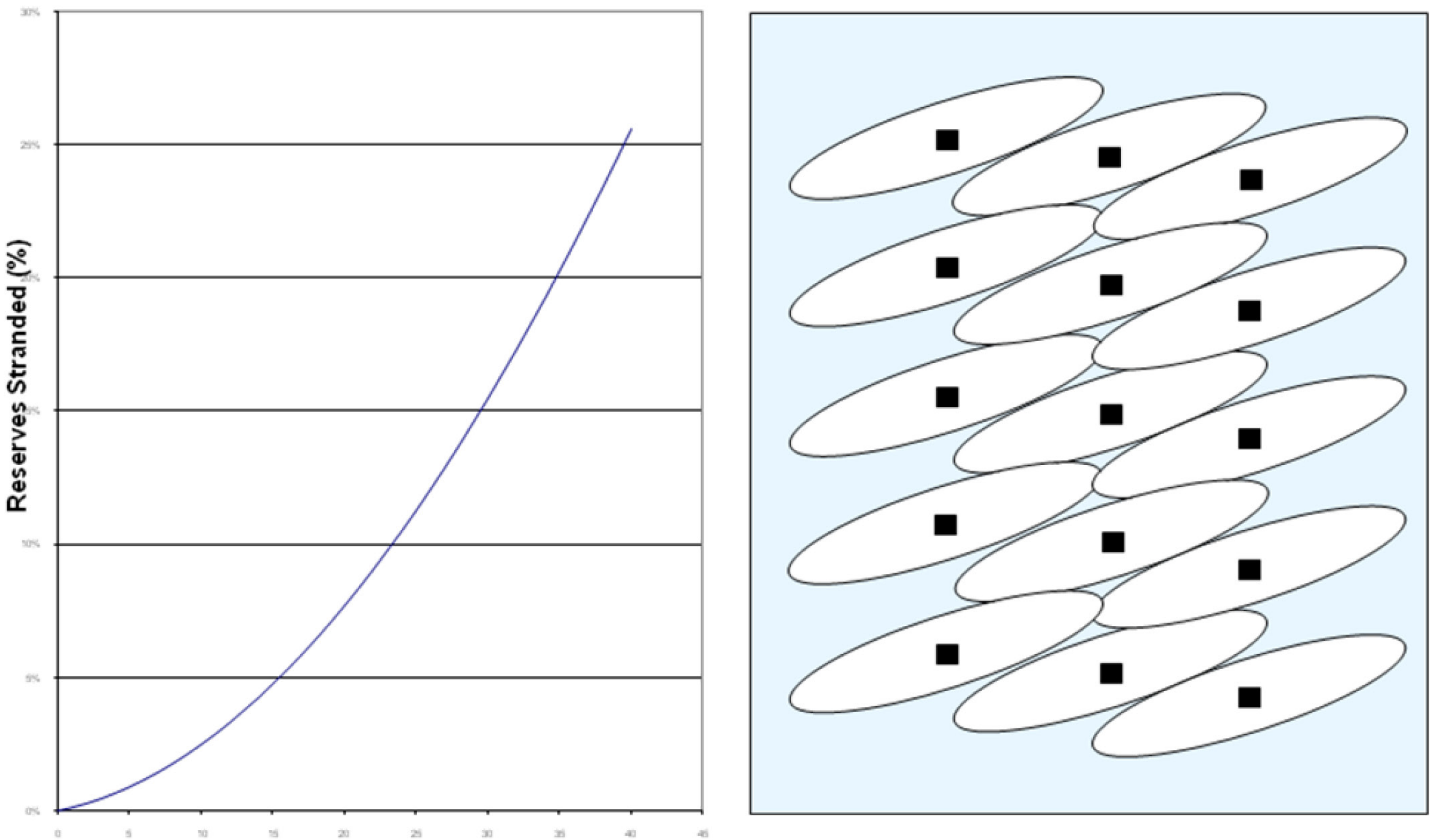



Figure 9. Stranded reserves versus azimuthal error in development drilling layout.

| Conventional | Nonconventional |
|---|---|
| 1. Resource Recovery Factor | 1. Profitability |
| 2. Net Present Value | 2. Capital Expense |
| 3. Environmental Impact | 3. Environmental Impact |
| 4. Rate of Return | 4. Net Present Value |
| 5. Operating Expense | 5. Rate of Return |
| 6. Capital Expense | 6. Operating Expense |
| 7. Profitability | 7. Resource Recovery Factor |

Table 1 – Measures of business success.