MULTI-WELL MANAGEMENT SYSTEMS
Part Two – Methods for Maintaining Peak Performance in Old Gas Fields

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ABSTRACT

This paper presents a method for identifying opportunities to increase production in gas wells using graphical analysis techniques and numerical simulation methods. The method is quick, easily repeatable and can be applied to large numbers of producing wells in a mature gas field. Significant economic benefits can be achieved with the use of this combination of technologies and it is applicable to a vast number of mature fields throughout North America. Two case histories are presented. Case 1 is from western Canada and illustrates applications to finding wells in need of fracture treatment. Case 2 is from the central US and illustrates how this technology was used to maximize production increases from a gas compression system expansion project.

This paper also illustrates one of the many ways in which added value may be obtained from real-time gas well production data when revitalizing mature fields.

REVIEW OF PREVIOUS PAPER

In April 2004, the first paper on this topic, "Multi-Well Management Systems, Part One – Gas Well Operations", was presented at the Southwestern Petroleum Short Course in Lubbock, Texas. This paper was oriented towards operational considerations, particularly the identification of under performing gas wells, using graphical discovery tools. A performance analysis method utilizing "Dynamic Baselines" was introduced. This method is designed to take advantage of the continuous rate and pressure measurements in gas wells made possible by real-time, remote well surveillance systems. The technique offers a dynamic measurement of well performance through a continuous comparison of actual production to a predicted average or baseline production which moves with time. It is designed to assist Operations personnel in quickly identifying those wells whose production is beginning to lag due to mechanical or operational problems.

NEW TECHNIQUES FOR OPTIMIZING MATURE GAS FIELDS

This paper expands upon the methods in the first paper. The use of graphical and empirical tools is refined through the use of "production indicators". Certain key production data from the performance of a well, such as decline rate, maximum rate, best year production, can often be used to quickly identify wells which may be impaired. Refer to Case History No. 1 at the end of this paper for an example of how this method works and the type of results which can be expected from such an analysis.

We also introduce the use of a numerical reservoir simulator in this paper for use in diagnosing problem wells and developing production enhancing solutions. It is now possible to perform very rapid simulation runs using well production and pressure data that makes it practical to use this tool on an every day production engineering and operations basis. The use of this technology, coupled with real-time empirical tools such as production indicators, dynamic baselines and cross-hair plots creates a powerful new method of finding new production in mature fields which are being revitalized. Case History 1 and 2 illustrate some of the many new possibilities now available from this combination of technologies.

CASE HISTORIES

Case 1

Canadian Gas Field

This western Canadian gas field contains many separate pools, all within the same geologic formation. About 500 producing wells were studied. Because of the high degree of heterogeneity, it was difficult to develop methods to identify problem wells since correlations between pools and wells are difficult. The objective of the study was to identify wells which could be profitably fracture treated and then implement such projects. The method of using "production indicators", mentioned above, worked well in this situation.

The process used for this analysis was as follows:

1. Analyze the gas well rate and pressure data to determine which production indicators might prove most useful in finding underperforming wells. Some of the potential indicators considered included decline rate, maximum first year gas, initial gas rate, and best year production.

2. Identify leading candidates for frac treatment using production indicator analysis.

3. Utilize a reservoir simulator to analyze the top candidate(s) for frac treatment and carry out hydraulic fracture treatment operations.

4. Take the results from Step 3 above and use it to calibrate and improve results from Step 1.

Refer to Case 1 below for an example of this process and the results which may be expected. The first well analyzed with this process showed a 25% increase (1.5 BCF) in ultimate gas recovery.

Case 2
Hugoton Gas Field

A small portion of the Hugoton Field in southwestern Kansas, with about 400 producing wells, was used in this example. A project was planned for this area to drop the suction pressure on the compressor station from about 100 psia to 45 psia. This was carried out over a period of about five years, with the intake pressure being gradually reduced by adding stages to the compressor. Overall gas production rates increased approximately 5 MMCF/d from wells connected to the compressor expansion. The purpose of the analysis reported in this paper was to study the effect of drop in line pressure on individual well performance and use this information to further optimize and increase production from wells in the system.

The availability of real-time flowing rate and pressure data was of great assistance in getting accurate and detailed results from this study.

The following general process was used.

1. Construct an empirical model which could display real-time changes in well production rates and tubing head pressures as line pressure was dropped.

2. Identify wells or groups of wells with unexpected performance changes and prioritize them for reservoir simulation analysis.

3. Perform simulation analysis on individual wells and compare predicted versus actual performance.

4. Use simulation results to calibrate and improve results from Step 1 and 2 above.

5. Identify areas within the field with additional uplift potential, areas requiring stimulation, and areas within which the surface gathering system needs optimizing.

Refer to Case 2 below for an example of this process and the results which may be expected. The first well analyzed with this process experienced over a 100% increase in gas recovery from 370 to 758 MMCF. A significantly expanded understanding of the reservoir, wells and pipeline system was also obtained at a very reasonable cost with many additional opportunities for production increases identified.

BENEFITS

Some of the benefits to be obtained from this type of field optimization include the following:

1. Rapid identification of gas wells which may be producing below their full potential.

2. Much more detailed information regarding the performance of the reservoir and well system, resulting in improved success rates on well production enhancement projects.

3. Identification of opportunities to increase production from compressor expansion projects by analyzing well and piping system performance as the line pressure is reduced.

4. Manage hundreds or even thousands of wells with the same degree of confidence as with just small numbers of wells.

5. Obtain significant added value from real-time SCADA system data being collected in mature gas fields.

6. Very quickly perform the analysis required for the above benefits and be able to repeat them on a periodic basis to maintain the field at peak performance.

CONCLUSIONS

It is now possible and feasible to combine high-tech reservoir simulation with simple graphical and empirical production models to permit the rapid optimization of large producing gas fields on a continuing basis. This technology is affordable and sustainable, that is it can be made a permanent part of any gas field production operation.

Results from this type of optimization activity have yielded economic benefits far in excess of the expense required for the effort. With the current sales price of natural gas, utilization of this technology becomes a great asset to any gas field operator.

The availability of real-time, high frequency production data from gas wells is also of significant benefit to this process and permits much more accurate results as well as the identification of opportunities which would not be seen using more conventional, non-digital production data.

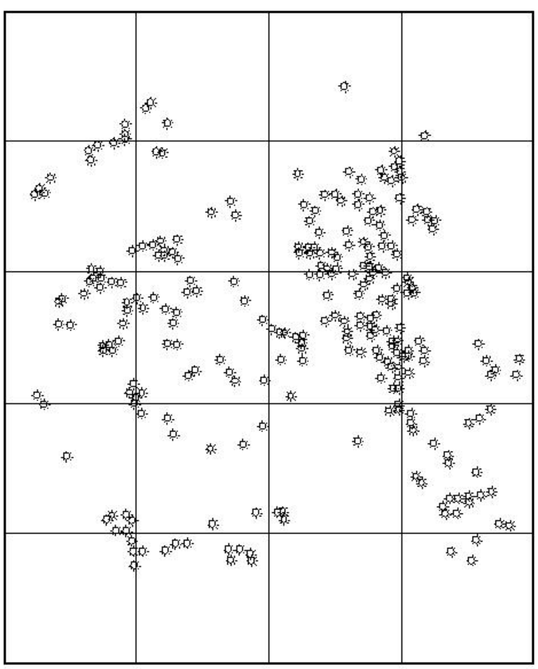
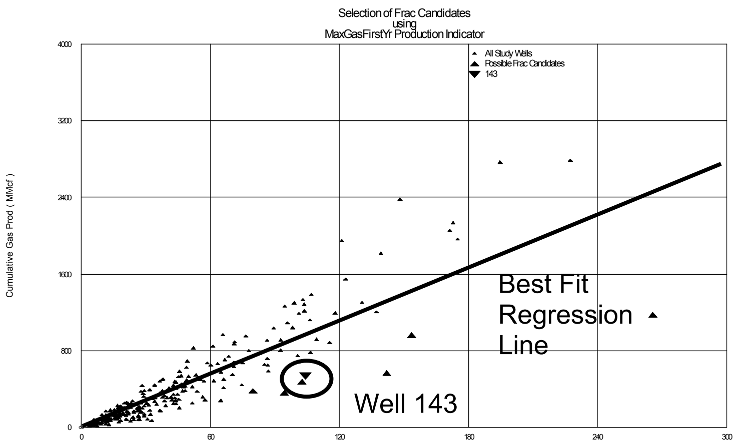


Figure 1
Case 1

Figure 1 shows the base map for the Canadian gas project. Approximately 500 wells are distributed over a large area containing many separate pools. Many wells had impairment problems. It was difficult to determine the difference between wells with poor quality reservoir rock and those which had skin damage from drilling or production operations.

This was an ideal case to use production indicators for the first selection of candidate wells for frac treatment.

Selection of Frac Candidates
Using
MaxGasFirstYr Production Indicator



MaxGasFirstYr Rate (Mcf/d)

Figure 2
Case 1

Figure 2 shows how the MaxGasFirstYr Production Indicator was used to select damaged wells. The X-axis is the maximum one day gas rate produced during the first year and y-axis is the cumulative gas produced during the first 18 months of production. A best-fit regression line has been drawn in to highlight off-trend wells.

Notice the wells with the large black triangles for well symbols. These wells have high MaxGasFirstYr rates but low 18 month cumulative production. Wells with similar MaxGasFirstYr rates typically produced much higher cumulative volumes of gas. Well 143 was selected as one of these anomalous wells to study further.

Table 1
Screening Matrix For Lift Methods Designed To Lift
Liquids Off Gas Wells

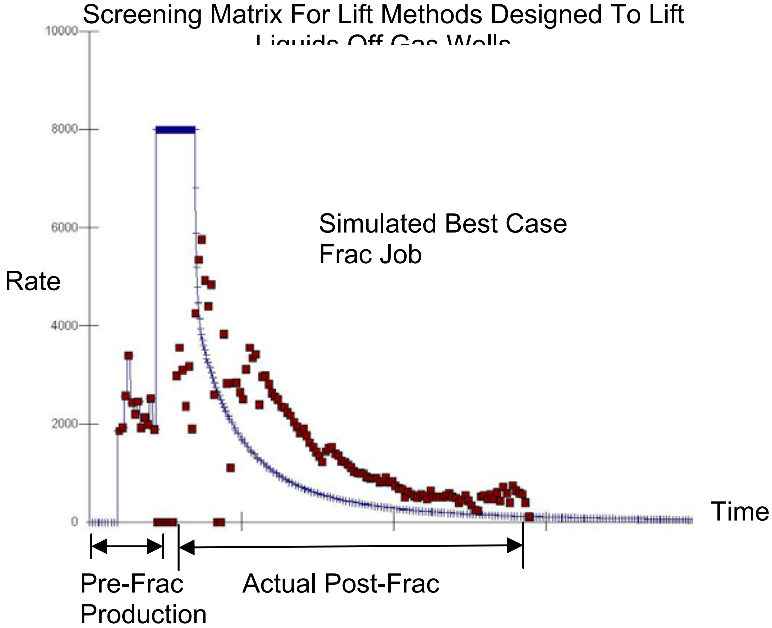


Figure 3
Case 1

Figure 3 contains the results of the reservoir simulation study for Well 143. The Pre-Frac production of Well 143 was used to calibrate the reservoir simulation model. Once this was accomplished, the reservoir simulation model predicted future performance for Well 143 following a frac job.

In this graphic the Pre-Frac production is shown on the left side of the graph, the forecasted production from the simulator (shown with the smooth line), and finally the actual results from the frac job are shown as small squares. The frac job was a tremendous success. Knowledge gained in this evaluation was then used to identify other wells with similar potential in this project.

Results from the Well 143 frac increased ultimate recovery by 33%:

EUR after frac	6.211 BCF
EUR before frac	4.656 BCF
Net EUR increase	1.555 BCF

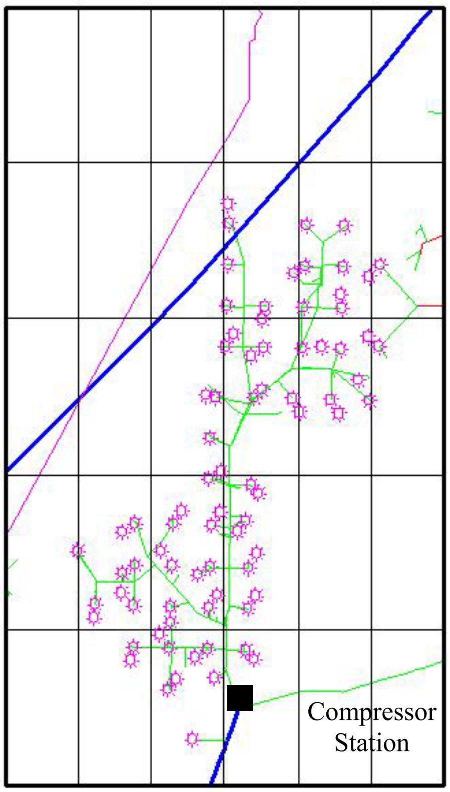


Figure 4
Case 2

Figure 4 is the basemap and pipeline system for a portion of the Hugoton field studied in this analysis. Approximately 400 wells were involved. Production is from shallow zones, approximately 1000 to 2000 feet deep and has been underway for over 40 years. This mature field still has many opportunities to increase production as shown by the study below.

In this Case history, we will review the results of a compressor expansion project. The line pressure in this area of the field was approximately 100 psia at the time this study began. After the expansion, the average line pressure was been reduced to 45 psia.

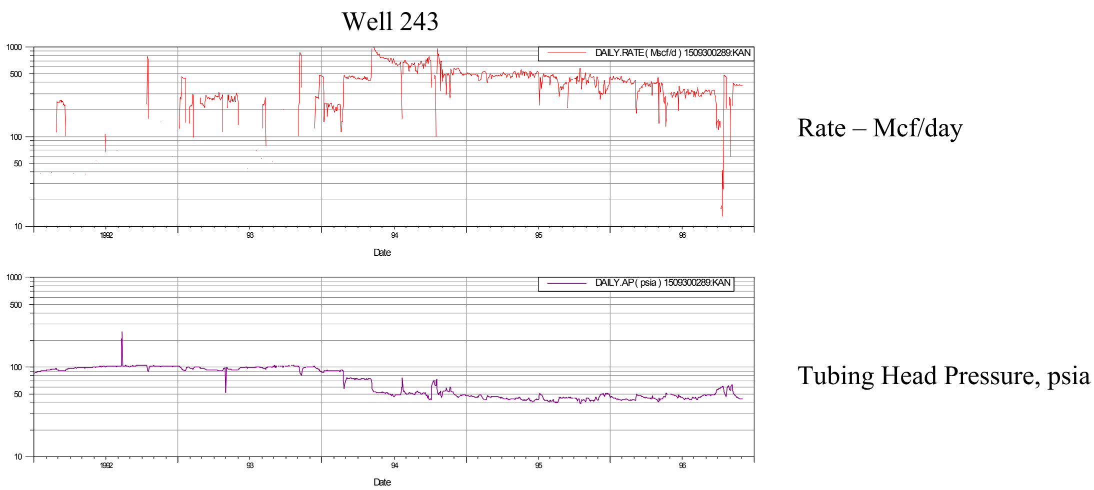


Figure 5
Case 2

Figure 5 shows a sample of real-time data for Well 243 used in this project. All data used in this analysis was from a SCADA system. Real-time data taken on 15 second intervals was reduced down to daily flow rates and tubing head pressures. As seen in the results at the end of this write-up, this high frequency data revealed details in the character of well performance that permitted a much better understanding of the many opportunities available to increase production.

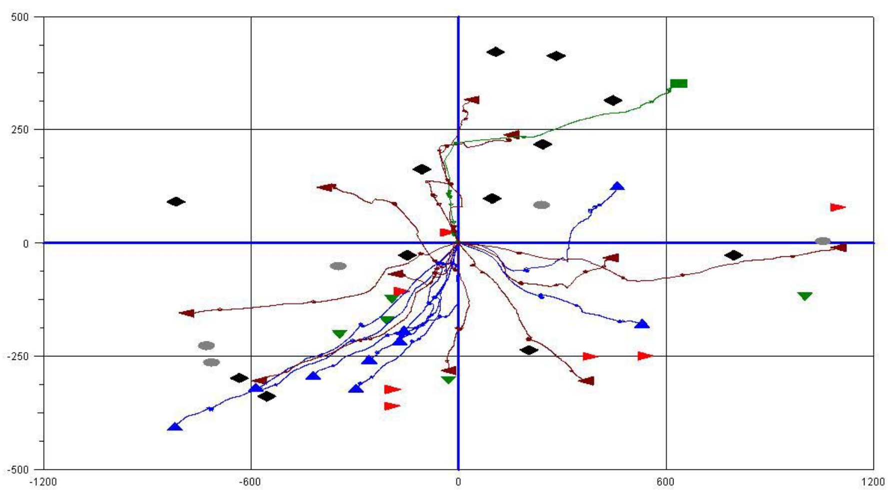


Figure 6
Case 2

Figure 6 shows a Cross-Hair Plot of Cumulative Normalized Flow Rates of individual wells on the X axis and Cumulative Normalized Tubing Head Pressures on the Y axis. Each dot represents a well at a point in time. The diagram can be animated to see the patterns of performance with time. (Note: if a particular well had average flow rates and pressures during the study period, it would remain in the center of the cross-hair.)

Selected wells have tracks turned on to permit seeing their historical performance. Notice some of the wells have radically changed their flow patterns on this diagram.

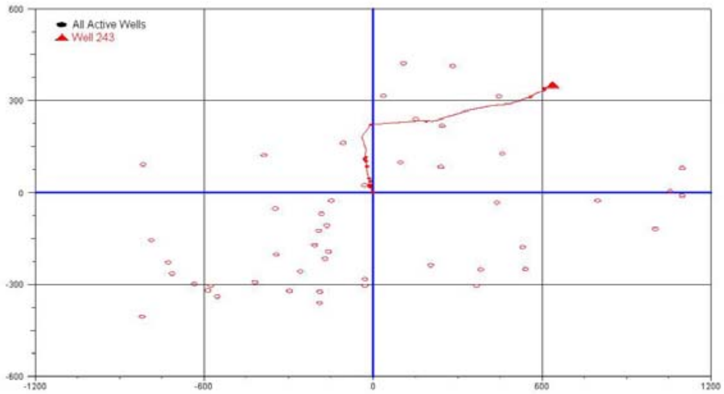


Figure 7
Case 2

Figure No. 7 shows the performance of Well 243 during the time period of drop in line pressure. This is the well which was selected for simulation study in order to calibrate this model.

Notice that Well 243 was very positively affected as the line pressure at the compressor was reduced. Its production relative to the other wells increased significantly.

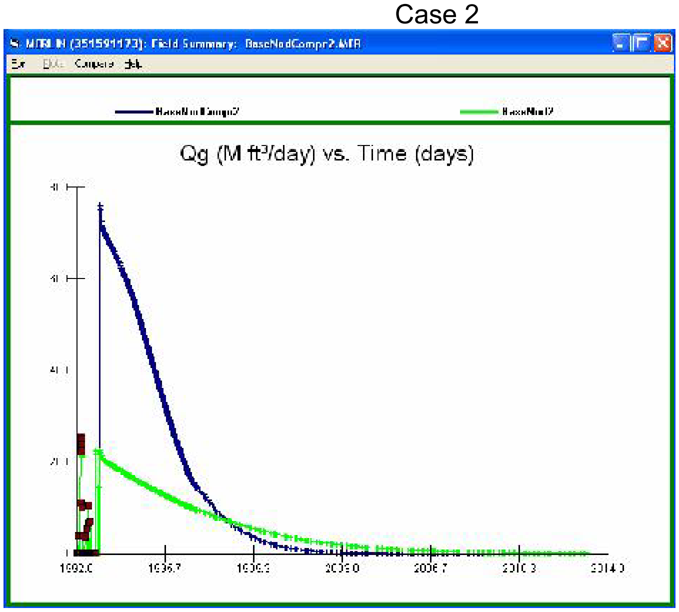


Figure 8
Case 2

Figure 8 shows the results of a reservoir simulation model which has compared the forecasted production of Well 243 with a 100 psi line pressure (in green, lower curve), and dropping line pressure to 45 psi (in blue, upper curve) starting in 1993.   Note that the producing rate doubles.

The reservoir simulation model was first calibrated to by matching production rate and flowing tubing pressures from the well prior to 1993.   The resulting model very closely approximates the actual reservoir conditions, and allows accurate forecasts to be made for different future producing scenarios

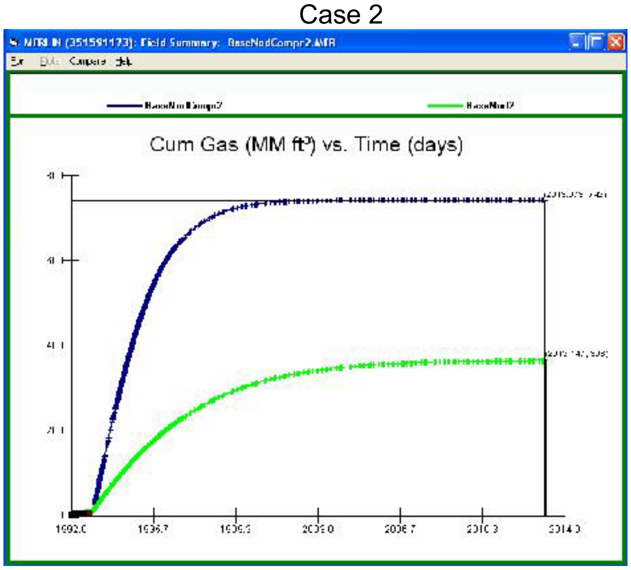


Figure 9
Case 2

Figure 9 shows a forecast of cumulative productive from Well 243 with compressor intake pressure equal to 100 psi (in green, lower curve) and intake pressure lowered to 45 psi (in blue, upper line)

Adding the additional compression more than doubled the predicted ultimate recovery from Well 243. The estimated remaining reserves in this well increased from 370 MMCF to 758 MMCF.

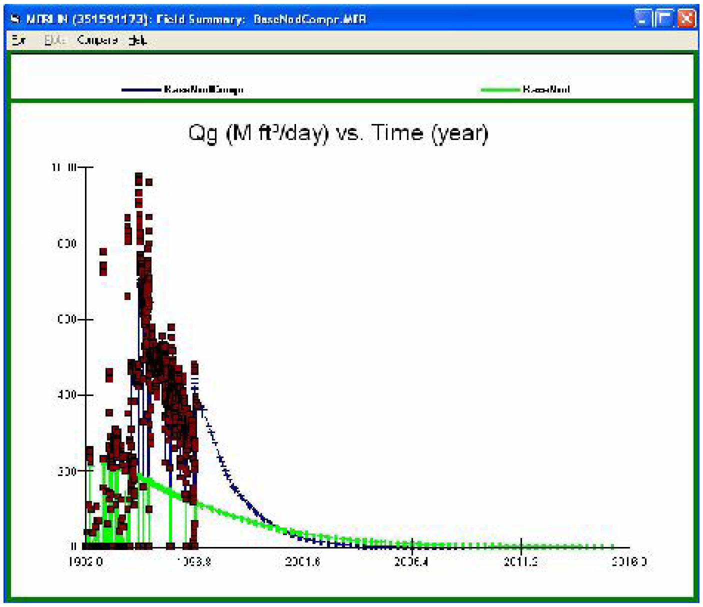


Figure 10
Case 2

Figure 10 shows what actually happened in this reservoir when compression lowered the line pressure from 100 psi to 45 psi. The historical data from 1993 to 1996 has been added to the plot and is indicated by the small boxes. The forecast with 45 psi line pressure starting in 1997 is shown in blue, and the forecast from 1993 forward with 100 psi line pressure is shown in green.

The model accurately predicted the benefits of compression for Well 243, thus making it possible to identify other significant opportunities as shown below.

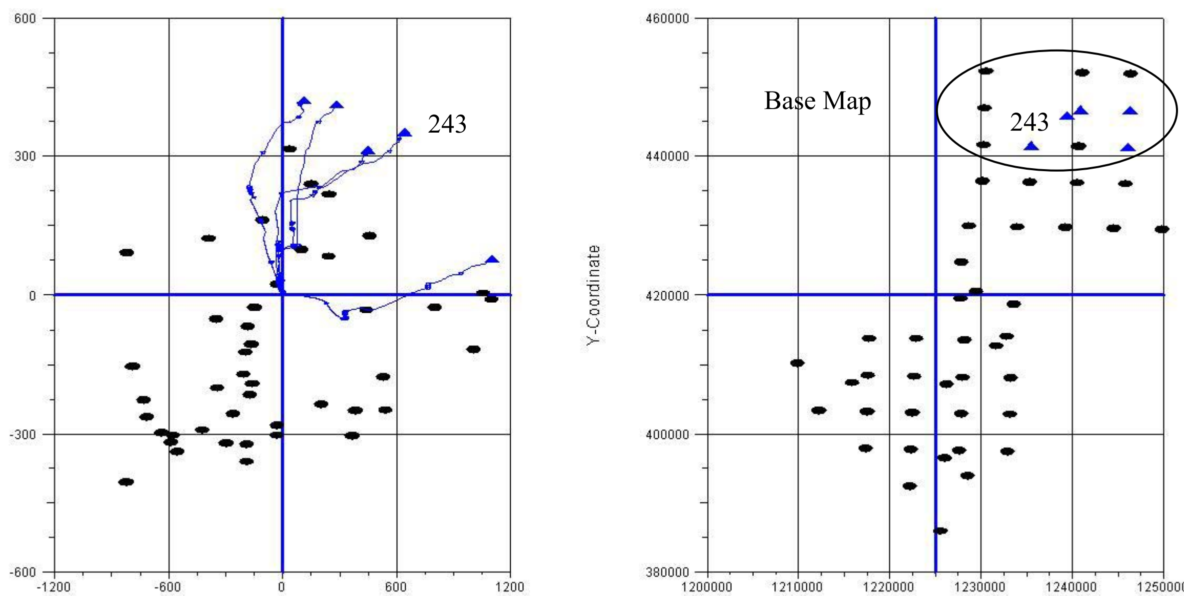


Figure 11
Case 2

On the left hand graph of Figure No. 11 we see the same cross-hair plot as in Figures 6 and 7. Recall that wells which drift to the right of the origin are steadily producing at a high than average rate and wells with steadily higher than average tubing head pressure are drifting up from the origin. The time frame for this plot is the same as the time frame for the compressor expansion during which the line pressure for this group of wells was dropped from 100 psia to 45 psia over a period of about 5 years. A group of wells in the upper right quadrant have had their tracks turned on to show how they reacted to the drop in line pressure. All of these wells responded very well to the compressor expansion.
On the right hand side of the plot is a base map showing the location of the wells which have been highlighted. Note that Well 243, which was analyzed with a numerical simulator, may be seen on both plots for reference.

Almost all the wells with strong response to the drop in line pressure are located in the same area. This is the northern end of the lateral and these wells are farthest from the compressor.

As a result of the simulation study of Well 243, we know that significant reserves still remain in this northern area. We also know that 11 other wells are behaving similarly. Using the potential of 400 MMCF additional recovery per well for 12 wells, the potential of recovering another 4.8 BCF of gas exists. Further studies are now justified and potential action could include:

- Drilling infill wells
- Fracing selected wells
- Adding more compression
- Expanding the main lateral to this area

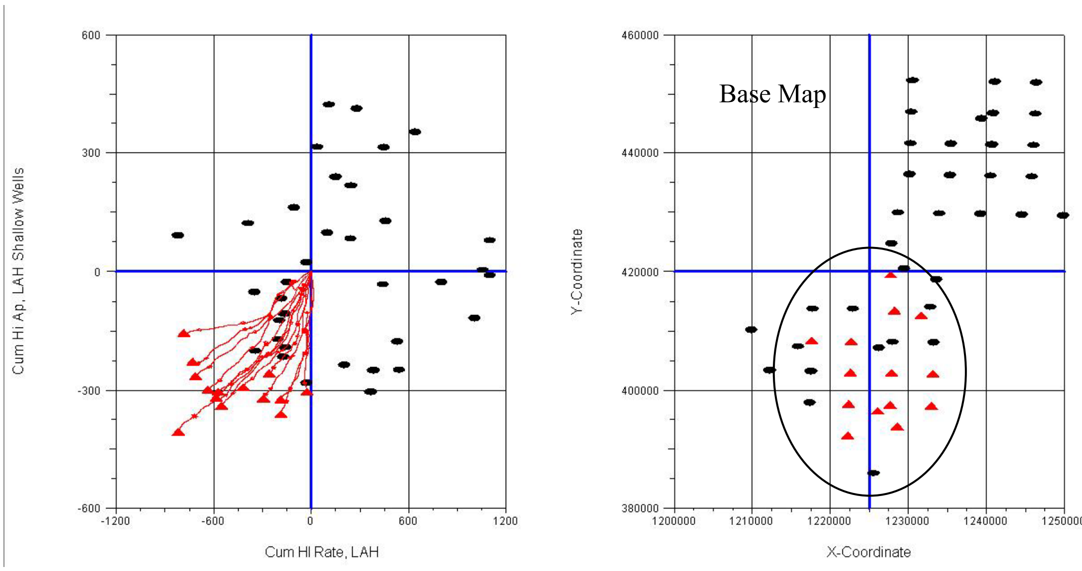


Figure 12
Case 2

Figure No. 12 is a the same plot as Figure No. 11. In this case wells in the lower left quadrant have been highlighted and their tracks turned on. These wells are responding very poorly to the compressor expansion. Note that all these wells are grouped at the southern end of the lateral, and are closest to the compressor. This part of the field may be depleted, or there may be lower quality reservoir rock. A simulation analysis of at least one well in this group needs to be made to determine the nature of the problem. If the area is not depleted, then significant potential may exist to increase production through well stimulation work or optimization of the local gas gathering system.