

**MOVING DOMAIN ANALYSIS TO IDENTIFY INFILL WELL POTENTIAL
QUEENSTON FORMATION
CAYUGA COUNTY, NEW YORK
Final Report**

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Abstract

Project objectives included identifying available infill candidates on Meridian's acreage, their geographic location, and their estimated reserves. In addition, each well's recovery potential was weighed against a five-year cumulative hurdle volume necessary for economic viability. A secondary objective was to identify the best stimulation treatment (i.e. single-stage versus multi-stage) for future wells by evaluating methods used in the past. The methodology used is characterized into three areas:

- Moving Domain™
- Reservoir analysis with PROMAT™, and
- Quantifying infill reserves and spotting infill wells.

The approach used Moving Domain Analysis (MDA) to blend PROMAT-derived original gas-in-place estimates with drainage area calculations. MDA is a mosaic of localized performance studies that blends analogy, statistics, and conventional engineering to identify infill locations. During this process, three types of information are utilized: (1) magnitude of production performance, (2) geographic location of that performance, and (3) the date when this performance was observed. A basic principal is that infill expectation is based on previous performance around the infill location in both time and geographic position, while considering the amount of undrained acreage available.

Based on the results of this study, the following conclusions are provided:

1. The best historic areas in Meridian's acreage were identified and in addition, numerous step-out areas that have exhibited substandard performance were recognized.
2. The Moving Domain analysis identified areas that should not be drilled due to a statistically poor chance of economic success.
3. Single-stage stimulation treatments out performed multi-stage treatments.
4. Additional infill wells can be drilled at gas prices approaching \$3.00/Mscf or greater.

For each of the ± 200 wells, a bounded study was performed to quantify the infill-candidate potential. Each study evaluated the production potential of a small area (i.e., the smaller of 2,000 acres or the 15 nearest wells). Recoveries were calculated by multiplying the amount of undrained acreage available by estimates of local productivity per acre. The expected performance of an infill candidate was also weighed by the performance of the newest wells surrounding it.

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Summary

Schlumberger Holditch – Reservoir Technologies Consulting Services (H-RT) has conducted a study of production infill potential of the Queenston Formation in Cayuga County, New York. This study was performed for Meridian Exploration (Meridian) as part of a New York State Energy Research Development Authority (NYSERDA) project under Contract No. 4481-ERTER-ER-97.

The study area includes over 200 wells operated by Meridian. Twenty-nine candidate infill wells located in the north-central portion of the acreage were identified in the original study. For this analysis, it was estimated that each infill well would recover approximately 200 MMscf over 20 years providing a combined recovery of five Bscf from the 29 wells. This represents an 18% recovery increase above Meridian's projected Proved Developed Producing (PDP) reserves.

Of the 29 candidate wells, Meridian has drilled five infills to verify initial productivity and obtain additional reservoir data. These wells showed evidence of depletion resulting in an average expected EUR of 89 MMscf/well. Previous drainage-area estimates were too small based upon a low initial water saturation assumption that resulted in greater than anticipated depletion.

The primary objective of this study was to evaluate infill potential of the Queenston Formation in Cayuga County, New York. This objective included quantifying the number of infill drillsites, their geographic location, and respective reserves. An additional objective was to analyze production results from single-stage versus multi-stage stimulation methods. This study showed that single-stage completions outperformed multi-stage treatments, after taking into consideration differing geographic regions and well vintage.

Meridian and the state of New York provided all data used in this study, including monthly well production, X/Y location coordinates, and API number. Geologic information such as net pay thickness, porosity, etc. was provided by Meridian's project geologist. Meridian also made available initial shut-in surface pressures for the majority of the wells, flowing pressure data, and completion/stimulation histories.

The methodology used is characterized into three areas:

- Moving Domain™
- Reservoir analysis with PROMAT™, and
- Quantifying infill reserves and spotting infill wells.

Moving Domain Analysis (MDA) is a mosaic of localized studies and blends geology, analogy, statistics, and conventional petroleum engineering to discern infill locations based upon local performance and

drainage patterns. The procedure focuses on three types of information: (1) magnitude of production performance, (2) X/Y location of that performance, and (3) date when the performance was observed. A basic principal behind MDA is that infill expectations should be based upon pre-existing well performance regarding both length of production and proximity, while considering the amount of undrained acreage available.

For each of the ± 200 wells, a bounded study was performed to quantify the infill-candidate potential. Each study evaluated the production potential of a small area (i.e., the smaller of 2,000 acres or the 15 nearest wells). Recoveries were calculated by multiplying the amount of undrained acreage available by estimates of local productivity per acre. The expected performance of an infill candidate was weighed by the performance of the newest wells surrounding it. An infill well was positioned geographically so that its anticipated drainage area would not overlap those of existing wells or previously spotted infill candidates.

Two critical assumptions used during the pre-infill drilling MDA including an estimated water saturation value and cylindrical drainage-area geometry. Since log analysis was unable to provide reliable estimates of water saturation due to mineralogical influence upon the resistivity values, a water saturation of 30% was assumed based upon prior experience with the Queenston in New York. Although the analyses were based upon a cylindrical drainage area assumption, the Queenston in reality is a layered reservoir consisting of different drainage radii for each layer. The log analysis of the five-infill wells drilled by Meridian in this study shows a higher-than-anticipated water saturation of 45% to 55%.

For the initial five infill wells, Meridian ran an advanced log suite, and measured the reservoir pressure. Along with post-fracture production data analysis, this data helped us to refine porosity and water saturation values and reserve estimates for the remaining infill locations.

Based on the infill well results, it is recommended to continue drilling new infill wells when gas prices reach, or exceed \$3.00/Mscf. Short-term production data (3 to 6 months), flowing pressure information, and reservoir pressures should be collected from new infills for use in optimally determining the next set of wells. It is also critical to install casing plunger lifts, or similar fluid-removal system, in these wells to unload produced salt water.

1 INTRODUCTION

The West Auburn Gas Field is located in the Finger Lakes region of central New York between Cayuga and Owasco Lakes and is shown by **Figure 1.1**.

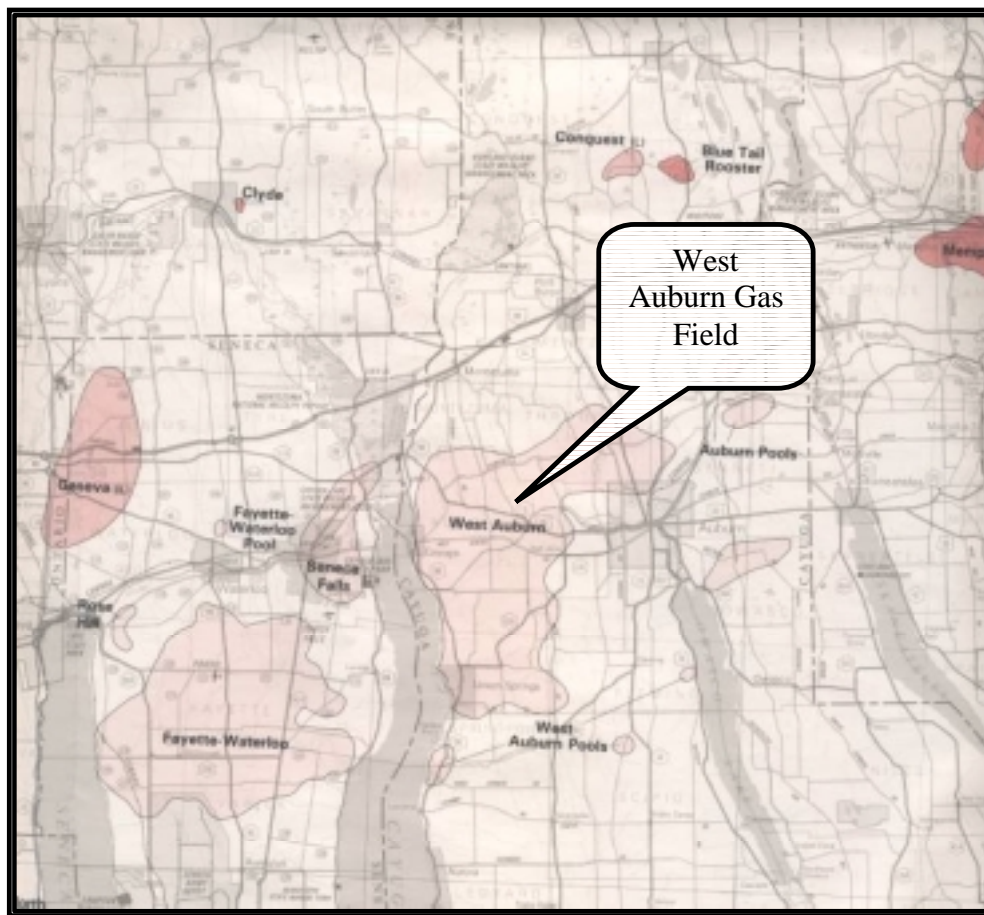


Figure 1.1 - Location map of West Auburn gas field, Cayuga County, NY.

The Upper Ordovician Queenston Formation is the major natural gas producing reservoir within this field and is typically encountered at depths of 2,000 to 2,500 ft. Although Meridian has drilled and completed over 200 Queenston Formation producers since the 1960's, most have been drilled in the mid- to late-1980's. There are also several hundred offset wells to the Meridian acreage operated by Miller Brewing Co., which were not evaluated.

The Queenston consists of multiple sand and shale sequences (see **Figure 1.2**) and Meridian typically completes all gas-bearing formations using foam fracture treatments.

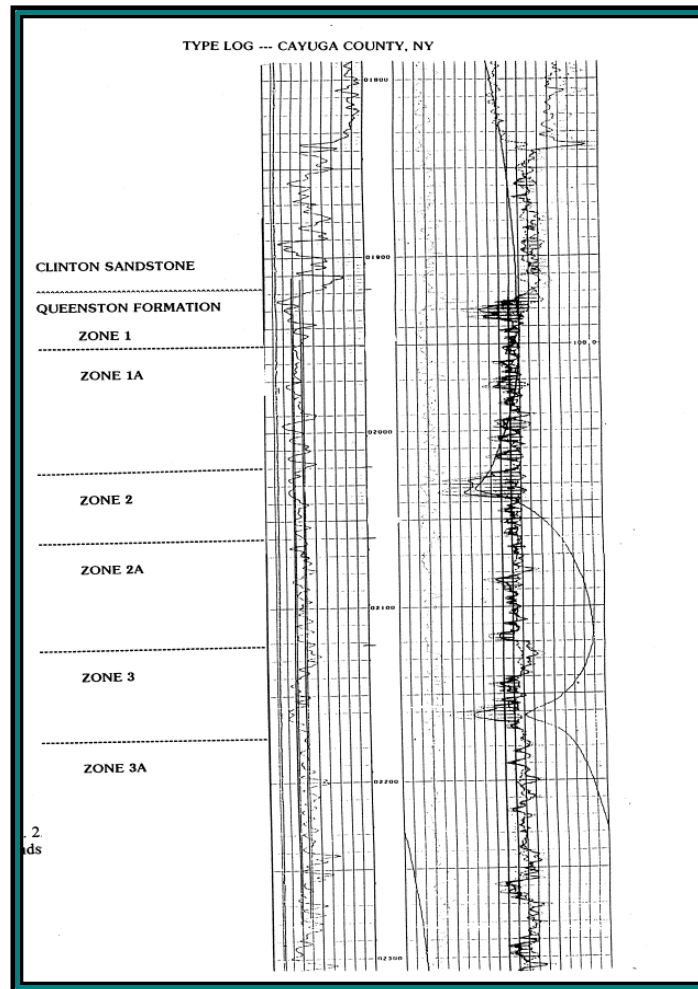


Figure 1.2 – Type log of Queenston formation.

Note that this figure shows the following geophysical logs: Gamma ray, compensated density, density porosity, neutron, temperature, and caliper.

The gas-bearing Queenston is approximately 350 ft thick and frequently consists of six sandstone units. Most wells were stimulated primarily with single-stage, nitrogen-foam treatments carrying 90,000 lbs of proppant, however some wells were stimulated with multiple treatments in the late 1980's, but the total proppant amount remained at 90,000 lbs. A stimulation comparison that will be discussed in Section 5.7 was also performed.

Approximately 13 Bscf have been produced to date and PDP reserves are estimated at 15 Bscf by Meridian as of 1998. The average estimated ultimate recovery (EUR) per well is approximately 110 MMscf, however these values range from 10 MMscf to one Bscf in the study area. It is likely that natural fractures enhance production in certain portions of the reservoir. Wells have been drilled on 30 to 160 acre spacing, however the average spacing is approximately 50 acres. A Moving Domain Analysis (MDA) was performed to investigate drilling infill wells in Meridian's property.

2 CONCLUSIONS

Based on the results of this study, the following conclusions are provided:

1. The best historic areas in Meridian's acreage were identified. These areas are located in the north-central and southeastern portion of the property.
2. Numerous step-out areas that have not been highly productive were identified
3. Infill areas that should not be drilled due to a statistically poor chance of economic success were identified
4. In the original study, 29 infill locations, based on economic criteria provided by Meridian, were distinguished
5. An average EUR of 200 MMscf/well for the infills was originally estimated
6. Total infill reserves were estimated as high as 5 Bscf, which would have been an 18% increase above the PDP reserves
7. Meridian drilled five infill wells that encountered some depletion. Original reservoir pressure was 550 to 650 psi and the infill wells encountered a reservoir pressure of 375 psi. The 20-year average well EUR is 89 MMscf, which is substantially less than predicted.
8. The primary reason the initial forecasts were too high can be attributed to an assumed water saturation of 30%. Actual water saturation values are actually higher (45% to 55%), thus, the drainage areas are larger.
9. Additional infill wells can be drilled at gas prices approaching \$3.00/Mscf or higher
10. Single-stage stimulation treatments out performed multi-stage treatments.

3 RECOMMENDATIONS

Based on the results of our study, the following recommendations are shown below:

1. Infill wells should be located within the north-central portion of the field.
2. Data should be collected if future infill wells are drilled to verify the current reservoir pressure, the in-situ water saturations, the impact of layering, and any depletion effects.
3. A future study should investigate why the single-stage treatments out performed the multi-stage treatments.

4 GEOLOGY AND LOG ANALYSIS

This section describes the geology of Cayuga County and the results of initial geophysical log analyses that were performed by the project geologist.

4.1 STRUCTURAL SETTING

Cayuga County is situated up dip on the northern flank of the Appalachian Basin. Regional bedding strikes eastward and dips homoclinally to the south at 40 to 50 ft per mile. Extensive regional fracture and fault systems are not present. Local bedding strikes northwestward and localized natural fractures frequently occur in the Queenston.

Although seismic data was not available, areal magnetic and regional maps indicate the presence of basement structures and reactivated faults. The basement-related faults almost certainly have influenced production through numerous micro-fractures that enhance reservoir permeability. Another probable source of fracturing is isostatic rebound (i.e. vertical crustal readjustment) resulting from mass unloading and weight removal of post-Devonian age sediments subsequent to the retreat of Pleistocene-age glaciers.

4.2 DEPOSITIONAL HISTORY AND DISTRIBUTION

Upper Ordovician clastics entered the Appalachian Basin from erosion of sedimentary rocks located in an eastern highland provenance during the medial pulse of the Taconic Orogeny. The Queenston is the uppermost preserved section of these Ordovician sediments and is composed of multiple, stacked, fluvial sandstones, siltstones, and shales. These sands and shales were obtained by recycling previously lithified sedimentary sequences of the eastern highlands through a network of rivers that flowed over a low-gradient coastal plane system located close to sea level. These eastward-lying materials were eroded and transported westward into the basin.

The producing zones are channel lag deposits and vary from braided-fluvial to tidal-inlet sandstones. The gentle slope of the ancient plain and shallow, near-shore marine region made it possible for sea level changes to have a significant impact on reservoir distribution. These eustatic fluctuations cycled between periods of erosion and stages of deposition, with attrition occurring during times of low sea level and channel fill deposition during phases of higher sea level. This succession of erosion and subsequent deposition created the stacked channel deposits found in the Queenston Formation.

Disconformably overlying the Queenston Formation is the Lower Silurian Medina group. Although the Queenston is approximately 800 ft thick below this unconformity, only the upper 300 ft contain zones with sufficient porosity to be reservoir rocks in the West Auburn Field. Common pay zones are usually found in similar stratigraphic units from well to well, however individual sands are often discontinuous, and result in well-to-well facies changes. Reservoir quality within these stratigraphic units is variable, and changes in porosity and permeability are often present between wells.

4.3 GEOPHYSICAL LOG ANALYSIS

Geophysical logs were analyzed by Dan Billman, the geologic project consultant, for an initial group of 21 wells to assist with H-RT's production data analysis. Porosity, net feet of pay, and water saturation values were estimated. The porosity and gas saturation values were determined using a Density-Resistivity method that is documented in Schlumberger's "Log Interpretation Principles and Applications," regarding air-filled holes, and the equations used are shown in Appendix A. After this procedure, a shaly formation evaluation utilizing a dual-water model was then applied to the total porosity and water saturation values to calculate effective porosity and effective water saturation. A five percent effective porosity cutoff was utilized for this log analysis.

X-ray diffraction (XRD) analysis of a core taken from Meridian's Ralph Webster Unit No. 1 Well in the 1980's showed 65-80% quartz, 0.5-2% feldspar, 2-5% dolomite, 10-15% illite, 2-10% chlorite, 0.5-2% sodium chloride, and 0.5-5% hematite. The substantial clay volumes, and presence of salt and hematite, make it difficult to determine water saturation from log analysis. Hematite is present as sand-grain coatings and as fringes on the clay particles, and was formed during the oxidation of iron-bearing grains. Iron bearing minerals such as hematite, have a considerable effect on geophysical log response and particularly on the resistivity log. Since they are often conductive, they tend to lower the resistivity log response used to calculate formation water saturation. These low resistivity values prevent an accurate determination of water saturation using conventional logs. Therefore, since calculated water saturation values were believed to be erroneously high (55 to 65%), a value of 30% was assumed based upon the team's Appalachian experience.

During the log analysis process, signs of obvious fracturing (wash-out zones) were not observed in the 21 well logs. However, numerous zones did show signs of gas entry into the wellbore by a cooling "gas kick" on the temperature log potentially indicating naturally fractured intervals. There were only three natural wells identified in this study (i.e., wells that encountered a significant gas show while drilling). The remaining wells had to be hydraulically fractured to produce economic gas rates.

Table 4.1 lists the 21 wells and shows net pay thickness and porosity estimates. Overall, average net pay and mean porosity values are 146 ft and 8.5% respectively. Net pay thickness was estimated for remaining wells by considering the average of its offsets.

Table 4.1
Log Analysis Results

Permit Number	Well Number	Net Pay Thickness (Ft)	Average Porosity (Fraction)
20452	522	193	0.091
20455	613	179	0.073
20464	520	129	0.085
20466	684	142	0.083
20499	347	144	0.084
20503	708	135	0.084
20509	803	147	0.084
20511	805	158	0.090
20522	817	204	0.079
20515	809	132	0.086
20555	944	151	0.085
20556	950	160	0.087
19647	430	127	0.088
20612	1034	138	0.079
20614	1039	112	0.084
20615	1033	113	0.083
20626	1058	145	0.079
20634	1035	182	0.066
20649	1080	159	0.083
20672	1102	141	0.095
20675	1100	133	0.082

Figure 4.1 is a color-filled map of net pay showing that the thickest intervals are in the western and southwestern sections of the study area. The average net pay thickness ranges from 140 to 170 ft.

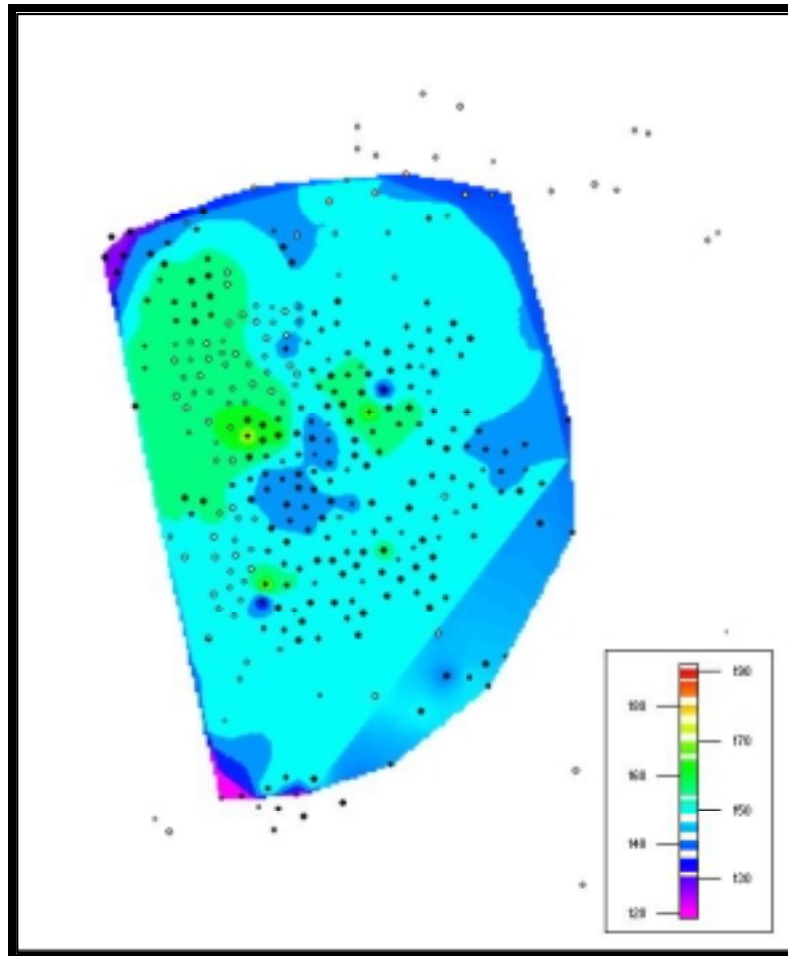


Figure 4.1 - Colorfill map of net pay thickness.

5 DISCUSSION OF RESULTS

5.1 MOVING DOMAIN ANALYSIS

In this section, the results of the MDA process used to calculate infill potential of the West Auburn Field are discussed. Project objectives included determining the number of infill wells available, the geographic location, and their estimated reserves. In addition, each well's recovery potential was weighed against a five-year cumulative hurdle volume necessary for economic viability. A secondary objective was to identify the best stimulation treatment (i.e. single-state versus multi-stage) for future wells by evaluating methods used in the past.

5.2 DATABASE CONSTRUCTION

All the data used in this study was supplied by Meridian or was obtained from New York State public records. Primary data consisted of individual-well monthly production, X/Y location coordinates, and API number. Meridian also provided perforation intervals, stimulation statistics, flowing pressure information, fluid levels, and initial surface shut-in pressures taken after well completion. The database contained production volumes for approximately 214 wells.

Cumulative production for the entire study area is almost 13 Bscf of gas with 15 Bscf of PDP remaining reserves as of 1998 (provided by Meridian). Net pay thickness and porosity was estimated by the Meridian project geologist for 21 wells, and these results were extrapolated to the remaining wells in the West Auburn Field. Although the Meridian wells are offset by Miller Brewing Company wells, no production data was available for these wells and thus they were not included in the evaluation.

All the data received was incorporated into various Microsoft ACCESS™ databases and EXCEL™ spreadsheets designed to facilitate the analyses.

5.3 ANALYSIS METHODOLOGY

The methodology employed in this study is characterized into three areas:

- Moving Domain™,
- Reservoir analysis utilizing PROMAT™, and
- Quantifying infill reserves and spotting infill wells.

The foremost analysis approach used Moving Domain to blend PROMAT-derived original gas-in-place estimates, with drainage area calculations. MDA is a mosaic of localized performance studies that blends analogy, statistics, and conventional engineering to identify infill locations. Three types of information are utilized: (1) magnitude of production performance, (2) geographic location of that performance, and (3) the

date when this performance was observed. A basic principal is that infill expectation is based on previous performance around the infill location in both time and geographic position, while considering the amount of undrained acreage available.

MDA expertise makes use of production indicators to measure well quality, estimate long-term recovery, and estimate gas volumes that may be in communication with other wellbores. A production indicator is a means to estimate long-term production from short-term data. Since at least five years of production history was available for each well, a five-year cumulative gas volume was used for a main production indicator. In many cases, a “Best-Year” can be used as a production indicator. This is the summation of the highest 12 consecutive months of production divided by 12 (Mscf/month). However, the five-year cumulative volume is a better short-term indicator of long-term performance (20 year EUR) due to its longer time span.

A localized study for each of the 214 existing wells was performed to identify infill candidates and their respective production potential. Each study evaluated the potential of a small area (i.e. the lesser of 2,000 acres or the 15 closest wells). Expected recoveries were derived by multiplying the amount of undrained acreage by the expected local productivity per acre. An infill well’s anticipated performance was weighted toward the performance of newer surrounding wells relative to older wells. In addition, an infill location was spotted so that its drainage area would not overlap those of existing wells or other infill drillsites.

For the study, it was assumed that drainage areas are cylindrical; however, in reality the Queenston is a layered reservoir with different drainage radii for each layer. The actual infill wells will enable gauging the impact of this layered description and the results can be incorporated into estimating the potential of future infills. If actual depletion is higher or lower than predicted, forecasts for subsequent drillsites can be adjusted.

5.4 PRODUCTION INDICATORS

This section discusses several correlations that were used to reach project-wide conclusions. The objective of these correlations and production indicators are several fold:

- 1) Predict long-term performance from short-term data.
- 2) Provide qualitative and quantitative comparisons.
- 3) Look for regional trends.
- 4) Identify high and low-quality areas, evaluate depletion effects, and determine optimal stimulation methods (single or multi-stage).

Figure 5.1 is a map showing each well's location and its date of first production phase. Note that 15 wells were drilled between 1960 and 1969, five from 1980 through 1985, and most (171 wells) between 1986 through 1991.

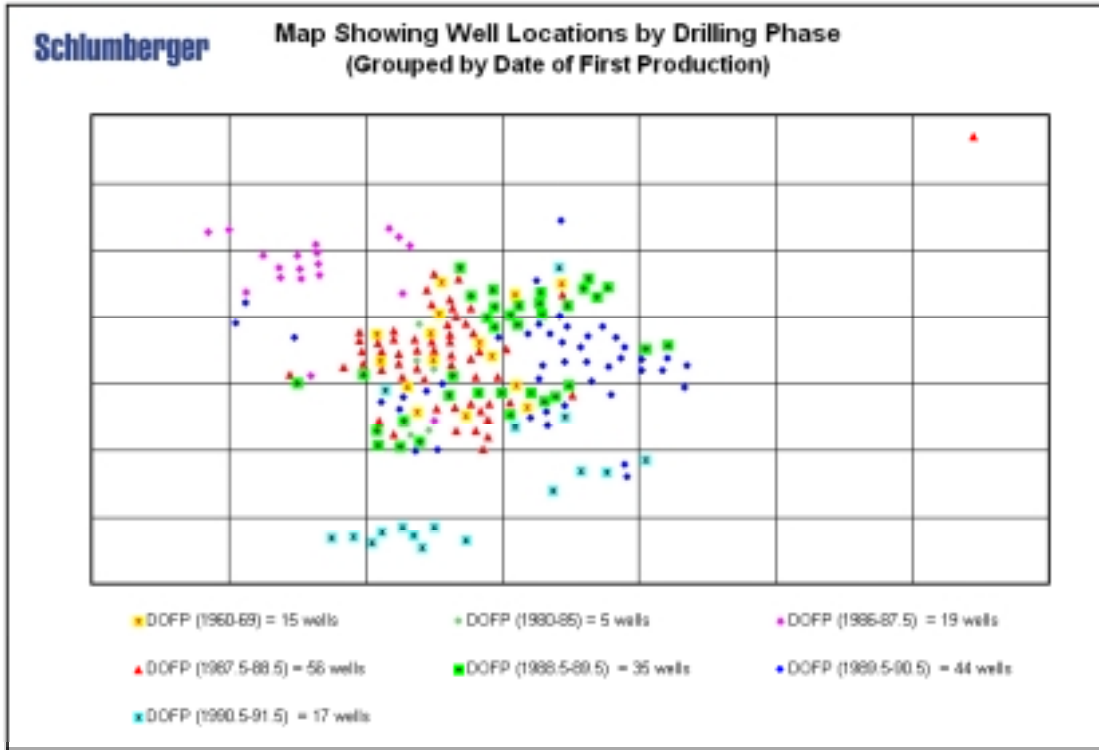


Figure 5.1 - Map of well locations showing drilling phase.

Figure 5.2 is a graph of five-year cumulative gas production on the y-axis versus date of first production on the x-axis. Each diamond represents one well. Notice that it shows drilling activity between 1960 through 1968, a few wells drilled around 1980, and the majority of the drilling from 1986 through 1991. A visual interpretation of this graph suggests that in general there have been good and bad wells drilled throughout time, and that substantial field-wide depletion effects are not evident. The best wells were drilled during the 1960's, 1980, and in 1987-1989 in the central portion of the field. The poor wells were drilled in 1990-1991. As will be discussed later, most of the poor wells resulted from their step-out status and not because of wide-ranging field depletion.

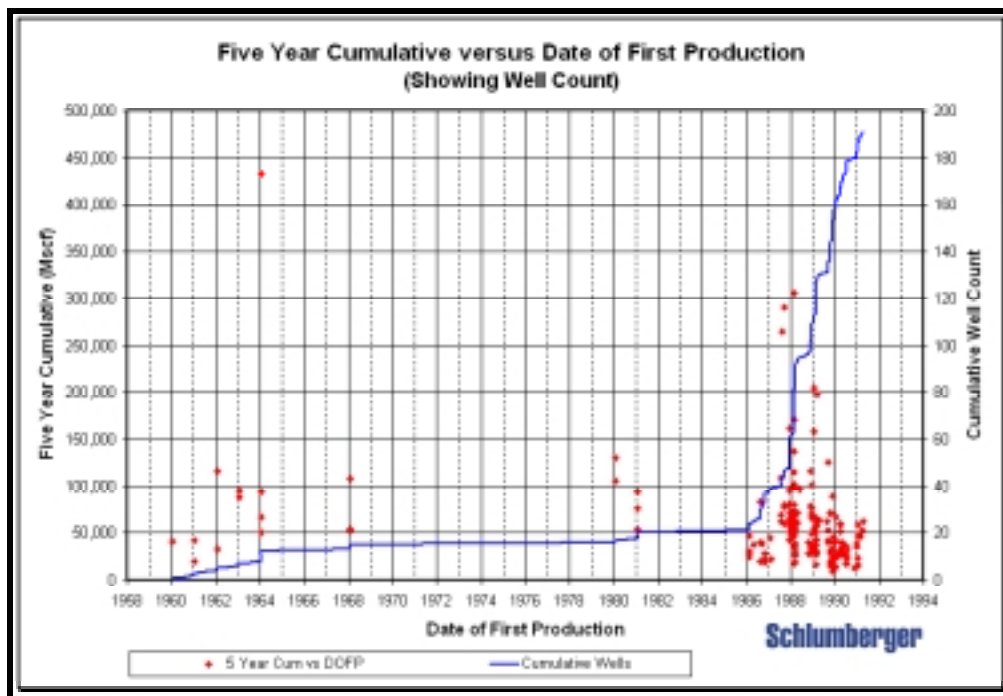


Figure 5.2 - Five-year cumulative production versus DOFP (showing well count).

As previously mentioned, the five-year cumulative production was used as a short-term indicator of long-term production (20-year EUR) since at least five years of production history was available for each well. Although other production indicators (Best Month and Best Year) were evaluated, it was determined that a five-year cumulative production is the most reliable statistical predictor of long-term performance. **Figures 5.3, 5.4, and 5.5** show that five-year cumulative values are the best statistical predictor of ultimate recovery, versus best month and best year, based upon a best-fit linear regression trend line. It has the highest R^2 (0.9368), versus 0.6360 for the best month, and 0.8499 for the best year.

In most field-wide studies, there is a strong statistical correlation between short-term and long-term performance, which signifies that a well's lifetime performance can be predicted from a limited amount of initial production data.

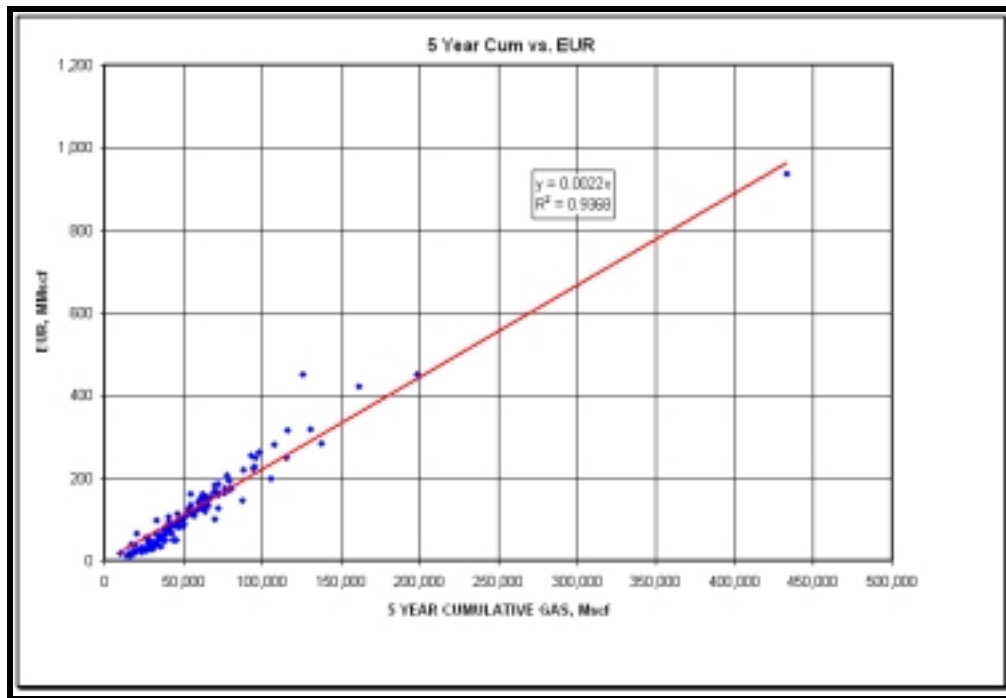


Figure 5.3 – Five-year cumulative production versus estimated ultimate recovery.

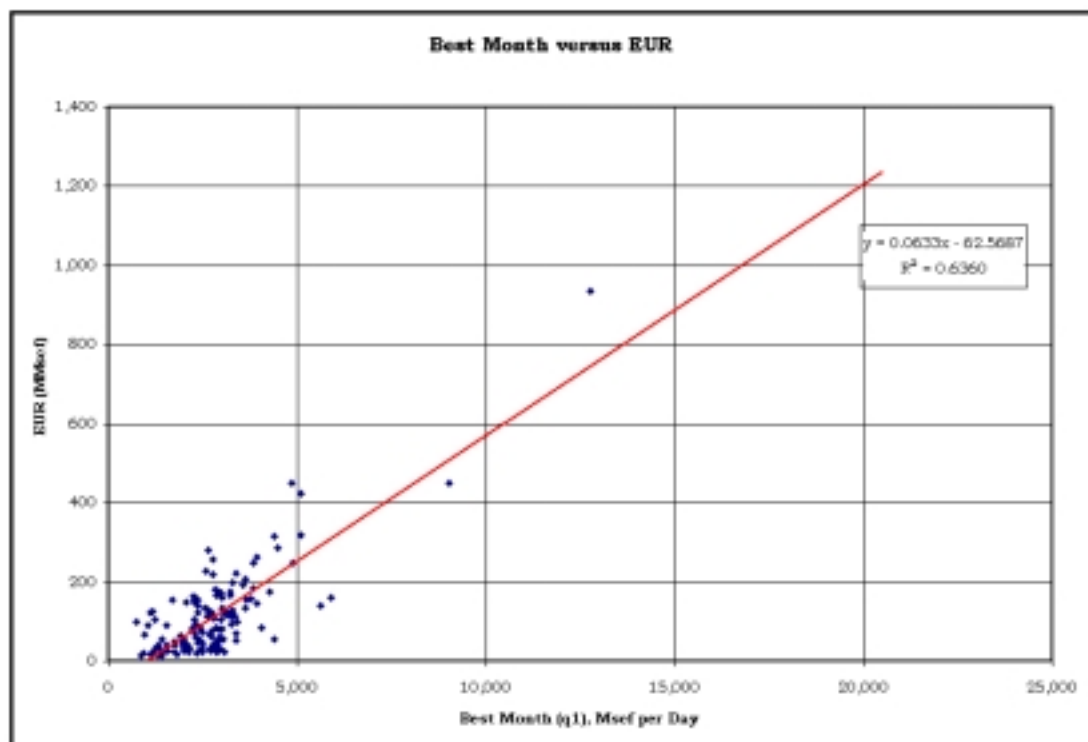


Figure 5.4 – Best month versus estimated ultimate recovery.

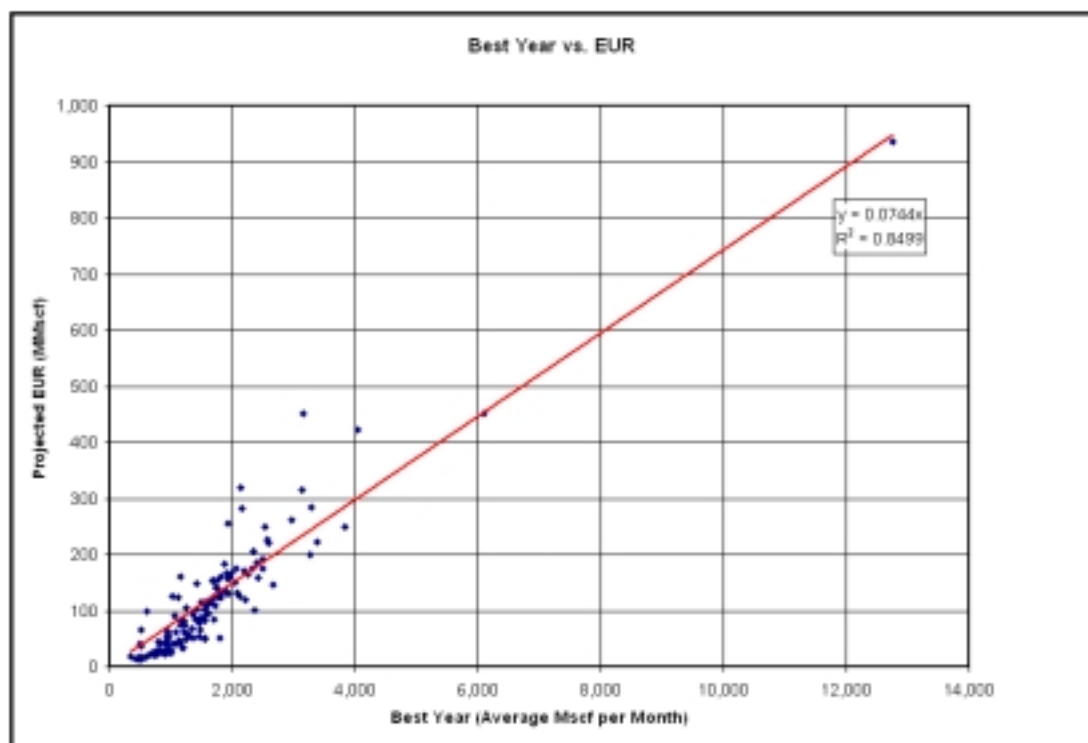


Figure 5.5 – Best year versus estimated ultimate recovery.

Figure 5.6 shows a graph of the Best Month versus the Best Year. The Best Month is the highest production month that occurred within the Best Year of production. As stated earlier, the Best Year indicator is the highest continuous 12-month production period divided by twelve and yields the units Mscf/month. The data in **Figure 5.6** provides an excellent correlation coefficient of 0.8187 to validate the use of the Best Month with Best Year. This provides a quick method to forecast long-term performance after obtaining only one month of data.

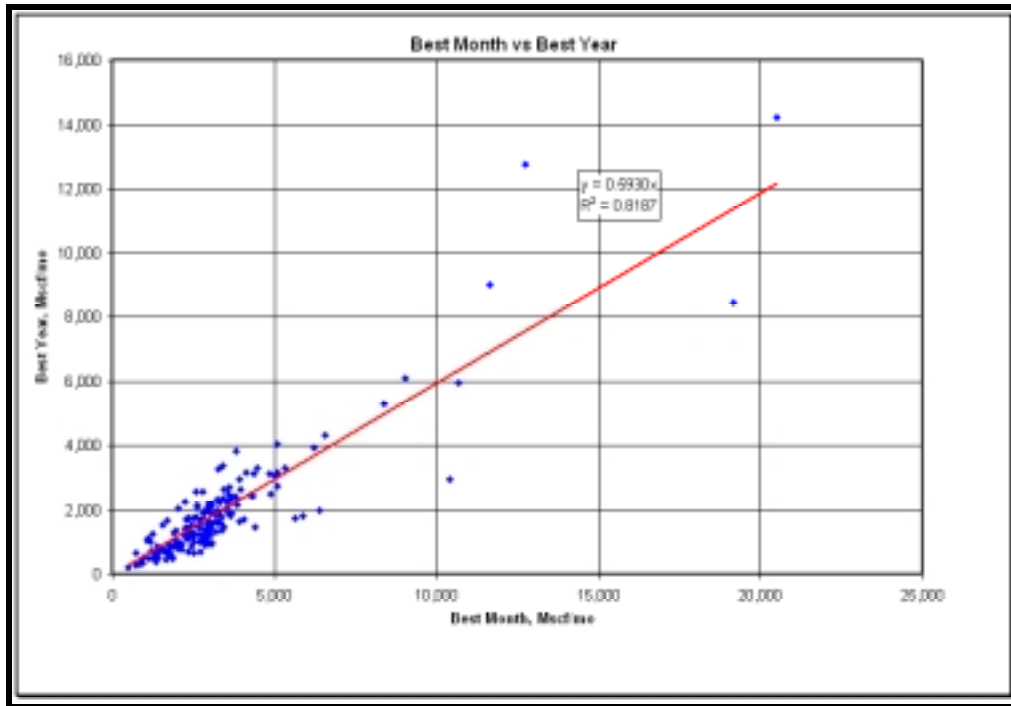


Figure 5.6 – Best month versus best year.

Figure 5.7 correlates the Best Year indicator with the five-year cumulative production indicator. This correlation yields an R^2 of 0.9174 and verifies that the Best Year and Best Month can be correlated to the five-year indicator.

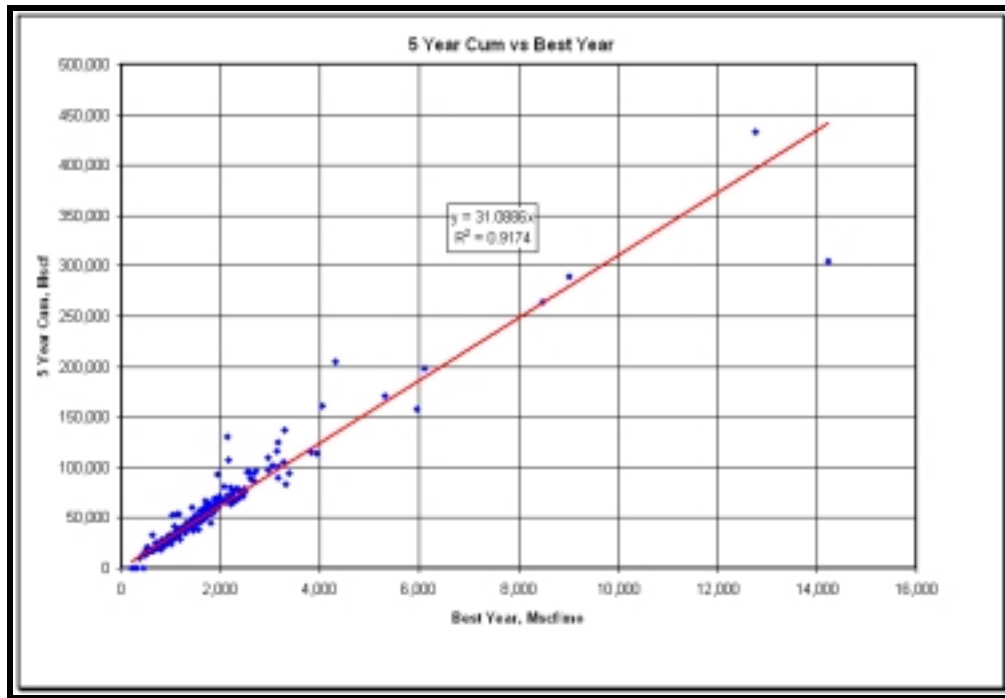


Figure 5.7 – Best year versus five-year cumulative production.

Figure 5.3 (presented earlier) shows the correlation between the five-year cumulative indicator and 20 year EUR provided by Meridian. Note the excellent correlation coefficient of 0.90 for this dataset. **Figures 5.3, 5.4, 5.5, 5.6, and 5.7** (also shown earlier) all illustrate how a short-term production volume can be correlated to long-term well performance. As new infill wells are drilled, these correlations can be used as a first-pass predictor of well productivity. When additional production data becomes available from the infill wells, adjustments may be needed in our predictions if depletion effects become evident from the first round of drilling.

Figure 5.8 is a probability plot of EUR showing a 50% likelihood of obtaining an estimated ultimate recovery of 84 MMscf. This is equal to a five-year cumulative recovery of 39 MMscf. Note the large range of EUR's in this field – from 12 MMscf to over 1 Bscf (not shown on graph).

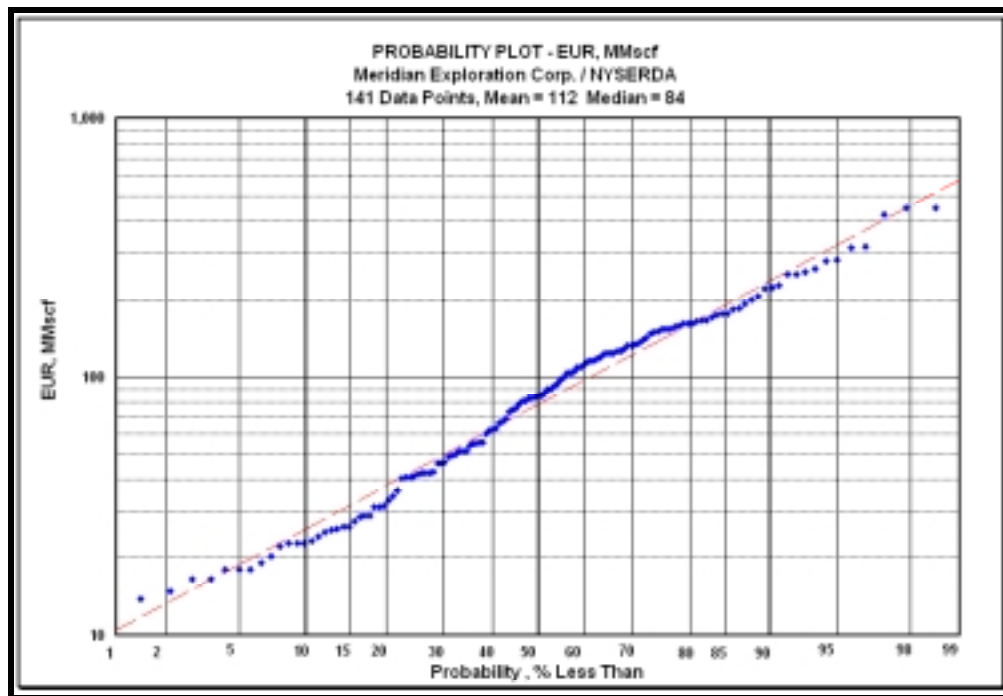


Figure 5.8 - Probability of occurrence versus EUR.

As previously mentioned, a primary objective of this NYSERDA infill study was to locate the best locations to drill economically viable infill wells. A five-year cumulative production economic hurdle volume of 75 MMscf economic was made available by Meridian, which correlates to a 20-year EUR of 165 MMscf shown previously on **Figure 5.3**. Thus, this study focused on the top 20% of the previously drilled wells.

A bubble map (**Figure 5.9**) and a color-filled map (**Figure 5.10**) of the five-year cumulative production indicator were also generated. Note that bubble sizes indicate a well's performance and not its drainage area. These maps are useful in quickly identifying areas of both high-quality and substandard performance.

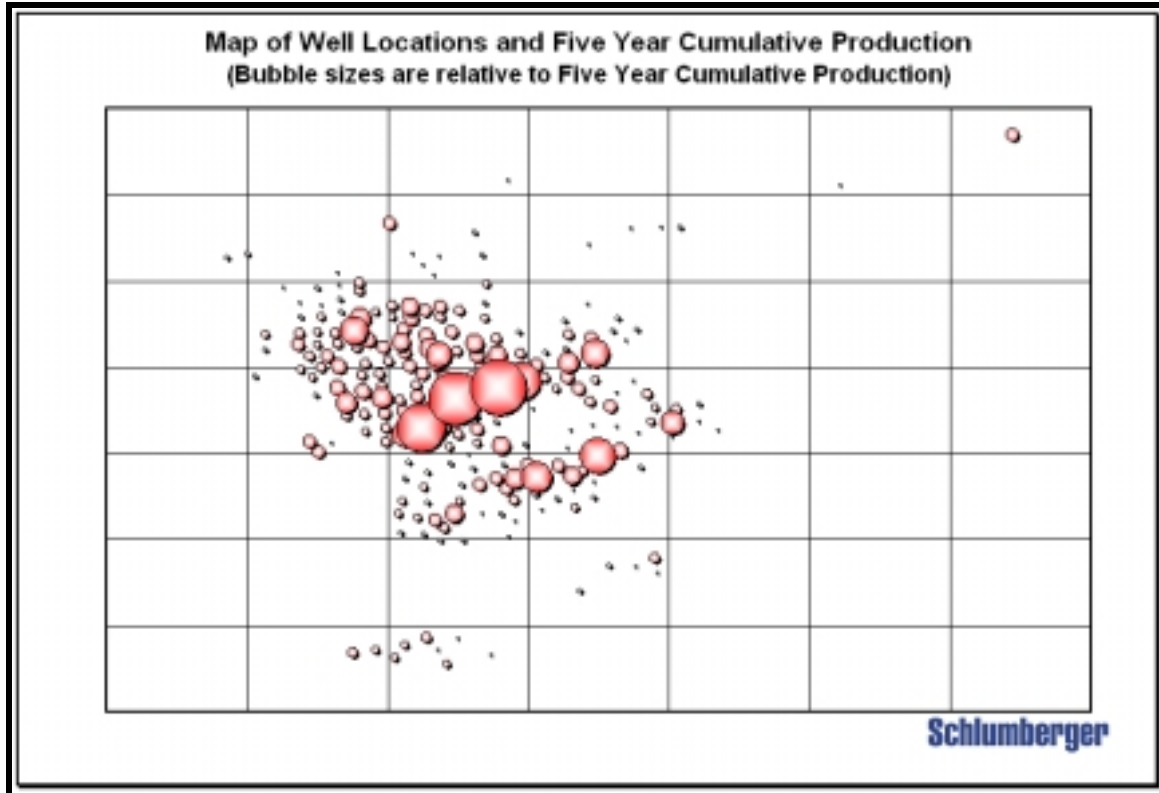


Figure 5.9 - Bubble map of five-year cumulative production.

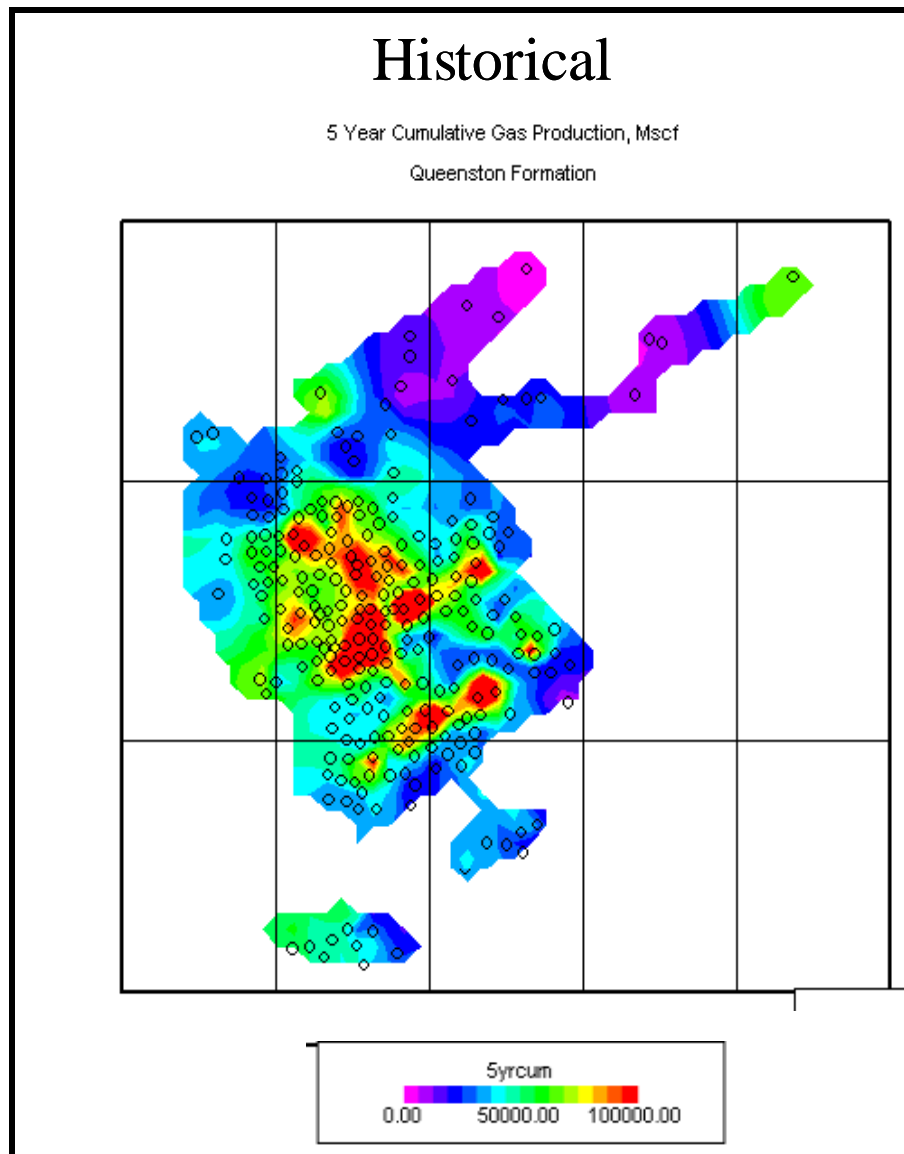


Figure 5.10– Color-filled map of five-year cumulative production (Mscf).

It is apparent that two areas trending NE/SW reveal better-than-average performance. In all likelihood, these indicate natural fracture patterns since log analysis reveals that these are not high permeability/porosity channel sands. In addition, it can be seen that the north-south channel in the central section is also an area with consistently good performance.

Various step-out wells that have had substandard performance are noticeable, which are most likely due to regions of lower reservoir quality.

5.5 ZERO-TIME PLOTS OF AVERAGE WELL GROUPS

This section discusses zero-time average production profiles used to compare well performance versus time. The shape and magnitude of profiles for wells grouped by date of first production were compared by first generating a composite, zero-time decline curve for each group. This is performed by taking all of the rate-time data for each individual well and normalizing this information to a “zero-time” basis. In other words, calendar time is converted to chronological time where the first month is Month 1, the second month is Month 2, the third month is Month 3, etc., regardless of the actual calendar production dates. Month 1 production for all wells within a group is summarized, and then divided by the number of wells for which Month 1 production data is available. At this point the average first month’s production for the group is calculated. This approach is continued for all months until the limit of the available data is reached. After this, the monthly volumes are summarized for each group and values for a cumulative production curve are calculated.

For this part of our discussion, refer back to **Figure 5.1** and notice each well’s DOFP group and location. All wells were placed into one of seven groups based upon their date of initial production.

After grouping the wells, zero-time production profiles of average monthly rates (Mscf/month) were created and are presented in **Figure 5.11**.

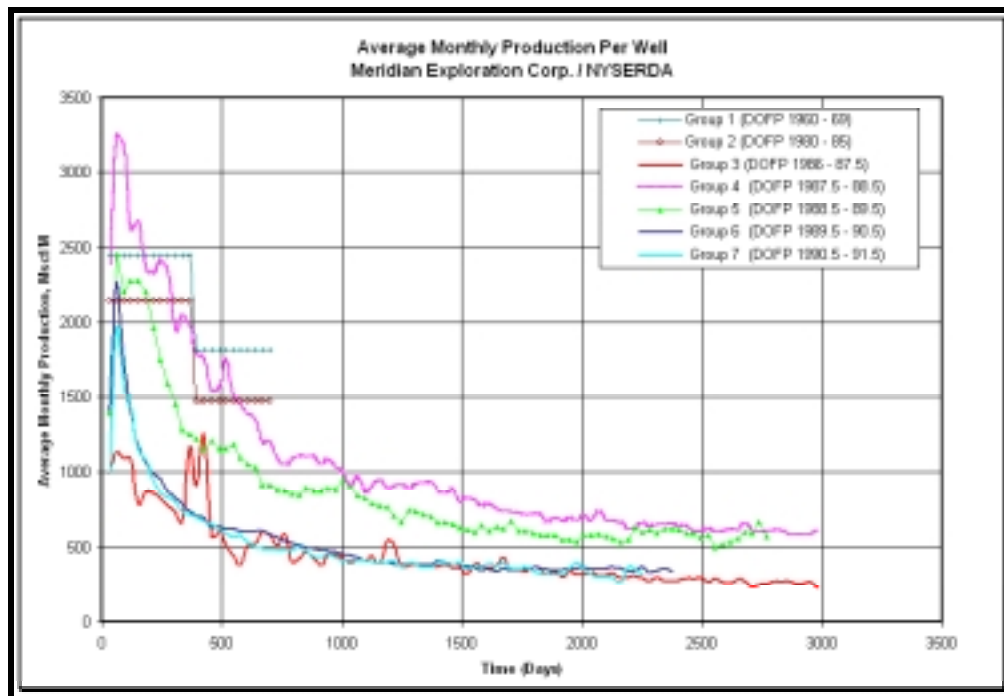


Figure 5.11 – Zero-time production plots of Groups 1-7.

It is evident that Groups 1, 2, and 4 (1960-69, 1980-85, 1987.5-88.5) all illustrate similar magnitudes and profiles. Notice that production history was only available as two years of annual data for the older Group 1 (1960-69) and Group 2 (1980-85) wells.

Group 5 (1988.5-89.5) shows a slightly lower production profile when compared to the previous three groups (Groups 1, 2, and 4), which may be indicative of some depletion effects. Wells in Groups 1, 2, 4, and 5 were all drilled in the central portion of the field.

Wells in Groups 3, 6, and 7 (1986-87.5, 1989.5-90.5, 1990.5-91.5) illustrate significantly lower production profiles. This is most likely due to the inferior reservoir quality present in step-out areas.

5.6 NEW-OLD WELL COMPARISONS

In addition to analyzing zero-time plots of well performance versus time, an evaluation of depletion affects and productivity trends was performed by studying production data and shut-in pressures. For this procedure, two colorfill maps were constructed based upon a Moving Domain Analysis of five-year cumulative production versus date of first production (DOFP).

Figure 5.12 shows the anticipated five-year cumulative production for the infill wells. This plot was generated with a Moving Domain Analysis that weighted the production performance of the newest wells within each domain, over the older wells. The yellow and orange colors draw attention to areas that meet the 75 MMscf five-year cumulative production economic hurdle. Drainage areas were not considered during this phase of the analysis, thus the results in **Figure 5.12** represent the maximum expectation. Drainage areas were integrated later into the analysis and are discussed in **Sections 5.7** and **5.8**.

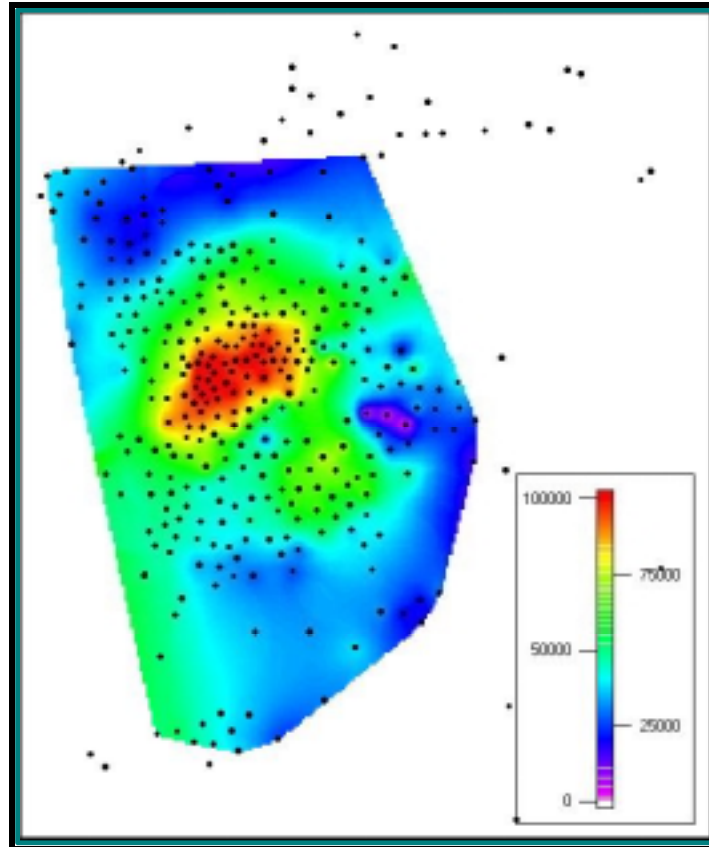


Fig. 5.12 - Anticipated five-year cumulative infill well production (Mscf).

The slope of a best-fit trend line of each domain's five-year cumulative versus DOFP was calculated, and is illustrated in **Figure 5.13**.

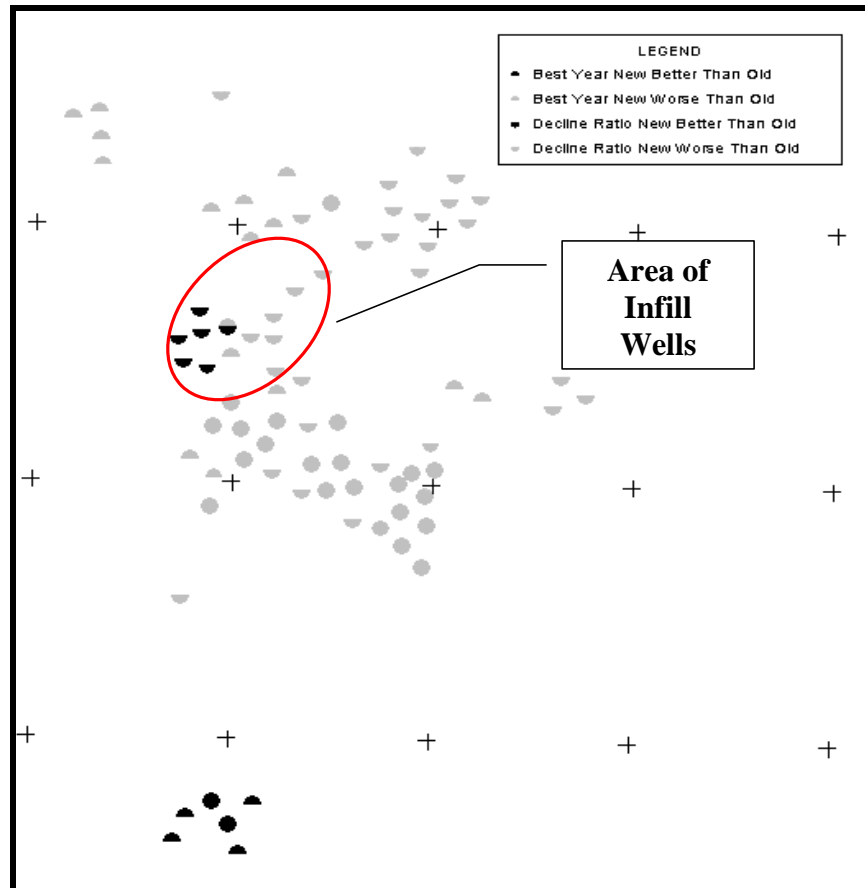


Figure 5.13 - Map showing slope of best-fit trend line of five-year cumulative production versus DOFP.

Figure 5.13 uses gray or black semicircles to emphasize slopes possessing a 90% or greater statistical confidence. Black designates new wells having better performance (i.e. 5-year cumulative production, and/or decline ratio) relative to old wells, and gray is used to exhibit new wells that have performed inferior to older wells.

The upper half-moon pertains to a wells five-year cumulative production, and the lower half-moon symbolizes its decline ratio. The decline ratio measures the initial decline in well performance. Depletion effects frequently illustrate a flatter (less steep) initial decline in new wells.

An example of a domain's statistical analysis is shown in **Figure 5.14**. A linear regression least-squares trend line for every well within each domain is plotted on an x-y scatter plot of DOFP versus five-year cumulative. The slope and statistical confidence of the trend line is calculated and used to aid our evaluation.

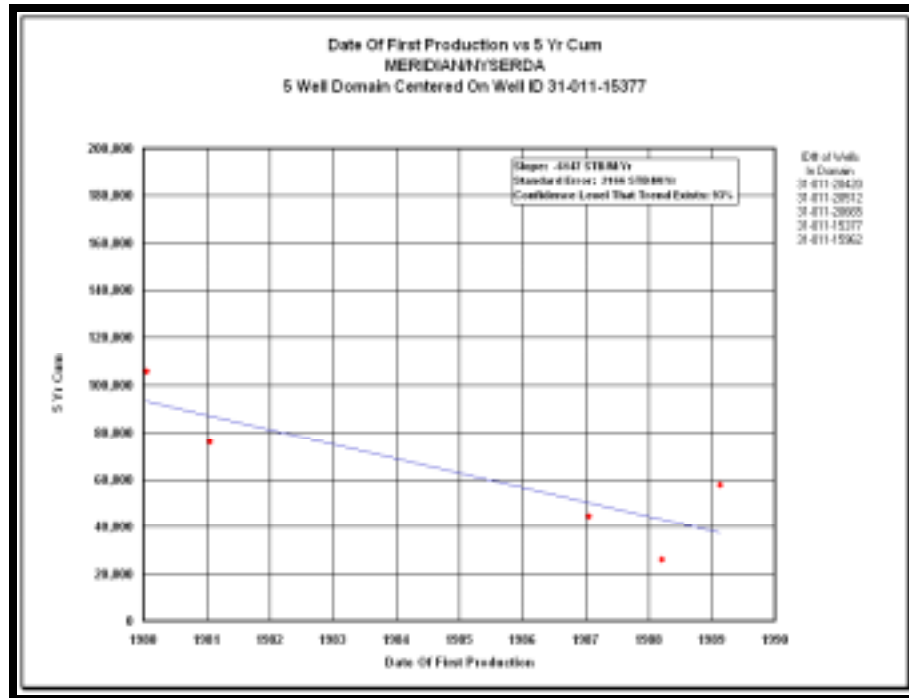


Figure 5.14 – Example of a best-fit trend line of a domain.

In this study, two areas have upper gray dots positioned in areas with blue colorfill and these areas probably show some depletion effects. The first area centers on a well drilled in the 1960's that is a prolific producer. The Moving Domain results suggest that this well is the cause of depletion in some of the offsets. The second area focuses around two wells in the east and may reflect some localized depletion around these wells.

To the southeast, there were also a significant number of gray dots. In this area, it is possible that the reservoir quality is changing quickly between wells (natural fractures) or that differing stimulation methods affected well performance. Though it is also possible that depletion effects are occurring, surface pressures are similar in these wells.

Also plotted are initial surface shut-in pressures for numerous wells on a colorfill map shown in **Figure 5.15**.

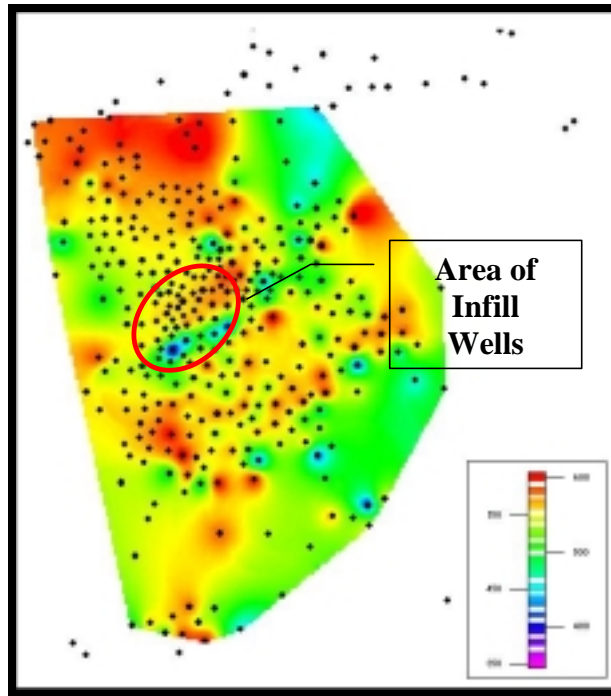


Figure 5.15 - Colorfill map of initial surface shut-in pressures.

The pressures were recorded after cleaning-up the stimulation fluids and shutting in for 24 to 72 hours.

Figure 5.15 supports the results discussed above pointing to depletion effects in the same areas shown in **Figure 5.13**. The green-blue colors in **Figure 5.15** show pressures between 400 to 500 psi, and the yellow-orange colors correspond to original reservoir pressures of 550 to 600 psi. It should be noted that some of the lower shut-in pressures may be a result of (1) poor cleanup, (2) fluid in the wellbore, or (3) insufficient shut-in time.

5.7 STIMULATION COMPARISONS

Meridian stimulated most wells with a single-stage, nitrogen-foam job and in the late 1980's experimented with multi-stage treatments. The well stimulation type is shown in **Figure 5.16** as different color dots for the single and multi-stage jobs. However, not enough information was available concerning stimulation methods for every well.

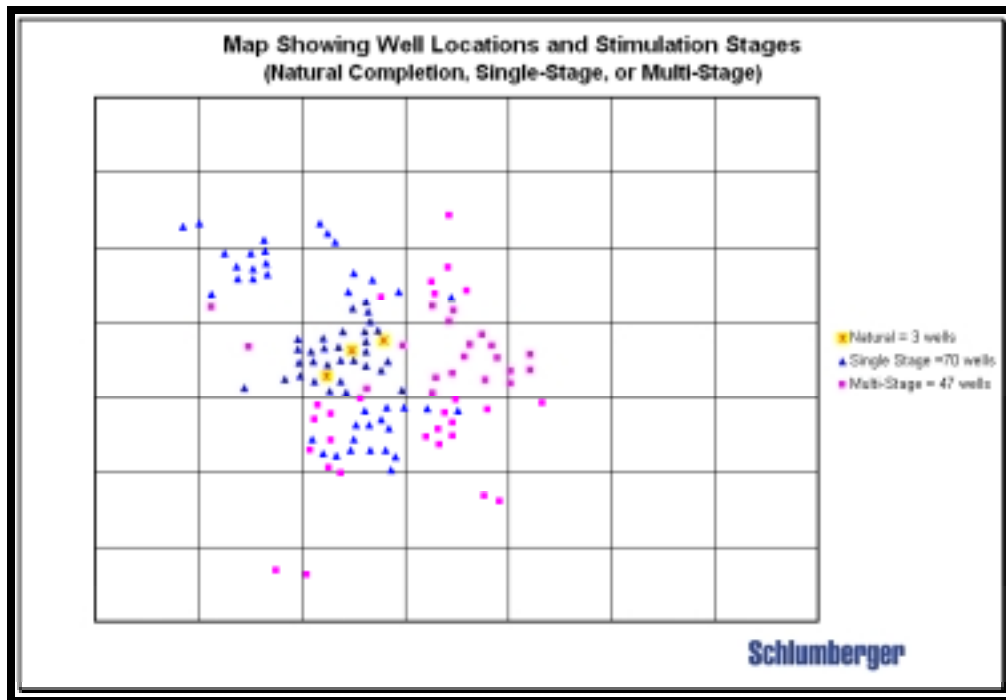


Figure 5.16 – Well location map identifying number of stimulation stages.

The background colorfill represents the five-year cumulative production for all wells. Most multi-stage treatments were performed in the southeast, eastern, and northeastern areas as development moved outward.

As a method to compare wells stimulated with single and multi-stage treatments, **Figures 5.17** through **5.20** were generated. These plots show zero-time average well plots from four areas (SE, SW, Central, and NE) and draw a distinction between single-stage and multi-stage treatments. The data from three of the four groups (SE, SW, and Central) show that single-stage treatments outperformed multi-stage treatments. Although the rate for wells in the fourth area (NE) was higher initially for the multi-stage treatment wells, it quickly matched the single-stage wells within 1½ years. Meridian consistently used 90,000 lbs of sand for both the single- and multi-stage treatments, so proppant volume was not an influential factor.

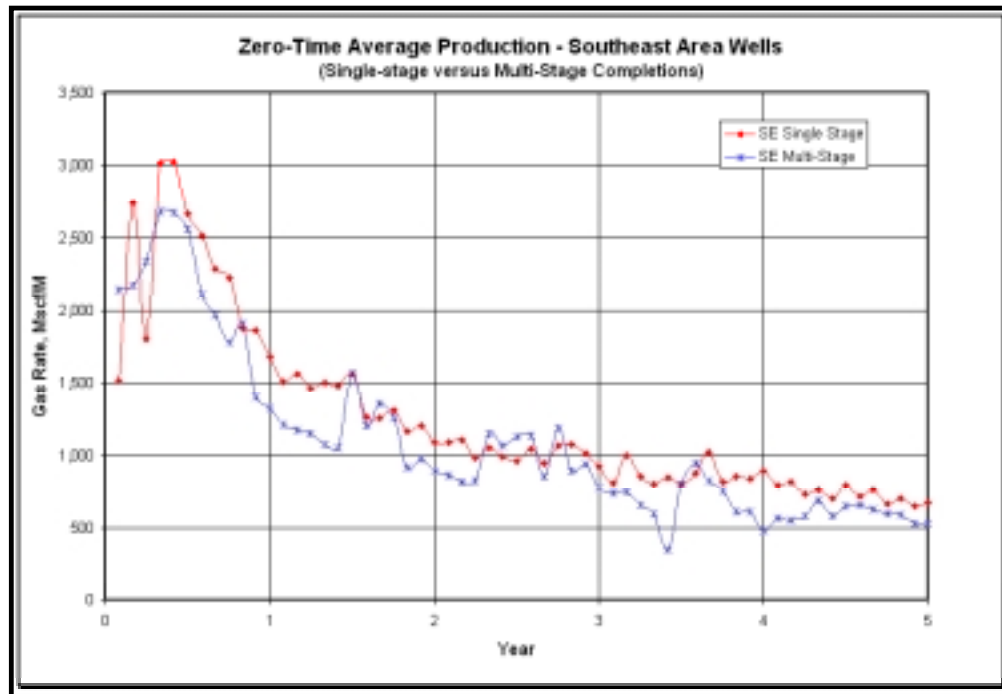


Figure 5.17 - Zero-time average production - SE area wells (single-stage versus multi-stage completions).

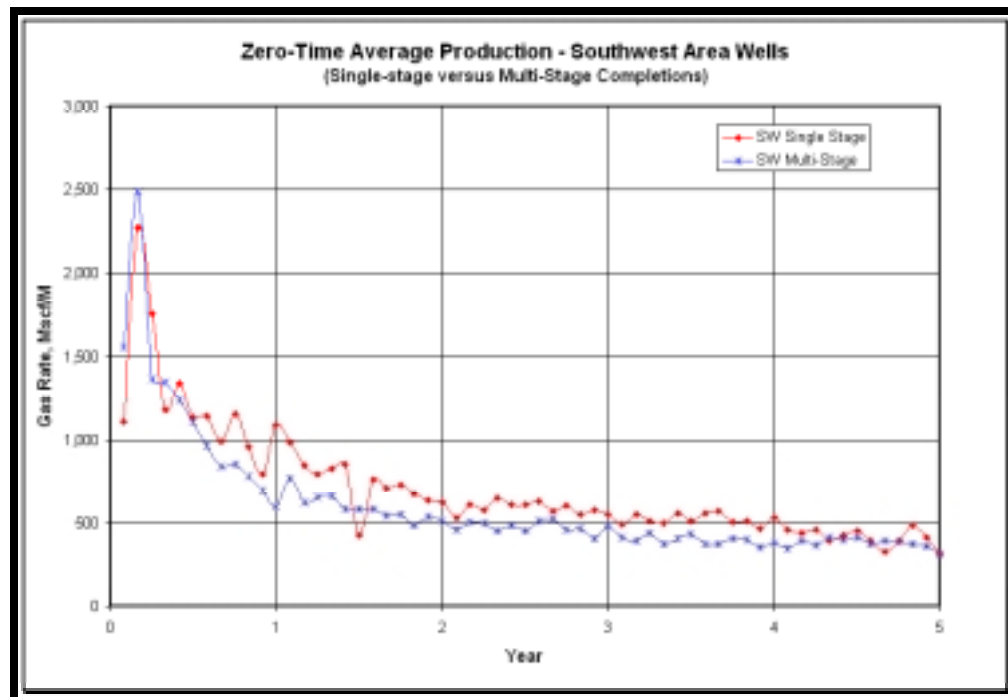


Figure 5.18 - Zero-time average production - SW area wells (single-stage versus multi-stage completions).

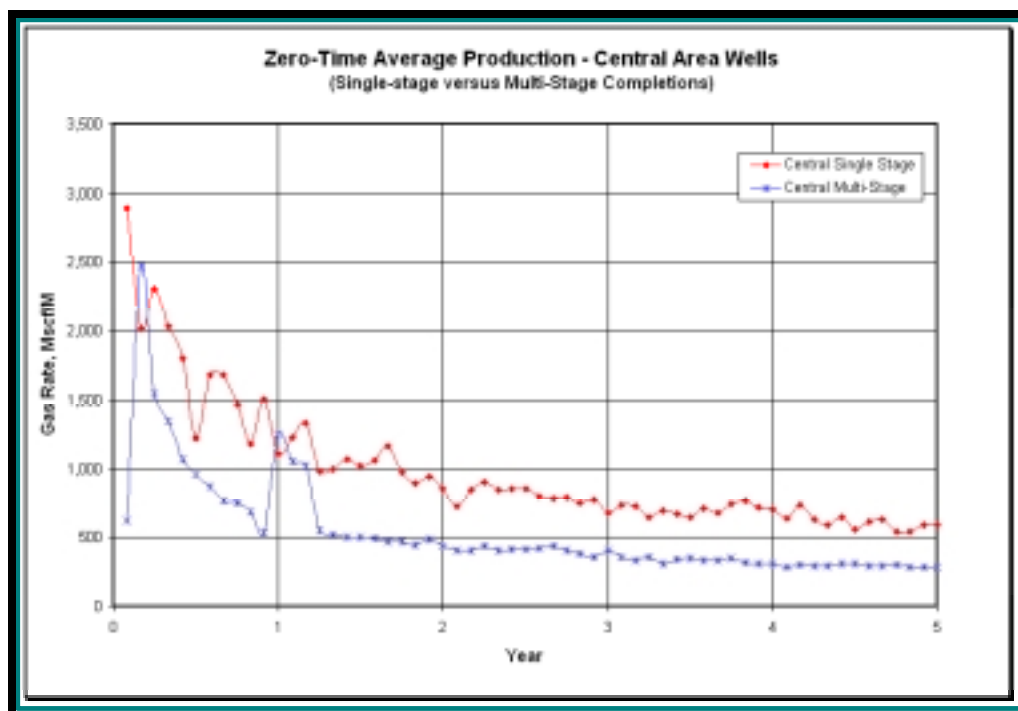


Figure 5.19 - Zero-time average production - central area wells (single-stage versus multi-stage completions).

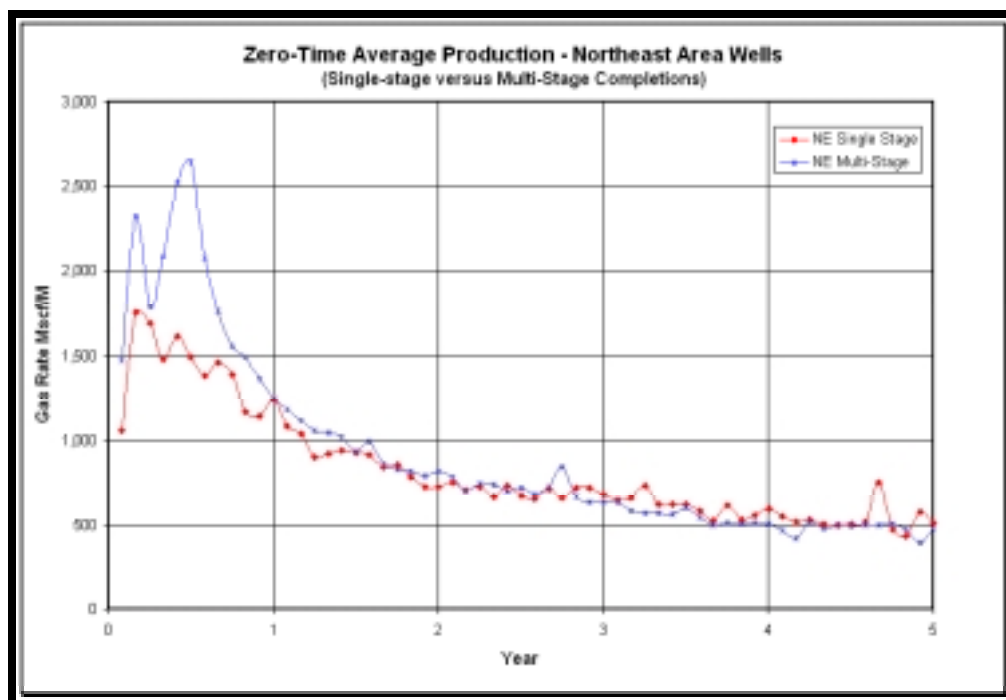


Figure 5.20 - Zero-time average production - NE area wells (single-stage versus multi-stage completions).

Table 5.1 lists permit numbers and completion dates for the wells shown in **Figures 5.17** through **5.20**.

Table 5.1
Wells Used In Stimulation Comparison

Geographic Area	Year	Single-Stage	Year	Multi-Stage
NE	1987	20518	1988	20673
	1988	20668	1989	20612
	1988	20624	1989	20647
	1988	20625	1988	20659
	1988	20638	1988	20646
	1988	20678	1989	20613
Central	1987	20500	1988	20670
	1987	20501	1989	21238
	1987	20502		
SW	1987	20522	1988	20610
	1987	20560	1988	20614
	1988	20639	1988	20635
SE	1988	20619	1988	20655
	1987	20520	1989	21255
	1988	20609	1989	21276
	1988	20618	1988	20626
			1989	20657

Direct offset wells drilled within a year of each were compared with each other to minimize any depletion effects. The comparisons illustrated in **Figures 5.17** through **5.20** show that single-stage treatments are the most favorable, and should be performed in the future, however it is uncertain why the multi-stage treatments were not as effective as the single-stage jobs. A future study can evaluate these jobs in more detail to compare and better understand the fracture geometries resulting from each method.

5.8 PROMAT™ DRAINAGE AREA ANALYSIS

To estimate drainage areas, production history matching was performed on 29 Meridian wells with H-RT's single-well, single-phase, analytical reservoir model (PROMAT™). The primary objectives of this work were: (1) to determine the original gas-in-place and drainage area of the 29 wells, and (2) to develop a correlation between the five-year cumulative gas production, the original gas-in-place, and the drainage areas for all wells based upon results of the 29 wells. The average drainage area for the 29 wells was eleven acres and ranges from 3 to 82 acres. The 11-acre drainage area is significantly smaller than the average well spacing of 50 acres. Also projected were 20-year EUR's for each well. The 29 wells that were evaluated and their PROMAT analysis results are shown in **Table 5.2**.

Table 5.2
Summary of PROMAT™ Analysis Results

Permit	Well	Reservoir Pressure (psia)	Permeability (md)	Skin Factor	Drainage Area (ac)	OGIP (MMscf)	Flowing Bottomhole Pressure (psia)	Online Date
20612	1034	640	0.0350	-6.3	27	396	100	1/89
20634	1035	640	0.0490	-6.0	52.5	870	160	1/89
04389	784	640	0.0210	-6.0	16	241	160	1963
20455	613	640	0.0150	-6.6	13	251	100	9/87
04216	787	640	0.0350	-6.4	18	321	100	1962
04571	773	640	1.1000	-2.0	82	1,390	100	1964
04580	774	640	0.0430	-6.6	20	317	100	1964
06060	778	640	0.0230	-5.3	30	503	100	1968
20472	683	540	0.1300	-5.4	43	681	150	8/87
20457	660	640	0.1300	5.4	41	627	150	9/87
20557	951	640	0.2400	-4.7	24	441	150	2/88
20626	1058	640	0.1400	-3.0	30	479	75	3/89
20511	805	640	0.0600	-5.0	24	476	75	2/88
20466	684	640	0.0460	-5.0	28	460	150	12/87
20649	1080	550	0.0240	-4.5	9	160	75	10/89
20555	944	500	0.0280	-4.6	18	235	150	3/88
20675	1100	640	0.0770	-3.6	22.5	342	100	9/89
20509	803	640	0.0190	-4.5	17	285	150	2/88
20522	817	640	0.0100	-4.0	7.5	160	150	2/88
20503	708	640	0.0140	-6.0	22	346	75	2/88
20672	1102	575	0.0120	-6.0	10.5	175	150	10/89
20615	1033	640	0.0160	-6.0	17	222	75	11/88
20452	522	640	0.0090	-6.0	16.4	402	150	7/87
19647	430	640	0.0110	-6.5	21	327	300	8/86
20556	950	640	0.0110	-6.1	18	349	100	5/88
20499	347	640	0.0075	-6.2	14	236	150	2/88
20614	1039	640	0.0060	-6.2	14.5	190	150	2/89
20515	809	400	0.0900	-6.5	40	384	150	2/88
20464	520	640	0.0040	-6.3	9	138	150	12/87
* A naturally fractured reservoir model was used in many wells. Typical $\lambda = 1 \times 10^{-6}$ and $\omega = 0.003$.								

Net pay thickness and porosity determined by log analysis were used in the PROMAT evaluation. In addition, initial surface shut-in pressures recorded after the stimulation treatments were used to estimate reservoir pressure for each well, based upon a water saturation of 30%. It is important to note that actual water saturation values should be further evaluated in the future by running an advanced log suite including a Combined Magnetic Resonance (CMR™) tool, a resistivity log, and a lithodensity log. In addition, rotary sidewall cores should be cut and analyzed to better determine in-situ water saturation. The water saturation is used in the drainage area calculation. The core analysis should be performed with special care to avoid drying out clays, leaching salt, and/or artificially enhancing porosity, since porosity is also used to compute water saturations.

The PROMAT analysis showed permeabilities ranging from 0.009 to 1.1 md and skin factors ranging from -2 to -6.5. Most wells appear to be highly stimulated, however layering and natural fractures could cause this behavior. The dual-porosity option in PROMAT was used to simulate the production data since it exhibited an early steep decline, followed by a long period of relatively shallow decline. A multi-layer, finite-difference reservoir simulator could also have been used to match the observed production instead of the single-layer PROMAT analytical model.

Correlations were developed between the drainage area, original gas-in-place, and the five-year cumulative production indicator for the 29 wells. **Figure 5.21** shows the correlation between effective gas-in-place and drainage area for these wells. It is readily apparent that there is an excellent 0.93 correlation coefficient for this dataset.

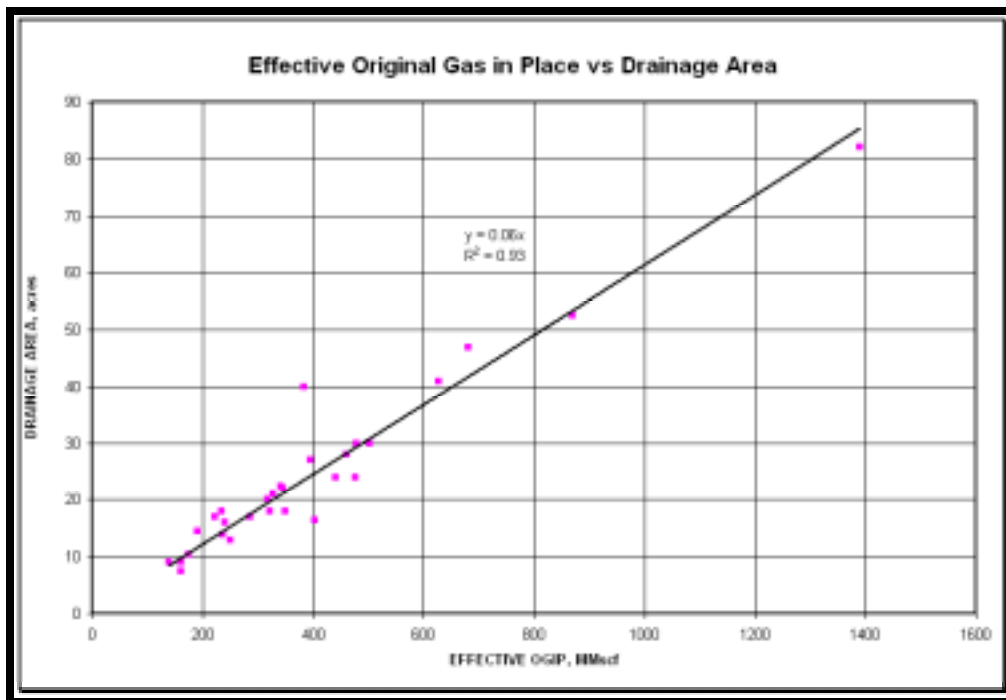


Figure 5.21 - Correlation between effective original gas-in-place and drainage area.

Five-year cumulative gas versus effective gas-in-place was also plotted for the 29 wells as shown in **Figure 5.22**. Again, the correlation coefficient is excellent at 0.90 for the data.

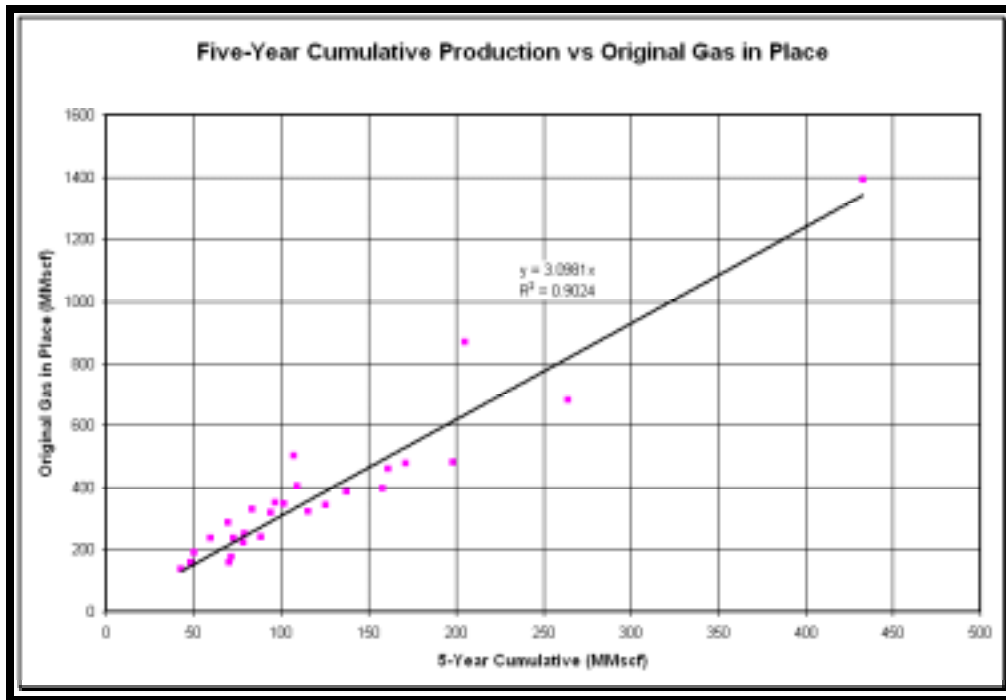


Figure 5.22 - Five-year cumulative gas versus effective gas-in-place.

At this point, it is feasible to use the correlation shown in **Figure 5.22** and the five-year cumulative value of each well to calculate original gas-in-place of the remaining Meridian wells. After obtaining an estimate of original gas-in-place for all wells, drainage areas were calculated using a volumetric equation. Net pay thickness and porosity were estimated based on extrapolating the results of the log analysis to every well with the Moving Domain technique. The above methodology is useful to quickly estimate drainage areas for many wells based on detailed analysis from only $\pm 10\%$ of the wells.

5.9 INFILL POTENTIAL

In this section, many of the intermediate steps and calculations used to determine infill-well drainage areas and recovery expectations are discussed. The infill-well potential was computed without considering its direction from an existing well. In addition, the infill wells were spotted so that their future drainage areas would not overlap those of the existing wells. The processes of calculating well spacing, undrained acreage, and recovery expectations are briefly described in this section.

5.9.1 Well Spacing

The well spacing (or well density) for each individual well was computed with a Voronoi gridding technique and the results are shown in **Figure 5.23**. A Voronoi polygon was constructed around each well encompassing all the acreage around the well closer to it than any other well. The area of each polygon was calculated and it became the well spacing for each individual well. The Voronoi area is used in several calculations for evaluating infill wells and a maximum polygon area of 640 acres was assumed. This resulted in a circle positioned around wells located in sparsely drilled areas.

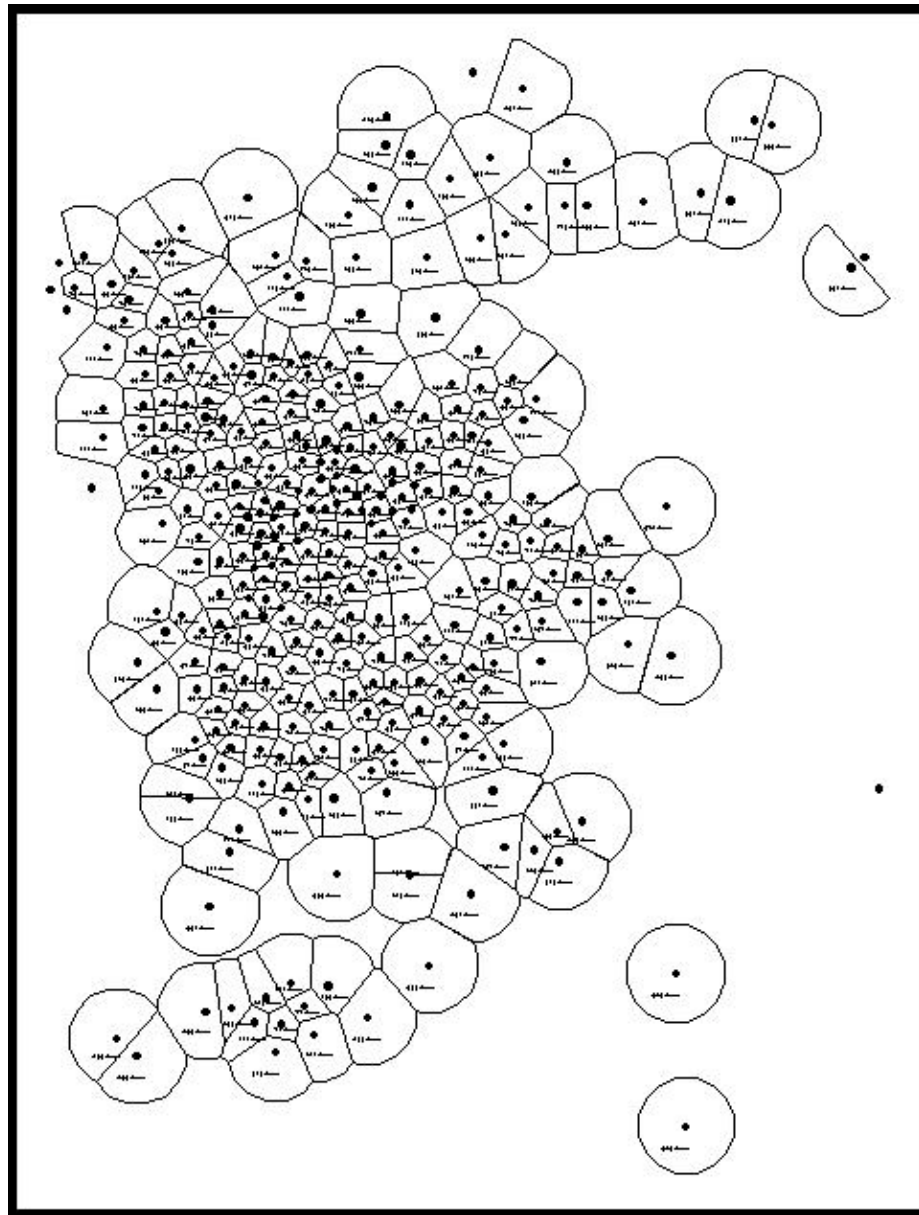


Figure 5.23 - Voronoi grid illustrating well density.

5.9.2 Undrained Acreage

The drainage areas are shown in orange for the Meridian wells discussed in Section 6.8. They were superimposed on the Voronoi grid map as shown in **Figure 5.24**. The undrained acreage is apparent as the white area inside each Voronoi polygon. Note the lack of calculated drainage area for the offset Miller Brewing wells. In the central portion of Meridian's property, many drainage area bubbles were as large or larger than the Voronoi polygon. The calculations indicate that there is little or no undrained acreage in this region, and therefore no infill potential surrounding these wells. In other areas where the drainage areas of the existing wells were small, a significant number of infill locations were found within an existing well's Voronoi polygon. At this point, the productivity in the undrained acreage was estimated to determine if a viable infill candidate existed.

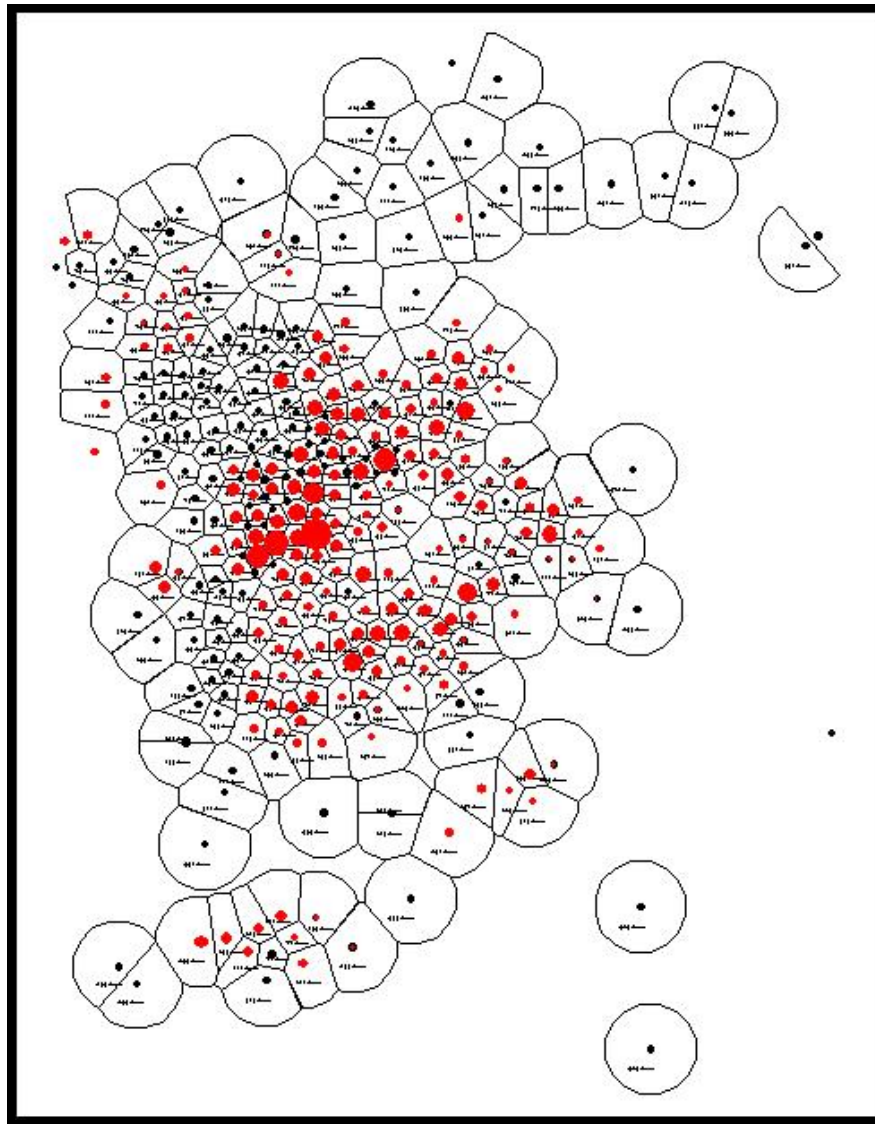


Figure 5.24 - Drainage areas superimposed on a Voronoi grid.

5.9.3 Newest-Well Five Year Indicator

The newest well's five-year production indicator was another input parameter considered during the process of discerning infill wells, and it represents the production expectation for a recently drilled well in each area of the field. This value was generated by plotting each well's DOFP on the x-axis, versus its five-year cumulative on the y-axis, and was performed for every domain. A best-fit line was drawn through the data using linear regression, and the value of that line used as the date for the newest well drilled in each domain. This methodology was discussed previously in Section 6.6. The results of these calculations were plotted at the center of each domain, as previously shown in **Figure 5.14**, and used in our infill well calculations.

Regardless of the amount of undrained acreage, an infill candidate was not permitted to have a five-year expectation that exceeded what is presented on this map. If the undrained acreage was small and it reduced the expected infill drainage area, the five-year expectation was decreased accordingly.

5.9.4 Infill Recovery and Drainage Area

The preliminary infill recovery is estimated as the lesser of (1) the infill drainage area multiplied by the recovery per acre, and (2) the newest well five-year indicator as defined in the previous sub-section. Recovery per acre was calculated by dividing the newest well five-year indicator by the drainage area of that domain. The final infill drainage area was set to the smaller of the preliminary infill drainage area or the undrained acreage within the Voronoi polygon. If the undrained area was smaller than the preliminary infill drainage area, the drainage area and the five-year cumulative expectations were reduced by the same percentage. This reduction maintained a constant recovery per acre. All of these calculations were performed to assess infill potential for each existing well. After finishing this process, the infill candidates were spotted on a map.

5.9.5 Spotting Infill Candidate Wells

At this point in the calculations, each existing well was assigned expected values for its infill wells drainage areas and recoveries. These expectations were optimistic since undrained acreage would most probably exist in a ring around an existing well's drainage area, and not in a geometry enabling a single infill well to economically drain it. To test this concept, the infill drainage areas were spotted on a map to see if it overlapped existing well drainage areas. During this analysis procedure, an infill candidate was initially arbitrarily positioned to the west of an existing well, and if a suitable location could not be found at this location, the infill location was moved incrementally counter-clockwise into 35 additional positions around the existing well. The first viable location found was accepted and the infill well spotted at that location. If the 36 possible locations around each existing well were not viable and an infill location could not be found, an infill was spotted on the largest contiguous undrained acreage area available by reducing

its drainage area to fit. If the reduced drainage area and its corresponding reduction in recovery expectations still exceeded our minimum five-year cumulative recovery hurdle (75 MMscf), then an infill well was spotted at this point.

The highest-recovery infill locations were identified first and the entire process was repeated to identify a full program of wells. During this process, up to four infill locations were spotted offsetting a single existing well. The results of this process are shown in **Figure 5.25** on an infill-well drainage-area bubble map.

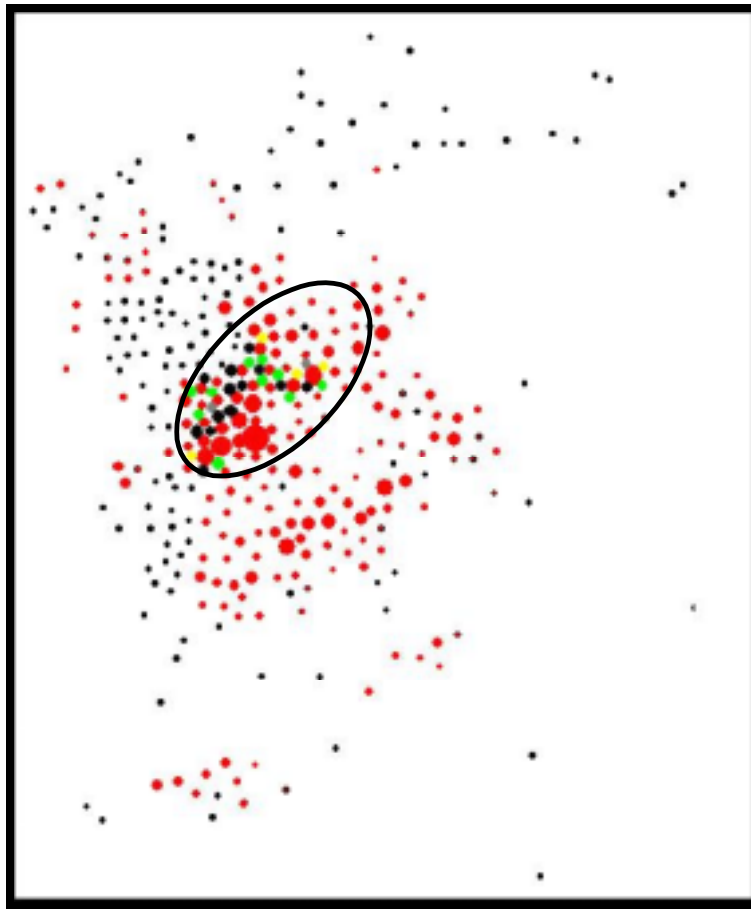


Figure 5.25 – Infill well locations (green) and drainage areas superimposed with existing wells.

Using the above technique, 29 potential infill wells were spotted that met Meridian's economic hurdle volume corresponding to a forecasted five-year cumulative production volume of 75 MMscf. **Table 5.3** shows well coordinates (latitude/longitude), expected five-year cumulative production, and anticipated drainage area of each infill well. The EUR's were expected to average ~ 200 MMscf per well with drainage areas ranging from 13 to 18 acres. A combined cumulative of five Bscf is expected, which is an 18% increase above the PDP reserves.

Table 5.3
Estimated Infill Well Five-Year Cumulative
Production and Drainage Area

Well ID	X Latitude	Y Longitude	5 Year Cumulative (Mscf)	Drainage Area (acres)
31-011-20466X1	1193106	15585750	103,250	19
31-011-04389Y2	1195553	15588002	99,318	16
31-011-04389X1	1193970	15587632	99,318	16
31-011-20471X1	1192134	15585242	97,190	18
31-011-04580X1	1190482	15584104	96,538	18
31-011-20456X1	1193033	15587348	93,664	16
31-011-04448X1	1191126	15588175	90,288	15
31-011-04448Y2	1190063	15587188	90,027	15
31-011-20462X1	1195261	15588865	87,776	15
31-011-20462X2	1196749	15588466	87,776	15
31-011-20557X2	1197597	15586775	87,623	14
31-011-20557X3	1198216	15588477	87,623	14
31-011-20557X1	1197001	15587626	87,623	14
31-011-20515X2	1192133	15581601	87,001	17
31-011-20515X1	1191001	15581074	87,001	17
31-011-16149X2	1194518	15589434	84,742	15
31-011-16149X1	1193137	15588790	84,742	15
31-011-04216X1	1194529	15590471	82,800	14
31-011-04216X2	1195504	15589652	82,800	14
31-011-20515Y3	1190118	15582204	80,786	16
31-011-04216Y3	1195536	15591275	79,464	13
31-011-20634Y4	1198878	15589272	78,406	13
31-011-20634X3	1200244	15589081	78,406	13
31-011-20634X1	1198940	15587527	78,406	13
31-011-20634X2	1200117	15587630	78,406	13
31-011-20455X2	1191634	15587146	76,921	13
31-011-20455X1	1191634	15585994	76,921	13
31-011-20469X1	1191525	15584171	75,339	13
31-011-20469X2	1190652	15585419	75,339	13

Figure 5.26 shows two predicted flow streams for the infill wells. The blue diamonds correspond to a forecasted infill recovery between 75 - 90 MMscf in 5 years, and the green squares show projected rates for an infill recovering between 90 - 105 MMscf in 5 years. These curves are based upon actual performance of existing wells.

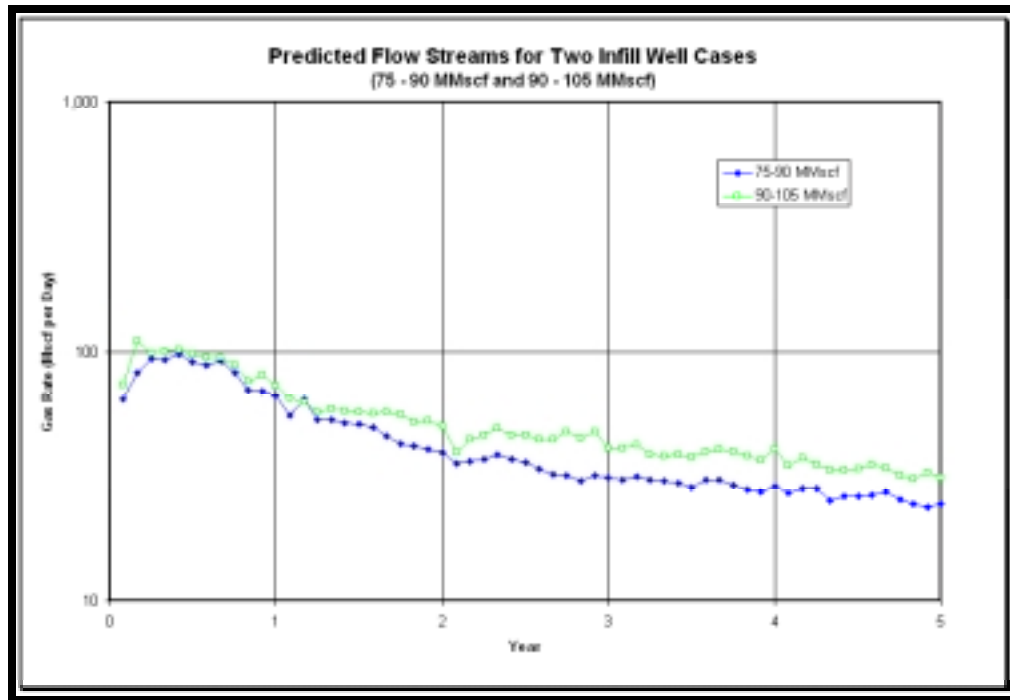


Figure 5.26 – Infill well predicted flow rates.

The infill wells were all located in the north-central portion of Meridian's acreage surrounding wells with good historical production. No infill wells were spotted in the southeast (where several excellent wells have been drilled in the past), due to poor recent performance and/or large drainage areas. Had a Moving Domain study not been performed, a drilling program in this area almost certainly would have resulted in substandard production and economics. Moving Domain analysis statistically identified a high chance of encountering inferior wells here, and thus they were not selected for infill potential. Meridian may still desire to drill test wells in this area surrounding the better wells, but there is a higher risk of encountering depleted or low productivity regions.

Figure 5.27 is a probability plot of estimated five-year cumulative production for the 29-infill wells. All infill wells are projected to meet the economic hurdle of 75 MMscf in five years.

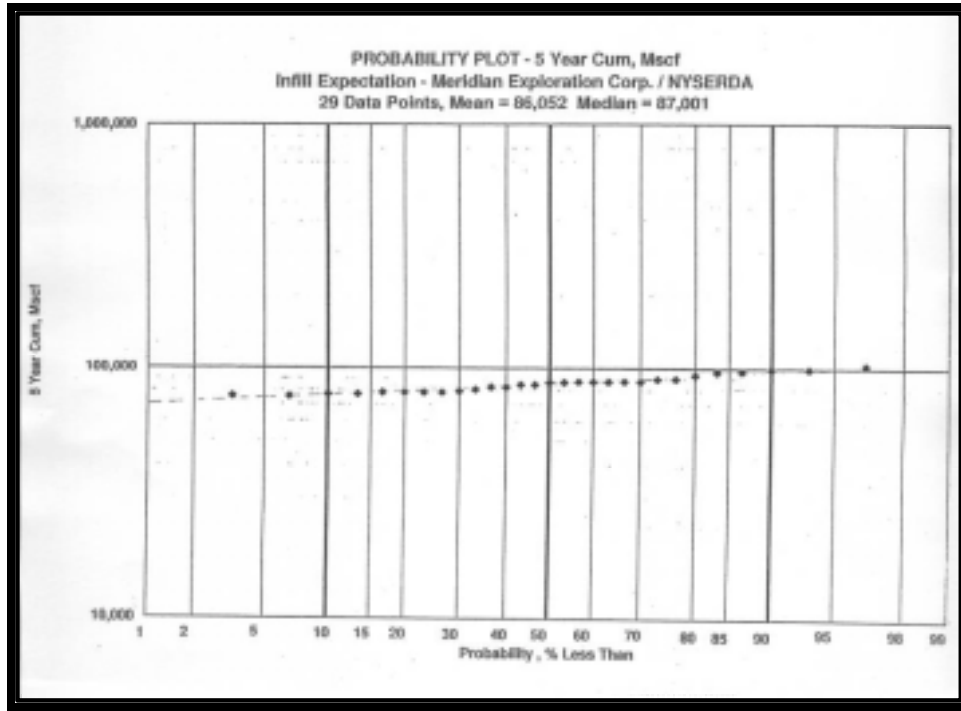


Figure 5.27 - Probability plot of estimated five-year cumulative production (infill expectations).

Figure 5.28 plots the 5 year cumulative production for the closest 21 wells to the infill locations. These wells showed a 70% probability of encountering an economic well. The evaluation and spotting procedure maximizes the chance for obtaining economic infill wells around the 21 offset wells. The infills most likely will vary in quality, but the entire group of wells are expected to meet the economic hurdle volume.

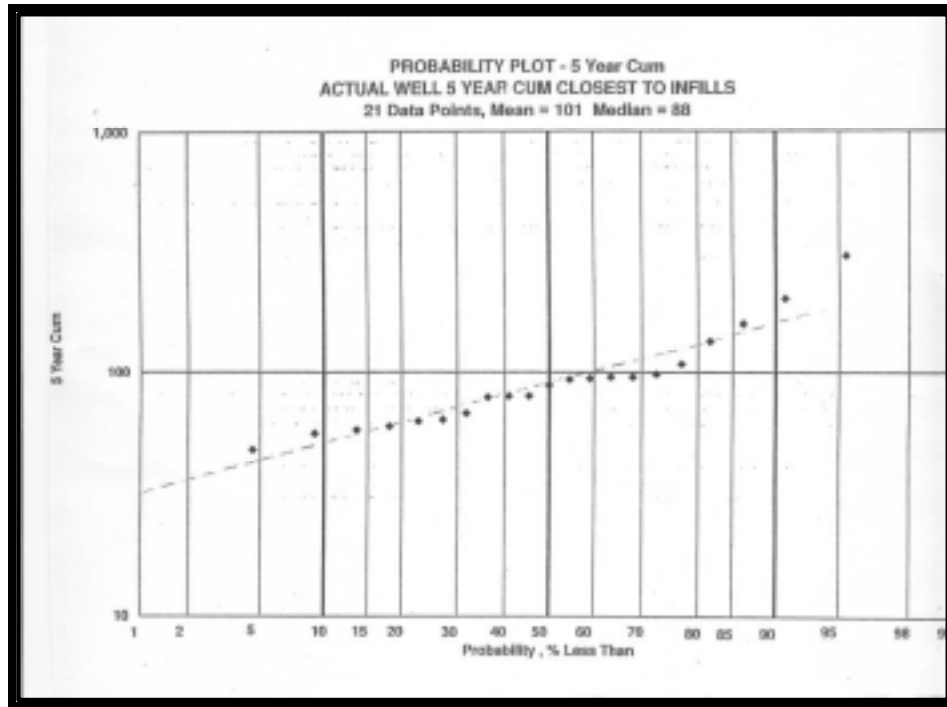


Figure 5.28 – Probability plot of closest 21 wells to infill locations (five-year cumulative production).

Meridian selected five infill well locations from the 29 recommended sites. Many were not chosen in the order shown in our priority list due to surface constraints or lease/unitization issues. It is recommended that Meridian drill a minimum of 10 infills because of the statistical nature of the MDA procedure. However, budget constraints only permitted five to be drilled.

5.10 INFILL WELL PERFORMANCE

Figure 5.29 shows the location of the five infill wells drilled by Meridian in 1998.

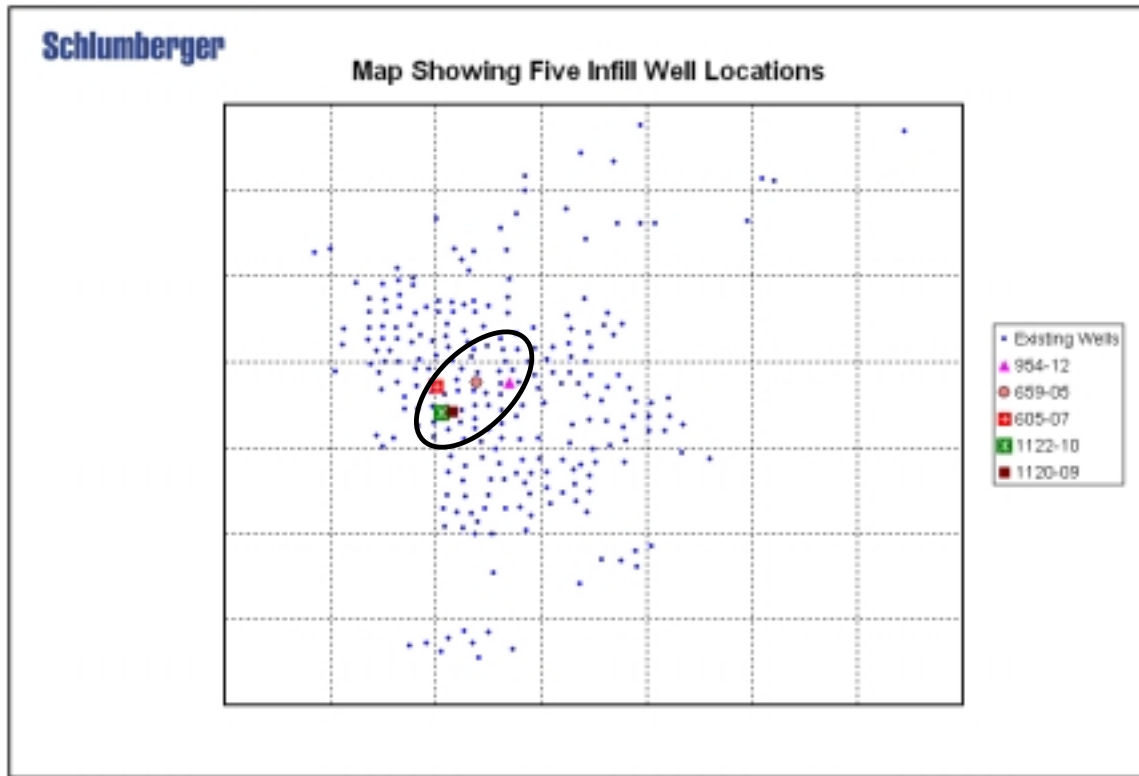


Figure 5.29 – Location map of five infill wells drilled in 1998.

The actual well performance is 56% less than predicted by MDA due to depletion effects. This depletion was not expected because an estimated water saturation of 30% was used rather than the actual 45-55% value revealed later by the new geophysical logs. Thus, the initial calculated drainage areas were too small.

Figure 5-30 is a rate-time plot comparing actual historical production of the five infill locations.

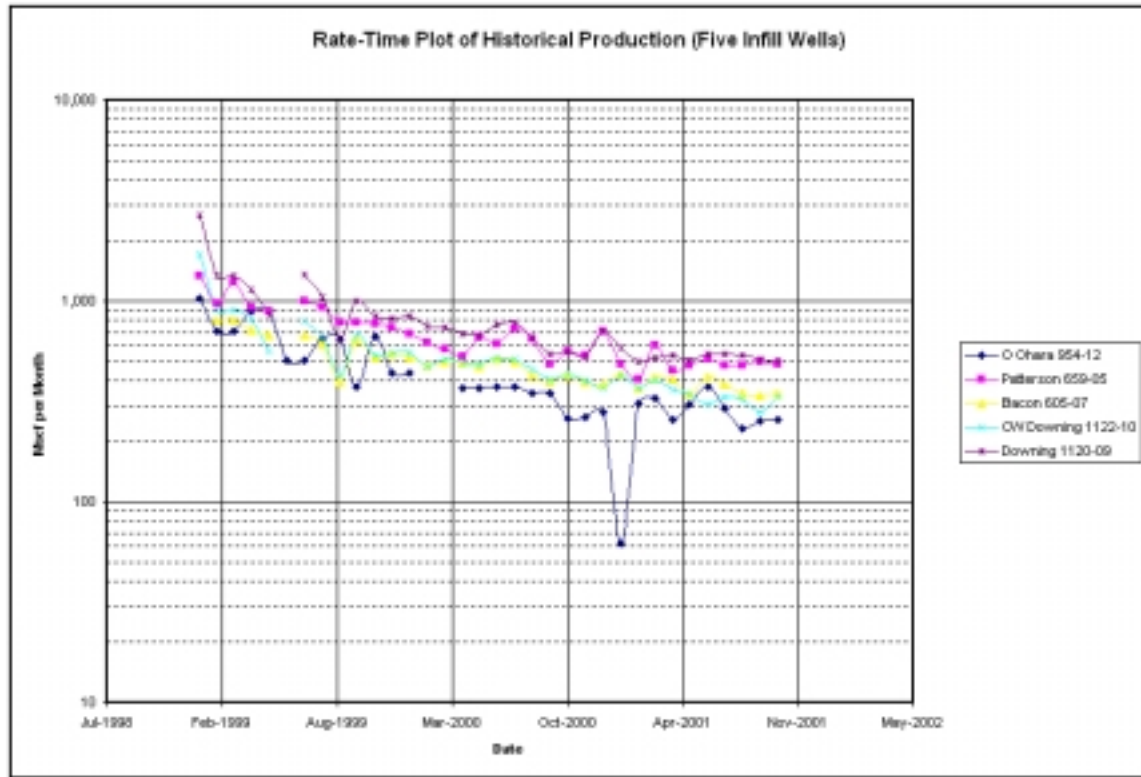


Figure 5-30 – Rate-time plot of historical production (five infill wells).

Figures 5.31 and 5.32 are rate-time and rate-cum charts respectively, showing projected infill-well production volumes for a 20-year period. A flowing bottomhole pressure of 50 psi was used, based upon an assumption that casing plungers would be installed to continuously unload produced formation water. In actual practice however, plungers were not installed in any of the wells resulting in early fluid loading. The wells were not maintained in a manner that enabled them to produce similar to the profiles predicted.

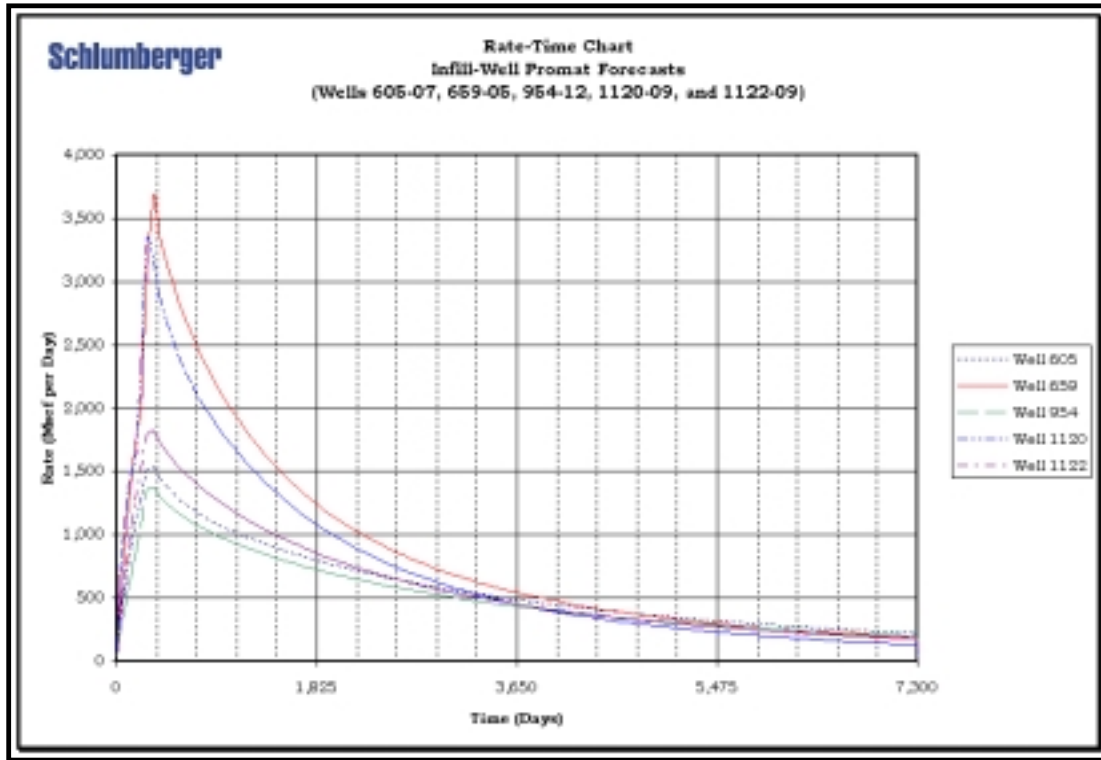


Figure 5.31 – Rate-time plot of five infill wells showing 20-year forecast volumes.



Figure 5.32 – Rate-cum plot of five infill wells showing 20-year forecast volumes.

For comparison purposes, **Table 5.4** lists 1-year, 5-year, and 20-year forecasted volumes for the infill locations.

Table 5.4
Projected 1-year, 5-year, and 20-year cumulative production
(PROMAT derived)
For the five infill wells

Well	1-Year Cum (Mscf)	5-Year Cum (Mscf)	20-Year Cum (Mscf)
605-07 (Bacon)	11,411	36,342	75,440
659-05 (Patterson)	20,533	69,034	113,309
954-12 (O Hara)	9,195	31,942	66,979
1120-09 (Downing)	22,414	63,997	100,668
1122-10 (C.W. Downing)	13,383	42,140	78,331

Table 5.5 provides a summary of log analysis results of the five-infill wells regarding net pay thickness, porosity, and water saturation. Net pay, porosity, and water saturation values were obtained from Schlumberger's analysis of the openhole logs. Permeability and skin factor estimates are also shown and were calculated via PROMAT analysis of the actual production data.

Table 5.5
Log analysis summary data of productive zones
(Five infill wells)

Well	Net Pay (feet)	Porosity	Water Saturation	Permeability (md) – from PROMAT	Skin Factor – from PROMAT
605-07 (Bacon)	147	0.115	0.54	0.020	-6.000
659-05 (Patterson)	153	0.107	0.50	0.060	-5.167
954-12 (O' Hara)	140	0.100	0.55	0.059	-3.910
1120-09 (Downing)	135	0.118	0.53	0.046	-5.895
1122-10 (CW_Downing)	140	0.100	0.51	0.030	-5.625

Table 5.6 provides information regarding formation temperature, initial reservoir pressure, and wellbore radius utilized for analysis.

Table 5.6
Reservoir Data of Five Infill Wells

Well	Formation Temperature (°F)	Initial Reservoir Pressure (psi)	Wellbore Radius (Feet)
605-07 (Bacon)	78	370	0.25
659-05 (Patterson)	78	407	0.25
954-12 (O' Hara)	78	349	0.25
1120-09 (Downing)	78	450	0.25
1122-10 (CW_Downing)	78	386	0.25

5.11 VALIDATION STUDY

5.11.1 Performance-Based Predictions

Because depletion effects were evident in the infill wells and actual production was less than predicted, a validation study was performed as a means to extrapolate the actual infill well results to other future infill wells. A validation study is a process to authenticate the methodology used to predict the performance of groups of future completions. The methodology is tested by comparing these results with historical data. In a validation study, a “history match” is conducted for production performance (five-year cumulative gas production) from past drilling campaigns. The steps of a validation study include:

1. Choose a drilling program (in this case all wells drilled after 1990).
2. Use only production data available before that drilling program.
3. Predict the performance of the wells drilled during that drilling campaign.
4. Compare actual well performance to predicted performance.
5. Modify the prediction method and repeat the predicted/comparison process until satisfied the methodology is reasonable.
6. Apply the prediction method to the recently drilled infill wells.
7. Predict future infill-well performance.

The method used to predict the performance of a validation well at a given location is to:

1. Develop a domain around that well.
2. Graph the DOFP vs. five-year cumulative gas production for all wells in the domain completed before the validation well.
3. Draw a best-fit line through the data points.

Figure 5.33 is an example of a graph constructed for a domain around a single well. If the slope of the best-fit line is negative, and the confidence level that the trend exists is greater than 90%, the predicted "New" five-year cumulative gas is calculated by extending the best-fit line to the maximum date within that domain. If the slope is positive, or if the confidence level that the trend exists is less than 90%, the "New" five-year cumulative gas is calculated by taking the average of all wells in the domain. The size of the domain, and the number of wells included in the domain, are variables and are determined through trial and error in the validation study.

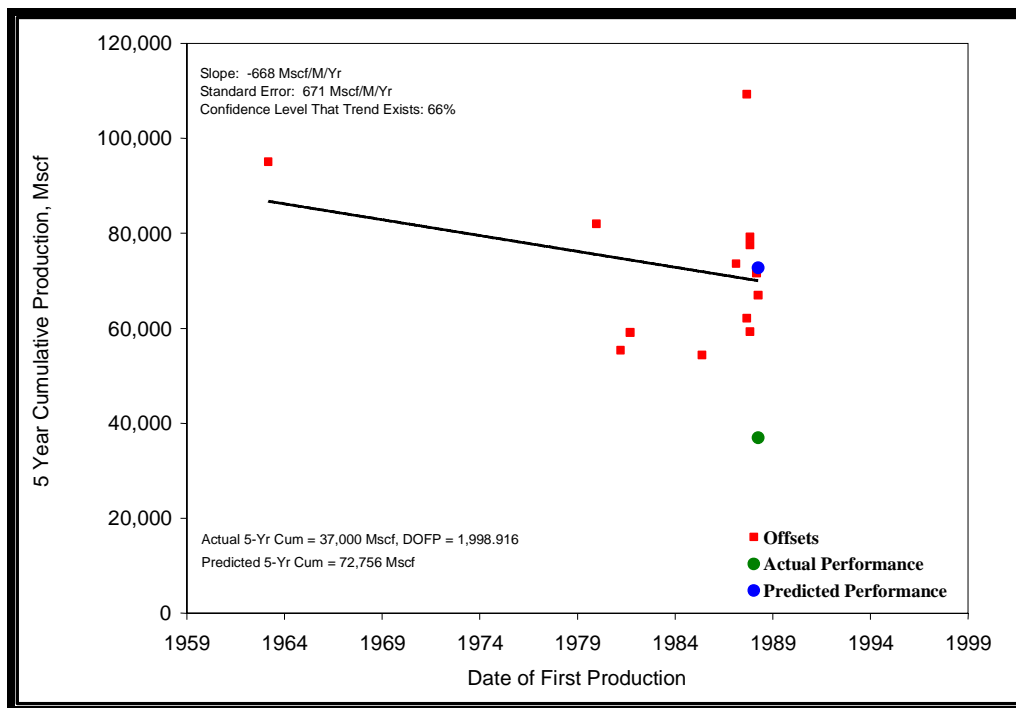


Figure 5.33 - Example calculation of predicted five-year cumulative gas in a domain for wells drilled before 1990.

In **Figure 5.33**, the blue dot is the average of all wells in the domain since the confidence level is less than 90%. The green dot is the actual performance of the infill well in this domain. **Figure 5.32** indicates a very poor correlation in this domain between the actual and predicted performance.

For this study, the prediction method was confirmed by “history matching” the production performance, or five-year cumulative gas production, of those Queenston wells with a date of first production after 1990 (Validation Wells). The process used production data prior to the DOFP for each set of validation wells, calculated a “New” five-year cumulative gas production at the validation well locations, and compared the predicted five-year cumulative gas production to the actual five-year cumulative gas production.

During the process of comparing predicted to actual five-year cumulative gas production, a scatter plot of the data and distribution patterns are studied. These provide insight regarding the effectiveness of matching individual wells, and the overall drilling program.

It was discovered that the most favorable domain size was 750 acres, and that the best method of predicting future performance within a domain was to multiply the median five-year Cumulative by 65%. The typical method of prediction, as described above in Section 5.11.1, proved to be too optimistic.

Figure 5.34 shows that, on a well-by-well basis, the predicted five-year cumulative does not particularly match the actual five-year cumulative of the validation wells. However, there is a good match regarding well quality. For example, the five-year cumulative gas prediction is high when forecasting the actual high cumulatives, and the predicted five-year cumulatives are low when forecasting actual low five-year values.

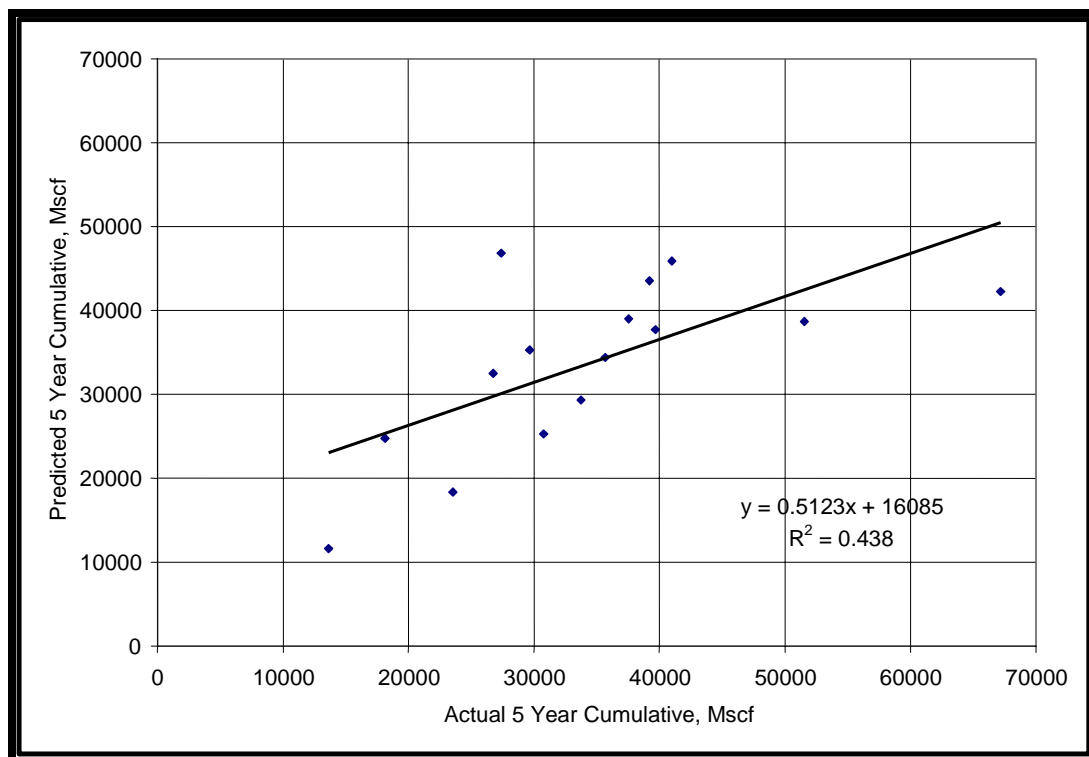


Figure 5.34 – Comparison of predicted to actual five-year cumulative for wells drilled before 1990 (validation wells).

Figure 5.35 shows that the average and median predicted five-year cumulatives closely match the average and median actual five-year cumulatives for the validation wells.

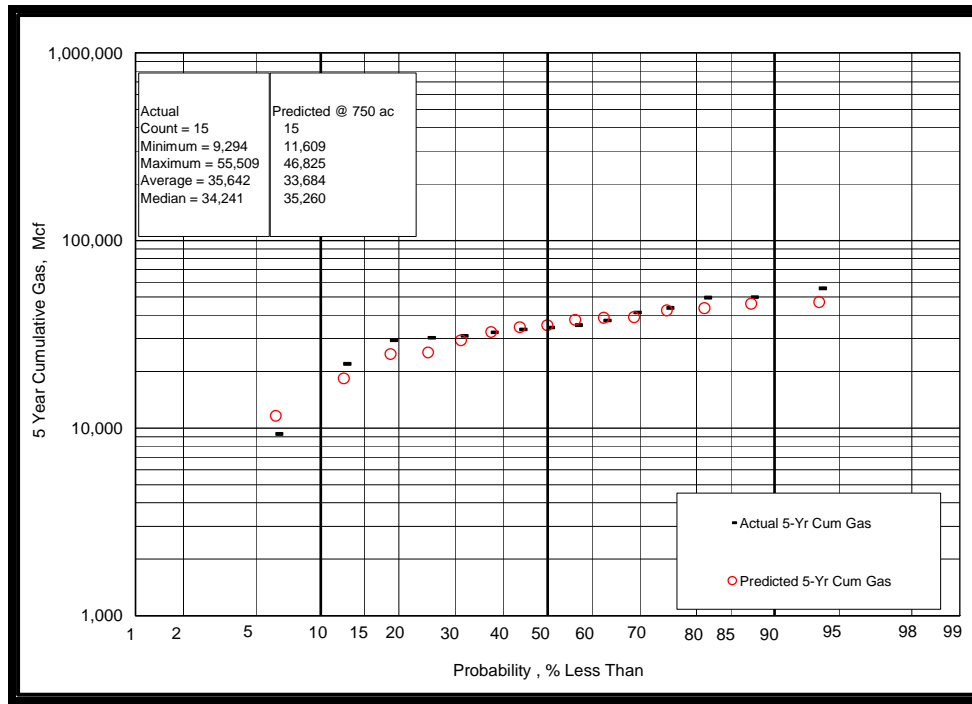


Figure 5.35 – Probability distribution comparison – predicted to actual five-year cumulative for wells drilled before 1990 -(validation wells).

Figure 5.35 shows that there is a notable relationship between predicted and actual values for the entire validation well drilling program. However, this figure illustrates the large range of five-year cumulatives and the difficulty in predicting the performance of individual wells and high-grading specific locations. If a significant number of wells are drilled (e.g. 10 to 15), this method in all likelihood can reasonably forecast the collective performance of an entire drilling program.

To check the dependability of applying this method to the most recent drilling, Meridian's 1998 five-well infill program was evaluated. Although information from at least ten wells were desired to aid in predicting performance, only five wells had been drilled. The results regarding these five wells are shown in **Figure 5.36**.

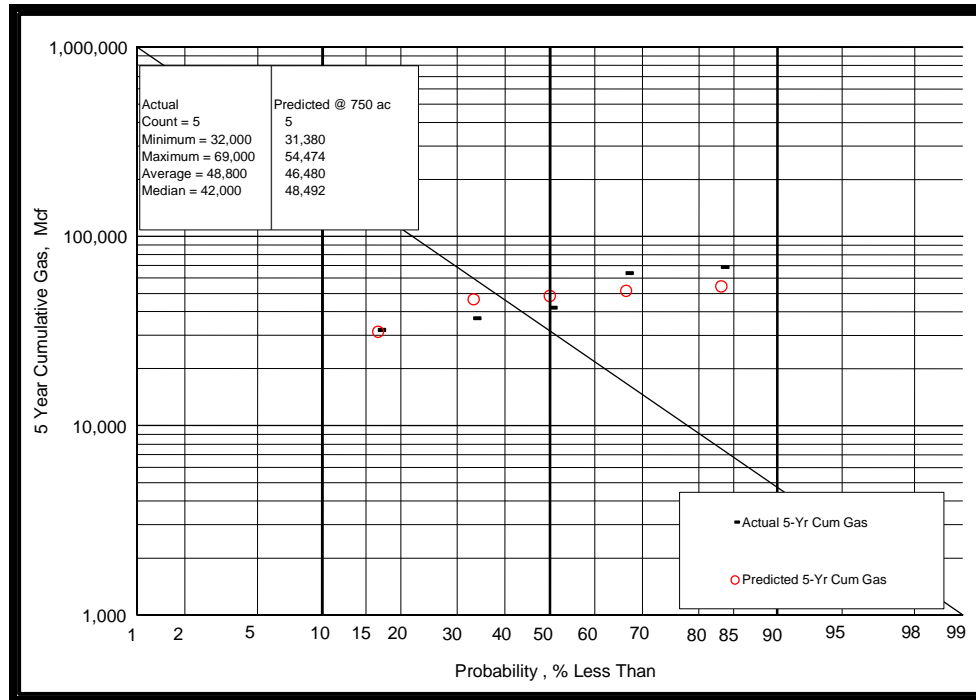


Figure 5.36 - Probability distribution comparison - predicted to actual five-year cumulative (1998 wells).

Figure 5.36 shows a probability distribution comparison between the actual and the predicted five-year cumulative production for the five 1998 wells. Since these infill wells have not produced for five years, PROMAT was used to forecast their total five-year cumulative production based upon a history match of actual performance. This figure shows that the average and median predicted five-year cumulatives closely match the actual values. The average predicted five-year cumulative production is 48,800 Mscf; considerably lower than the original 75,000 Mscf. As discussed earlier, this is due to the low water saturation assumed in the original drainage area calculations.

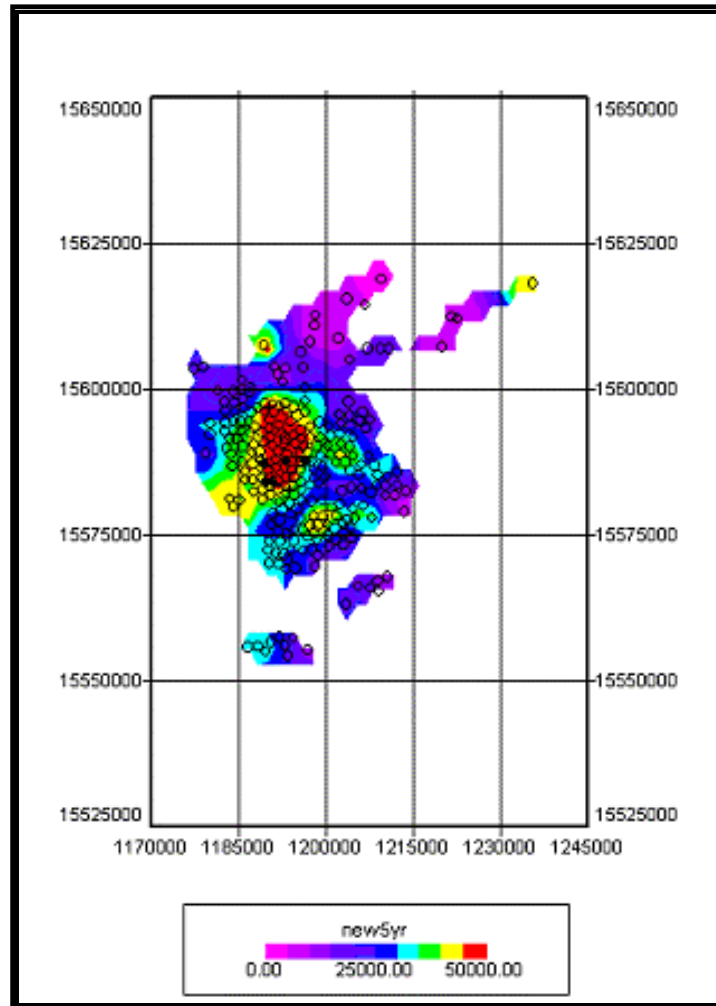


Figure 5.37 – Color-filled contour map of predicted five-year cumulative gas production for future infill wells.

Based on the results of our validation study, it is believed that one can reasonably predict the overall performance of future Queenston infill drilling campaigns in the original specified area, while taking into consideration the depletion occurring throughout the study area. Although predicting the production profile of a specific well is difficult, it is possible to reliably forecast the performance of an entire drilling program if 10 or more wells are drilled. **Figure 5.37** shows a color-filled contour map of predicted five-year cumulative gas production for future infill wells. The figure shows an area where wells can be drilled and produce approximately 50 MMscf in five years. At a gas price of \$3.00/Mscf, an investment cost of \$100,000, monthly operating costs of \$250 per well, and net revenue interest of 87.5%, economic analyses reveal a Before Tax Rate of Return of 15%.

6 REFERENCES

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3. Frantz, Jr. J. H.: "Technique Finds Oil & Gas Potential," *The American Oil & Gas Reporter* (November 1997) 142-145.