Tight Sand Evaluation Applied to the Medina Group of Chautauqua County, NY

Final Report

Prepared for

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ABSTRACT

To help determine if natural gas production and reserve improvement opportunities exist in the large, continuous, low permeability gas accumulation of the Medina Group in Chautauqua County, New York, a systematic geologic and engineering evaluation was performed in 1998. Petrophysical analysis of well logs, geological mapping and advanced production type curve analysis was performed over a 200 well study area covering 38,000 acres. Net pay, net sand and hydrocarbon pore-feet were determined from the log analysis. Formation permeability, well stimulation effectiveness and well drainage areas were estimated by using advanced decline curve techniques. Structure, isopach, pay thickness, gas in place, permeability, well drainage areas and other parameters were mapped.

Several infill/stepout locations were identified based on geologic parameter mapping and four new wells were drilled in the fall of 1998. Medina pay was encountered in agreement with the geologic prognosis for the wells. However, pore pressure was below original conditions, indicating partial depletion at the new locations. Differential depletion of the Whirlpool compared to the Grimsby is the probable cause of the reduced reservoir pressure. Weekly production data was collected from the new wells for a six-month period and decline curve analysis performed to estimate recovery.

The geologic and engineering evaluations indicated gross original gas in place for the area is large compared to the current estimated ultimate recovery. This is not consistent with the reduced pore pressure encountered in the new wells and suggests that a significant portion of the gross gas in place is either unrecoverable or has not been effectively accessed by current development.

Keywords: Medina, Chautauqua, Petropysics, Mapping, Decline Curves

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The authors express their appreciation to Belden & Blake Corporation for their cooperation in the execution of this project.

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SUMMARY

Natural gas has been produced in Chautauqua County, New York for many decades. The most significant gas reservoir in the area is the Silurian Age Medina Group of sediments, particularly the Whirlpool Sandstone Formation and the overlying Grimsby Formation. These two formations are separated by the intervening Cabot Head Shale Formation. In the study area, the Medina Group is found at depths from –1,450 feet to –1,800 feet, subsea. Generally speaking, the quality of the Whirlpool and Grimsby reservoirs is poor. Permeability and porosity are low. Continuity of individual sandstone beds and water saturation are variable in the Grimsby. However, natural gas is prevalent in a nearly continuous accumulation in the area, which is controlled more by stratigraphic than structural trapping mechanisms. Thus, Medina Group gas wells are characterized by a high drilling success ratio but low production rate, low ultimate recovery and a long producing life at marginal economic conditions.

This project was undertaken to determine if advanced reservoir evaluation techniques could be applied to the Medina reservoirs to better define and perhaps improve their recovery potential. The study area covered approximately 38,000 acres in Chautauqua County with field data from 160 wells provided by the dominant operator in the area, Belden & Blake Corporation (BBC). If suitable potential could be determined, BBC agreed to test the potential by the drilling of a new well or the recompletion of an existing well.

The technical aspects of the project were broken down into several discrete steps; 1) geologic correlation and petrophysical analysis of the available well logs, 2) type curve analysis of well production data, 3) geologic mapping, 4) evaluation and testing of production potential, 5) data collection and evaluation of the new production test.

Geologic correlations among the study wells were developed based upon a type log section selected by the operator. The correlation horizons were the tops of the Packer Shell Lime, Upper Grimsby Sand, Lower Grimsby Sand, Cabot Head Shale, Whirlpool Sand and the Queenston Shale. The available paper copy logs were then digitized and a data base created for use with PRIZM© petrophysical analysis software. Cutoffs for net sand and net porosity provided by the operator were used to determine gross, net sand and net pay zone average values for thickness, percent sand, percent porosity and percent water saturation.

Production data from study area wells was reviewed using advanced type curve analysis software. The software is proprietary to Advanced Resources International and is designed specifically for use with low permeability, hydraulically fractured gas wells and includes the effects of variation in fluid compressibility and viscosity. Results of the analysis provided estimates of permeability, hydraulic fracture half-length, drainage area and future production.

Results from the above work were used in an extensive mapping exercise of geologic and engineering parameters. More than 60 maps were created for the various formations. Included in the mapping were not only the more common parameters such as structure, isopach, isoporosity, isowater saturation and net pay, but also less common parameters such as porosity and percent sand at stratigraphic depth (slice) maps, hydrocarbon pore-feet, permeability and estimated ultimate recovery.

Based on the mapping of geologic parameters and previous operating experience in the Medina, five new well locations were identified. Due to the approaching end of the 1998 summer season, drilling of the locations proceeded with only limited engineering results available from the type curve analysis. Four of the locations were drilled and completed as commingled Whirlpool / Grimsby producers.

Results from the new wells were mixed. The wells were in agreement with their geologic prognoses developed from the new maps. However, production was disappointing due to reduced reservoir pressure. Production and pressure data were collected weekly from the new wells for a period of six months. Type curve analysis was performed using the new data.

The project has revealed several valuable comparisons between gas in place estimates and well performance. Net gas in place (GIP) is an estimated 1.6 MMSCF per acre, but gross GIP is about 5.1 MMSCF per acre. When comparing these estimates to actual production, one could conclude that drainage effectiveness of the Medina Group is poor. Further, the two reservoirs, the Grimsby and the Whirlpool, are separated by a thick shale. The characteristics of the two formations are sufficiently different to cause differential depletion. The Whirlpool is volumetrically much smaller, but is less variable and appears to have a higher average permeability. If true, the Whirlpool may be contributing a disproportionate share of the production and undergoing effective depletion while most of the GIP remains in the larger, but more dispersed, Grimsby reservoir.

BACKGROUND

Successful development of tight gas sand resources across the U.S. has presented a technical challenge for decades. Research by the U.S. Department of Energy (DOE) and the Gas Research Institute (GRI) that has been directed toward Rocky Mountain basins has resulted in technology improvements and identified several technology areas that promise to help convert more of these gas resources into reserves:

- Detection of naturally fractured high permeability areas
- Well log analysis
- Completion and stimulation procedures
- Infill development
- Recompletion of old wells
- Best practices to minimize costs

Concentrated efforts on these technology areas were successful at the Rulison Field in the Pieance Basin.[1,2]

In order to test the applicability of some of these technologies in the Appalachian Basin, the New York State Energy Research and Development Authority (NYSERDA) authorized Advanced Resources International, Inc. (ARI) to perform the technical analysis of this study. Belden & Blake Corporation (BBC) provided the study area, a 38,000 acre region in Chautauqua County, New York where over 200 wells produce gas from the low permeability Medina Group Grimsby and Whirlpool Formations. In return, pending positive results of the study, BBC agreed to test the study results by drilling a new well or recompleting an existing well. The index map of the study area is shown in Figure 1.

GEOLOGY AND ENGINEERING

THE MEDINA GROUP

The Group is part of the Silurian Niagran Provincial Series deposited along the northern rim of the Appalachian foreland basin. The region has a long history of geologic study, dating as early as the work of Amos Eaton in 1824. The Medina Group sediments were deposited in deltaic and shallow marine environments. The sequence from the Whirlpool Sandstone through the Grimsby Formation records an early Silurian marine transgression over the eroded Queenston deposits, followed by regression resulting from active progradation of the Medina fringe delta.[3] The Medina Group is the primary gas producing interval of western New York.

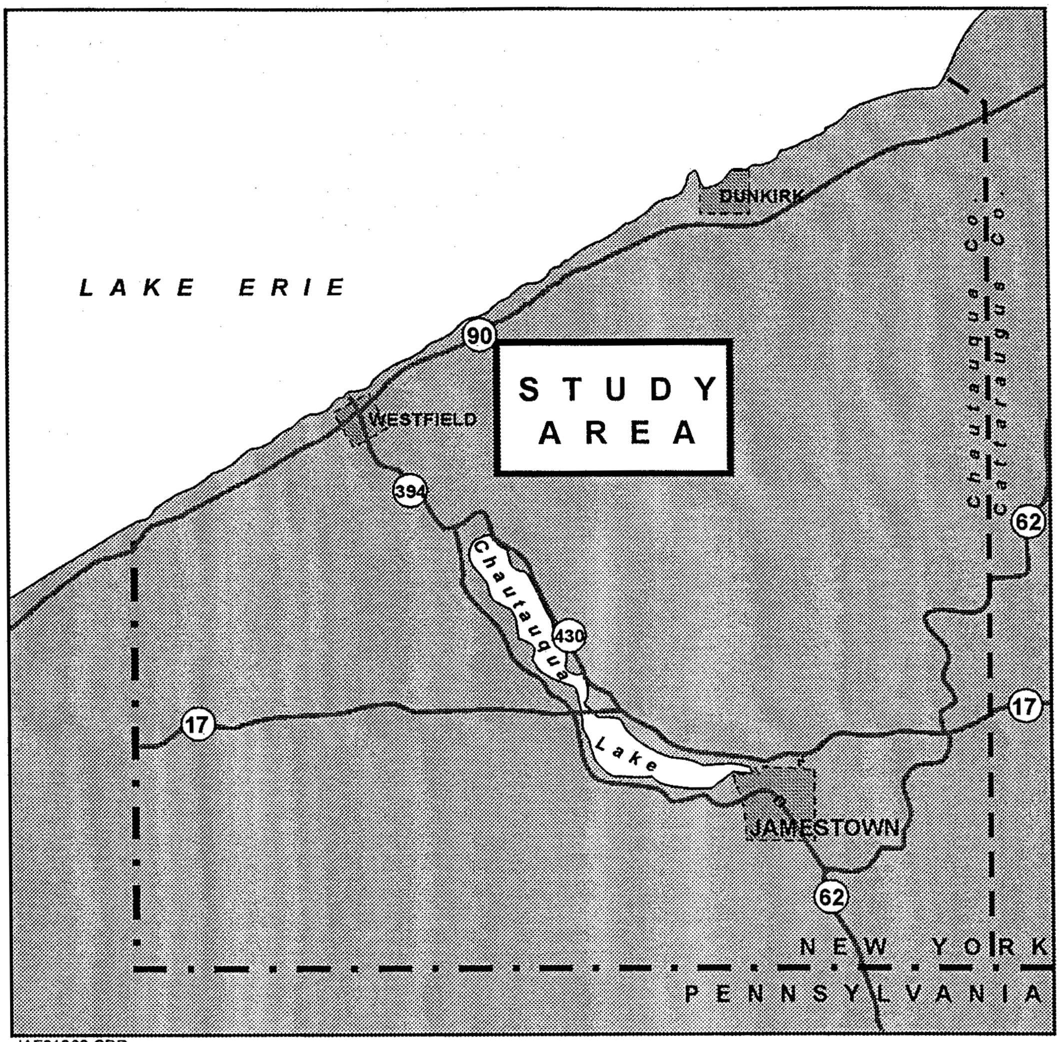

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Figure 1. Index Map of the Study Area

The Medina Group is widespread over New York, Pennsylvania, Ohio and West Virginia and the geologic terminology of the units within the Group are not consistently applied and may vary by geographic location. We have chosen to use local petroleum industry terminology, used by BBC, for these horizons. From the underlying Queenston Shale, the Medina succession is termed as Whirlpool Sandstone (WS), Cabot Head Shale (CH), Lower Grimsby (LG) and Upper Grimsby (UG). The Medina Group is overlain by the Packer Shell Lime (PS). The area correlation type log provided by BBC is the Bissel Babcock #2, shown in Figure 2. The first step in the project was to consistently correlate the well logs across the study area.

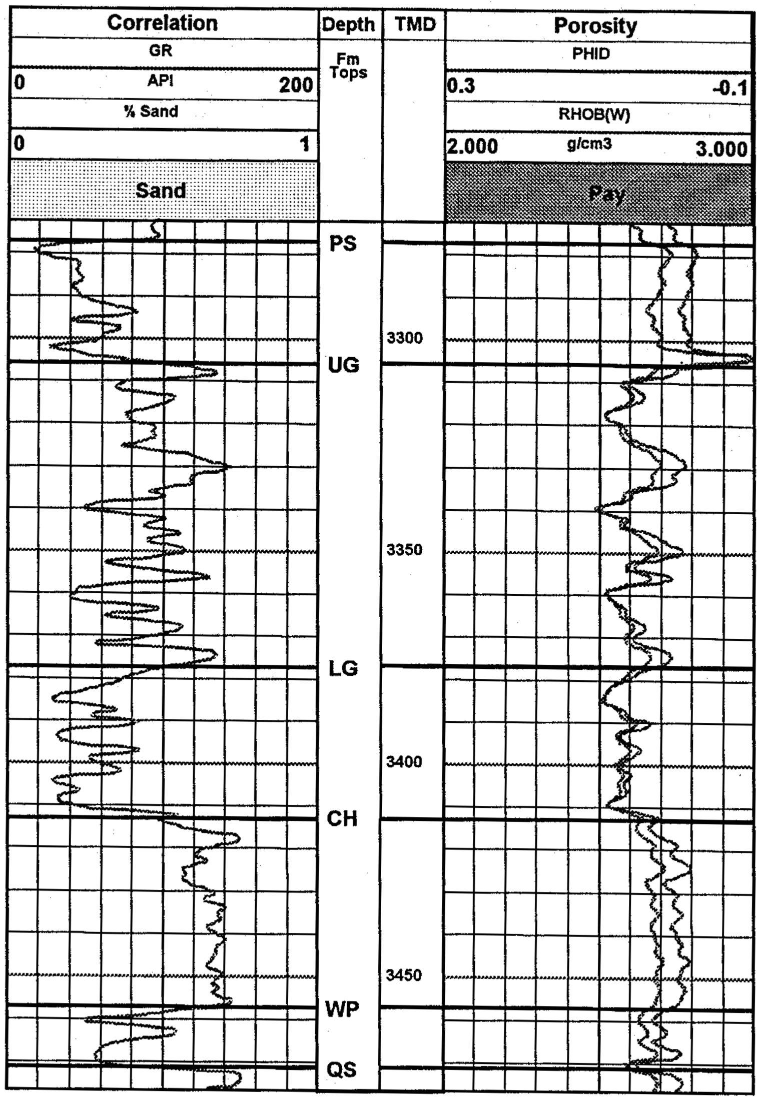

Figure 2. Correlation Type Log - Bissel Babcock #2.

Besides a type log, correlations imply a characteristic description for each interval or zone interface to clearly understand the intentions behind the work. The correlation descriptions used for the study are as follows, beginning at the top of the geologic sequence of interest:

<u>Packer Shell Top</u>

Is defined as the inflection of a sharp downward deflection of the gamma ray (GR), accompanied by an increase in the density log to ~2.8 g/cc, suggesting dolomite. This point was selected by ARI for the convenience of this study only, considering the limited section of log data available. It may not be consistent with other recognized correlations for the top of this unit. Packer Shell +/- 25 feet thick.

Packer Shell Base, Upper Grimsby Top

Is located at the inflection of a sharp upward deflection of the GR, confirmed by a sharp positive spike in density, often to a value of 3.0 g/cc. Ryder, et al. suggest the presence of iron enrichment as the cause of this log response. Below this point the relatively thinner bedded sand/shale sequence of the Grimsby begins. This point is normally easily identifiable. Upper Grimsby 50-75 feet thick.

Upper Grimsby Base, Lower Grimsby Top

This correlation point is not so readily apparent, but is taken to define the bottom of the last shale stringer of the Upper Grimsby. Below this point, the sequence of the Lower Grimsby generally has a cleaner, somewhat more thickly bedded GR signature, although still variable. Density values are slightly lower than above. Lower Grimsby 25-50 feet thick.

Lower Grimsby Base, Cabot Head Shale Top

This point is usually observed at the inflection of a positive GR deflection, starting a massive, uniform shale, referred to as the Cabot Head. However, this point is often obscured by the interfingering of one or more sand and shale stringers from the two units. These stringers may approach 10' in thickness each. Per definition for this study, the correlation point shall be at the base of the bottom 50% sandstone stringer. This allows all potential pay sand stringers to be included as part of the Grimsby and avoids considering potential pay zones in the Cabot Head Shale. Cabot Head 20-50 feet thick.

Cabot Head Base, Whirlpool Top

Is defined at the inflection of a sharp negative GR deflection, indicating a sharp contact from clean shale to clean sand. The Whirlpool is an easily identifiable marker due to its clean appearance, thinness, and a sharp return to massive shale below. Whirlpool Sandstone 8-20 feet thick.

Whirlpool Base, Queenston Top

Occurs at the inflection of a sharp positive GR deflection, indicating a sharp contact from clean sand to massive shale. The top of the Queenston is the base of the section for this study and continues off the bottom of the logs provided.

PETROPHYSICS

After well-to-well correlations were made, paper logs from 135 wells were digitized to create a petrophysical database. The typical log suite included gamma ray, compensated density and induction-laterolog curves, although not all wells have an induction-laterolog. Fortunately, most logs were run by the same service provider, Schlumberger, which allows for a higher degree of consistency both for making correlations and petrophysical analysis.

Percent sand was calculated from the gamma ray curve by selecting representative maximum and minimum values from each well as 100% shale and clean sand, respectively. Porosity was determined from the density log assuming a sand matrix density of 2.68 grams per cubic centimeter (g/cc). Water saturation was developed using the Archie equation assuming 1.0, 2.0 and 2.0 for a, m and n, respectively, as described in the nomenclature. Rw was selected as 0.04 ohm-m. Apparently, no formal petrophysical field study has been previously performed for the area. However, these assumptions were consistent with earlier hand calculations and acceptable to BBC. Analysis results from this model appeared reasonable, although possibly conservative, compared to a shaly sand dual water or Waxman-Smits model. Necessary data for this type of analysis was not available. The cutoffs used by BBC, 75% clean sand and 7% porosity were applied to the analysis to calculate net sand and net pay for the Whirlpool, Lower and Upper Grimsby. Results of a typical analysis from the Francis Winchell #1 well are shown in Figure 3. The analysis for each log used in the study appears in Appendix A.

Net sand and net pay zone averages for the 135 well petrophysical study are shown in Tables 1 and 2, respectively. Net-to-gross ratio for the Net Pay was only 8%. Net-to-gross ratio for the Net Sand was 26%. Compared to the average values of net pay, the net sand averages indicated a 240% greater net thickness and a 65% greater hydrocarbon pore thickness. From the above discussion, it is apparent that the application of log analysis cutoffs has a big impact on describing the portion of the Medina Group gas resource that contributes to reserves and production.

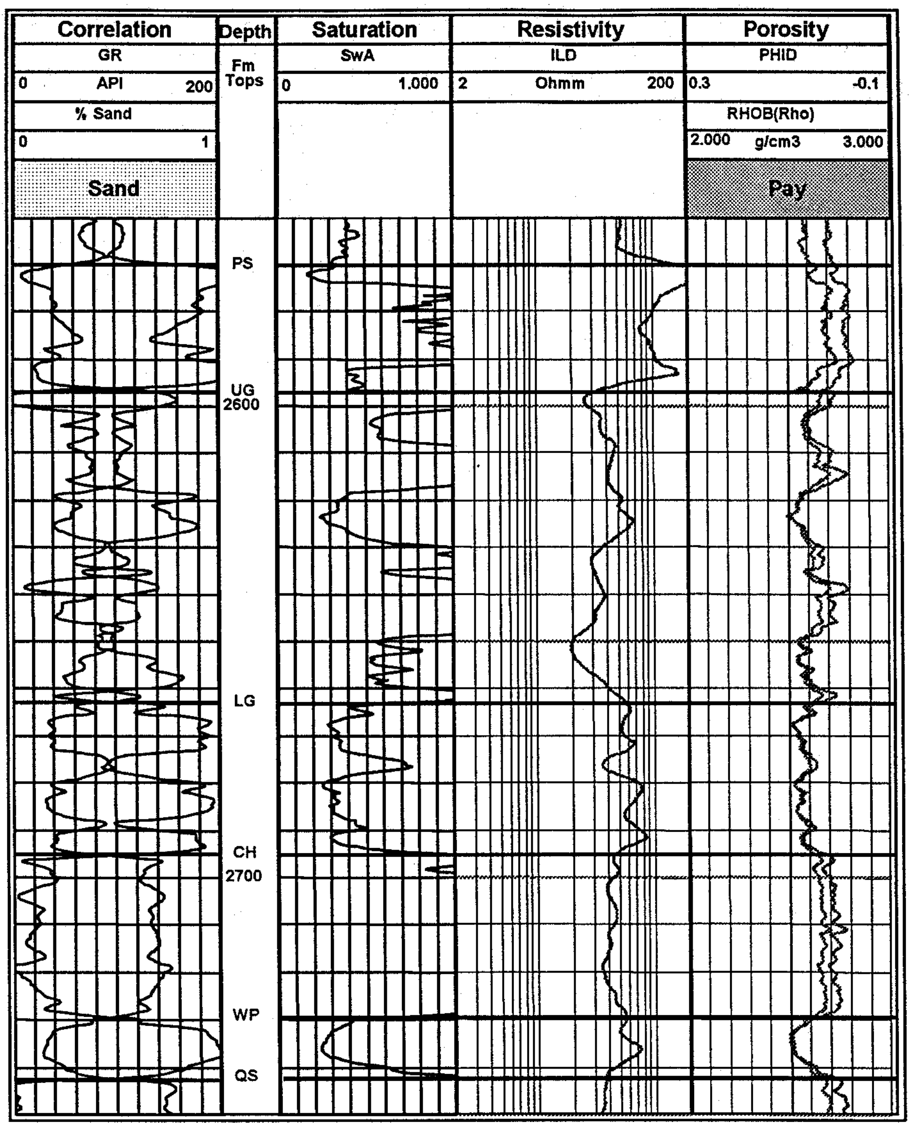

Figure 3. Typical Log Analysis Result, Francis Winchell #1.

Table 1. Net Sand Averages, 135 Wells

Zone	Gross Thickness (ft)	Net Thickness* (ft)	Net ϕ* (%)	Net S_W* (%)	Net Hyd-Pore-Feet (ft)
U. Grimsby	70.4	9.1	5.7	59	0.21
L. Grimsby	33.9	14.4	5.9	53	0.40
Whirlpool	13.3	7.3	6.3	61	0.18
Total/Avg.	117.6	30.8	6.0	58	0.79

**Net sand cutoff, 75% clean*

Table 2. Net Pay Averages, 135 Wells

Zone	Gross Thickness (ft)	Net Thickness* (ft)	Net ϕ* (%)	Net S_W* (%)	Net Hyd-Pore-Feet (ft)
U. Grimsby	70.4	2.5	8.1	43	0.12
L. Grimsby	33.9	3.8	8.0	37	0.20
Whirlpool	13.3	2.7	8.7	41	0.16
Total/Avg.	117.6	9.0	8.2	40	0.48

**Net pay cutoffs, 75% clean sands, 7% porosity*

Cutoffs are frequently determined as guidelines representing formation intervals that will produce water-free hydrocarbons, if perforated. It is easy to use such "net pay" thickness values for subsequently calculating the volume of gas in the reservoir and, with a recovery factor estimate, reserves. However, the same set of cutoffs is not necessarily applicable to both perforated interval and contributing reservoir, particularly in wells that are naturally or hydraulically fractured. The formation thickness that is representative for calculation of gas in place and reserves is frequently larger than perforating guidelines. This general observation is not new, but it is supported by ARI's previous experience in evaluating low permeability reservoirs in the Rocky Mountain basins. An argument for the existence of this condition in the Medina Group is supported by the completion of at least four wells in the study area that have zero net pay, yet were completed and produce; some of them better than many other wells. Therefore, the net pay might be considered as a conservative minimum basis for volumetric calculations.

PRODUCTION ANALYSIS

All the wells in the study were originally hydraulically fractured. Typically, the Whirlpool, Lower and Upper Grimsby were perforated and stimulated together and production is commingled. Hydraulically fractured wells during their producing life can pass through several flow regimes such as an initial clean up period, bilinear flow, linear flow, pseudo-radial flow and boundary affected flow.[4] Advanced type curve analysis, given adequate production and reservoir data, allows a determination of permeability-thickness product, Kh, fracture half-length, Xf, and drainage area, A.

Most wells in the area have been producing since the 1970's. However, ownership of the wells has changed hands several times and BBC acquired the wells relatively recently. Consequently, well data is frequently incomplete for events after the initial completion. Early life monthly production data is often lacking, with only annual totals available. In such cases, an average rate for the year was inserted as monthly data. Operational history is also incomplete. Specific information concerning downtime, workover data, changes in operating pressure, or changes in market conditions is generally not available.

Figure 4 shows the Claude Cranston #312 as a type curve match with typical data quality. Using the dimensionless rate and time match points together with thickness, porosity and water saturation determined from the petrophysical analysis, values for permeability, fracture half-length and drainage area are estimated. Figure 5 shows a relatively good quality match for the newer Eckert #2 well. Figure 6 shows the Van Dette #356 well that has large amount of data scatter. The quality of this type curve match is poor and the accuracy of the calculated results is therefore uncertain.

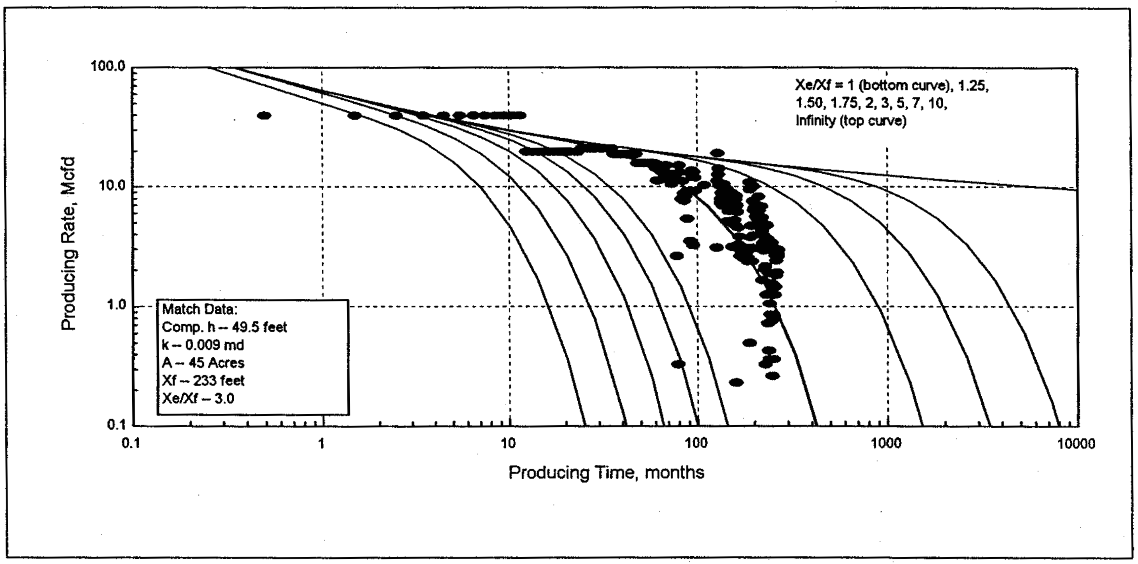

Figure 4. "Typical" Type Curve Match, Claude Cranston #312.

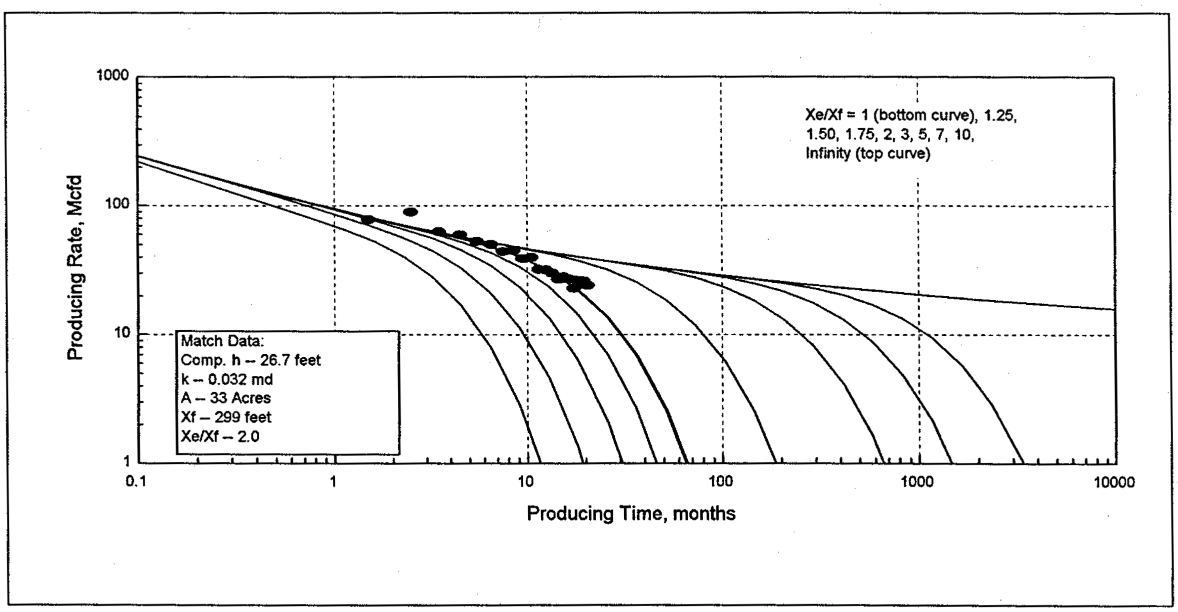

Figure 5. Good Type Curve Match for a Newer Well, Eckert #2.

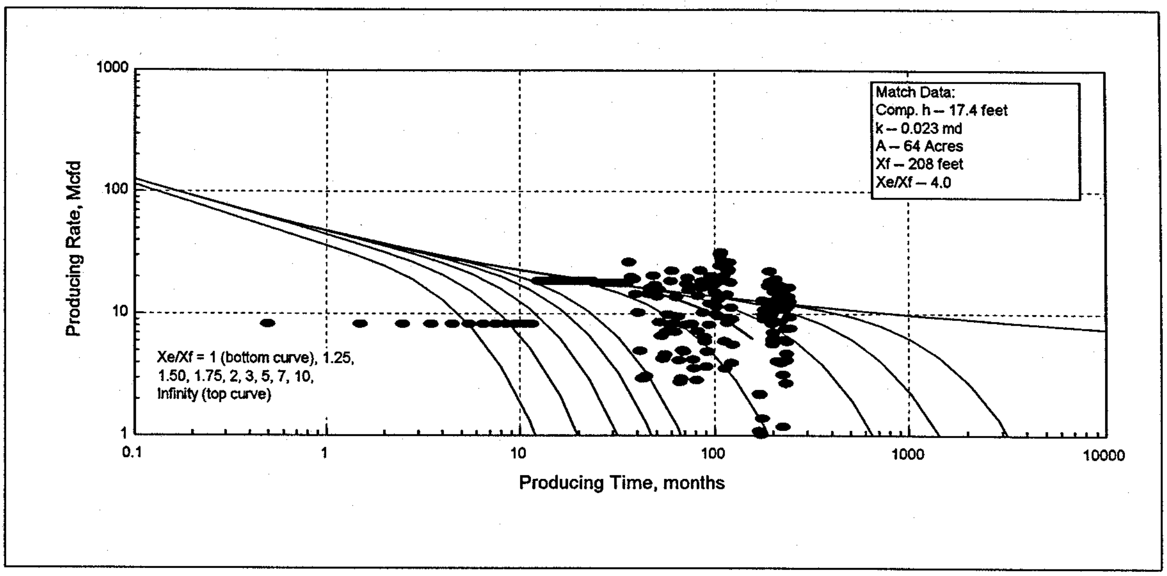

Figure 6. Example of Scattered Type Curve Data, Van Detta #356.

The above process was repeated for the 131 wells with production and petrophysical data. The incomplete early time (transient) production data hindered the analysis, particularly the estimation of fracture half-length. Effective reservoir thickness, as discussed in the petrophysics section, is also a source of uncertainty. Matching of the production data initially assumed net pay thickness. However, this resulted in large values for equivalent infinite conductivity fracture half-length that were not consistent with the reported size of the stimulations. Gross thickness was considered too optimistic as an estimate of effective reservoir. The production matches were repeated using net sand as a better estimate for reservoir thickness.

Results of this analysis for the 106 commingled wells indicated an average reservoir thickness of 31.7 feet and a permeability of 0.023 millidarcies. The estimated fracture half-length was 285 feet, which is still large compared to the size of the fracture treatments. Average drainage area was calculated to be 88 acres. Twenty-five wells, approximately 20% of the total, were completed only in the Grimsby Formation. Average results for this group were net thickness of 22.6 feet, permeability of 0.021 millidarcies and a fracture half length of 295 feet. Comparing the average results for the commingled wells to the Grimsby wells allows an indirect estimation of some of the Whirlpool Formation parameters. This resulted in an estimated average Whirlpool reservoir thickness of 9.1 feet and a permeability estimate of 0.029 millidarcies. Average values from the type curve analysis are summarized in Table 3.

Table 3. Average Values of Type Curve Analysis from 131 Wells

	Kh (md-ft)	H (ft)	K (md)	X_f (ft)	Area (Ac.)
Commingled Grimsby/ Whirlpool, 106 wells	0.73	31.7	.023	285	88
Grimsby Only, 25 wells	0.47	22.6	.021	295	99
Whirlpool*	0.25	9.1	.029		

*Inferred from difference calculation of the two groups above.

MAPPING

Besides petrophysics and production analysis, a third major task of the project was a thorough mapping exercise over the study area. More than 60 maps were created to take advantage of the well data, interval correlations, petrophysical analysis and type curve matching. Table 4 presents the list of the prepared maps. The maps appear in Appendix B. Note that each map shows the wells as circles of varying diameter. The size of the circle is representative of each wells estimated ultimate recovery (EUR) relative to the other wells in the study area. Red well symbols indicate Whirlpool and commingled Grimsby/Whirlpool completions. Blue well symbols indicate Grimsby only completions.

Table 4. Project Maps

Gross		**Net**	
Structure	6	Avg % porosity	4
Isopach	7	Avg % Sw	4
Porosity slice	5	Pay	4
% sand slice	5	Porosity-thickness	4
HPF	5	% sand of pay	4
	28	Sand thickness	4
Others		HPF	4
Base map w/ EUR	1	EUR/pay	1
Permeability	1		29
Drainage area	1	**Total 62 maps of the study area**	
Geophysical	2		
	5		

Structure and isopach for each horizon in the area were in agreement with regional trends. Medina structure gently dips to the southeast from –1,450 feet subsea in the northwest to –1,800 feet in the southeast corner of the study area, 11 miles away. Based on the well control, no significant structural closures were observed. Isopach of the Medina Group gradually thickens to the southeast from 130 feet in the northwest to approximately 160 feet in the southeast. Porosity, water saturation, percent clean sand and porosity-thickness maps of the net pay were also created. The correlation between these maps and reported production performance was poor. To help identify intervals that may better correlate with production trends, slice mapping techniques were employed. Two series of maps were made, porosity and percent sand. Values for both parameters were selected at 20 foot increments through the Grimsby Formation and contoured. Although the technique identified the generally better quality sand in the Lower Grimsby, a definitive correlation with production was not apparent.

Pay mapping showed better correlation with well performance. Net pay, net hydrocarbon pore-feet (HPF) and gross HPF maps were generated by zone. Figure 7 shows the net HPF map of the Whirlpool Formation with the EUR values for each well superimposed as a bubble map. With the exception of a few stronger wells in the northeast of the study area, higher EUR values correlate with Whirlpool hydrocarbon concentration. A similar correlation is observable in the Whirlpool Net Sand Thickness map. When viewing that map in Appendix B, note that there are virtually no strong producers in areas where there is less than six feet of net Whirlpool sand. Conversely, there is not a good correlation of EUR with the Grimsby Net HPF or net sand thickness maps. In those areas of Grimsby pay concentration where there is not also a Whirlpool pay concentration, the wells are poor producers. None of the 25 Grimsby-only completions, several of which are completed in areas of Grimsby pay concentration, are among the top 10% of study area wells in terms of estimated EUR, and only two Grimsby-only wells are in the top 25%.

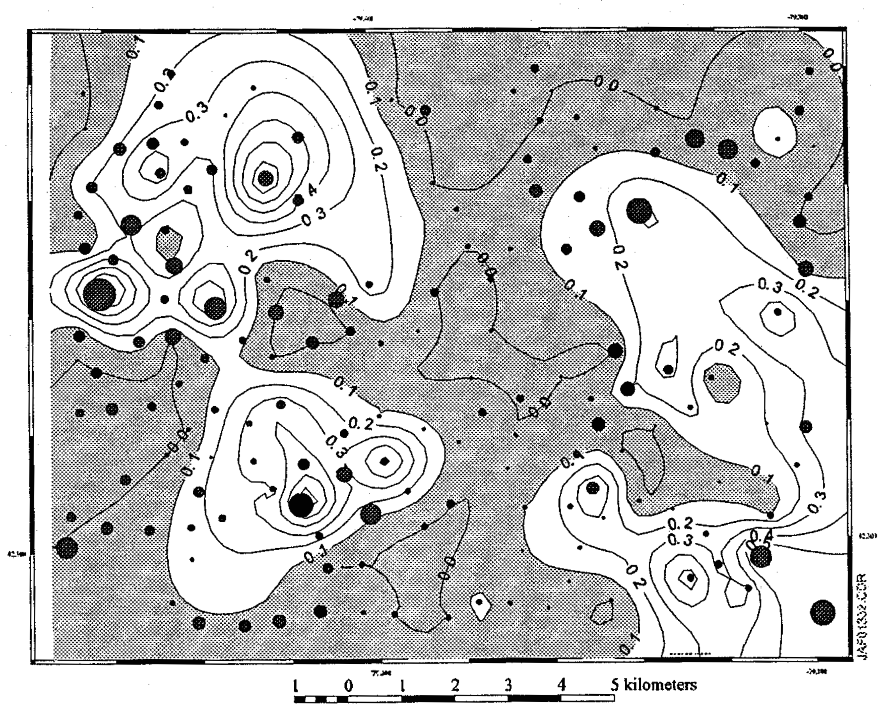

Figure 7. Net Hydrocarbon Pore Feet, Whirlpool Formation. Contour Interval = 0.1 ft.

Figure 8 shows the estimated average permeability map as determined from the type curve analysis. Again, the EUR bubble map is superimposed. Although the average well permeability in the study is 0.023 md, there are areas of significant variation. The correlation between permeability and EUR is very good. Although there are numerous weak producers in higher permeability areas, all wells with an EUR greater than 200 MMCF (21 of 131 wells) are located in areas with a permeability greater than 0.02 md. Note that the previously referenced wells with high EUR in the northeast part of the study area that do not correlate with good concentration of HPF do have the highest estimated local permeability.

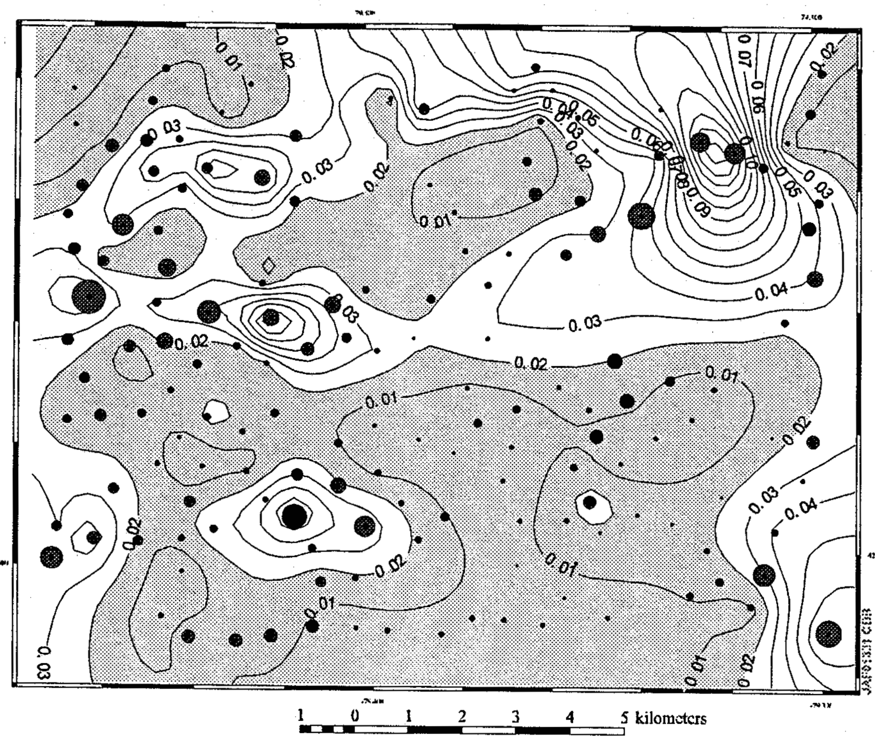

Figure 8. Estimated Average Permeability, Total Well. CI = 0.01 md.

VOLUMETRICS

Volumetric estimates of gross gas in place were made based upon petrophysics, the mapping exercise and initial reservoir pressure. Gross initial gas in place (IGIP) was an estimated 5.1 MMSCF per acre; 193 BSCF for the 38,000 acre study area. Use of the net sand cutoffs reduces these numbers to 2.7 MMSCF per acre and 102 BSCF, respectively. Net pay cutoffs further reduce volumes to 1.6 MMSCF per acre and 60 BSCF. An accounting of the volumetrics is given in Table 5. Note that 84% of the gross IGIP is in the thicker Grimsby Formation with only 16% in the Whirlpool sand. However, as the increasingly stringent net sand and net pay cutoffs are applied, the percentage of IGIP increases from 16% to 25% and then to 32% for the much thinner, but more concentrated, Whirlpool sand.

Table 5. Project Area Volumetrics

Zone	Gross			Net Sand			Net Pay		
	IGIP (BSCF)	IGIP/Ac (MMscf /Acre)	%	IGIP (BSCF)	IGIP/Ac (MMscf /Acre)	%	IGIP (BSCF)	IGIP/Ac (MMscf /Acre)	%
Grimsby	162.4	4.3	84	76.4	2.0	75	40.8	1.1	68
Whirlpool	30.3	0.8	16	25.4	0.7	25	19.2	0.5	32
Summary	192.7	5.1	100	101.8	2.7	100	60.0	1.6	100

NEW WELLS

LOCATION SELECTION

The hope of the initial project proposal was to identify one justifiable drilling or recompletion candidate. Based on the results of mapping the geologic and engineering parameters such as isopach, net pay and HPF, discussion between BBC and ARI revealed several potential new well locations. Additional considerations for location selection included good offset well production, BBC lease position and location access. To accommodate the summer drilling weather window, four new well locations were selected and internally justified before the production analysis was completed. Only local permeability and drainage area estimates of key wells adjacent to the new locations were available to help confirm the selection process. The wells were drilled in September and October 1998. Completion of the production analysis later provided more complete estimates and maps of permeability and drainage area, as shown in Figures 8 and 9, respectively. Note that Figure 9 is a bubble map showing the estimated relative sizes of the drainage areas of the wells. The new well locations are also posted on this map. Also note that the sizes of the bubbles on Figure 9 are relative drainage area sizes only and do not correspond with the well's estimated drainage areas in acres.

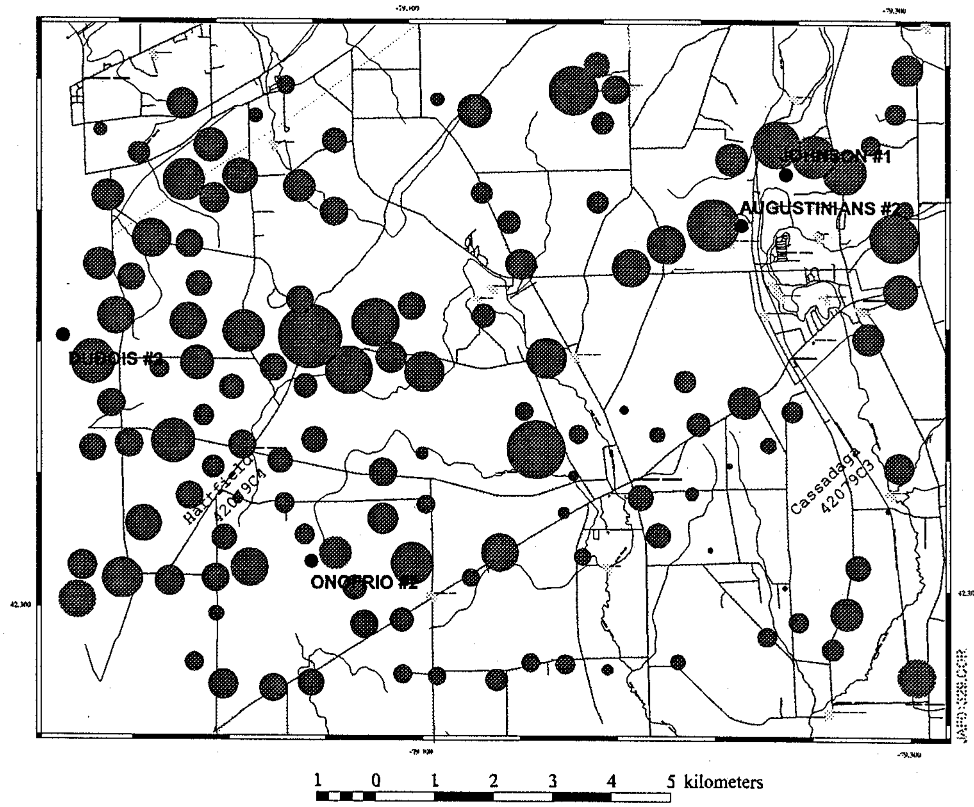

Figure 9. Relative Sizes of Estimated Drainage Areas.

NEW WELL RESPONSE

After drilling, the project called for six months of production monitoring and type curve matching of the data. Electric logging of the wells showed results that were in agreement with the geologic prognosis that was based on the new maps. However, resistivity logs were not run in the wells, a common practice in the area, and thus, reliable water saturation estimates are not available. Permeability of the new wells is good, based on the type curve match of the limited early production data. Results of the type curve matches are summarized in Table 6. The type curve matches of weekly production for the four new wells are shown in Figures 10 to 13. Generally, the quality of the matches is good, considering the limited producing life of the wells. Additional monitoring and an updated match are necessary before the results could be considered definitive. This is especially true of the well Augustinians #2, which appears to be just beginning its transition from transient behavior to decline.

Table 6. Results of Type Curve Matches from New Wells

	Kh (md-ft)	H (ft)	K (md)	Xf (ft)	Area (Ac.)
Augustinians 2	3.84	32	0.12	288	68
Dubois 2	1.82	13	0.14	218	39
Johnson 1	9.62	37	0.26	136	15
Onofrio 2	2.88	24	0.12	205	35

The most intriguing aspect of the new wells is that they all showed varying degrees of depletion. Initial pressure in the area ranged from 900 to 1,050 psi, but estimated reservoir pressure of the new wells varied from 250 to 750 psi. This is at variance with the calculated drainage areas of the project area wells. The estimated average drainage area from type curve matching was 90 acres with a range from 6 to 310 acres. Nominal well spacing in the study area is 176 acres. Based on the initial analysis assumptions, the new wells should have encountered higher pore pressure. Because of the reduced reservoir pressure, production results have been disappointing.

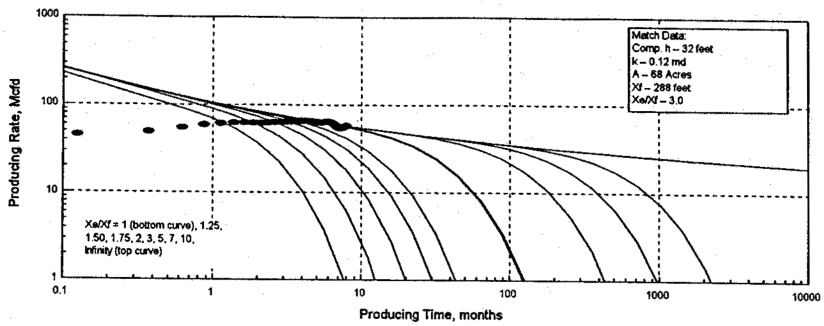

Figure 10. Type Curve Match of Weekly Data, 3 Point Smoothing, Augustinians #2.

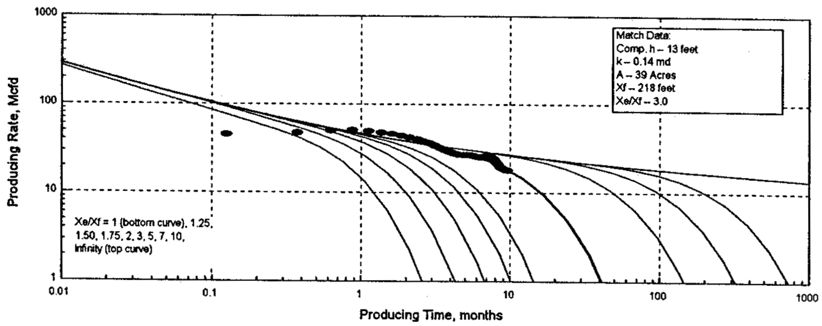

Figure 11. Type Curve Match of Weekly Data, 3 Point Smoothing, Dubois #2.

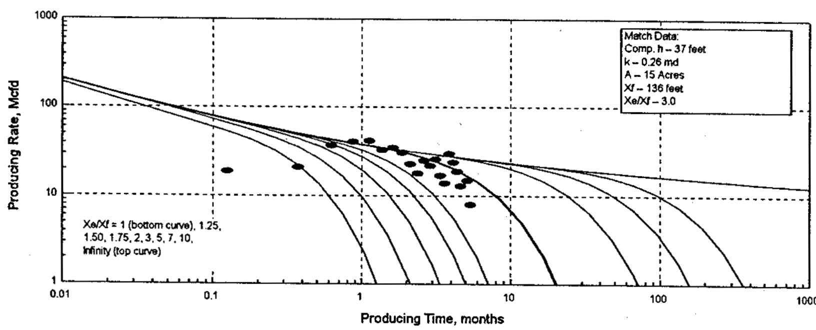

Figure 12. Type Curve Match of Weekly Data, No Smoothing, Johnson #1.

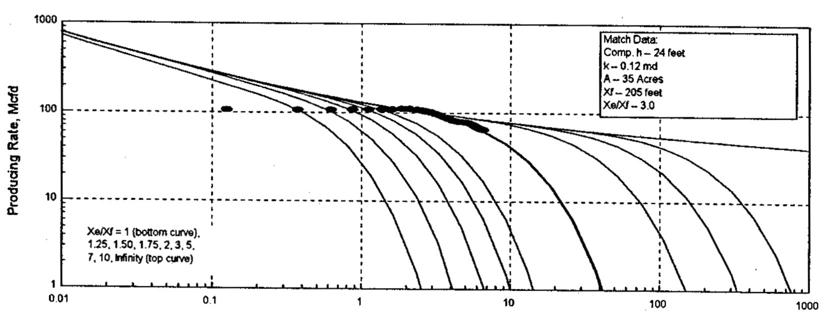

Figure 13. Type Curve Match of Weekly Data, 3 Smoothing, Onofrio #2.

DISCUSSION OF RESULTS

Eighty percent of the wells in the area are commingled producers. The average drainage area of these wells was determined to be 88 acres. Considering this and that the nominal well density in the area of 176 acres, there should be opportunities for infill drilling. However, the results from the new wells were disappointing. Observations from the project work and field results warrant further discussion. Key elements of the discussion are the several volumetric estimates of gas in place that can be calculated and production performance of the Whirlpool Formation compared to the Grimsby. It should be kept in mind when reading the following discussion that the volumes, pressures and recovery factors given are *average* values for the entire study area. Conditions in intensively developed areas may be significantly different from less developed areas.

The most appropriate criteria to estimate the gas in place as a basis for reserves and drainage of the resource remain uncertain. Production history for the BBC project wells indicates a cumulative recovery of 13.6 BCF from 160 wells. Estimated combined EUR for these wells is 16.6 BCF. Since gas in place estimates are made for the entire 38000 acre study area, the above listed numbers should be scaled up to be representative all of the wells (216) producing from the study area. The scaled estimates for cumulative production and EUR are 18.4 and 22.4 BCF, respectively.

A comparison of the above numbers with the gross IGIP estimate of 193 BCF suggests a very low overall recovery factor of 12%. This is not consistent with the reduced pressures encountered in the new wells and suggests that gross IGIP is too optimistic as a basis for estimating the fraction of the resource that is effectively contributing to production and reserves.

Net pay has historically been used as a guideline for perforating and completion design. Therefore, the net pay IGIP of 60 BCF might be considered a reasonable basis from which to estimate production and reserves. The EUR of 22.4 BCF then suggests an overall recovery factor of 37% for the current development. However, a few wells that have no net pay have been completed and they produce commercial gas quantities. Also, decline curve matching results indicated that the use of net pay thickness in the calculations resulted in very long fracture half-length estimates. This forced a re-calculation of parameters using the less restrictive net sand parameters. These observations suggest that the established net pay cutoffs may be slightly conservative as a basis for estimating production and reserves.

The net sand IGIP volume of 101.8 BCF is an intermediate estimate. 76.4 BCF is attributed to the Grimsby and 25.4 BCF to the Whirlpool. If 101.8 BCF is considered as the basis for estimating production and reserves, the overall recovery factor would be 22% for the current development.

A review of type curve matching results summarized in Table 3 suggests that the Whirlpool may have, on average, 36% of a commingled well Kh. This percentage is higher than the Whirlpool's share of the IGIP estimates. The Whirlpool has only 16% of the gross IGIP, 25% of the net sand IGIP and 32% of the net pay IGIP. Also, it is apparent from reviewing the well logs and completion records that there are noteworthy differences in reservoir quality. When the more concentrated Whirlpool accumulation is perforated and stimulated, virtually the entire reservoir thickness is in contact with the well. The same cannot be said for all Grimsby completions where typically only a few feet of this thicker, more dispersed accumulation is perforated. The effectiveness of Grimsby stimulations in contacting the entire accumulation is therefore less certain. Thus, a lower recovery factor might be expected from the Grimsby. Also, recall the earlier observation that better production levels are associated with mapped concentrations of gas in the Whirlpool. From this list of evidence, it is reasonable to assume that the Whirlpool is contributing a disproportionate share of well production.

Under these conditions, differential depletion of the Whirlpool would appear to be occurring. From early wellhead pressure data recorded at the start of production for the new wells, estimated average formation pressure was 515 psig. In the case of commingled production wells, a short-term "measured" reservoir pressure is normally representative of the lower pressure layer due to differences in permeability and crossflow effects in the wellbore. A reduction in Whirlpool average pressure to 515 psig implies a corresponding change in the gas formation volume factor, B_g, and gas in place. Thus, approximately a 52% recovery has been achieved from the volume of gas that is effectively contributing to production and reserves. This recovery factor was caused by an unknown fraction of the cumulative commingled production of 18.4 BCF.

The initial gas in place estimates for the Whirlpool are 30.3, 25.4 and 19.2 BCF for the gross, net sand and net pay, respectively. The corresponding 52% recovery volume for each estimate is 15.8, 13.2 and 10.0 BCF, respectively. Subtracting these numbers from the 18.4 BCF cumulative production leaves 2.6, 5.2 and 8.4 BCF of production from the Grimsby for the gross, net sand and net pay cases, respectively. The contribution of Whirlpool production for each case would be 86, 73 and 54 percent for the gross, net sand and net pay, respectively. The Grimsby would contribute the remaining fraction. It has been previously noted that wells completed only in the Grimsby are weaker producers. However, these Grimsby-only producers are not so weak as to suggest that when commingled with the Whirlpool the Grimsby would produce only 14 percent, or even 27 percent, of commingled well total. Therefore, the possible relative production split of 54/46 percent for the Whirlpool / Grimsby that would be associated with the net pay case appears to be the most appropriate. This implies 8.4 BCF of production from the Grimsby net pay, which had an IGIP of 40.8 BCF. The current recovery factor for the Grimsby would therefore be about 21 percent. Using the remaining gas in place to recalculate the pressure associated with the formation volume factor yields an average reservoir pressure of about 800 psi. This pressure, 800 psi, is perhaps a surprisingly high estimate. Again, it is important to keep in mind that this estimate is based on the most conservative IGIP volume, net pay and represents average value for the entire study area where the effectiveness of current completions to contact and drain all Grimsby pay may be less than perfect. Please refer to Table 7, which summarizes the above depletion scenario for the net pay.

Table 7. Net Pay Depletion Scenario

	Grimsby	Whirlpool	Total
1/Bg (Scf/ft^3), Initial	75	75	75
1/Bg (Scf/ft^3), 515 psig		36	
Recovery Factor (%)		52	
Net Pay IGIP (BSCF)	40.8	19.2	60.0
Recovery (BSCF)		10.0	
Production Distribution (BSCF)	8.4	10.0	18.4
Production Distribution (%)	46	54	100
Recovery Factor (%)	21		
1/Bg (Scf/ft^3)	59		
Pressure (psig)	800		

CONCLUSIONS

Unified petrophysical analysis combined with thorough mapping of the project area identified numerous possibilities for new drilling. Four new wells were drilled. The reservoir properties encountered by the new wells supported field mapping results. However, the new wells also encountered partial reservoir depletion and production has been disappointing . Additional consideration of permeability distribution, local density of existing wells and their completions and differential depletion may improve future drilling efforts.

Good production performance of commingled Medina wells is strongly associated with Whirlpool Formation HPF mapping that identifies hydrocarbon concentration. Grimsby Formation HPF maps do not correlate as well with performance. This contrasts with the fact that 84% of the gross gas in place is in the Grimsby.

Good production performance is also associated with high permeability sweet spots that do not necessarily conform to hydrocarbon concentration.

Differential depletion of the Whirlpool Formation is probable, with the implied less efficient drainage of the lower permeability and more vertically dispersed Grimsby accumulation. An estimated average Whirlpool formation pressure of 515 psig implies a current recovery factor of 52 percent. An estimated average Grimsby formation pressure of 800 psig implies a current recovery factor of 21 percent. Additional investigation of layered-no-crossflow reservoir behavior in the Medina is justified. Due to the apparent low recovery factor in the Grimsby, significant potential may exist for recompletions or additional drilling.

Gross gas in place is an estimated 5.1 MMCSF per acre, yielding a gross gas in place of 193 BCF for the 38,000 acre study area. The application of net pay cutoffs of 75% clean sand and 7% porosity reduces the net gas in place to 1.58 MMSCF per acre, yielding a net gas in place of 60 BCF for the 38,000 acre study area.