Solving the Shugart Queen Sand Penasco Unit Declining Production Problem

Contract No. DE-FG26-99BC15245

MNA Enterprises LTD. Co.
106 West Alabama
Hobbs, NM 88242
505-392-2702

Final Report
August 25, 2000

Prepared by: Lowell Deckert, Principal

Solving the Shugart Queen Sand Penasco Unit Declining Production Problem

Abstract

The Penasco Shugart Queen Sand Unit located in sections 8, 9, 16 & 17, T18S, 31E Eddy County New Mexico is operated by MNA Enterprises Ltd. Co. Hobbs, NM. The first well in the Unit was drilled in 1939 and since that time the Unit produced 535,000 bbl of oil on primary recovery and 375,000 bbl of oil during secondary recovery operations that commenced in 1973. The Unit secondary to primary ratio is 0.7, but other Queen waterfloods in the area had considerably larger S/P ratios. On June 25 1999 MNA was awarded a grant under the Department of Energy's *Technology Development with Independents* program. The grant was used to fund a reservoir study to determine if additional waterflood reserves could be developed.

A total of 14 well bores that penetrate the Queen at 3150 ft are within the Unit boundaries. Eleven of these wells produced oil during the past 60 years. Production records were pieced together from various sources including the very early state production records. One very early well had a resistivity log, but nine of the wells had no logs, and four wells had gamma ray-neutron count-rate perforating logs.

Fortunately, recent offset deep drilling in the area provided a source of modern logs through the Queen. The logs from these wells were used to analyze the four old gamma ray-neutron logs within the Unit. Additionally the offset well log database was sufficient to construct maps through the unit based on geostatistical interpolation methods.

The maps were used to define the input parameters required to simulate the primary and secondary producing history. The history-matched simulator was then used to evaluate four production scenarios. The best scenario produces 51,000 bbl of additional oil over a 10-year period. If the injection rate is held to 300 BWPD the oil rate declines to a constant 15 BOPD after the first year. The projections are reasonable when viewed in the context of the historical performance (~30 BOPD with a ~600 BWPD injection rate during 1980-1990). If an additional source of water is developed, increasing the injection rate to 600 BWPD will double the oil-producing rate.

During the log evaluation work the presence of a possibly productive Penrose reservoir about 200 ft below the Queen was investigated. The Penrose zone exists throughout the Unit, but appears to be less permeable than the Queen. The maps suggest that either well 16D or 16C are suitable candidates for testing the Penrose zone.

Volume I
Table of Contents

Volume I
Discussion and Engineering Methodolgy
Solving the Shugart Queen Sand Penasco Unit Declining Production Problem

Summary

The Penasco Shugart Queen Sand Unit located in sections 8, 9, 16 & 17, T18S, 31E Eddy County New Mexico is operated by MNA Enterprises Ltd. Co. Hobbs, NM. The first well in the Unit was drilled in 1939 and since that time the Unit produced 535,000 bbl of oil on primary recovery and 375,000 bbl of oil during secondary recovery operations that commenced in 1973. The Unit secondary to primary ratio is 0.7, but other Queen waterfloods in the area had considerably larger S/P ratios. On June 25 1999 MNA was awarded a grant under the Department of Energy's *Technology Development with Independents* program. The grant was used to fund a reservoir study to determine if additional waterflood reserves could be developed.

A total of 14 well bores that penetrate the Queen at 3150 ft are within the Unit boundaries. Eleven of these wells produced oil during the past 60 years. Production records were pieced together from various sources including the very early state production records. One very early well had a resistivity log, but nine of the wells had no logs, and four wells had gamma ray-neutron count rate perforating logs.

Fortunately, recent offset deep drilling in the area provided a source of modern logs through the Queen. The logs from these wells were used to analyze the four old gamma ray-neutron logs within the Unit. Additionally the offset well log database was sufficient to construct maps through the unit based on geostatistical interpolation methods.

The maps were used to define the input parameters required to simulate the primary and secondary producing history. The history matched simulator was then used to evaluate four production scenarios. The best scenario produces 51,000 bbl of additional oil over a 10-year period. If the injection rate is held to 300 BWPD the oil rate declines to a constant 15 BOPD after the first year. The projections are reasonable when viewed in the context of the historical performance (~30 BOPD with a ~600 BWPD injection rate during 1980-1990). If an additional source of water is developed, increasing the injection rate to 600 BWPD will double the oil producing rate.

During the log evaluation work the presence of a possibly productive Penrose reservoir about 200 ft below the Queen was investigated. The Penrose zone exists throughout the Unit, but appears to be less permeable than the Queen. The maps suggest that either well 16D or 16C are suitable candidates for testing the Penrose zone.

Introduction

The focus of this report is Shugart the Queen Sand Penasco Unit, however early in the course of the study the possibility of a productive interval 200 ft below the Queen was detected. Discussion of this Penrose interval is included in this report. This final report consists of two volumes. Volume I contains the text of the discussion and Volume II contains the color geologic maps.

The Shugart Queen Sand Penasco Unit at 3150-ft depth is located in sections 8, 9, 16, and 17 in T18S, R31W in Eddy County NM. The location cartoon seen in Fig. 1 depicts the location of the Shugart Queen Pool. The Penasco Unit is within the Pool boundaries.

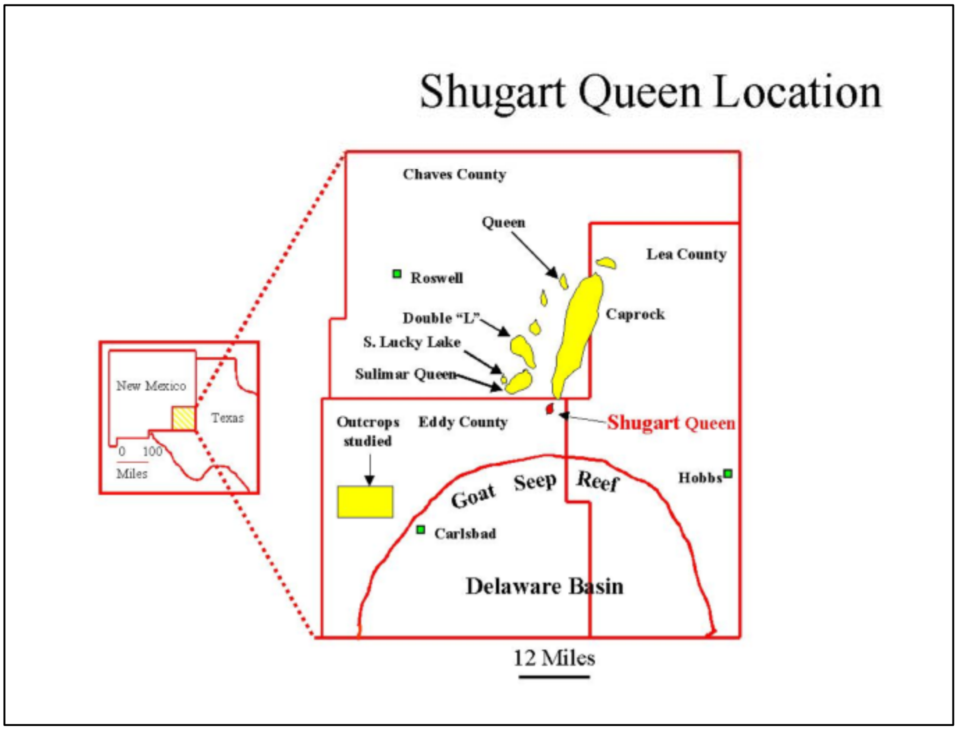

Figure 1. Project Location.

The economic limit of the Penasco Unit is approaching, but a recent DOE publication AIntegration of Advanced Geoscience and Engineering Techniques to quantify Interwell Heterogeneity in Reservoir Models@ suggests that considerable reserves may not be recovered under the current reservoir management scenario. The historical production information seen in Fig. 2 supports the issue of increasing ultimate recovery. The Unit oil rate appears to be a function of the injection rate as seen in Fig. 2 where the decrease in the injection rate is followed by a reduced oil rate. Cumulative oil produced through 1994 was 779,060 barrels according to public records.

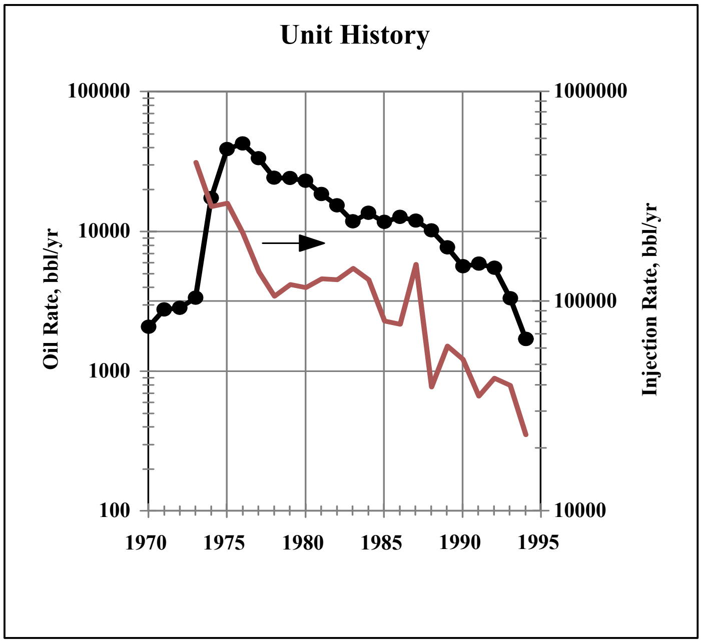

Figure 2. Production/Injection History.

The production records are summarized in Table I. The table includes information from the previously mentioned DOE Sulimar Queen study. The Sulimar Queen is located about 20 miles northwest of Shugart Penasco Queen Unit.

Table I
Production Parameters

	Primary bbl	Secondary bbl	S to P Ratio	Injection bbl	Injection to Primary Production Ratio
Sulimar	532,000	1,482,000	2.8	10,425,000	19.6
Shugart	535,000	244,000	0.5	2,800,000	5.2

The prospect of additional recovery prompted MNA to submit a proposal to the DOE's *Technology Development with Independents* program. The project was awarded a grant to evaluate the future of the 27-year-old Penasco Unit waterflood. The objective of this study is to develop a base case for the future and three different reservoir management scenarios.

Background

Primary production from the Penasco Unit Queen Sand commenced in 1939, followed by a waterflood in 1973. A total of 14 wellbores were drilled through the Queen prior to advent of modern logging techniques. Only four Unit wells had useful logs from which gross thickness could be estimated. Fortunately, recent deep drilling in the offset area provided a source of modern logs through the Queen. Unit well 9N2 has modern logs. The logs from the offset wells were used to analyze the available gamma ray-neutron perforating logs. Porosity and water saturations were calculated from the modern logs as well as 4 Unit wells. A total of 38 well logs were available as database for a geostatistical interpolation of thickness, porosity, and water saturation values throughout the Unit. The location of the wells is seen in Fig. 3. Wells located with a white dot have no logs.

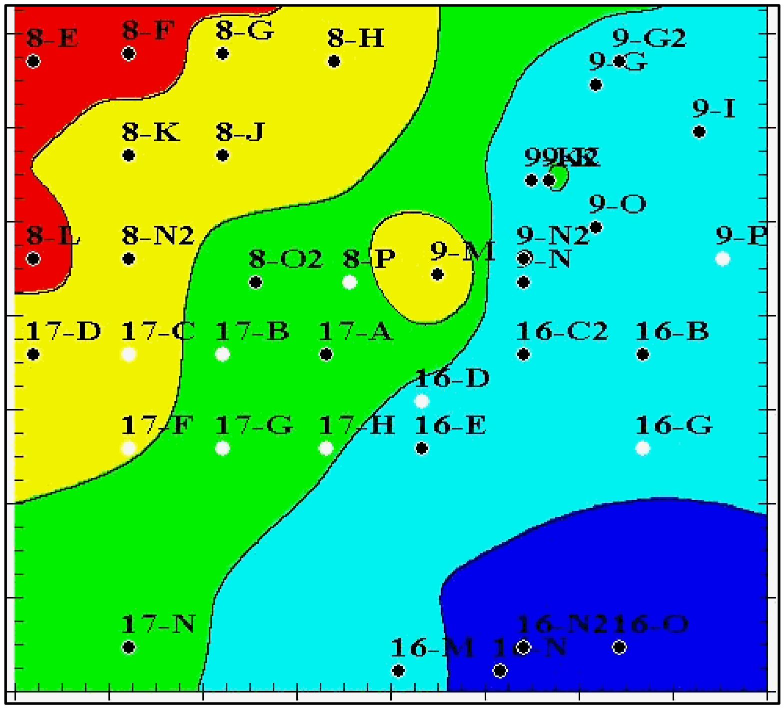

Figure 3. The 14 Unit wells are 8O2, 8P, 9M, 9N, 9N2, 16C2, 16D, 16E, 17A, 17B, 17C, 17F, 17G, and 17H.

The geostatistical maps were used to define the input parameters required to simulate the primary and secondary producing history of 13 wells that produced more than 1000 bbl in the Unit.

During the log evaluation work the presence of a possibly productive Penrose reservoir about 200 ft below the Queen was investigated. Many of the Unit wells penetrated the Penrose, but drill stem tests were not reported or were negative.

Log Evaluation

The neutron porosity log from well 9N2 was converted to a neutron count rate format (NCR). The NCR and the gamma ray log were used to train a neural network to predict the cross-plot (M_N & M_D) porosity through the same zone. Illustrated in Fig. 4 are the predicted values based on the 9N2 trained neural network used to predict the actual cross-plot (M_N & M_D) values from another well (9B). The uncompensated neutron porosity and gamma ray logs were from well 9B were used as the input for to the trained neural network. Notice that the predicted values are very close to the measured cross-plot values. Thus, the goodness of the neural network as a predictive tool when only gamma ray and NCR logs are available is validated.

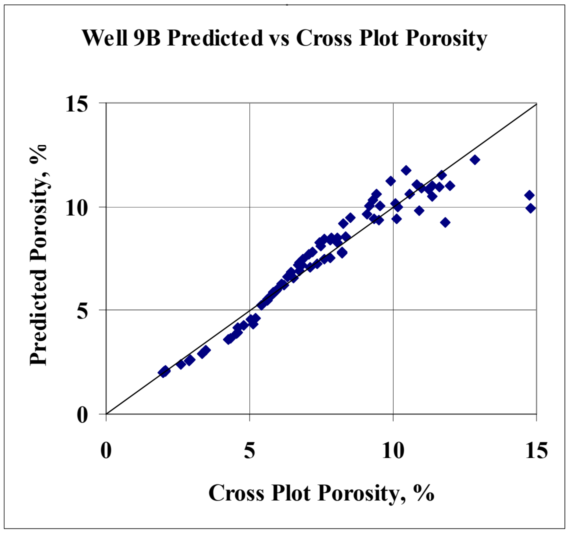

Figure 4. Gamma Ray and NCR Logs Used to Predict Porosity.

The trained Neural Network was used to estimate the porosity of the Queen interval of wells that did not have modern logs. The neural network was used to estimate porosity from the gamma ray and NCR log from well 16M. In Fig. 5 the predicted porosity is compared to limited core data from the same well. It appears that the core depth is 5 ft off the log depth. The agreement is good considering that the core porosity varies from 8-12%.

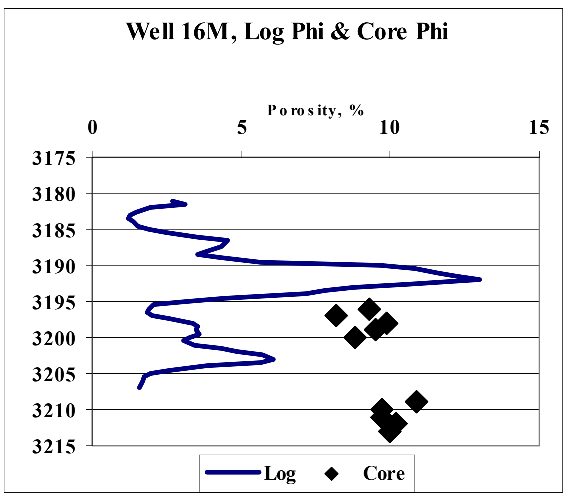

Figure 5. Neural Net Predicted Porosity & Core Porosity.

Permeability was correlated with porosity using the relationship seen in Fig. 6. The regression equation in the lower left-hand corner is based on 183 Queen core samples. Notice that permeability-porosity values from a 10-ft core cut from well 16M are included on the chart and agree well with the other values.

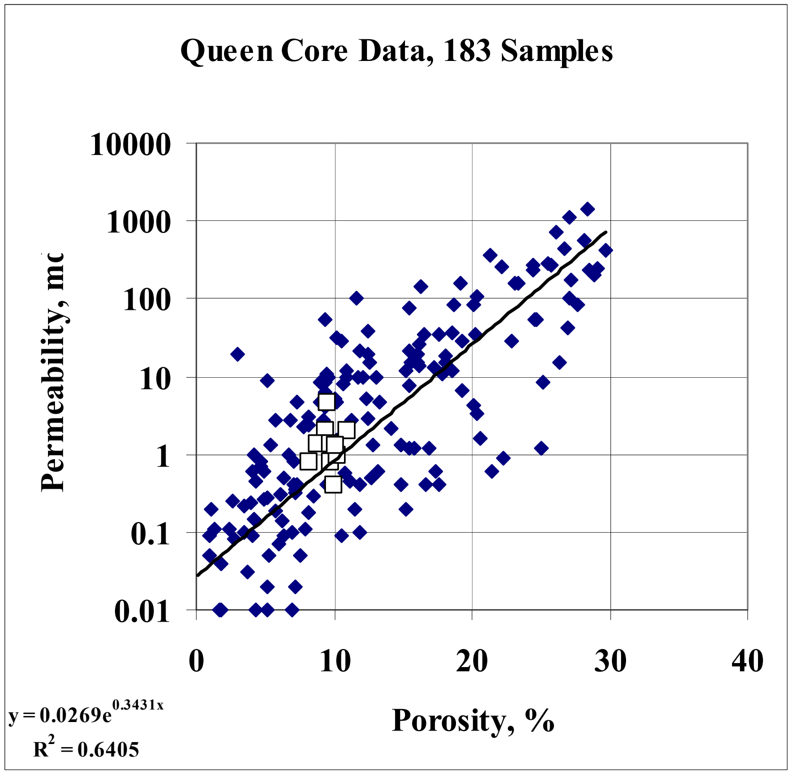

Figure 6. Permeability versus Porosity Based on Core Measurements. Open Boxes are from Well 16M Core.

Water saturations were difficult to estimate. Estimates based on Archie's equation using a 4.0 ohm-meter Rw from a Pickett Plot of porosity versus deep resistivity resulted in a maximum Queen interval Sw value of 15% that experience suggests is too conservative even though the Unit wells reportedly did not produce water during the primary producing period. A Eumont, Penrose zone neural network trained to predict water saturation given gamma ray and NCR logs also indicated very conservative Sw values.

Core water saturation measurements from 70 Queen samples cut prior to waterflooding the Double L Queen field are plotted versus core permeability in Fig. 7. The Sw values from well 16M are included in the figure as open boxes. Notice that the 16M values fall below the Double L Queen best-fit line. A parallel line through the 16M data points intercepts 1.0 md at 38% rather than the 57% Double L Queen intercept. The Double L Queen regression equation was used with a 38% Sw intercept was used to estimate the Queen interval initial water saturations.

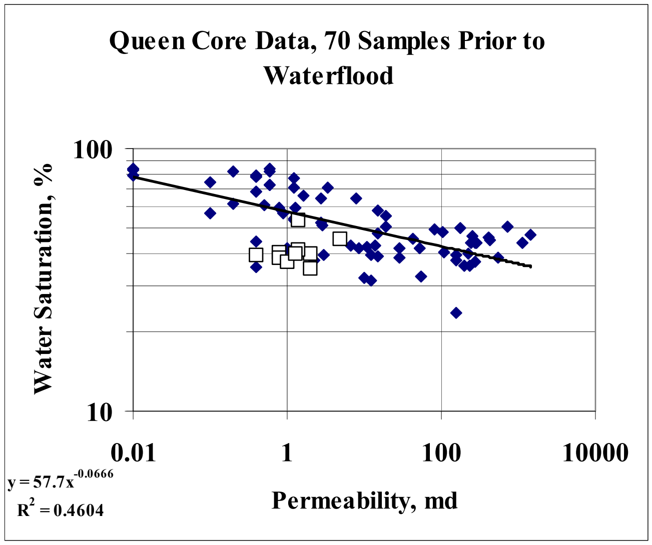

Figure 7. Permeability versus Sw used to Establish Initial Water Saturation.

Queen Mapping

The number of control points was sufficient to use a nearest neighbor-mapping algorithm for interpolating values throughout the Penasco Unit. The maps are included in a separate Volume II for ease of viewing. The discussion of the seven maps follows.

- Structure
- Thickness
  - Gross
  - Net
- Porosity
- Permeability
- Connate Water Saturation

Structure

The structure map seen in Fig. 1 (separate Volume II) is based on the 37 control points denoted by the black dots. The white dots represent wells without log data. Note that this color map is the same as Fig. 3 with 60-ft contour intervals. The Unit boundaries are superimposed on the map for clarity. The calculated dip between wells 8O2 and 16E is 1.2° or 110ft/mile suggesting that gravity is not an important factor in the recovery process.

Fig. 2 is the structure mapped on 10-ft contours. Notice that the contour rate of change is greatest near well 9M which is the best producer in the study area. A similar observation was noted at the Sulimar Queen field where the best wells are located near rapid changes in the subsurface elevation.

Gross Thickness

The gross thickness defined as the top of the interval to the bottom of the entire Queen interval generally consisting of two subintervals totaling about 50-ft. The gross thickness on 6-ft contours is seen in Fig. 3.

Net Thickness

The net thickness seen in Fig. 4 is based on an 8% porosity cutoff. Seventeen wells had porosity measurements equal to or greater than 8%. The net thickness is the sum of those values in each well. The open dots represent wells that did not have sufficient logs to estimate porosity.

Porosity

Fig. 5 maps the porosity averaged over the gross Queen interval. The porosity values were estimated from M_N - M_D cross-plot where modern logs were available or from the Queen neural network when only gamma ray-NCR logs were available. A total of 20 control points were used to construct the map.

Permeability

The porosity averaged over the gross Queen interval and the regression equation seen in Volume I Fig. 6 were used to construct the permeability map seen in Fig. 6. Considerably larger values were obtained during the history matching process.

Initial Water Saturation

The spatial distribution of the initial water saturation based on regression equation seen in Volume I-Fig. 7 is illustrated in Fig. 7. Again the values are based on the gross Queen interval and are lower when the larger net porosity values are used in the regression equation.

Simulation

The simulation model consisted of 630 gridblocks in a 9900 ft by 6930 ft rectangle. Each gridblock is 330 ft by 330 ft or 2.5 acres. The size of study area is 1575 ac that includes the 520 ac Penasco Unit. A single layer was characterized to simulate the 54 years of producing history. The initial reservoir parameters were 10% porosity, 36% water saturation, 50-md horizontal permeability and 5-md vertical permeability.

Relative permeability, capillary pressure, PVT and rock compressibility values from the Reed-Sanderson Unit study were adapted to the Penasco Unit. Discovery pressure was 1260 psi based on hydrostatic head and the initial GOR was assumed to be 1000 scf/bbl based on limited early production records from offset wells.

Oil producing rate was selected as the constraining value for the history match. Only the oil-producing rate was recorded during the Unit primary producing period and is assumed to be accurate. The patchy nature of the Unit gas and water production records is evident in the history matching results.

A public domain black oil simulator, BOAST III, available from DOE was used to simulate the historical producing rates from 13 wells during primary production and 5 wells that produced during the water flood. The individual well status and oil production is summarized in Table II. The Engineering Committee records list the cumulative oil produced through 1994 as 779,060 bbl that is less than the Unit total seen in Table II. Since simulation requires complete well production files, the history match is based on the documented data seen in Table II.

Table II Well Records				
Well	Status	Primary Oil, bbl	Cumulative Oil, bbl	Total Injection, bbl
80	IW	40,209	*40,209*	1,075,387
8P	PW	60,564	81,312	
9M	PW	92,406	129,953	
9N	IW	77,664	*77,664*	562,579
16D	TA	4,620	*4,620*	
16C	TA	3,551	*3,551*	
16E	IW	12,353	*12,353*	644,244
17A	PW	80,726	182,936	
17B	PW	56,387	113,626	
17C	TA	15,799	*15,799*	
17F	TA	14,438	*14,438*	
17G	IW	35,697	*35,697*	535,579
17H	PW	50,008	80,473	
Unit		544,422	792,631	2,817,789

Matching the performance history of the wells required adjustments to the initial estimates of porosity, permeability and relative permeability. The Unit properties following the history match are seen in Table III.

Table III Reservoir Properties			
Depth	3150 ft	Oil Gravity	35^{o} API
BHT	102 ^{o}F	Dead Oil Viscosity @BHT	5.0 cp
Water Salinty	300,000 ppm	Reservoir Oil Viscosity	0.8
Water Viscosity, @BHT	1.5 cp	Porosity	11.7% (5-20%)
Pi, (0.4 psi/ft)	1260 psi	Permeability, md	108, (25-200)
Solution GOR	1000 scf/bbl	Connate Water Saturation	36%

The problem of the missing gas and water primary production records is seen in history matches of well 9M, 17A and 17H as seen in Figs. 8-14. There is no primary history to match since the gas production and the primary water production was not recorded. The focus of the history match is water production during the secondary recovery operation.

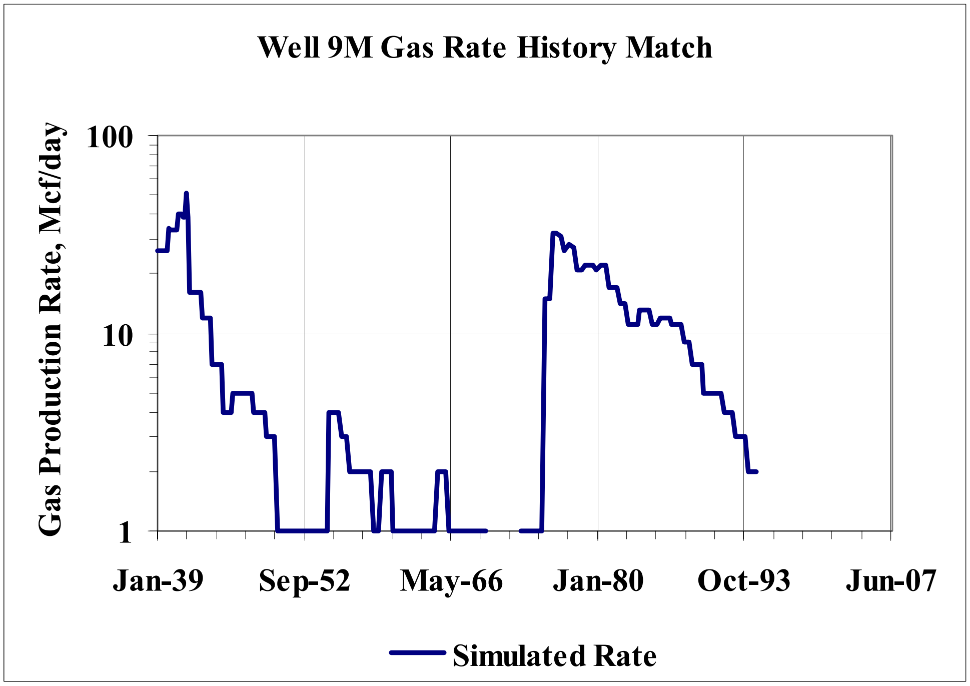

Figure 8. Gas Rate Simulated Only. No Gas Production Recorded.

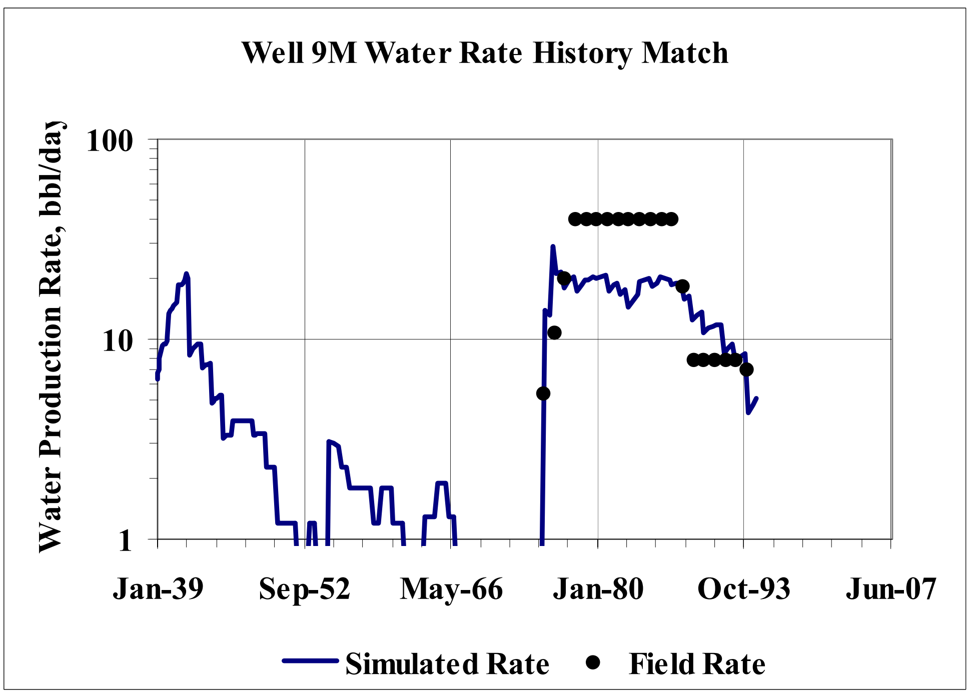

Figure 9. Water Production Recorded During Secondary Only.

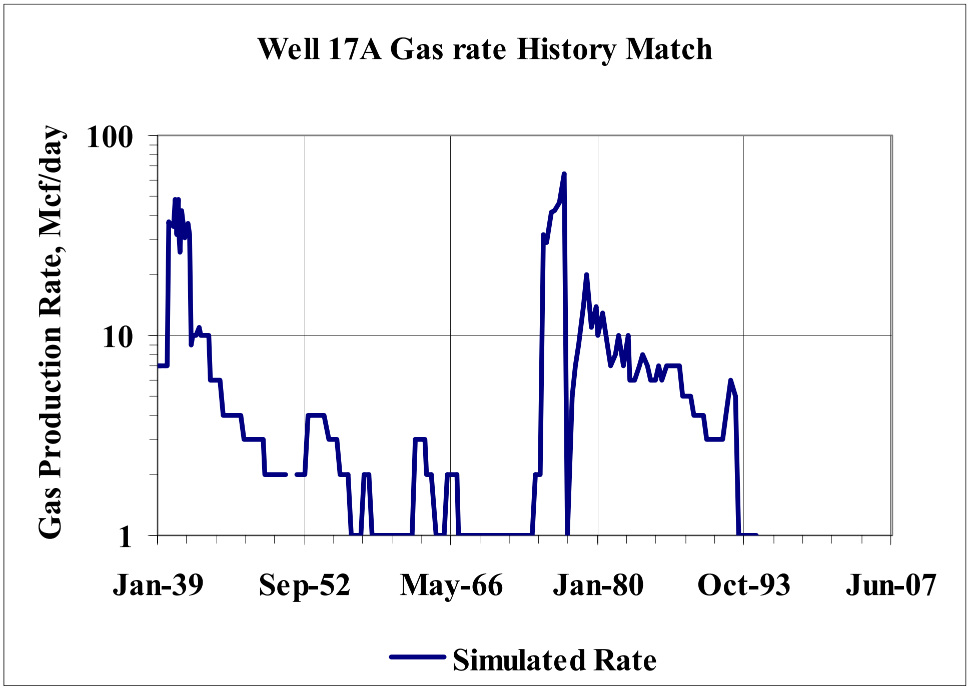

Figure 10. No Gas Production Records to Match, Simulation Only.

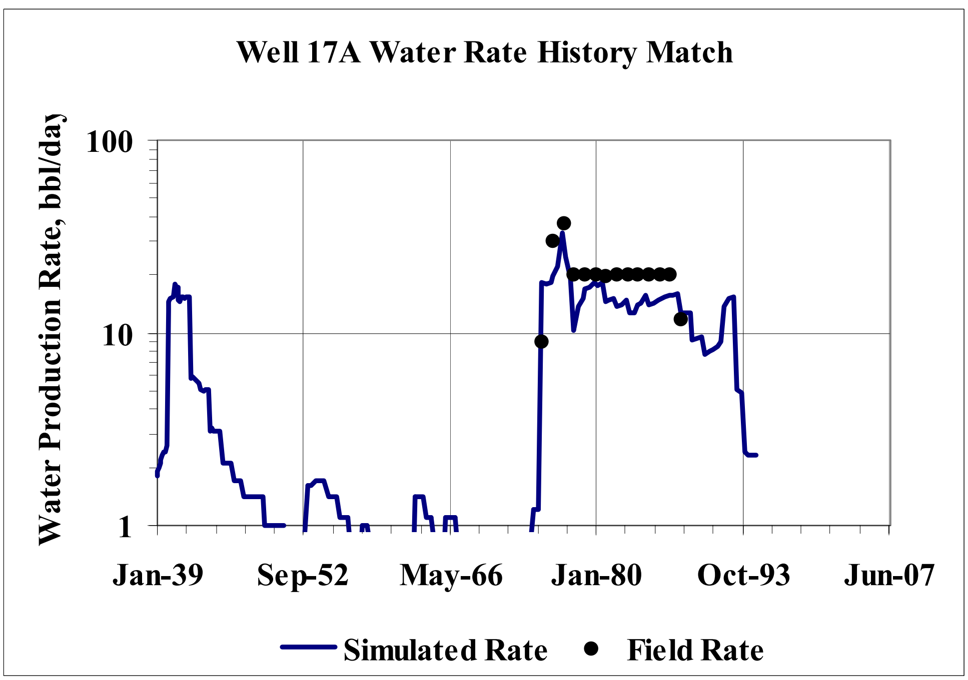

Figure 11. No Water Production Recorded During Primary.

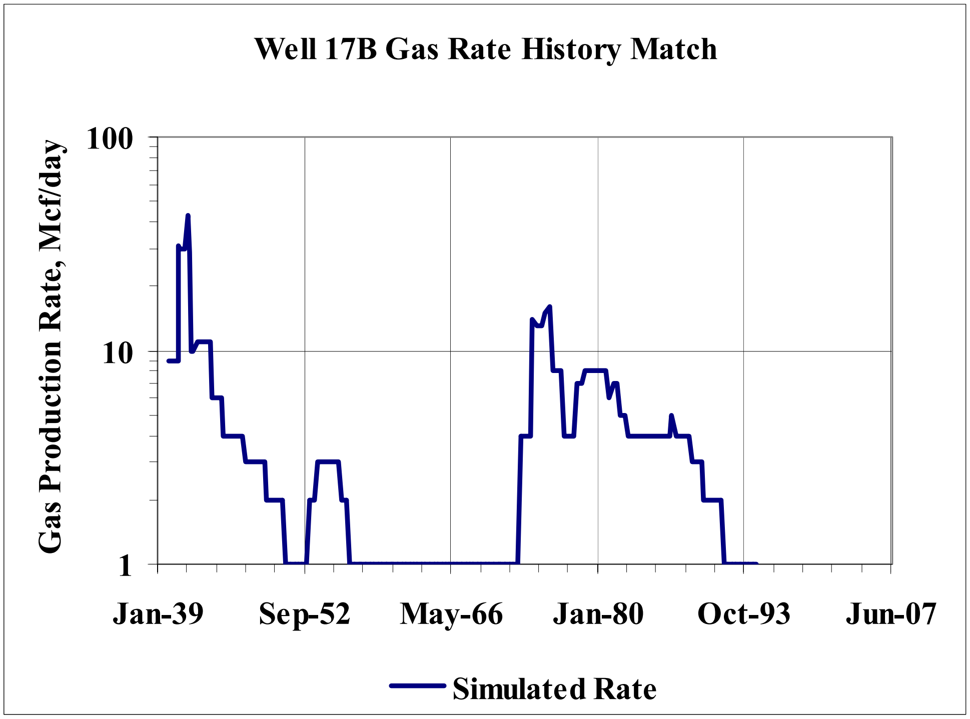

Figure 12. No Gas Production Recorded.

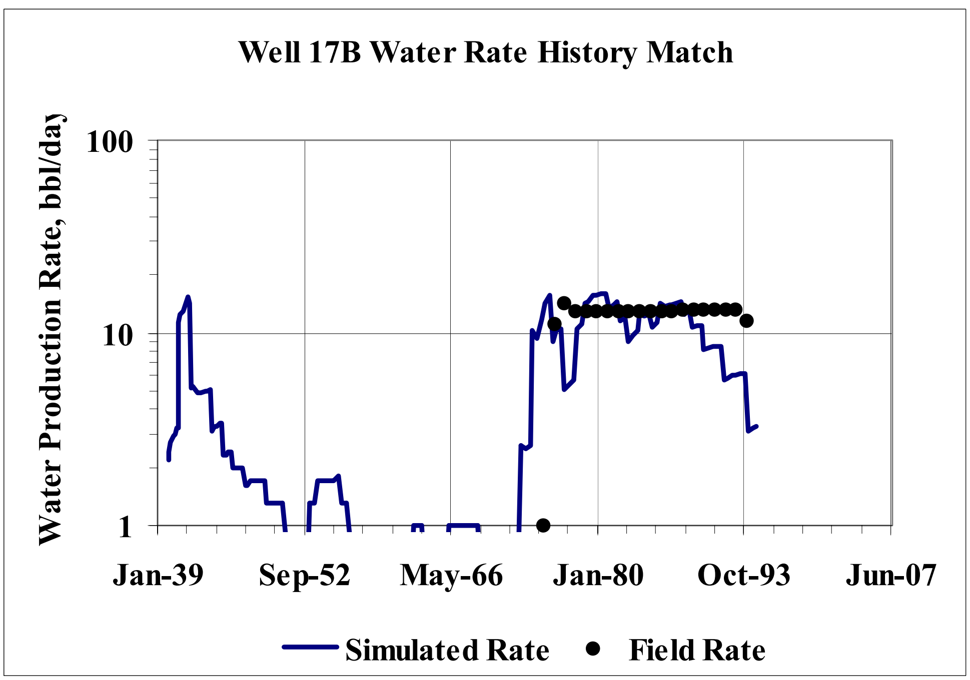

Figure 13. Water Production Recorded During Secondary Only.

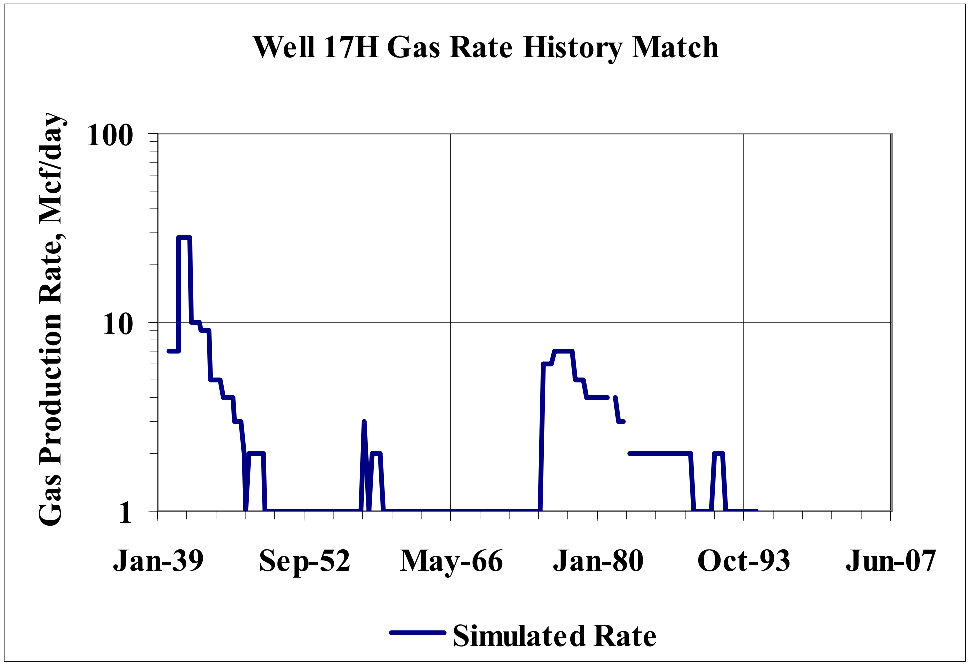

Figure 14. No Gas Production Recorded.

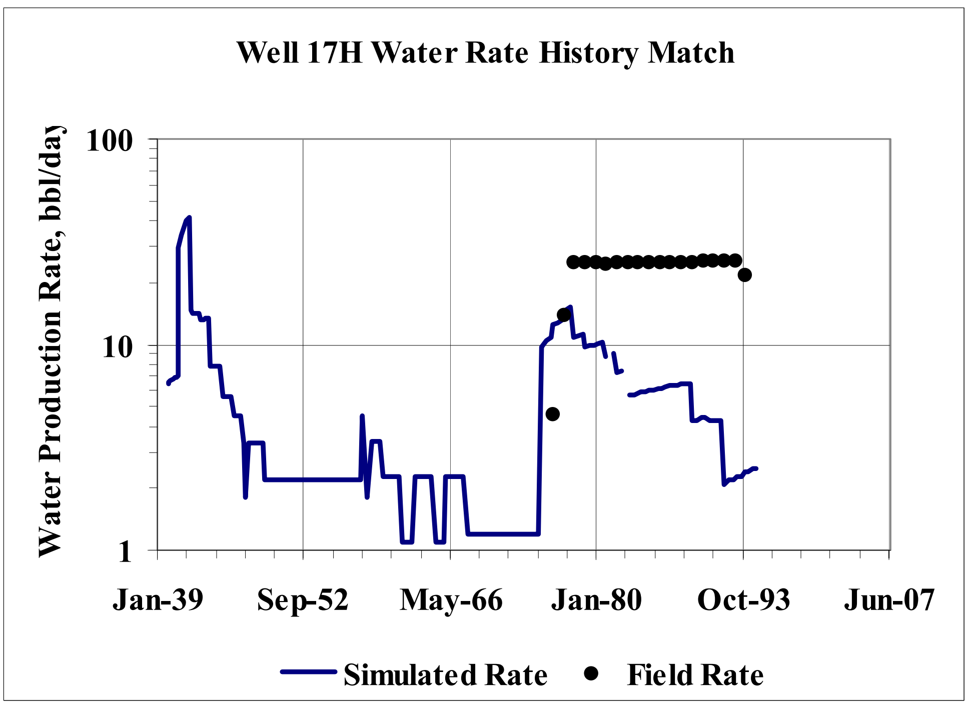

Figure 15. Water Production Recorded Only During Secondary.

The match of the simulated water production to the values recorded is a measure of the goodness of the history match. Gas production was not recorded at the Penasco Unit and it could be surmised that the oil did not contain solution gas. However, it would extremely unusual for a 35^{o} API oil not to contain any dissolved gas, plus the offset Queen wells to the northeast (Kaiser Frances Oil Co.) reported the production of gas and water during the primary phase. Therefore the simulated results are judged to be reasonable. The initial Penasco Unit GOR of 1000 scf/stb was estimated from the performance of these offset wells. The individual well performances are summed in the following Unit-wide simulated oil, gas and water production histories.

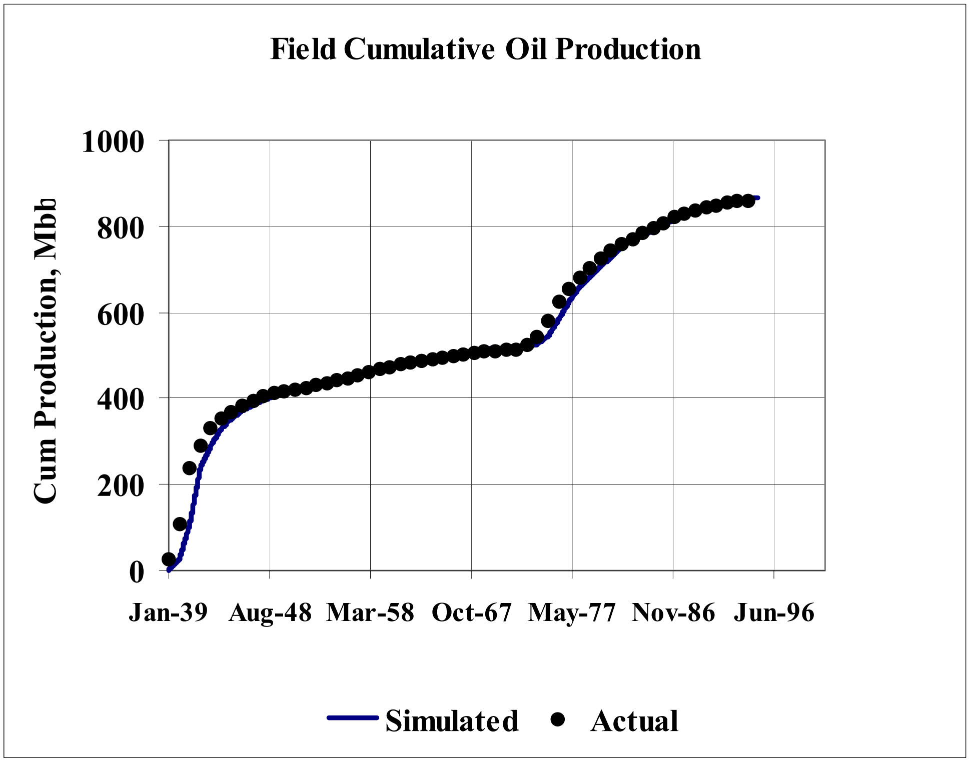

Figure 16. Actual and Simulated Cumulative Oil Production.

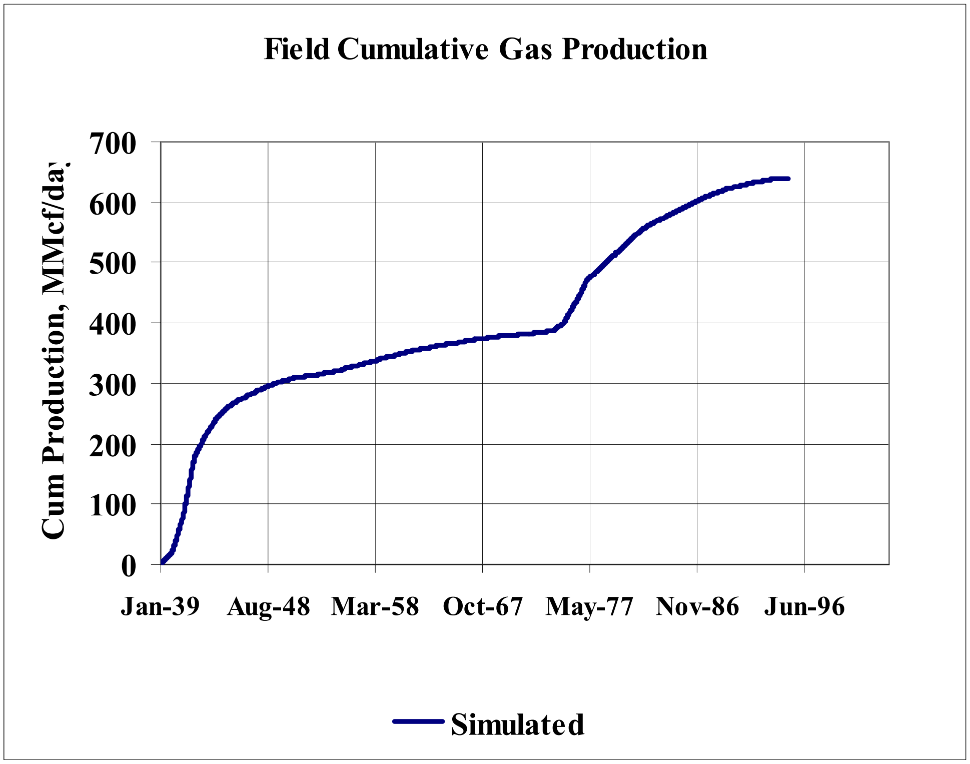

Figure 17. Simulated Penasco Unit Cumulative Gas Production.

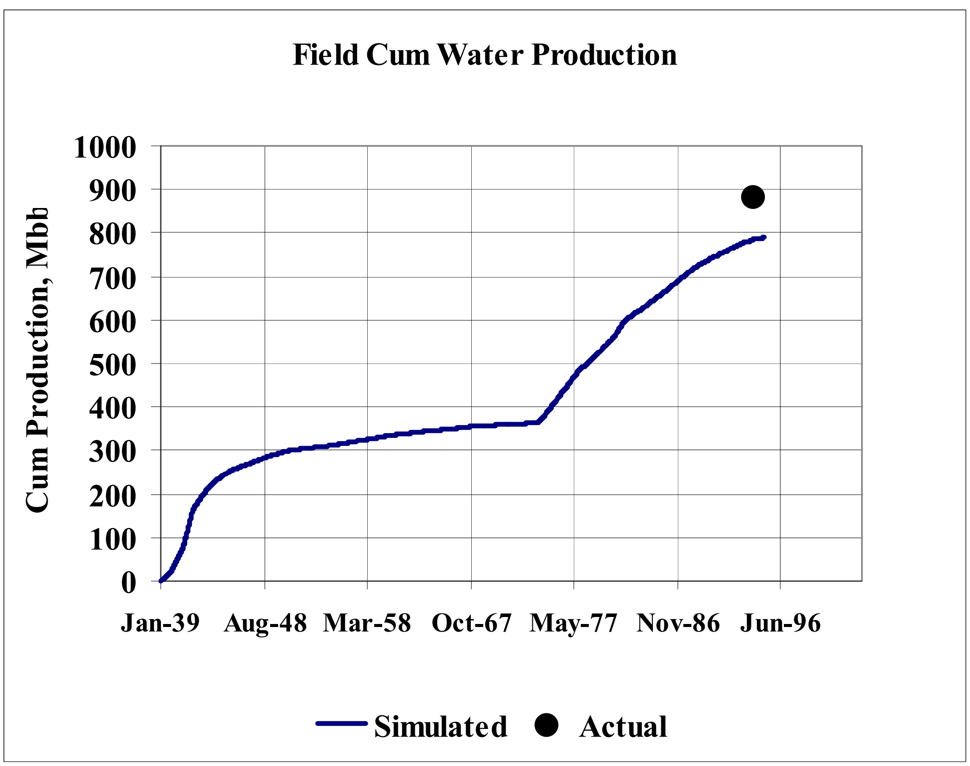

Figure 18. Simulated Water Production with Recorded Value Through 1994.

Simulation Predictions

Based on the history match the original oil in place (OOIP) in the 1575 ac study area is 18,000,000 bbl or 11,428 bbl/ac. Thus, the 520 ac Penasco Queen Unit contained 5,942,560 bbl OOIP. Primary recovery from the Unit was 544,422 bbl or 9.2 % OOIP, secondary recovery through 1994 was 198,201 bbl or 3.3% OOIP and cumulative recovery through 1994 was 742,623 bbl or 12.5% OOIP.

Following the history match the simulator was used to predict the results of 4 scenarios including a base case.

- Simulated Base case

08/04/2000 - Result 7,000 bbl over 5 years, operated continuously with a 300 BWPD injection rate, no down time. Unit actually produced 4302 bbl from 1994 through 1999.

- Scenario #1

Convert well 8-O2 to a production well.
Convert well 17A to injection well. Inject 100 bbl water per day (BWPD).
Maintain well 16E (100 BWPD) and Well 17 G (100 BWPD) as injection wells.
Leave well 9N shutin.
08/04/2000 - Result 36,000 bbl over 10 years.

- Scenario #2

Same as Scenario #1 except add 16D as a producing well.
08/04/2000 - Result 51,000 bbl over 10 years.

- Scenario #3

Same as Scenario #1 except add a producing well between well 16C and 16D.
08/04/2000 - Result 45,000 bbl over 10 years.

Production data to 1994 was used to history match the Unit performance. Therefore the predicted cases start in 1994 rather than 2000. The predicted producing rates for the base case and the three scenarios are seen in Fig. 19. Notice that there is very little decline once production rates level. The predicted oil cut during the stabilized period is about 5% just as it was at the end of 1994. If an additional source of injection water is obtained and the injection rate could be doubled to about the 600 BWPD injected, the projected oil rates would double for each scenario.

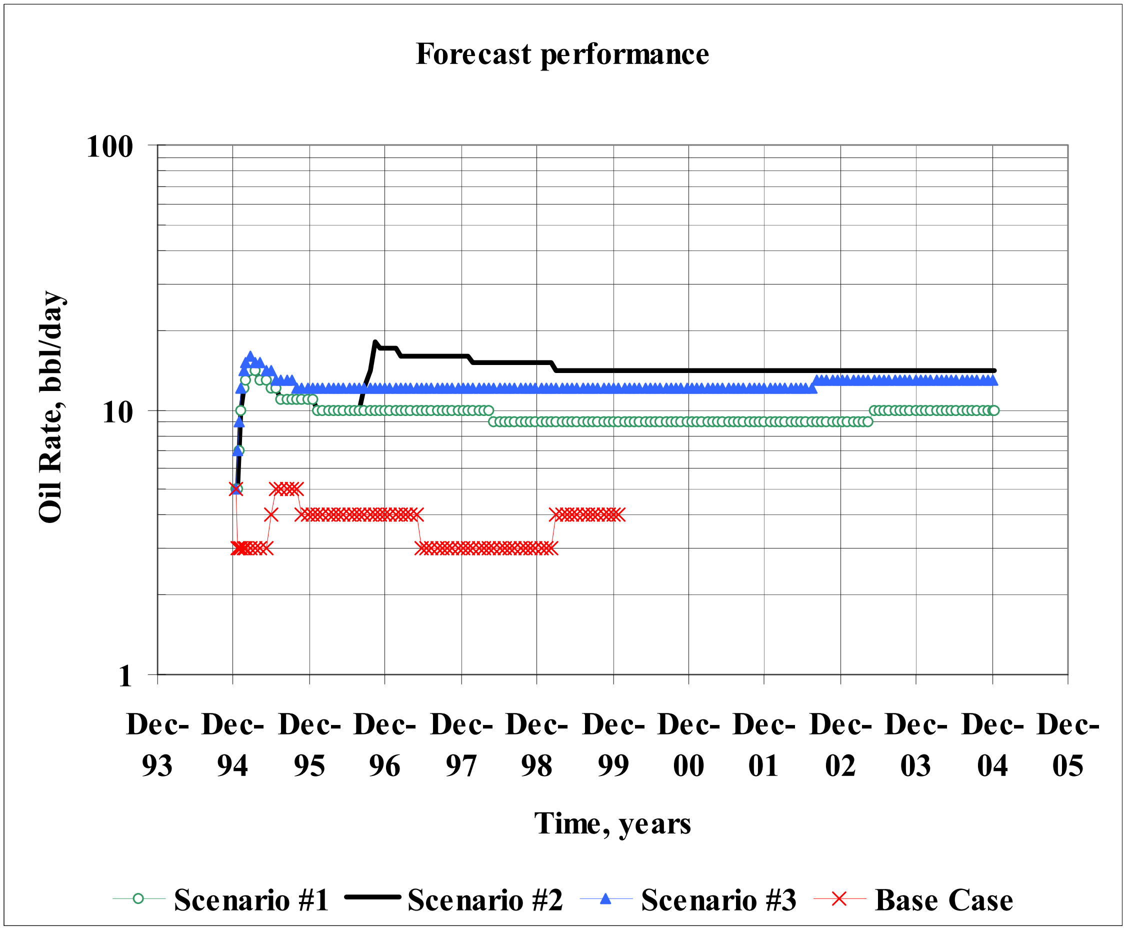

Figure 19. Predicted Oil Rates of Four Management Strategies.

Penrose Zone

During the log evaluation work the presence of a possibly productive Penrose reservoir about 200 ft below the Queen was investigated. Many of the Unit wells penetrated the Penrose, but tests were not reported or were negative. The methodology used to characterize the Queen interval was applied to the Penrose. All Penrose maps are included in Volume II of this report.

Log Evaluation

The modern neutron porosity log from well 9N2 was converted to a neutron count rate format (NCR). The NCR and the gamma ray log were used to train a neural network to predict the cross-plot (M_N & M_D) porosity through the same zone. The cross-plot (M_N & M_D) porosity is considered as "truth." The goodness of the neural network as a predictive tool when only gamma ray and NCR logs are available is seen in Fig. 20.

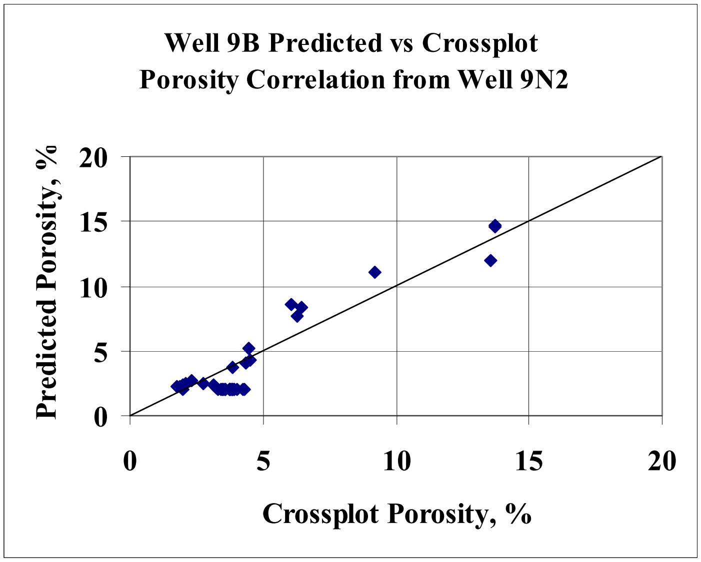

Figure 20. Gamma Ray and NCR Logs Used to Predict Porosity.

The trained Neural Network was used to estimate the porosity of the Penrose interval of wells that did not have modern logs. The prediction is quite good except for cross-plot values less than 4% porosity. If modern logs were available porosity was estimated from the M_N & M_D logs cross-plot.

Permeability was correlated with porosity as seen in Fig. 21. The regression equation in the lower left-hand corner is based on core samples from well 164 in the NW Eumont field.

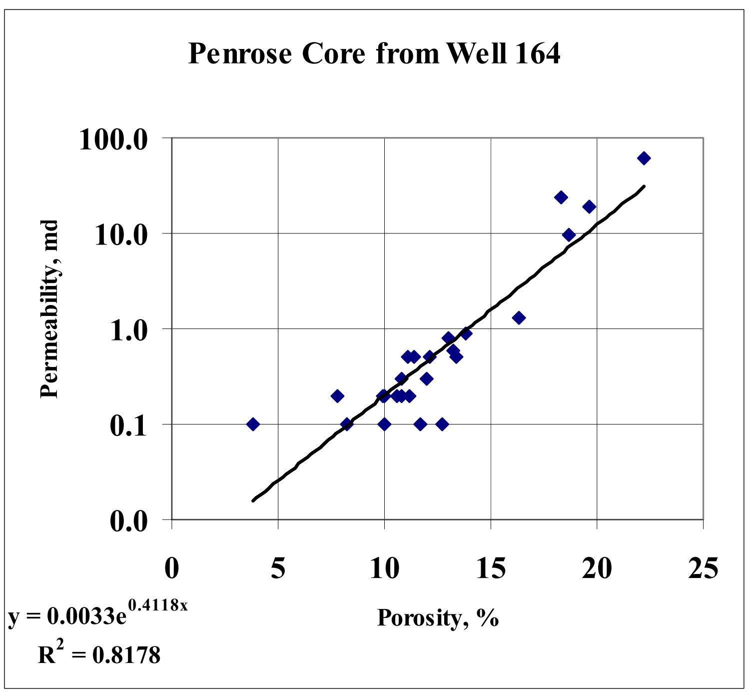

Figure 21. Permeability versus Porosity Based on Core Measurements.

Penrose water saturations were difficult to estimate. Estimates based on Archie's equation using a 4.0 ohm-meter Rw from a Pickett Plot of porosity versus deep resistivity resulted in a maximum Penrose interval Sw value of 10% that experience suggests is too conservative even though the Unit wells reportedly did not produce water during the primary producing period. A Eumont, Penrose zone neural network trained to predict water saturation given gamma ray and NCR logs was used to estimate the spatial distribution of the initial water saturation. The Eumont Penrose oil zone core was cut prior to waterflooding and measurments could only be affected be the water based coring fluid. Hence the Swi estimates are conservative.

Penrose Mapping

The number of control points was sufficient to use a nearest neighbor-mapping algorithm for interpolating values throughout the Penasco Unit. The maps are included in a separate Volume II for ease of viewing. The discussion of the seven Penrose maps follows.

- Structure
- Thickness
  - Gross
  - Net
- Porosity
- Permeability
- Connate Water Saturation

Structure

The structure map seen in Fig. 8 is based on the 35 control points denoted by the black dots. The white dots represent wells without log data. Note that this color map is constructed with 60-ft contour intervals. The Unit boundaries are superimposed on the map for clarity.

Fig. 9 is the structure mapped on 10-ft contours. Notice that the contour rate of change is greatest between well 9M well 16C2. A similar observation was noted at the Sulimar Queen field where the best wells are located near rapid changes in the subsurface elevation.

Gr*oss Thickness*

The gross thickness defined as the top of the interval to the bottom of the entire Penrose interval generally consisting of one interval totaling about 35-ft. The gross thickness on 6-ft contours is seen in Fig. 10.

Net Thickness

The net thickness seen in Fig. 11 is based on an 8% porosity cutoff. The open dots represent wells that did not have sufficient logs to estimate porosity. Only 5 control points were available to construct the map.

Porosity

Fig. 12 maps the porosity averaged over the <u>gross</u> Penrose interval. The porosity values were estimated from M_N - M_D cross-plot where modern logs were available or from the Penrose neural network when only gamma ray-NCR logs were available. A total of 18 control points were used to construct the map.

Permeability

The porosity averaged over the <u>gross</u> Penrose interval and the regression equation seen in Volume I Fig. ? were used to construct the permeability map seen in Fig. 13.

Initial Water Saturation

Core measured water saturations from the Eumont field oil zone were used to train a neural network to correlate gamma ray and NCR logs with Sw. The Sw values mapped in Fig. 14 are based on the <u>gross</u> Penrose interval.

In conclusion the Penrose zone is tighter than the Queen interval and the Sw appears to be greater, but not great enough to prevent oil production. Either Wells 16C or 16D provide suitable locations to test a Penrose completion.

Final Report

Volume II – Geologic Maps

Queen Interval

Penrose Interval

Volume II
List of Figures

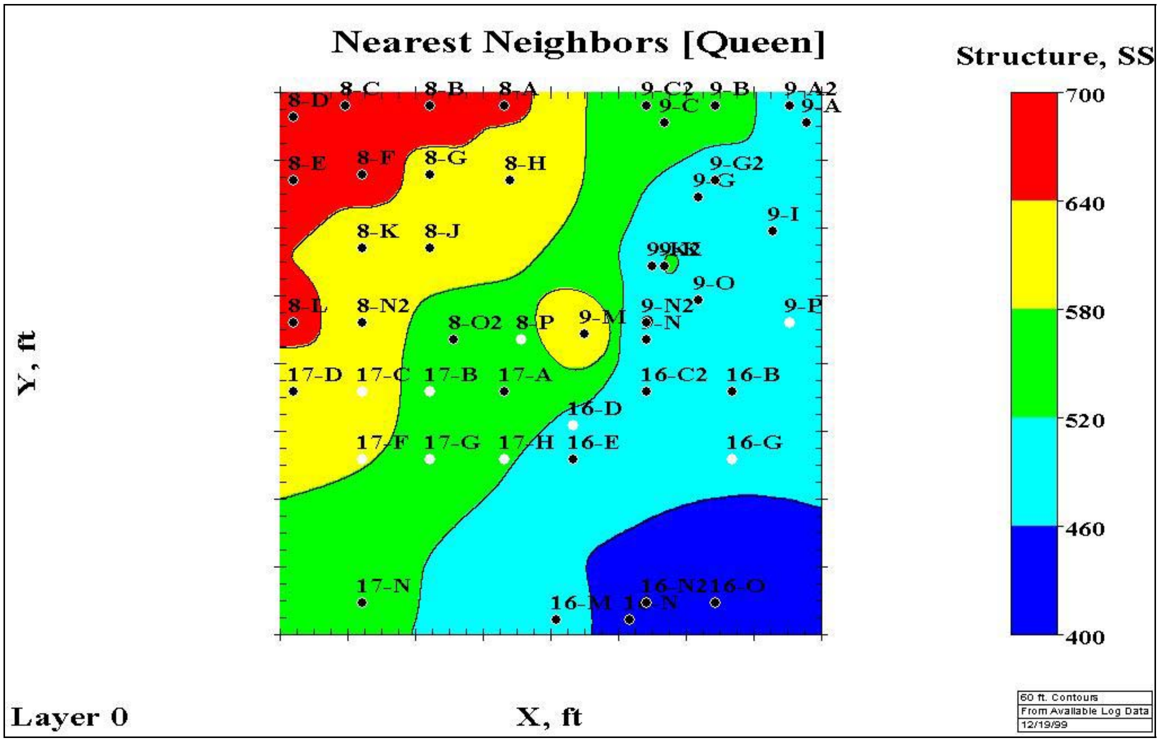

Figure 1 Queen Structure Map – 60 ft Contours

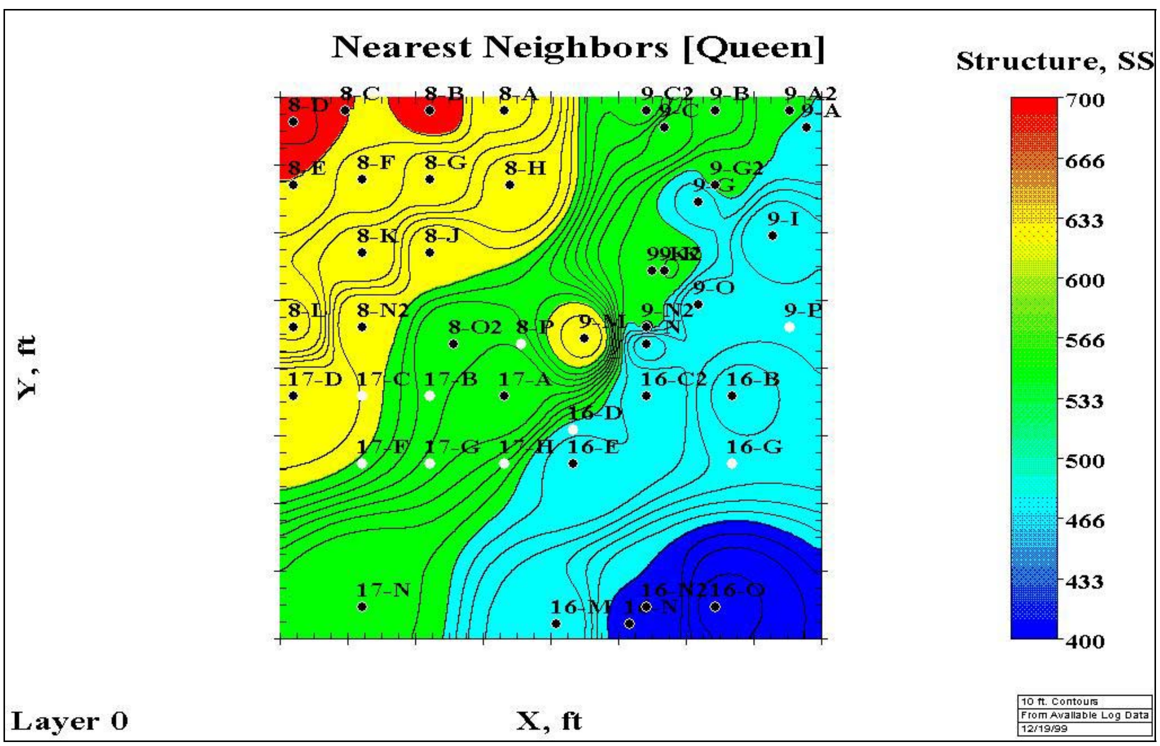

Figure 2 Queen Structure Map-10 ft Contours

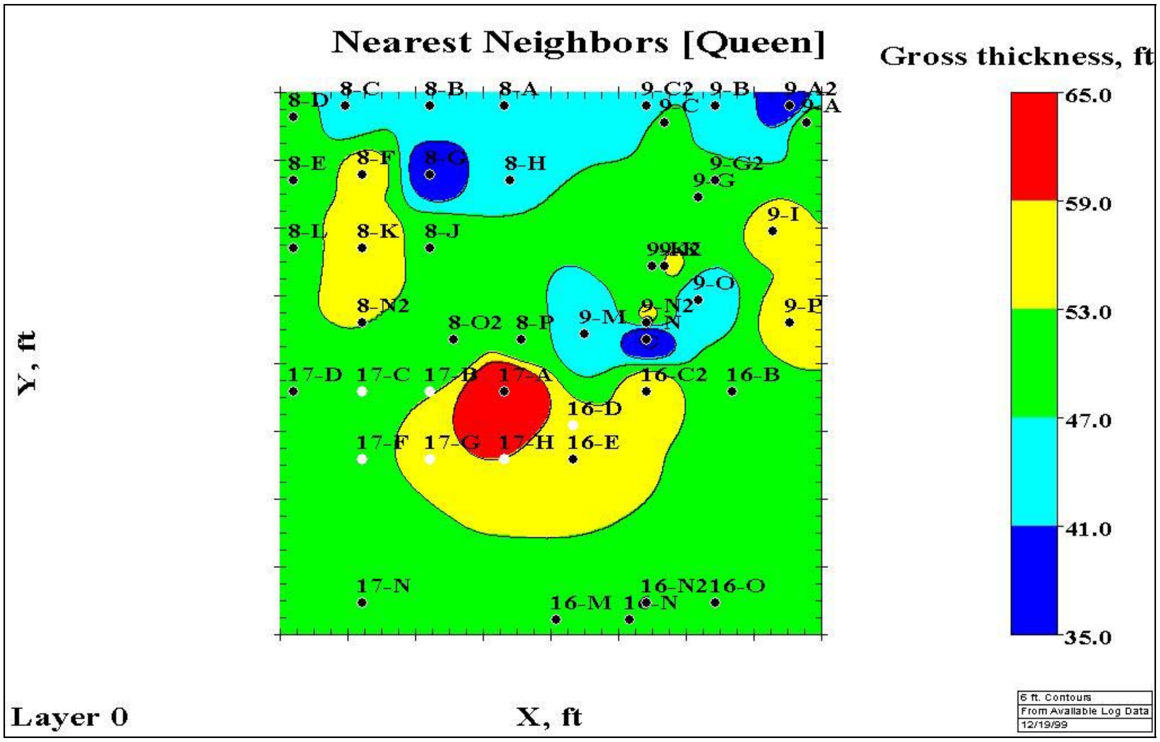

Figure 3 Queen Gross Thickness Map - 6 ft Contours

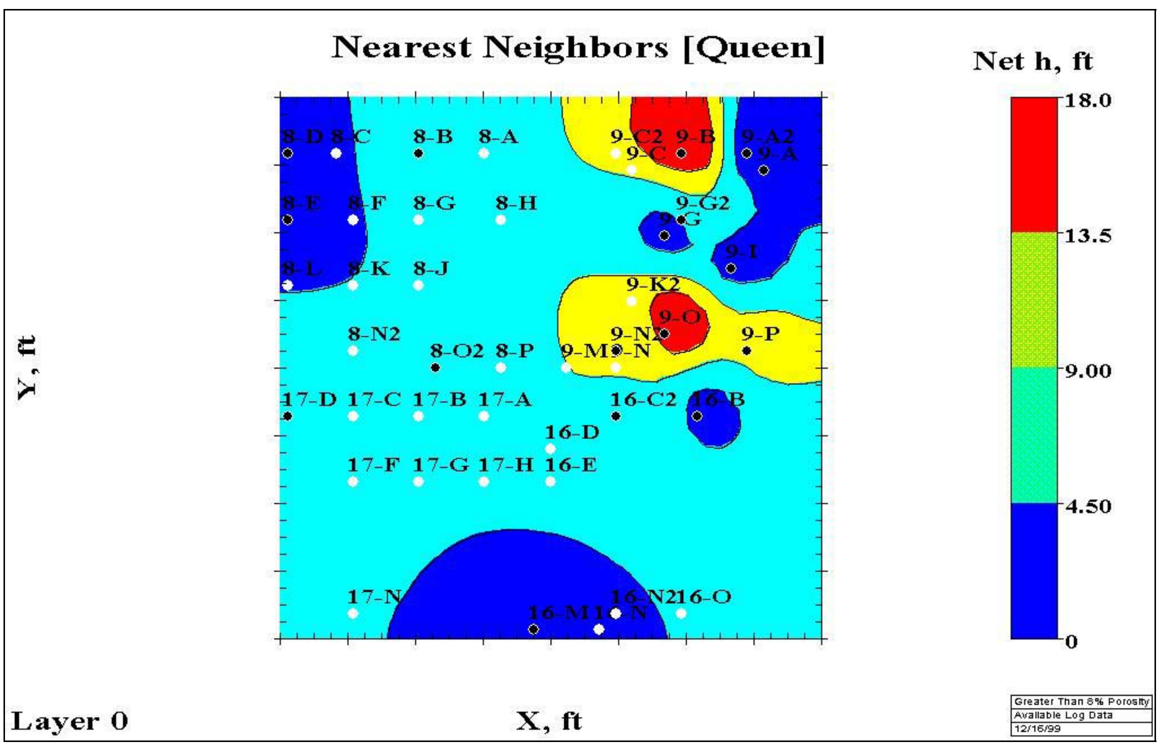

Figure 4 Queen Net Thickness Map - 6ft Contours

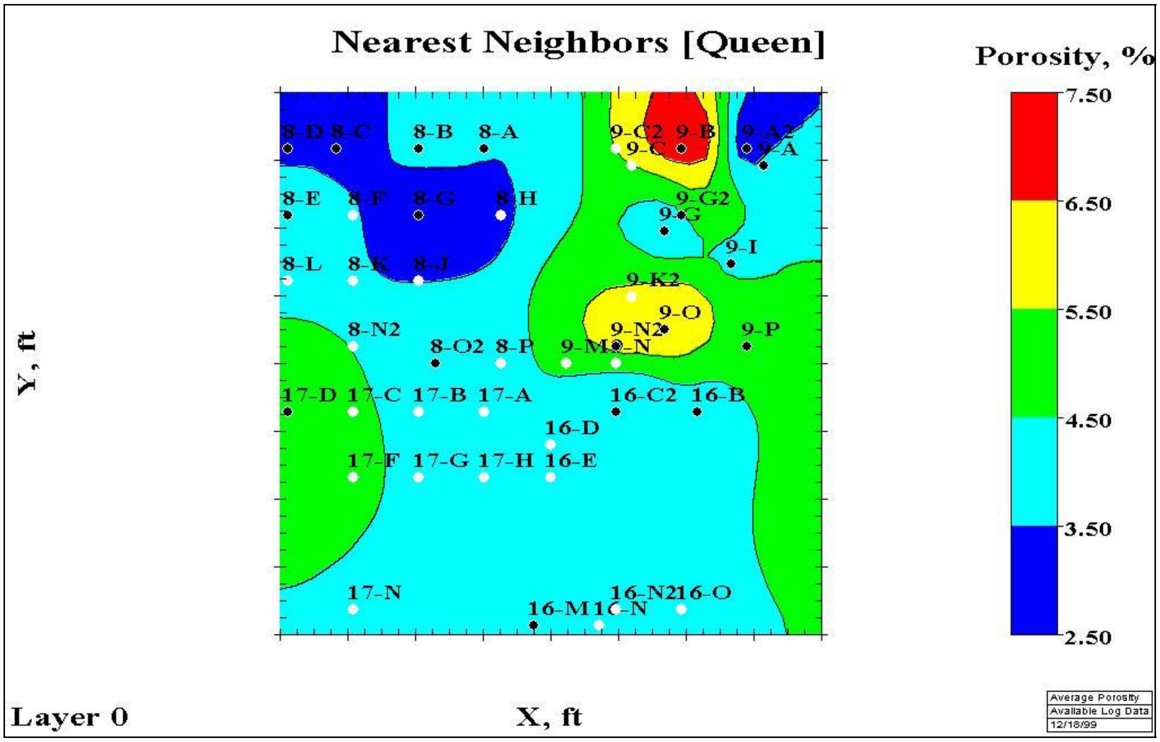

Figure 5 Queen Average Porosity Map - Gross Interval

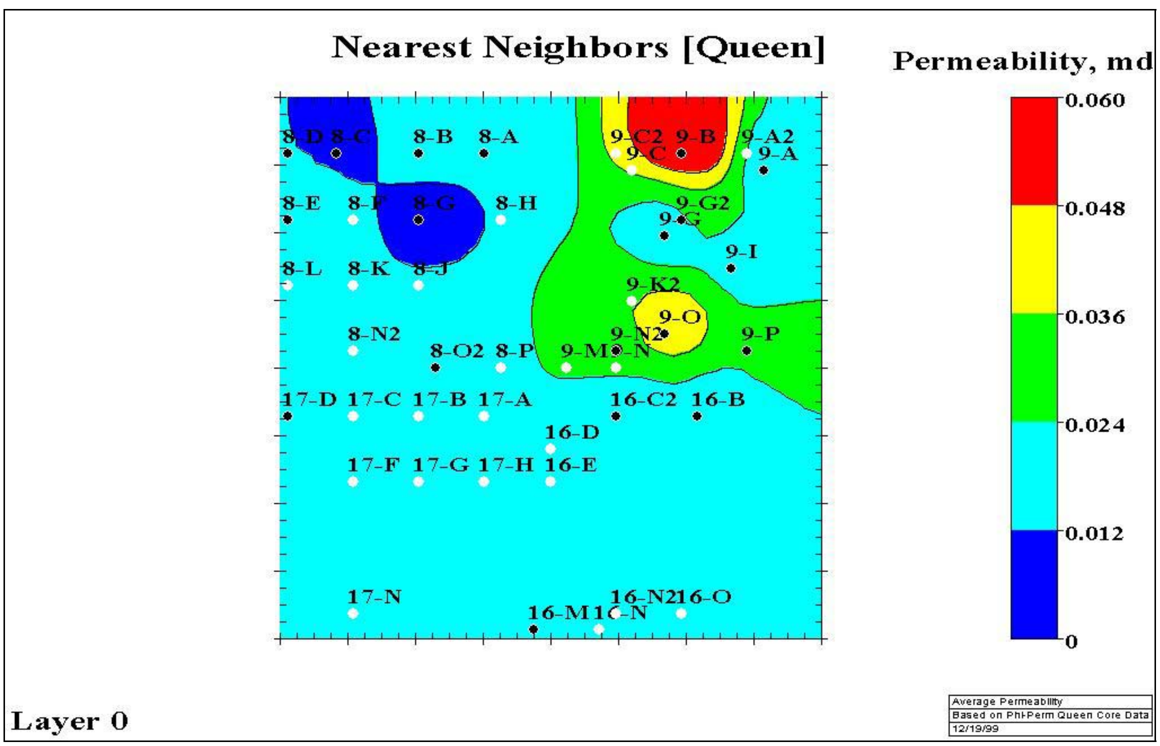

Figure 6 Queen Average Permeability Map - Gross Interval

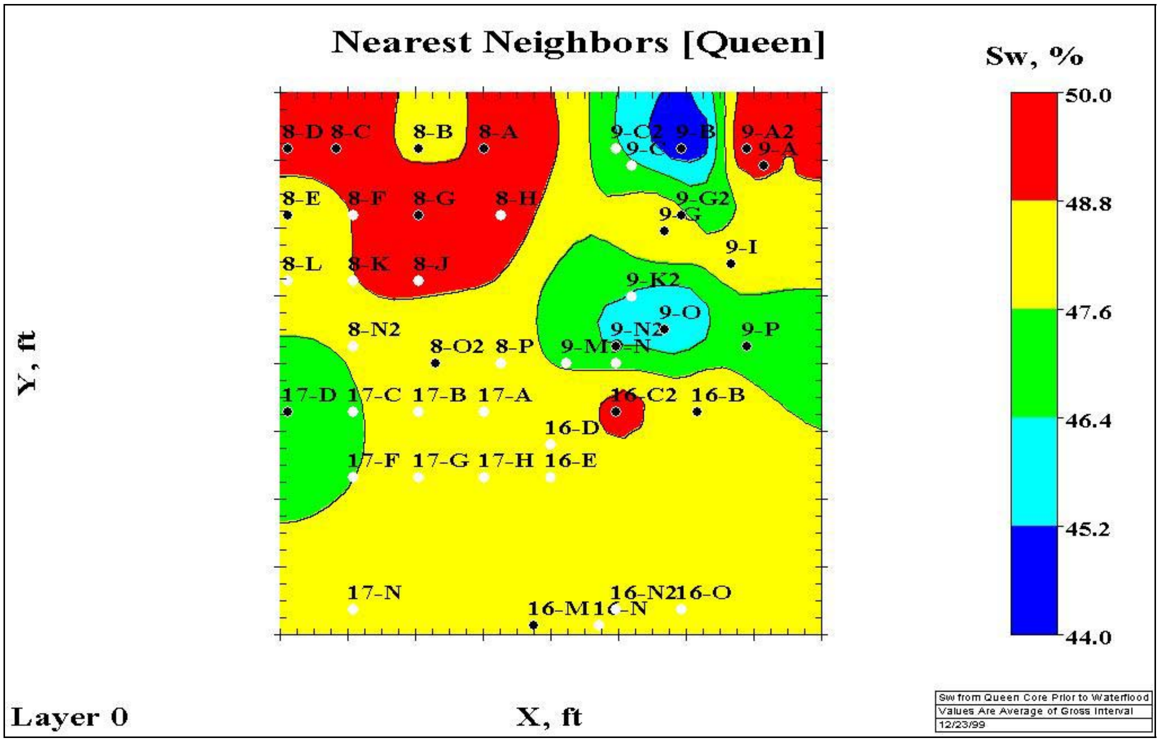

Figure 7 Queen Average Connate Water saturation Map - Gross Interval

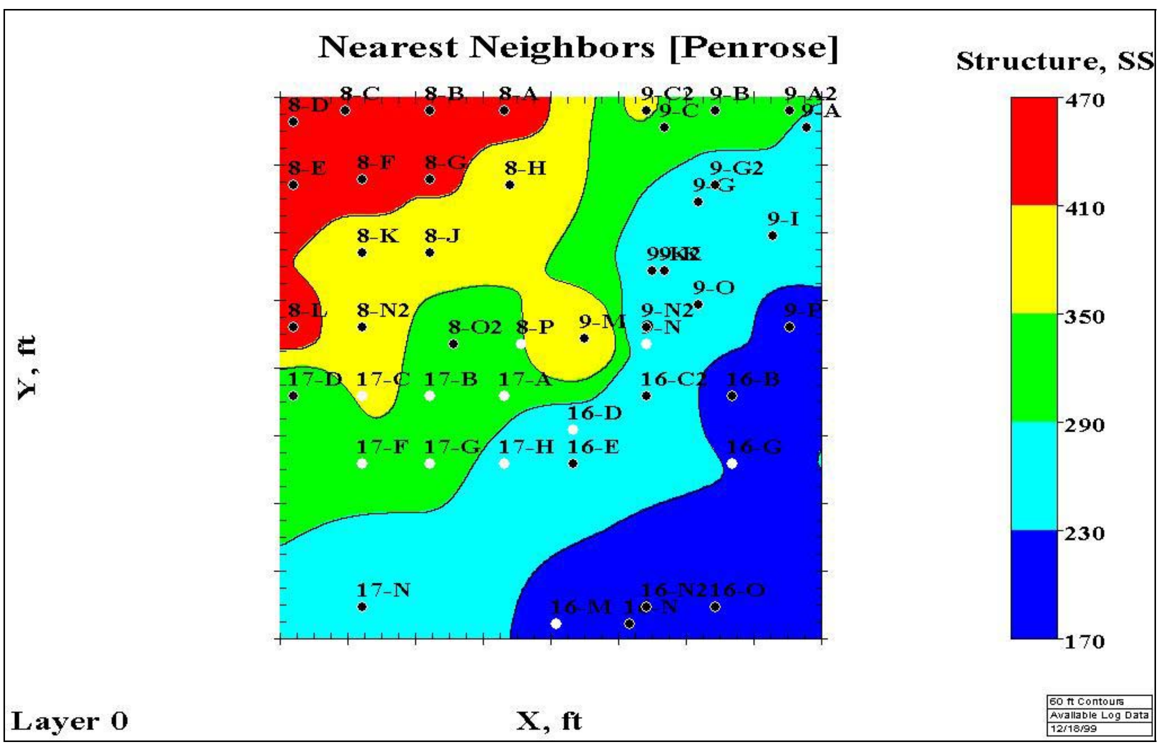

Figure 8 Penrose Structure Map - 60 ft Contours

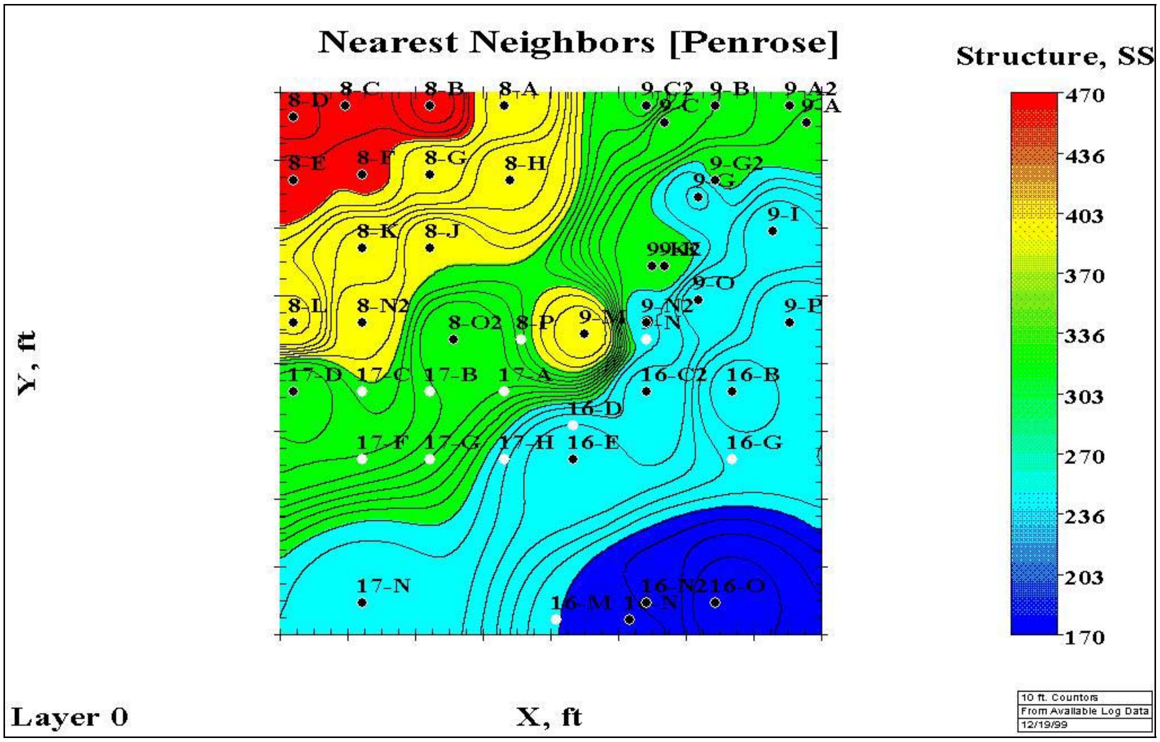

Figure 9 Penrose Structure Map - 10 ft Contours

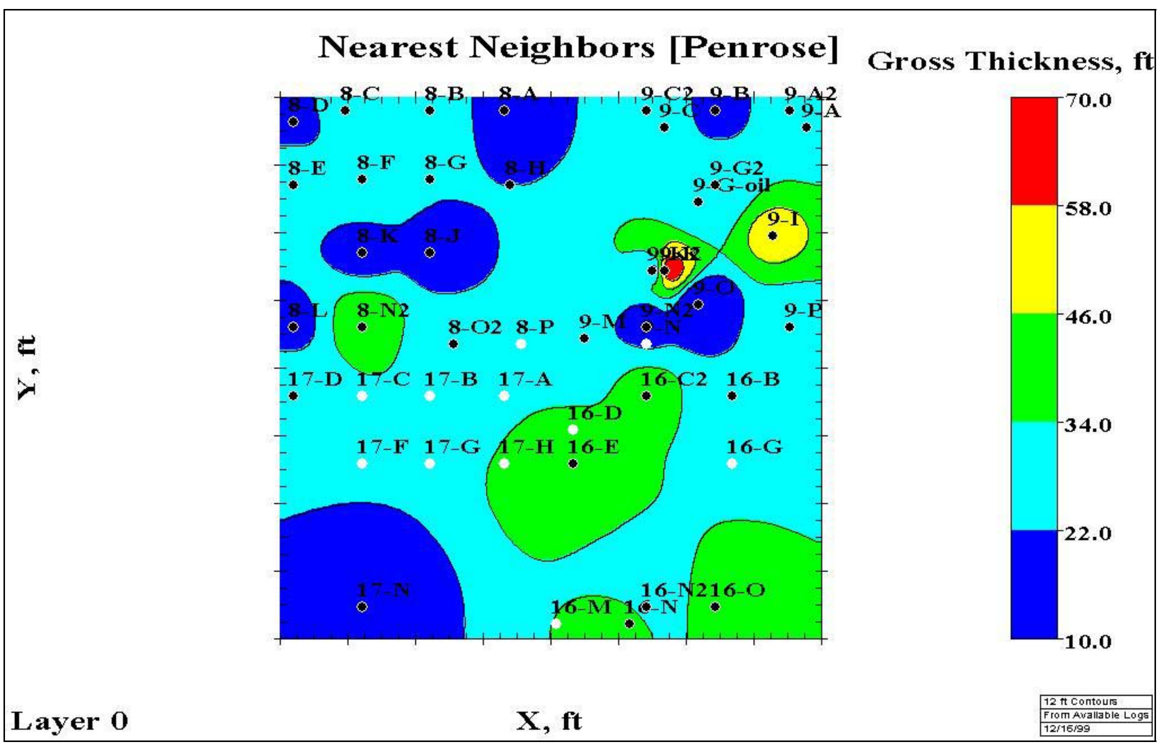

Figure 10 Penrose Gross Thickness Map - 6 ft Contours

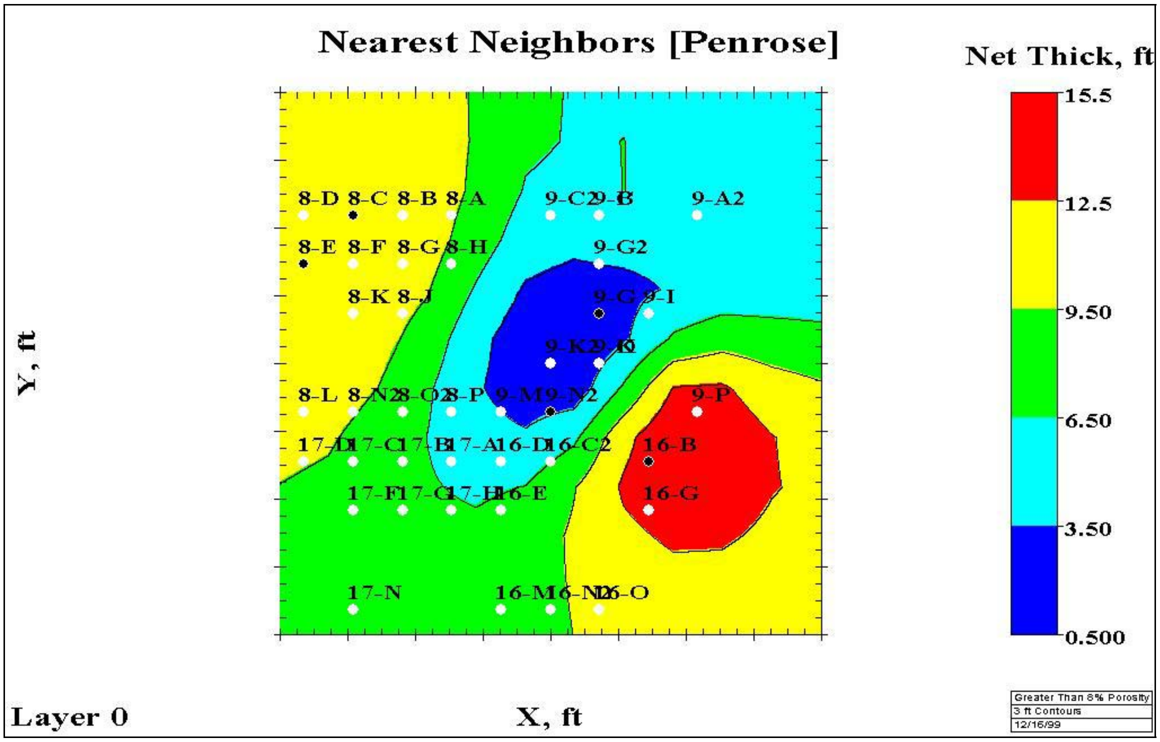

Figure 11 Penrose Net Thickness Map - 6 ft Contours

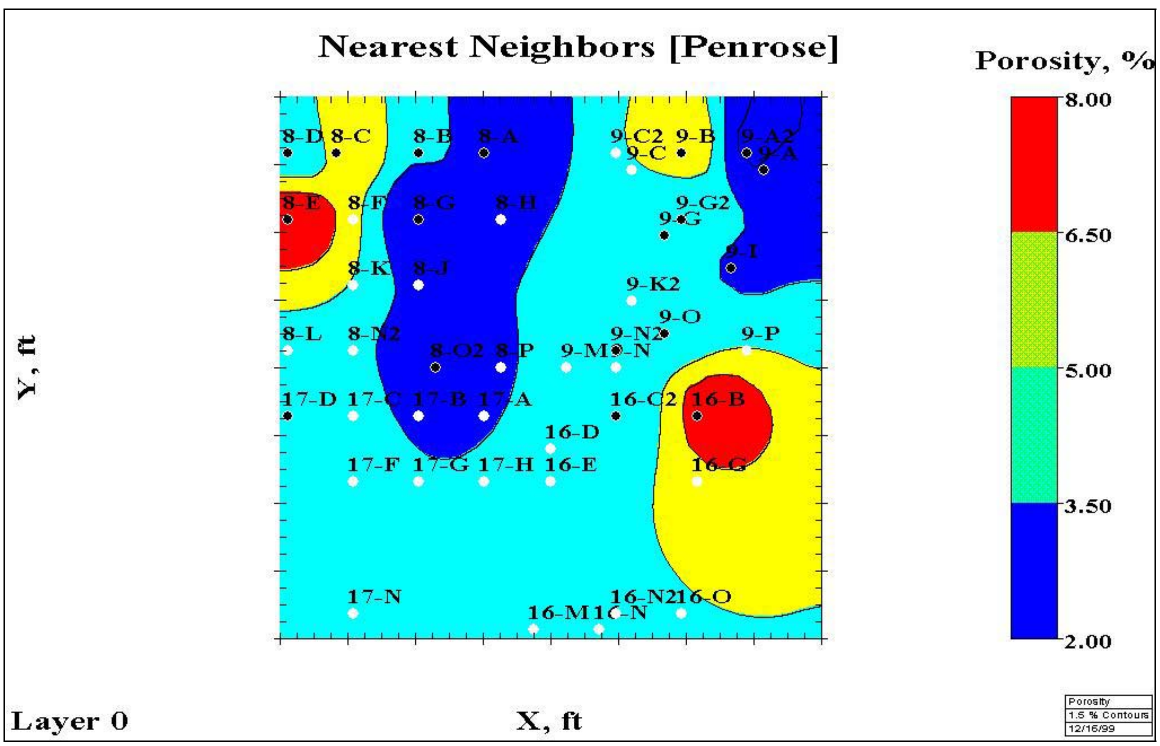

Figure 12 Penrose Average Porosity Map - Gross Interval

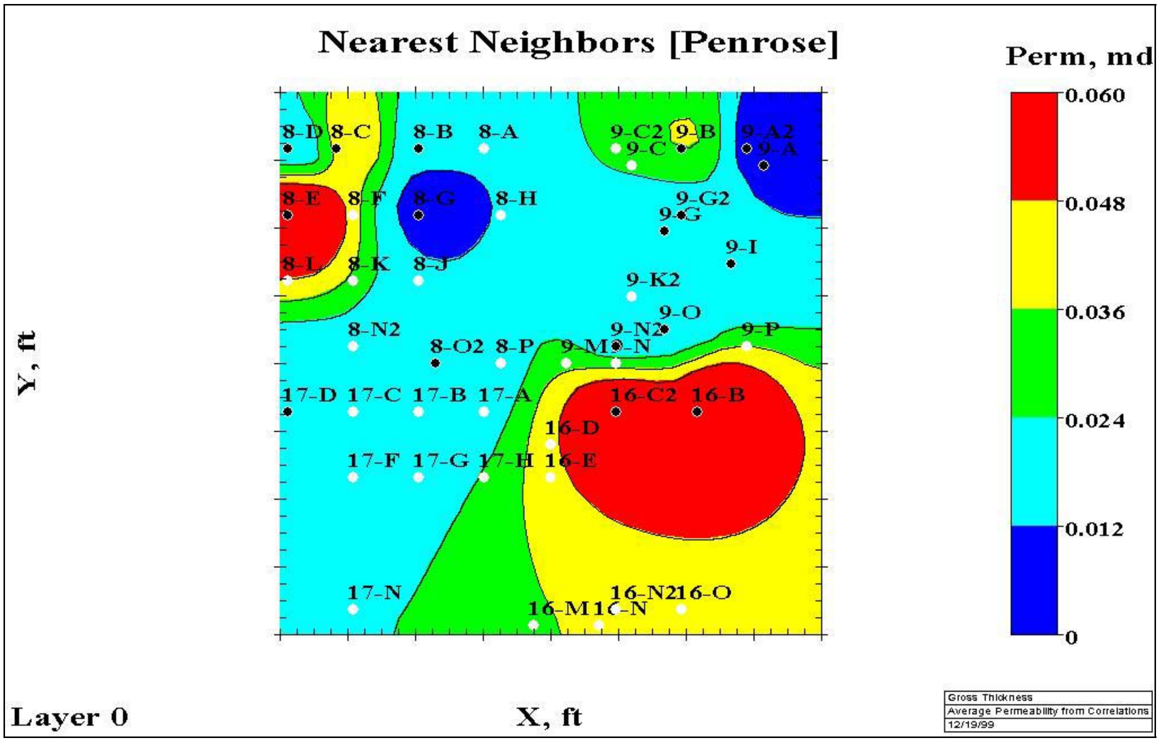

Figure 13 Penrose Average Permeability Map - Gross Interval

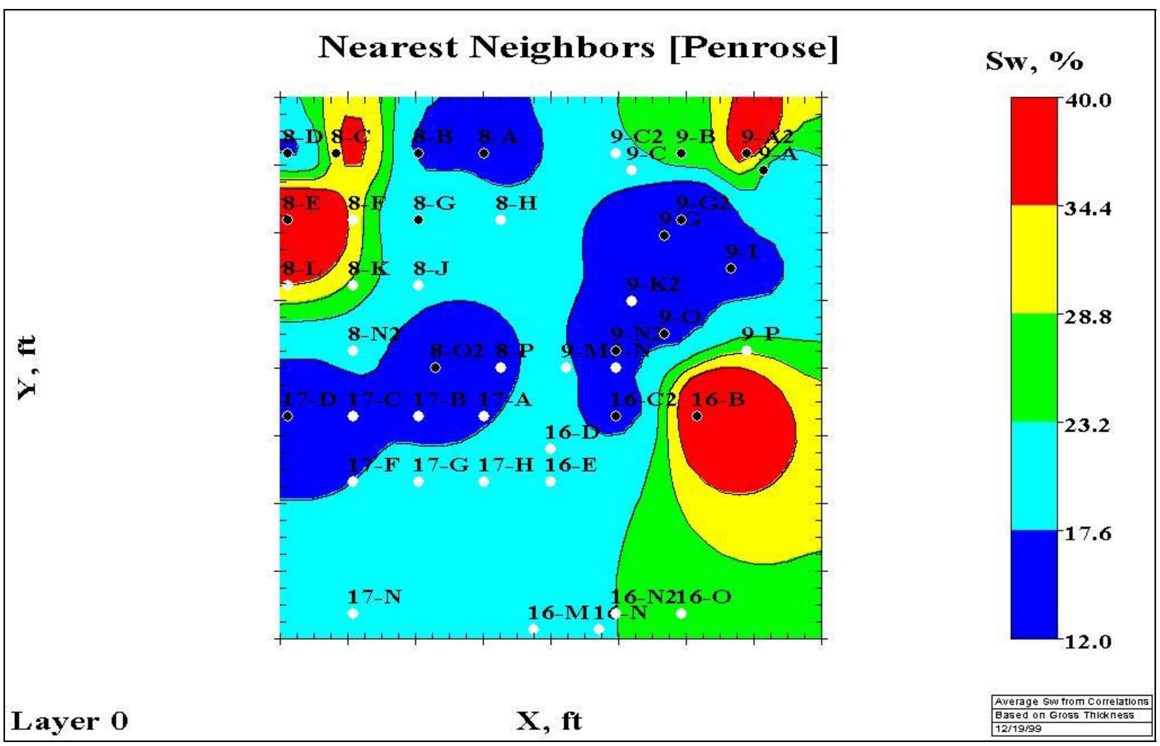

Figure 14 Penrose Average Connate Water Saturation Map - Gross Interval