KANSAS GEOLOGICAL SURVEY
OPEN-FILE REPORT 2003-79

RESERVOIR CHARACTERIZATION AND SIMULATION – NESS CITY NORTH, NESS COUNTY, KANSAS
(based on a revised geo-model)

by

Saibal Bhattacharya
Martin K. Dubois
Alan P. Byrnes

Disclaimer

Kansas Geological Survey
1930 Constant Avenue
University of Kansas
Lawrence, KS 66047-3726

Reservoir characterization and simulation – Ness City North, Ness County, Kansas (based on a revised geo-model)

Kansas Geological Survey
Open File Report No. 2003-79

Authors:
Saibal Bhattacharya
Martin K. Dubois
Alan P. Byrnes

Introduction

An integrated reservoir characterization study was carried out on Ness City North field, Ness County, Kansas, to build a 3D-geomodel, which served as the basis for reservoir simulation. The reservoir geomodel developed and applied in this study is different from that described in a previous study (KGS Open File Report 1999-58) which served as the basis for a reservoir simulation study (KGS Open File Report 2000-80). An infill horizontal well was drilled, logged, and produced for a short period in this field in April 2000. A gamma-ray log run along with the MWD (measurement while drilling) tool was able shed new light on the reservoir geology of this field. Inputs from this horizontal well along with cuttings description and geologic drilling reports from wells in and around the field were assimilated with log and core data available from the field to build a new reservoir geomodel for Ness City North field. This field produces from a Mississippian carbonate reservoir with production commencing in August 1963. Simulation studies were initially carried out to history-match fluid production from the vertical wells while also matching the limited available pressure decline. Upon completion of history matching on vertical wells, the simulator model predicted the performance of the infill horizontal well that was drilled in 2000. Only a slight local adjustment in the effective permeability was required for the simulator output to closely match the available production data from this infill well. Thereafter, a map of remaining reserves was generated for the field, and was used to spot two additional horizontal infill trajectories. Simulation studies were carried out to evaluate the production potential of each of these infill horizontal wells.

Geologic Model

Appendix A contains figures that describe the reservoir geomodel that was used for simulation in this study. Figure A1 shows the location and the boundary of the study area for this project. Petrophysical well logs, core data (from two wells in the field), cuttings description, DST test results, and geologic reports from wells within and around the study area were used to build a geomodel for the reservoir. Tops of marker beds above and below the reservoir interval and the layers describing the reservoir were identified at each well within and around the study area. A series of cross-sections were built from different directions to cross-check and fine tune the geomodel. The reservoir was modeled with 4 layers, and Figure A2 shows that subsea structure top (feet) of the top layer (Layer 1). Layers 1 and 3 contribute to the production while the intermediate layers 2 and 4 are tight water saturated non-productive shale rich layers. Of the two productive layers, Layer 3 is more pervasive over the study area and has greater potential than layer 1. Figures A3 to A10 display the isopach, porosity, and initial water saturation (Sw) maps of each of the 4 reservoir layers. Few logs penetrate the layer 4, and the porosity averages between 0.15 to 0.16 in these instances. Thus, a uniform porosity of 0.15 was assigned to layer 4 in the simulation model. Few Sw values were available for layer 4, and an approximate Sw distribution was mapped (Figure A10) for this layer by projecting the known Sw values down dip to the oil-water contact (OWC). Figure A11 is an example cross-section across the field with the productive layers shown in green while the intervening non-productive layers are shown in blue.

Production data

The Ummel lease (Sec 23) was drilled and developed by Mull Drilling Company (MDC). Records of regular barrel tests were available for the Ummel wells, and these were used to recreate the oil and water production histories of these wells. Water production data from wells in the Pfannenstiel and Pember leases were not available. Only well level oil production histories were available for these wells. Ummel 1 (MDC, Sec 23) is the most productive well in the lease with a cumulative production of 174 MSTB. This well is also characterized by the lowest WOR. Ummel 2 shows a mediocre WOR vs. cumulative production profile while Ummel 3 has always produced water volumes far in excess to that from any of the other wells in the field. Figure B1 (Appendix B) plots WOR against cumulative production for Ummel 1 and 3 (MDC, Sec 23) wells. Limited water production data (after 1998) was available from Pfannenstiel 2A-24 (MDC, Sec 24), and upon plotting in Figure B1 was found to closely match the trend established by Ummel 2

(MDC, Sec 23). Thus, the linear equation best fitting the WOR vs. cumulative production for Ummel 2 (MDC, Sec 23) was used to estimate water production from Pfannenstiel 1 (Sun Oil, Sec 24), Pfannnenstiel 2 (Associates O&G, Sec 24), and Pember A5 (Mineral Exploration, Sec 25). Figure B2 lists the cumulative oil production from each well within the study area.

Decline Curve Analysis

One of the critical inputs to a simulation model for history matching is the bottom-hole pressure (BHP) history under which a well is produced over its life. Unfortunately, a regular record of BHPs was not available for any of the wells in the study area. The industry partner in this project, an operator of some wells within and around the study area, advised as per prevalent practices that given the volumes of oil produced from each well it would not be uncommon for these wells to be produced under minimal BHPs, (back pressure in the range of 100 psi). To test this assumption, decline curve analysis was carried out by plotting the average annual oil production rate at each well on a plot whose axes coincided (in cycle-length) with that of the standard Fetkovich decline curve (SPE-AIME, 1980). Figure C1 (Appendix C) shows the results for Pfennestiel 1 (Associates O&G, Sec 35). As a single decline curve was found to represent most of the well production history neglecting the production increases after the 70th month. Records are insufficient to explain the reasons behind each of these production increases. Based on standard operating practices in this area, stimulation and/or pump change(s) are likely causes of these production increases. However without proper documentation of the changes, it is not possible to include these changes in well operation in the simulation model for this well. The decline curve indicates that significant cumulative production is not associated with these production bumps as the well production rates are below 3 BPD, and therefore material balance of fluid withdrawal from the reservoir will not be affected if a uniform decline in production (blue line) was assumed for this well. Figures C2 to C7 show the decline curves best fitting the oil production data for the other wells. For most wells, a single decline curve is able to represent most of the production history except the very last segment when production increases stray from the decline curve.

Thus for most of the well history, it is not unreasonable to assume that the well produced under unchanging bottom hole conditions, i.e., the skin and bottom hole pressure (BHP) remained mostly unchanged.

Petrophysical Log Analysis

Super-Pickett analysis of petrophysical logs from the Ness City North field have already been reported in KGS OFR – 1999-58. A complete suite of petrophysical logs was available from only two wells. Figures D1 to D3 (Appendix D) summarize the Super-Pickett analysis. Standard values of m (=2.0) and n (=2.0) were used to analyze the logs. Based on the water salinity information (Cl^- ppm of 19,500) the formation water resistivity (Rw) was calculated as 0.13. From the limited data, it appears that bulk volume water (BVW) values have to be less than 0.07 for water-free production or production with minimal water (Figures D2). Perforated zones with BVW values greater than 0.07 (Figures D1) result in a non-commercial well such as Ummel 4 (MDC, Sec 23). A Rhomma-Umma plot (Figure D3) on data from Pfannenstiel 2A-24 (MDC, Sec 24, and previously called Pfannenstiel 1-24) indicates that the reservoir rock is cherty-dolomite like many other Mississippian fields (such as Schaben field) in this area.

DST Analysis

DST analyses had been previously reported in KGS OFR – 1999-58. Appendix E summarizes the results of the DST analysis. DST pressure-time data was available for 5 wells within the study area. Figure E1 shows the initial pressure (Pi) psi calculated from the available DST data. Based on this pressure profile, the initial reservoir pressure was assumed to be 1350 psi. Producing fluid levels from the horizontal infill well, Ummel 4H (MDC, Sec 23), drilled in 2000 gives some indication as to the current reservoir pressure. This well produced 57 BOPD and 52 BWPD against a standing fluid column of 1860 feet above the perforations. Thus as of mid 2000, the reservoir pressure must have been greater than 950 psi.

PVT and Relative Permeability/Capillary Pressure Inputs

Appendix E summarizes the PVT and other field wide inputs to the simulation model. There is no mention of any gas production being recorded at Ness City North field wells. Thus, the bubble point pressure is low given that no gas production has been recorded at the wells even when they are produced under pumped off conditions. The reservoir produces under a strong water drive. Within the simulation model, each well is produced at least under a BHP of 100 psi and to prevent any three-phase flow from occurring a low bubble point of 100 psi was assumed (at subsea –1996 feet) in this study. There was no measured bubble point data available. Oil PVT properties are listed in Table F1. Bubble point pressure, reservoir temperature, and oil and gas gravities were input to the inbuilt PVT calculator within the reservoir simulator (Computer Modeling Group's IMEX) to generate other necessary PVT tables. Other field wide assumptions, particularly relating to each well, that were input to the simulator are listed in Table F1.

A Mississippian core was available from Pfannenstiel 2 (Sun Oil, Sec 24) located within the field. Also, two other cores from just outside the field were available, namely from Ummel 1 (Sun Oil, Sec 23) and Pfannenstiel 1 (Sun Oil, Sec 24). Details of routine core analyses have been described in KGS OFR – 1999-58. Core plug measurements were used to develop representative permeability-porosity correlations (Tables F2 & F3) for both the reservoir and non-reservoir rock. Also, capillary pressure measurements were carried out on representative core plugs along with recordings of end-point saturations. Data collected from these core studies integrated with the data set on Mississippian core plugs that has been built by virtue of studies, carried out at the KGS, on other Mississippian fields of the Mid-continent. Porosity was found to correlate with end-point saturations such as Swi (irreducible water saturation) and Sorw (irreducible oil saturation to water). Using these correlations and measured capillary pressure curves, a "new" relative-permeability/capillary pressure calculator was created using Corey-type equations. These calculators help to input a consistent set of relative-permeability/capillary pressure tables into the simulator upon making changes in effective permeability over the drainage area of a well during the history matching phase.

Thus, changing the permeability input updates the table by changing the saturation end points while preventing dramatic changes in the capillary pressure curve shapes. Also, the relative permeability exponents (m and n) enable changing the relative ease of flow between the two fluid phases in the reservoir, i.e., the oil and water, especially during history-matching well-level production. Table F2 shows the calculator for the reservoir rock (Layers 1 and 3) while Table F3 displays that for the non-reservoir rock (Layers 2 and 4).

Sporadic measurements of standing fluid columns over production life were available for some of the wells. These records served as the basis for determining the BHP under which each well was flowed within the simulator. Table F4 summarizes the BHP under which each well was flowed within the simulator. In particular, Pfannenstiel 2A-24 (MDC, Sec 24) was initially flowed under pumped off conditions when it was perforated only in layer 1. Later in January 2001, its perforations were extended to layer 3 and the well was produced under significant standing fluid column. It was due to a pump change in November 2002 that the well started to produce under a lower BHP.

Simulation study – History matching

The reservoir was simulated as a 4-layer model with 110 feet by 110 feet grid cells and an analytical bottom aquifer. The aquifer properties were fine-tuned so that the calculated current reservoir pressure was around 1100 psi. Initial saturation (Sw) and pressure distributions in the drainage area of each well was input with the help of capillary pressure curves and having the simulator perform gravity-capillary equilibrium calculations. The initial permeability in each layer was populated using the permeability-porosity correlations generated from core analysis. The correlation for the reservoir rock is stated in Table F2 while Table F3 shows the relevant correlation for the non-reservoir rock. Each well was produced under a constant/variable BHP (Table F4) with the simulator calculating the oil and water production at the end of every time step. Parameters that were fine-tuned to history match individual well performance included effective permeability in the drainage area of the well and relative permeability exponents "m" and "n".

Figure G1 (Appendix G) shows the layers that each well was perforated inside the simulator model. Figures G2 to G7 show the history matches obtained at each of the original vertical wells in the field. After completion of history matches of the original vertical wells, the simulator was instructed to predict the performance of the vertical infill well Pfannenstiel 2A-24 (MDC, Sec 24). Figure G8 compares the simulator output with the recorded production from this well. The match during the initial period of the well's life (pre-2001) is modest, but improves after extension of the perforations in 2001. It needs to be remembered that only limited information is available about production practices prior to 2001, and additional information is required to improve the match. Finally, the simulator model was used to predict the performance of the horizontal infill well Ummel 4H (MDC, Sec 23) drilled in 2000. Figure G9 shows that the simulator predicted average initial production is close to that recorded at the well during its brief (1 month) life before the well stopped production due to formation collapse along its uncased lateral length. In the simulation model, this horizontal infill well is located within the drainage area of Ummel 1 (MDC, Sec 23). The only parameter that was locally modified to obtain this match was changing the horizontal permeability to 15 md from 25 md. The simulator calculated average reservoir pressure as of January 2003 was 1185 psi. Overall, this revised geomodel was able to better the history matches and improve the predicted production from the horizontal infill well than reported earlier in KGS OFR 2000-80.

Simulation study – Performance evaluation of different horizontal infill trajectories

Appendix H summarizes the results of the performance evaluation studies carried out with the help of the simulator on different horizontal infill trajectories. Upon completion of well history matches, a map of residual reserves (oil-ft, product of porosity, oil saturation and grid thickness) was generated as of January 2003. Most of the remaining potential was found to reside in Layer 3 (L3), and the remaining oil-ft map as of January

2003 is shown in Figure H1. Productive potential of two infill trajectories was studied. In each case, the horizontal was assumed to be 6 inch in diameter and to have been produced for 10 years (starting January 1, 2003) under a constant BHP = 200 psi and a skin factor of 1.5. One of the first infills, a 990 feet long East-West well that was evaluated is shown in Figure H2. The effects of the drainage capability of this well is shown in the residual reserve (oil-ft) map (also Figure H2) as of January 2013, particularly when compared with that of January 2003. The expected production from this well is tabled and plotted in Figure H3. Simulation studies indicate that after 10 years the expected cumulative production from this well will be in the range of 60 MSTB while requiring to move about 1000 MSTB of water. The location of this infill is in close proximity to two producing wells, namely Ummel 1 (MDC, Sec 23) and Pfannenstiel 2A-24 (MDC, Sec 24). Interference effects of this infill well on the production of the above two wells are shown in Figure H4. Figures H5 to H7 show the drainage effects of a second infill trajectory (south-west to north-east diagonal well), it cumulative production and interference on Ummel 1 (MDC, Sec 23) and Pfannenstiel 2A-24 (MDC, Sec 24). The infill well is expected to produce about 76 MSTB (Figure H6) over 10-year production life but also result in an estimated total production loss of 30 MSTB (Figure H7) at Pfannenstiel 2A-24 (MDC, Sec 24).

Appendix A

Geologic Model

General location of study area – Mississippian structure, subsea feet

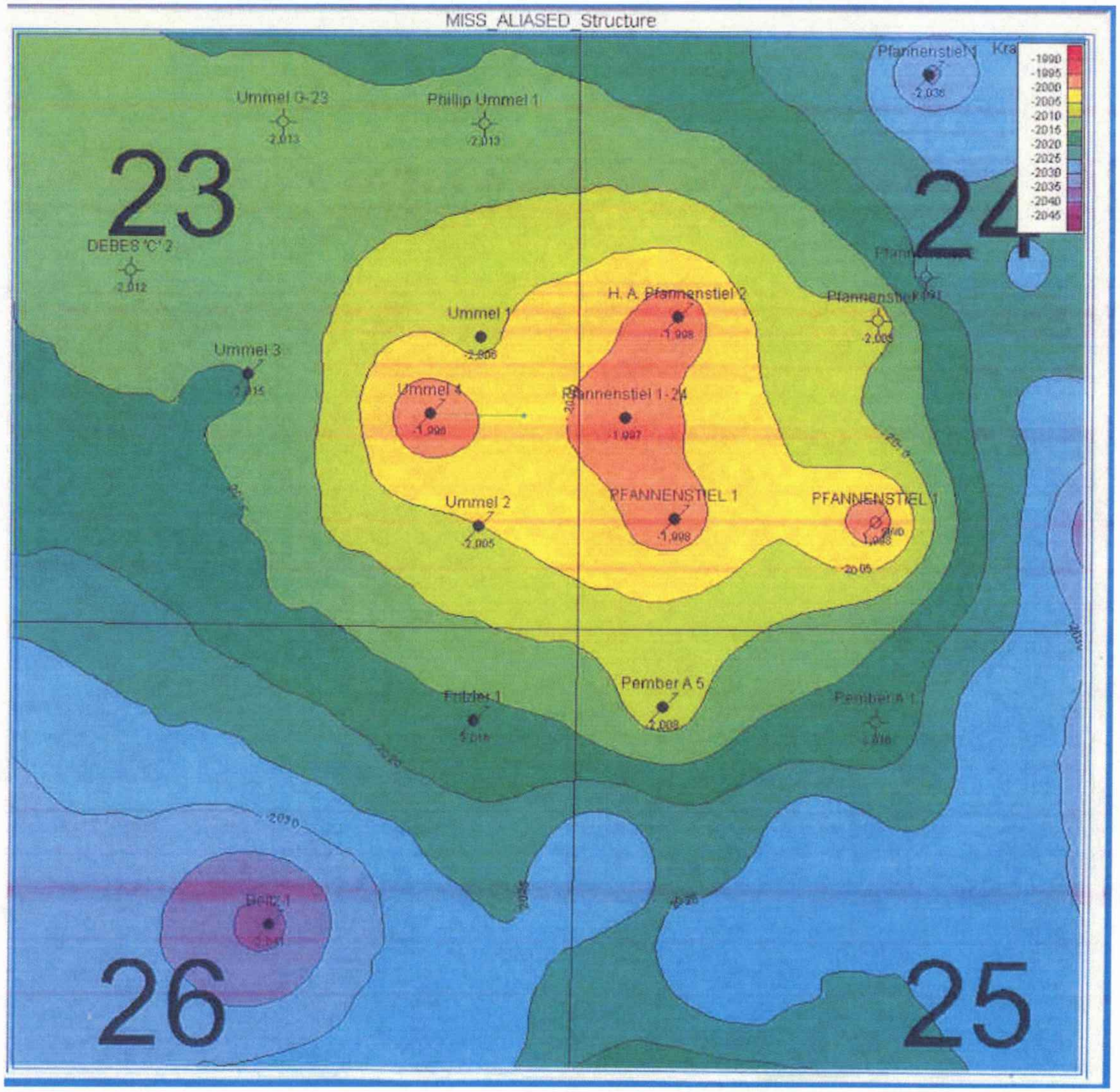


Figure A1

Structure top on Layer 1, subsea feet

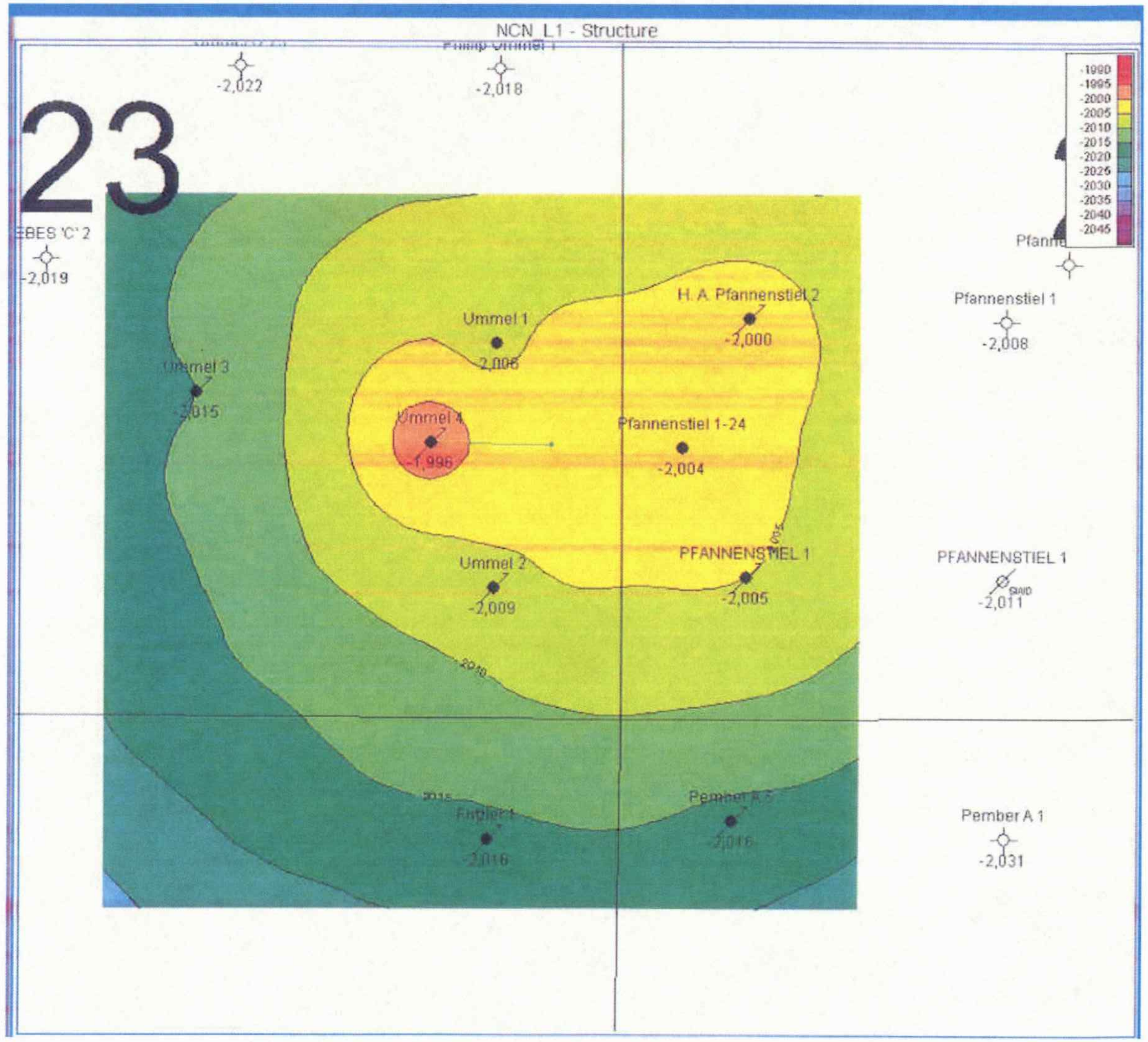


Figure A2

Layer 1 Isopach, feet

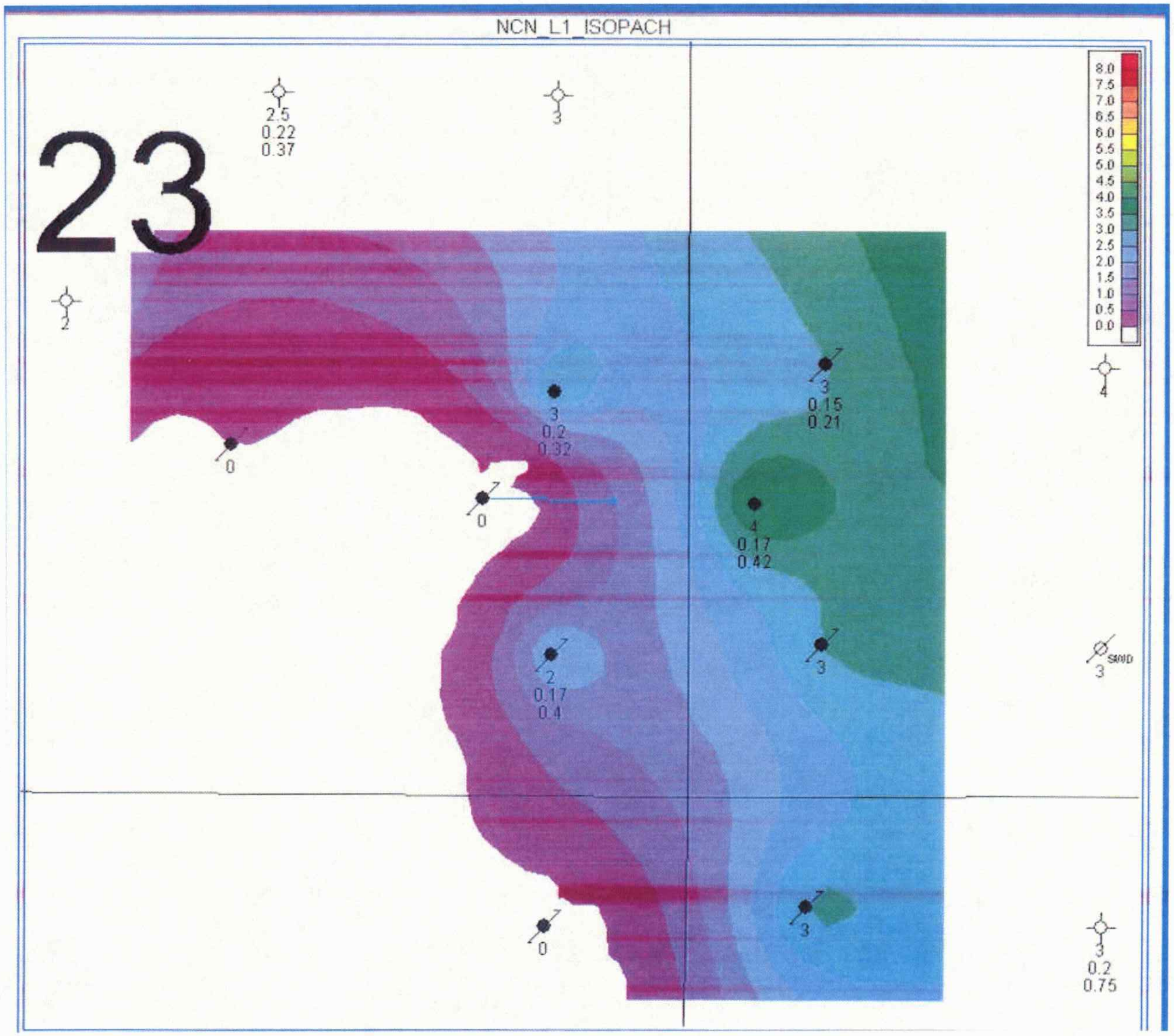
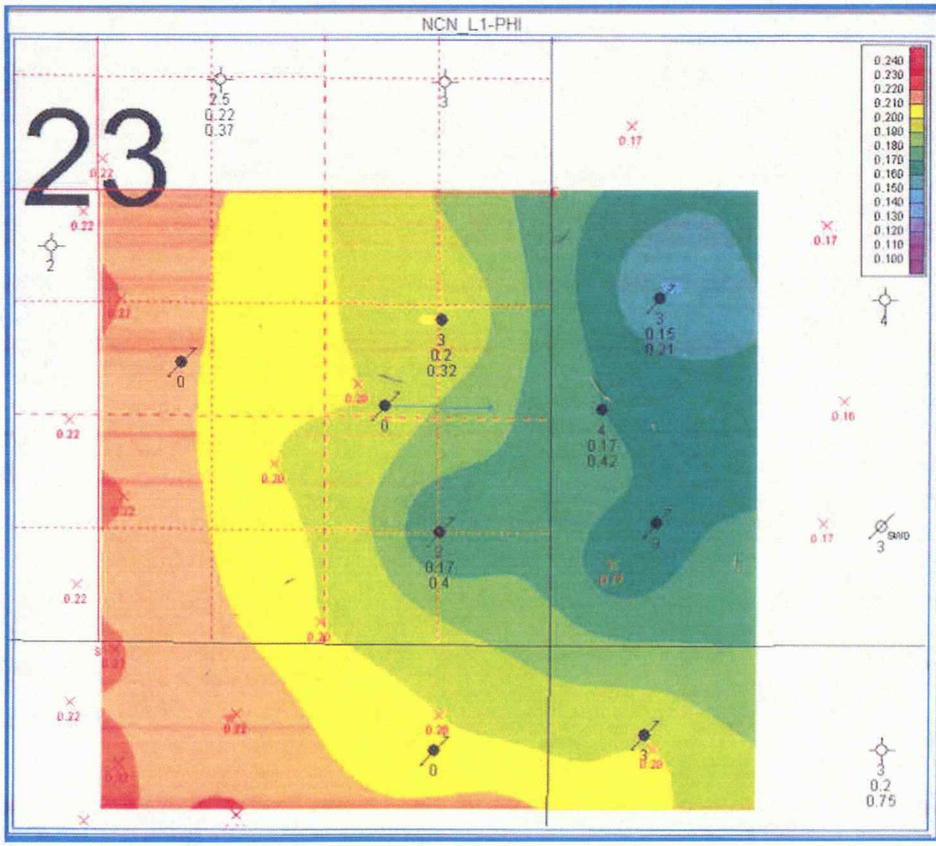


Figure A3

Porosity – Layer 1



Sw – Layer 1

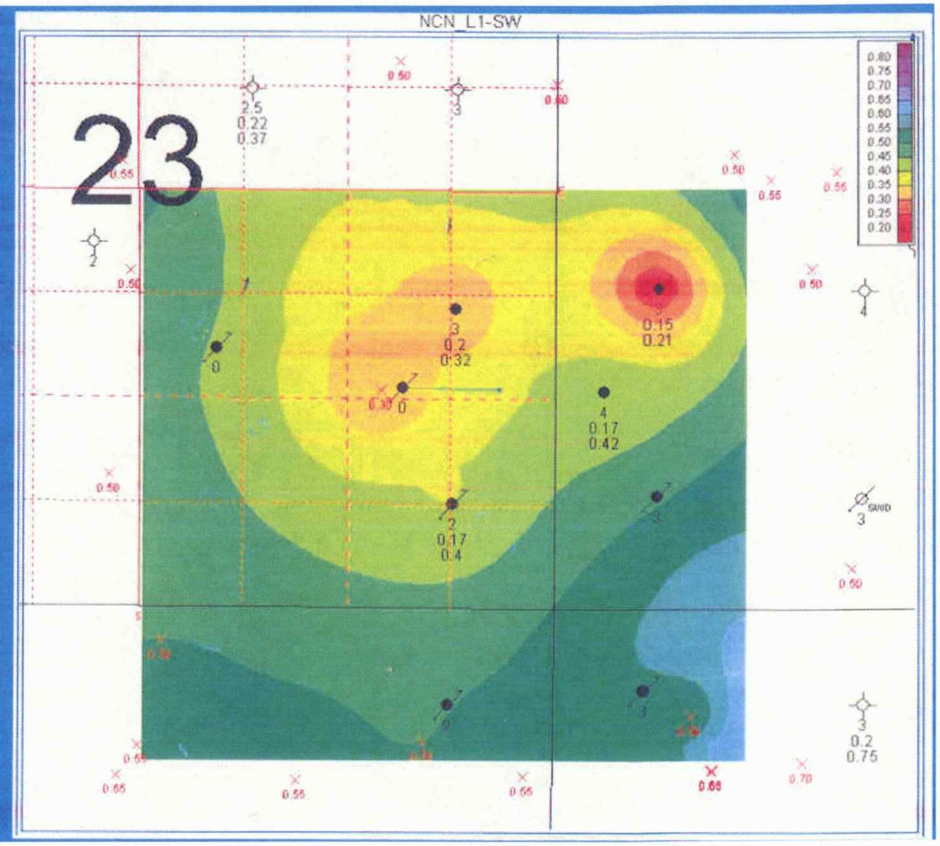


Figure A4

Layer 2 Isopach, feet

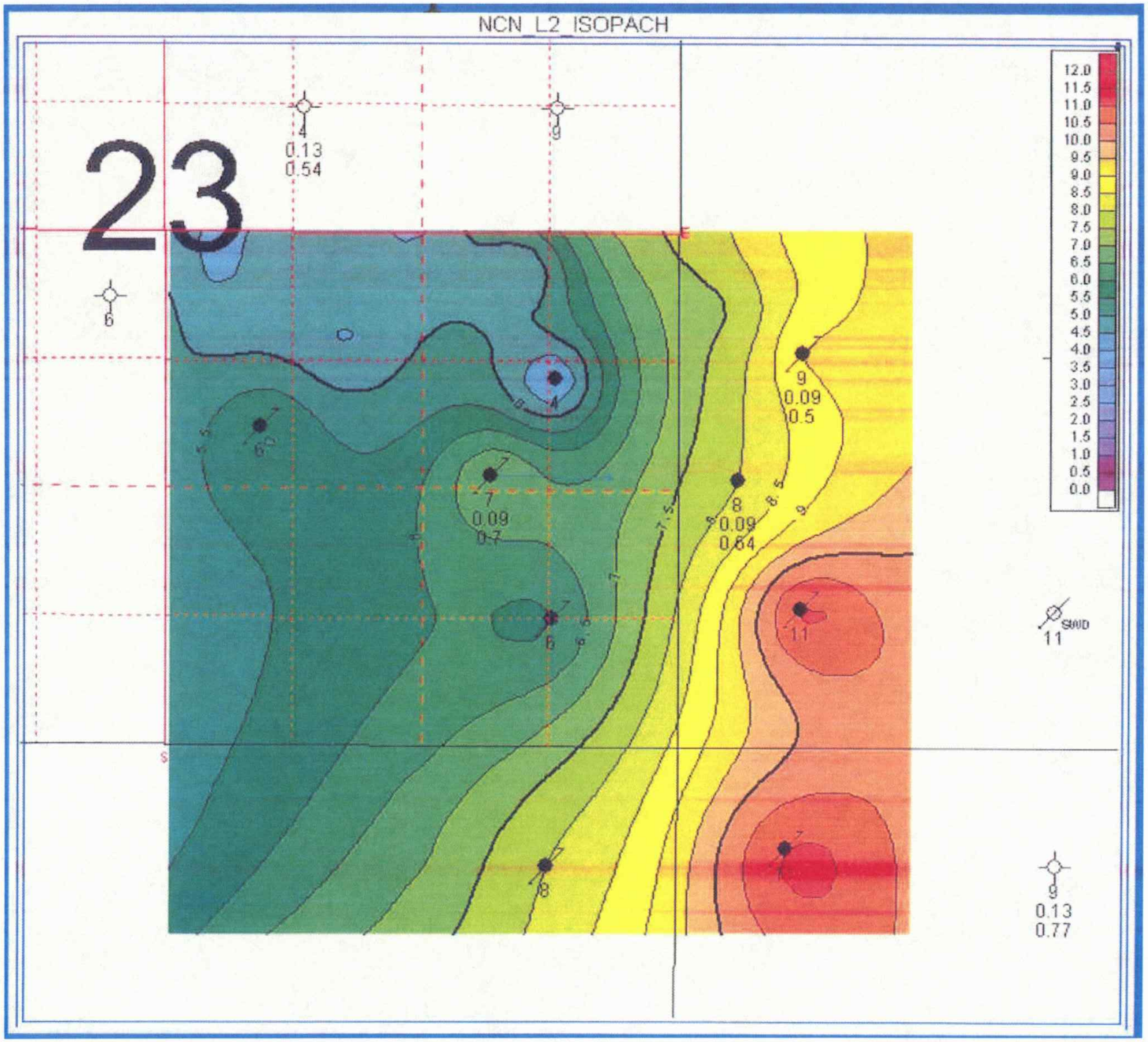
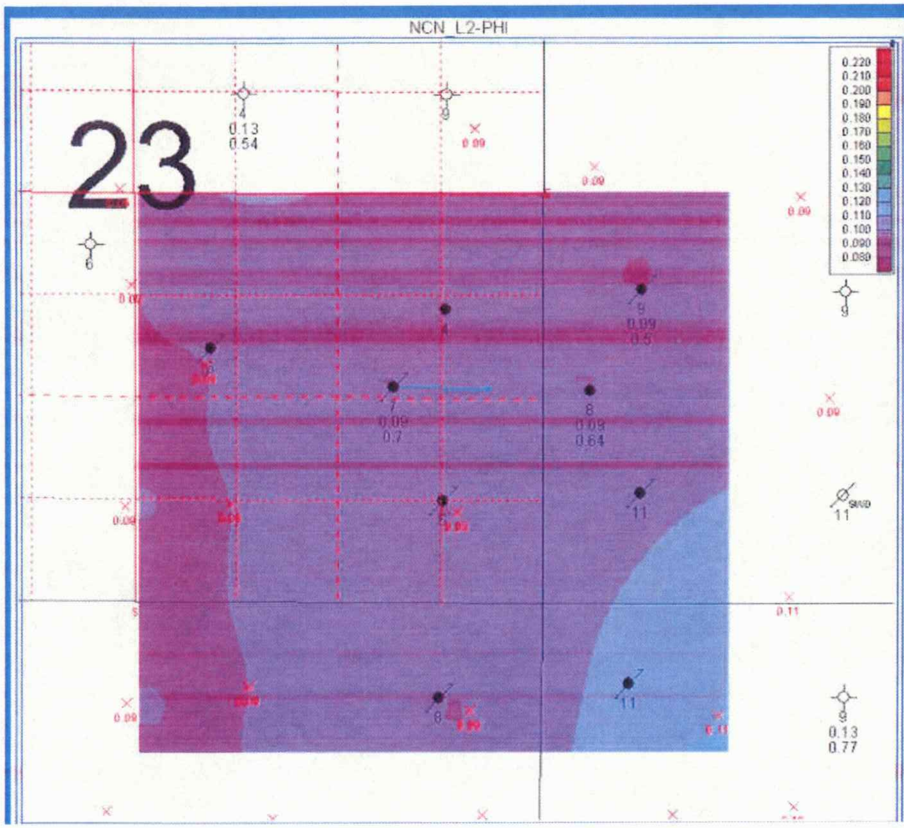


Figure A5

Porosity – Layer 2



Sw – Layer 2

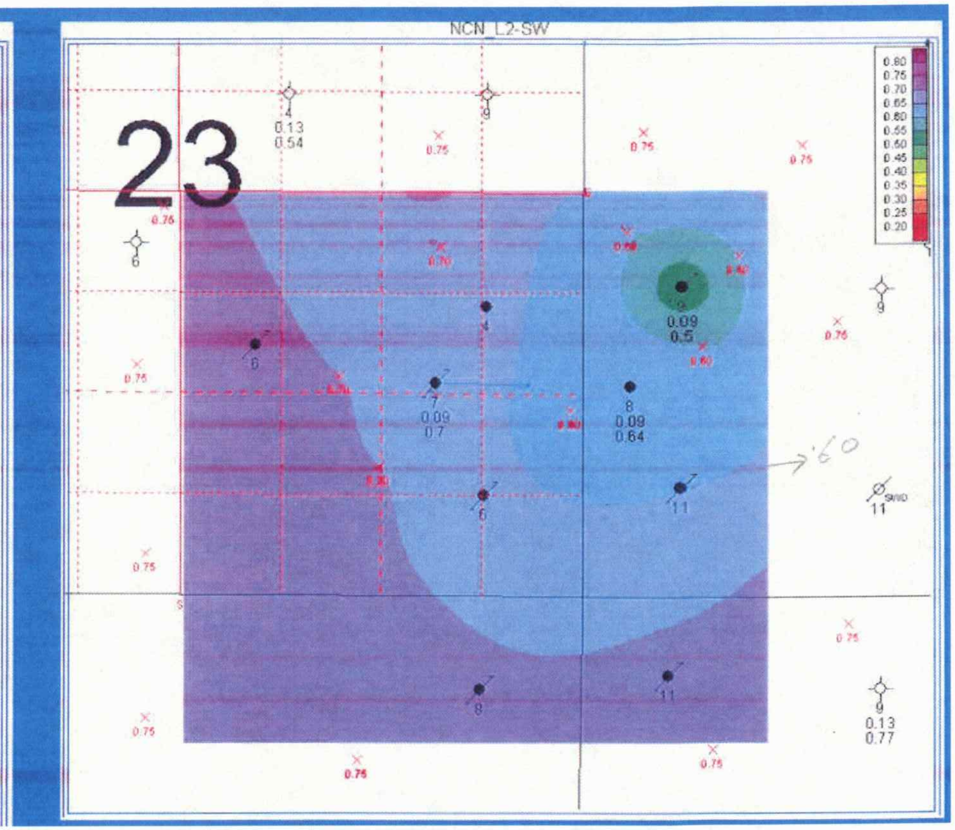


Figure A6

Layer 3 Isopach, feet

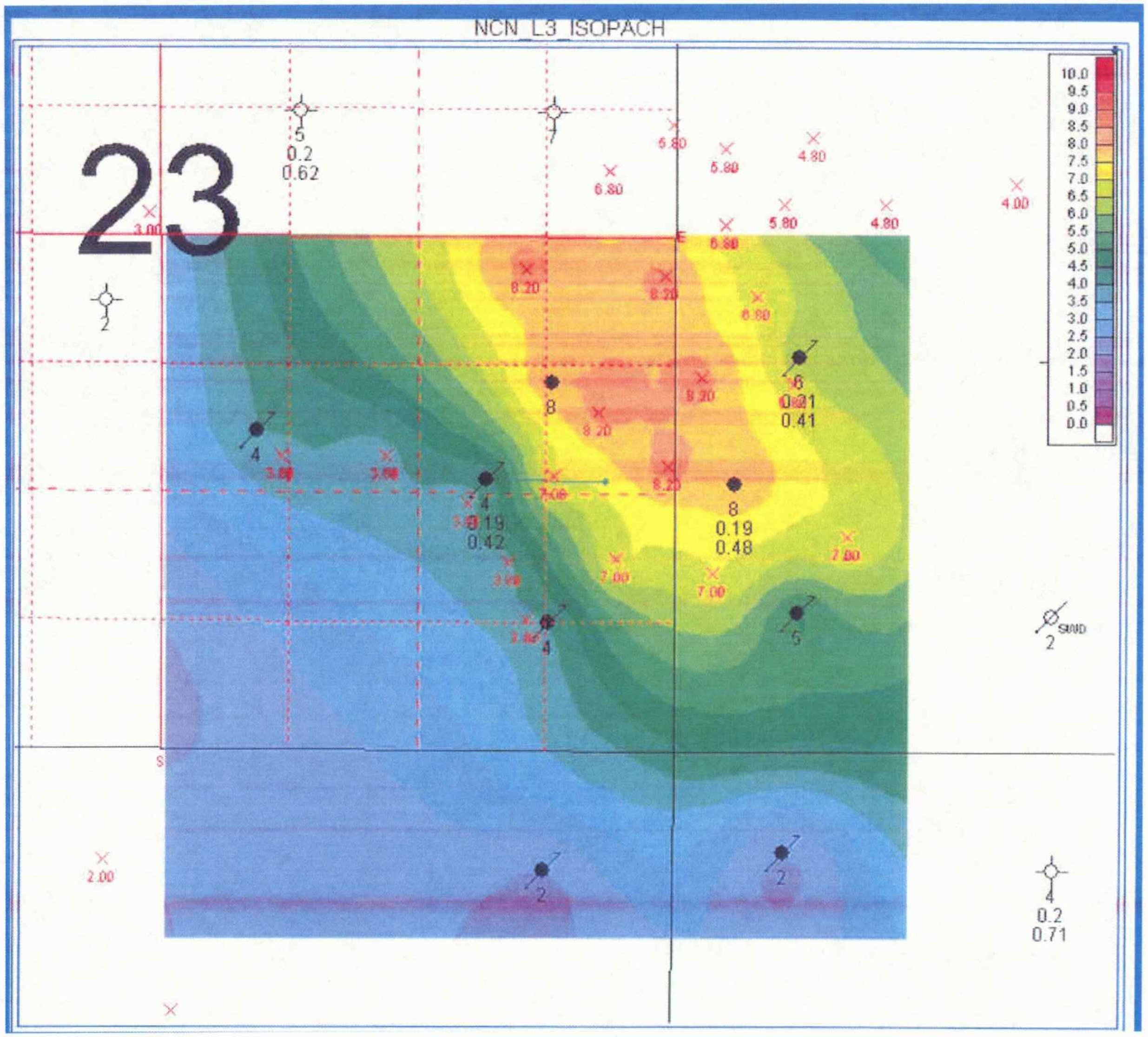
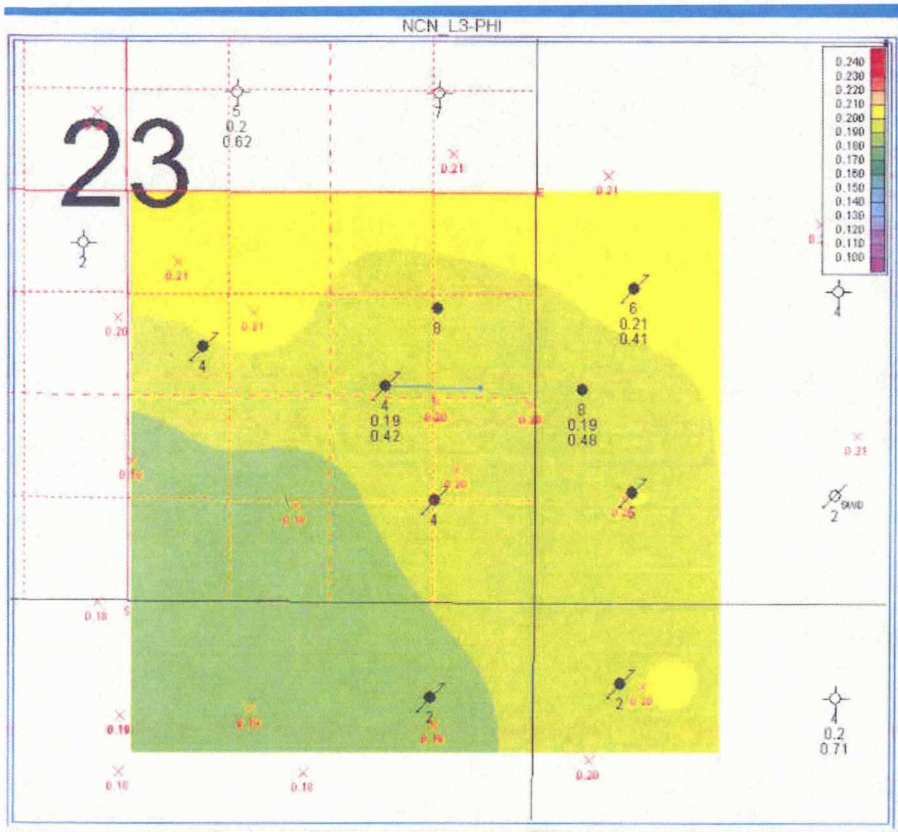


Figure A7

Porosity – Layer 3



Sw – Layer 3

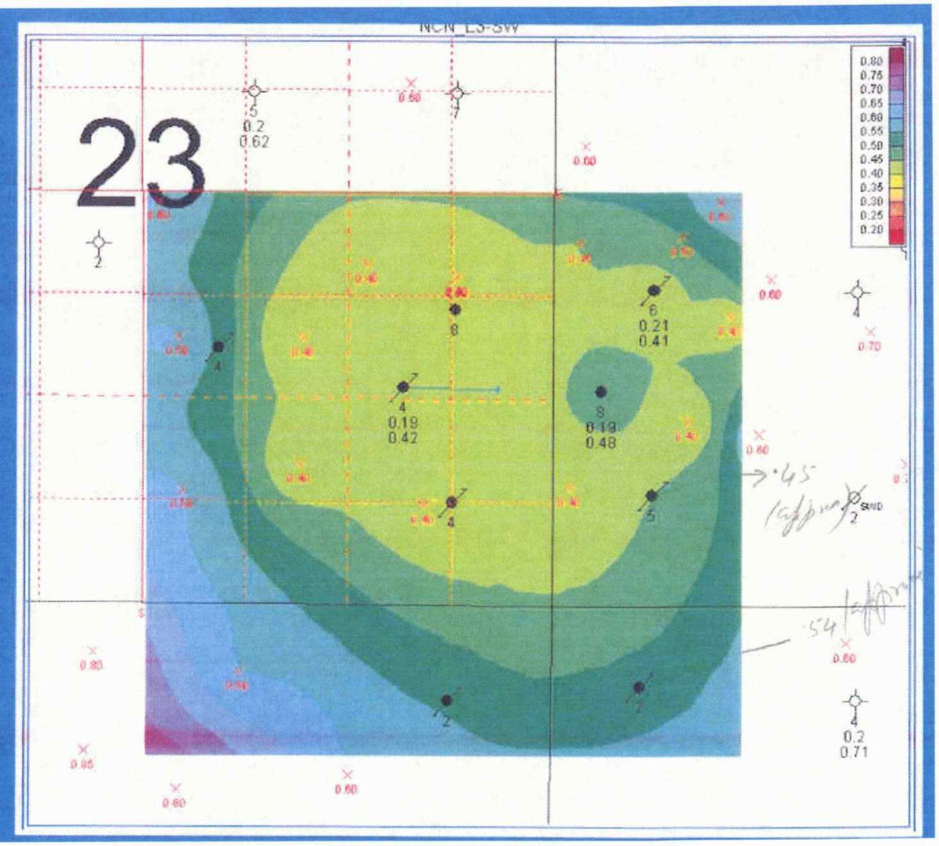


Figure A8

Layer 4 Isopach, ft

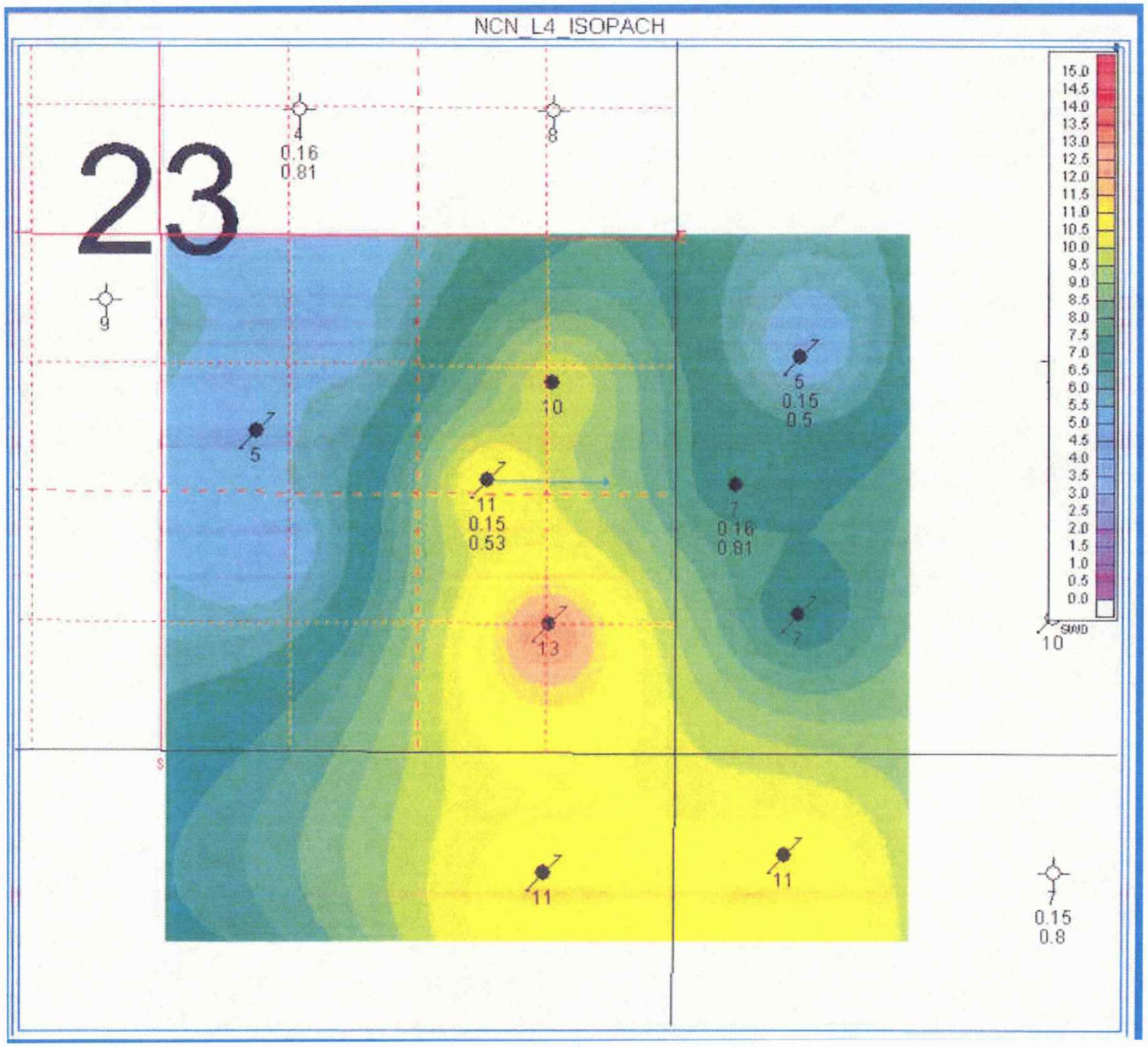


Figure A9

Sw – Layer 4

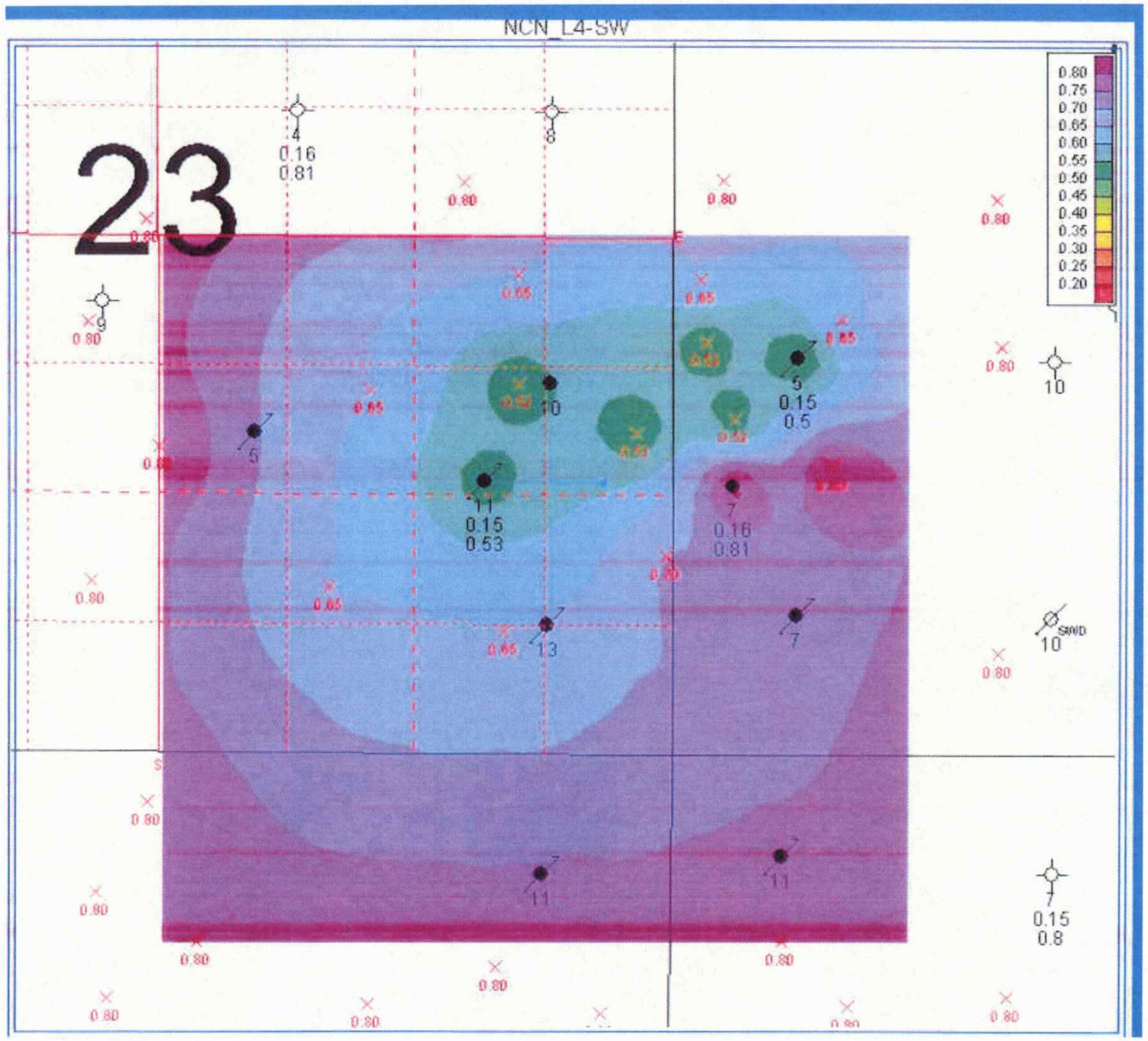
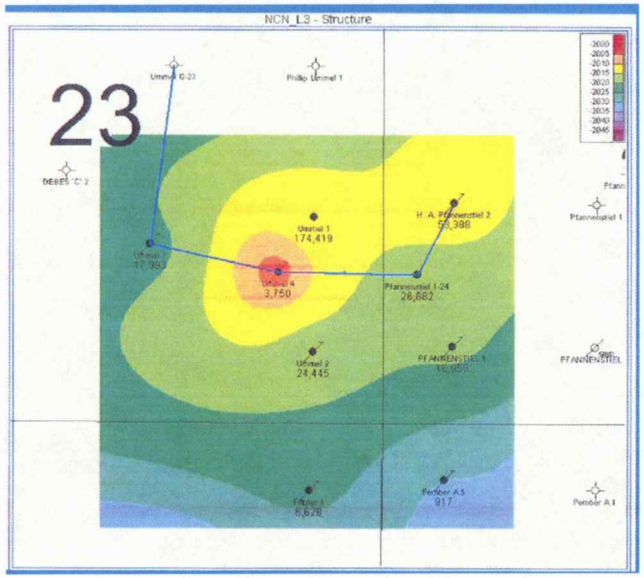


Figure A10

Example cross section



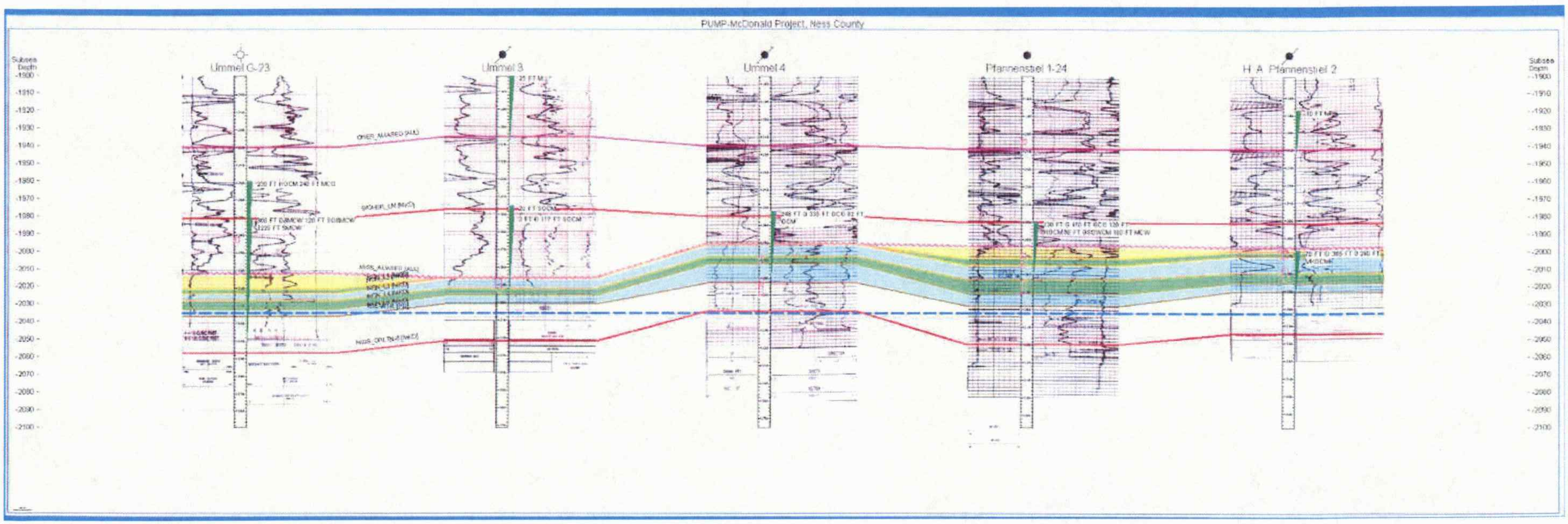


Figure A11

Appendix B
Production data

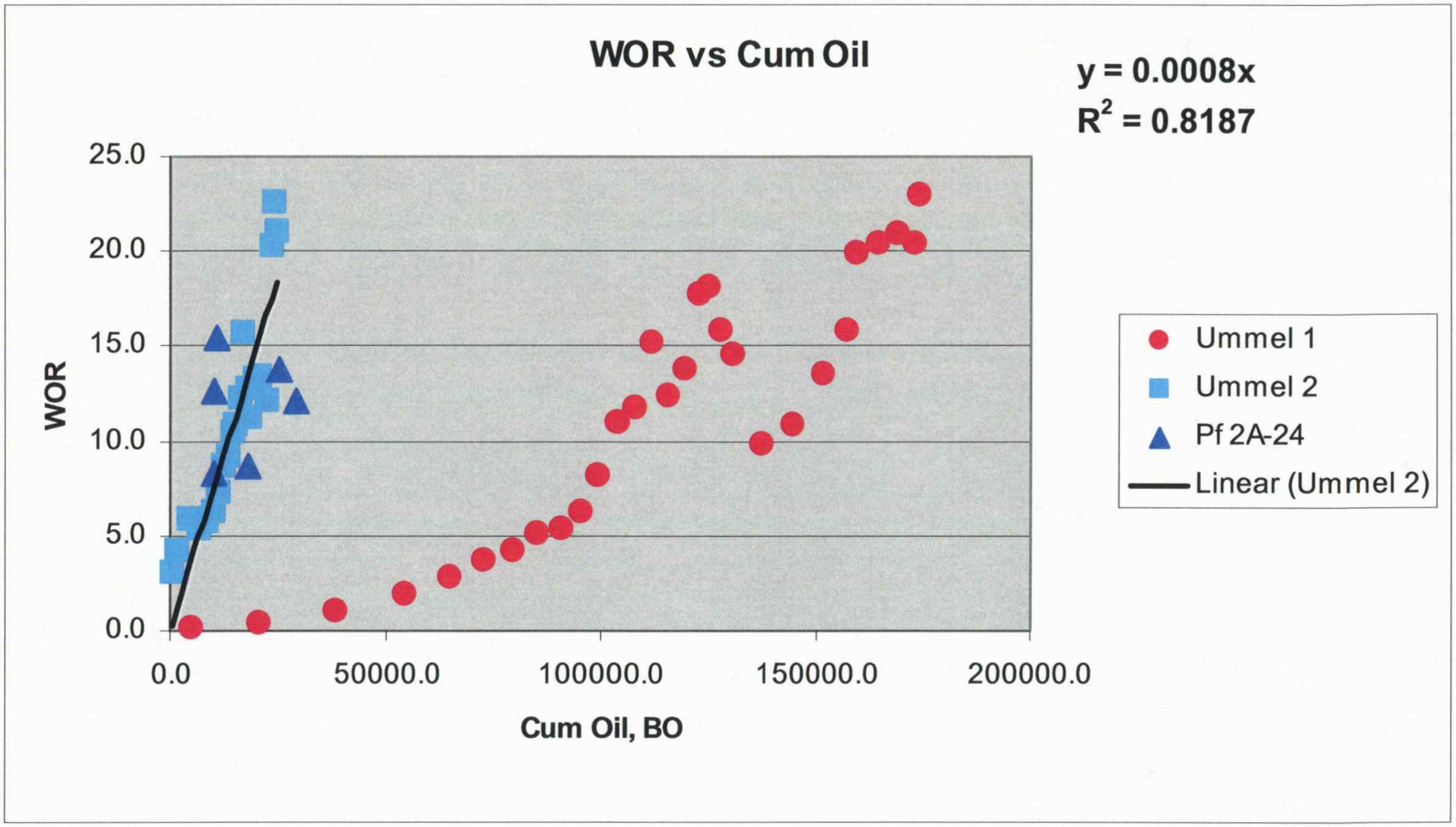

WOR vs Cum Oil
y = 0.0008x
R2 = 0.8187
25.0
20.0
15.0
10.0
5.0
0.0
WOR
0.0
50000.0
100000.0
150000.0
200000.0
Cum Oil, BO
Ummel 1
Ummel 2
Pf 2A-24
Linear (Ummel 2)

Figure B1

Well	Cumulative oil production, bbls
Ummel 1	174,419
Ummel 2	24,445
Ummel 3	17,993
Pfannenstiel 2	53,388
Pfannenstiel 1	16,056
Pfannenstiel 2A-24	26,088
Pember A5	917

Figure B2

Appendix C

Decline Analyses

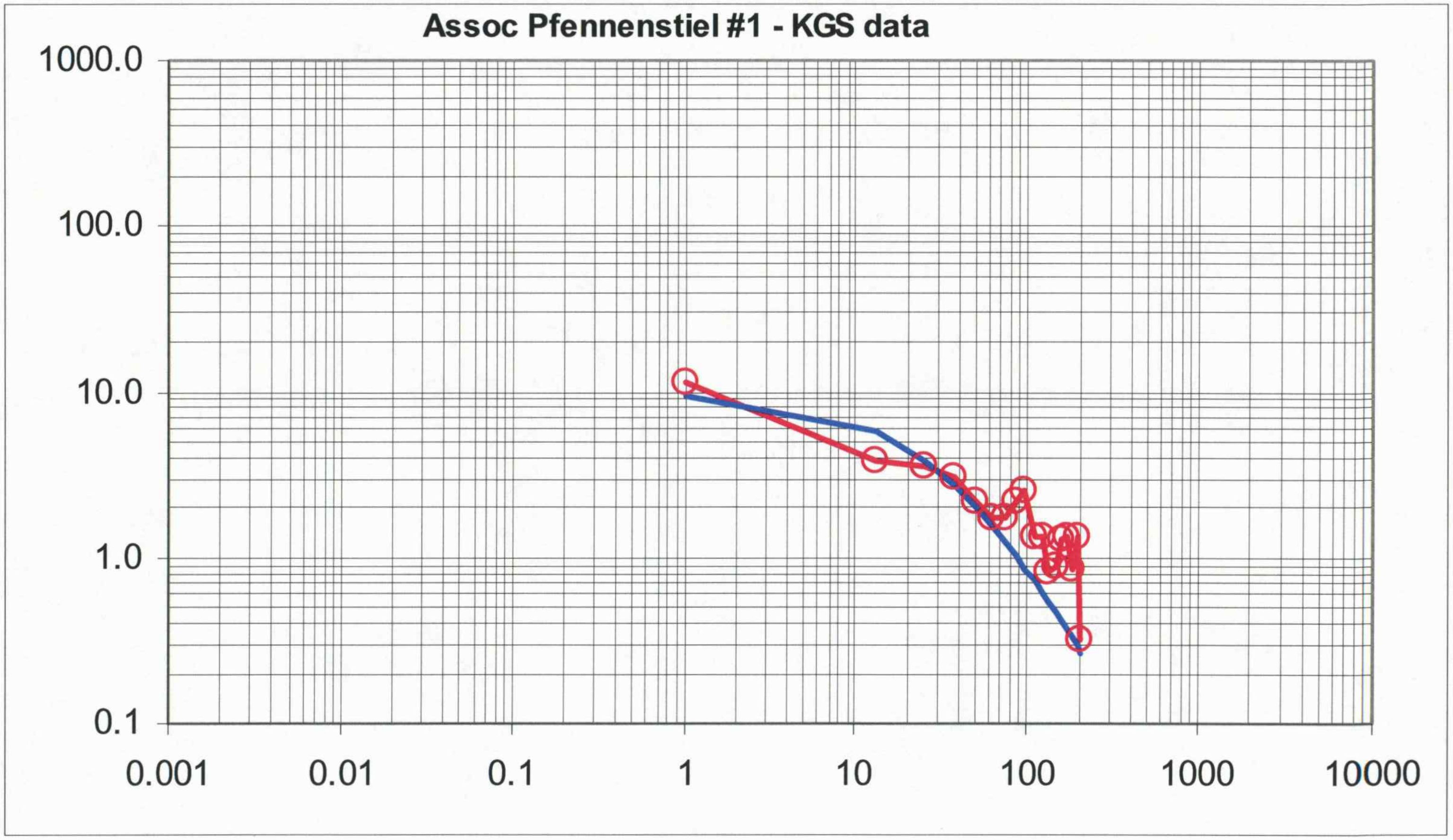

Assoc Pfennenstiel #1 - KGS data
1000.0
100.0
10.0
1.0
0.1
0.001
0.01
0.1
1
10
100
1000
10000

Figure C1

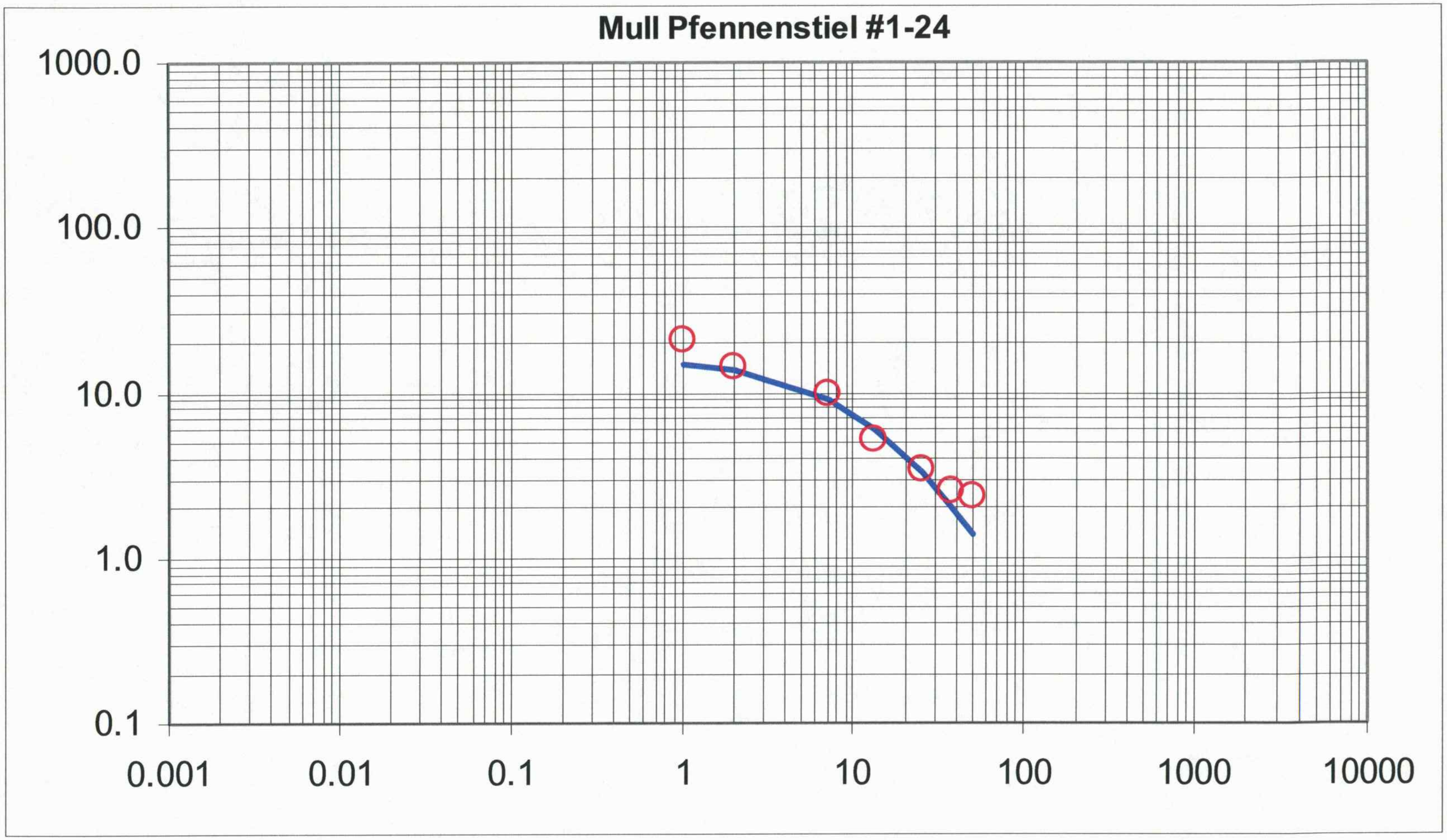

Mull Pfennenstiel #1-24
1000.0
100.0
10.0
1.0
0.1
0.001
0.01
0.1
1
10
100
1000
10000

Figure C2

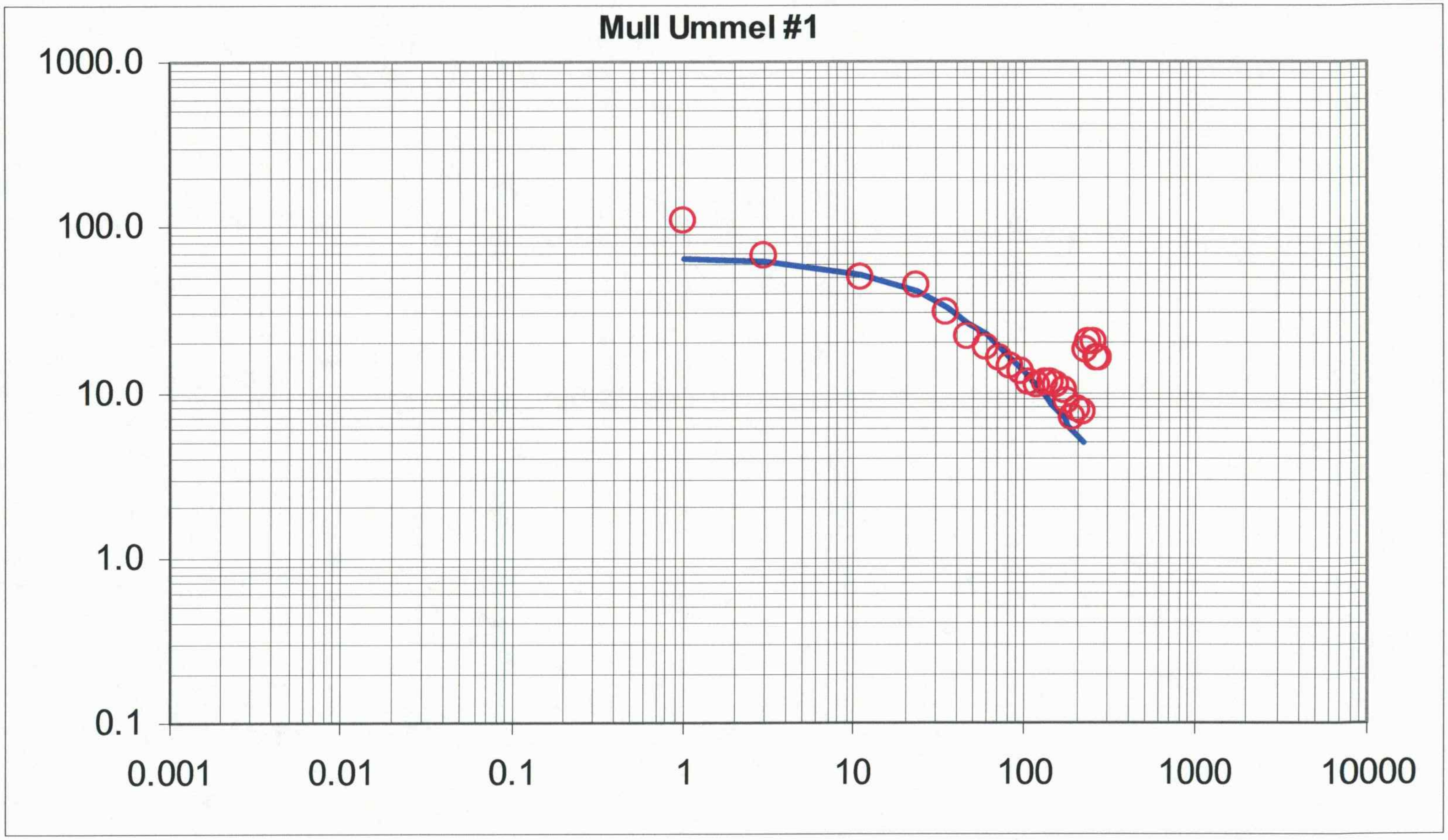

Mull Ummel #1
1000.0
100.0
10.0
1.0
0.1
0.001
0.01
0.1
1
10
100
1000
10000

Figure C3

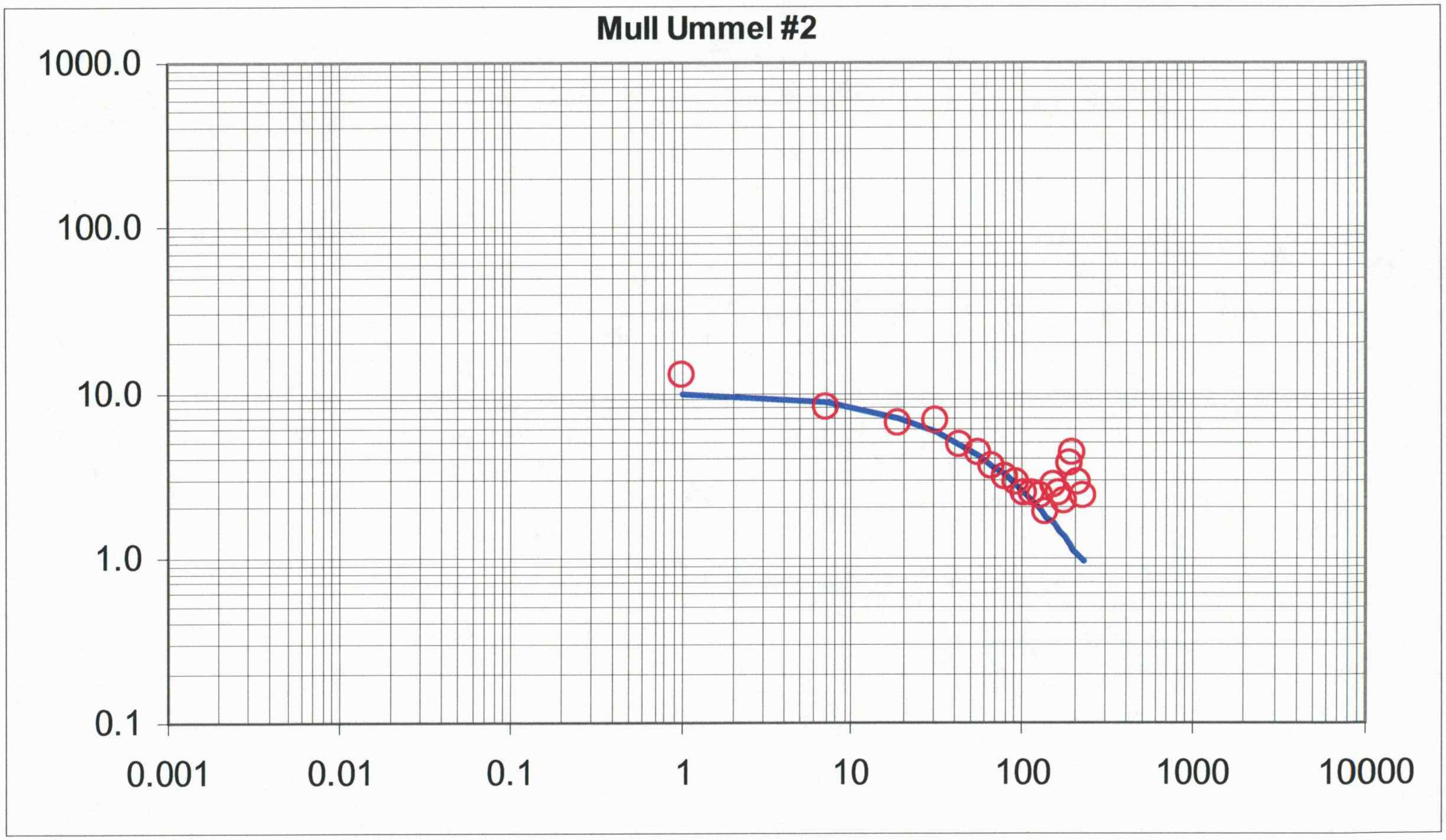
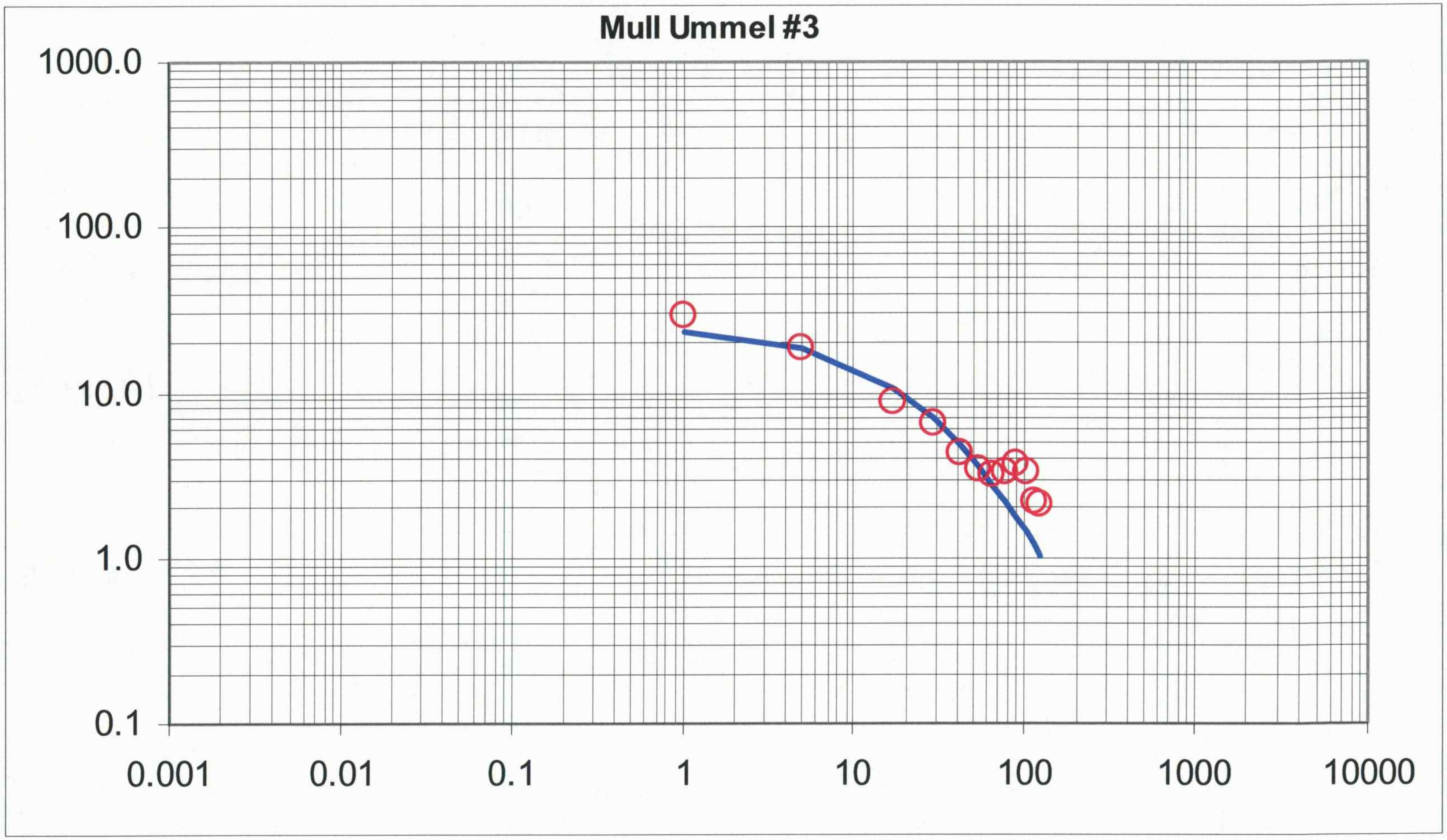

Mull Ummel #2
1000.0
100.0
10.0
1.0
0.1
0.001
0.01
0.1
1
10
100
1000
10000

Figure C4



Mull Ummel #3
1000.0
100.0
10.0
1.0
0.1
0.001
0.01
0.1
1
10
100
1000
10000

Figure C5

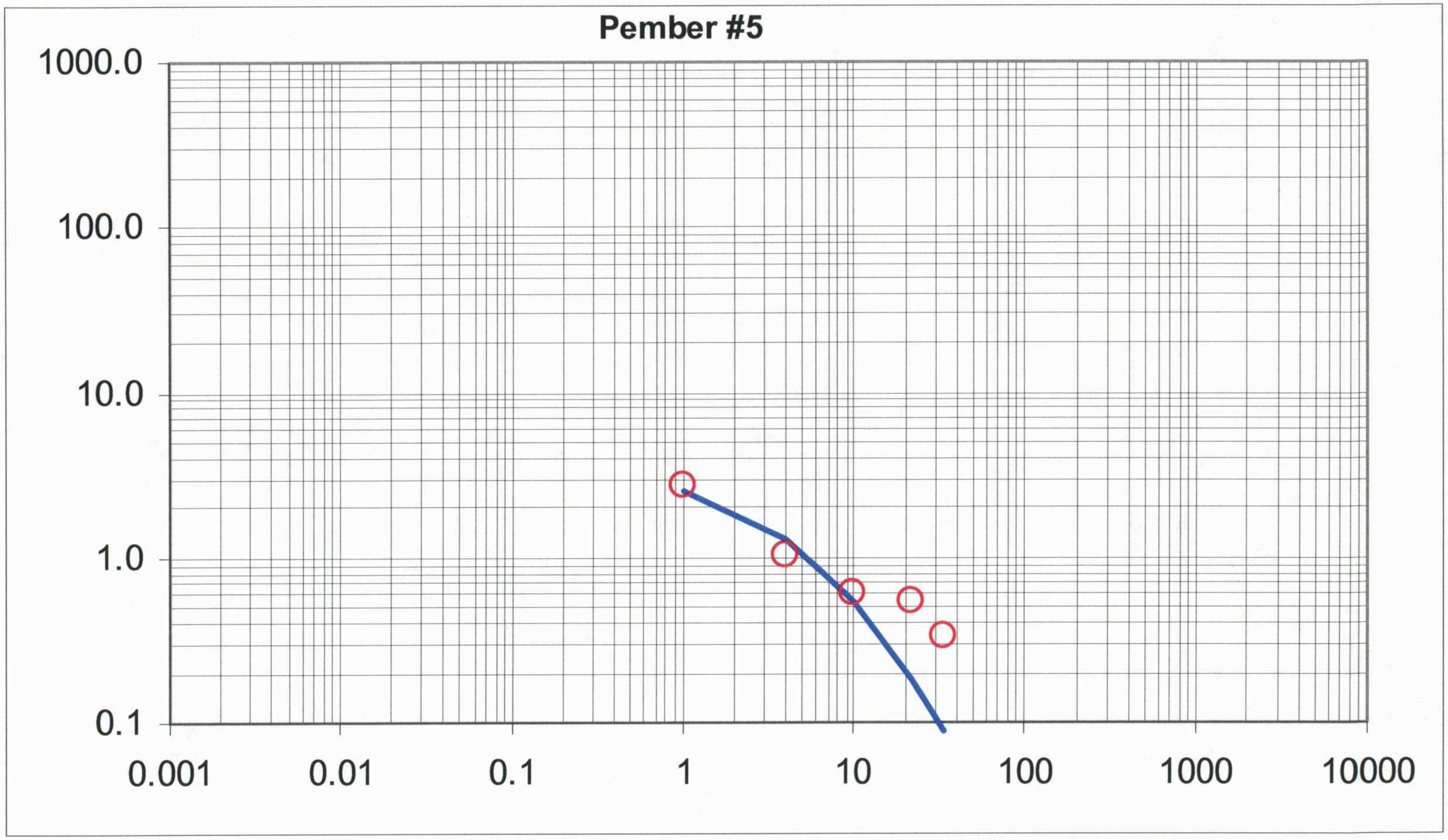


Figure C6

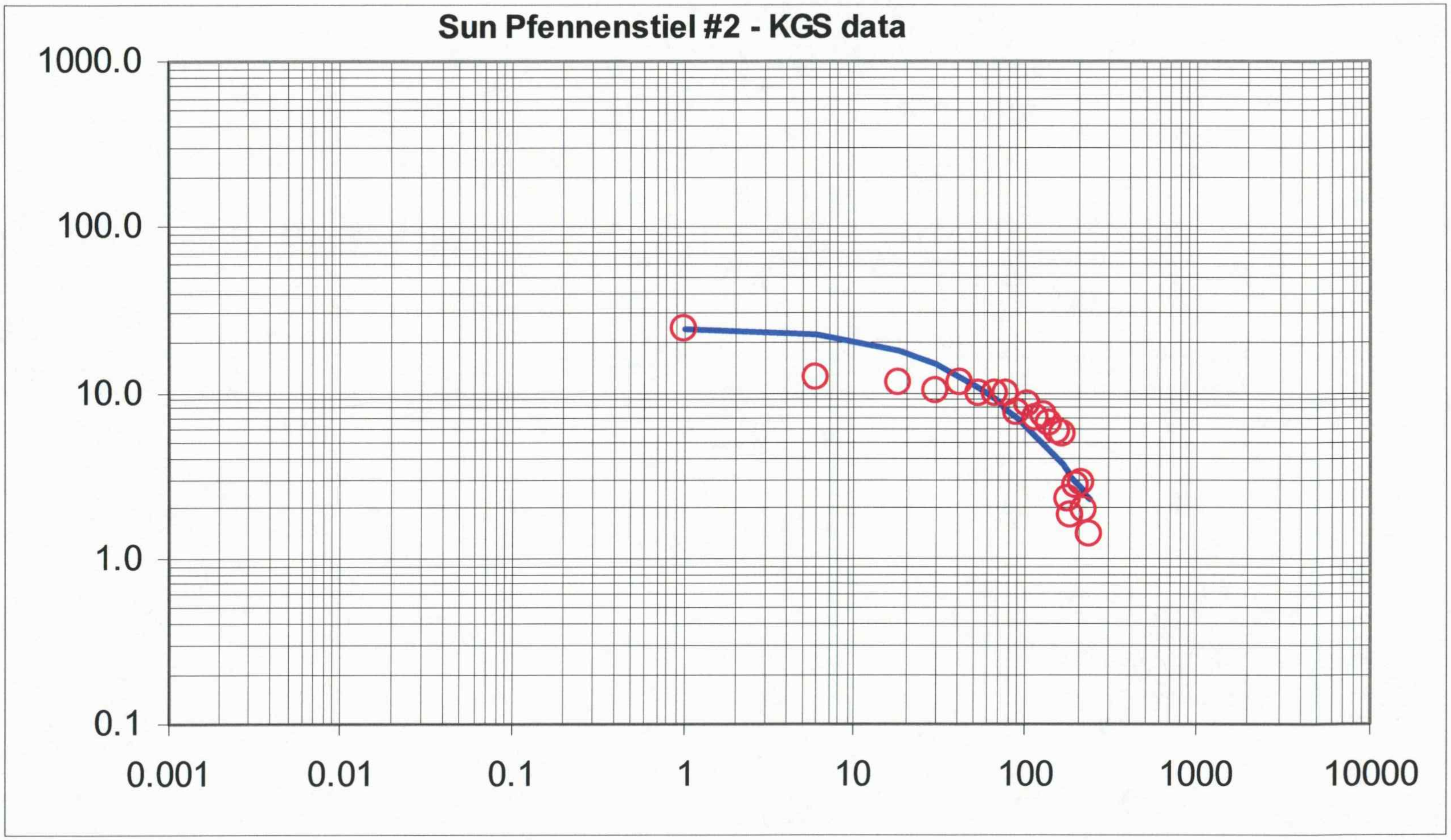
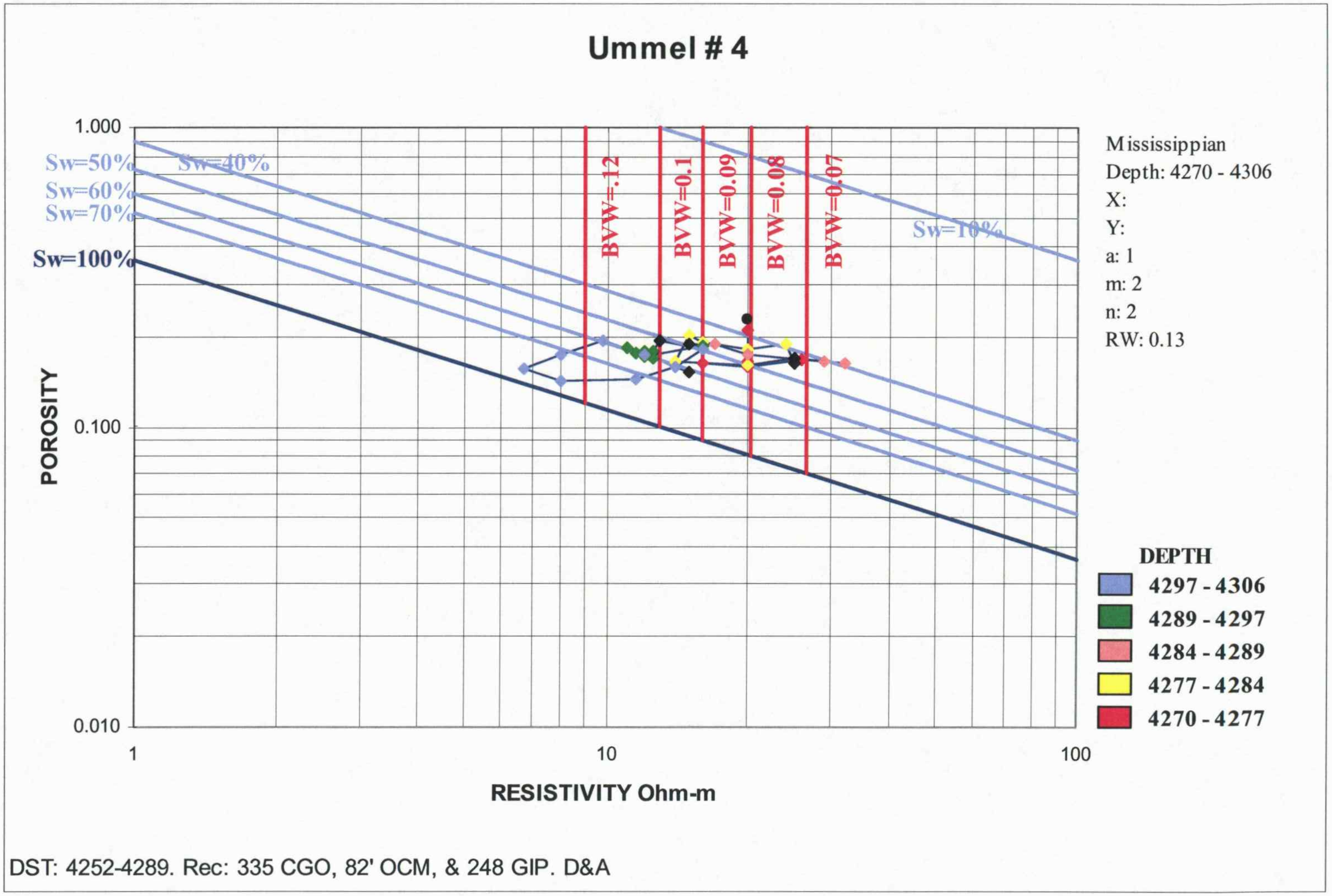

Sun Pfennenstiel #2 - KGS data
1000.0
100.0
10.0
1.0
0.1
0.001
0.01
0.1
1
10
100
1000
10000

Figure C7

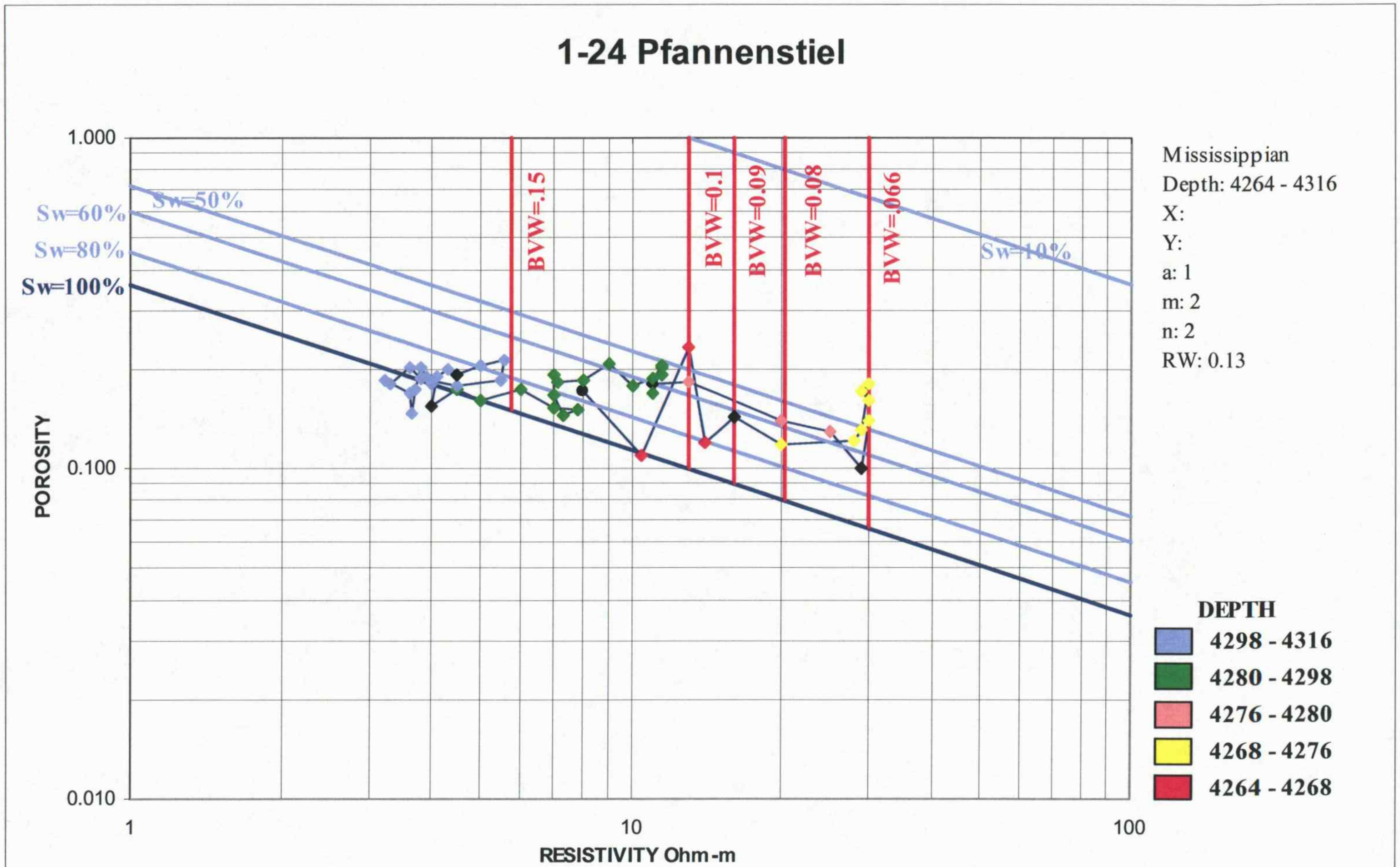
Appendix D

Petrophysical log analyses



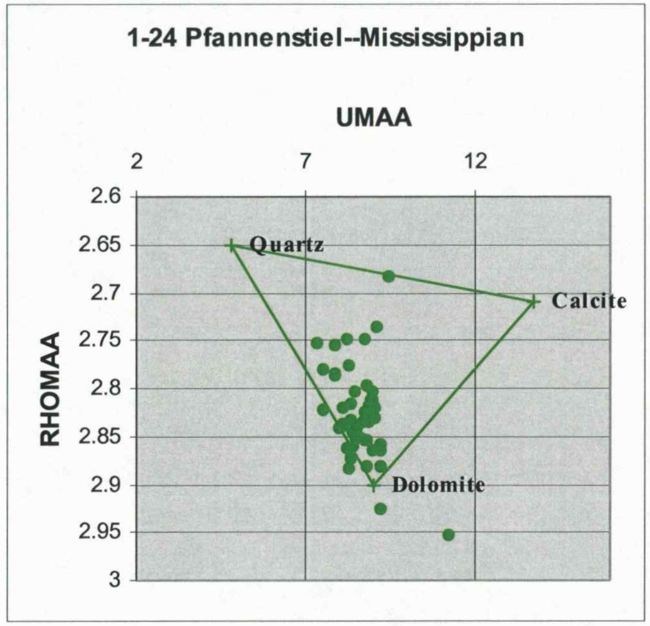
Ummel # 4
1.000
0.100
0.010
POROSITY
1
10
100
RESISTIVITY Ohm-m
Sw=50%
Sw=40%
Sw=60%
Sw=70%
Sw=100%
Sw=10%
BVW=.12
BVW=0.1
BVW=0.09
BVW=0.08
BVW=0.07
Mississippian
Depth: 4270 - 4306
X:
Y:
a: 1
m: 2
n: 2
RW: 0.13
DEPTH
4297 - 4306
4289 - 4297
4284 - 4289
4277 - 4284
4270 - 4277
DST: 4252-4289. Rec: 335 CGO, 82' OCM, & 248 GIP. D&A

Figure D1



DST: 4250-4280. Rec: 130' GIP, 170' GsyO, 120' HOCM, 60' GSOWCM, 180' MW
Original perf: 4268-76. IP: 15 bopd, tr w. Later perf: 4264-68. IP: N/A

Figure D2


1-24 Pfannenstiel--Mississippian
UMAA
2
7
12
RHOMAA
2.6
2.65
2.7
2.75
2.8
2.85
2.9
2.95
3
Quartz
Calcite
Dolomite

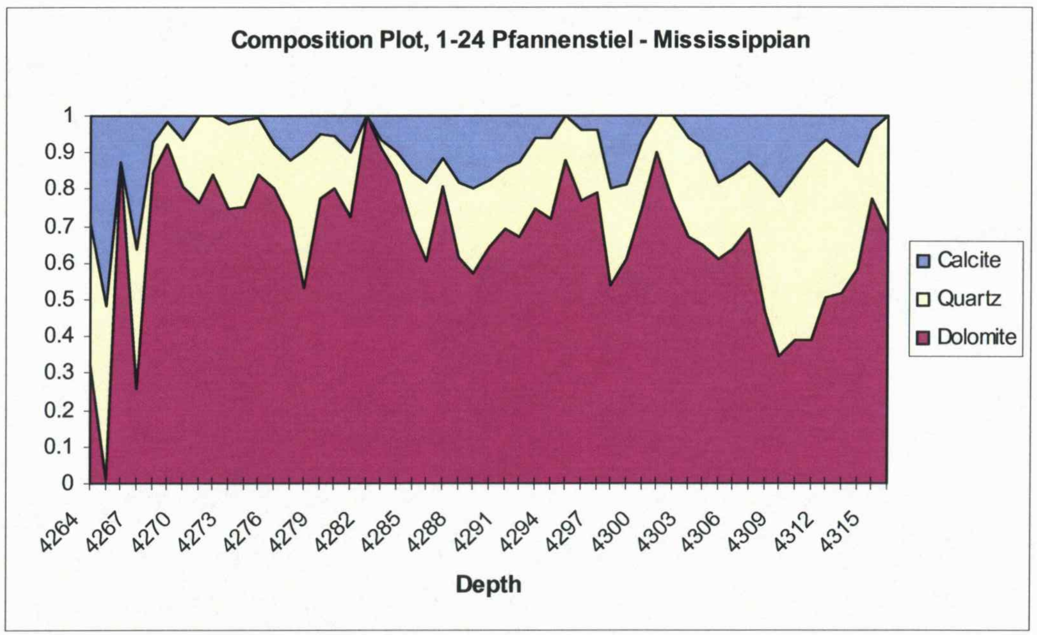

Composition Plot, 1-24 Pfannenstiel - Mississippian
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
4264
4267
4270
4273
4276
4279
4282
4285
4288
4291
4294
4297
4300
4303
4306
4309
4312
4315
Depth
Calcite
Quartz
Dolomite

Figure D3

Appendix E

DST Analyses

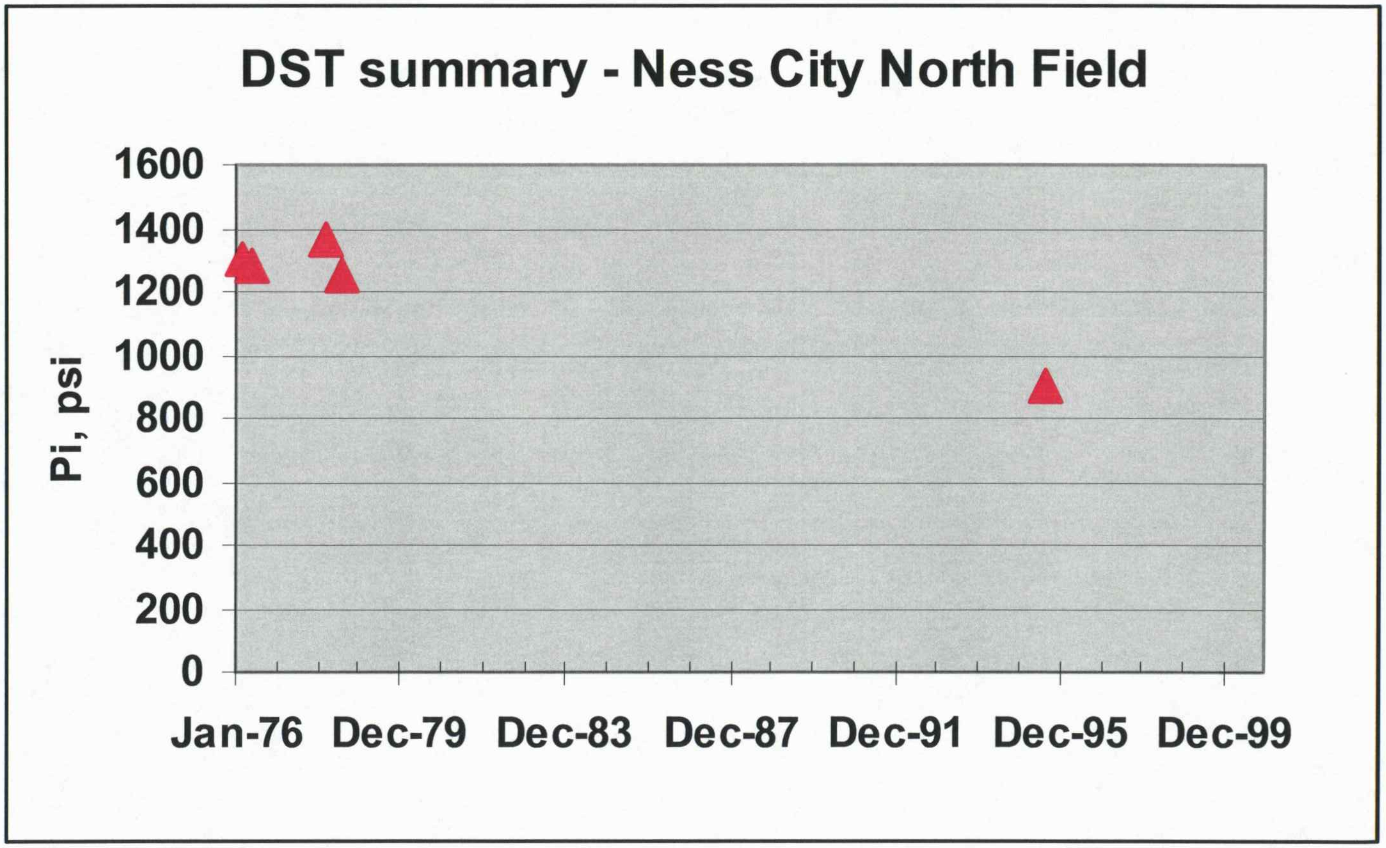

DST summary - Ness City North Field
1600
1400
1200
1000
800
600
400
200
0
Pi, psi
Jan-76
Dec-79
Dec-83
Dec-87
Dec-91
Dec-95
Dec-99

Figure E1

Appendix F

PVT & Relative Permeability/Capillary Pressure Inputs

PVT properties	
Reservoir temperature	116F
API	37 degrees
Gas gravity (Air = 1.0)	0.75
Water salinity	19,500 ppm
Water resistivity	0.13 ohm-m
Reference initial reservoir pressure	1350 psi
Depth of reference pressure (subsea, feet)	-1996

Table F1

Calculator for Reservoir rock

K, md

Phi (%)

k=0.00200*Phi^3.514					
K(md)=	**24.1**	**Phi(%)=**	**14.5**		
Krwmax=	0.22	Kromax=	1	Pcentry=	0.606
Krw -m=	0.5	Swi=	0.340	Pcslope=	-1.451
Kro - n=	3.1	Sorw=	0.160	PcSwiH(ft)=	40.0
water grad	0.438	W sp grav=	1.0111	input value	
oil grad	0.365	Oil sp grav=	0.8439	calc value	
Krgmax=		Kromax=			
Krg -m=		Sgc for kro=		Sgc for krg=	
Kro - n=		Sorg for kro=		Sorg for krg=	
IFTgo/IFTow=		Sorg for kro=			

Note: krg calculated using SwDkrg to allow Sgc>0 while still allowing kro approach 1 below Sgc

Calculator for Ness City North Field

SW	KRW	KROW	PCOW	Height above free water (ft)	SwD
0.3400	0.000000	1.000000	2.896	40.00	0.00000
0.3500	0.031058	0.939501	2.777	38.36	0.01993
0.4000	0.076188	0.672983	2.288	31.60	0.11993
0.4500	0.103173	0.463036	1.929	26.64	0.21993
0.5000	0.124437	0.302633	1.655	22.86	0.31993
0.5500	0.142564	0.184837	1.441	19.91	0.41993
0.6000	0.158634	0.102812	1.271	17.55	0.51993
0.6500	0.173218	0.049840	1.131	15.63	0.61993
0.7000	0.186667	0.019343	1.016	14.03	0.71993
0.7500	0.199210	0.004919	0.919	12.70	0.81993
0.8000	0.211009	0.000399	0.837	11.56	0.91993
0.8500	0.220000	0.000000	0.767	10.59	1.00000
0.9000	0.220000	0.000000	0.706	9.75	1.00000
0.9500	0.220000	0.000000	0.652	9.01	1.00000
1.0000	0.220000	0.000000	0.606	8.36	1.00000
1.0000	0.220000	0.000000	0.606	8.36	1.00000
1.0000	0.220000	0.000000	0.606	8.36	1.00000
1.0000	0.220000	0.000000	0.606	8.36	1.00000
1.0000	0.220000	0.000000	0.606	8.36	1.00000
1.0000	0.220000	0.000000	0.606	8.36	1.00000
1.0000	0.220000	0.000000	0.606	8.36	1.00000

Table F2

Calculator for Non-reservoir rock

K, md

Phi (%)

k=0.000262*Phi^3.3702

K(md)=	3.7	Phi(%)=	17		
Krwmax=	0.2396	Kromax=	1	Pcentry=	1.334
Krw -m=	0.5	Swi=	0.513	Pcslope=	-1.767
Kro - n=	3.1	Sorw=	0.100	PcSwiH(ft)=	60.0
water grad	0.438	W sp grav=	1.0111	input value	tan
oil grad	0.365	Oil sp grav=	0.8439	calc value	yellow
Krgmax=		Kromax=			
Krg -m=		Sgc for kro=		Sgc for krg=	
Kro - n=		Sorg for kro=		Sorg for krg=	
IFTgo/IFTow=		Sorg for kro=			

Note: krg calculated using SwDkrg to allow Sgc>0 while
still allowing kro approach 1 below Sgc

Calculator for Ness City North Field

SW	KRW	KROW	PCOW	Height above free water (ft)	SwD
0.5125	0.000000	1.000000	4.344	60.00	0.00000
0.5500	0.074491	0.729605	3.835	52.97	0.09669
0.6000	0.113816	0.452431	3.288	45.42	0.22574
0.6500	0.142687	0.257093	2.855	39.43	0.35478
0.7000	0.166628	0.128727	2.504	34.59	0.48383
0.7500	0.187537	0.052767	2.217	30.62	0.61287
0.8000	0.206338	0.015013	1.978	27.32	0.74191
0.8500	0.223563	0.001751	1.777	24.55	0.87096
0.9000	0.239553	0.000000	1.606	22.19	1.00000
0.9500	0.239553	0.000000	1.460	20.17	1.00000
1.0000	0.239553	0.000000	1.334	18.42	1.00000
1.0000	0.239553	0.000000	1.334	18.42	1.00000
1.0000	0.239553	0.000000	1.334	18.42	1.00000
1.0000	0.239553	0.000000	1.334	18.42	1.00000
1.0000	0.239553	0.000000	1.334	18.42	1.00000
1.0000	0.239553	0.000000	1.334	18.42	1.00000
1.0000	0.239553	0.000000	1.334	18.42	1.00000
1.0000	0.239553	0.000000	1.334	18.42	1.00000
1.0000	0.239553	0.000000	1.334	18.42	1.00000
1.0000	0.239553	0.000000	1.334	18.42	1.00000
1.0000	0.239553	0.000000	1.334	18.42	1.00000

Table F3

Well	BHP, psi	Comments
Ummel 1	250	
Ummel 2	150	
Ummel 3	800	
Ummel 4H	650	
Pfannenstiel 1	100	
Pfannenstiel 2	100	
Pfannenstiel 2A-24	100	(from 1994 to 1999)
	800	(from Jan 2001 to Oct 2002. Perforations extended to Layer 3.)
	350	(from Nov 2002 to date)
Pember A5	100	

Table F4

Appendix G

Simulation Study

- History Match

Well perforations in simulation model

					Subsea	Subsea	L1 Top	L1 Bot	L3 Top	L3 Bot	Perfs in
Well	**KB**	**Perf top**	**Perf Bot**	**Comments**	**Perf Top**	**Perf Bot**					**Sim**
Ummel 1	2281	4285	4295	OH	-2004	-2014	2005.7	2007.7	2012	2019.4	**L1, L3**
Ummel 2	2265	4272	4280	OH	-2007	-2015	2008.5	2009.8	2015.7	2019.5	**L1, L3**
Ummel 3	2271	4286	4292	OH	-2015	-2021			2021.2	2024.9	**L2, L3**
Ummel 4H	2277	4289	4289		-2012	-2012					**L3**
Pfannenstiel 2	2268	4277	4284		-2009	-2016	2000.5	2003.4	2012.1	2018.7	**L3**
Pfannenstiel 2A-24	2267	4268	4276		-2001	-2009	2003.9	2007.5	2015.4	2023.2	**L1**
	2267	4264	4276		-1997	-2009					**L1**
	2267	4284	4291		-2017	-2024					**L3**
Pfannenstiel 1	2266	4266	4282	OH	-2000	-2016	2005	2007.8	2018.6	2023.7	**L1**
Pember 5A	2262	4270	4282		-2008	-2020	2015.8	2018.4	2029.2	2031.3	**L1**

Figure G1

History match - Ummel 1

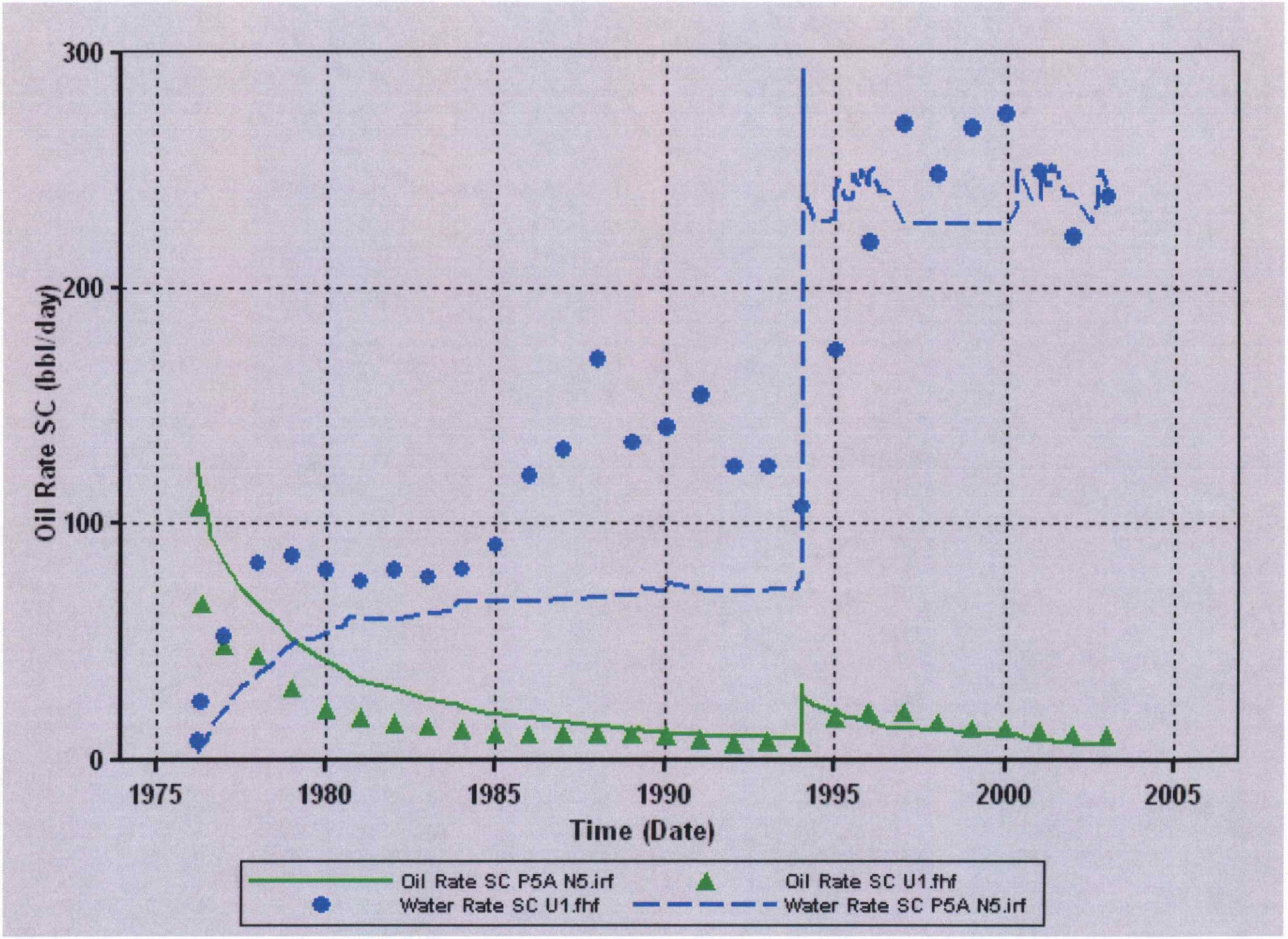


Figure G2

History Match - Ummel 2

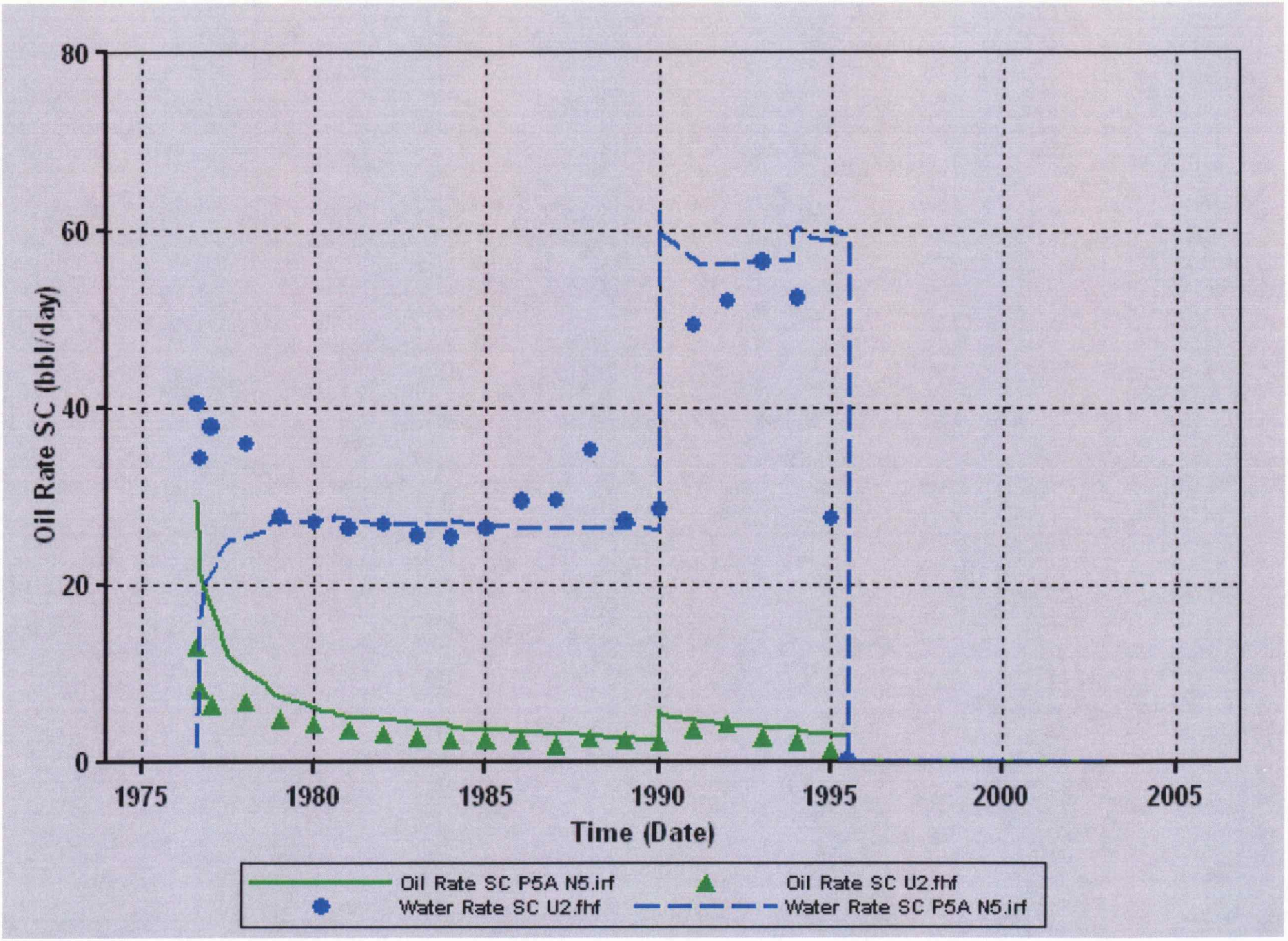


Figure G3

History match - Ummel 3

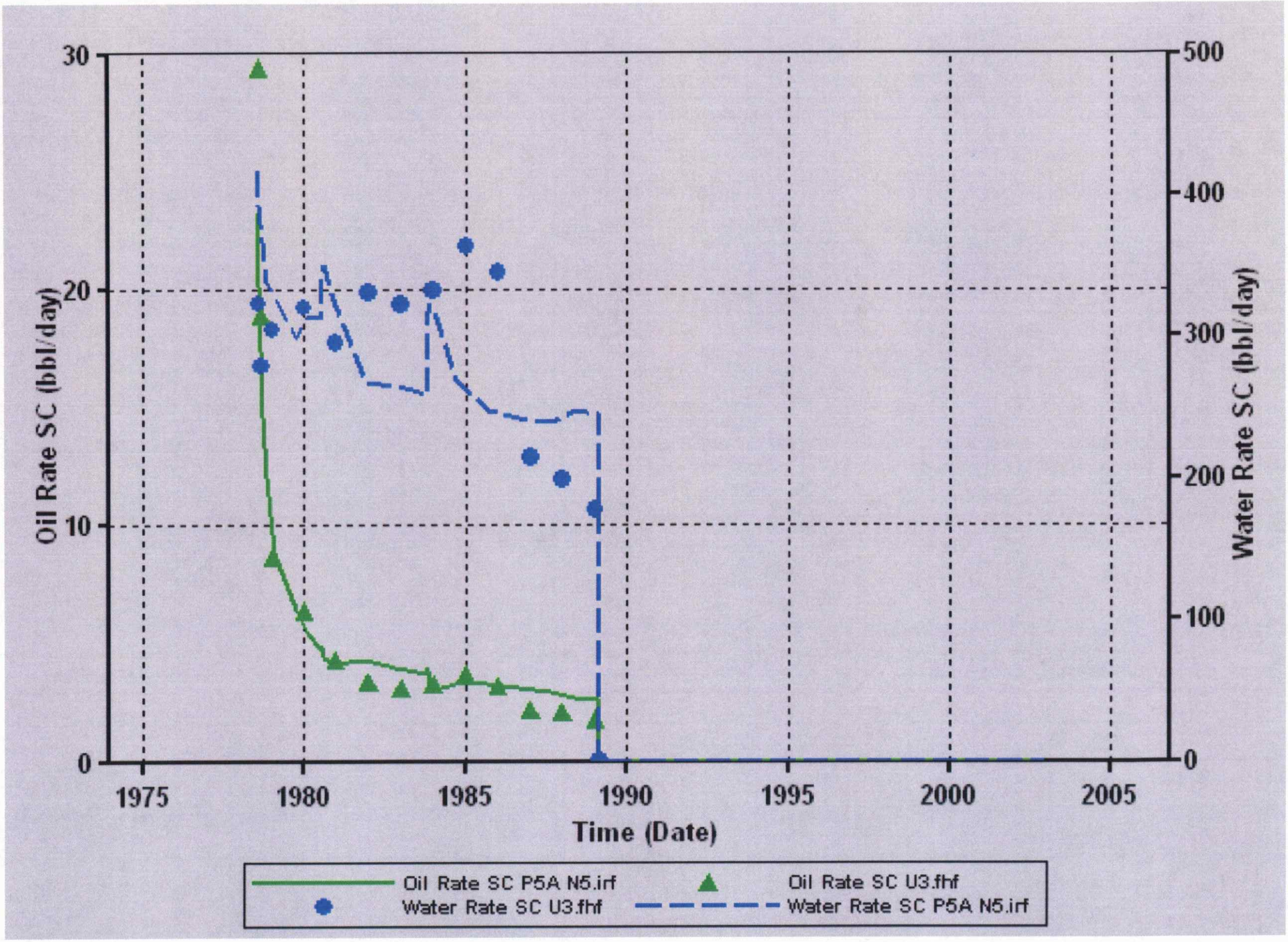


Figure G4

History match - Pfannenstiel 1

Water production data not available.

Wtr production history estimated using WOR Vs. Cum oil from Ummel 2

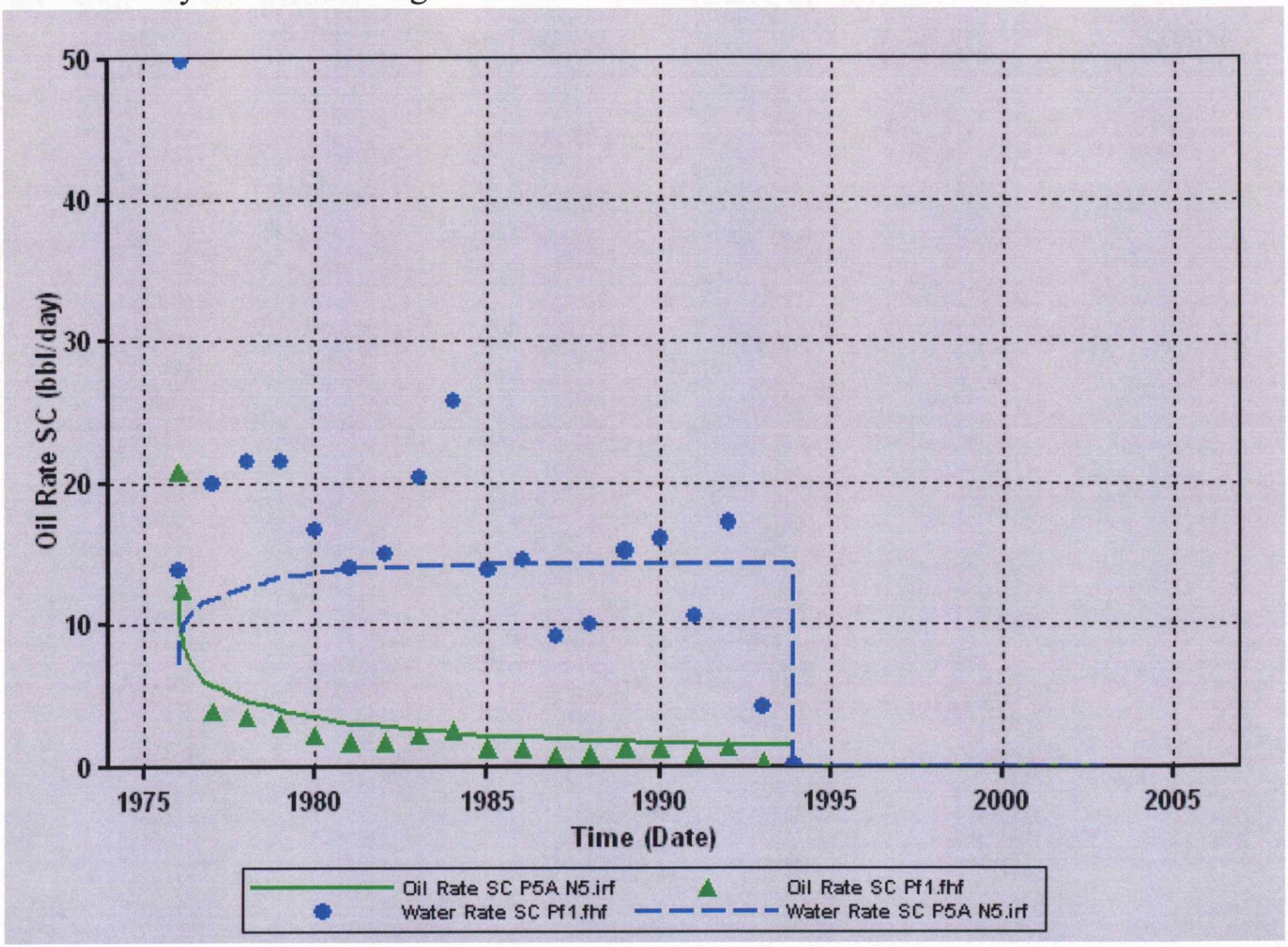


Figure G5

History match - Pfannenstiel 2

Water production not available.

Wtr production history estimated using WOR Vs. Cum oil from Ummel 2

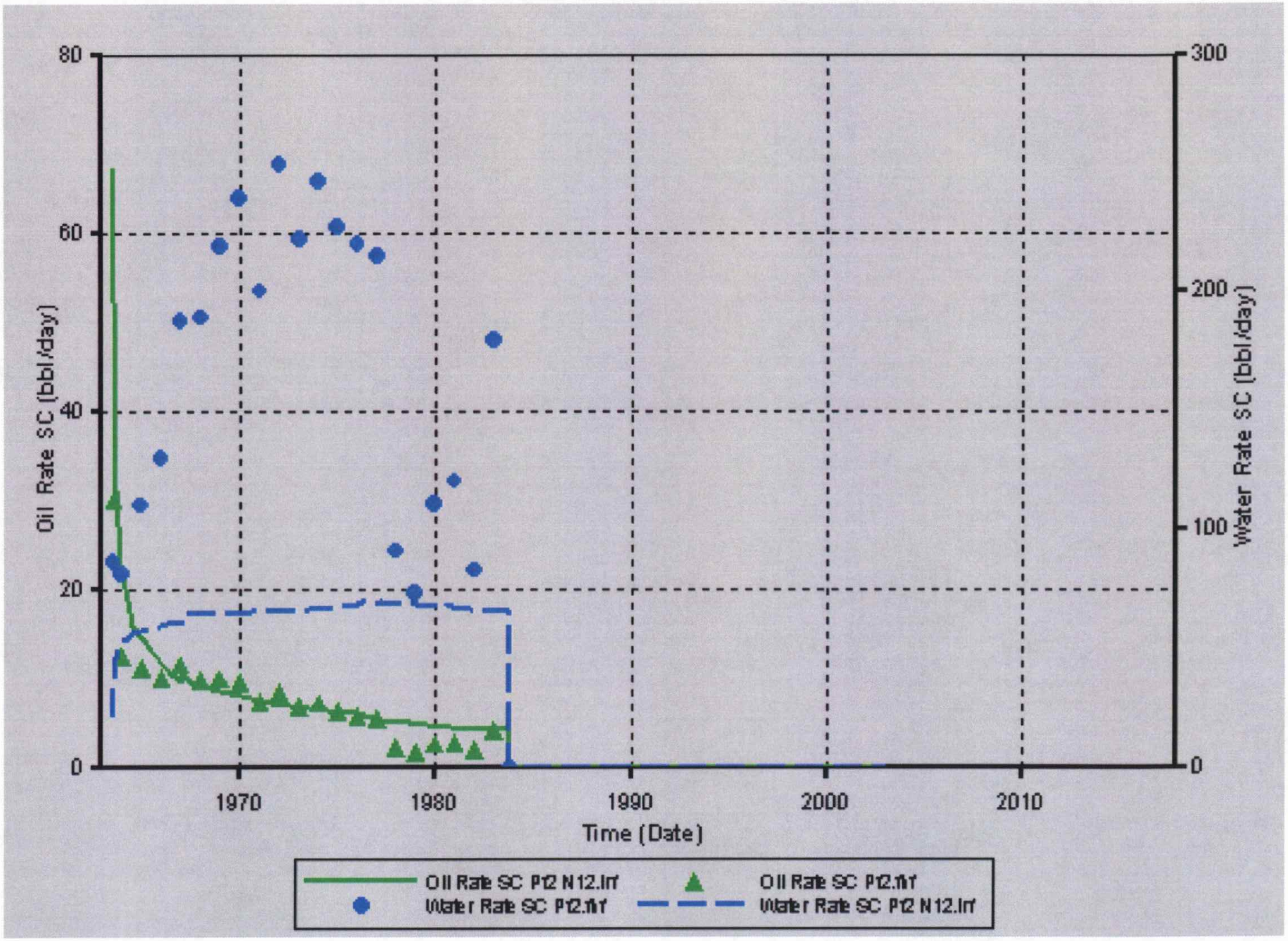


Figure G6

History match - Pember 5A

Water production not available.

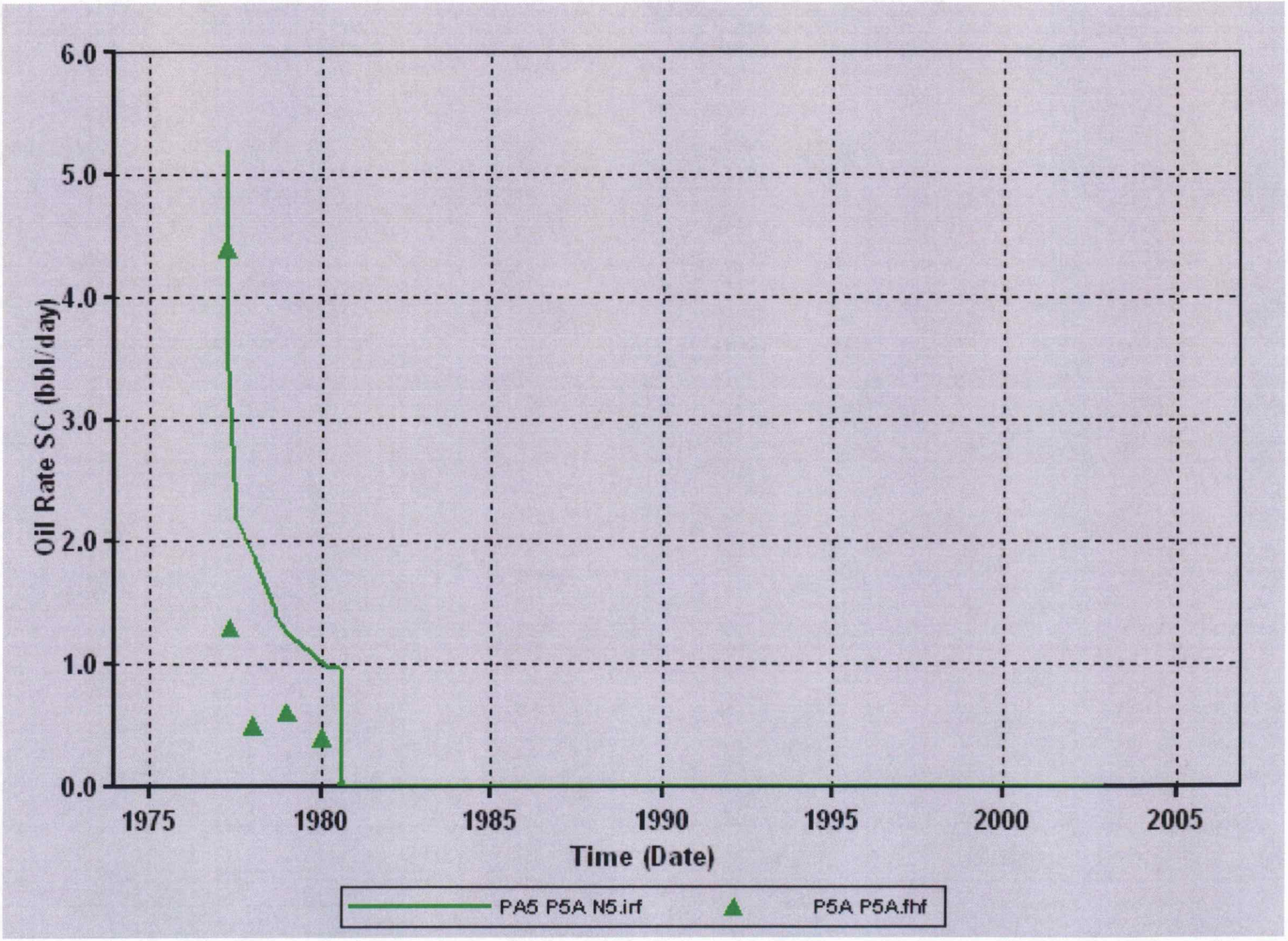


Figure G7

Simulation prediction for infill well - Pfannenstiel 2A-24

Match obtained by drilling this infill well after completion of history matching of all original wells.

Sw at Pf 2A-24 from logs at Jan 1994:

L1 = 0.42, L2 = 0.64,
L3 = 0.48, L4 = 0.81

Sw at Pf 2A-24 calculated by simulation at Jan 1994:

L1 = 0.41, L2 = 0.52,
L3 = 0.46, L4 = 0.73

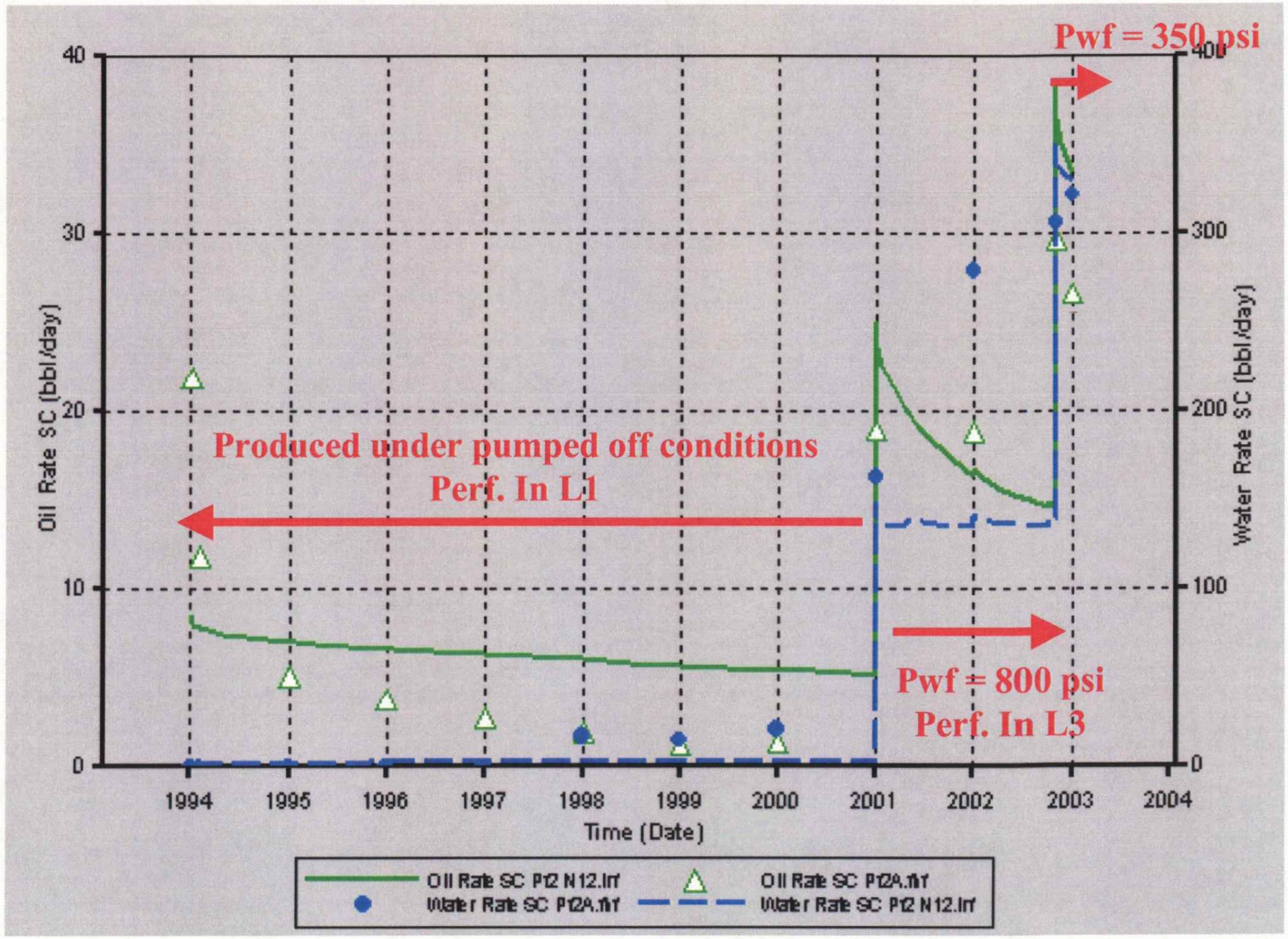


Figure G8

Simulation prediction for infill horizontal well - Ummel 4H

Well produced for 1 year to estimate production decline. Actually, well produced for 1 month only. Results obtained by drilling this well after history matching all original wells. This well lies in the drainage area of Ummel 1. Only parameter changed for the horizontal well has been the horizontal permeability Kxy. Ummel 1 Kxy = 25 md. Ummel 4H Kxy = 15 md.

Simulator calculated

Initial IPs:

Qo = 52 bopd

Qw = 65 bwpd

Pwf = 550 psi.

Skin = 1.5

Well diameter = 6 inches

Well length = 330 ft

Prod. Rates actually observed:

Averaged over 1st month:

Avg Qo = 59 bopd

Avg Qw = 55 bwpd

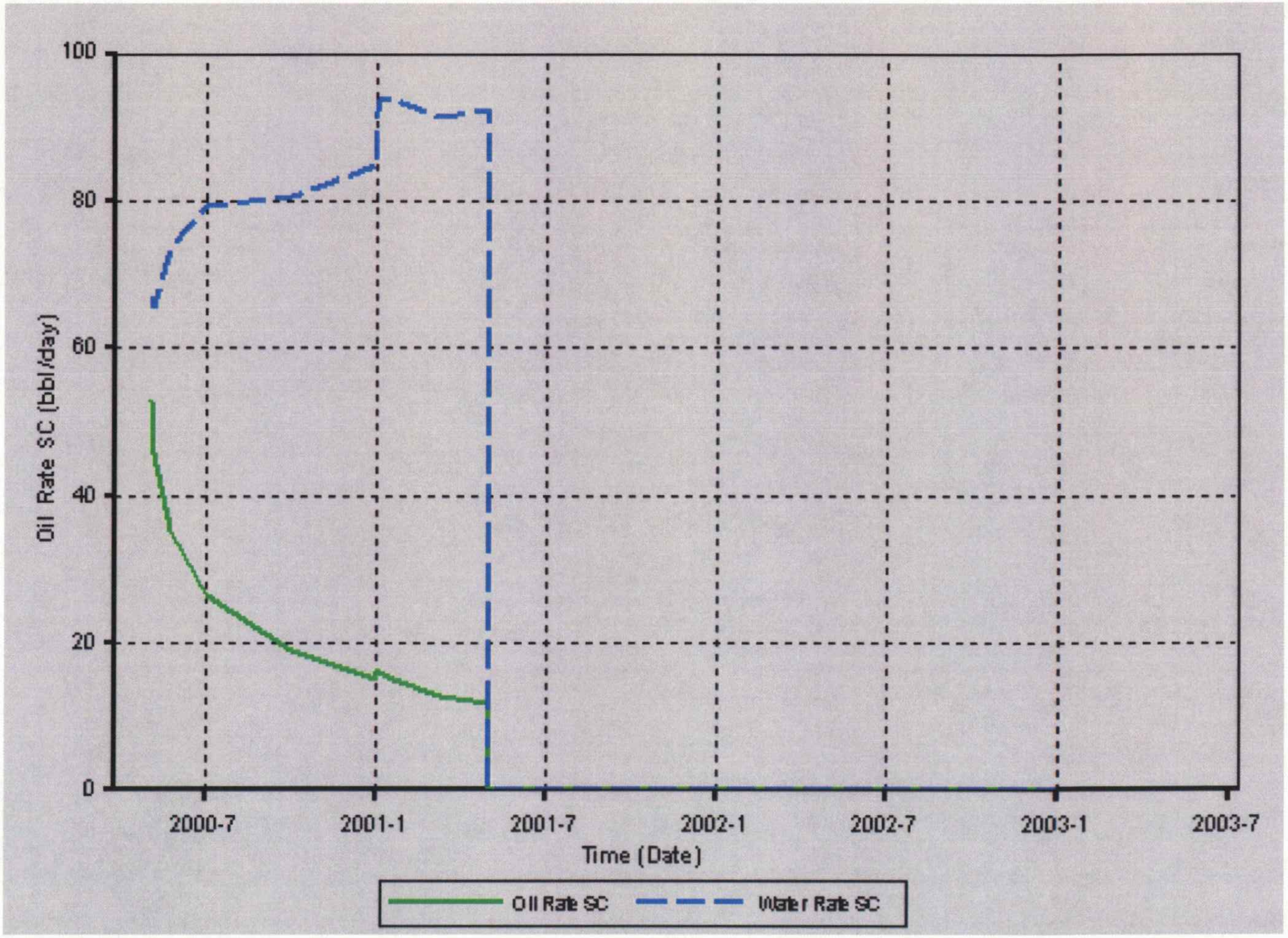


Figure G9

Ness City North field

4 Layer model

L1 – productive layer

L2 – tight, water saturated non-productive layer

L3 – productive layer (most pervasive and potential richer than L1)

L4 – tight, water saturated non-productive layer

Initial reservoir pressure = 1350 psi

Simulator calculated average reservoir pressure as of Jan 2003 = 1185 psi.

Appendix H

Simulation Study

- Evaluate performance of different horizontal infill wells

Remaining rerserves (oil-ft) in Layer 3 as of Jan 2003

Pfannenstiel 2

Main area of remaining potential.

Ummel 1

Residual potential just an approximation as Pf1 has no logs.

Ummel 3

Ummel 4- dry hole with poor localized reservoir

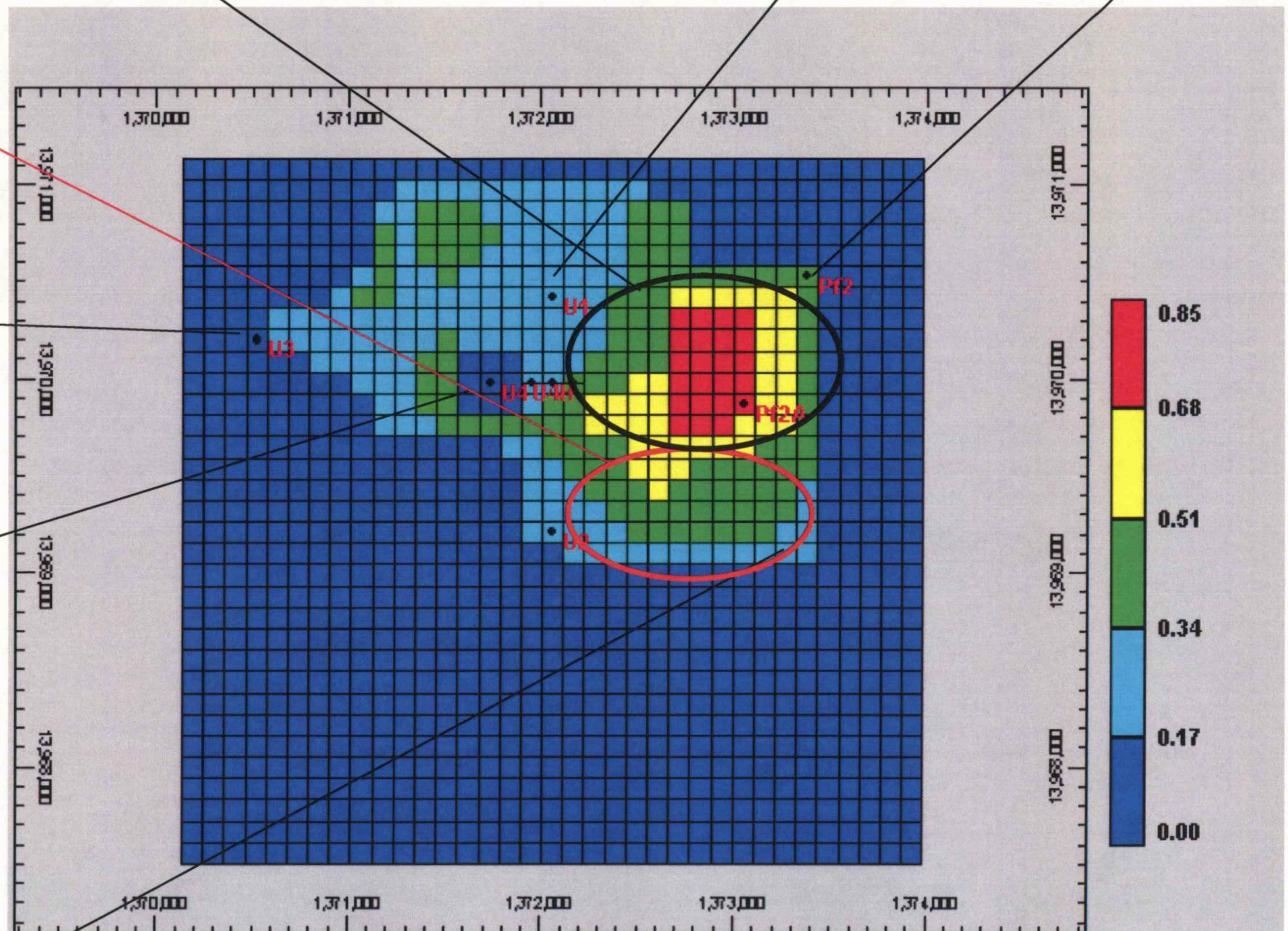


Figure H1

Pfannenstiel 1 – perf in L1 only. No logs available for this well. Pay thickness, porosity and Sw estimated in L1 to L4 from regional cross sections.

Performance prediction

Horizontal Infill well
East-West

Oil-ft in Layer 3 as of Jan 2003

Oil-ft in Layer 3 as of Jan 2013

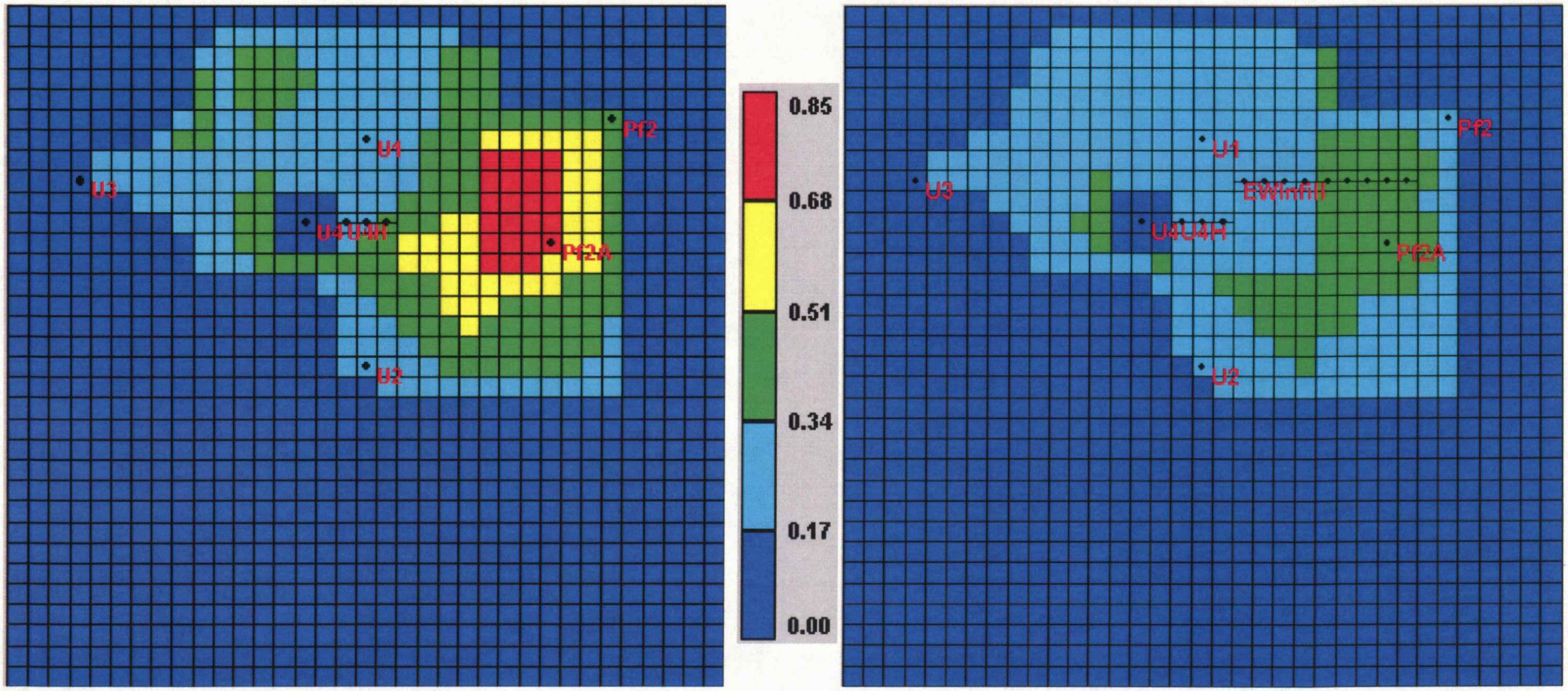


Figure H2

Performance prediction - East-West Horizontal Infill well

Cum oil produced over 10 years = 71272 bbls.

Well length = 990 ft. skin = 1.5, Pwf = 200 psi, well diameter = 6 inch

Year end	Cum Oil, BO	Cum Wtr, BW
2003	17,723	109,401
2004	27,946	220,121
2006	40,956	441,753
2008	49,478	659,336
2013	60,572	1,074,080

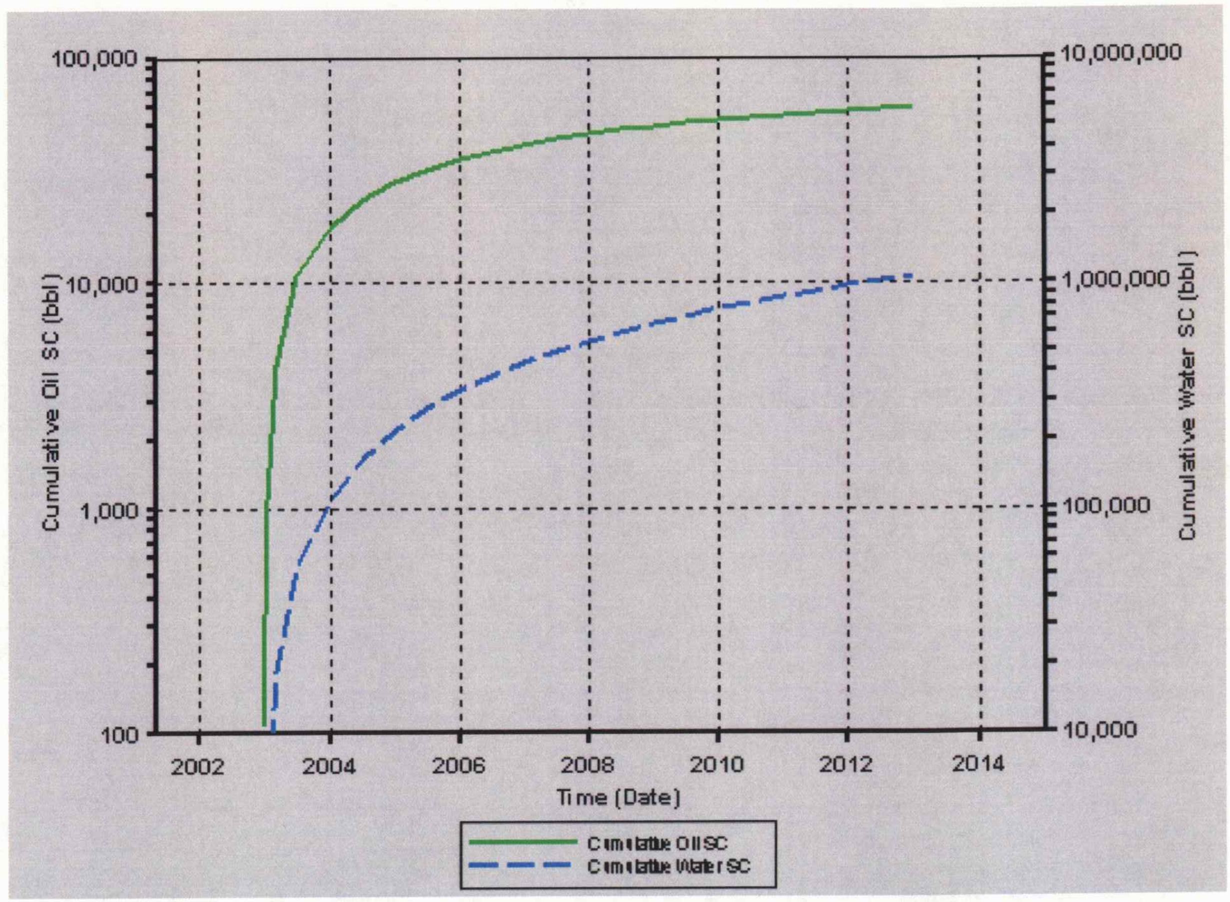


Figure H3

Performance prediction - East-West Horizontal Infill well
Production loss – interference at adjacent wells

	Ummel 1 Cum Oil, BO No Infill	Ummel 1 Cum Oil, BO Infill E-W	Ummel 1 Prod loss, BO
Jan-2003	229,096		
Jan-2006	235,530	233,406	2,124
Jan-2008	239,113	235,687	3,426
Jan-2013	246,420	240,369	6,051

	Pf2A-24 Cum Oil, BO No Infill	Pf2A-24 Cum Oil, BO Infill E-W	Pf2A-24 Prod loss, BO
Jan-2003	29,224		
Jan-2006	56,657	47,000	9,657
Jan-2008	68,616	53,002	15,614
Jan-2013	88,642	61,598	27,044

Figure H4

Performance prediction

Horizontal Infill well –
North-East to South-West (diagonal)

Oil-ft in Layer 3 as of Jan 2003

Oil-ft in Layer 3 as of Jan 2013

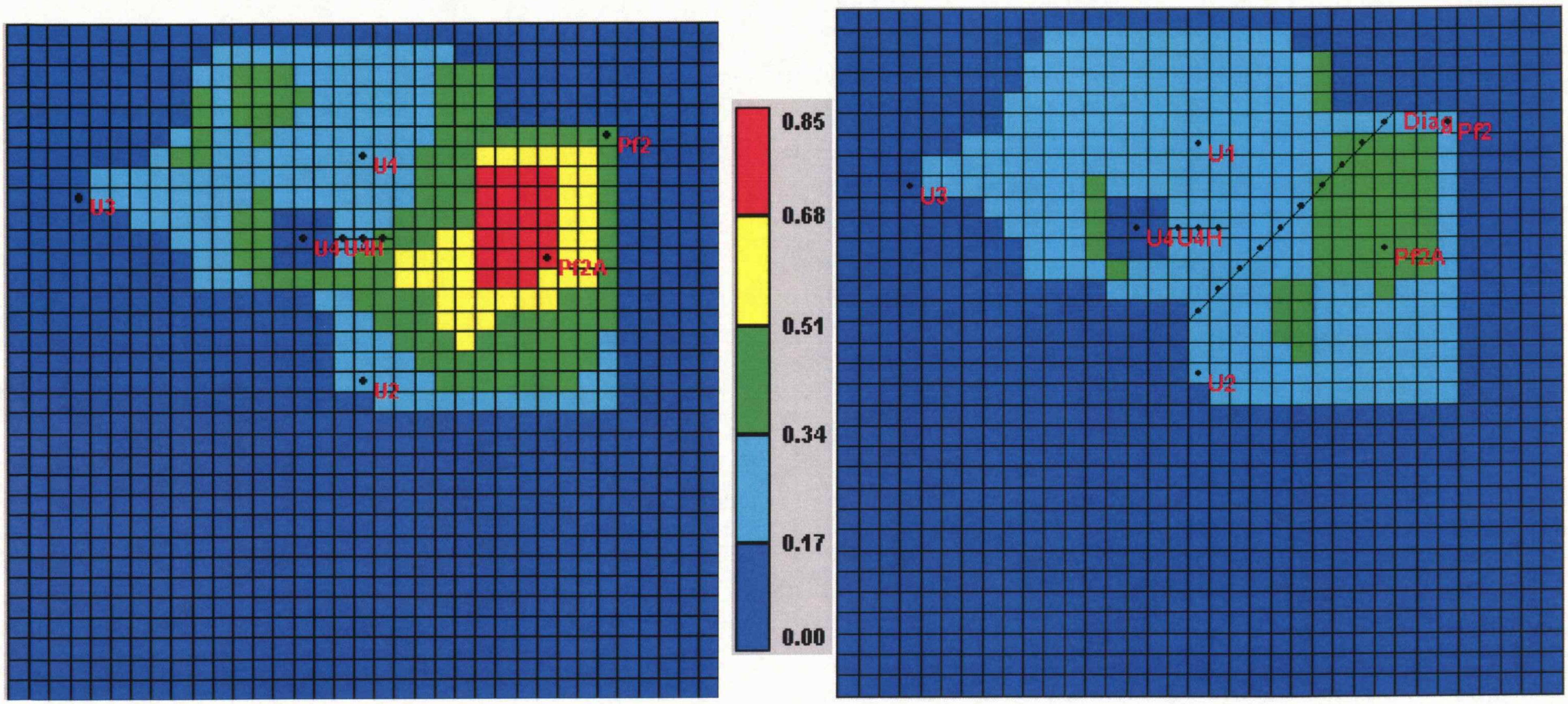


Figure H5

Performance prediction

NE to SW Horizontal Infill well

Cum oil produced over 10 years = 83922 bbls.

Well length = 1100 ft. skin = 1.5, Pwf = 200 psi, well diameter = 6 inch

Year end	Cum Oil, BO	Cum Wtr, BW
2003	29,327	190,629
2004	41,359	377,940
2006	55,800	747,658
2008	64,850	1,104,510
2013	76,399	1,769,580

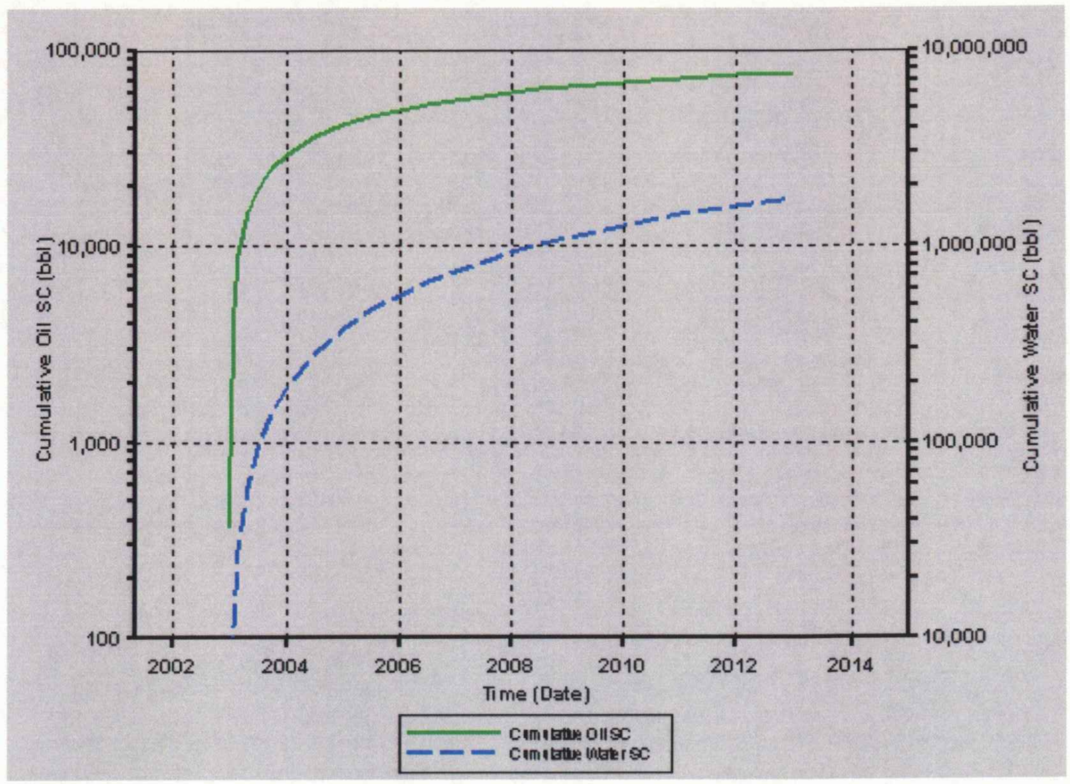


Figure H6

Performance prediction - NE to SW Horizontal Infill well
Production loss – interference at adjacent wells

	Ummel 1 Cum Oil, BO No Infill	Ummel 1 Cum Oil, BO Infill NE-SW	Ummel 1 Prod loss, BO
Jan-2003	229,096		
Jan-2006	235,530	233,939	1,591
Jan-2008	239,113	236,254	2,859
Jan-2013	246,420	240,678	5,742

	Pf2A-24 Cum Oil, BO No Infill	Pf2A-24 Cum Oil, BO Infill NE-SW	Pf2A-24 Prod loss, BO
Jan-2003	29,224		
Jan-2006	56,657	46,354	10,303
Jan-2008	68,616	51,794	16,822
Jan-2013	88,642	59,233	29,409

Figure H7