KANSAS GEOLOGICAL SURVEY
OPEN-FILE REPORT 2001-70

Waterflood Design and Implementation for a South-central Kansas Mississippian Carbonate Reservoir Using Cost-effective Reservoir Characterization and Simulation: Geologic Study and DST Analyses of Wellington West Field, Sumner County, Kansas

by

Saibal Bhattacharya
Paul Gerlach
Alan P. Byrnes

Disclaimer

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

Waterflood design and implementation for a south-central Kansas Mississippian carbonate reservoir using cost-effective reservoir characterization and simulation:

Geologic study and DST analyses of Wellington West field, Sumner County, Kansas

(Sponsored Under US DOE Contract No. IND 27960)

Kansas Geological Survey

Open File report No. 2001-70

Authors:

Saibal Bhattacharya

Paul Gerlach

Alan P. Byrnes

Waterflood design and implementation for a south-central Kansas Mississippian carbonate reservoir using cost-effective reservoir characterization and simulation:

<u>Geologic study and DST analyses of Wellington West field, Sumner County, Kansas</u>

Background

Of the 1 billion m^3 (6.2 billion barrels) of oil produced in Kansas, Mississippian carbonate reservoirs have produced about 1 billion barrels (i.e., 17% as of 2000; Figure 1). With declining production from the Arbuckle and Lansing-Kansas City formations, the contribution of Mississippian reservoirs to the state's oil production has increased significantly over the past ten years and presently represents over 40% of the state's $5.6*10^6$ m^3 (35 million barrels) annual production.

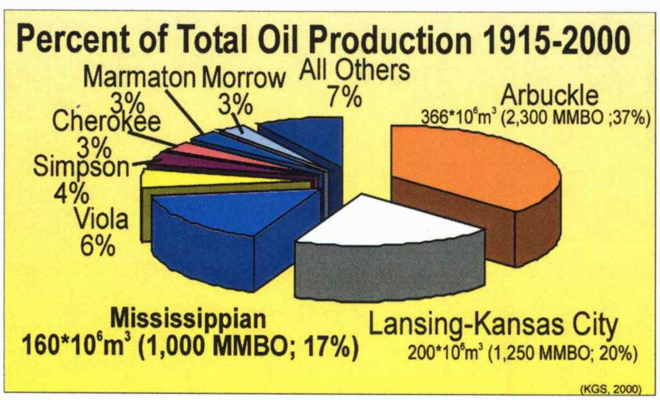


Figure 1. Relative contribution of Mississippian reservoirs to total Kansas oil production (1915-2000).

Mississippian production is concentrated along the western and southern flank of the Central Kansas Uplift where Mississippian rocks of various ages were exposed and eroded and presently subcrop and are sealed by overlying Pennsylvanian shales (Figure 2). Small independent operators, with limited technical and financial resources, operate most Mississippian fields. Reservoir heterogeneity, insufficient natural reservoir drive, and low recovery efficiencies place operations in many fields at or near economic limits. Primary production without pressure support is one of the major causes for significant reserves to remain unproduced in these fields.

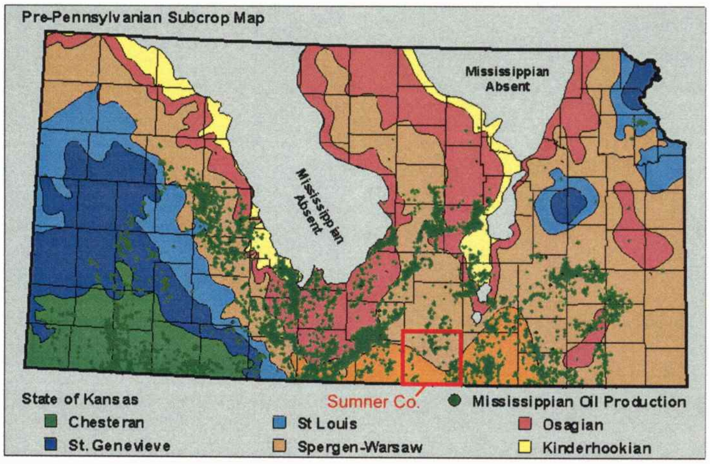


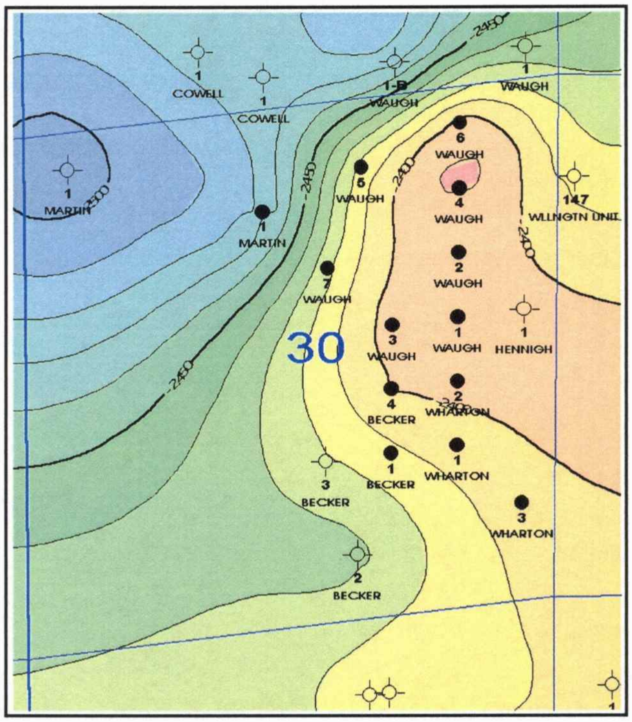
Figure 2. Location of Mississippian oil production in Kansas (shown by green dots) and the age of Mississippian subcropping pre-Pennsylvanian unconformity.

In addition, designs of waterfloods in many fields are based on limited reservoir studies and thus exhibit low recovery efficiencies. Low average recovery factors, less than 12%, result in high well abandonment rates, and significant residual reserves (estimated to be $1.2*10^9$ m^3, 7.3 billion barrels) in the ground. In this regard, developing and demonstrating the application of cost-effective integrated reservoir characterization, PC-based simulation, and waterflood design followed by its implementation that result in an additional recovery of as little as 10% of residual reserves could translate to an increase in domestic production of up to $116 *10^6$ m^3 (730 million barrels). For small independent oil producers of Kansas, with limited technical and financial resources, access to new technology is vital for sustaining production and increasing profitability. These problems of limited operator resources, heterogeneous reservoirs, and low primary recovery are prevalent throughout the shallow shelf carbonate reservoirs of Midcontinent region of the United States and therefore extend over most of Kansas and northern Oklahoma.

Location, Field Properties and History

Wellington West field is located in Sumner County, Kansas (Figure 2). The Mississippian-Warsaw age reservoir rock is dolomite-wackestone to packstone. The field produces from a structural-stratigraphic combination trap (Figure 3). The discovery well was Becker No. 1 (located in the SW-NW-SE, Sec30 T31S, R1W), drilled by Zenith Drilling in 1977.

Figure 3. Strucure map of the top of Mississippian in region around Wellington West field showing well locations.



The initial production (IP) recorded at Becker No. 1 was 8 m^3/day (50 bopd). Most of the primary field development occurred between 1983 and 1986. By 1986, the total number of wells in the field was 13 and resulted in the annual oil production to peak at $8.9*10^3$ m^3 (55,962 bbls; Figure 4). The combination trap allows wells located low on the structure (subsea depth of –747 m; –2450 feet) and with average permeability to produce oil. Two infill wells, drilled in the later years, were unable to halt the production decline in the field. The reservoir drive mechanism is attributed to a combination of solution gas drive and an edge water drive. Shut-in pressures from drill stem tests (DSTs) recorded in the initial wells indicate the initial reservoir pressure to be close to 12,400 kPa (1800 psi). IP rates for most of the wells have ranged between 2.4-4.8 m^3 (15 to 30 bopd). However, field-wide differences between the final shut-in pressures (FSIPs) and the final flow pressures (FFPs), from DST records, indicate permeability heterogeneity within the pay zone.

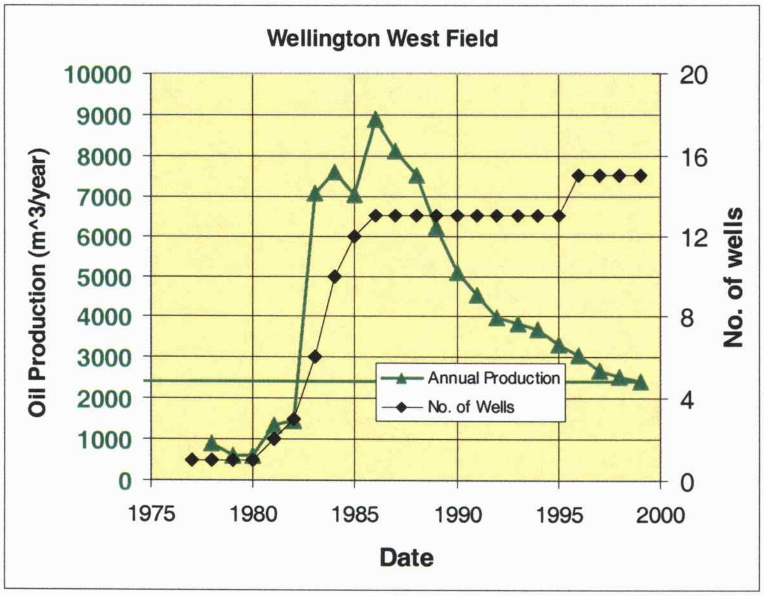


Figure 4. Annual oil production and drilling history for Wellington West Field.

From its discovery to the present, the field has been under primary production without any artificial pressure support. Over the field history of 24 years, reservoir pressure has declined from 12,400 kPa (1800 psi) to below 700 kPa (100 psi). The initial recoverable reserves in Wellington West field have been estimated at $9.7*10^5 m^3$ (6.1 MMstb). Total cumulative recovery, as of 2000, has been $9.5*10^4 m^3$ (600 Mstb), resulting in a primary recovery efficiency of about 10%.

The American Energies Corporation (AEC) currently operates the Wellington West field. With primary production having reached economic limits, AEC must design and implement an effective secondary recovery strategy to continue operating the field. Recoveries from infill vertical wells have been marginal due to low reservoir pressure and reservoir heterogeneity. Several waterfloods are in operation in fields surrounding the Wellington West field, and most of them have met with only marginal success or have shown delayed response. Some of the major reasons for this lackluster secondary production include a) insufficient injection volumes to fill-up the reservoir and develop a flood front, b) improper placement of injectors and producers, c) lack of knowledge about the location of unswept reserves in these mature fields, d) uncertainity about the permeability distribution both laterally and vertically, and e) difficulty in identifying payzones using wireline logs. Also, most of these waterfloods in the surrounding fields were designed on the basis of general (approximate) volumetric analyses using average pay thicknesses, porosities, and saturation values. As such these floods were not designed to deal with reservoir heterogeneity and/or to maximize the response in pockets of high remaining oil saturations.

Project Objectives and Design

Depleted reservoir drive energy indicates that restoration of reservoir pressure by waterflood may provide the most economic method for improved oil recovery. Successful waterfloods of similar fields, regionally, have demonstrated that proper characterization and design can result in significant incremental recovery. Optimum flood design requires that information be obtained and integrated for different petrophysical properties of the reservoir. Using wireline logs, it is difficult to identify and delineate the dolomitic pay from the overlying chert and this adds uncertainty to reserve calculations. Also, the chert zone needs to be analyzed for possible contribution to reserve calculation and/or loss of injected water volumes before design and implementation of any waterflood. Microporosity in chert results electric logs to show high porosity and water saturation values. Therefore, logs signatures need to be developed to delineate "effective pay" from the "non-pay". Permeability-porosity trends for the dolomite need to be generated to map the distribution of horizontal permeability, which plays a critical role in determining the sweep efficiency in a waterflood. The dolomite needs to be studied for micro-porosity to differentiate between log derived total water saturation and the water saturation in the effective porosity, i.e., mobile water saturation. Also, the vertical transmissibility between the dolomite and chert needs to be understood to properly design a waterflood in this reservoir.

Low primary recovery factors have resulted in significant volumes of residual reserves, estimated at $8.75*10^5 m^3$ (5.5 MMstb), in the Wellington West field. To implement a development plan capable of recovering some of these reserves an integrated characterization and simulation study of this field has been initiated to develop a reservoir geomodel and map the residual reserves. Based on the distribution of the remaining reserves in the field, various options will be simulated to select the optimum waterflood strategy. Finally, AEC will implement the selected secondary recovery strategy to breathe new life into a field that is on the verge of closure. The proposed project is a partnership between AEC, the KGS, and the North Midcontinent PTTC.

Major aspects of the proposed study involve a series of tasks directed at obtaining a representative reservoir model to study responses to various waterflood designs. Tasks involved include:

1. Consolidation of available data into a digital database
2. Geologic and wireline log reservoir characterization
3. Core petrophysical characterization
4. Engineering characterization
5. Development of an integrated geomodel of the reservoir
6. Reservoir simulation studies to history match primary production and to design an effective waterflood program
7. Field implementation of the optimum waterflood design

Spreadsheet based material balance calculations will be used to confirm the reservoir drive mechanism and to approximate effective petrophysical properties for the aquifer. A PC-based reservoir simulator will be used to history match the primary production of the producing wells in the field and to map the residual reserves. Based on the residual reserve map, different waterflooding strategies will be simulated to determine an appropriate field management plan. Provided that simulation indicates a commercially successful program can be implemented, the optimum design indicated by the simulation will be implemented in the Wellington West field.

Well-designed successful waterfloods in analogous reservoirs have dramatically increased the field production. The Lee field in Sumner County, Kansas, had eight operating wells at the time of the implementation of the waterflood. The secondary recovery strategy in this field yielded an additional 40.5m^3 (255 Mstb) of oil after the primary recovery of 42.3m^3 (266 Mstb). Even after 18 years since the initiation of the flood, the field production remains at a level higher than the preflood stage. Examples of this and other successful waterfloods in similar reservoirs/fields have been one of the major motivations to AEC to undertake the proposed study and thereby effectively exploit the remaining assets in this mature field.

Geologic Studies

A major problem in these Mississippian fields is the difficulty in identifying the dolomitic interval on some wireline logs and identifying effective porosity within the dolomitic interval. To identify the dolomitic interval geologic sample logs were correlated with wireline logs to properly identify the productive dolomitic interval. For most wells, the productive dolomite interval underlying the chert interval is between 10 and 50 ft in thickness. Analysis indicates that where the dolomitic interval is less than 15 feet in thickness porosity is less than 15% and permeabilities are near the lower limit or below values suitable for good reservoir rock. Since these thin dolomites do not contain good reservoir rock, an isopach map of the dolomite was utilized to delineate the reservoir boundaries in the north, east and the south side (Figure 5). In the northwest, well production data were used to identify an OWC (oil-water contact) that acts as the reservoir boundary. Wireline logs were used in cross-sections of the field to correlate the top and thickness of the dolomitic and the chert zones. Figures 6 shows the top of the dolomite, Figure 7 shows dolomite isopach, Figure 8 illustrates porosity distribution within the dolomite layer, and Figure 9 presents the storativity (porosity-feet) of the dolomite interval.

Overlying the Mississippian surface is a chert zone ranging in thickness from 8 to 20 ft. Though this zone has been reported to have oil shows, permeability in this chert interval is poor. Electric wireline log analysis and sample descriptions can be interpreted to indicate that this chert zone is unproductive. However, a cross-plot of vertical (k_v) and horizontal permeability (k_h) in Anson-Bates field indicates that the high k_v/k_h ratio may allow water injected during a waterflood operation to move into the chert zone. This possibility will be investigated during future reservoir simulation.

Figure 5. Approximate edge of reservoir quality Mississippian dolomite in Wellington West Field.

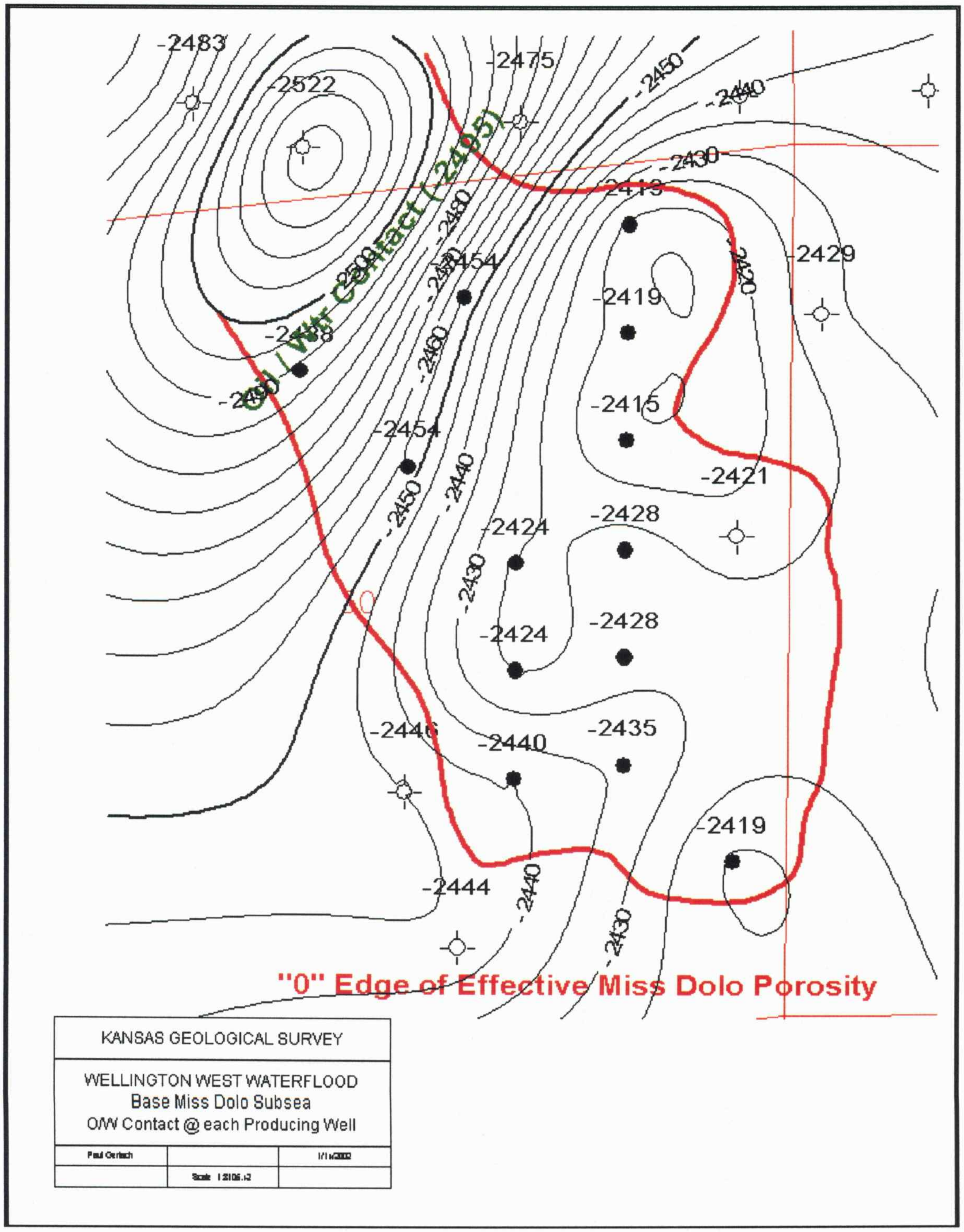


Figure 6. Top of Mississippian subsea elevation in Wellington West Field.

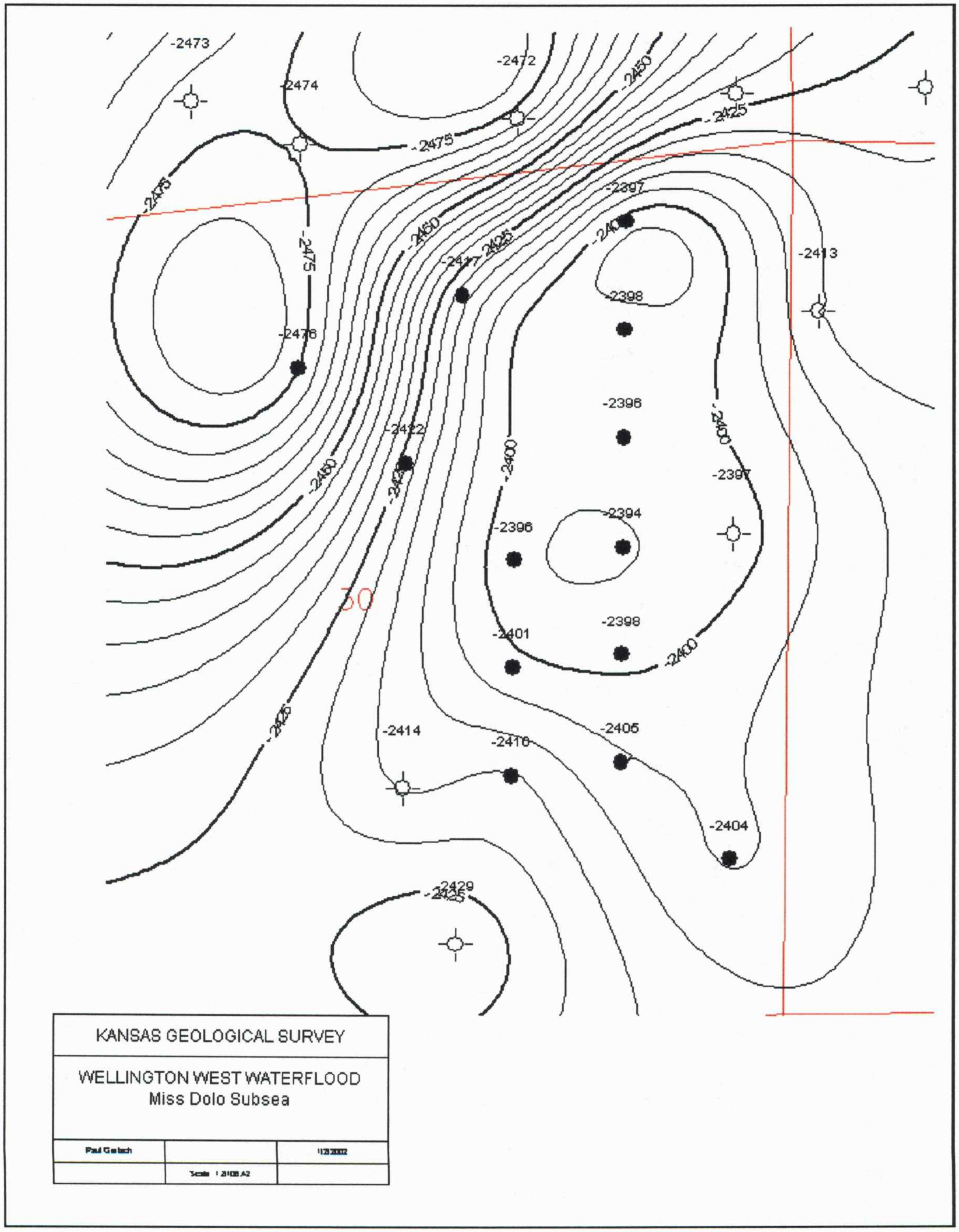


Figure 7. Isopach map of Mississippian in Wellington West Field.

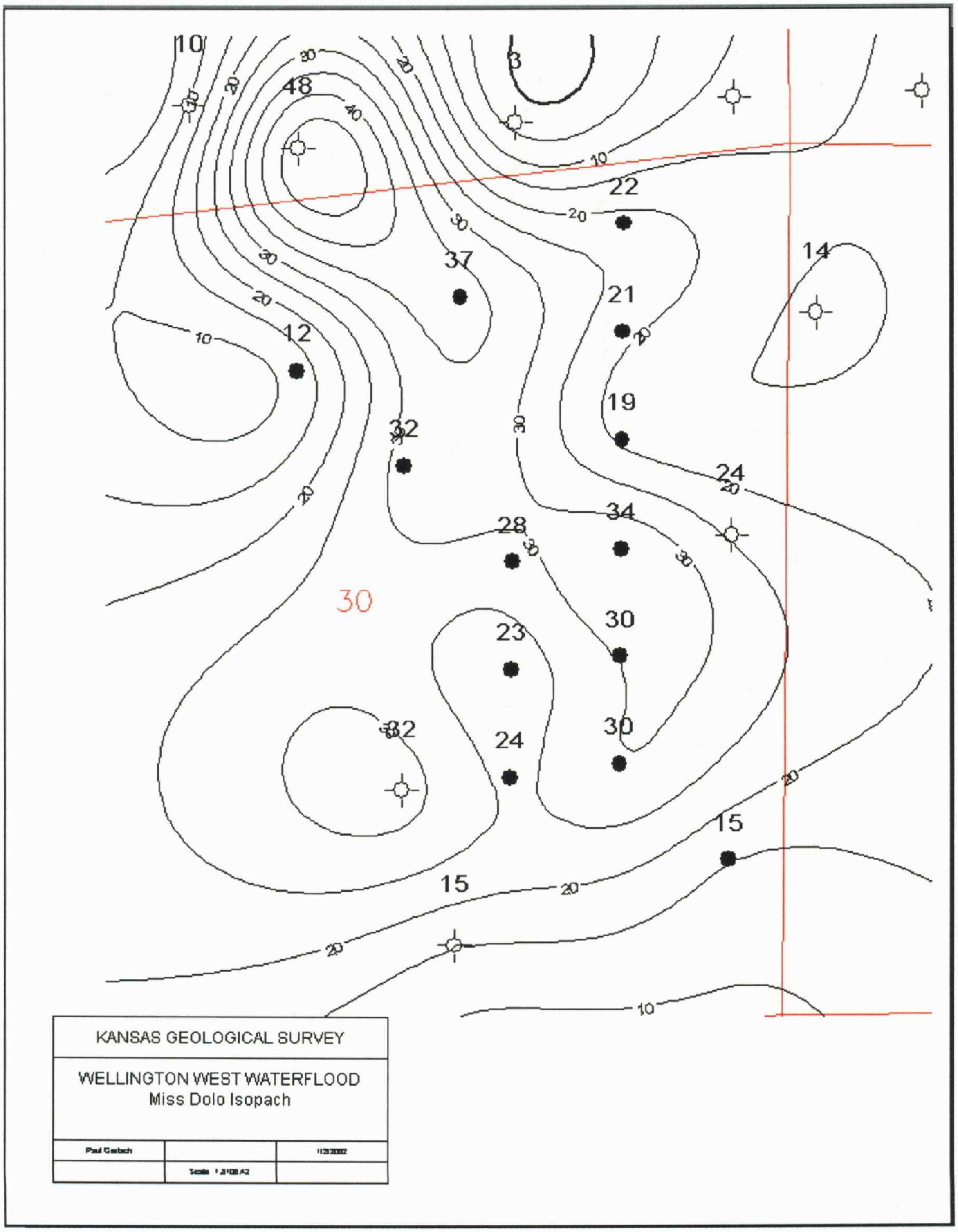


Figure 8. Mississippian average porosity distribution map for Wellington West Field.

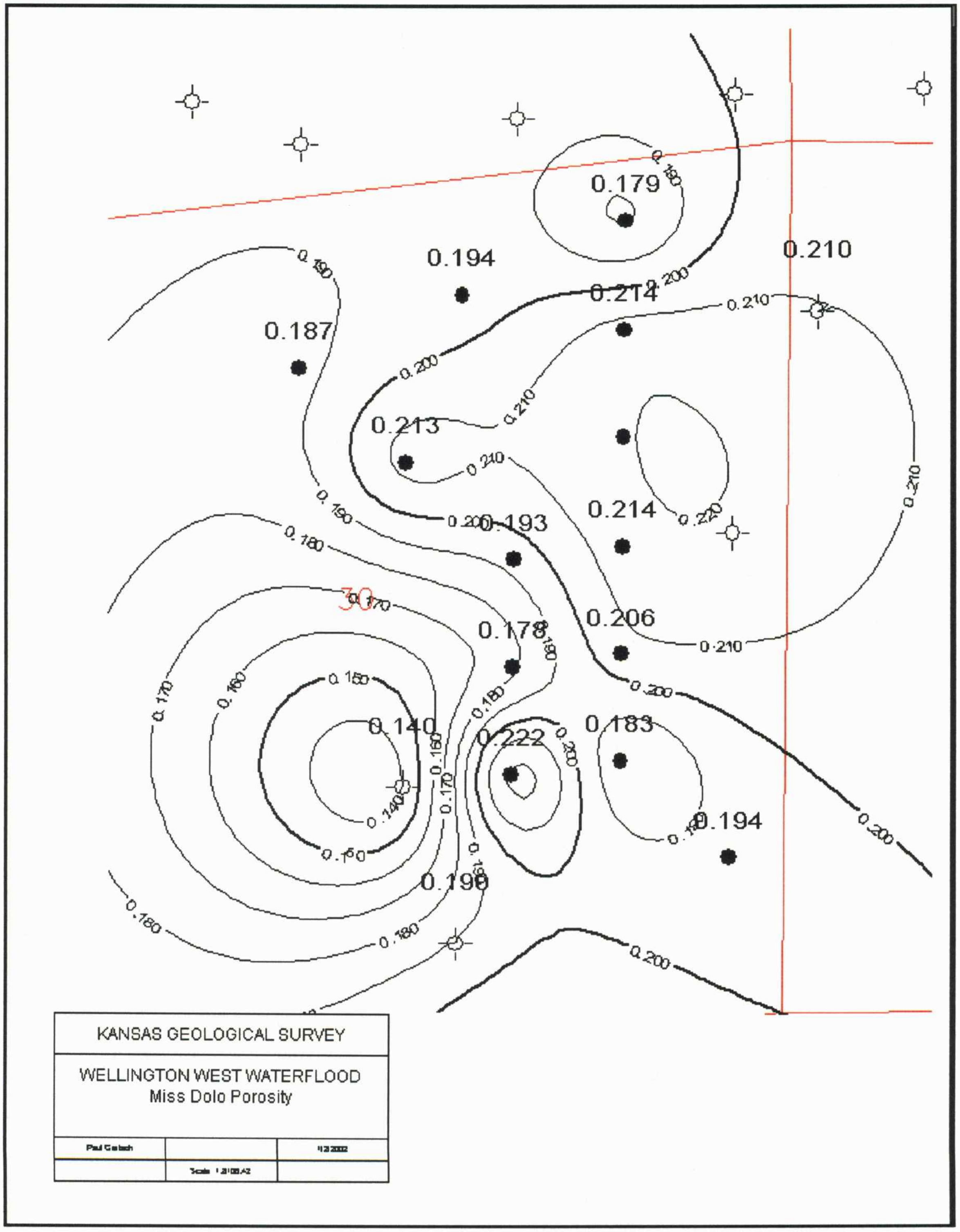
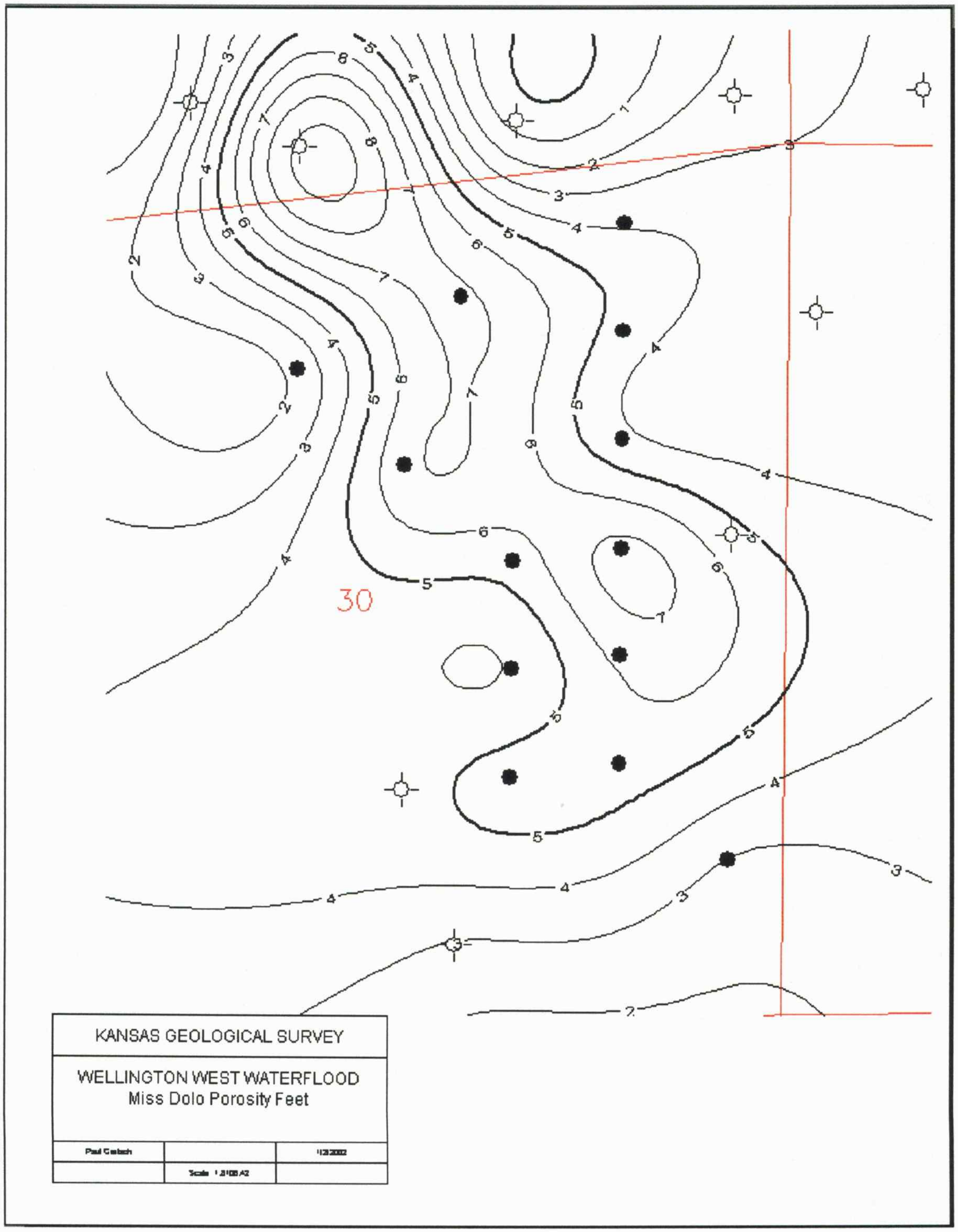


Figure 9. Storativity, porosity x feet, for Mississippian dolomites in Wellington West Field.



DST Analyses

Shut-in pressures from drill stem tests (DSTs) recorded in the initial wells indicate the initial reservoir pressure is approximately 1800 psi. Initial potential (IP) rates for most of the wells range between 15 and 30 barrels of oil per day (bopd). However, field-wide differences between the final shut-in pressures (FSIPs) and the final flow pressures (FFPs), obtained from from DST records, indicate permeability heterogeneity within the pay zone. DST data from five (5) wells in Wellington West field were available for analysis. Analysis results are summarized in Table 1. Appendix A includes the details of the DST analysis. From its discovery to the present, the field has been under primary production without any artificial pressure support. Over the field history of 24 years, reservoir pressure has declined from 1800 psi to below 100 psi.

Table 1 Reservoir Pressure and Permeability from DST

Well name	date	Perf	Res pr	DST - K md	Rs, scf/bbl
Waugh 4	8/1/83	3672-86	1555	7	372
Waugh 2	5/10/83	3652-66	1845	16.3	
Becker 1	11/18/76	3790-00	1722	0.3	
Becker 4	5/3/83	3652-70	1758	1	299.7
Waugh 1	12/21/82	3654-70	1825	0.1	

Core Petrophysical Charaterization

Since no cores are available from the Wellington West field, core petrophysical data have been compiled from the nearby Bates field. For core from this field, porosities range from 4-26% and average 15.4±5% (Figure 10). Permeabilities range from less than 0.1 md (shown as 0.1 in figures) to 60 md and average 3.6 md (Figure 11).

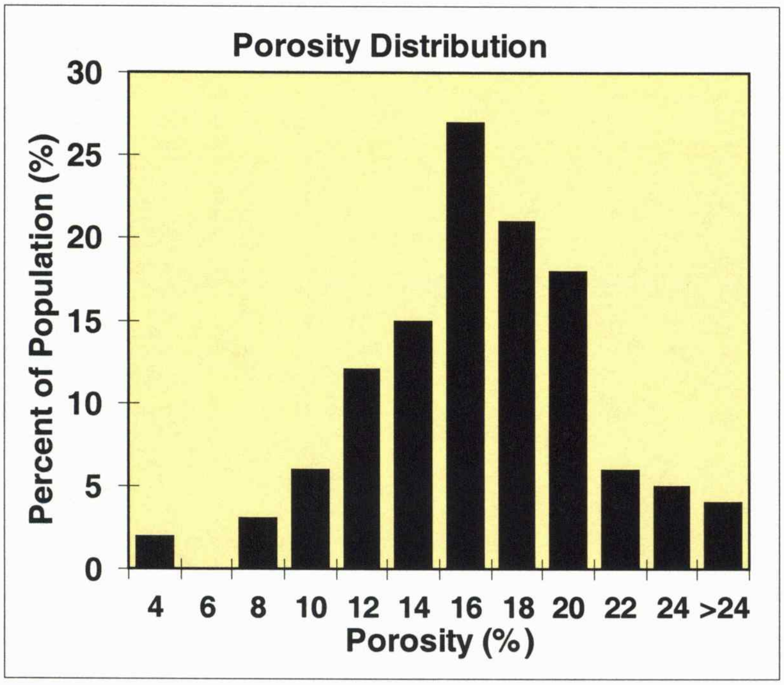


Figure 10. Porosity distribution for Mississippian dolomites in Anson-bates Field.

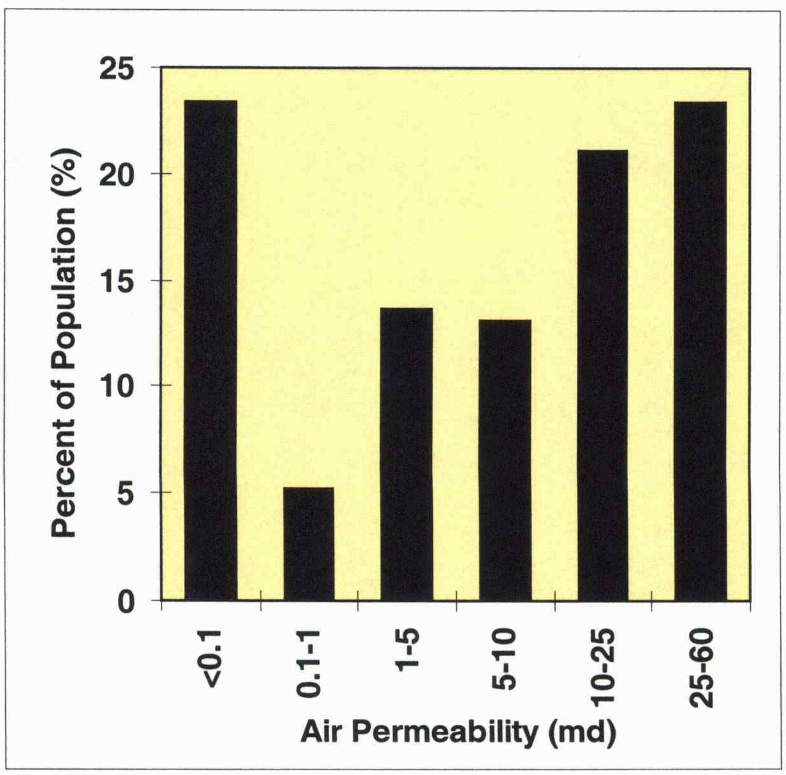


Figure 11. Full-diameter air permeability distribution for Mississippian dolomites in Anson-Bates Field.

Vertical permeabilities at the full-diameter scale average 0.74±0.3 times horizontal permeabilities (Figure 13).

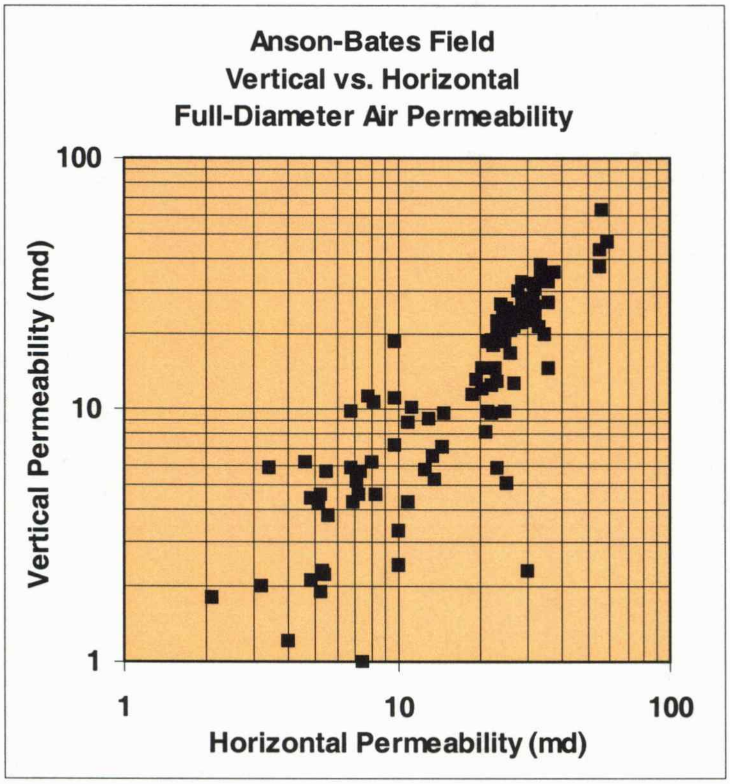


Figure 13. Vertical versus horizontal air permeability in Mississippian dolomites, Anson-Bates Field.

A cross-plot of the full-diameter air permeability versus porosity (Figure 14) for eleven wells exhibit a log-linear trend, typical of most rocks, with a maximum permeability of 40-60 md reached at approximately 17% . For porosity values greater than 17% these rocks do not exhibit significant increase in permeability. This upper limit to permeability may be a function of increasing moldic or vuggy porosity that is isolated by matrix with permeability in the 30-50 md range.

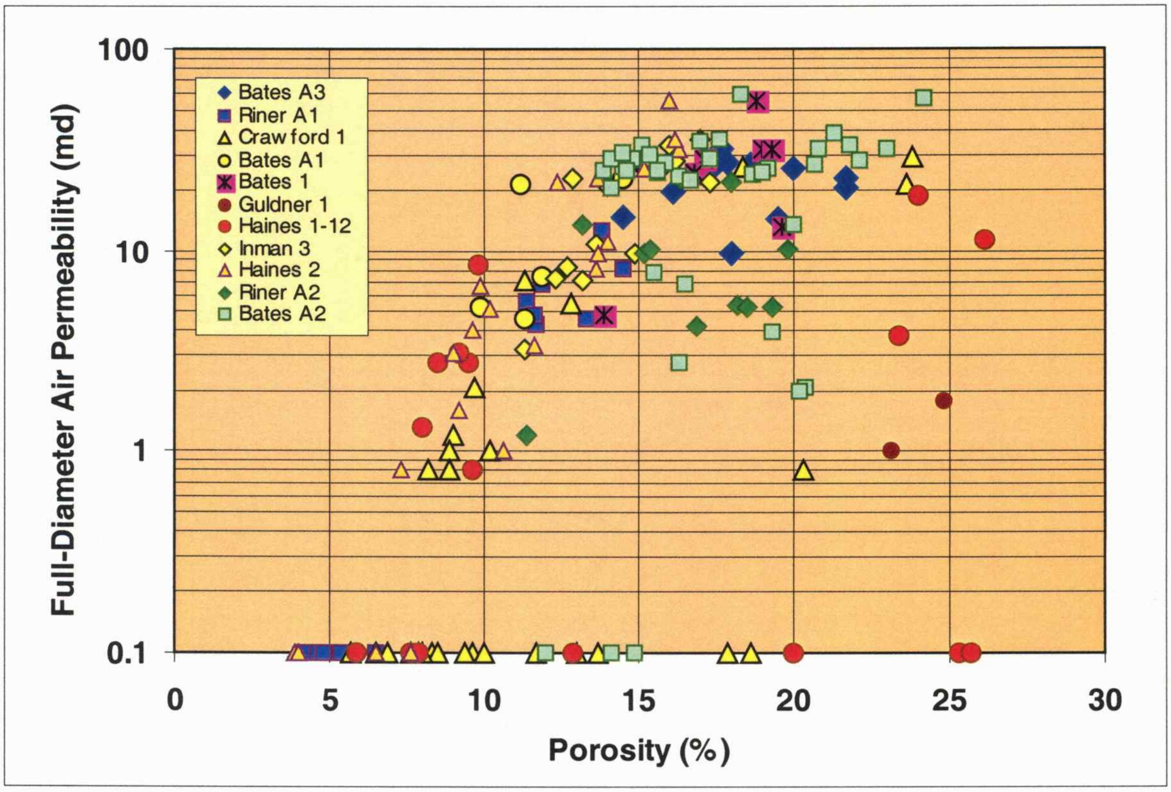


Figure 14. Full-diameter air permeability versus porosity for Mississippian dolomitic rocks in Anson-Bates Field.

Bates Field sucrosic dolomites are not cherty but represent the evolution of the dolomite mudstones in a laterally equivalent setting to the Mississippian "chat" reservoirs to the west. In these rocks chert replacement has not occurred The development of sucrosic dolomites does not significantly increase the porosity above that found in dolomite mudstones but results in permeabilities that are two orders of magnitude greater. Properties of patchy sucrosic dolomite within the cherty dolomite mudstone facies appear to exhibit similar properties when similar grain sizes develop.

It is important to note that in there investigation of Mississippian 'Chat" reservoirs, including some dolomites, Watney et al (2001) found that full-diameter core permeabilities are on average 5 to 10 times greater than plug permeabilities at any given porosity. Plug data are being obtained for the Bates to compare with the full-diameter permeabilities presented in Figure 11. Based on examination of core, three mechanisms are believed to cause this difference: 1) stress-release microcracking, that would not exist in the subsurface; 2) natural microfractures, particularly around breccia clasts and within inter-clast infill; and 3) enhanced preserved permeability channels along clast boundaries.

Appendix A

Table A5										
Well:	**Waugh 4**									
	from, ft	to, ft	Pay, ft					entered data		
DST range:	3665	3698	9					read from correlations		
Perf	3672	3686						read from Horner plot		
								calculation		
Reservoir gas properties:										
Sp gr., Rog =	0.73		gas specific gravity (avg from 3 samples)				GO, ft	240		
Tpc =	386	R	pseudocritical temp				MGO, ft	690	oil %	75
Ppc =	660	psia	pseudocritical pressure							
DST analysis - Oil:							**Production rate calculation:**			
Pi =	1555	psi					***Liquid recovery:***			
m =	305	psi/cycle					GO	240	ft	
Qo =	137.0	bbl/d					Additional oil	517.5	ft	
Qg =		Mcf/d					Total =	757.5	ft	
Pwf =	343	psi	(related to Qo - end of second flow)							
P I hr =							Drill collar length =		420	feet
							Drill collar ID =		2.25	inch
Transmissibility:							Drill pipe ID =		3.8	inch
							Fluid in drill collar =		420	feet
Kh/Muo =	162.6*Qo*Bo/m						Fluid in drill pipe =		337.5	feet
Bo =		bbl/STB								
Muo =		cp					Effective ID =		3.04	inch
							Effective capacity =		0.00898	bbl/ft
GOR, Rs =	372.7	scf/bbl					***Pre-flow recovery:***			
API stock tank =	40									
Sp gr oil, Roo =	0.83						FFP - end of pre-flow =		199	psi
Res temp, T =	120	F					FFP - end of main flow =		343	psi
Bo = 0.972+0.000147*(Rs*(Rog/Roo)^0.5+1.25*T)^1.175							Recovery from pre-flow =		439.5	ft
Bo @ bubble pt =	1.19	bbl/STB					Pre-flow volume =		3.9	bbl
							Pre-flow time =		30	min
Final Bo =	1.19	bbl/STB								
							Pre-flow rate =		189.4	bbl/d
Muod (dead oil) = 10^(10^(1.8653-.025086*API-.5644*log(T)))-1										
Muod =	2.1	cp	(dead oil)				***Main-flow recovery:***			
Muo (with GOR) = (10.715*(Rs+100)^(-.515))*Muod^(5.44*(Rs+150)^(-.338))							Recovery from main-flow =		318.0	ft
Muo =	0.73	cp					Main-flow volume =		2.85	bbl
							Main flow time =		30	mins
Kh/Muo =	86.95	md-ft\cp								
							Main-flow rate =		137.0	bbl/d
Permeability:										
h =	9	ft	pay							
Final Muo =	0.73	cp								
K =	7.0	md								

Table A4										
Well:	**Waugh 2**									
	from, ft	to, ft	Pay, ft					entered data		
DST range:	3615	3682	14					read from correlations		
Perf	3652	3666						read from Horner plot		
								calculation		
Reservoir gas properties:										
Sp gr., Rog =	0.73		gas specific gravity (avg from 3 samples)				GO, ft			
Tpc =	386	R	pseudocritical temp				GSOCM, ft	1746	oil %	2
Ppc =	660	psia	pseudocritical pressure							
DST analysis - Oil:							**Production rate calculation:**			
Pi =	1845	psi					***Liquid recovery:***			
m =	163	psi/cycle					GO	0	ft	
Qw =	330.3	bbl/d					Water	1711.08	ft	
Qg =		Mcf/d					Total =	1711.08	ft	
Pwf =	944	psi	(related to end of second flow)							
P I hr =							Drill collar length =		360	feet
							Drill collar ID =		2.25	inch
Transmissibility:							Drill pipe ID =		3.8	inch
							Fluid in drill collar =		360	feet
Kh/Muw =	162.6*Qw*Bw/m						Fluid in drill pipe =		1351.08	feet
Res temp, T =	121	F					Effective ID =		3.53	inch
API stock tank =	42						Effective capacity =		0.01211	bbl/ft
Sp gr oil, Roo =	0.82									
							Pre-flow recovery:			
del Vwt = -1.0001/100+1.33391*T/10000+5.50654*(T^2)/10^(-7)										
del Vwt =	0.014						FFP - end of pre-flow =		317	psi
							FFP - end of main flow =		944	psi
del Vwp = -1.95301*10^(-9)*P*T - 1.72834*10^(-13)*P^2*T - 3.58922*10^(-7)*P - 2.25341*10^(-10)*P^2										
del Vwp =	-0.0019						Recovery from pre-flow =		574.6	ft
							Pre-flow volume =		7.0	bbl
Bw = (1+del Vwp)*(1+del Vwt)							Pre-flow time =		30	min
Bw =	1.012	bbl/STB								
Final Bw =	1.01	bbl/STB					Pre-flow rate =		334.0	bbl/d
							Main-flow recovery:			
Muw1 @ atm =	0.63	cp	(salinity 7.5% - from Waugh 4)							
Muw @ res pr = (0.9994+4.0295*P*10^(-5)+3.1062*P^2*10^(-9))*Muw1							Recovery from main-flow =		1136.5	ft
Muw =	0.68	cp					Main-flow volume =		13.76	bbl
Final Muw =	0.68	cp					Main flow time =		60	mins
Kh/Muw =	333.54	md-ft\cp					Main-flow rate =		330.3	bbl/d
Permeability:										
h =	14	ft	pay							
K =	16.3	md								

Table A3							
Well:	**Waugh 1**						
	from, ft	to, ft	Pay, ft		entered data		
DST range:	3623	3682	16		read from correlations		
Perf	3654	3670			read from Horner plot		
					calculation		
FFP - end of main flow, psi		102				oil%	
Liquid col - end of main flow, ft		270		SOCM, ft	30	10	
Avg gradient, psi/ft		0.38	oil analysis	OCM, ft	60	23	
				OCM, ft	60	38	
Reservoir gas properties:				OCM, ft	60	50	
Sp gr., Rog =	0.73		gas specific gravity (avg from 3 samples)	OCM, ft	60	90	
Tpc =	386	R	pseudocritical temp				
Ppc =	660	psia	pseudocritical pressure	**Production rate calculation:**			
DST analysis - Oil:				Total liq recovery =	123.6	ft	
Pi =	1825	psi		Drill collar length =		150	feet
m =	625	psi/cycle		Drill collar ID =		2.25	inch
Qo =	6.1	bbl/d		Drill pipe ID =		3.8	inch
Qg =		Mcf/d		Fluid in drill collar =		123.6	feet
Pwf =	102	psi	(related to Qo - end of second flow)	Fluid in drill pipe =		0	feet
P I hr =							
				Effective ID =		2.25	inch
Transmissibility:				Effective capacity =		0.00492	bbl/ft
Kh/Muo =	162.6*Qo*Bo/m			***Pre-flow recovery:***			
Bo =		bbl/STB					
Muo =		cp		FFP - end of pre-flow =		59	psi
				FFP - end of main flow =		102	psi
GOR, Rs =	325.0	scf/bbl	(Waugh 4 = 372, Becker 4 = 300 scf/bbl)	Recovery from pre-flow =		71.5	ft
API stock tank =	40		(avg)	Pre-flow volume =		0.4	bbl
Sp gr oil, Roo =	0.83			Pre-flow time =		30	min
Res temp, T =	131	F					
				Pre-flow rate =		16.9	bbl/d
Bo = 0.972+0.000147*(Rs*(Rog/Roo)^0.5+1.25*T)^1.175							
Bo @ bubble pt =	1.17	bbl/STB		***Main-flow recovery:***			
Final Bo =	1.17	bbl/STB		Recovery from main-flow =		52.1	ft
				Main-flow volume =		0.26	bbl
Muod (dead oil) = 10^(10^(1.8653-.025086*API-.5644*log(T)))-1				Main flow time =		60	mins
Muod =	1.9	cp	(dead oil)				
				Main-flow rate =		6.1	bbl/d
Muo (with GOR) = (10.715*(Rs+100)^(-.515))*Muod^(5.44*(Rs+150)^(-.338))							
Muo =	0.74	cp					
Kh/Muo =	1.88	md-ft\cp					
Permeability:							
h =	16	ft	pay				
Final Muo =	0.74	cp					
K =	0.1	md					

Table A2										
Well:	**Becker 4**									
	from, ft	to, ft	Pay, ft					entered data		
DST range:	3621	3675	18					read from correlations		
Perf	3652	3670						read from Horner plot		
								calculation		
Reservoir gas properties:									oil%	
Sp gr., Rog =	0.73		gas specific gravity (avg from 3 samples)				CGO, ft	38	100	
Tpc =	386	R	pseudocritical temp				GMO, ft	545	78	
Ppc =	660	psia	pseudocritical pressure				Additional, ft			
DST analysis - Oil:							**Production rate calculation:**			
Pi =	1758	psi					***Liquid recovery:***			
m =	176	psi/cycle								
Qo =	22.6	bbl/d					Total =	463.1	ft	
Qg =		Mcf/d								
Pwf =	198	psi	(related to Qo - end of second flow)				Drill collar length =		360	feet
P I hr =							Drill collar ID =		2.25	inch
							Drill pipe ID =		3.8	inch
Transmissibility:							Fluid in drill collar =		360	feet
							Fluid in drill pipe =		103.1	feet
Kh/Muo =	162.6*Qo*Bo/m									
Bo =		bbl/STB					Effective ID =		2.67	inch
Muo =		cp					Effective capacity =		0.00695	bbl/ft
							Pre-flow recovery:			
GOR, Rs =	299.7	scf/bbl								
API stock tank =	42						FFP - end of pre-flow =		140	psi
Sp gr oil, Roo =	0.82						FFP - end of main flow =		198	psi
Res temp, T =	118	F								
							Recovery from pre-flow =		327.4	ft
Bo = 0.972+0.000147*(Rs*(Rog/Roo)^0.5+1.25*T)^1.175							Pre-flow volume =		2.3	bbl
Bo @ bubble pt =	1.16	bbl/STB					Pre-flow time =		30	min
Final Bo =	1.16	bbl/STB					Pre-flow rate =		109.2	bbl/d
Muod (dead oil) = 10^(10^(1.8653-.025086*API-.5644*log(T)))-1							***Main-flow recovery:***			
Muod =	1.7	cp	(dead oil)							
							Recovery from main-flow =		135.7	ft
Muo (with GOR) = (10.715*(Rs+100)^(-.515))*Muod^(5.44*(Rs+150)^(-.338))							Main-flow volume =		0.94	bbl
Muo =	0.72	cp					Main flow time =		60	mins
Kh/Muo =	24.13	md-ft\cp					Main-flow rate =		22.6	bbl/d
Permeability:										
h =	18	ft	pay							
Final Muo =	0.72	cp								
K =	1.0	md								

Table A1										
Well:	**Becker 1**									
	from, ft	to, ft	Pay, ft					entered data		
DST range:	3766	3806	10					read from correlations		
Perf	3790	3800						read from Horner plot		
								calculation		
Reservoir gas properties:										
Sp gr., Rog =	0.73		gas specific gravity (avg from 3 samples)				GMWSHO, ft	30		
Tpc =	386	R	pseudocritical temp				GCMWFO, ft	60		
Ppc =	660	psia	pseudocritical pressure				HGCMWFO, ft	60	oil %	
DST analysis - Oil:							**Production rate calculation:**			
Pi =	1722	psi					***Liquid recovery:***			
m =	524	psi/cycle					GO		ft	
Qw =	14.1	bbl/d					Water	150	ft	
Qg =		Mcf/d					Total =	150	ft	
Pwf =	70	psi	(related to end of second flow)							
P I hr =							Drill collar length =		622	feet
							Drill collar ID =		2.56	inch
Transmissibility:							Drill pipe ID =		2.86	inch
							Fluid in drill collar =		150	feet
Kh/Muw =	162.6*Qw*Bw/m						Fluid in drill pipe =		0	feet
Res temp, T =	121	F	(recorder broke)				Effective ID =		2.56	inch
API stock tank =	42						Effective capacity =		0.00637	bbl/ft
Sp gr oil, Roo =	0.82									
							Pre-flow recovery:			
del Vwt = -1.0001/100+1.33391*T/10000+5.50654*(T^2)/10^(-7)										
del Vwt =	0.014						FFP - end of pre-flow =		27	psi
							FFP - end of main flow =		70	psi
del Vwp = -1.95301*10^(-9)*P*T - 1.72834*10^(-13)*P^2*T - 3.58922*10^(-7)*P - 2.25341*10^(-10)*P^2										
del Vwp =	-0.0018						Recovery from pre-flow =		57.9	ft
							Pre-flow volume =		0.4	bbl
Bw = (1+del Vwp)*(1+del Vwt)							Pre-flow time =		30	min
Bw =	1.012	bbl/STB								
Final Bw =	1.01	bbl/STB					Pre-flow rate =		17.7	bbl/d
							Main-flow recovery:			
Muw1 @ atm =	0.63	cp	(salinity 7.5% - from Waugh 4)							
Muw @ res pr = (0.9994+4.0295*P*10^(-5)+3.1062*P^2*10^(-9))*Muw1							Recovery from main-flow =		92.1	ft
Muw =	0.68	cp					Main-flow volume =		0.59	bbl
Final Muw =	0.68	cp					Main flow time =		60	mins
Kh/Muw =	4.42	md-ft\cp					Main-flow rate =		14.1	bbl/d
Permeability:										
h =	10	ft	pay							
K =	0.3	md								

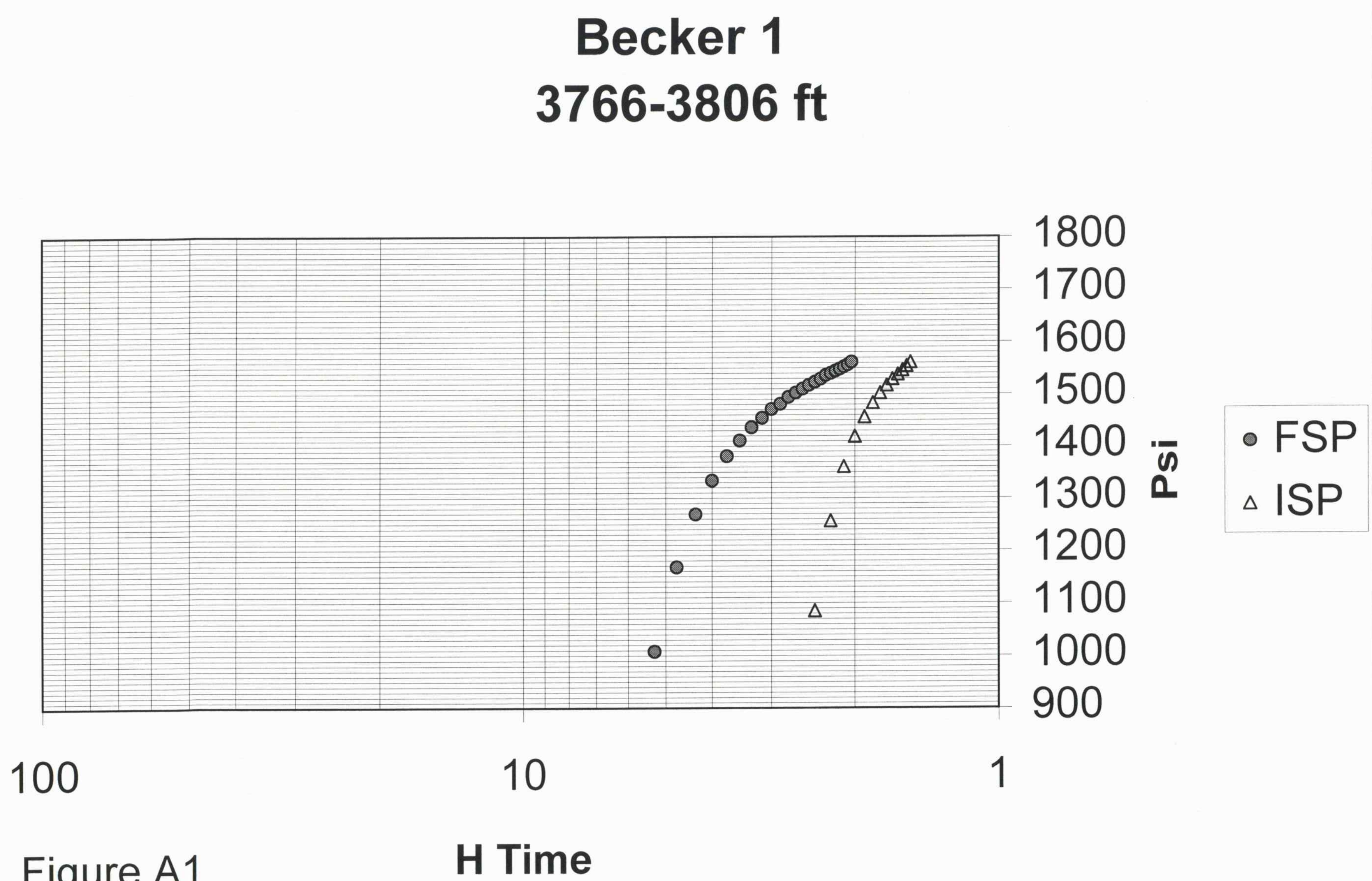
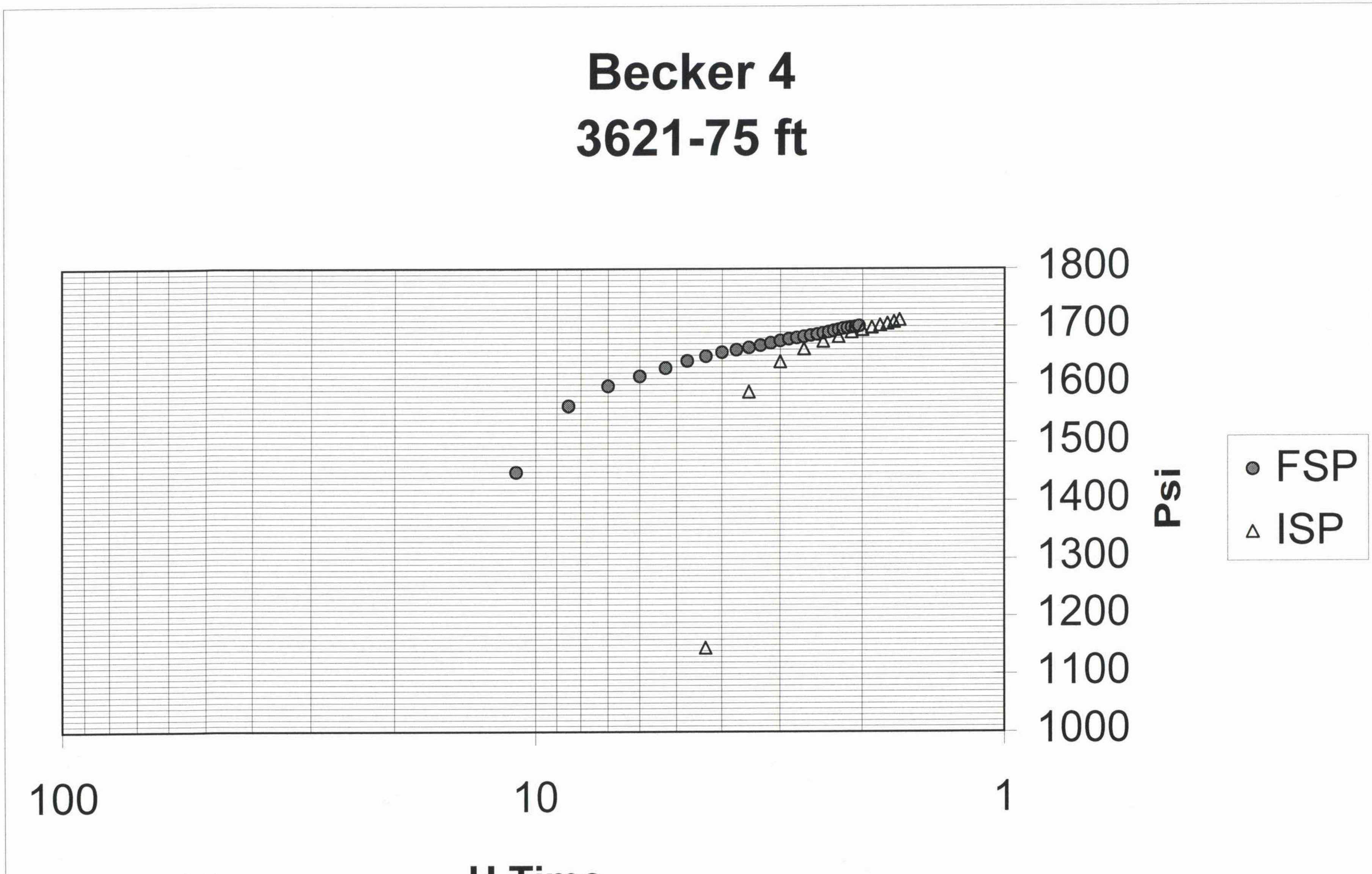

Becker 1
3766-3806 ft
1800
1700
1600
1500
1400
1300
1200
1100
1000
900
Psi
FSP
ISP
100
10
1
H Time

Figure A1


Becker 4
3621-75 ft
1800
1700
1600
1500
1400
1300
1200
1100
1000
Psi
FSP
ISP
100
10
1
H Time
Figure A2

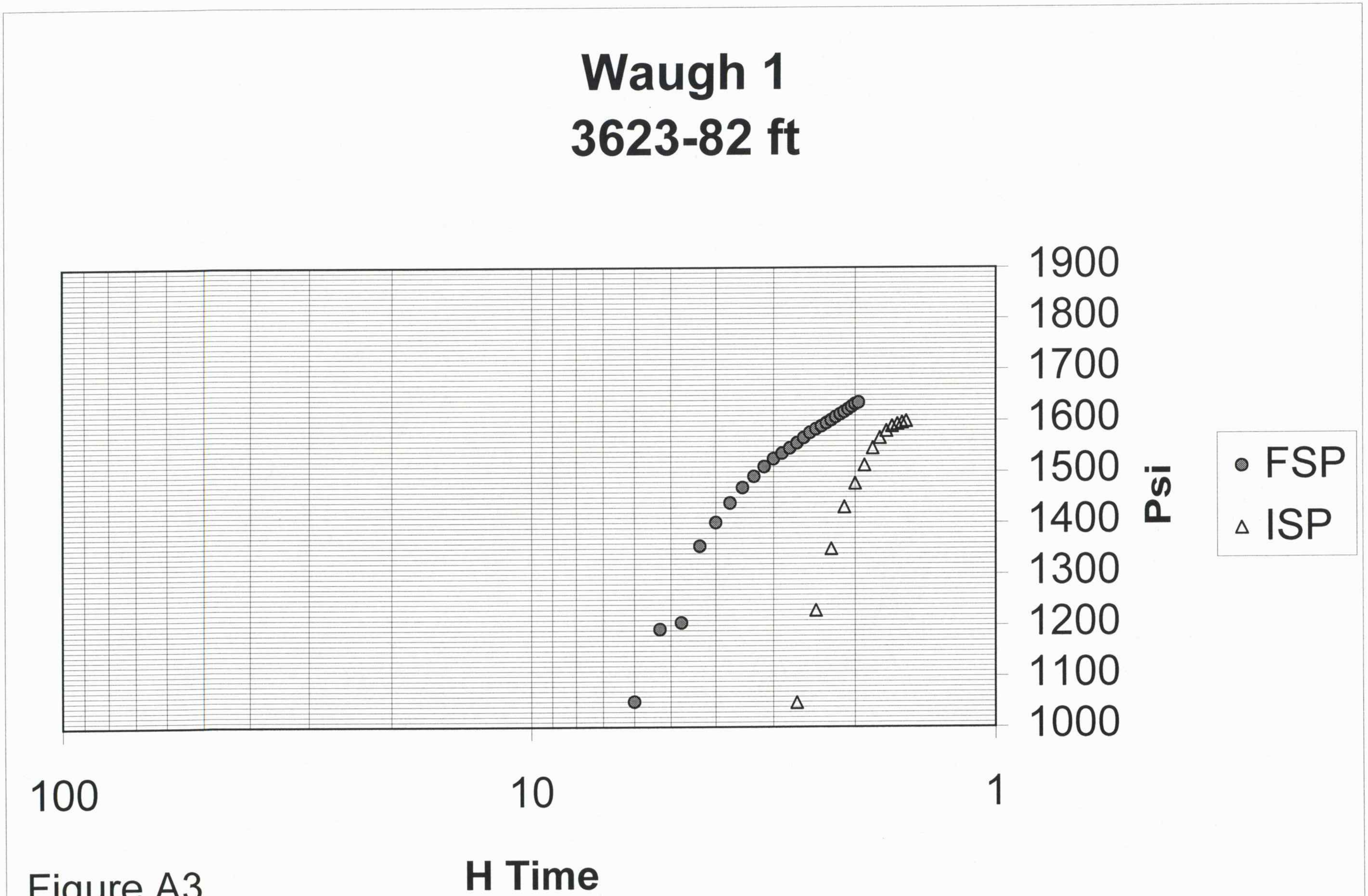
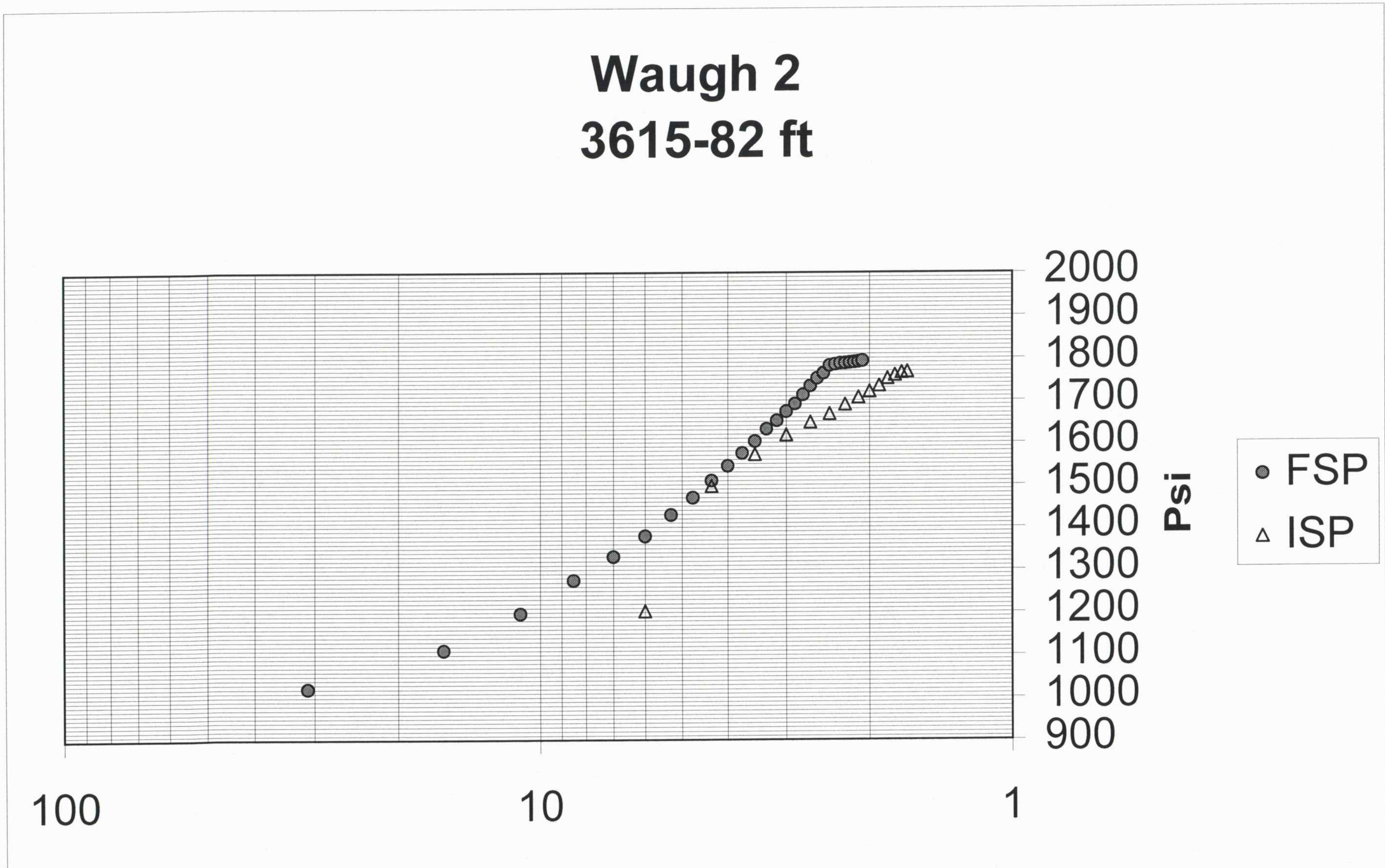

Waugh 1
3623-82 ft
1900
1800
1700
1600
1500
1400
1300
1200
1100
1000
Psi
FSP
ISP
100
10
1
H Time

Figure A3



Waugh 2
3615-82 ft
2000
1900
1800
1700
1600
1500
1400
1300
1200
1100
1000
900
Psi
FSP
ISP
100
10
1
H Time

Figure A4

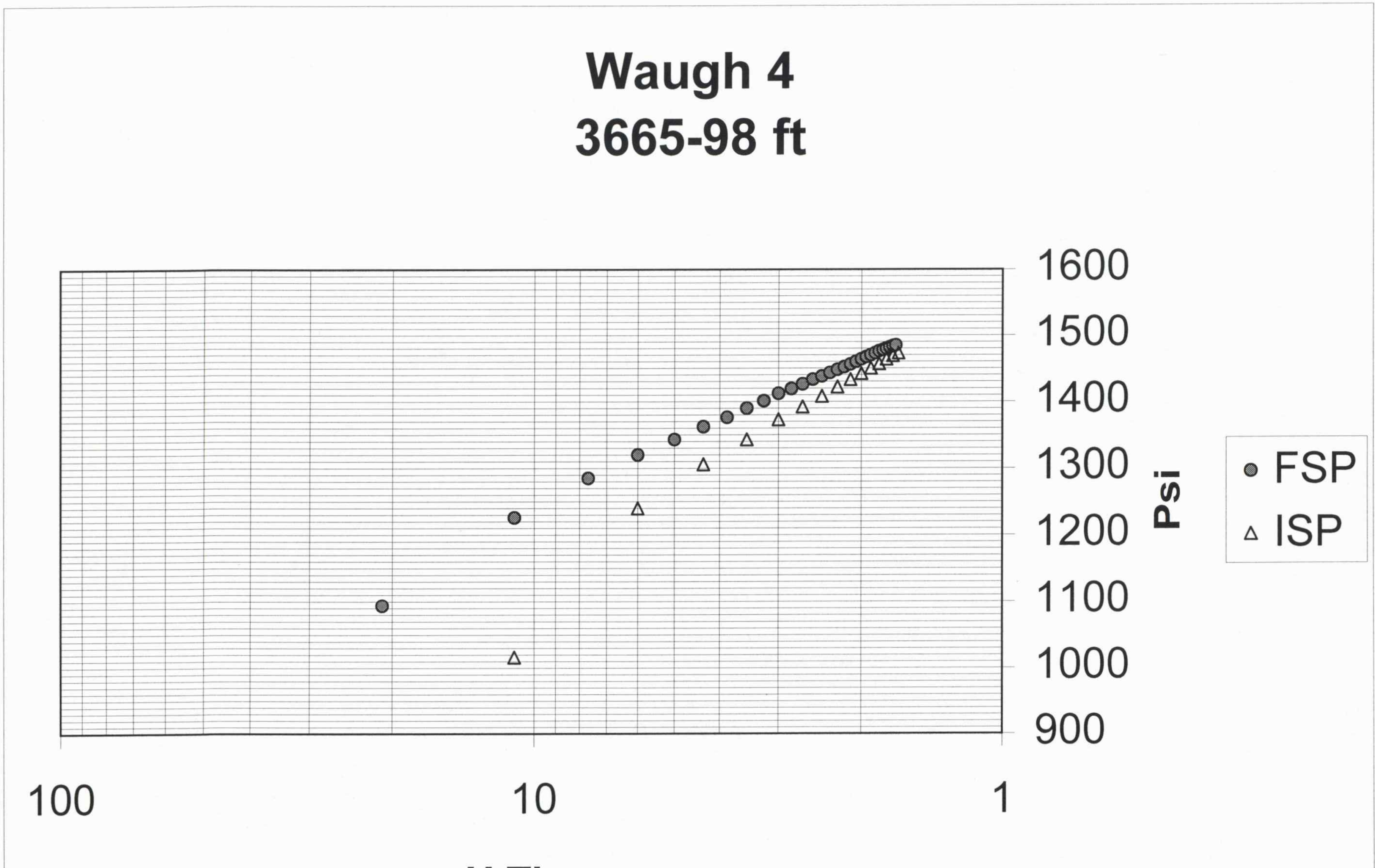

Waugh 4
3665-98 ft
1600
1500
1400
1300
1200
1100
1000
900
Psi
FSP
ISP
100
10
1
H Time

Figure A5