KANSAS GEOLOGICAL SURVEY
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PRESSURE AND PRODUCTION ANALYSES - VENT WELLS AROUND THE YAGGY GAS STORAGE FACILITY, HUTCHINSON, KANSAS

by

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Introduction

A natural gas explosion and fire destroyed two downtown Hutchinson businesses on January 17, 2001. Another explosion occurred the following day at a mobile home park 3 miles away from the city's downtown. As a result of these explosions two residents died of injuries. Also, these events forced the evacuation of hundreds of people as gas geysers, spewing natural gas and salt water, began erupting in the area. Abandoned brine wells, used for solution mining during the late 1800s and early 1900s, provided pathways for the natural gas to reach the surface at both of the explosion sites. The natural gas is suspected to have come from a leak that occurred at the Yaggy underground gas storage facility that is located approximately seven miles northwest of Hutchinson.

The Yaggy Storage Field is located in the southeast quarter of section 25, T22S-R7W and the southwest portion of section 30, T22S-R6W. The facility is owned and operated by MidContinent Marketing Center, a subsidiary of Kansas Gas Service (K-Gas). The Yaggy Storage Field consists of 98 caverns in the Hutchinson Salt Member of the Wellington Shale at depths greater than 500 ft. The caverns were formed by salt dissolution using brine wells. The capacity of the facility has been reported[1] as 3.2 billion cubic feet of natural gas. The caverns are accessed by wells located on a grid with less than 400 ft spacing between wells. Subsequent to a pressure drop in the POD 1 group of wells on January 17, 2001, a leak was discovered in well S-1 at a depth of about 601ft. The cavern connected to well S-1 reportedly[1] holds 60 million cubic feet of gas. When full, the gas pressure inside the cavern ranges from 550 to 684 pounds per square inch (psi), and is normally kept at about 675 psi.

Since the explosions in the city and the detection of the leak at the Yaggy facility, a series of vent wells were drilled in and around the city to provide additional pathways to the released gas to bleed to the surface in a controlled manner. Kansas Geological Survey (KGS), using geologic and seismic studies, played an active role in locating some of the productive vent wells and in identifying and characterizing the gas bearing interval. K-Gas continued to monitor the performance of the vent wells through a series of shut-in surveys and a build-up test. They also recorded the surface flow rates at these wells. Shut-in pressure, build-up, and flow rate data, provided by K-Gas, were analyzed at the KGS. Vent wells that flowed and/or recorded build-up pressures upon shut-in were categorized as Group-1, while those that never flowed gas or showed a build-up were put in Group-2.

Analysis of Shut-in pressure data

Analysis of records from vent-well drilling indicate that the gas-bearing interval in the Hutchinson area ranges from a depth of 270 feet on the east side of the city to 400 feet below the surface several miles northwest of the city[1]. This interval has a gentle dip, approximately 20 feet per mile, to the west-northwest. Core samples from DDV #67 and wireline logs indicate that the gas-bearing interval contains thin interbedded layers of gray to dark gray and red-brown shale with several distinctive and widespread, but relatively thin beds of gypsum and dolomite. The gas is associated with the occurrence of three thin (<3 ft, thick) dolomite layers. However, core analysis of these dolomite layers in DDV 67, a well that produced very limited amounts of gas, indicates very low matrix porosity (<3%) in the form of small vugs and discontinuous fractures. DDV #67 is offset from a highly productive well, DDV #53. This low porosity pore system observed in DDV #67 cannot account for the observed distribution of natural gas. Moreover, an isolated fracture system is believed to provide the limited, linear conduit for gas migration. The strata immediately overlying the gas-bearing interval include a thicker gypsum bed that appears to act as seal, preventing the upward migration of natural gas. Thus, available conduits for the gas to escape to the surface were through unplugged, abandoned brine wells near Hutchinson or through vent wells drilled purposely under controlled conditions to intercept the gas. The dolomite layers are referred to as the "gas zone" in future references in this report. Geologic studies[2], including log analysis, core studies and subsurface cross-sections, along with driller's logs helped to map the distribution of the gas zone in and around the city.

At the Group-1 wells, surface shut-in pressures along with water levels were recorded in surveys conducted in March and August 2001 (Tables 1 and 2). Table 1 shows the data recorded in March 2001. When a water column was not found in a well, it was assumed that the water table was at the TD (total depth of the well). The quality of recorded data was checked by comparing the BHSP (bottom hole shut-in pressure) with the sum of THSP (tubing head shut-in pressure and the pressure of the water column in the well).

> Gas zone pressure = THSP + pressure due to water column above the top of the gas zone.

Figure 1 maps the pressure in the gas zone as of March 2001. However, the shut-in times for the wells in this survey are not uniform. K-Gas reported that shut-ins were terminated when the THSP came close to the limits of safe operation at the surface. Based on a hydrostatic gradient of 0.5 psi/ft, the gas zone shut-in pressure at each vent well was compared to the hydrostatic head. The gas zone is presently sub-hydrostatic in almost all the vent wells (Figure 2). Table 2 shows the data recorded in the August 2001 survey. Wells that show significant build-up upon closure are DDV #53, #67, and #68. The OB wells are observation wells that have been drilled to the top of the salt to monitor gas pressure/flow. The tubing heads in these wells are open to the top of the salt while the annulus is open to the gas zone. An extended build-up test, for 234 hours, was conducted in well OB #2 and upon analysis revealed a reservoir pressure close to 250 psi. The casing-tubing annulus in well OB #3 recorded a shut-in pressure of 145 psi. Water column in the annulus was not recorded and thus the pressure in the gas zone at this well has to be at least 145 psi. The shut-in test was terminated prematurely in DDV #64 because the surface pressure came close to exceeding the pressure limitations at the surface. Recordings were unavailable at DDV #9 and DDV #32. Figure 3 shows the distribution of pressure in the gas zone as of August 2001. Figure 4 shows the gas zone pressure relative to the hydrostatic head. Though most of the wells show a pressure build-up upon closure, the gas zone pressure is generally sub-hydrostatic except for OB #2. Also, the gas zone pressure at OB #3 can not be calculated in absence of the water column in the casing tubing annulus. It is therefore very important that both THSP and water columns be recorded in the annulus of the OB wells to know if the area to the east of Yaggy field has gas that is above hydrostatic pressure.

Surveys carried out in April, June, August, and October 2001 recorded the THSP only. Fluid levels were not recorded in these surveys. The shut-in times and the surface shut-in pressures recorded in each of the above surveys are shown in Table 3 and are mapped in Figures 5 to 8b along with the outline of Hutchinson city. In the absence of fluid level recordings, a map of surface shut-in pressure is only indicative of the presence of gas in the sub-surface and not the pressure in the gas zone. The shut-in pressure maps indicate that presence or absence of gas in the gas zone over time and is not a reflection of the gas zone pressure or its change with time. Water columns can change in the wells and without knowing the water column pressure it is impossible to calculate the pressure in the gas zone given the THSP. Figures 5 to 8b show that a few months after the leak, in April 2001, gas remained pressurized in a wide area that extended from the northwest (this is direction and not location) into the city of Hutchinson. With time, much of the gas pressure vented from under the city leaving behind only small pockets (Figures 8a and 8b). However, a pressurized zone still exists from the northwest borders of the city on towards the direction of the Yaggy field. Close monitoring of vent wells (including the OB wells), therefore, needs to be carried out in this area.

In the October 2001 survey, shut-in pressures were recorded at the surface at the end of 98 hours and also over an extended period of 408 hours. A comparison of Figures 8a and 8b show that the increase in the shut-in period from 98 to 408 hours only results in a modest increase in the surface pressures. However, wells showing the most significant pressure build-up at surface at the end of 98 hours (such as DDV #53, #67, and #68) were not shut-in for the extended period, and this precludes one from understanding if these wells were close to their equilibrium pressure. Wells DDV #53 and #67 are very close neighbors, and yet upon shut-in they register different surface shut-in pressures after similar hours of closure during the April and June 2001 surveys. This difference in surface pressures decreases with time, with the October survey showing almost equal surface shut-in pressures. One possible reason may be different fluid levels existing in these two wells earlier during the year which resulted in a varying THSP despite similar BHSP. This clearly demonstrates the need for obtaining fluid levels at each of the vent along with THSPs.

The Group 2 wells were shut-in for 26 days during June-July 2001 (Table 4). Most of the wells show no/little pressure build-up at the surface and none of them have ever recorded any measurable volumes of gas flow.

The surface shut-in pressure maps indicate that areas with gas under pressure remain in the area between the Yaggy field and the city of Hutchinson. The vent wells appear to have drained some of the pressure pockets under the city. However, an area extending from the northwestern part of the city to close to the storage facility still show gas under pressure as late as October 2001. Two surveys, in March and in August 2001, collected the fluid-levels in the wells in addition to the surface shut-in pressures thus allowing calculation of the pressure in the gas zone. Most of the wells were shut-in for a short period (close to 30 hours) during the March survey and this may have prevented the wells from arriving at an equilibrium pressure. However, the August survey shut-in the wells for at least 70 hours and the resulting pressure and fluid level data can be considered to be more representative of the equilibrium conditions. The pressure in the gas zone is mostly sub-hydrostatic except near well OB #2. Though the remaining pressure is sub-hydrostatic, much of the gas zone still remains charged and therefore pressurized (close to 100 psi at some places). Select wells from Group 1 must therefore be allowed to vent most of the remaining gas because subsurface gas under pressure can unexpectedly surface through an unplugged abandoned well or a fracture. The surface shut-in pressure maps and the gas zone pressure maps both indicate that the remaining gas fills a narrow linear southeast trending zone extending from close to Yaggy to under the city of Hutchinson. In all these pressure maps, red arrows indicate slope (dip) direction of the structure formed by the top of the dolomite. It may be noted that areas where the subsurface is pressurized often coincide with the structural highs including narrower portions of a distinct anticline at DDV #53 and #67 and a dome along the anticline at DDV #64.

Build-up Analysis

An 11-day (September 21 to October 1, 2001) build-up study was carried out at well OB #2. This well was selected because it was the only well that was producing gas volumes in excess of 1 mcf/d during the later half of the year. The basis for analyzing build-up data in gas wells is the line source solution of the diffusivity equation. This equation was originally formulated for slightly compressible fluids such as oil. However, the viscosity and isothermal compressibility of gas is pressure dependent unlike oil. Thus, for analyzing data from the flow of highly compressible fluids, such as gas, the equations are altered by replacing pressure with real-gas pseudopressure[3].

$$m(p) = 2\int_{Pb}^{P} \frac{p\,dp}{\mu Z}$$

The real-gas pseudopressure (m(p)) is calculated as above between a base pressure (Pb) and the pressure of interest (P). The gas viscosity is expressed as μ (cp) and the Z represents the gas compressibility factor. Expressing all flow equations in terms of pseudopressures improves the accuracy of the semi-log analysis of the buildup data in gas wells. Also, conventional buildup test analysis techniques have been developed for wells producing at a constant rate before shut-in. However, the vent wells at Hutchinson have been open and flowing to the atmosphere before shut-in and have therefore been producing at constant BHP (bottom hole pressure). For Horner analysis of build-up data at a well flowing under constant BHP, the Horner-time plotting function is calculated by using the actual producing time[4] that the well was open before shut-in.

All parameters in the integrand are themselves functions of pressure and can be obtained directly from PVT analysis of the gas at reservoir temperature, or from standard correlations of μ and Z knowing only the gas gravity and reservoir temperature. K-Gas did not provide the measured values of μ and Z for the vent gas at different pressure and reservoir temperature. In the absence of laboratory measured PVT data, standard correlations were used to estimate (eyeball) the Z value for different pressure values till 300 psi. Table 5a summarizes the PVT inputs used in this analysis along with development of a correlation between reservoir pressure P and m(p). Correlations available for the calculation of gas viscosity (μ) display a minimum pseudoreduced pressure (P_{pr}) of 1.0. As evident from Table 5a, the maximum P_{pr} calculated in the range of interest of reservoir pressure was only 0.47. Thus, the gas viscosity values used in these calculations were that of natural gas at 1 atmosphere pressure including a correction for the mole percentage of nitrogen present in the vent gas. Lacking laboratory measured PVT values, the PVT values used in these calculations are only approximate.

Table 5b includes the plot of the build-up data along with the calculations for determining the average effective permeability in the area under drainage by the well OB #2, the average reservoir pressure in this drainage area and the skin. Based on the straight line slope of the middle-time region, when the pressure transient has moved into the undamaged formation outside the immediate neighborhood of the well, the effective permeability of the flowing phase, gas, is estimated to be about 2.77 md. The current average pressure in the drainage area of the well is about 255.3 psi. The well was shut-in for almost 234 hrs during this build-up test. The bottom-hole shut-in pressure was close to 251 psi after a shut-in time of 73 hrs. Based on the low permeability of the reservoir, it has been recommended that future shut-in pressure and fluid-level measurements, conducted during the year 2002, be carried out after a minimum shut-in time of 73 hrs.

The porosity for the tested interval was estimated from wireline logs measured in well OB #2. These logs indicate that a washout occurred at the test interval. The average porosity from a nearby interval whose lithology is similar to the test zone is estimated to be about 23%. Based on this average porosity value the skin around the well is calculated to be 0.11 (Table 5b). The shale corrected porosity, from wireline log, for the test interval is about 15%, and the skin factor corresponding to this porosity is about –0.1. The well OB #2 was deepened to the top of the salt before the build-up study. Before onset of this workover operation, the well was averaging production close to 6 mcf/d (June 18, 2001). Written details about the workover operations, carried out at this well, were not available to KGS. Based on informal conversations with K-Gas, it is understood that the gas zone, tested by the build-up, was damaged during the process of the workover operations. This resulted in a sudden reduction in the well production rate to 0.45 mcf/d. Records provided to the KGS indicate that the well took 32 days to recover to 1.3 mcf/d. Production records do not make an explicit mention of well stimulation during this time period. It appears, though, that the production from the well was allowed to accumulate over weekends and holidays. Upon opening of the well, this accumulated production was bled off and this exercise might have created pressure surges that stimulated the well. Without additional information about the well workover operations and the effective porosity across the test interval, it is difficult to account for the calculated skin values.

Decline-Curve Analysis

The basis of decline-curve analysis for estimating gas in place and reserves at some future abandonment condition is the assumption that future production performance can be modeled with past history. Any changes in field development strategies or production operation practices could change the future performance of a well and significantly affect reserve estimates from decline-curve techniques. Most conventional decline-curve analysis is based on Arps' empirical rate/time equation[4],

$$q(t) = \frac{q_i}{\sqrt[b]{(1 + bD_i t)}}$$

where D_i is the initial decline rate, q_i is the initial gas flow rate, and b is the decline exponent. Based on the value of decline exponent, three forms of decline are described by the above equation. The decline is exponential when b = 0, is harmonic when b = 1, and hyberbolic when b is between 0 and 1. These three forms of decline have a different shape on Cartesian and semilog graphs of gas production rate vs. time and gas production rate vs. cumulative gas production. Thus, these curve shapes help to identify the type of decline for a well and, a linear trend can be extrapolated to some future point to make a prediction.

It is important to note that the above decline equation is based on four important assumptions.

1. For the equation to be applicable, the well has to be produced at constant bottom hole pressure (BHP).
2. The equation is valid for a well that is producing for an unchanging drainage area with no-flow boundaries. Thus, entry of water in the drainage area will cause an abrupt change in the decline character of the well.
3. An underlying assumption of the equation is that the well produces under constant permeability and skin. Thus, permeability change due to pore pressure decrease or change of skin by stimulation will affect the decline character of production.
4. As a predictive tool, the decline curve analysis must be applied only to boundary-dominated (stabilized) flow data. Data that fits the transient part of the decline curve can not be used to predict long term behavior. Thus, as an extension of assumption 2, predictions of a well's long term decline rate are non unique until all the drainage boundaries have started to affect the well's decline characteristics.

A plot of log q(t) vs. t for a well under exponential decline will be a straight line with a slope of $-D_i/2.303$ and show an intercept of log q_i. The calculated decline rate D_i along with the initial gas flow rate (q_i) can be used to extrapolate the production trend into the future to some economic limit. For a well under harmonic decline, a plot of log q(t) vs. $G_p(t)$ (cumulative production) will result in a linear slope of $-(D_i/2.303q_i)$ that has an intercept of $\log(q_i)$. Hyperbolic decline can not be expressed by a straight-line relationship such as rate/time or rate/cumulative.

The basis of the decline curve analysis is the assumption that boundaries affect the rate response. Thus, only the boundary dominated flowing conditions can be analyzed. There is no theoretical basis for decline curve analysis if boundary dominated flow has not been established. Wells in low permeability reservoirs often take significant time before true boundary dominated flow takes effect. Fetkovich decline type curves can be used to identify if the production data for a well belongs to the boundary dominated flow period. Fetkovich decline type curves are based on theoretical considerations unlike the empirical decline curve analysis of Arps'. These are based on analytical solutions to the flow equations that model a well flowing at constant BHP and centered within a circular drainage area that is bounded by no flow boundaries. Both the transient and boundary dominated periods are represented in these type curves. The transient curves converge at dimensionless time of about 0.3, thus indicating the onset of the boundary dominated flow period. Flow responses in the boundary-dominated period are generated from Arps' decline equations and are characterized by different values of "b". Exponential decline is represented by "b" = 0, while the harmonic decline is defined by "b" = 1.

Application of Fetkovich type curves requires that the profile of the field production data be matched with a type curve. Gas production rate data (recorded between February and March 2001) were made available to the KGS for wells OB #2, DDV #4, DDV #5, DDV #17, DDV #32, DDV #36, DDV #53, DDV #54, DDV #59. Additionally, daily production volumes were also made available for these and other vent wells but in the absence of the daily flow-time for each of the wells, the daily production rate could not be calculated. For each of the above wells, the flow rate was q(t) was plotted vs. time (days) on a tracing paper carrying log-log axes whose size of the logarithmic cycles matched those of the Fetkovich decline type curve[5]. Figures 9a to 9i plot the data for all the above mentioned wells. It is apparent the boundary dominated flow becomes active soon after the start of flow in all these wells except DDV #05 because most of the plotted data fall to the right of the inflection point (marking the boundary between transient and boundary flow). This perhaps is indicative of the fact that the boundaries of the drainage area are in close proximity to the vent wells provided each of the wells satisfies the 4 underlying assumptions of the decline curve analyses. Also, the appearance of boundary-dominated flow lends relevance to decline rate calculations for these wells. Wells that display a harmonic decline are DDV #32, DDV #36, DDV #53, DDV #54, and DDV #59, while DDV #04 and DDV #17 show an exponential decline. The data trend for OB #02 is indicative of perhaps a hyperbolic decline (b = 0.8). Exponential decline is indicative of a more severe (faster) decline in production as compared to harmonic or hyperbolic. Hyperbolic decline occurs when natural or artificial driving energies slow down pressure depletion in the reservoir. Data from well DDV #05 (Figure 9i) could not be matched with the decline type curves and was therefore not analyzed for decline rates. Tables 6a to 6h summarize the decline rate calculations for the wells whose production rates matched a decline type curve.

Conclusions

a) Surface shut-in pressures indicate that gas zone still remains pressurized as late as the date of the last test data analyzed, i.e., October 2001.
b) Measurement of fluid levels in the wells under shut-in conditions enabled approximation of the pressure in the gas zone in August 2001. From the limited data available, it appears that gas zone is sub-hydrostatic in most places.
c) Though the gas zone pressure is sub hydrostatic, the sub-surface pressures in some areas are close to 250 psi. Therefore, the risk of this gas reaching the surface through an abandoned brine well or fracture still remains. Thus, vents wells must continue to be operated to bleed off gas zone.
d) Overlay of sub-surface pressure on the dip map indicates that pressurized pockets coincide with structural highs at some places.
e) Build-up analysis indicate that the permeability of the gas zone is well OB #2 is low.
f) Provided each of these wells satisfies the 4 assumptions that underlie decline curve analysis, the decline curve analysis on some of the vent wells show that boundary dominated flow is active soon after opening of the well.

REFERENCES

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Table 2
Data source K-Gas

Results from Aug 2001 tests

Well	Surface pr, psig	Elevation	Csg depth, ft	Water level, ft	TD ft	BHFP Flow Pr at TD, psig	SI time hrs	THSP Surface Pr shutin, psig	BHSP Static Pr at TD, psig	Data quality check BHSP-(THSP+wtr col)	Build-up BHSP - BHFP psig	Elevation of TD	Top of Gas ft	Wtr column above Gas, ft	Pr @ Gas zone, psi	Pr @ Gas Rel Hyd	Comments
DDV #4	0	1529	243	348	578	105.4	74	7	137	15	32	951	278	0	7	-132	
DDV #5	0	1540	201	463	564	53.9	75	2	71	19	17	976	310	0	2	-153	
DDV #9		1532	201	0	65		>75 hrs	33	64	-2			286	286	176	33	wtr level till surface. Well SI earlier
DDV #12	0	1523	201	130	557	212.3	73	18	226	-6	14	966	262	132	84	-47	
DDV #15	0	1535	205	182	547	180.8	74	15	192	-6	11	988	286	104	67	-76	
DDV #17	0	1529	201	524	562	18.7	73	1	24	4	5	967	270	0	1	-134	
DDV #21	0	1522	216	392	478	36.9	72	0	39	-4	2	1044	235	0	0	-118	
DDV #32													299			-150	No above grd well head
DDV #36	0	1547	201	220	523	154.3	76	3	156	2	2	1024	322	102	54	-107	
DDV #37	0	1522	201	60	546	252	71	8	252	1	0	976	234	174	95	-22	
DDV #42	0	1525	202	418	550	56.2	72	3	57	-12	1	975	248	0	3	-121	
DDV #43	0	1528	202	195	551	171.7	73	2	172	-8	0	977	262	67	36	-96	
DDV #44	0	1532	202	195	536	152.9	70	1	154	-18	1	996	291	96	49	-97	
DDV #53	0	1557	202	260	578	144.8	76	105	242	-22	97	979	341	81	146	-25	
DDV #54	0	1557	202	325	570	127.5	77	10	138	6	11	987	342	17	19	-153	
DDV #55	0	1544	208	455	482	13.6	76	6	18	-2	4	1062	315	0	6	-152	
DDV #59	0	1537	202	165	170	6.4	75	12	17	3	11	1367	300	135	80	-71	
DDV #64	0	1541	201		576	3.2		197				965	300	300	347	197	SI not recrded - Pr. Incr to pr limit.
DDV #67	0	1556	201	385	569	115.1	77	90	200	18	85	987	338	0	90	-79	
DDV #68	0	1545	201	392	392	0	75	106	106	0	106	1153	311	0	106	-50	
DDV #70	0	1540	202	165	548	194.3	75	17	208	-1	14	992	308	143	89	-66	
OB #1	0	1569	250	410	453	21	96	0	20	-2	-1	1116	394	0	0	-197	
OB #2	0	1565	536	637	637	1.64	95					928	387	0	250	57	BHSP = 250 from buildup ???
OB #3	0	1579	537	45	599	268.7	96					980	407		>145		Fluid level in csg/tbg annulus NA
OB #4	0	1574	539									1574	427				
OB #5	0	1570	538									1570	430				

Table 1

Data Source - K-Gas

Results from March 2001 flow tests

			THSP					BHSP	Data quality check			Gas Zone	Pr @ Gas	
Well	**Date**	**SI Time**	**Pr - psig**	**Elevation**	**Csg depth**	**Water level**	**TD**	**Pr @ TD**	**BHSP -**	**Top of Gas**	**Wtr col above gas**	**Pr - psig**	**relative Hyd**	**Comments**
				ft	ft	ft	ft	psi	(THSP + wtr column)	ft	ft		psi	
DDV #4	3/9/01	27.0	60	1529	243	300	304	58	-4	278	0	60	-79	
DDV #5	3/9/01	50.0	137	1540	201	250	311	156	-11.5	310	60	167	12	
DDV #9	3/9/01	27.0	2	1532	201	0	225	125.7	11.2	286	286	145	2	
DDV #12	3/8/01	25.0	116	1523	201	300	456	175	-19	262	0	116	-15	
DDV #15	3/9/01	29.5	21	1535	205	292	292	23	2	286	0	21	-122	No wtr level. Wtr assumed at TD
DDV #17	3/9/01	open	0	1529	201	155	155	0.6	0.6	270	115	57.5	-77.5	Csg depth > TD. Pr @ TD & surface -flowing
DDV #21	3/9/01	42.0	0	1522	216	460	480	9.6	-0.4	235	0	0	-117.5	
DDV #32	3/9/01	18.0	137	1538	202	212	212	138	1	299	87	180.5	31	No above ground well head in Aug
DDV #36	3/9/01	14.0	185	1547	201	350	494	256.6	-0.4	322	0	185	24	
DDV #37	3/9/01	25.0	62	1522	201	175	426	190.2	2.7	234	59	91.5	-25.5	
DDV #42	3/9/01	24.0	112	1525	202	212	212	115	3	248	36	130	6	No wtr level. Wtr assumed at TD
DDV #43	3/9/01	?	71	1528	202	460	478	79	-1	262	0	71	-60	
DDV #44	3/9/01	26.0	20	1532	202	488	488	22	2	291	0	20	-125.5	
DDV #53	3/11/01	24.0	60	1557	202	531	531	63.1	3.1	341	0	60	-110.5	No wtr level. Wtr assumed at TD
DDV #55	3/11/01	27.0	104	1544	208	221	221	106	2	315	94	151	-6.5	
DDV #59	3/11/01						212			300		112	-38	Aug TD < Mar TD. Pr released @ 112 psi
OB #1	3/10/01	?	0	1569	250	415	456	17.1	-3.4	394	0	0	-197	
OB #2	3/11/01	25.0	82	1565	210	415	415	83.9	1.9	387	0	82	-111.5	No wtr level. Wtr assumed at TD. Deepened - Aug
OB #3	3/11/01	22.5	20	1579	537	425	603			407	0	20	-183.5	From Mar 11 test - pr gradient record

Table 3

Data from K-Gas - Year 2001

Well	UTM X	UTM Y	SI - Apr	THSP - Apr	SI - June	THSP - June	SI - Aug	THSP - Aug	SI - Oct	THSP - Oct	SI - Oct	THSP - Oct (final)
DDV #4	593524.9	4212547	47.2	4	71	0	74	7	73	14	408	53
DDV #5	591777.8	4214814	51.3	2	70.9	2	75	2	73	0	408	0
DDV #9	594543.5	4213768			71.1	44		33				
DDV #12	594459.3	4211569	51.4	35	70.9	30	73	18	73	14	408	14
DDV #15	593774.7	4214020	49	49	70.9	40	74	15	73	5	408.2	5
DDV #17	595136.2	4213047	51	84	71	49	73	1	73	0	408	0
DDV #21	597731.5	4214524	50	0	70.8	1	72	0	73	0	408	0
DDV #32	593038.7	4214164	51.2	64	70.9	50	74.5	32	73	39	408	76
DDV #36	589669.4	4215811	51.5	98	70.6	3	76	3	73	27	408	75
DDV #37	597913.6	4212655	50.2	39	70.8	22	71	8	73	0	408	2
DDV #42	596414.9	4213093	52.2	20	70.8	34	72	3	73	40	408	94
DDV #43	595570.2	4213000	51	56	71.1	34	73	2	73	16	408	17
DDV #44	593194.5	4213122	51.3	13	70.9	9	70	1	73	5	408	20
DDV #53	587977.6	4216287	50.2	114	47.8	42	76	105	73	109	286.5	125.4
DDV #54	588012.3	4216730	9.2	118	70.7	18	77	10	73	7	408	16
DDV #55	591273.1	4215229	51.2	8	71	6	76	6	73	7	408	28
DDV #59	592119.2	4214490	50.4	36	70.9	20	75	12	73	12	408	16
DDV #64	590703.6	4215094	50.2	108	71	64	8	197	73	78	408	104
DDV #67	587969.1	4216269	49.6	54	47	82	76	90	73	107	98	124
DDV #68	589728.8	4215354	10.3	146	70.7	99	75	106	73	122	73	122
DDV #70	591330.9	4214689	49	36	70.6	22	75	17	73	17	408	31
OB #1	585177.7	4217759	45	6	70.5	0	96	0	98	0	408	0
OB #2	586030.9	4217505	6.6	150		136	95	255	98	255		255
OB #3	584522.9	4217401			70.6	47	96	145	98	126	408	140
OB #4	584273.5	4218364			70.6	0	96	0	98	0	408	6
OB #5	583770.3	4217762			70.6	0	96	0	98	1	408	0

SI - shut-in period (hrs)

THSP - tubing head shut-in pressure, psi

Table 4: Shut-in pressures at Group 2 wells

DATE==>	06/20/01		06/21/01		06/22/01		06/23/01		06/30/01		07/06/01	
	Time SI	PSIG	Hrs SI	PSIG	Hrs SI	PSIG	Hrs SI	PSIG	Hrs SI	PSIG	Hrs SI	PSIG
DDV#1	01:35 PM	0	24.66	0	46.66	0	70.66	0	240.41	0	384.41	0
DDV #02B	08:25 AM	0	24.16	7	47.41	12	70.83	18	240.00	32	384.17	35
DDV #03	09:25 AM	0	23.91	0	47.83	0	70.92	0	240.00	0	384.17	0
DDV #06	09:10 AM	0	23.91	0	47.83	0	70.69	0	240.08	0	384.16	0
DDV #07	08:50 AM	0	24.16	0	47.41	0	70.83	0	240.25	0	384.33	0
DDV #08	09:45 AM	0	24.16	0	47.83	0	70.92	0	240.08	0	384.25	0
DDV #10	10:25 AM	0	24.08	0	47.50	0	71.00	0	240.00	0	384.17	0
DDV #11	12:10 PM	0	25.61	0	47.25	0	70.91	0	240.75	0	384.92	0
DDV #13	08:40 AM	0	24.16	0	47.41	0	70.83	0	240.16	0	384.24	0
DDV #14	11:30 AM	0	25.25	0	47.25	VAC	70.91	VAC	240.08	0	384.25	VAC
DDV #18	01:20 PM	0	24.83	0	46.83	0	70.73	0	240.41	0	384.49	0
DDV #19A	09:35 AM	0	24.25	0	47.83	0	70.92	0	240.16	0	384.24	0.5
DDV #19B	09:35 AM	0	24.25	0	47.83	0	70.92	0	240.16	0	384.24	0.5
DDV #20		0		0	23.91	0	46.75	0	216.08	0	360.25	0
DDV #23	10:05 AM	0	24.08	0	47.66	0	70.75	0	240.16	0	384.33	0
DDV #26	10:50 AM	0	24.08	3	47.41	6	71.16	8	239.91	18	384.08	18
DDV #27	12:15 PM	0	25.16	0	47.25	0	70.91	0	240.83	0	385.00	0
DDV #28	11:55 AM	0	25.25	0	47.44	0	70.92	0	240.08	0	384.25	0
DDV #29	07:50 AM	0	24.10	0	47.41	0	71.00	0	240.16	0	384.33	0
DDV #30	11:05 AM	2	24.00	2	47.33	3	71.08	3	240.16	3	384.33	2.5
DDV#31	12:00 PM	0	25.25	0	47.33	0	71.00	0	240.25	0	384.42	0
DDV#35	01:55 PM	0	24.58	0	46.58	0	70.66	0	240.50	0	384.42	0
DDV#38	01:40 PM	0	24.66	0	46.66	0	70.66	0	240.41	0	384.41	0
DDV#39	10:30 AM	0	24.08	1	47.50	2	71.00	2	240.08	2	384.25	2
DDV#40	08:45 AM	0	24.16	0	47.41	0	70.83	0	240.08	0	384.16	0
DDV#45	11:25 AM	0	24.00	7	47.25	11	70.91	12	240.08	12	384.33	12
DDV#47	09:15 AM	0	23.91	0	47.83	0	70.67	0	240.16	0	384.33	1
DDV#50	08:05 AM	0	24.16	0	47.33	0	70.91	0	240.16	0	384.33	0
DDV#51	12:20 PM	0	25.16	0	47.25	0	70.91	0	240.83	0	385.00	0
DDV#56	03:35 PM	0	24.00	0	40.42	0	70.09	0	239.33	1	383.08	0
DDV#57	01:45 PM	0	24.66	0	46.66	0	70.74	0	240.50	0	384.42	0
DDV#58	11:40 AM	0	25.25	0	47.25	0	70.92	0	240.08	0	384.33	0
DDV#60	09:55 AM	0	24.08	0	47.75	0	70.83	0	240.16	0	384.33	0
DDV#61	11:00 AM	0	24.00	0	47.33	0	71.08	0	240.00	0	384.17	0
DDV#62	12:50 PM	0	25.16	0	47.25	0	71.00	0	240.66	0	384.74	0
DDV#63	02:10 PM	0	24.58	0	46.58	0	70.66	0	240.41	0	384.33	0
DDV#66	08:30 AM	0	24.16	0	47.41	0	70.83	0	240.08	0	384.16	0

Data Source - K-Gas

Table 5a (Reference 3)

Gas specific gravity	0.63	
Reservoir temp	64 F	524 oR
Pseudocritical pressure	672 psia	
Pseudocritical temperature	362 oR	
Vis of gas @ 1 atm	0.0104 cp	
Correction added to vis due to 8% (mole) Nitrogen in gas		0.0008 cp

Pressure psi	Psia, P	Ppr	Tpr	Z	Vis @ 1atm cp Mu1	2P/(Mu1*Z) psia/cp	X=Avg 2P/(Mu1*Z)	del P	X*del P psia^2/cp	m(P) psia^2/cp	Check m(p)
1	15.7	0.02	1.45	1	0.0112	2803.6	1401.8	1	1401.8	1401.8	7192.7719
50	64.7	0.10	1.45	0.992	0.0112	11646.7	7225.2	49	354032.8	355434.5	349221.298
100	114.7	0.17	1.45	0.983	0.0112	20836.4	16241.6	50	812077.7	1167512.2	1162589.5
150	164.7	0.25	1.45	0.972	0.0112	30257.9	25547.1	50	1277357.4	2444869.6	2445007.7
200	214.7	0.32	1.45	0.968	0.0112	39606.7	34932.3	50	1746615.9	4191485.6	4196475.9
250	264.7	0.39	1.45	0.961	0.0112	49186.1	44396.4	50	2219820.4	6411306.0	6416994.1
300	314.7	0.47	1.45	0.955	0.0112	58844.4	54015.3	50	2700763.6	9112069.5	9106562.3

Res pr	270	psia
Tpr	1.45	
Ppr	0.40	
Z	0.96	
del Z/del Ppr	-0.075	
Cpr	2.567	
cg	0.003820221	1/psi
Mu	0.0112	cp
cg*Mu	4.27865E-05	cp/psi

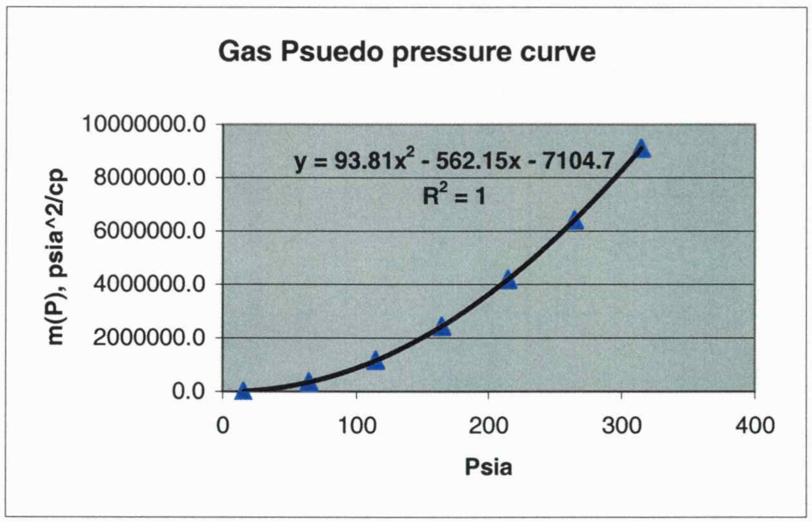


Table 5b

m =	**137500** psia^2/cp/log cycle			
K = 1637*Q*T/(m*H) md	Q =	1.333 mcf/d		
	T =	524 oR		
	H =	3 ft (409 to 412 ft)		
	K =	**2.77** md		
	m(Pi) =	**6706250** psia^2/cp	(at del T = infinity)	
	Pi =	270 psia	(refer to PVT page)	
		255.3 psi		
	m(P 1hr) =	**6187500** psia^2/cp		
Pwf = 16.34 psia	**m(Pwf) =**	**8756.63** psia^2/cp		
	Phi =	0.23		
	rw =	0.1875 ft		
	cg*Mu =	4.27865E-05 cp/psi		
	skin =	**0.11**		

Calculator

psia	*m(p)*
270	*6679864*

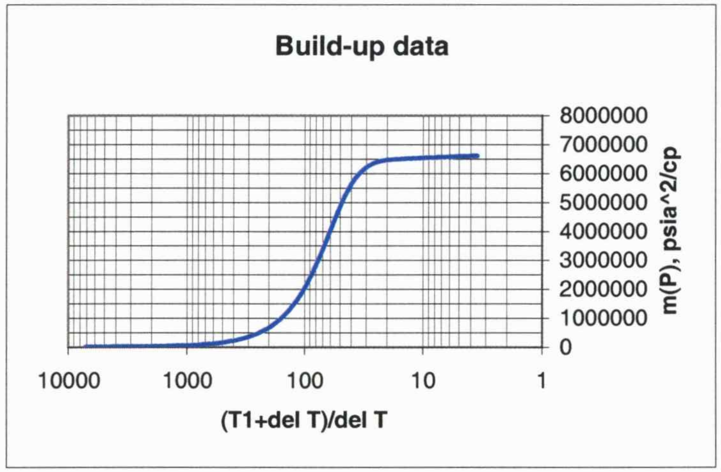


Table 6a

Harmonic decline calculations:

Initial rate calculation

at t = 0

Log (qt) = $\boxed{2.195}$

qi = 156.7 mcf/d

Decline rate calculation

m = - 1000*Di/(2.303*(= $\boxed{-0.4413}$

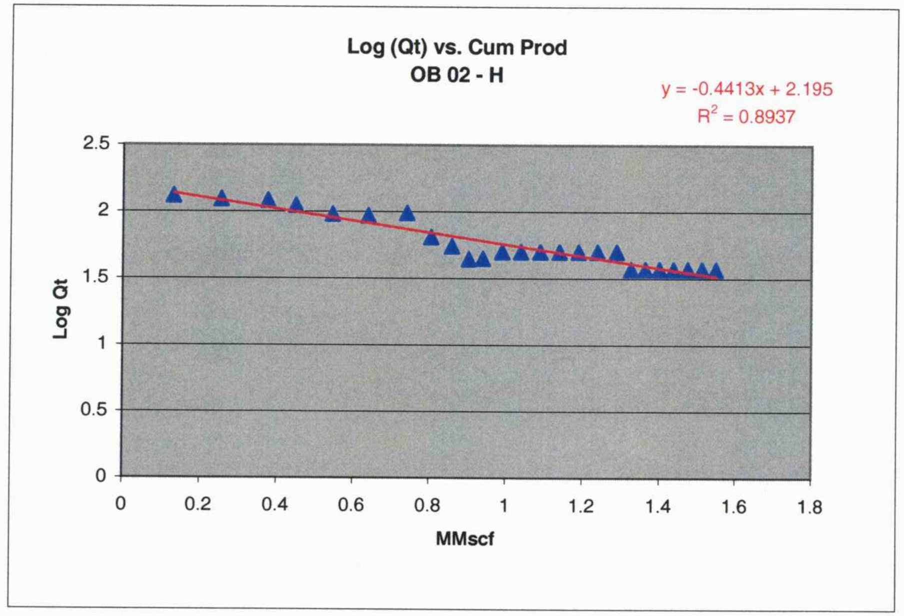
Di = 0.159231 1/day

58.1193 1/year

Decline equation

q(t) = qi/(1+Di*t) in days

Economic production rate (qe) $\boxed{1}$ mcf/d



Time to reach economic limit

1 = 156.7 / (1+Di*t)

1+ Di*t = 156.6751

t = 978 days

Ultimate recovery at economic limit

Gp(t) = (log(qi) - log(qt))*2.303*qi/Di

4973.941 Mscf

5 MMscf

Table 6b

Exponential decline calculations:

Decline rate calculation

m = - Di/2.303 = **-0.0698**

Di = 0.160749 1/day

58.6735 1/year

Initial rate calculation

at t = 0

Log (qt) = **1.6367**

qi = 43.3 mcf/d

Decline equation

q(t) = 43.3 e^ -0.16 in days

Economic production rate (qe) 1 mcf/d

Time to reach economic limit

1 = 43.3 e^ -0.16 t

-3.76932 = -0.16 t

t = 23.45 days

Ultimate recovery at economic limit

Gp(t) = (qi - qe)/Di

263.274 mscf
0.26 MMscf

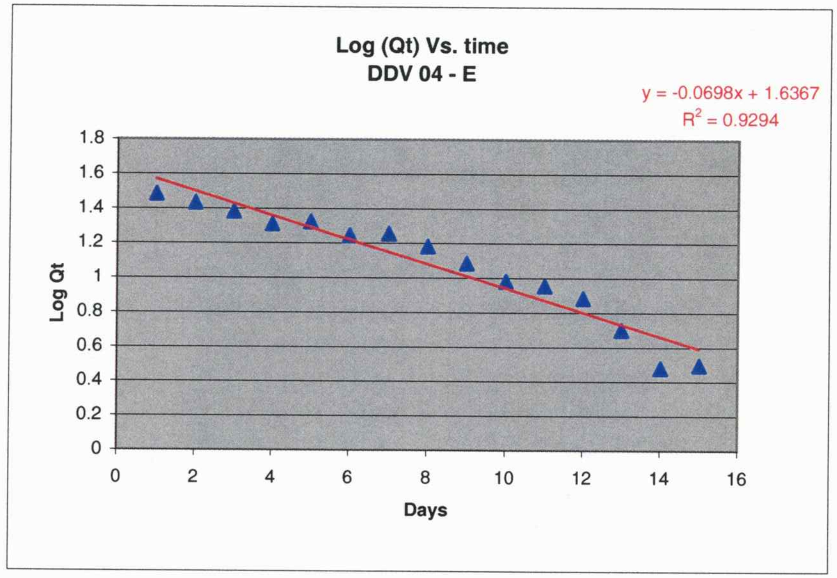


Table 6c

Exponential decline calculations:

Decline rate calculation

m = - Di/2.303 = $\boxed{-0.0912}$

Di = 0.210034 1/day

76.6623 1/year

Initial rate calculation

at t = 0

Log (qt) = $\boxed{2.1369}$

qi = 137.1 mcf/d

Decline equation

q(t) = 137.1 e^ -0.21 in days

Economic production rate (qe) $\boxed{1}$ mcf/d

Time to reach economic limit

1 = 137.1 e^ -0.21 t

-4.921281 = -0.21 t

t = 23 days

Ultimate recovery at economic limit

Gp(t) = (qi - qe)/Di

647.78 mscf

0.65 MMscf

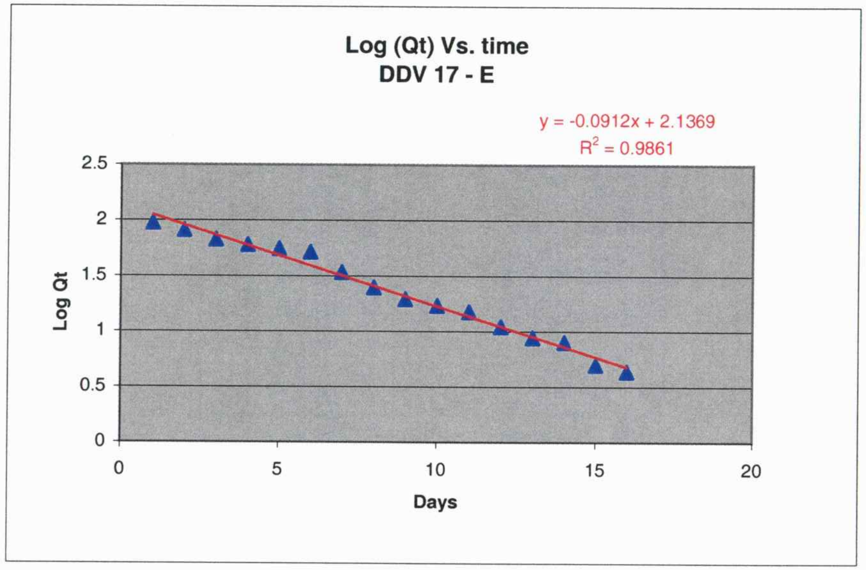


Table 6d

Harmonic decline calculations:

Initial rate calculation

at t = 0

Log (qt) = $\boxed{2.4402}$

qi = 275.5 mcf/d

Decline rate calculation

m = - 1000*Di/(2.303*(= $\boxed{-0.9237}$

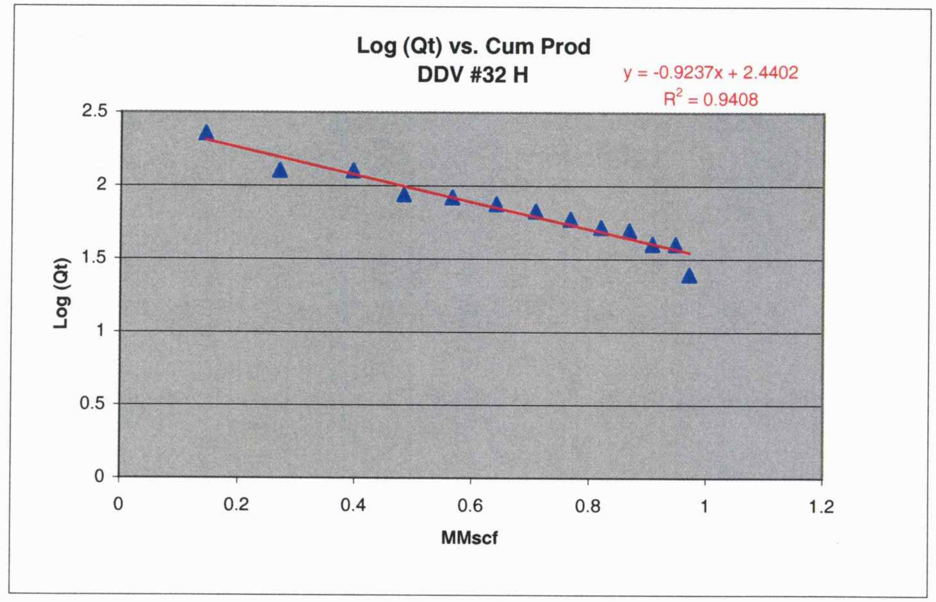
Di = 0.586172 1/day

213.9527 1/year

Decline equation

q(t) = qi/(1+Di*t) in days

Economic production rate (qe) $\boxed{1}$ mcf/d



Time to reach economic limit

1 = 275.5 / (1+Di*t)

1+ Di*t = 275.5497

t = 468 days

Ultimate recovery at economic limit

Gp(t) = (log(qi) - log(qt))*2.303*qi/Di

2641.767 Mscf

2.64 MMscf

Table 6e

Harmonic decline calculations:

Initial rate calculation

at t = 0

Log (qt) = **1.6518**

qi = 44.9 mcf/d

Decline rate calculation

m = - 1000*Di/(2.303*(= **-2.5194**

Di = 0.26025 1/day

94.9913 1/year

Decline equation

q(t) = qi/(1+Di*t) in days

Economic production rate (qe) 1 mcf/d

Time to reach economic limit

1 = 44.9 / (1+Di*t)

1+ Di*t = 44.85388

t = 169 days

Ultimate recovery at economic limit

Gp(t) = (log(qi) - log(qt))*2.303*qi/Di

655.63 Mscf

0.66 MMscf

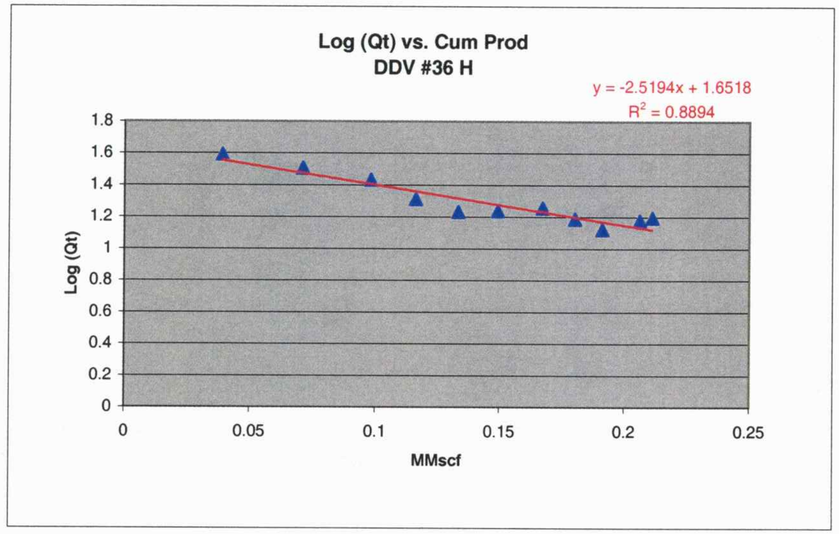


Table 6f

Harmonic decline calculations:

Initial rate calculation

at t = 0

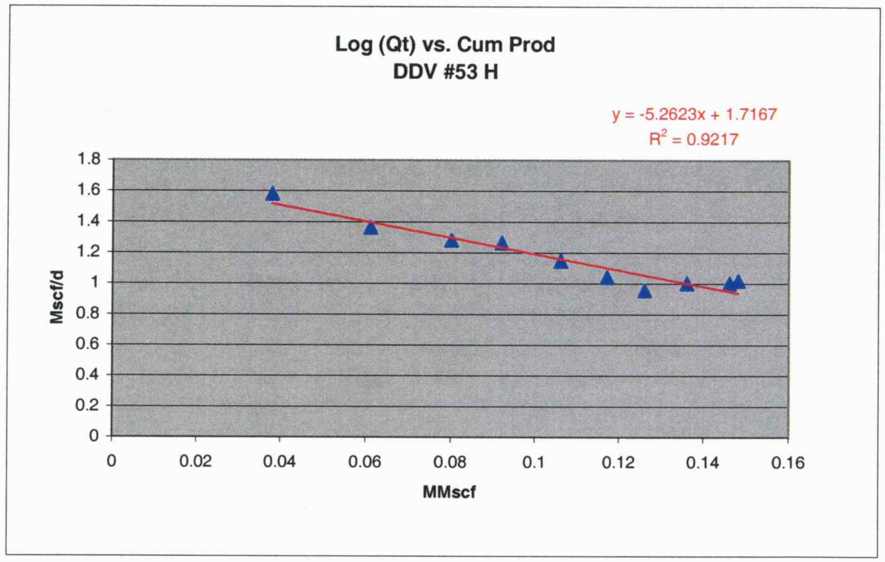
Log (qt) = $\boxed{1.7167}$

qi = 52.1 mcf/d

Decline rate calculation

m = - 1000*Di/(2.303*(= $\boxed{-5.2623}$

Di = 0.631204 1/day



Decline equation

q(t) = qi/(1+Di*t)

Economic production rate (qe) $\boxed{1}$ mcf/d

Time to reach economic limit

1 = 52.1 / (1+Di*t)

1+ Di*t = 52.08348

t = 81 days

Ultimate recovery at economic limit

Gp(t) = (log(qi) - log(qt))*2.303*qi/Di

326.23 Mscf

0.33 MMscf

Table 6g

Harmonic decline calculations:

Initial rate calculation

at t = 0

Log (qt) = $\boxed{1.5545}$

qi = 35.9 mcf/d

Decline rate calculation

m = - 1000*Di/(2.303*(= $\boxed{-5.4581}$

Di = 0.450646 1/day

164.4858 1/year

Decline equation

q(t) = qi/(1+Di*t) in days

Economic production rate (qe) $\boxed{1}$ mcf/d

Time to reach economic limit

1 = 35.9 / (1+Di*t)

1+ Di*t = 35.85089

t = 77 days

Ultimate recovery at economic limit

Gp(t) = (log(qi) - log(qt))*2.303*qi/Di

284.8061 Mscf

0.28 MMscf

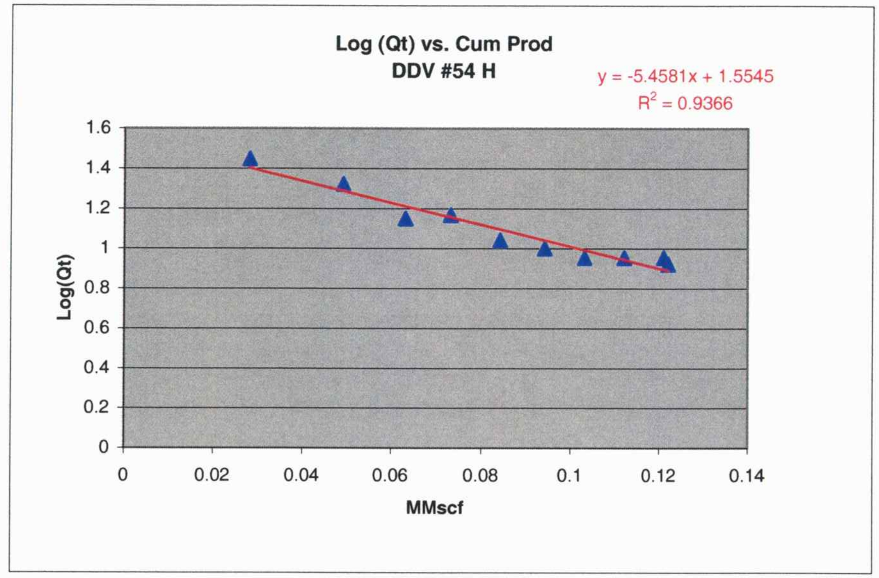


Table 6h

Harmonic decline calculations:

Initial rate calculation

at t = 0

Log (qt) = **2.1433**

qi = 139.1 mcf/d

Decline rate calculation

m = - 1000*Di/(2.303*(= **-5.1096**

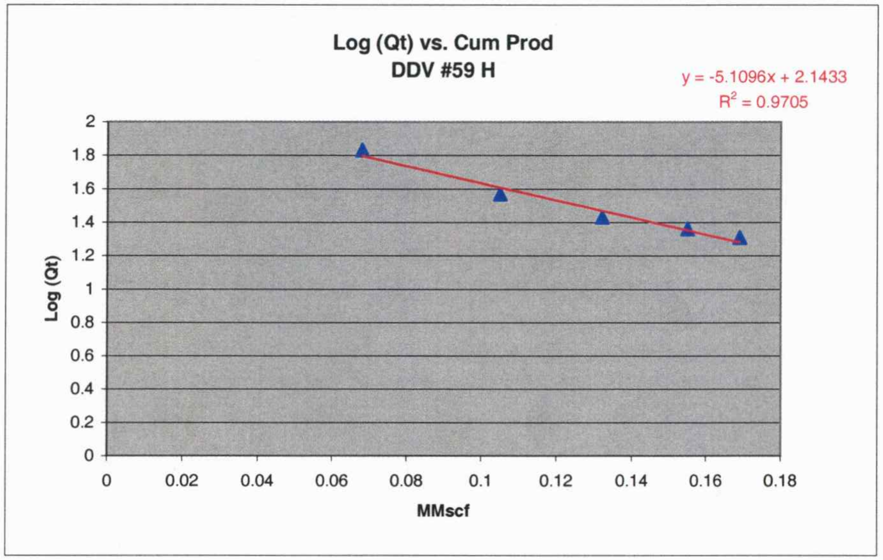
Di = 1.636744 1/day

597.4117 1/year

Decline equation

q(t) = qi/(1+Di*t) in days

Economic production rate (qe) **1** mcf/d



Time to reach economic limit

1 = 139.1 / (1+Di*t)

1+ Di*t = 139.0913

t = 84 days

Ultimate recovery at economic limit

Gp(t) = (log(qi) - log(qt))*2.303*qi/Di

419.4653 Mscf

0.42 MMscf

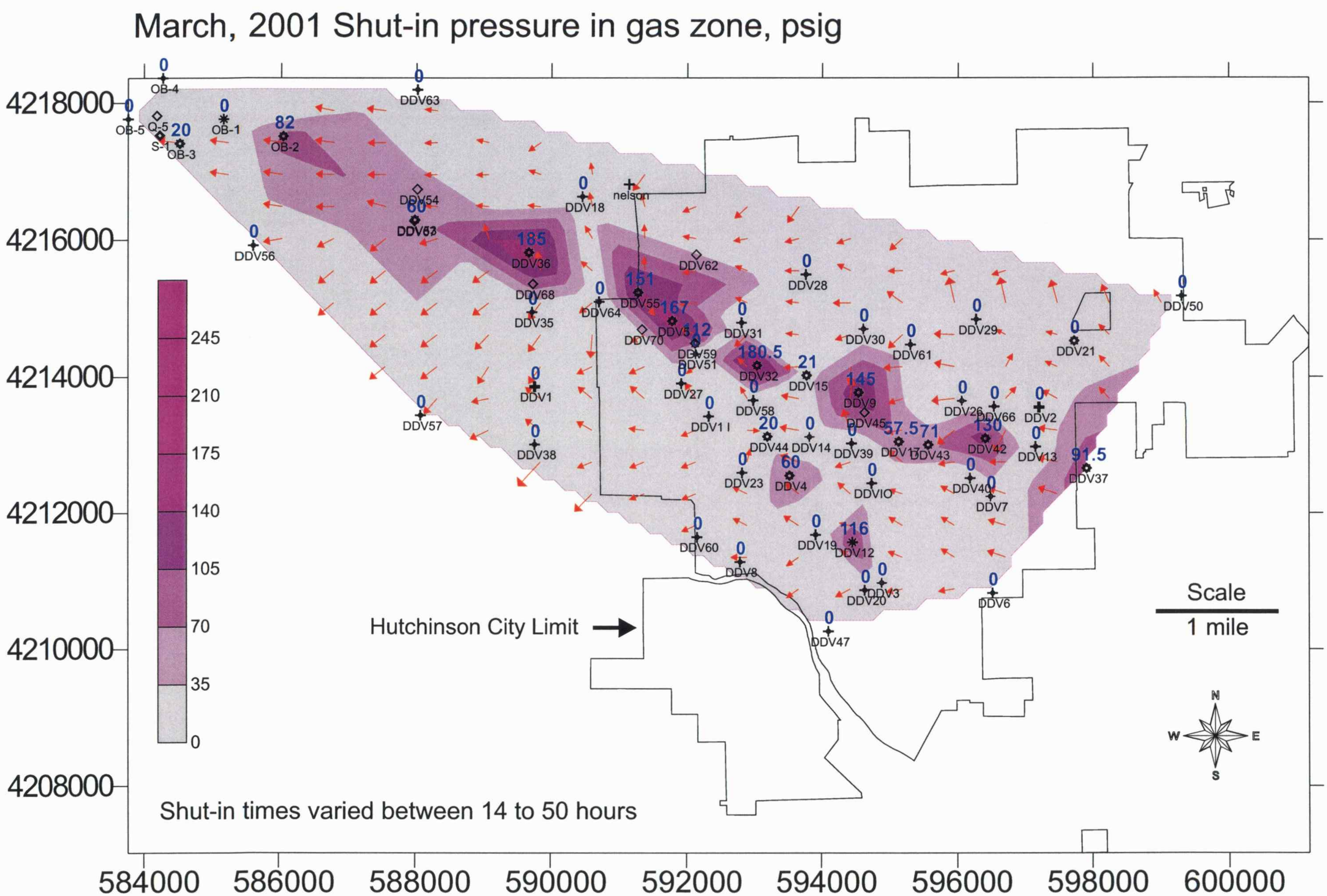
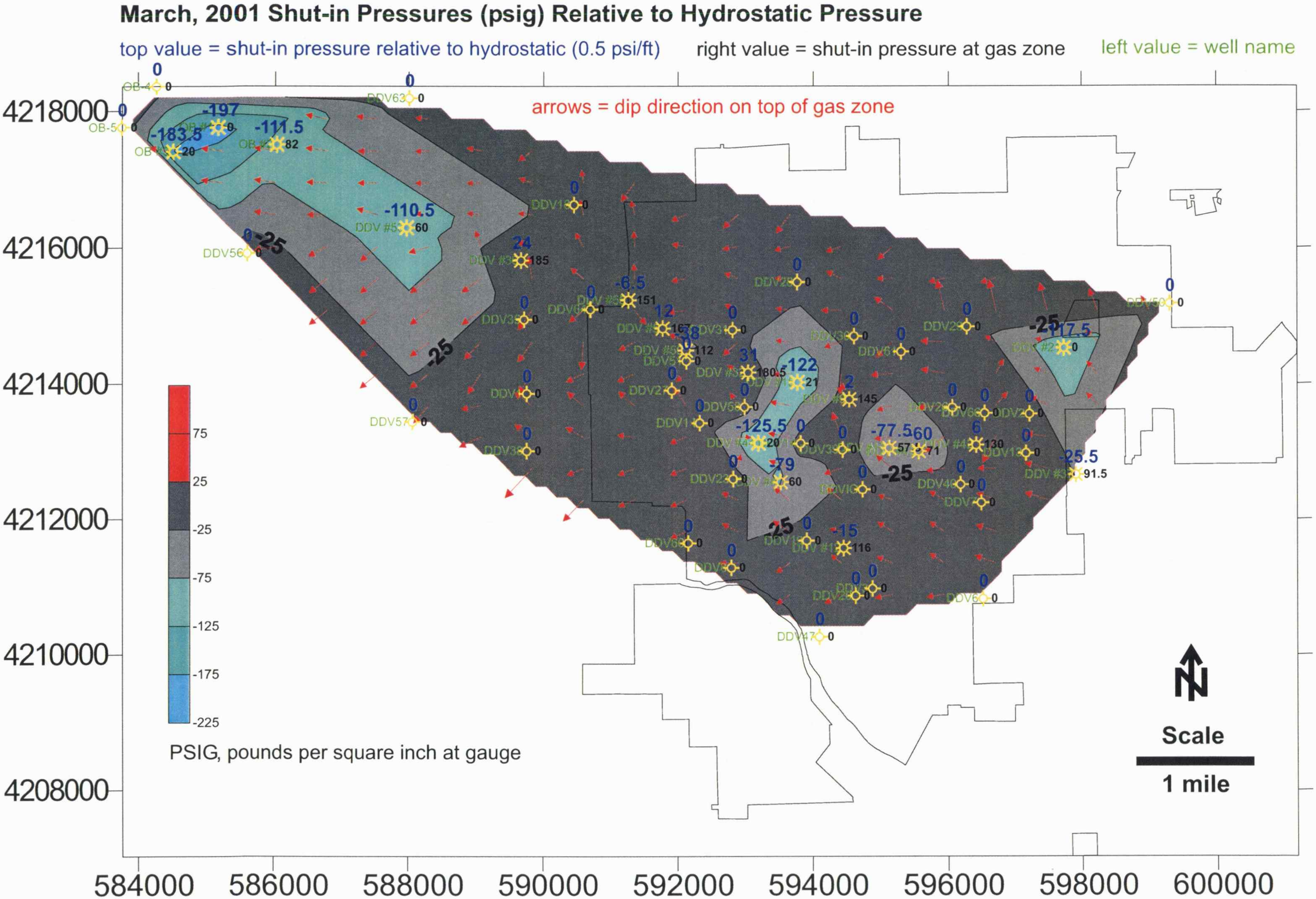
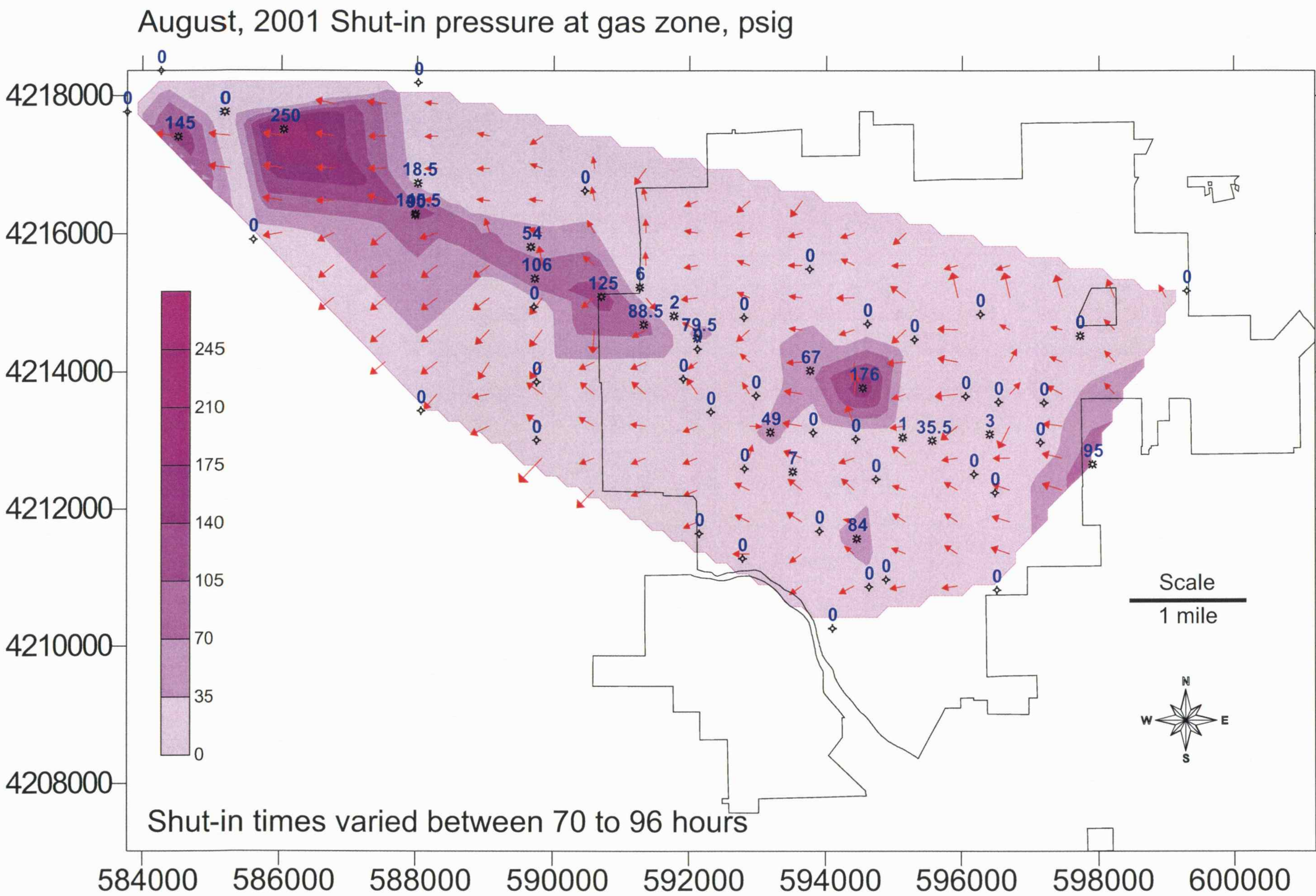

March, 2001 Shut-in pressure in gas zone, psig
Hutchinson City Limit
Scale
1 mile
Shut-in times varied between 14 to 50 hours
N
S
E
W

Figure 1



March, 2001 Shut-in Pressures (psig) Relative to Hydrostatic Pressure
top value = shut-in pressure relative to hydrostatic (0.5 psi/ft)
right value = shut-in pressure at gas zone
left value = well name
arrows = dip direction on top of gas zone
PSIG, pounds per square inch at gauge
75
25
-25
-75
-125
-175
-225
Scale
1 mile
4218000
4216000
4214000
4212000
4210000
4208000
584000
586000
588000
590000
592000
594000
596000
598000
600000

Figure 2



August, 2001 Shut-in pressure at gas zone, psig
4218000
4216000
4214000
4212000
4210000
4208000
584000
586000
588000
590000
592000
594000
596000
598000
600000
245
210
175
140
105
70
35
0
145
250
18.5
54
106
125
6
88.5
2
79.5
67
176
49
7
1
35.5
3
95
84
Scale
1 mile
N
W
E
S
Shut-in times varied between 70 to 96 hours

Figure 3

August, 2001 Shut-in Pressures (psig) Relative to Hydrostatic Pressure (96 hrs. Maximum)

top value = shut-in pressure relative to hydrostatic (0.5 psi/ft) right value = shut-in pressure at gas zone left value = well name

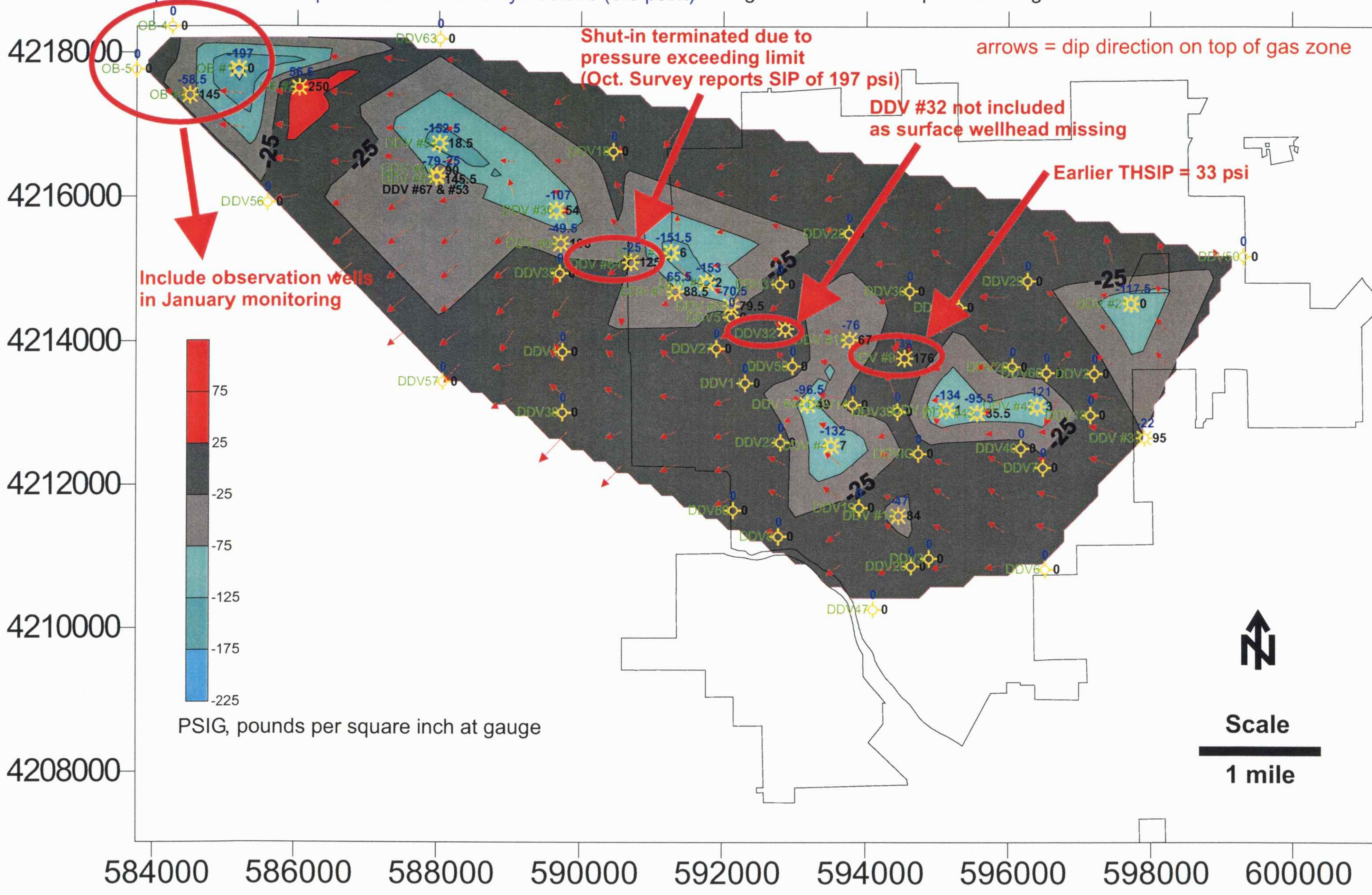
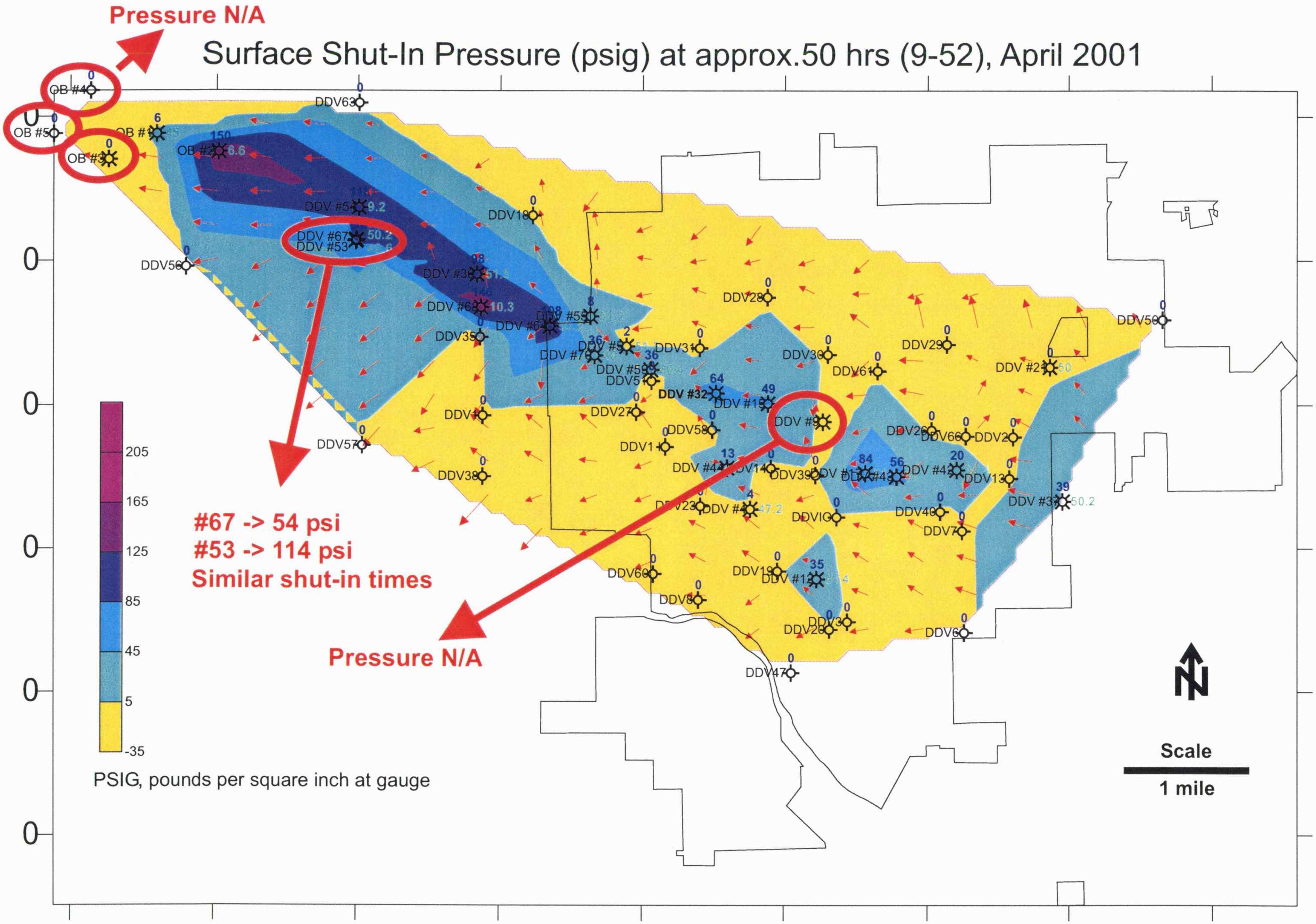


Figure 4



Pressure N/A
Surface Shut-In Pressure (psig) at approx.50 hrs (9-52), April 2001
#67 -> 54 psi
#53 -> 114 psi
Similar shut-in times
Pressure N/A
205
165
125
85
45
5
-35
PSIG, pounds per square inch at gauge
Scale
1 mile

Figure 5

Surface Shut-In Pressures (psig) at 70 hours, June 2001

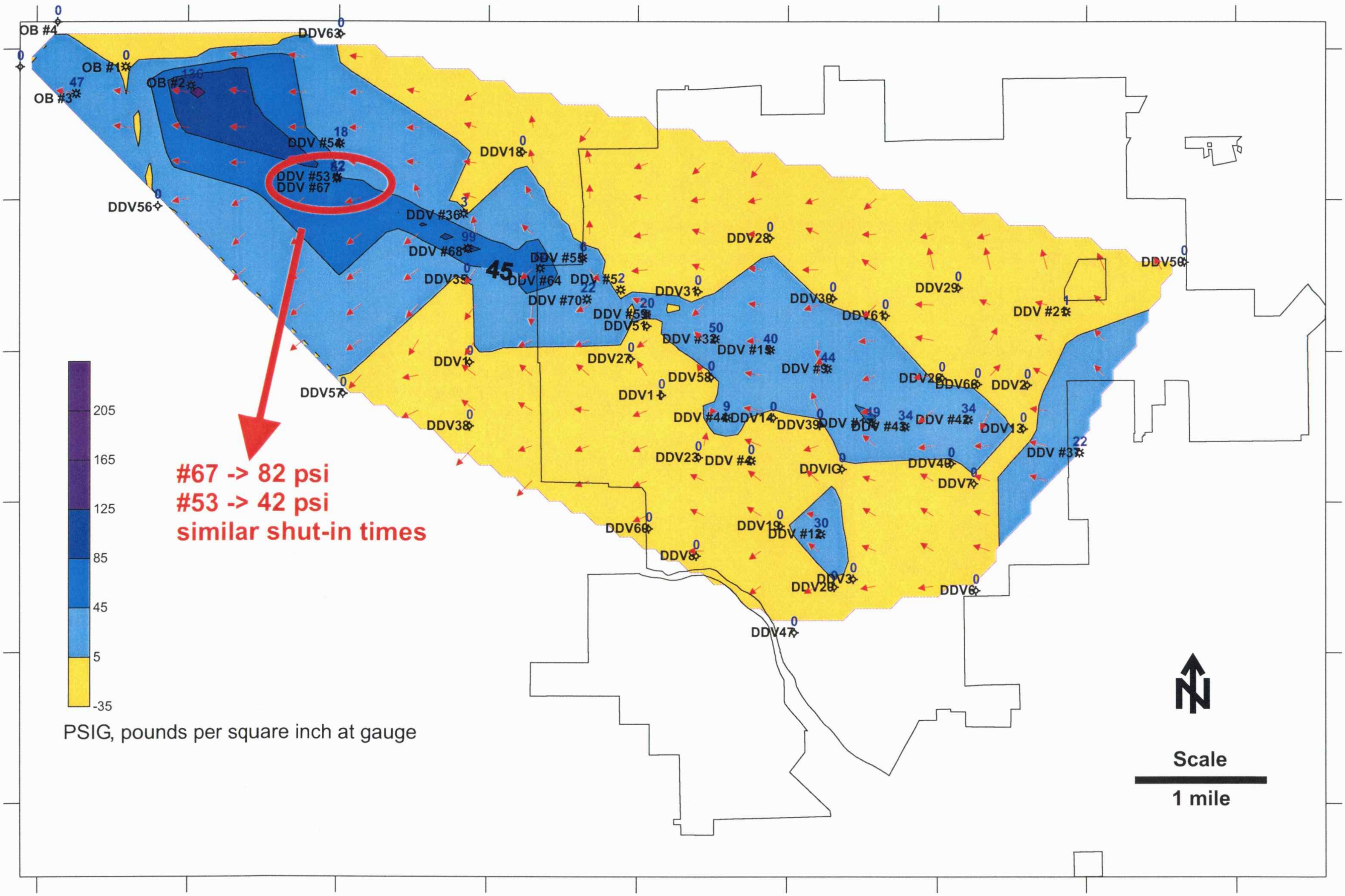


Figure 6

Surface Shut-In Pressures (psig) at 73-96 hours for August 2001

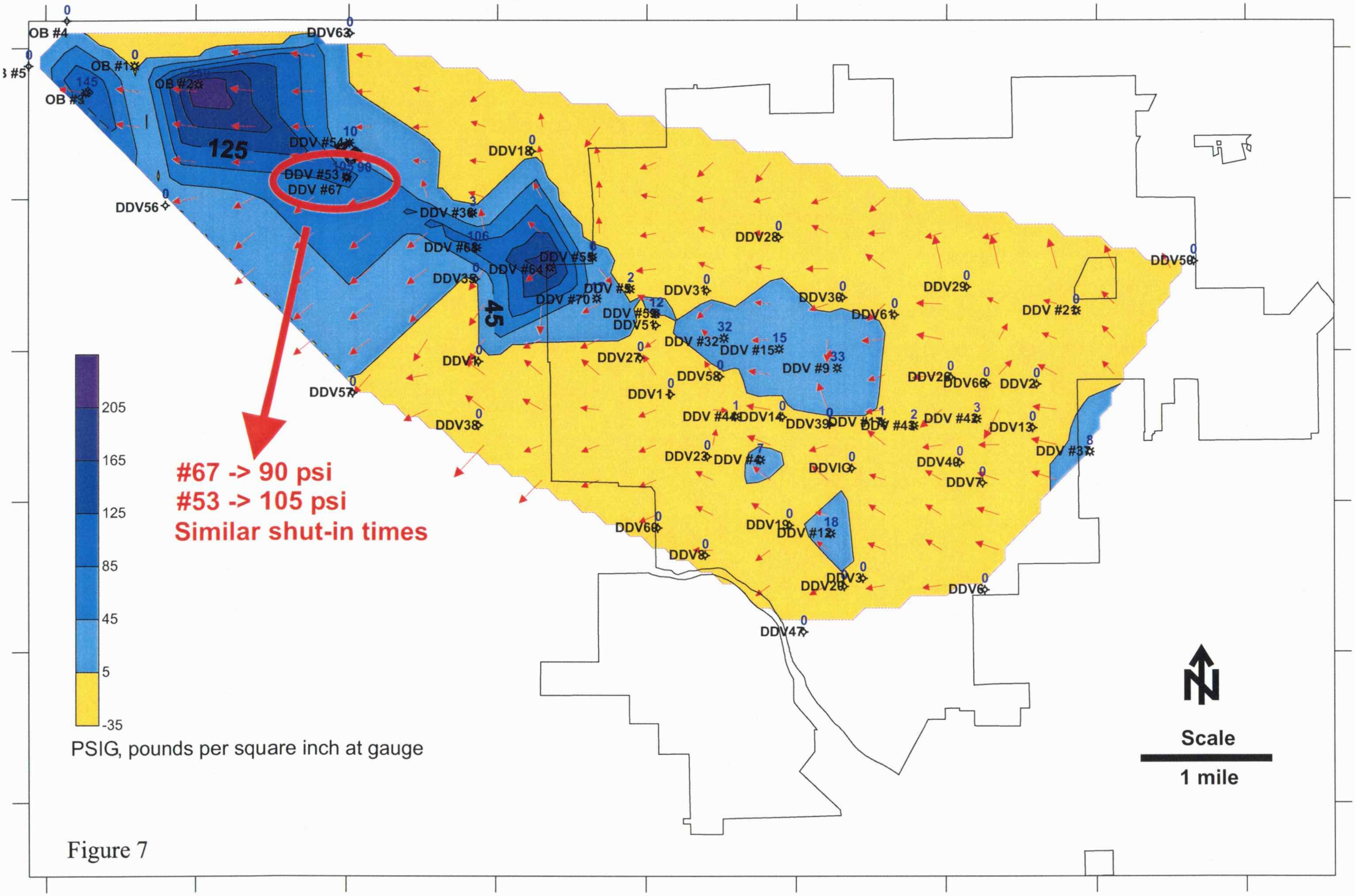


Figure 7

Surface Shut-In Pressures (psig) at 73-98 hours for October 2001

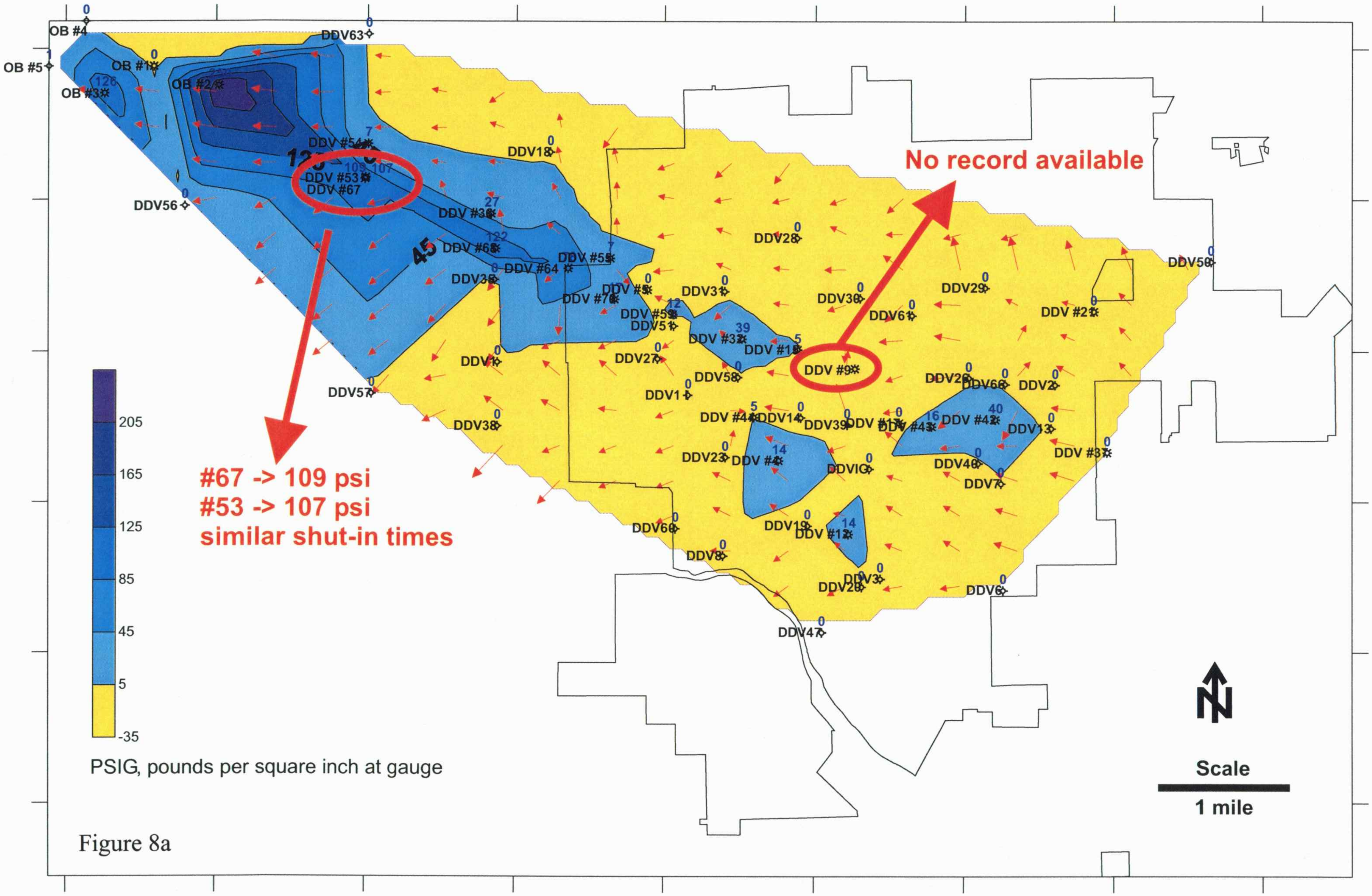


Figure 8a

Surface Shut-In Pressures (psig) at 400 hours, October 2001

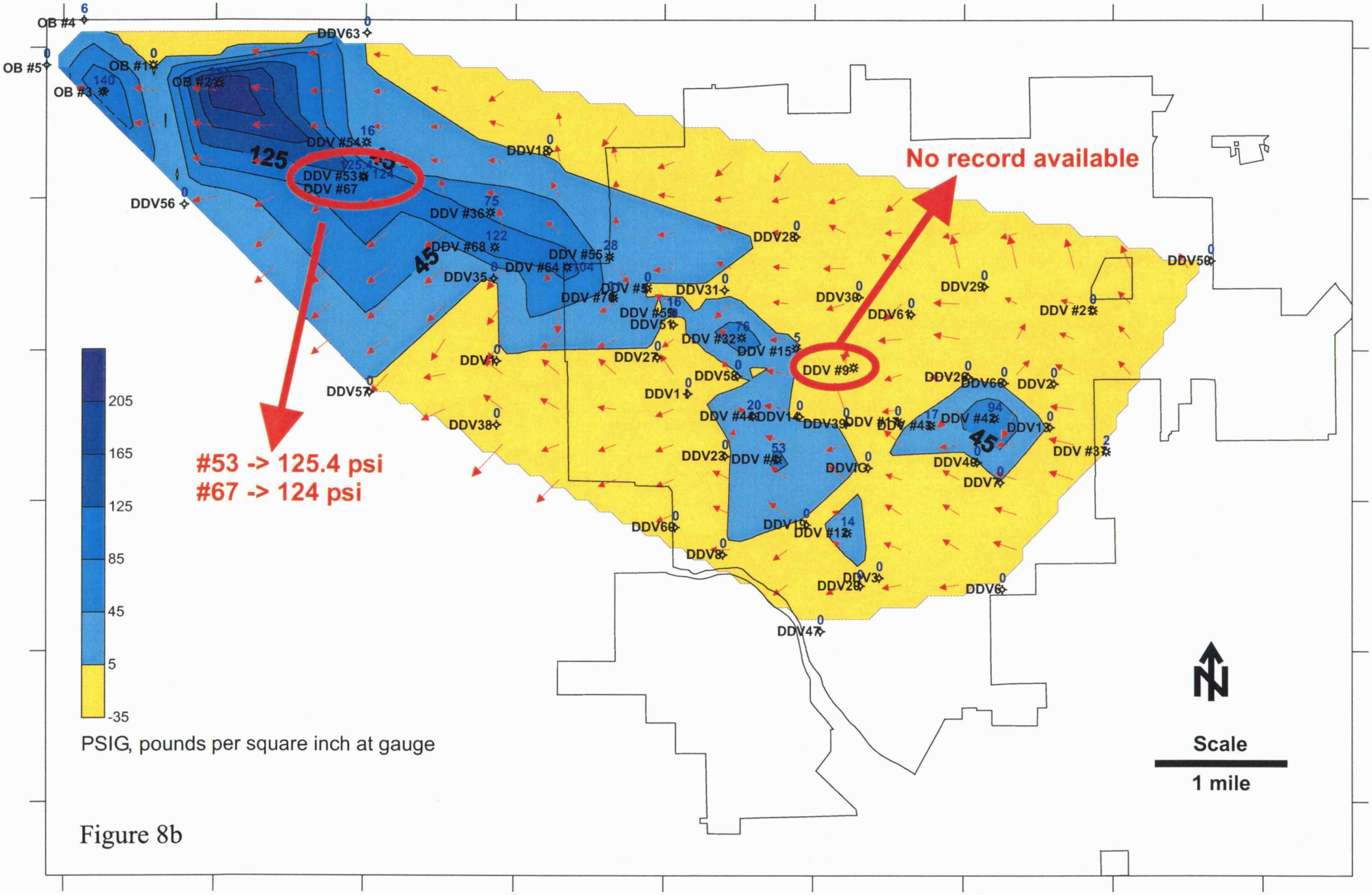


Figure 8b

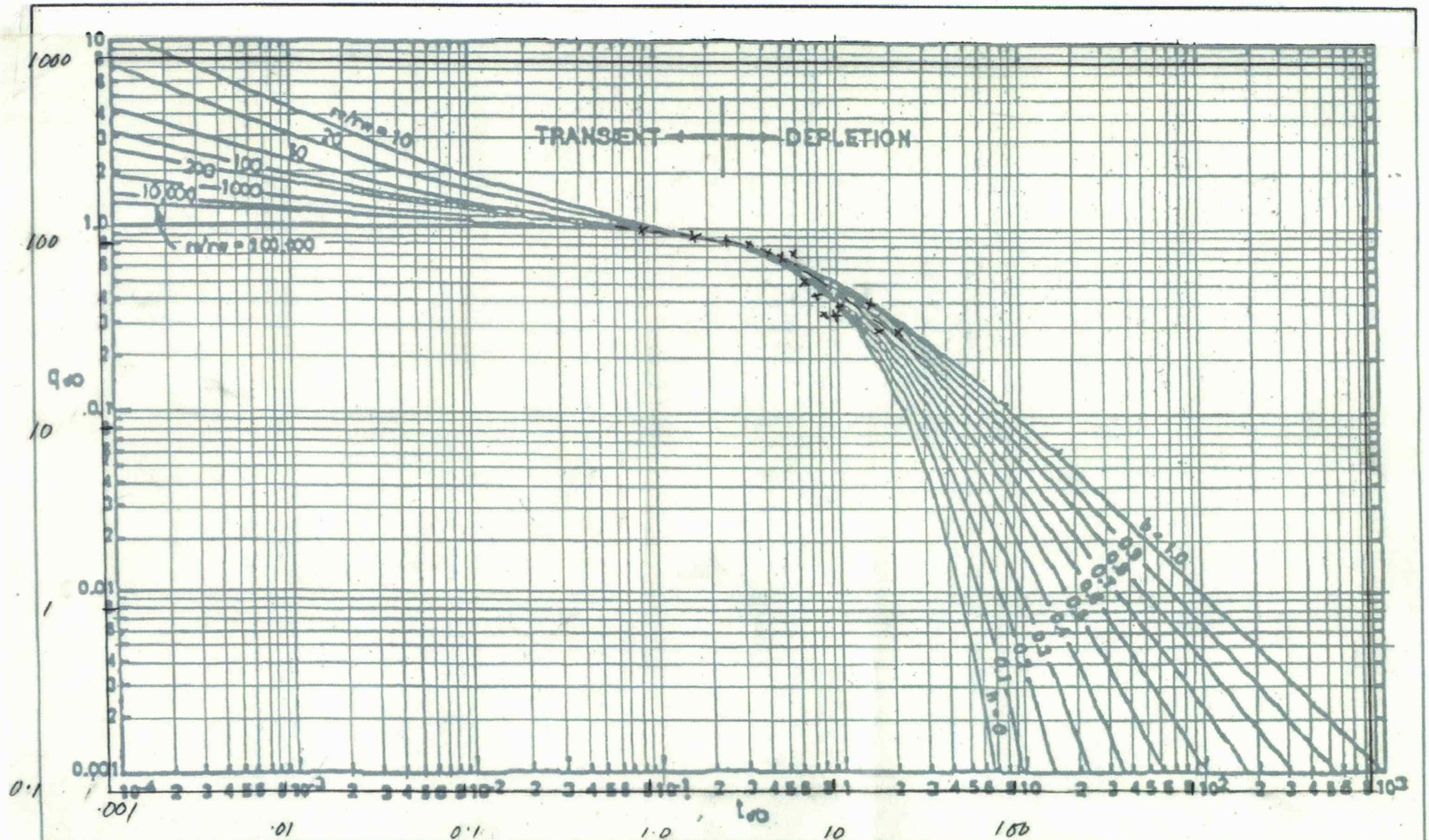


Fig. 9.10—The Fetkovich[4] rate/time decline type curve.

Figure 9a - OB #2

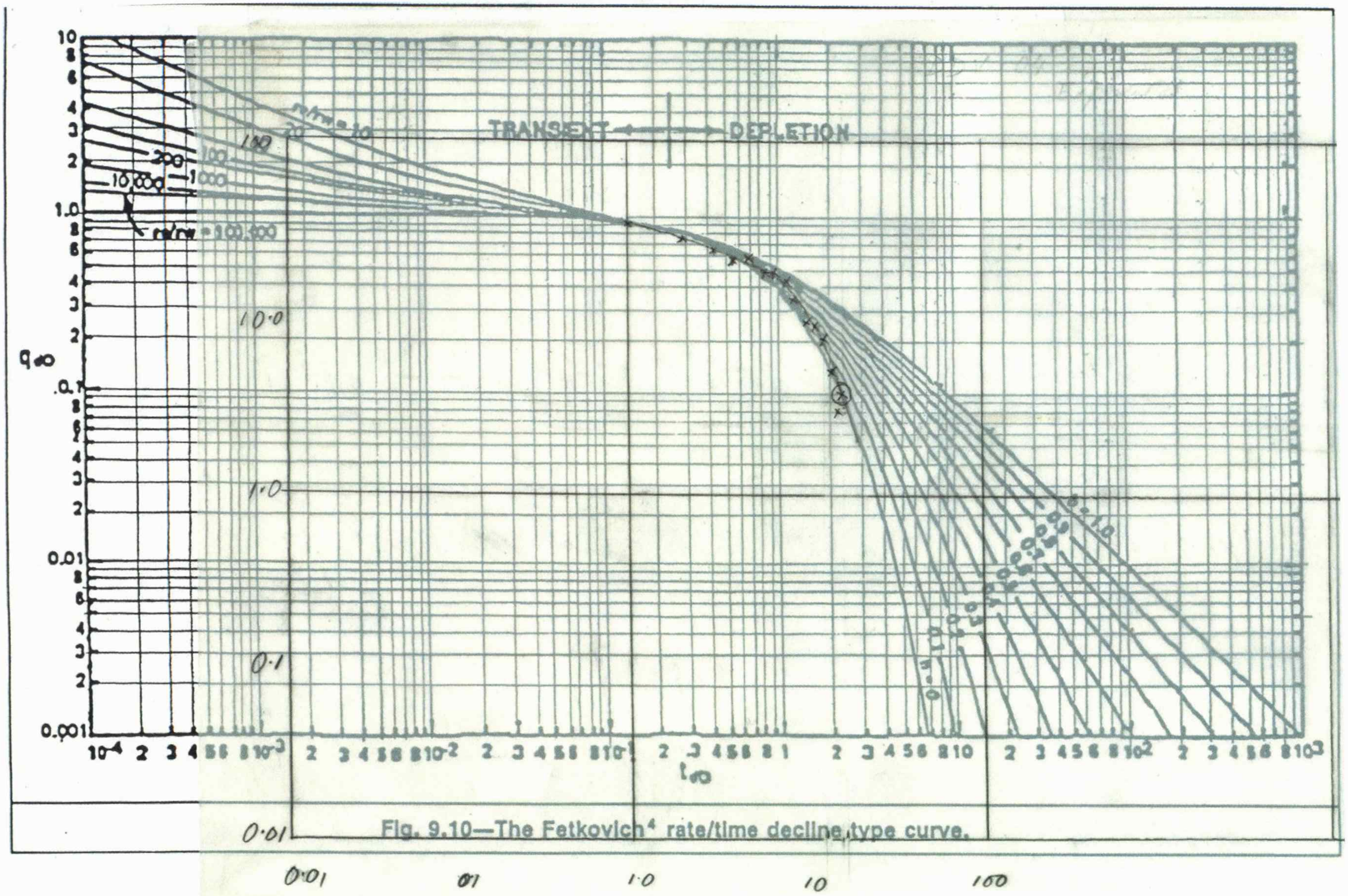


Figure 9b. DDV #04

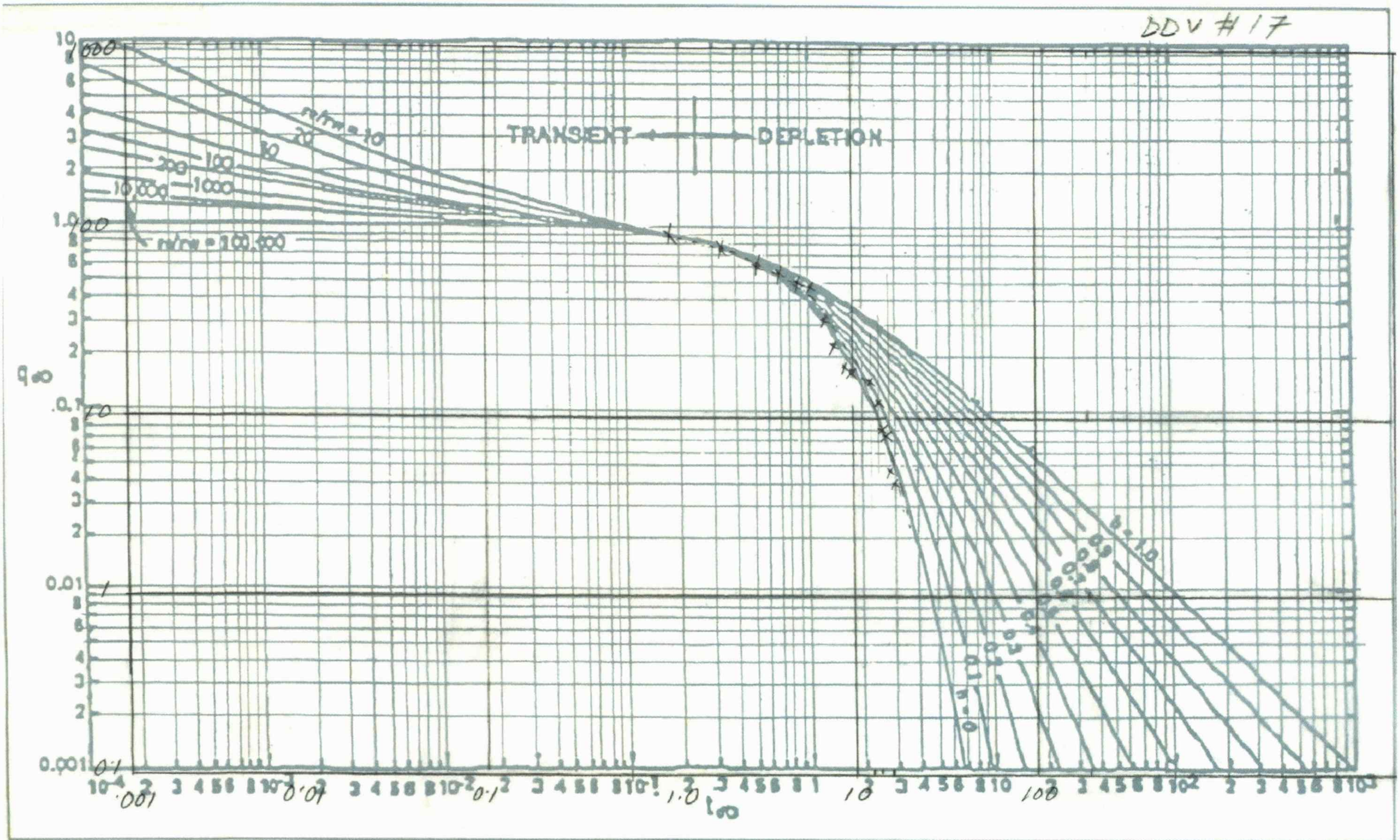


Fig. 9.10—The Fetkovich[4] rate/time decline type curve.

Figure 9c. DDV #17

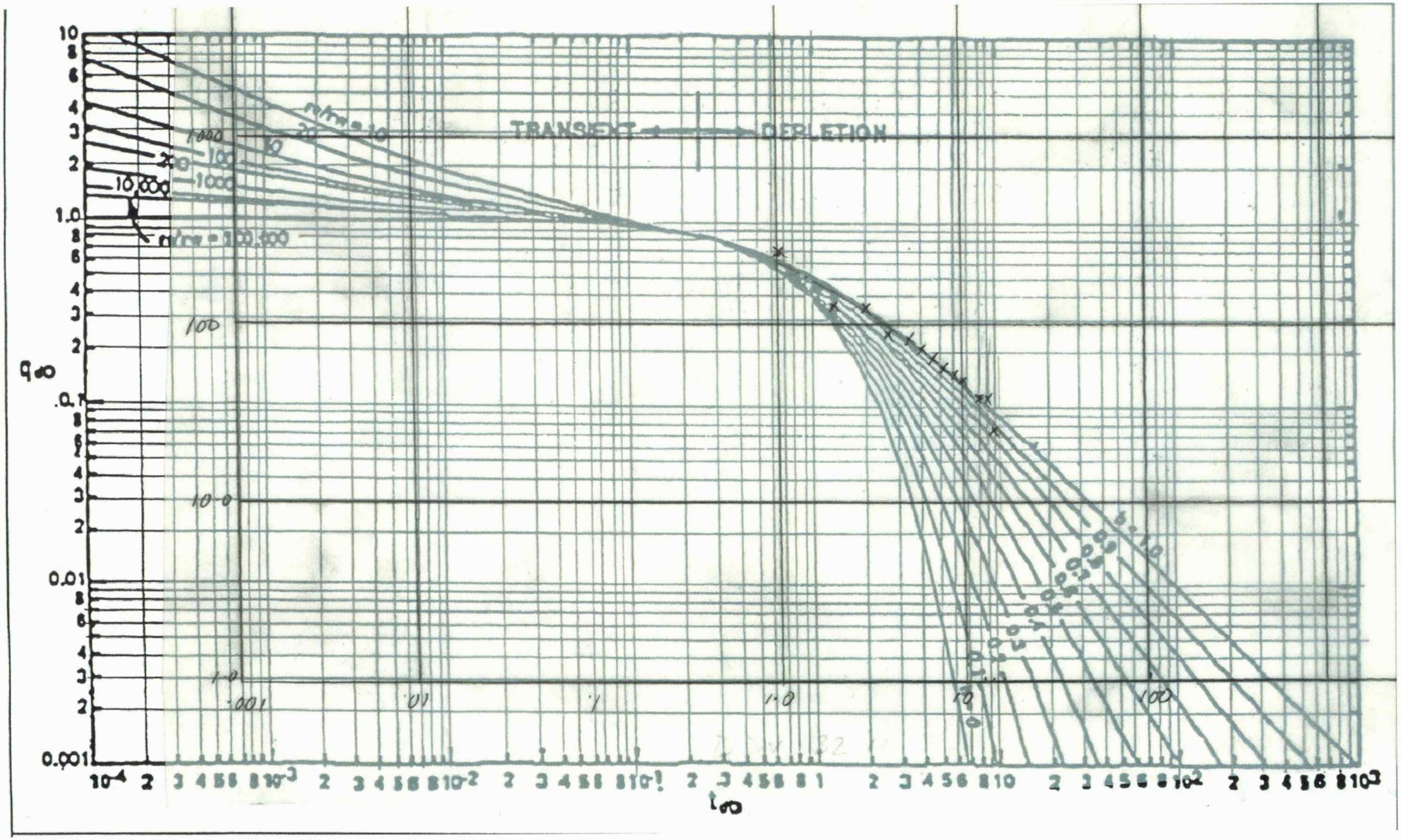


Figure 9d. DDV #32

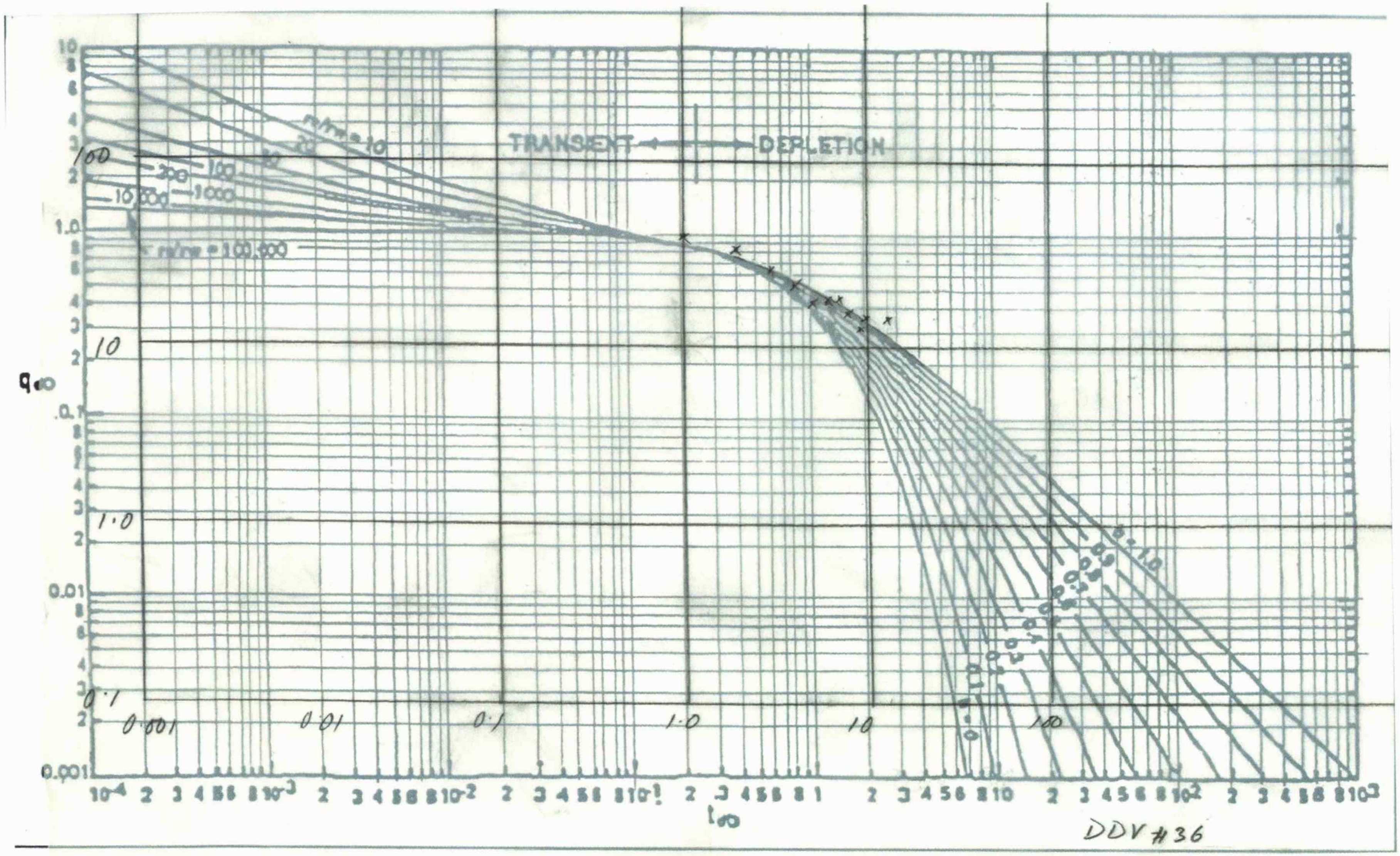


Figure 9e. DDV #36

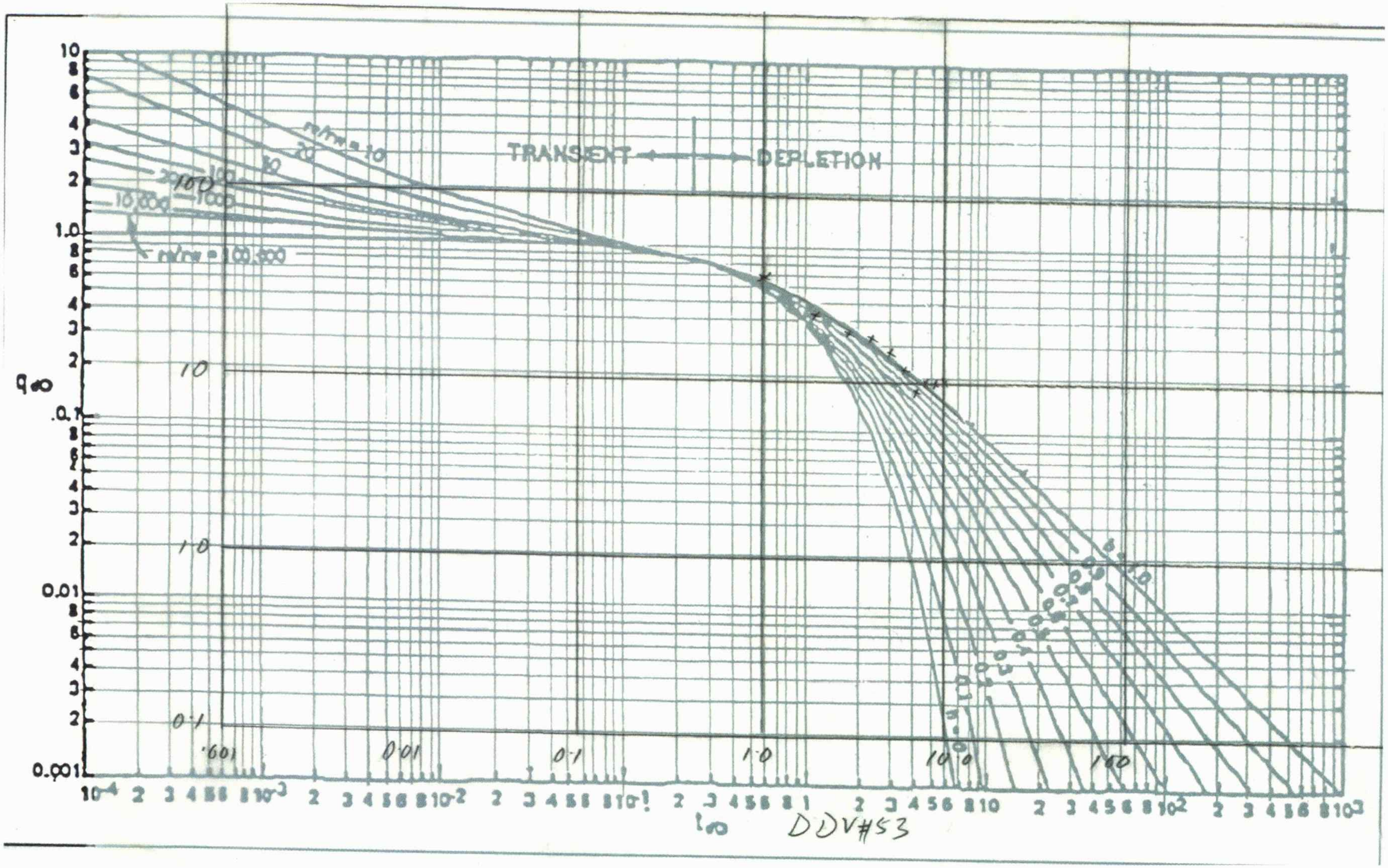


Figure 9f. DDV #53

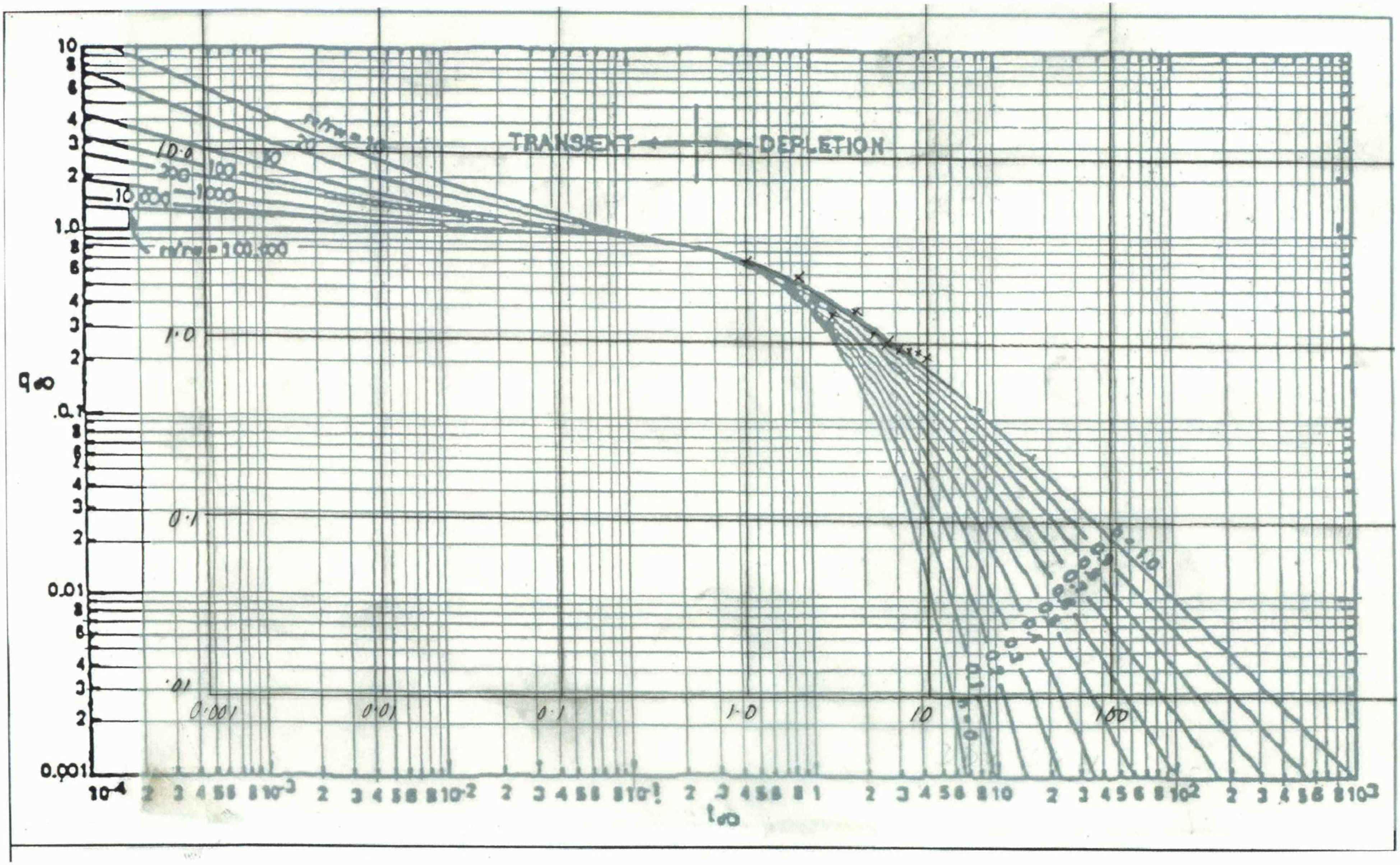


Figure 9g. DDV #54

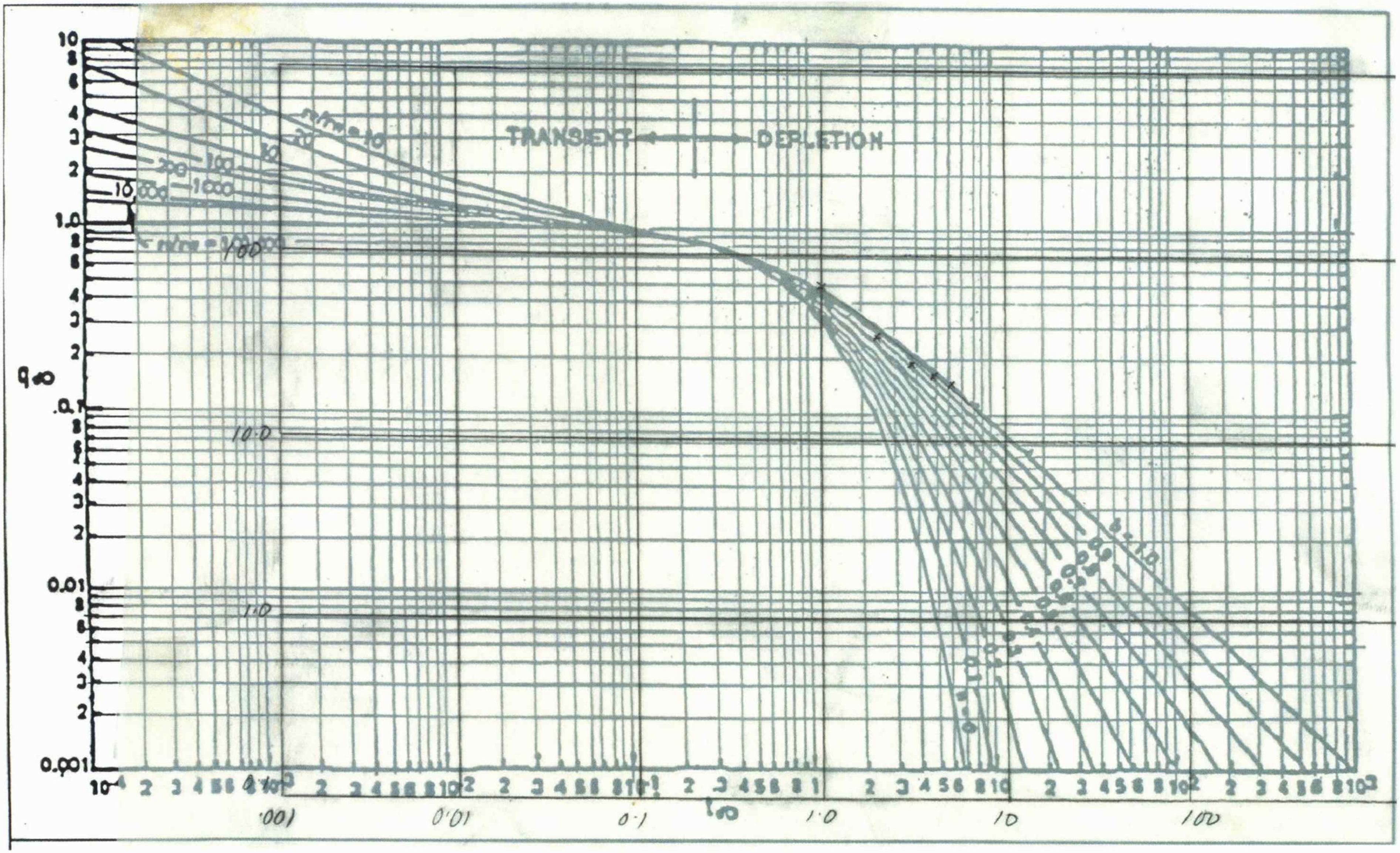


Figure 9h. DDV #59

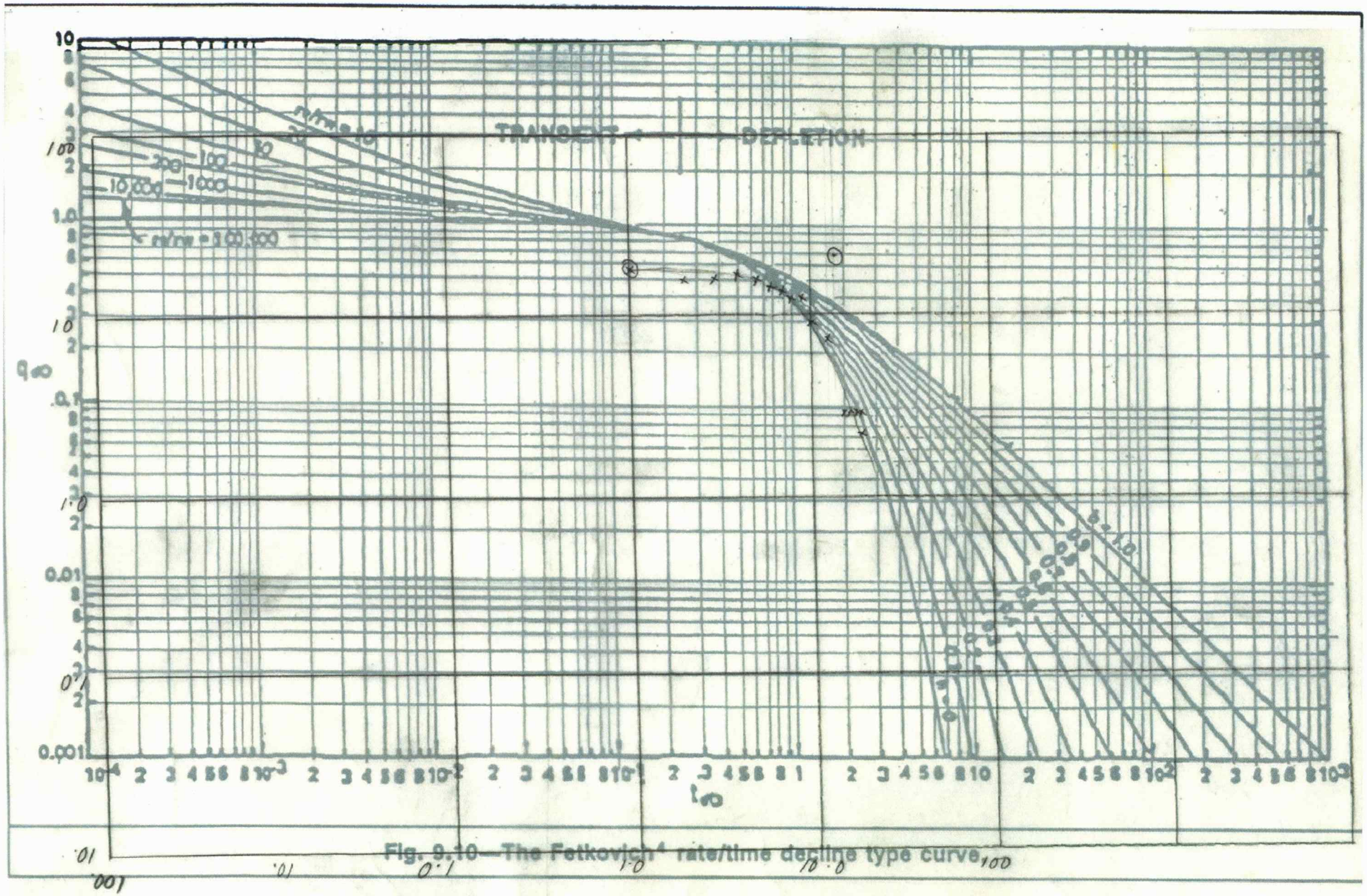


Figure 9i. DD #05. Match could not be obtained.