HETEROGENEOUS SHALLOW-SHELF CARBONATE BUILDUPS IN THE PARADOX BASIN, UTAH AND COLORADO: TARGETS FOR INCREASED OIL PRODUCTION AND RESERVES USING HORIZONTAL DRILLING TECHNIQUES

(Contract No. DE-2600BC15128)

DELIVERABLE 1.2.2
CAPILLARY PRESSURE/MERCURY INJECTION ANALYSIS: CHEROKEE AND BUG FIELDS, SAN JUAN COUNTY, UTAH

Submitted by

Utah Geological Survey
Salt Lake City, Utah 84114
December 2003

UTAH GEOLOGICAL SURVEY

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DISCLAIMER

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INTRODUCTION

Over 400 million barrels (64 million m^3) of oil have been produced from the shallow-shelf carbonate reservoirs in the Pennsylvanian (Desmoinesian) Paradox Formation in the Paradox Basin, Utah and Colorado. With the exception of the giant Greater Aneth field, the other 100 plus oil fields in the basin typically contain 2 to 10 million barrels (0.3-1.6 million m^3) of original oil in place. Most of these fields are characterized by high initial production rates followed by a very short productive life (primary), and hence premature abandonment. Only 15 to 25 percent of the original oil in place is recoverable during primary production from conventional vertical wells.

An extensive and successful horizontal drilling program has been conducted in the giant Greater Aneth field. However, to date, only two horizontal wells have been drilled in small Ismay and Desert Creek fields. The results from these wells were disappointing due to poor understanding of the carbonate facies and diagenetic fabrics that create reservoir heterogeneity. These small fields, and similar fields in the basin, are at high risk of premature abandonment. At least 200 million barrels (31.8 million m^3) of oil will be left behind in these small fields because current development practices leave compartments of the heterogeneous reservoirs undrained. Through proper geological evaluation of the reservoirs, production may be increased by 20 to 50 percent through the drilling of low-cost single or multilateral horizontal legs from existing vertical development wells. In addition, horizontal drilling from existing wells minimizes surface disturbances and costs for field development, particularly in the environmentally sensitive areas of southeastern Utah and southwestern Colorado.

GEOLOGIC SETTING

The Paradox Basin is located mainly in southeastern Utah and southwestern Colorado with a small portion in northeastern Arizona and the northwestern most corner of New Mexico (figure 1). The Paradox Basin is an elongate, northwest-southeast trending evaporitic basin that predominately developed during the Pennsylvanian (Desmoinesian), about 330 to 310 million years ago (Ma). During the Pennsylvanian, a pattern of basins and fault-bounded uplifts developed from Utah to Oklahoma as a result of the collision of South America, Africa, and southeastern North America (Kluth and Coney, 1981; Kluth, 1986), or from a smaller scale collision of a microcontinent with south-central North America (Harry and Mickus, 1998). One result of this tectonic event was the uplift of the Ancestral Rockies in the western United States. The Uncompahgre Highlands in eastern Utah and western Colorado initially formed as the westernmost range of the Ancestral Rockies during this ancient mountain-building period. The Uncompahgre Highlands (uplift) is bounded along the southwestern flank by a large basement-involved, high-angle reverse fault identified from geophysical seismic surveys and exploration drilling. As the highlands rose, an accompanying depression, or foreland basin, formed to the southwest — the Paradox Basin. Rapid subsidence, particularly during the Pennsylvanian and then continuing into the Permian, accommodated large volumes of evaporitic and marine sediments that intertongue with non-marine arkosic material shed from the highland area to the northeast (Hintze, 1993). The Paradox Basin is surrounded by other uplifts and basins that formed during the Late Cretaceous-early Tertiary Laramide orogeny (figure 1).

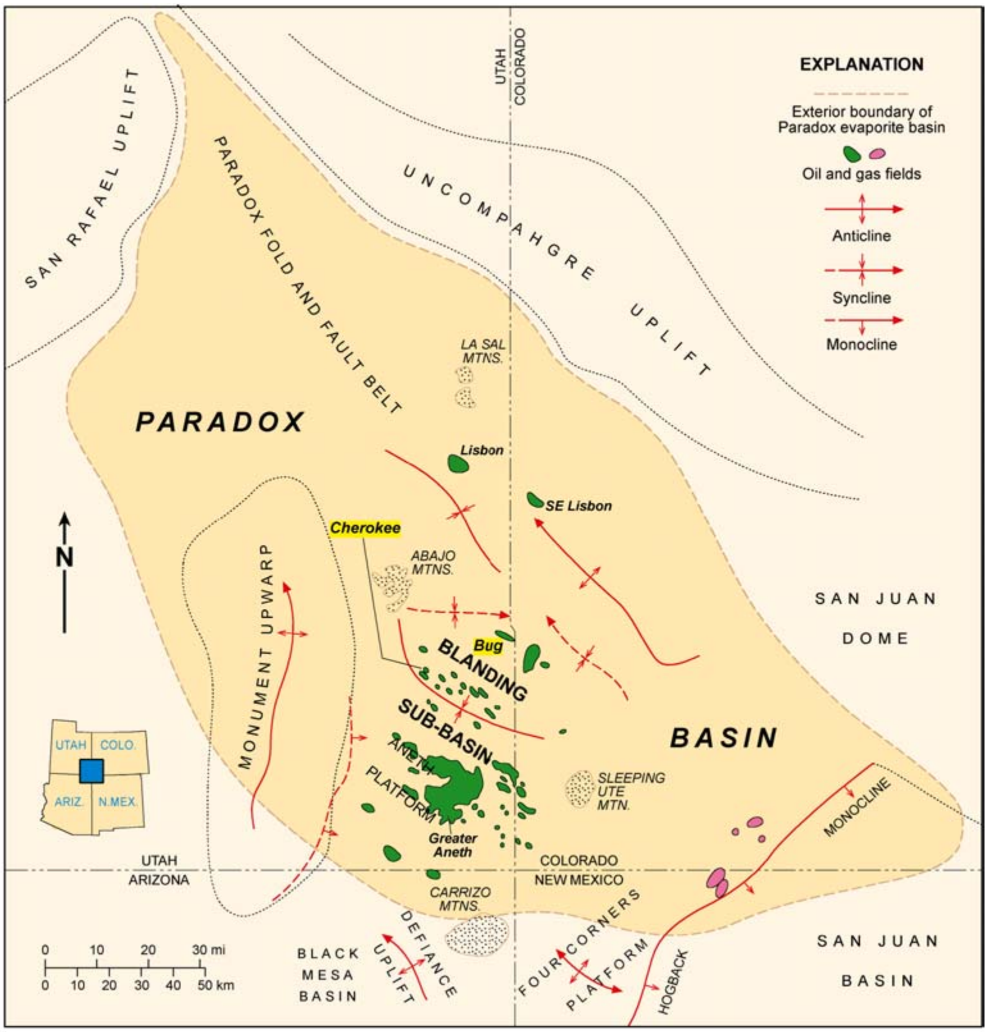

Figure 1. Location map of the Paradox Basin, Utah, Colorado, Arizona, and New Mexico showing producing oil and gas fields, the Paradox fold and fault belt, and Blanding sub-basin as well as surrounding Laramide basins and uplifts (modified from Harr, 1996).

The Paradox Basin can generally be divided into two areas: the Paradox fold and fault belt in the north, and the Blanding sub-basin in the south-southwest (figure 1). Most oil production comes from the Blanding sub-basin. The source of the oil is several black, organic-rich shales within the Paradox Formation (Hite and others, 1984; Nuccio and Condon, 1996). The relatively undeformed Blanding sub-basin developed on a shallow-marine shelf which locally contained algal-mound and other carbonate buildups in a subtropical climate.

The two main producing zones of the Paradox Formation are informally named the Ismay and the Desert Creek (figure 2). The Ismay zone is dominantly limestone comprising equant buildups of phylloid-algal material with locally variable small-scale subfacies (figure 3A) and capped by anhydrite. The Ismay produces oil from fields in the southern Blanding sub-basin (figure 4). The Desert Creek zone is dominantly dolomite comprising regional nearshore shoreline trends with highly aligned, linear facies tracts (figure 3B). The Desert Creek produces oil in fields in the central Blanding sub-basin (figure 4). Both the Ismay and Desert Creek buildups generally trend northwest-southeast. Various facies changes and extensive diagenesis have created complex reservoir heterogeneity within these two diverse zones.

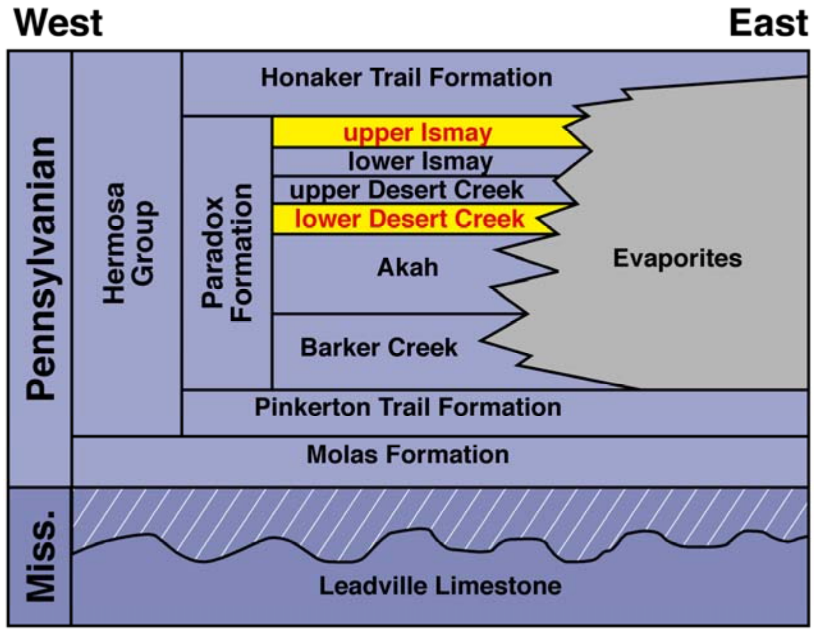

Figure 2. Pennsylvanian stratigraphy of the southern Paradox Basin including informal zones of the Paradox Formation; the Ismay and Desert Creek zones productive in the case-study fields described in this report are highlighted.

CASE-STUDY FIELDS

Two Utah fields were selected for local-scale evaluation and geological characterization: Cherokee in the Ismay trend and Bug in the Desert Creek trend (figure 4). This evaluation included data collection and capillary pressure/mercury injection analysis from selected wells in these fields as summarized in this report.

This geological characterization focused on reservoir heterogeneity, quality, and lateral continuity, as well as possible compartmentalization within the fields. From these evaluations, untested or under-produced compartments can be identified as targets for horizontal drilling. The models resulting from the geological and reservoir characterization of these fields can be applied to similar fields in the basin (and other basins as well) where data might be limited.

Cherokee Field

Cherokee field (figure 4) is a phylloid-algal buildup capped by anhydrite that produces from porous algal limestone and dolomite in the upper Ismay zone. The net reservoir thickness is 27 feet (8.2 m), which extends over a 320-acre (130 ha) area. Porosity averages 12 percent with 8 millidarcies (md) of permeability in vuggy and intercrystalline pore systems. Water saturation is 38.1 percent (Crawley-Stewart and Riley, 1993).

Cherokee field was discovered in 1987 with the completion of the Meridian Oil Company Cherokee Federal 11-14, NE1/4NW1/4 section 14, T. 37 S., R. 23 E., Salt Lake Base Line and Meridian (SLBL&M); initial potential flow (IPF) was 53 barrels of oil per day (BOPD) (8.4 m^3), 990 thousand cubic feet of gas per day (MCFGPD) (28 MCMPD), and 26 barrels of water (4.1 m^3). There are currently four producing (or shut-in) wells and two dry holes in the field. The well spacing is 80 acres (32 ha). The present field reservoir pressure is estimated at 150 pounds per square inch (psi) (1,034 Kpa). Cumulative production as of June 1, 2003, was 182,071 barrels of oil (28,949 m^3), 3.65 billion cubic feet of gas (BCFG) (0.1 BCMG), and 3,358 barrels of water (534 m^3) (Utah Division of Oil, Gas and Mining, 2003). The original estimated primary recovery is 172,000 barrels of oil (27,348 m^3) and 3.28 BCFG (0.09 BCMG) (Crawley-Stewart and Riley, 1993). The fact that both these estimates have been surpassed suggests significant additional reserves could remain.

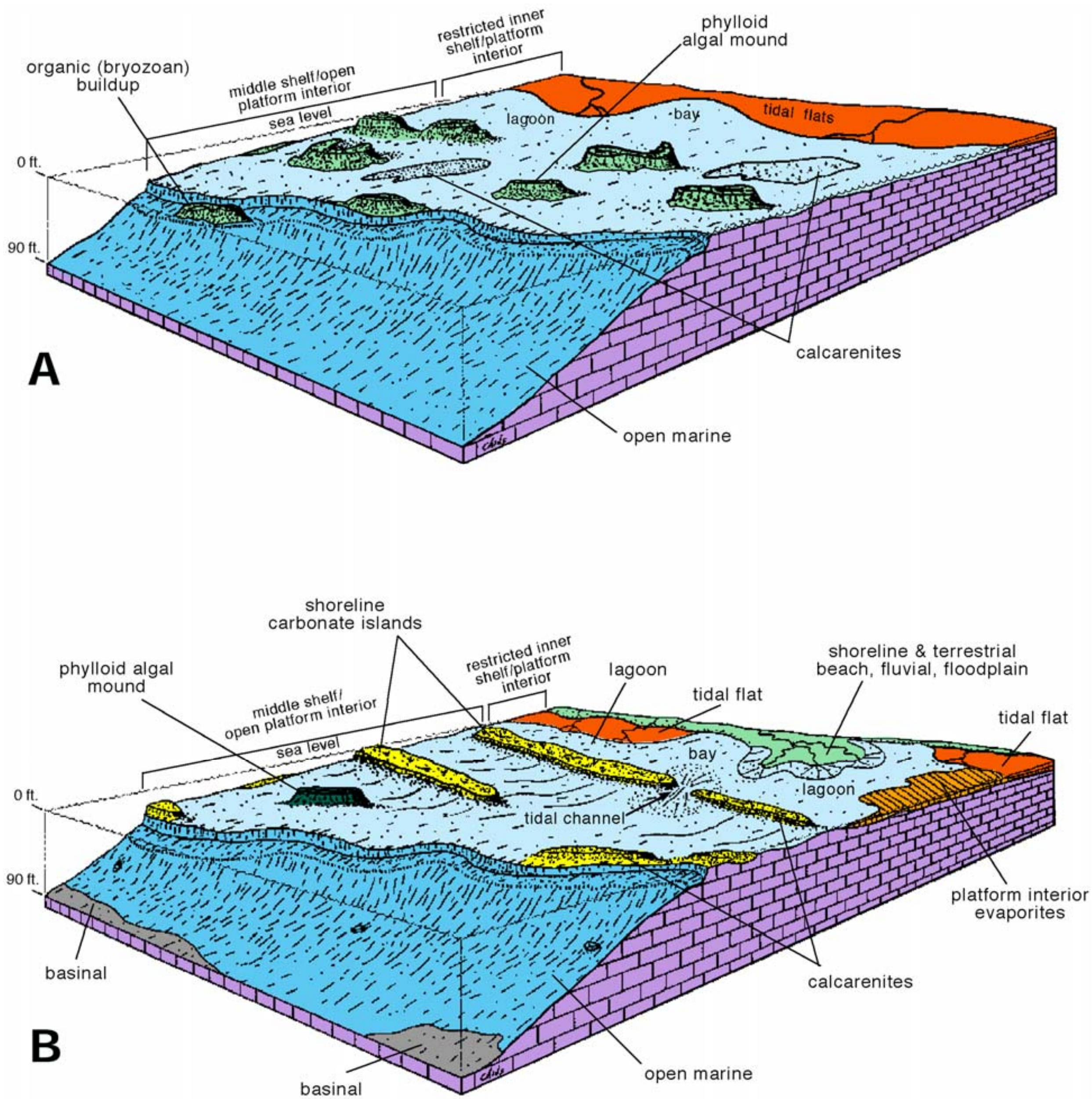

Figure 3. Block diagrams displaying major depositional facies, as determined from core, for the Ismay (A) and Desert Creek (B) zones, Pennsylvanian Paradox Formation, Utah and Colorado.

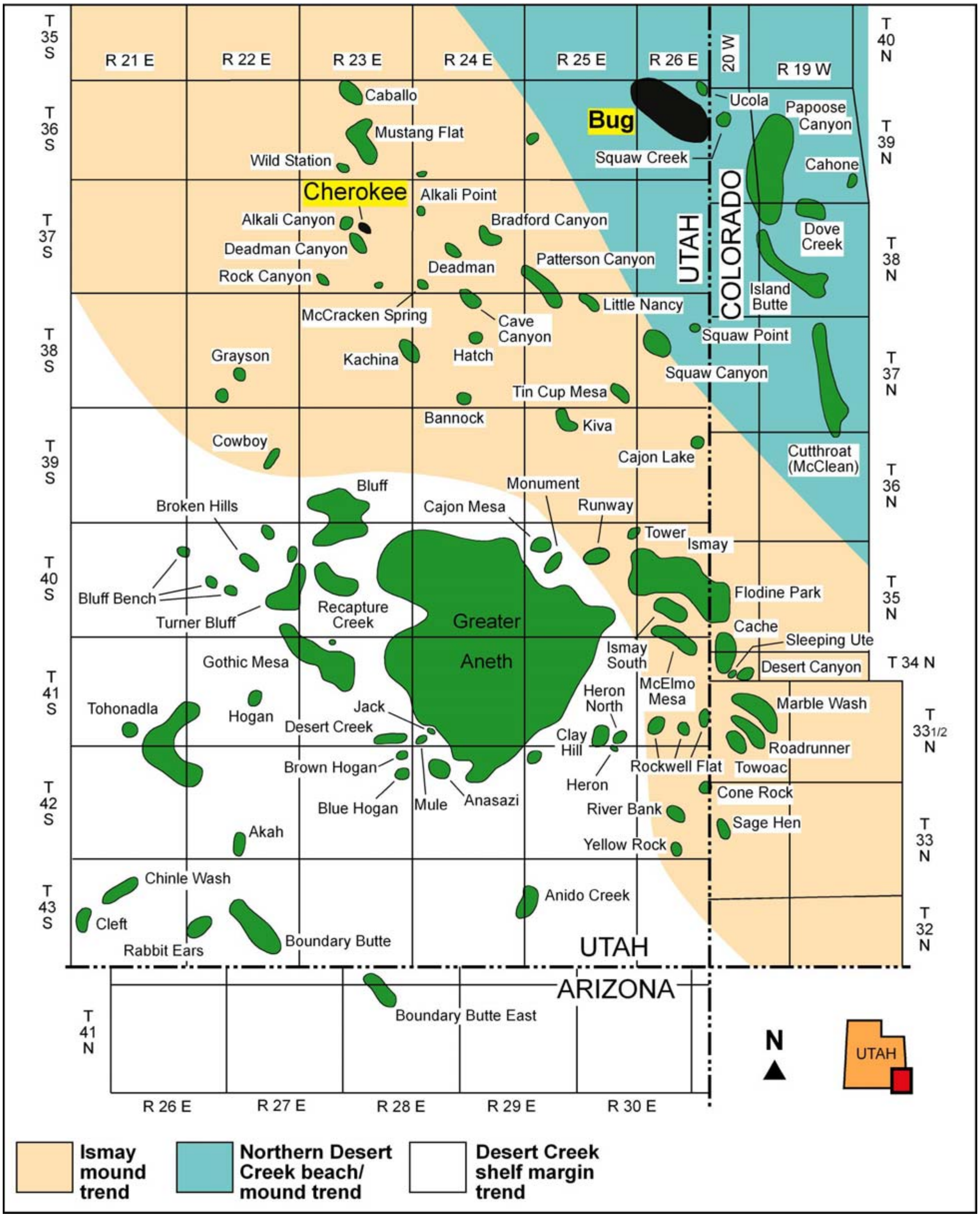

Figure 4. Map showing the project study area and fields (case-study fields in black) within the Ismay and Desert Creek producing trends in the Blanding sub-basin, Utah and Colorado.

Bug Field

Bug field (figure 4) is an elongate, northwest-trending carbonate buildup in the lower Desert Creek zone. The producing units vary from porous dolomitized bafflestone to packstone and wackestone. The trapping mechanism is an updip porosity pinchout. The net reservoir thickness is 15 feet (4.6 m) over a 2,600-acre (1,052 ha) area. Porosity averages 11 percent in moldic, vuggy, and intercrystalline networks. Permeability averages 25 to 30 md, but ranges from less than 1 to 500 md. Water saturation is 32 percent (Martin, 1983; Oline, 1996).

Bug field was discovered in 1980 with the completion of the Wexpro Bug No. 1, NE1/SE1/4 section 12, T. 36 S., R. 25 E., SLBL&M, for an IPF of 608 BOPD (96.7 m^3), 1,128 MCFGPD (32 MCMPD), and 180 barrels of water (28.6 m^3). There are currently eight producing (or shut-in) wells, five abandoned producers, and two dry holes in the field. The well spacing is 160 acres (65 ha). The present reservoir field pressure is 3,550 psi (24,477 Kpa). Cumulative production as of June 1, 2003, was 1,622,2020 barrels of oil (257,901 m^3), 4.47 BCFG (0.13 BCMG), and 3,181,448 barrels of water (505,850 m^3) (Utah Division of Oil, Gas and Mining, 2003). Estimated primary recovery is 1,600,000 bbls (254,400 m^3) of oil and 4 BCFG (0.1 BCMG) (Oline, 1996). Again, since the original reserve estimates have been surpassed and the field is still producing, significant additional reserves likely remain.

CAPILLARY PRESSURE/MERCURY INJECTION ANALYSIS

Capillary pressure/mercury injection analysis evaluates reservoir fluid saturation, and relates pore aperture size and distribution to porosity and permeability (Pittman, 1992). These data were used to assess reservoir potential and quality by: (1) determining the most effective pore systems for oil storage versus drainage, (2) identifying reservoir heterogeneity, (3) predicting potential untested compartments, (4) inferring porosity and permeability trends, and (5) matching diagenetic processes, pore types, mineralogy, and other attributes to porosity and permeability distribution.

High-pressure, mercury-injection porosimetry (MIP) measurements (see appendix and Excel spreadsheet ® on diskette) were conducted on five core samples (table 1). The core samples include: (1) a dolomitic, peloidal packstone to grainstone with anhydrite replacement and bitumen plugging from the Cherokee no. 22-14 well, (2) a micritic dolomitic mudstone to wackestone with a large amount of bitumen from the Cherokee no. 33-14 well, (3) a dolomitic phylloid-algal bafflestone with both early marine cement and leaching from the May Bug no. 2 well (6,304 feet [1,921 m]), (4) a dolomitic phylloid-algal bafflestone with internal sediment and leaching, also from the May Bug no. 2 well (6,315 feet [1,925 m]), and (5) a dolomitic phylloid-algal bafflestone with both early marine cement and leaching from the Bug 4 well.

Table 1. Well core-plug samples selected for capillary pressure/mercury injection analysis.

Sample Depth (feet)	Well Name	Porosity (%)	Grain Density (g/cm^3)
5768.7	Cherokee 22-14	24.38	2.875
5781.2	Cherokee 33-14	20.89	2.934
6304.0	May Bug 2	11.06	2.865
6315.0	May Bug 2	22.24	2.834
6289.7	Bug 4	12.45	2.857

Methods

Core plugs were obtained from the two Cherokee wells and three of the eight Bug wells that were cored. Core plugs were no more than 2 inches (5 cm) in length. Prior to MIP testing, the samples were dried in a low-temperature convection oven, and then ambient helium porosity and grain density measurements were conducted on each sample (table 1). These porosity values, along with the volume of mercury injected into each sample, were used to calculate cumulative saturation. The samples were also visually examined for open fractures that can contribute to anomalous results at low injection pressures. None of the samples tested contained open fractures or coring-induced cracks.

Results and Interpretation

All samples tested exhibited 100 percent mercury saturation at pressures less than 10,000 psi (68,950 Kpa) injection pressure. The selected reservoir rock samples vary in porosity from 11 to 24 percent, and have grain densities of 2.8 to 2.9 g/cm^3. Pore-throat-radius histograms and saturation profiles are presented in figures 5 through 11.

Cherokee Field

The pore-throat-radius histograms for both the Cherokee no. 22-14 and Cherokee no. 33-14 wells (figures 5 and 6), show that half of the pore size distribution falls under 2.0 microns, or in the microporosity realm. For the Cherokee no. 22-14 well, the distribution of pore-throat radii appears to be trimodal. Mode 1 ranges from 7.0 to 3.6 microns (the modal class [the most abundant radii in the mode] is 4.0 microns), and accounts for 3.8 to 8 percent of the pore space, with 30 percent of the pores saturated on the cumulative injection curve. Mode 2 ranges from 2.4 to 1.04 microns (the modal class is 1.6 microns), and accounts for 10 to 15 percent of the pore space, also with 30 percent of the pores saturated on the cumulative injection curve. Mode 3 ranges from 0.7 to 0.13 microns (the modal class is 0.7 microns), and accounts for the remaining pore space, but with 20 percent of the pores saturated on the cumulative injection curve. Modes 1 and 2 account for 60 percent of the injection and need 16 percent porosity to be effective for oil and gas production. Mode 3 needs 19.5 percent porosity to be effective for oil (1.0 micron radii) and gas (0.5 micron radii) production. The measured porosity is 24.4 percent.

For the Cherokee no. 33-14 well, the distribution of pore-throat radii appears to be unimodal. The primary mode ranges from 3.0 to 1.04 microns (modal class is 2.0 microns), accounts 6 to 15 percent of the pore space, but only 40 percent saturation of the cumulative curve at 2.0 microns. Thus of the two wells, the Cherokee no. 33-14 is a poorer producer than the Cherokee no. 22-14. This primary mode needs 15.5 percent porosity to be effective for oil and 19.5 percent porosity for gas production. The measured porosity is 20.1 percent.

The saturation profile for the Cherokee no. 22-14 well shows mode 1 covers 2 to 30 percent of the mercury saturation (percent of the pore volume) and requires injection pressure of 2 to 20 psi (14-138 Kpa) (figure 7). Mode 2 covers 30 to 70 percent of the mercury saturation and requires injection pressure of 20 to 40 psi (138-276 Kpa), and is the most important in terms of contribution to production. The first 50 percent of the mercury saturation requires 28 psi (193 Kpa) and is thus a good pore system; the second 45 percent requires 400 psi (2,758 Kpa). Most pores are filled under 1,000 psi (6,895 Kpa).

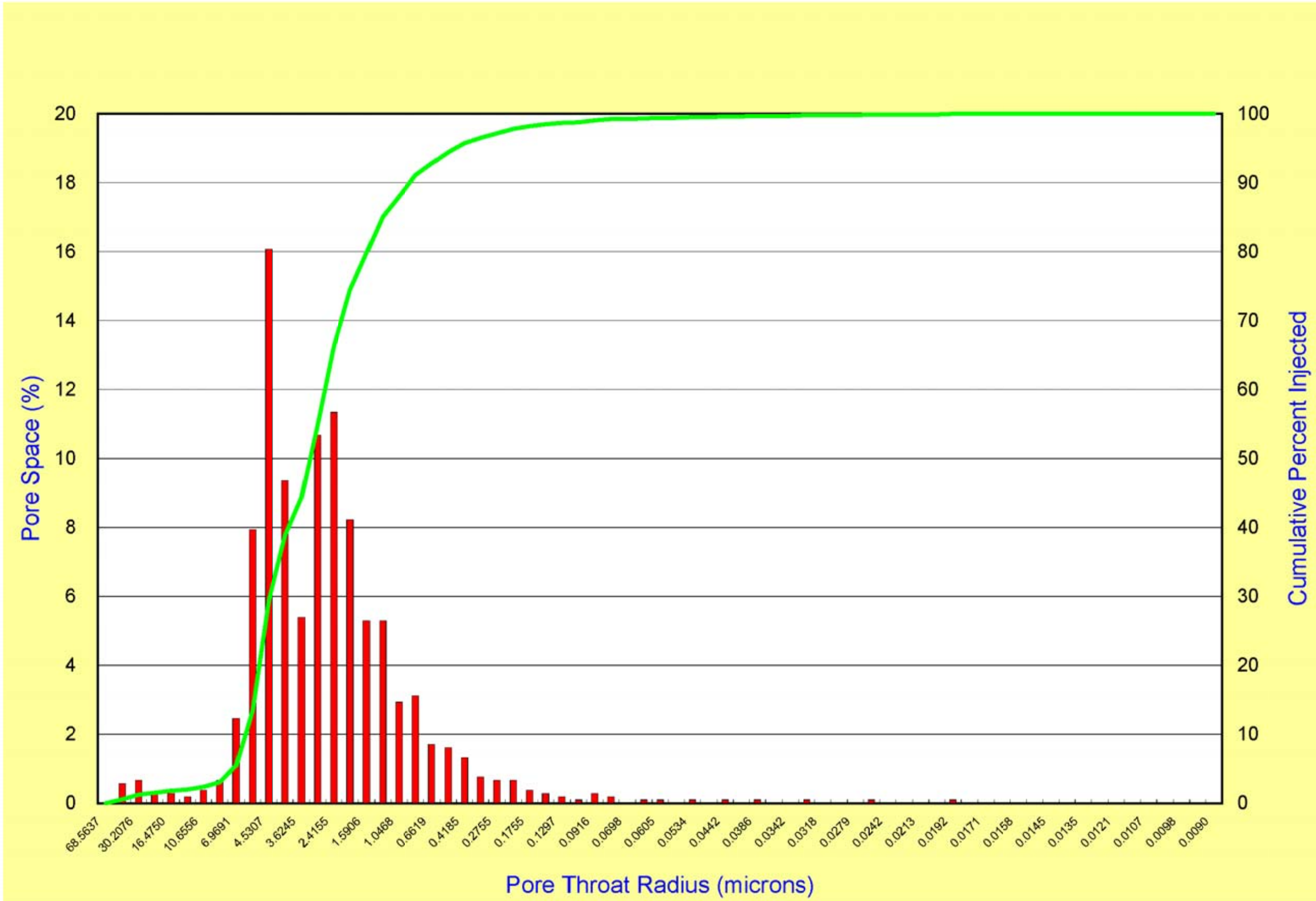

Figure 5. Pore throat radius histogram – sample depth, 5,768.7 feet – Cherokee no. 22-14 well.

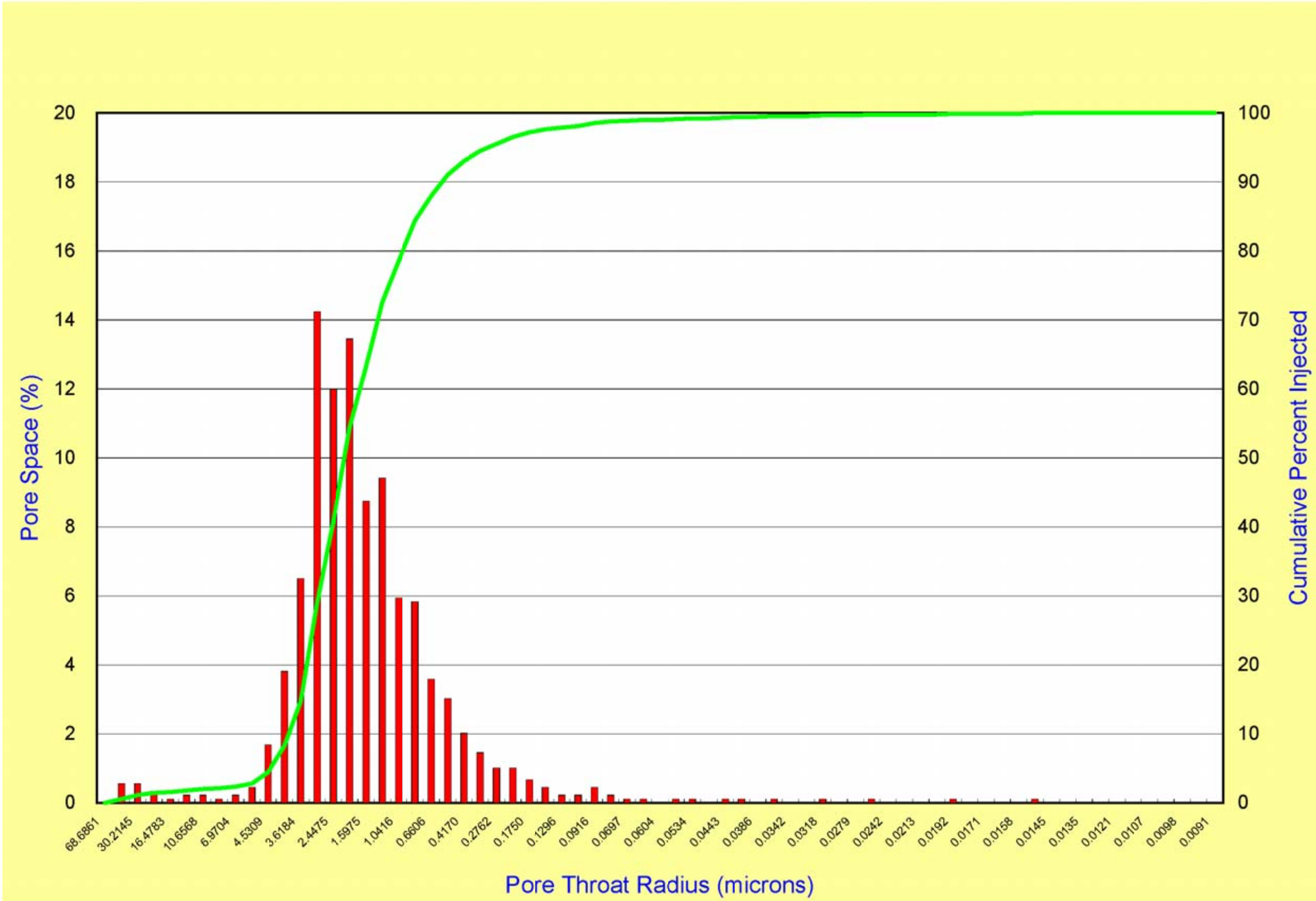

Figure 6. Pore throat radius histogram – sample depth, 5,781.2 feet – Cherokee no. 33-14 well.

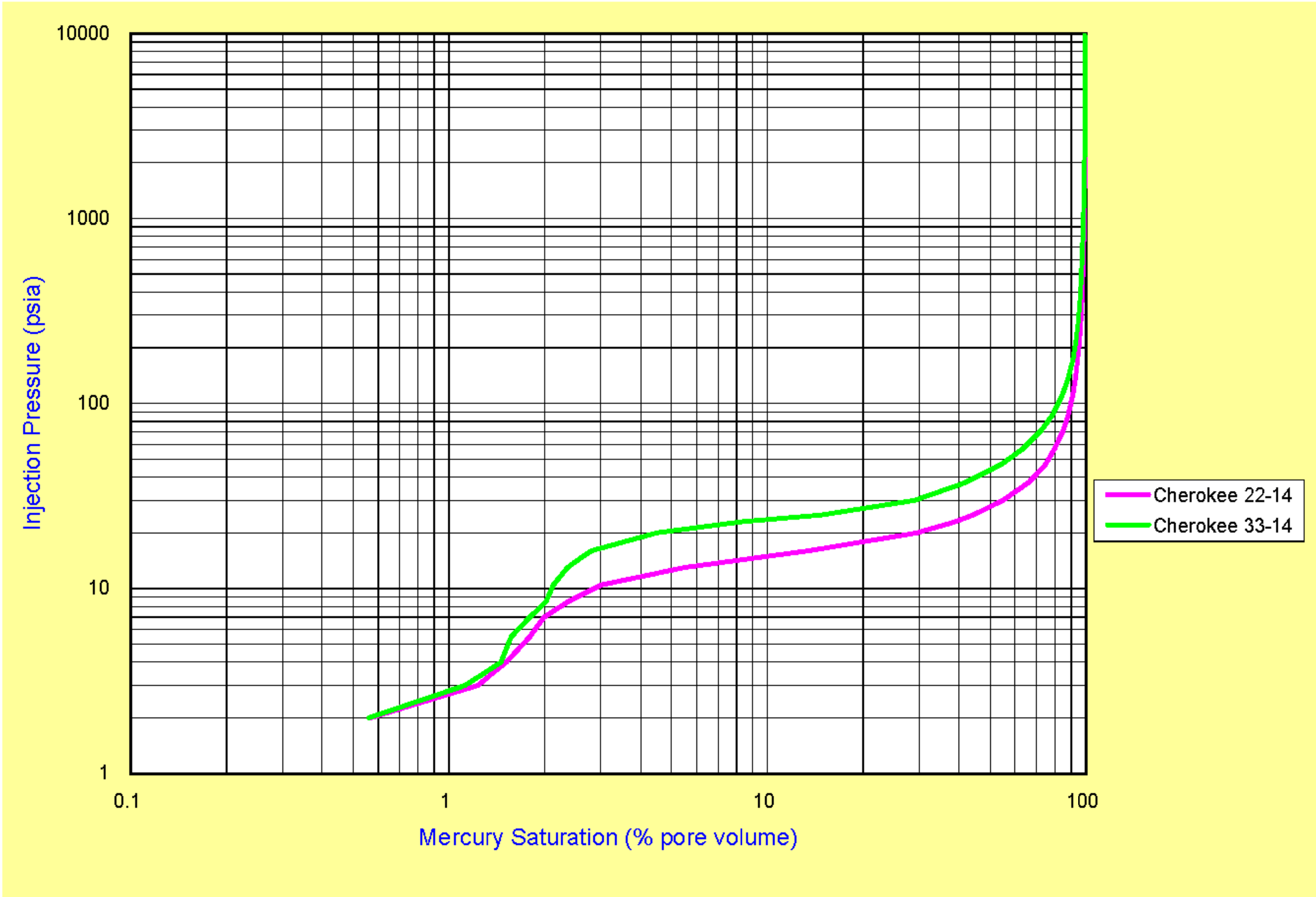

Figure 7. Saturation profiles, Cherokee no. 22-14 and Cherokee no. 33-14 wells.

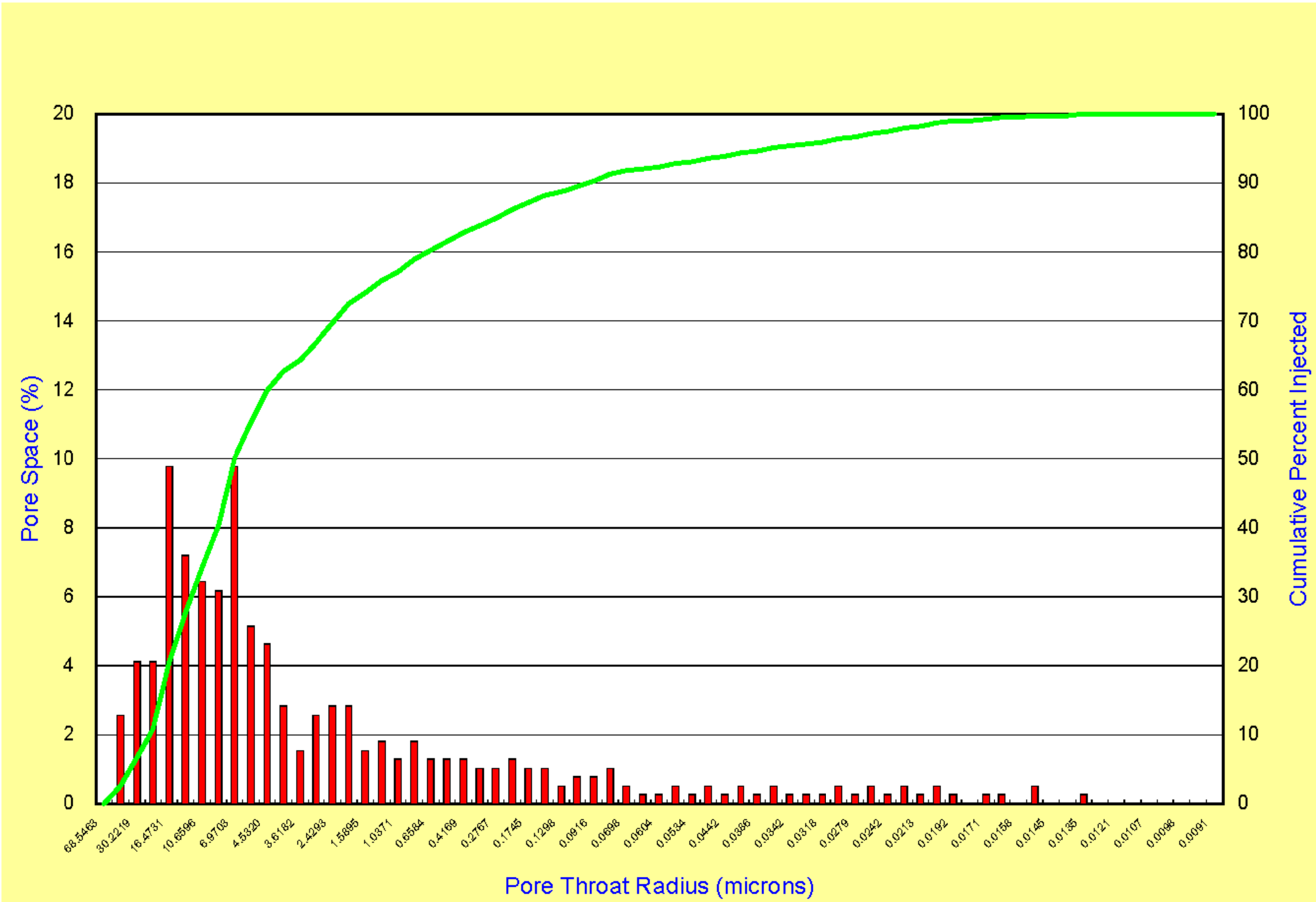

Figure 8. Pore throat radius histogram – sample depth, 6,304 feet – May Bug no. 2 well.

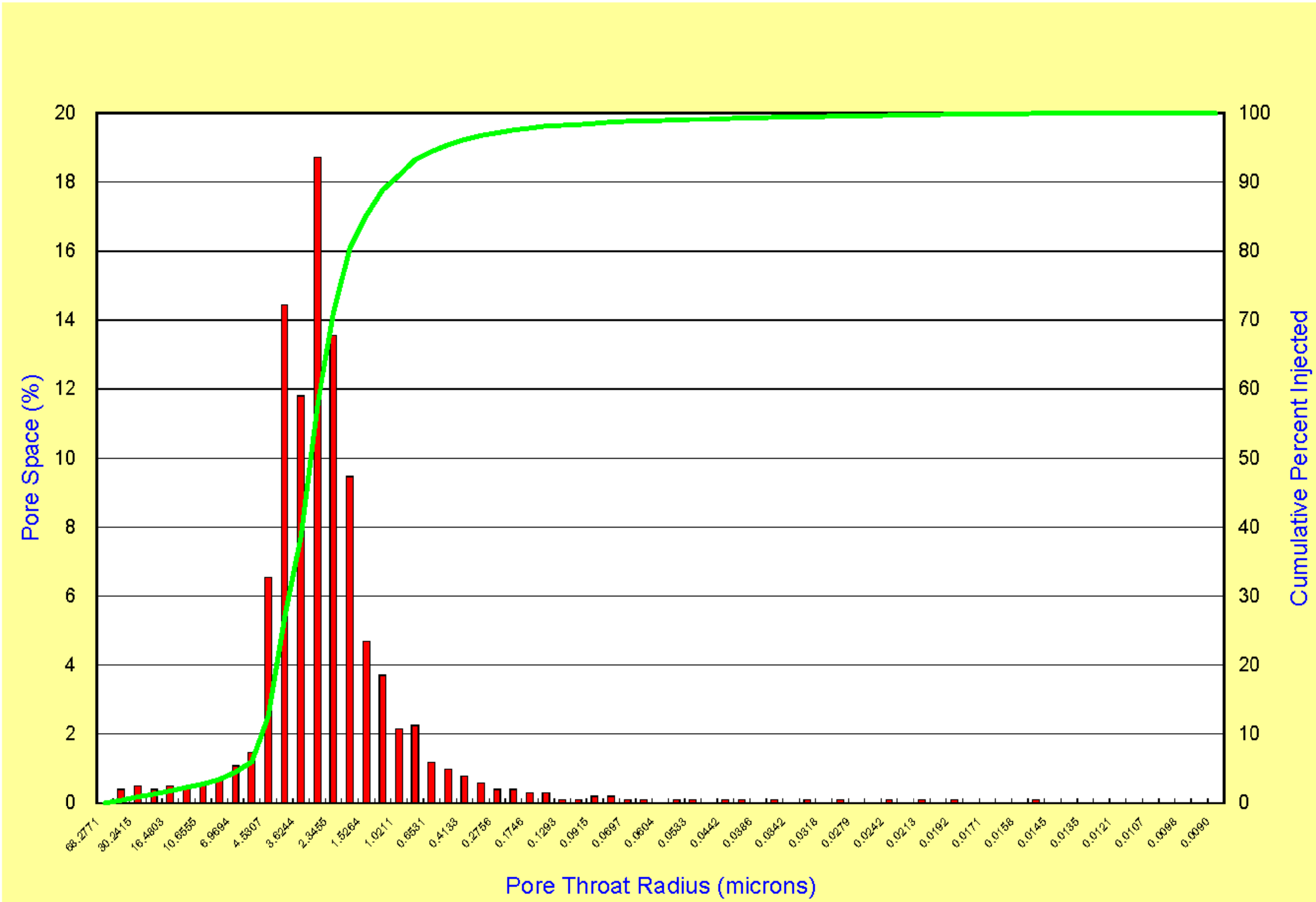

Figure 9. Pore throat radius histogram – sample depth, 6,315 feet – May Bug no. 2 well.

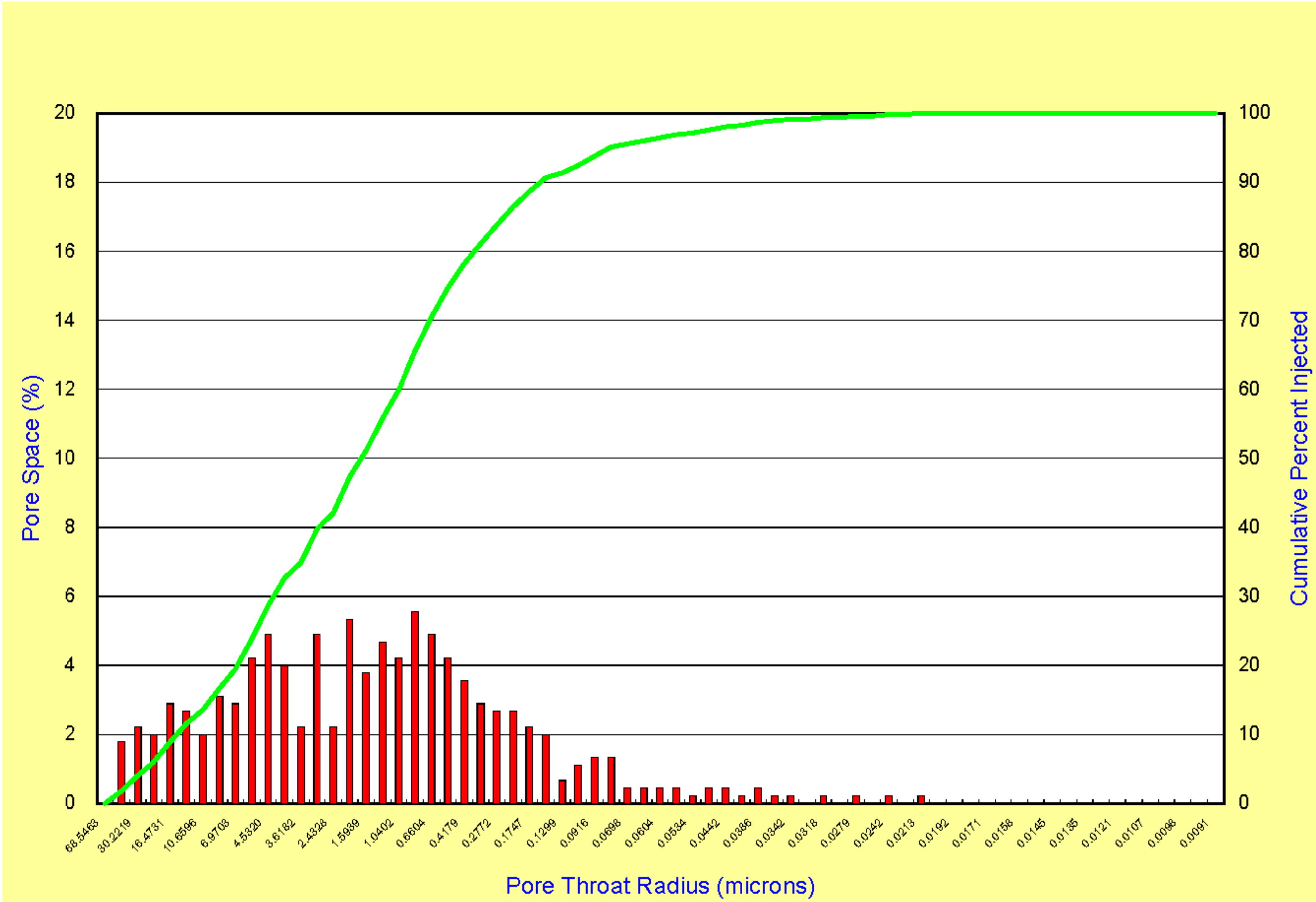

Figure 10. Pore throat radius histogram – sample depth, 6,289.1 feet – Bug no. 4 well.

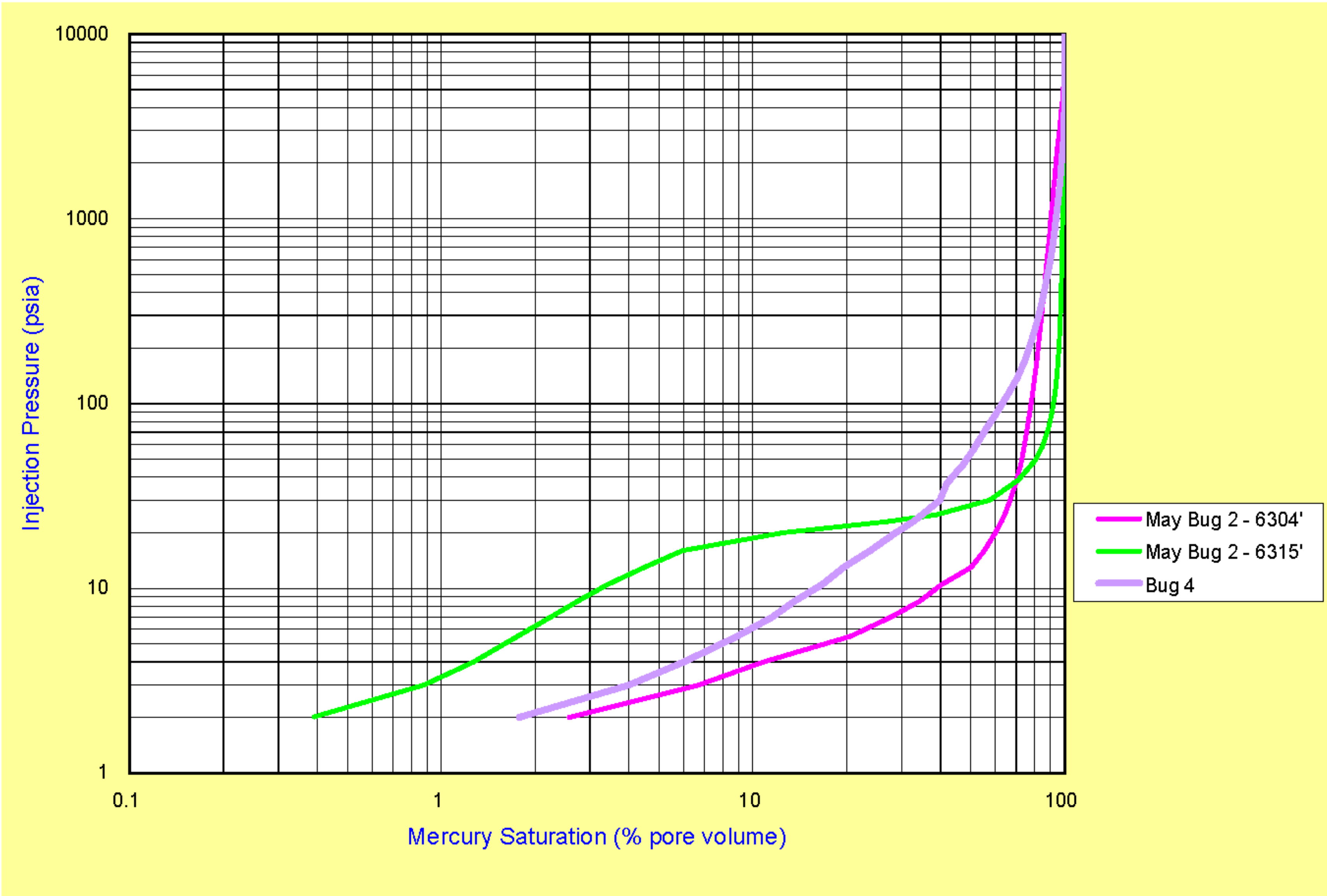

Figure 11. Saturation profiles, May Bug no. 2 and Bug no. 4 wells.

The saturation profile for the Cherokee no. 33-14 well shows the primary mode covers 2.5 to 70 percent of the mercury saturation and requires injection pressure of 15 to 70 psi (103-483 Kpa) (figure 7). The first 50 percent of the mercury saturation requires 45 psi (310 Kpa); the second 45 percent requires 600 psi (4,137 Kpa).

Both wells show that a relatively high injection pressure is required to occupy more than the last 70 percent of the pores (figure 7). The Cherokee no. 33-14 well has a steeper saturation profile than the Cherokee no. 22-14 indicating a greater amount of microporosity, and corresponding to the lower IPF (336 BOPD [53 m^3/D] and 349 MCFGPD [10 MCMGPD] for the Cherokee no. 33-14 well compared to 688 BOPD [109 m^3/D] and 78,728 MCFGPD [2,230 MCMGPD] for the Cherokee no. 22-14 well). However, the well has a high potential for untapped reserves.

Bug Field

Three capillary pressure/mercury injection tests were run on samples from Bug field: two from the May Bug no. 2 well (6,304 feet [1,921 m] and 6,315 feet [1,925 m]), and one from the Bug no. 4 well. For the May Bug no. 2 well sample from 6,304-feet, the distribution of pore-throat radii is trimodal (figure 8). Mode 1 ranges from 10 to 20 microns (the modal class is 10.65 microns), and accounts for 2 to 4 percent of the pore space, with 20 percent of the pores saturated on the cumulative injection curve. Mode 2 ranges from 6.9 to 4.5 microns (the modal class is 5.0 microns), and accounts for 10 to 12 percent of the pore space, with 10 percent of the pores saturated on the cumulative injection curve. The minor mode 3 ranges from 3.0 to 1.5 microns (the modal class is 2.0 microns), and accounts for 13 to 15 percent of the pore space, also with 10 percent of the pores saturated on the cumulative injection curve. Modes 1 and 2 account for 30 percent of the injection and need 16 percent porosity to be effective for oil and 17.5 percent porosity for gas production. The measured porosity is 11.1 percent.

For the May Bug no. 2 well sample from 6,315-feet, the distribution of pore-throat radii appears to be unimodal (figure 9). The primary mode ranges from 4.5 to 1.5 microns (modal class is 2.3 microns), and accounts 2 to 17 percent of the pore space, with 75 percent saturation of the cumulative curve. This primary mode needs 18 percent porosity to be effective for oil and 19.5 percent porosity for gas production. The measured porosity is 22.2 percent.

The distribution of pore-throat radii in the Bug no. 4 well is trimodal (figure 10). Mode 1 ranges from 5.5 to 3.6 microns (the modal class is about 4.0 microns), and accounts for 4.2 to 6.3 percent of the pore space, with 10 percent of the pores saturated on the cumulative injection curve. Mode 2 ranges from 2.4 to 1.0 microns (the modal class is 1.6 microns), and accounts for 8.3 to 10.3 percent of the pore space, also with 10 percent of the pores saturated on the cumulative injection curve. Mode 3 ranges from 1.0 to 0.4 microns (the modal class is 0.66 microns), and accounts for 12.3 to 14.3 of the remaining pore space, again with 10 percent of the pores saturated on the cumulative injection curve. Modes 1 and 2 account for 20 percent of the injection and need 11 percent porosity to be effective for oil production. Mode 3 needs 18 percent porosity to be effective for gas production. The measured porosity is 12.3 percent.

The saturation profile for the May Bug no. 2 well sample from 6,304-feet shows mode 1 covers 1 to 60 percent of the mercury saturation and requires injection pressure of 1 to 20 psi (7-138 Kpa) (figure 11). Mode 2 covers 60 to 75 percent of the mercury saturation and requires injection pressure of 20 to 50 psi (138-345 Kpa). The first 50 percent of the mercury saturation requires 15 psi (103 Kpa); the second 45 percent requires 400 psi (2,758 Kpa).

The saturation profile for the May Bug no. 2 well sample from 6,315-feet shows the primary mode covers 6 to 60 percent of the mercury saturation and requires injection pressure of 15 to 30 psi (103-207 Kpa) (figure 11). The first 50 percent of the mercury saturation requires 28 psi (193 Kpa); the second 45 percent requires 400 psi (2,758 Kpa).

The saturation profile for the Bug no. 4 well shows mode 1 covers 4 to 28 percent of the mercury saturation and requires injection pressure of 3 to 20 psi (21-138 Kpa) (figure 11). Mode 2 covers 45 to 70 percent of the mercury saturation and requires injection pressure of 40 to 150 psi (276-1,034 Kpa). Mode 3 covers 88 to 92 percent of the mercury saturation and requires injection pressure of 500 to 1,500 psi (3,448-10,343 Kpa). The first 50 percent of the mercury saturation requires 55 psi (379 Kpa); the second 45 percent requires 2,000+ psi (13,782+ Kpa).

As in Cherokee field, relatively high injection pressures are required to occupy more than the last 70 percent of the pores (figure 11). The steeper saturation profiles indicate a significant amount of micro-box-work porosity, and thus, an excellent target for horizontal drilling.

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APPENDIX

HIGH PRESSURE MERCURY INJECTION POROSIMETRY MEASUREMENTS, CHEROKEE AND BUG FIELDS, SAN JUAN COUNTY, UTAH

Table A-1. Sample Depth, 5768.7 Feet – Cherokee 22-14 Well.

Injection Pressure (psi)	Cumulative Mercury Injected (cc)	Saturation (%)	Throat Radius Size (microns)	Pore Space (%)
1.32	0.0000	0.00	68.5637	0.00
2.00	0.0134	0.57	45.2210	0.57
2.99	0.0291	1.23	30.2076	0.66
3.99	0.0358	1.51	22.6476	0.28
5.49	0.0426	1.80	16.4750	0.28
6.99	0.0470	1.98	12.9387	0.19
8.49	0.0560	2.36	10.6556	0.38
10.48	0.0717	3.02	8.6288	0.66
12.98	0.1299	5.48	6.9691	2.46
15.97	0.3180	13.42	5.6629	7.94
19.96	0.6987	29.49	4.5307	16.07
22.95	0.9204	38.85	3.9397	9.36
24.95	1.0481	44.23	3.6245	5.39
29.99	1.3011	54.91	3.0156	10.68
37.44	1.5699	66.26	2.4155	11.34
46.45	1.7647	74.48	1.9471	8.22
56.85	1.8901	79.77	1.5906	5.29
71.99	2.0155	85.07	1.2562	5.29
86.39	2.0850	88.00	1.0468	2.93
112.07	2.1589	91.12	0.8069	3.12
136.63	2.1992	92.82	0.6619	1.70
171.78	2.2372	94.42	0.5265	1.61
216.12	2.2686	95.75	0.4185	1.32
266.57	2.2865	96.50	0.3393	0.76
328.23	2.3022	97.16	0.2755	0.66
417.16	2.3179	97.83	0.2168	0.66
515.26	2.3268	98.20	0.1755	0.38
636.71	2.3335	98.49	0.1421	0.28
697.61	2.3380	98.68	0.1297	0.19
797.58	2.3403	98.77	0.1134	0.09
987.78	2.3470	99.05	0.0916	0.28
1199.28	2.3515	99.24	0.0754	0.19
1296.91	2.3515	99.24	0.0698	0.00
1397.06	2.3537	99.34	0.0648	0.09
1495.49	2.3559	99.43	0.0605	0.09
1598.41	2.3559	99.43	0.0566	0.00
1694.59	2.3582	99.53	0.0534	0.09
1895.79	2.3582	99.53	0.0477	0.00
2045.98	2.3604	99.62	0.0442	0.09
2194.39	2.3604	99.62	0.0412	0.00
2344.56	2.3627	99.72	0.0386	0.09
2494.08	2.3627	99.72	0.0363	0.00

Table A-1. Continued.

Injection Pressure (psi)	Cumulative Mercury Injected (cc)	Saturation (%)	Throat Radius Size (microns)	Pore Space (%)
2693.08	2.3649	99.81	0.0336	0.09
2844.35	2.3649	99.81	0.0318	0.00
2994.47	2.3649	99.81	0.0302	0.00
3242.65	2.3649	99.81	0.0279	0.00
3493.04	2.3671	99.91	0.0259	0.09
3742.24	2.3671	99.91	0.0242	0.00
3992.46	2.3671	99.91	0.0227	0.00
4241.10	2.3671	99.91	0.0213	0.00
4510.62	2.3671	99.91	0.0201	0.00
4726.36	2.3694	100.00	0.0192	0.09
4983.83	2.3694	100.00	0.0182	0.00
5280.77	2.3694	100.00	0.0171	0.00
5479.41	2.3694	100.00	0.0165	0.00
5734.45	2.3694	100.00	0.0158	0.00
5977.27	2.3694	100.00	0.0152	0.00
6230.29	2.3694	100.00	0.0145	0.00
6476.92	2.3694	100.00	0.0140	0.00
6728.06	2.3694	100.00	0.0135	0.00
6972.12	2.3694	100.00	0.0130	0.00
7472.55	2.3694	100.00	0.0121	0.00
7967.92	2.3694	100.00	0.0114	0.00
8473.75	2.3694	100.00	0.0107	0.00
8971.73	2.3694	100.00	0.0101	0.00
9267.44	2.3694	100.00	0.0098	0.00
9565.98	2.3694	100.00	0.0095	0.00
10021.43	2.3694	100.00	0.0090	0.00

Table A-2. Sample Depth, 5781.2 Feet – Cherokee 33-14 Well.

Injection Pressure (psi)	Cumulative Mercury Injected (cc)	Saturation (%)	Throat Radius Size (microns)	Pore Space (%)
1.32	0.0000	0.00	68.6861	0.00
2.00	0.0148	0.56	45.1746	0.56
2.99	0.0295	1.12	30.2145	0.56
3.99	0.0384	1.46	22.6665	0.34
5.49	0.0413	1.57	16.4783	0.11
6.99	0.0472	1.79	12.9428	0.22
8.49	0.0531	2.02	10.6568	0.22
10.48	0.0561	2.13	8.6289	0.11
12.97	0.0620	2.35	6.9704	0.22
15.97	0.0738	2.80	5.6620	0.45
19.96	0.1180	4.48	4.5309	1.68
22.96	0.2183	8.30	3.9389	3.81
24.99	0.3894	14.80	3.6184	6.50
29.99	0.7641	29.04	3.0156	14.24
36.95	1.0797	41.03	2.4475	12.00
46.97	1.4338	54.48	1.9254	13.45
56.61	1.6639	63.23	1.5975	8.74
71.95	1.9117	72.65	1.2568	9.42
86.83	2.0680	78.59	1.0416	5.94
111.86	2.2214	84.42	0.8085	5.83
136.90	2.3158	88.00	0.6606	3.59
172.14	2.3955	91.03	0.5254	3.03
216.89	2.4486	93.05	0.4170	2.02
267.31	2.4870	94.51	0.3383	1.46
327.50	2.5135	95.52	0.2762	1.01
417.37	2.5401	96.52	0.2167	1.01
516.84	2.5578	97.20	0.1750	0.67
638.97	2.5696	97.65	0.1416	0.45
698.08	2.5755	97.87	0.1296	0.22
796.92	2.5814	98.09	0.1135	0.22
987.47	2.5932	98.54	0.0916	0.45
1196.26	2.5991	98.77	0.0756	0.22
1297.18	2.6020	98.88	0.0697	0.11
1396.05	2.6050	98.99	0.0648	0.11
1497.62	2.6050	98.99	0.0604	0.00
1595.74	2.6079	99.10	0.0567	0.11
1695.12	2.6109	99.22	0.0534	0.11
1896.02	2.6109	99.22	0.0477	0.00
2044.03	2.6138	99.33	0.0443	0.11
2193.45	2.6168	99.44	0.0413	0.11
2344.97	2.6168	99.44	0.0386	0.00
2494.04	2.6197	99.55	0.0363	0.11

Table A-2. Continued.

Injection Pressure (psi)	Cumulative Mercury Injected (cc)	Saturation (%)	Throat Radius Size (microns)	Pore Space (%)
2694.76	2.6197	99.55	0.0336	0.00
2843.68	2.6227	99.66	0.0318	0.11
2993.84	2.6227	99.66	0.0302	0.00
3242.71	2.6227	99.66	0.0279	0.00
3491.91	2.6256	99.78	0.0259	0.11
3741.18	2.6256	99.78	0.0242	0.00
3991.77	2.6256	99.78	0.0227	0.00
4240.81	2.6256	99.78	0.0213	0.00
4492.54	2.6256	99.78	0.0202	0.00
4723.98	2.6286	99.89	0.0192	0.11
4982.58	2.6286	99.89	0.0182	0.00
5281.50	2.6286	99.89	0.0171	0.00
5480.77	2.6286	99.89	0.0165	0.00
5732.18	2.6286	99.89	0.0158	0.00
5980.20	2.6315	100.00	0.0151	0.11
6231.04	2.6315	100.00	0.0145	0.00
6477.33	2.6315	100.00	0.0140	0.00
6724.32	2.6315	100.00	0.0135	0.00
6972.68	2.6315	100.00	0.0130	0.00
7471.99	2.6315	100.00	0.0121	0.00
7970.25	2.6315	100.00	0.0114	0.00
8468.61	2.6315	100.00	0.0107	0.00
8970.68	2.6315	100.00	0.0101	0.00
9268.99	2.6315	100.00	0.0098	0.00
9567.26	2.6315	100.00	0.0095	0.00
10019.07	2.6315	100.00	0.0091	0.00

Table A-3. Sample Depth, 6304.0 Feet – May Bug 2 Well.

Injection Pressure (psi)	Cumulative Mercury Injected (cc)	Saturation (%)	Throat Radius Size (microns)	Pore Space (%)
1.32	0.0000	0.00	68.5463	0.00
2.00	0.0209	2.57	45.1942	2.57
2.99	0.0543	6.68	30.2219	4.11
3.99	0.0878	10.80	22.6686	4.11
5.49	0.1672	20.57	16.4731	9.77
6.98	0.2258	27.76	12.9477	7.20
8.48	0.2780	34.19	10.6596	6.43
10.48	0.3282	40.36	8.6295	6.17
12.97	0.4076	50.13	6.9703	9.77
15.97	0.4494	55.27	5.6632	5.14
19.95	0.4870	59.90	4.5320	4.63
22.95	0.5100	62.72	3.9398	2.83
24.99	0.5226	64.27	3.6182	1.54
29.99	0.5435	66.84	3.0154	2.57
37.23	0.5665	69.67	2.4293	2.83
46.92	0.5895	72.49	1.9275	2.83
56.90	0.6020	74.04	1.5895	1.54
72.31	0.6166	75.84	1.2507	1.80
87.20	0.6271	77.12	1.0371	1.29
111.36	0.6417	78.92	0.8121	1.80
137.35	0.6522	80.21	0.6584	1.29
171.40	0.6626	81.49	0.5276	1.29
216.91	0.6731	82.78	0.4169	1.29
267.51	0.6814	83.80	0.3381	1.03
326.87	0.6898	84.83	0.2767	1.03
417.66	0.7002	86.12	0.2165	1.29
518.20	0.7086	87.15	0.1745	1.03
637.54	0.7170	88.17	0.1419	1.03
696.91	0.7211	88.69	0.1298	0.51
798.15	0.7274	89.46	0.1133	0.77
987.84	0.7337	90.23	0.0916	0.77
1197.58	0.7420	91.26	0.0755	1.03
1296.38	0.7462	91.77	0.0698	0.51
1397.21	0.7483	92.03	0.0647	0.26
1497.67	0.7504	92.29	0.0604	0.26
1595.57	0.7546	92.80	0.0567	0.51
1695.26	0.7567	93.06	0.0534	0.26
1895.58	0.7609	93.57	0.0477	0.51
2047.02	0.7630	93.83	0.0442	0.26
2197.39	0.7671	94.34	0.0412	0.51
2346.13	0.7692	94.60	0.0386	0.26
2494.97	0.7734	95.12	0.0363	0.51

Table A-3. Continued.

Injection Pressure (psi)	Cumulative Mercury Injected (cc)	Saturation (%)	Throat Radius Size (microns)	Pore Space (%)
2694.00	0.7776	95.63	0.0336	0.26
2843.67	0.7797	95.89	0.0318	0.26
2993.69	0.7839	96.40	0.0302	0.51
3245.00	0.7859	96.66	0.0279	0.26
3492.20	0.7901	97.17	0.0259	0.51
3742.91	0.7922	97.43	0.0242	0.26
3993.17	0.7964	97.94	0.0227	0.51
4243.87	0.7985	98.20	0.0213	0.26
4510.57	0.8027	98.71	0.0201	0.51
4723.99	0.8048	98.97	0.0192	0.26
4982.05	0.8048	98.97	0.0182	0.00
5283.05	0.8068	99.23	0.0171	0.26
5482.50	0.8089	99.49	0.0165	0.26
5733.20	0.8089	99.49	0.0158	0.00
5982.74	0.8110	99.74	0.0151	0.51
6230.80	0.8110	99.74	0.0145	0.26
6476.61	0.8110	99.74	0.0140	0.00
6729.68	0.8131	100.00	0.0135	0.26
6971.59	0.8131	100.00	0.0130	0.00
7473.61	0.8131	100.00	0.0121	0.00
7969.93	0.8131	100.00	0.0114	0.00
8472.53	0.8131	100.00	0.0107	0.00
8971.55	0.8131	100.00	0.0101	0.00
9268.21	0.8131	100.00	0.0098	0.00
9567.52	0.8131	100.00	0.0095	0.00
10018.87	0.8131	100.00	0.0091	0.00

Table A-4. Sample Depth, 6315.0 Feet – May Bug 2 Well.

Injection Pressure (psi)	Cumulative Mercury Injected (cc)	Saturation (%)	Throat Radius Size (microns)	Pore Space (%)
1.32	0.0000	0.00	68.2771	0.00
2.01	0.0034	0.39	45.0993	0.39
2.99	0.0076	0.88	30.2415	0.49
3.99	0.0110	1.27	22.6750	0.39
5.49	0.0153	1.76	16.4803	0.49
6.99	0.0195	2.24	12.9402	0.49
8.49	0.0238	2.73	10.6555	0.49
10.48	0.0297	3.41	8.6290	0.68
12.98	0.0391	4.49	6.9694	1.07
15.97	0.0518	5.95	5.6624	1.46
19.96	0.1087	12.49	4.5307	6.54
22.95	0.2343	26.93	3.9396	14.44
24.95	0.3371	38.73	3.6244	11.80
29.98	0.5001	57.46	3.0160	18.73
38.56	0.6181	71.02	2.3455	13.56
49.04	0.7005	80.49	1.8441	9.46
59.25	0.7412	85.17	1.5264	4.68
73.62	0.7735	88.88	1.2285	3.71
88.56	0.7922	91.02	1.0211	2.15
114.03	0.8117	93.27	0.7931	2.24
138.46	0.8219	94.44	0.6531	1.17
173.74	0.8304	95.41	0.5205	0.98
218.81	0.8372	96.20	0.4133	0.78
268.75	0.8423	96.78	0.3365	0.59
328.15	0.8457	97.17	0.2756	0.39
418.70	0.8491	97.56	0.2160	0.39
518.15	0.8516	97.85	0.1746	0.29
638.91	0.8542	98.15	0.1416	0.29
699.38	0.8550	98.24	0.1293	0.10
798.64	0.8559	98.34	0.1133	0.10
988.71	0.8576	98.54	0.0915	0.20
1200.15	0.8592	98.73	0.0754	0.20
1297.01	0.8601	98.83	0.0697	0.10
1397.88	0.8609	98.93	0.0647	0.10
1497.58	0.8609	98.93	0.0604	0.00
1597.92	0.8618	99.02	0.0566	0.10
1696.46	0.8626	99.12	0.0533	0.10
1896.68	0.8626	99.12	0.0477	0.00
2046.00	0.8635	99.22	0.0442	0.10
2195.71	0.8643	99.32	0.0412	0.10
2345.48	0.8643	99.32	0.0386	0.00
2496.61	0.8652	99.41	0.0362	0.10

Table A-4. Continued.

Injection Pressure (psi)	Cumulative Mercury Injected (cc)	Saturation (%)	Throat Radius Size (microns)	Pore Space (%)
2698.23	0.8660	99.51	0.0335	0.10
2844.62	0.8660	99.51	0.0318	0.00
2996.08	0.8669	99.61	0.0302	0.10
3243.29	0.8669	99.61	0.0279	0.00
3494.71	0.8669	99.61	0.0259	0.00
3743.03	0.8677	99.71	0.0242	0.10
3994.13	0.8677	99.71	0.0227	0.00
4244.01	0.8686	99.80	0.0213	0.10
4494.40	0.8686	99.80	0.0201	0.00
4724.19	0.8694	99.90	0.0192	0.10
4984.13	0.8694	99.90	0.0182	0.00
5282.86	0.8694	99.90	0.0171	0.00
5484.37	0.8694	99.90	0.0165	0.00
5735.49	0.8694	99.90	0.0158	0.00
5980.78	0.8703	100.00	0.0151	0.10
6231.53	0.8703	100.00	0.0145	0.00
6477.91	0.8703	100.00	0.0140	0.00
6728.39	0.8703	100.00	0.0135	0.00
6979.98	0.8703	100.00	0.0130	0.00
7471.97	0.8703	100.00	0.0121	0.00
7972.37	0.8703	100.00	0.0114	0.00
8470.54	0.8703	100.00	0.0107	0.00
8971.27	0.8703	100.00	0.0101	0.00
9269.96	0.8703	100.00	0.0098	0.00
9570.39	0.8703	100.00	0.0095	0.00
10021.61	0.8703	100.00	0.0090	0.00

Table A-5. Sample Depth, 6289.1 Feet – May Bug 4 Well.

Injection Pressure (psi)	Cumulative Mercury Injected (cc)	Saturation (%)	Throat Radius Size (microns)	Pore Space (%)
1.32	0.0000	0.00	68.5463	0.00
2.00	0.0260	1.78	45.1942	1.78
2.99	0.0586	4.00	30.2219	2.22
3.99	0.0879	6.00	22.6686	2.00
5.49	0.1302	8.89	16.4731	2.89
6.98	0.1693	11.56	12.9477	2.67
8.48	0.1986	13.56	10.6596	2.00
10.48	0.2442	16.67	8.6295	3.11
12.97	0.2865	19.56	6.9703	2.89
15.97	0.3484	23.78	5.6632	4.22
19.95	0.4200	28.67	4.5320	4.89
22.95	0.4786	32.67	3.9398	4.00
24.99	0.5112	34.89	3.6182	2.22
29.99	0.5828	39.78	3.0154	4.89
37.17	0.6154	42.00	2.4328	2.22
46.81	0.6935	47.33	1.9320	5.33
56.74	0.7489	51.11	1.5939	3.78
72.09	0.8173	55.78	1.2544	4.67
86.94	0.8791	60.00	1.0402	4.22
111.02	0.9605	65.56	0.8146	5.56
136.95	1.0322	70.44	0.6604	4.89
170.94	1.0940	74.67	0.5290	4.22
216.40	1.1461	78.22	0.4179	3.56
266.97	1.1885	81.11	0.3388	2.89
326.30	1.2275	83.78	0.2772	2.67
417.06	1.2666	86.44	0.2169	2.67
517.57	1.2992	88.67	0.1747	2.22
636.89	1.3285	90.67	0.1420	2.00
696.25	1.3382	91.33	0.1299	0.67
797.48	1.3545	92.44	0.1134	1.11
987.15	1.3741	93.78	0.0916	1.33
1196.89	1.3936	95.11	0.0756	1.33
1295.68	1.4001	95.56	0.0698	0.44
1396.51	1.4066	96.00	0.0648	0.44
1496.97	1.4131	96.44	0.0604	0.44
1594.86	1.4196	96.89	0.0567	0.44
1694.56	1.4229	97.11	0.0534	0.22
1894.86	1.4294	97.56	0.0477	0.44
2046.31	1.4359	98.00	0.0442	0.44
2196.68	1.4392	98.22	0.0412	0.22
2345.41	1.4457	98.67	0.0386	0.44
2494.25	1.4489	98.89	0.0363	0.22

Table A-5. Continued.

Injection Pressure (psi)	Cumulative Mercury Injected (cc)	Saturation (%)	Throat Radius Size (microns)	Pore Space (%)
2693.28	1.4522	99.11	0.0336	0.00
2842.96	1.4555	99.33	0.0318	0.22
2992.97	1.4555	99.33	0.0302	0.00
3244.29	1.4587	99.56	0.0279	0.22
3491.49	1.4587	99.56	0.0259	0.00
3742.20	1.4620	99.78	0.0242	0.22
3992.46	1.4620	99.78	0.0227	0.00
4243.56	1.4652	100.00	0.0213	0.22
4509.86	1.4652	100.00	0.0201	0.00
4723.29	1.4652	100.00	0.0192	0.00
4981.35	1.4652	100.00	0.0182	0.00
5282.35	1.4652	100.00	0.0171	0.00
5481.80	1.4652	100.00	0.0165	0.00
5732.50	1.4652	100.00	0.0158	0.00
5982.04	1.4652	100.00	0.0151	0.00
6230.10	1.4652	100.00	0.0145	0.00
6475.91	1.4652	100.00	0.0140	0.00
6728.99	1.4652	100.00	0.0135	0.00
6970.90	1.4652	100.00	0.0130	0.00
7472.92	1.4652	100.00	0.0121	0.00
7969.24	1.4652	100.00	0.0114	0.00
8471.84	1.4652	100.00	0.0107	0.00
8970.86	1.4652	100.00	0.0101	0.00
9267.51	1.4652	100.00	0.0098	0.00
9566.83	1.4652	100.00	0.0095	0.00
10018.18	1.4652	100.00	0.0091	0.00