Chapter PA (Production Analysis)

PRODUCTION ANALYSIS OF NORTH SLOPE OIL AND GAS FIELDS

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Abstract

Production data, pressure data, and fluid characteristics of currently producing Alaska North Slope oil fields are presented. Relationships among these are examined. Production from individual wells shows low variability within pools.

Assumptions and Data Sources

Production data, pressure data, and fluid characteristics of currently producing Alaska North Slope oil fields are presented as the model for production in the 1002 area of ANWR. This production analysis concerns reservoir information that affects the calculated volume of oil or gas production as it moves from reservoir to stock tank and pipeline conditions.

Data came from two sources: The Alaska Oil and Gas Conservation Commission 1996 Annual Report (Alaska Oil and Gas Conservation Commission, 1997, hereafter referred to as the 1996 AOGCC Report) and Petroleum Information Corporation 1996 PetroROM - Production Data (Petroleum Information Corporation, 1996, hereafter referred to as PI data or database).

Figure PA1 is a table of the information taken from the 1996 AOGCC Report. The plots in figures PA2 and PA3 are derived from the data in figure PA1. In cases where the tabulated data for a given entry is a range of values, a value in the middle of the range was used for plotting. Figures PA4 and PA5 represent information derived from the PI data. The production data used in figures PA4 and PA5 is from all of the North Slope wells in the PI database. The names in the legends of figures PA4 and PA5 are the field and formation names used by the PI database and do not exactly correspond with the naming convention used in the 1996 AOGCC Report.

Formation Volume Factor

The plots in Figure PA2 (A through D) are of the oil formation volume factor, normally represented as B_O. The units of B_O are defined as reservoir barrels per stock tank barrel and account for the expansion that the hydrocarbon undergoes as a result of moving from a high-pressure, high-

temperature environment to one of standard conditions (14.7 psi, 60° Fahrenheit). B_O is plotted against API gravity, original pressure, reservoir temperature, and depth. Each of these plots yields a formula for estimating B_O from the other parameter. Depth (Figure PA2 (D)) provides the best correlation, but B_O should be estimated from the value given the most credence in a particular application.

Pressure versus Depth

The two data points indicating an overpressured region in the pressure versus depth plot (Figure PA3 (A)) are both from the Thomson Sandstone in the Point Thomson Unit. This unit is directly adjacent to the ANWR boundary and the formation appears to continue into the 1002 area. To estimate pressures for non-overpressured reservoirs, the formula from the plot (Figure PA3 (C)) with the overpressured data removed should be used. Pressures in the Thomson wells are approximately 3900 psi above values calculated by the figure PA3 (C) trend line equation. Addition of 3900 psi to the calculated value for any reservoir believed to be pressure-connected to the Point Thomson wells will provide a realistic value for further calculations.

Gas-oil Ratio

The correlation for gas-oil ratio (GOR) and API gravity (Figure PA3 (B)) is insignificant, and should not be used. The plot of gas-oil ratio versus pressure (Figure PA3 (D)) has a better fit but should only be used for a general guideline. The ability of an oil reservoir to retain gas and hence a high gas-oil ratio is dependent on a seal that is capable of holding the gas. Light end hydrocarbons are very mobile and will migrate out of the oil through any escape route. Presence of an effective seal differentiates deposits with high gravity oil from those with low gravity oil. When the oil leaves the source rock, a spectrum of hydrocarbons is present. If a reservoir has a leaky seal or the seal is temporarily breached, the lighter hydrocarbons escape leaving dead or heavy oil behind. Therefore the quality of a sealing formation in regard to its ability to retain gas is the most important factor in determining feature gas-oil ratios and should override any calculation of GOR from the pressure plot.

Production Data from North Slope Fields

The data presented in figures PA4 and PA5 represent production values from all of the wells in the PI database for North Slope fields. The best monthly production (Figure PA4) is the single best monthly production value for each of the wells, while the best 12 month value (Figure PA5) represents the best consecutive 12 months with no regard for any particular production period such as calendar year.

The data were grouped by pool and then ordered and plotted in the same manner. Each group was sorted into descending order of production magnitude and plotted with a probability value on a linear scale on the x-axis. A probability value is assigned by numbering each data point for each data set (such as Kuparuk River - West Sak) and dividing the sample number by the highest sample number plus one. Using the Kuparuk River - West Sak data set as an example, there are production values from 12 wells in this data set. After the data set is sorted into a descending value sequence starting with the highest value, the values are assigned numbers ranging from one (the highest value) to twelve (the lowest value). Each of these numbers (not the values) are divided by thirteen, the result being the probability of that value. This method allows data sets with widely varying numbers of values to be plotted on the same graph with a common horizontal scale.

After all of the data sets are plotted, the variability coefficient of each data set can be calculated. The variability coefficient is an indicator of the steepness of the slope of the data set. It is calculated as the value at .95 probability minus the value at .05 probability, all divided by the value at .50 probability.

From preliminary research into this concept (Dyman and others, 1996), it is believed that the value of variability coefficient is directly related to the heterogeneity of the reservoir. High variability coefficients indicate a heterogeneous reservoir while low values, as found in all of the North Slope pools, indicate a homogeneous reservoir. In the areas studied by Dyman and others (1996), variability coefficients for peak yearly and peak monthly production were mostly less than 10 but reached as high as 12.46. The highest for the North Slope pools was 3.92. This limited range of variability coefficients may be the result of regional economics in that very heterogeneous reservoirs would be less likely to be economically viable on

the North Slope. There is quite a bit of variety in the magnitude of production values between the reservoirs. Yet all of the reservoirs have approximately the same slope and that slope is very low.

References

Alaska Oil and Gas Conservation Commission, [1997], 1996 Annual Report: Anchorage, Alaska Oil and Gas Conservation Commission, 251 p.

Dyman, T.S., Schmoker, J.W., and Quinn, J.C., 1996, Reservoir heterogeneity as measured by production characteristics of wells – preliminary observations: U.S. Geological Survey Open-File Report 96-059, 11 p.

Petroleum Information Corporation, 1996, PetroROM - Production Data 1996: Littleton, CO, Petroleum Information Corp., [database available from Petroleum Information Corp., 4100 East Dry Creek Road, Littleton, CO 80122].

Figure PA1. Data from North Slope oil and gas fields used in this production analysis.
Data taken from the State of Alaska, Alaska Oil and Gas Conservation Commission 1996 Annual Report.
[API = American Petroleum Institute, GOR = gas-oil ratio, RB = reservoir barrels, STB = stock tank barrels,
Bo = formation volume factor, OP = original pressure, SCF = standard cubic feet.

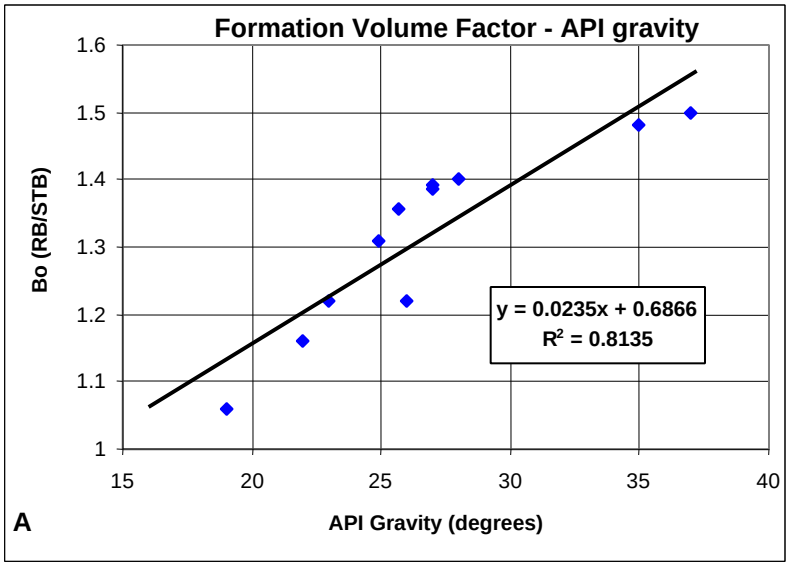
Field	Producing Formation	Gas/Oil Pool	Depth (feet subsea)	Original Pressure (psia)	Gross Pay (feet)	Net Pay (feet)	Temperature (Degrees Fahrenheit)	Oil Gravity (API)	Gas Specific Gravity	Average Porosity (%)	Permeability (millidarcy)	Average Swi (%)	Formation Volume Factor (RB/STB)	Saturation Pressure (psia)	Original GOR (SCF/STB)	12/96 GOR (SCF/STB)	Oil Viscosity (cp@OP)	Oil Viscosity (cp@SP)
Endicott Field	Kekiktuk	Endicott	10000	4870			218	22		21	150-1200				763	5623		
	Sadlerochit	Ivishak	10000	4825			212	25		20	2-600				700	849		
	Lisburne	Alapah	10000	4900			216	28-29		17.5	5-200				600			
Kuparuk River Field	Kuparuk River	Kuparuk River	6200	3360			150	22.9-29.0		21		35	1.22		228-413	1072		
	West Sak	Undefined																
Milne Point Field	Kuparuk River	Kuparuk River	7200	3555	30-75	10-40	178	22		23	20-2000	37	1.16	2140	320	460	3.8	3.25
	West Sak and Ugnu	Schrader Bluff	4267	1940	21	21	65	19		21	143	31	1.06	1507	202	371	52	47
	Sag River	Undefined	9500	4440	60	30	235	35-39		18	4	40	1.41-1.56	3500-3800	784-974	921	.28-.35	.26-.33
North Star Unit	Sadlerochit	Undefined	11000	5290			246								2000			
Point McIntyre Field	Kuparuk River	Point McIntyre	8800	4377	0-450		180	27		22	200	15-65	1.391	4308	806	1002		0.9
Prudhoe Bay Field	Kuparuk River	Kuparuk River	6200	3210	40-95	30-80	150	23		23	3-200	28-47	1.22	2980	450	NA	1.8-4.0	NA
	Sag River, Shublik, Ivishak	Prudhoe	8800	4390	350-630	0-444	200	28		22	265	20.77	1.4	4390	730	10581	0.81	0.81
	Wahoo and Alapah	Lisburne	8900	4490	0-2000	NA	183	27		10	0.1-2.0	20-40	1.385	4300	830	15302	0.7	NA
Prudhoe Bay Field	Kuparuk River	Niakuk	8900	4461	110	98	181	24.9		20	500	28	1.31	3835	662	732		1.4
Prudhoe Bay Field	Ivishak	North Prudhoe Bay	9245	3922	42	20	206	35		20	590	38	1.48	3870	923	9467		0.425
Prudhoe Bay Field	Kuparuk River	West Beach	8800	4257	106	71	175	25.7		19	107	35-41	1.356	4160	752	6952		1.04
Point Thomson Unit	Thomson SS	Undefined, Ak St A-1	12500	9850			195	23.1							864-934			
		Undefined, Pt Th #1	12900	10160			205	18.4							5830			
Barrow Field	Unnamed Jurassic&Cret.	S. Barrow Pool	2250	1103		27	63		0.56	20	30	52						
	Unnamed Jurassic&Cret.	E. Barrow Pool	2000	1000		18	58		0.57	22	44	55						
East Umiat Field	Ninuluk / Chandler	Undefined	1929	750	73	66	50		0.6	15	15	32						
Kavik Field	Sag River / Sadlerochit	Undefined	3500	2391-2400	260-900	40-280	114-127		.587-.588	5-13	2-200	50						
Kemik Field	Shublik	Undefined		2678			123		0.6									
Walakpa Field	Walakpa Sandstone	Walakpa		1030	27	24	64		0.571	24	187	29						

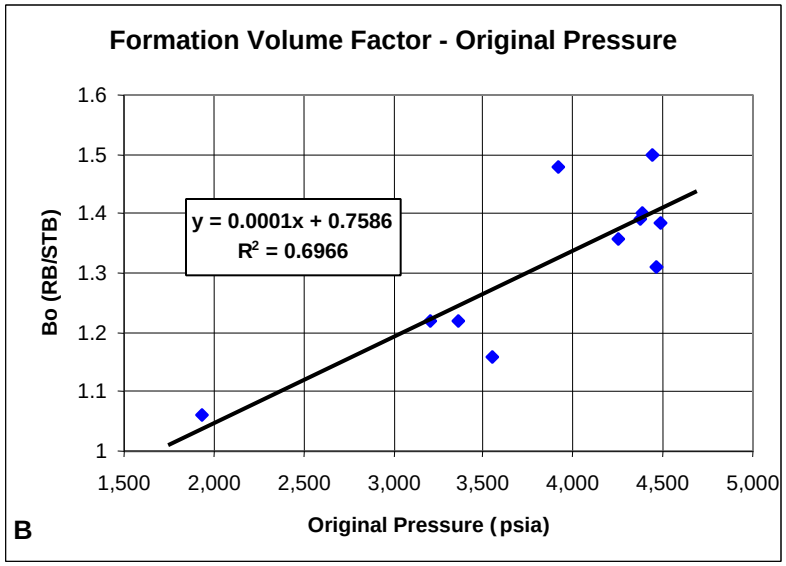
API = American Petroleum Institute
Bo = formation volume factor
cp = centipoise

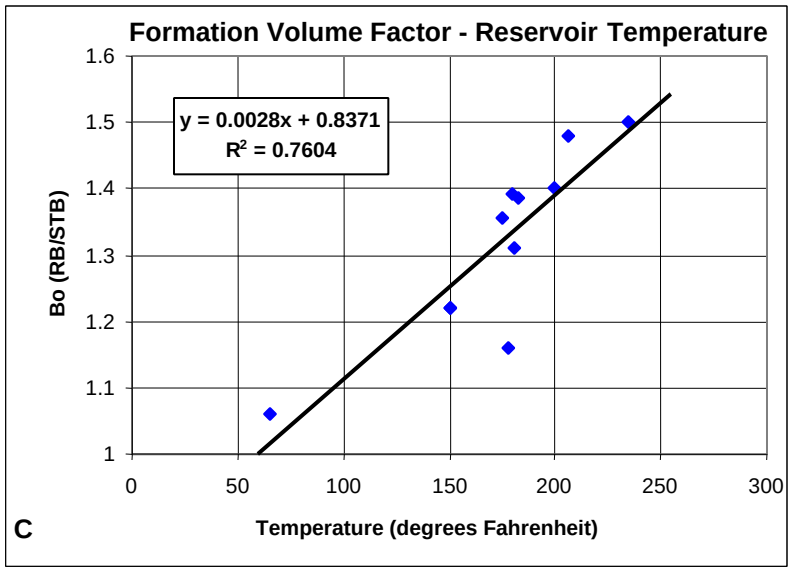
GOR = gas-oil ratio
OP = original pressure
psia = pounds per square inch absolute

RB = reservoir barrels
SCF = standard cubic feet
SP = saturation pressure

STB = stock tank barrels
Swi = irreduceable water saturation







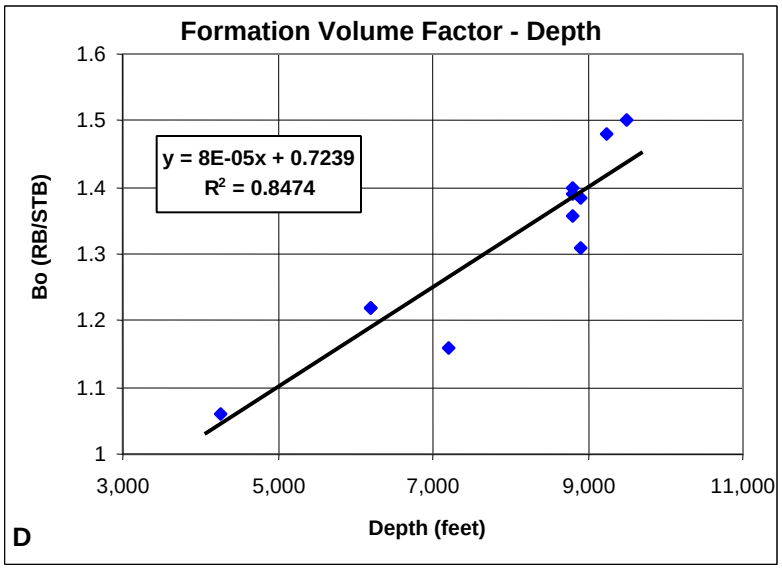
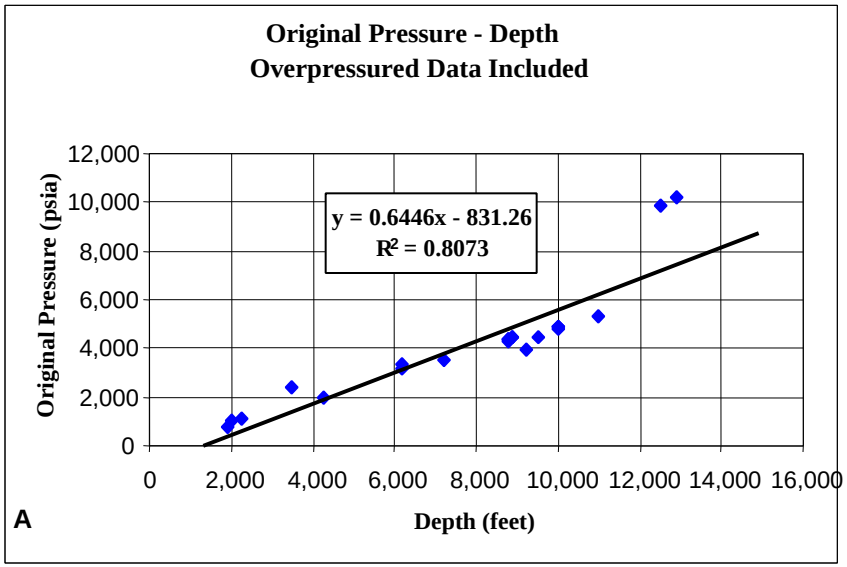
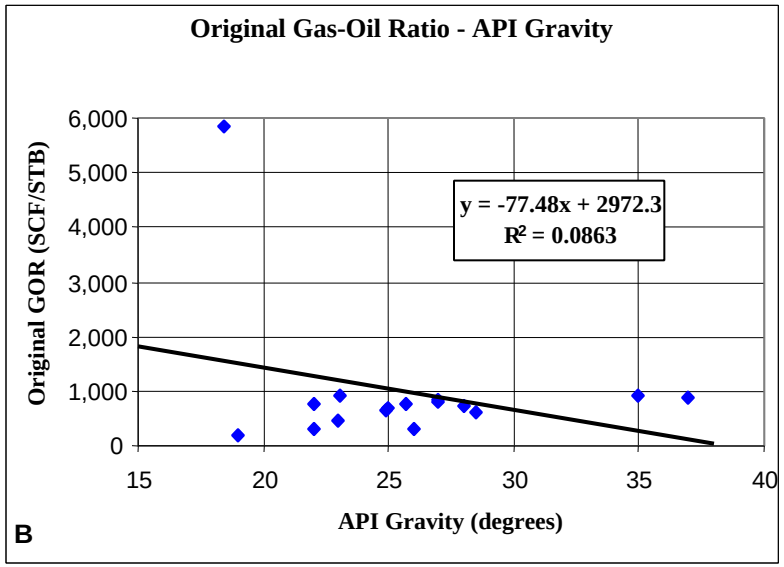
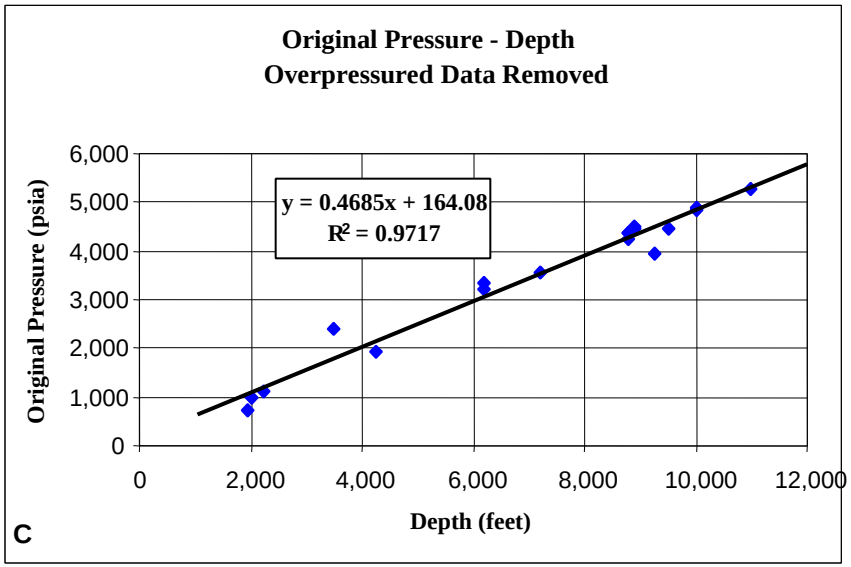


Figure PA2. Plots showing formation volume factor (Bo) versus: (A) API gravity, (B) original pressure, (C) reservoir temperature, and (D) depth. See Figure PA1 for data source and abbreviations.







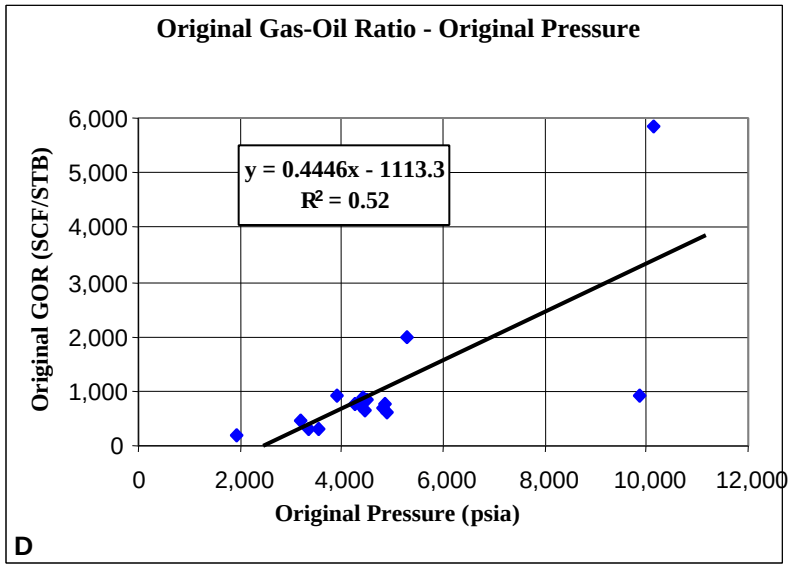


Figure PA3. Plots showing: (A) original pressure vs depth with overpressured data, (B) GOR vs API gravity, (C) original pressure vs depth without overpressured data, and (D) GOR vs original pressure. See Figure PA1 for data source and abbreviations.

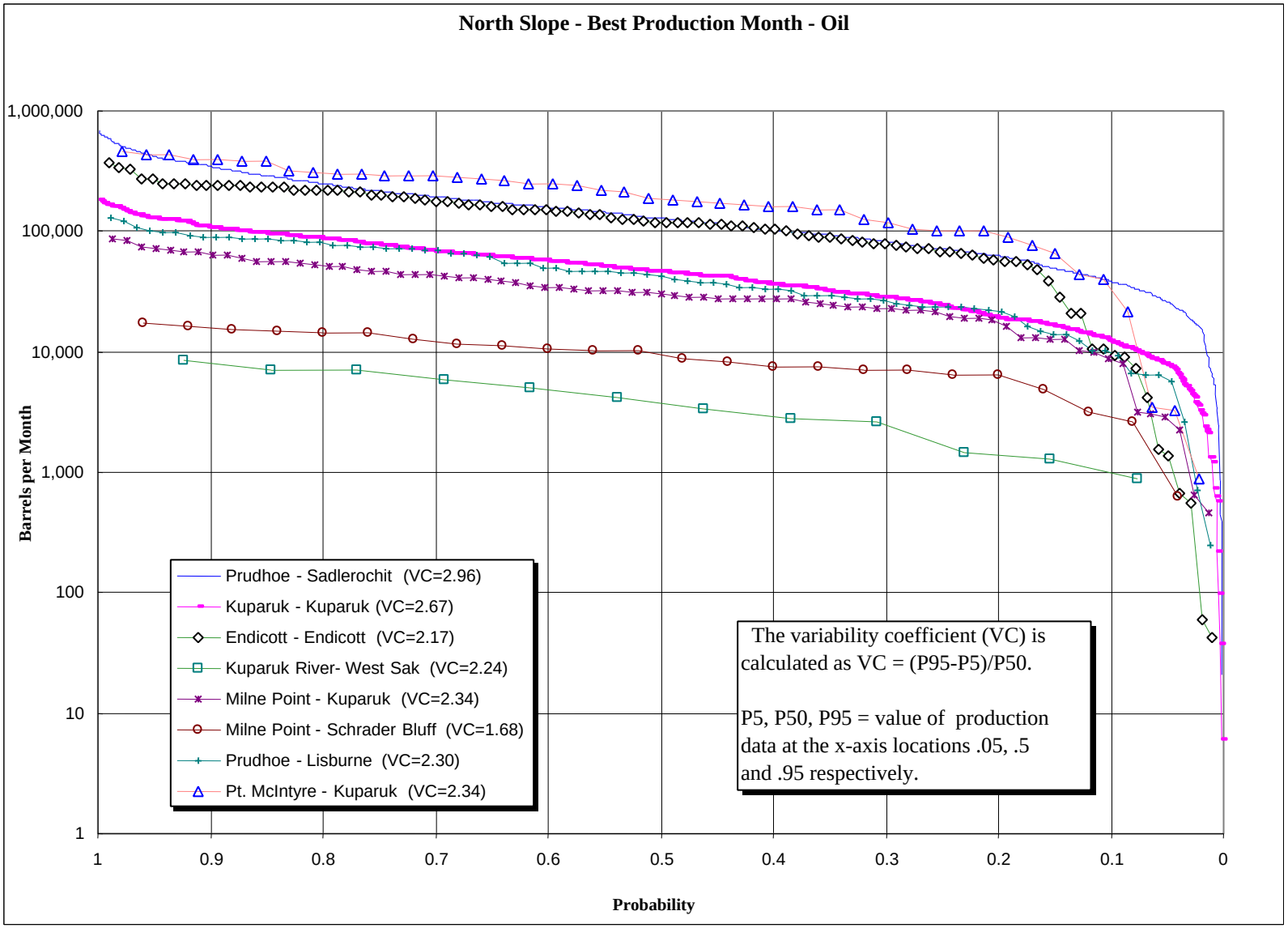


Figure PA4. Plot showing the best single month's production for North Slope wells grouped by pool. See text for full explanation. Data from Petroleum Information Corporation, 1996.

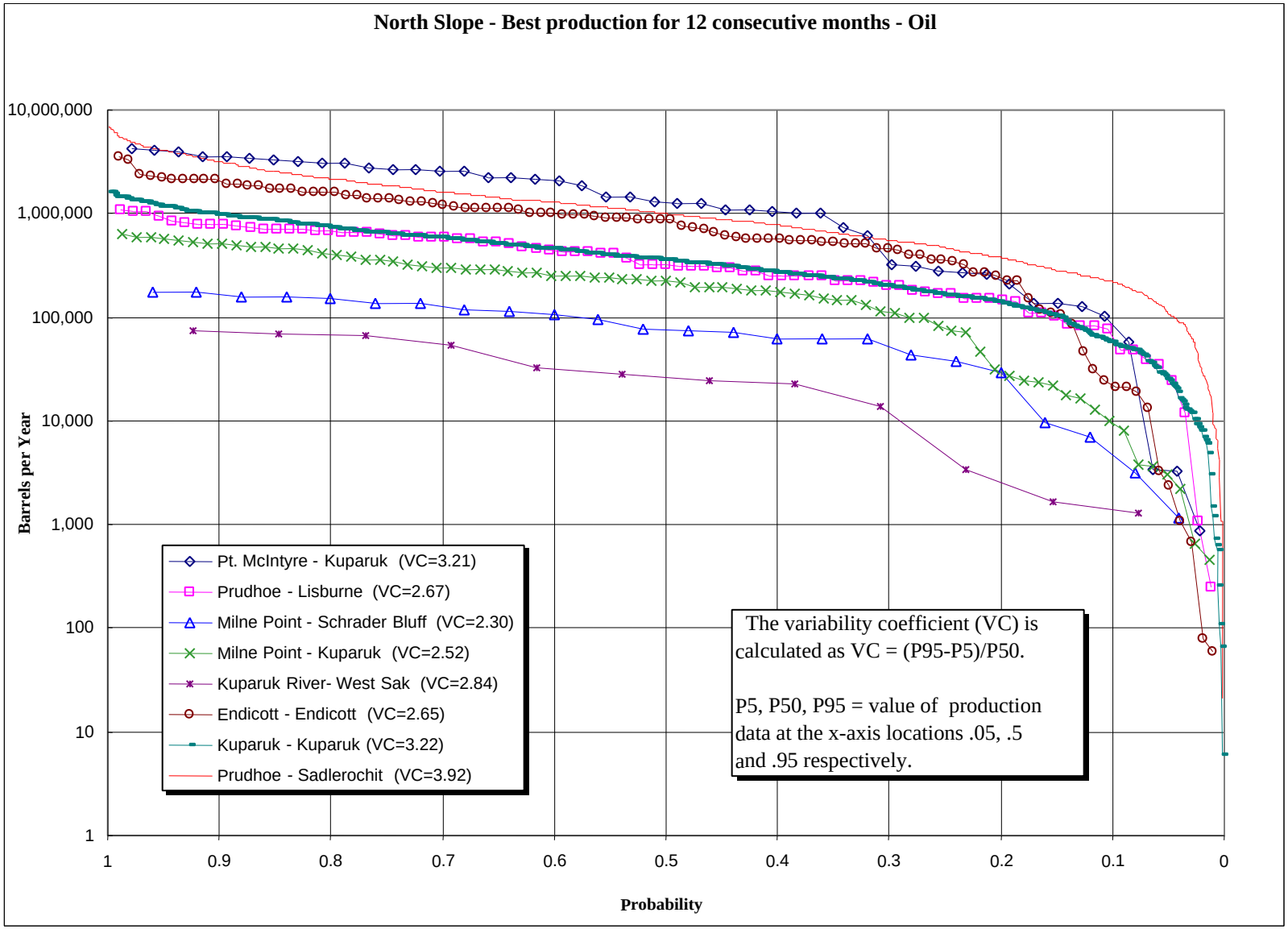


Figure PA5. Plot showing the best consecutive 12 month period's production for North Slope wells grouped by pool. See text for full explanation. Data fromPetroleum Information Corporation, 1996.