Appendix B

Data Analysis

Appendix B

Data Analysis

Reservoir Parameters

Parameters needed for the estimation of oil and gas in place were not available for all reservoirs. Missing data were determined based on analogous data within common areal location and geologic intervals. Fluid properties were calculated for each reservoir using correlations adapted for personal computer spreadsheet software. Unknown reservoir pressures were calculated using an equation for the pressure gradient of the entire basin. Unknown temperatures were determined from separate gradient equations for each of the four Areas of the basin listed in **Table 3**.

Distributions of known porosity, permeability, productive area, gross thickness, and net pay along with the distributions of the calculated water saturation for each geologic interval listed in **Table 4** are shown as **Figures 18B through 27B**.

Field Location

Field locations were verified by charting the fields of the basin by latitude and longitude coordinates (**Figure 1B**). Minor location problems were solved by locating fields on maps or checking several data sources. Regional boundaries are not always distinct; therefore, some fields along the boundaries may be listed in the incorrect Region. Field locations and Region and Area listed in the field summary tables are listed in **Appendix D**. The location of fields that produce from the geologic intervals of **Table 4** are also charted as coordinate graphs of latitude and longitude in **Figures 2B - 11B** to show the areas of the basin that are productive from the geologic intervals

Reservoir Pressure

The initial reservoir pressure was calculated for each reservoir that did not have a reported measured pressure. The depth to the reservoir and the pressure gradient of the basin were used in the calculation. The pressure gradient was determined for each Area of the basin. When compared, the gradients were approximately equal so a single gradient for the entire basin was calculated and used to obtain unreported pressures. When no measured pressure was reported, the reservoir depth (usually the top of the pay) was used as the reference depth for calculating the reservoir pressure. Depths were not corrected to a subsea datum is as much as the flat topography reduces most errors of depth measurements within the fields. Errors between fields may be introduced because of the small differences in surface elevations but the errors were considered insignificant. The graph of reported pressures at reservoir depth does not show significant scatter (**Figure 12B**). The fitted linear equation used to calculate unknown pressures is:

$$BHP = 0.451 * Depth$$

Where:
BHP = Pressure at reservoir depth (psi)
0.451 = Pressure gradient (psi / foot)
Depth = Depth to reservoir (feet)

Reservoir Temperature

Linear equations fitted from measured temperatures at reservoir depth were used to calculate unknown reservoir temperatures. Reservoir temperatures vary across the basin so equations were determined for each Area of the basin. Most of the data indicated that a linear equation with a constant of approximately 30 degrees Fahrenheit could be used to calculate reservoir temperature. The equations used for each Area are:

$$North\ BHT = (0.0152 * Depth) + 30$$
$$South\ BHT = (0.0197 * Depth) + 30$$
$$West\ BHT = (0.0241 * Depth) + 30$$
$$Middle\ ObBHT = (0.0191 * Depth) + 30$$

Where:
Area BHT = Temperature at depth in area (ºF.)
0.0xxx = Temperature gradient (ºF./foot)
Depth = Depth to reservoir (feet)
30 = Constant

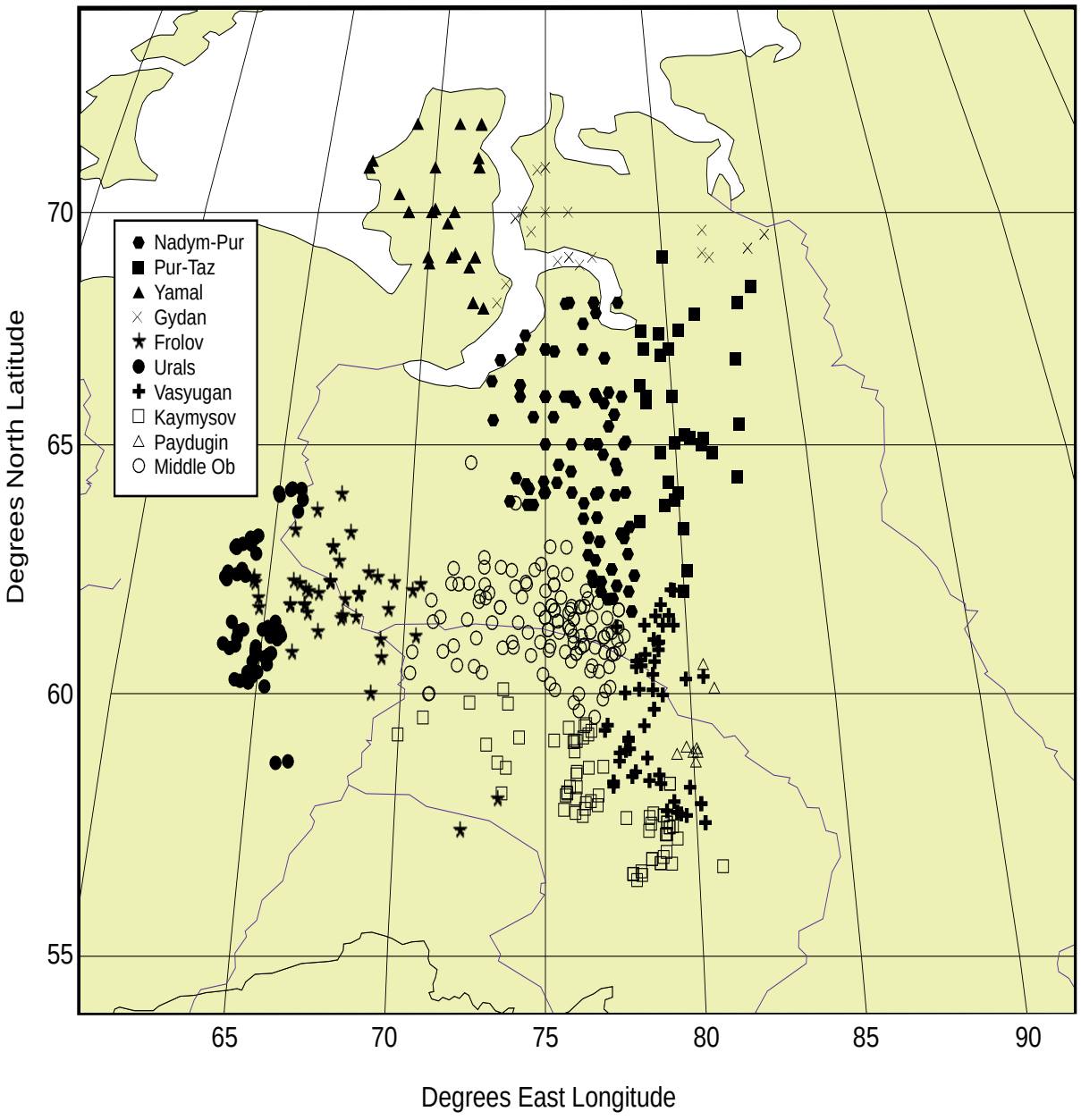
Porosity

For reservoirs with no reported porosity data, porosity was imputed based on a random selection from the observed distribution of porosity in the geologic interval. Reported porosity values ranged from 4 percent to 35 percent. Average values of the geologic intervals ranged between 12 percent and 26 percent.

Permeability

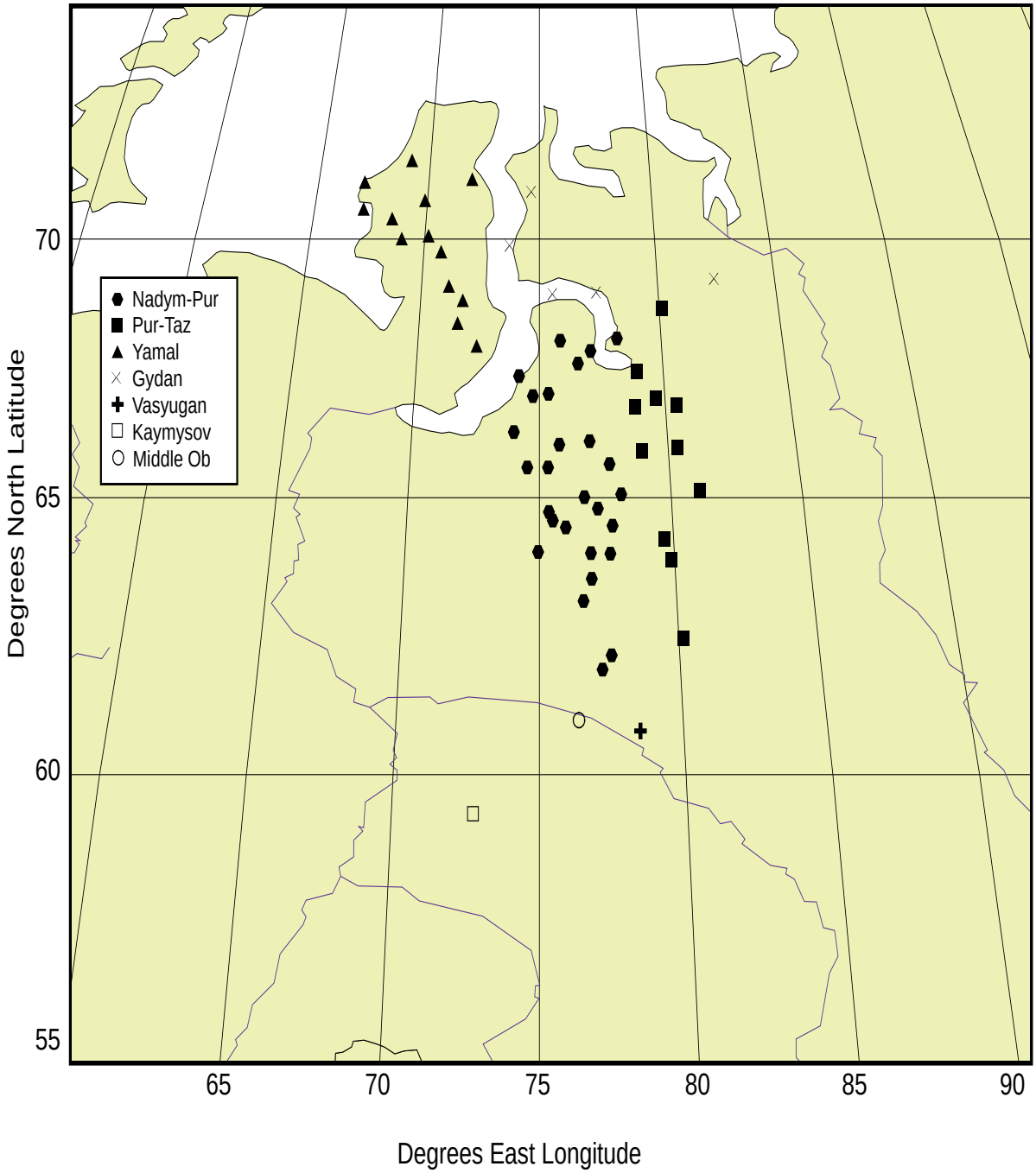
The distribution of permeability within each geologic interval was determined and graphed. The mode of the reported permeability of each geologic unit was used where data were not available. Permeabilities ranged from 0.1 millidarcys to 1,900 millidarcys. Permeability is used in the calculation of water saturations and recovery efficiencies.

Figure 1B. Location of Fields Within Regions of West Siberian Basin by Latitude and Longitude



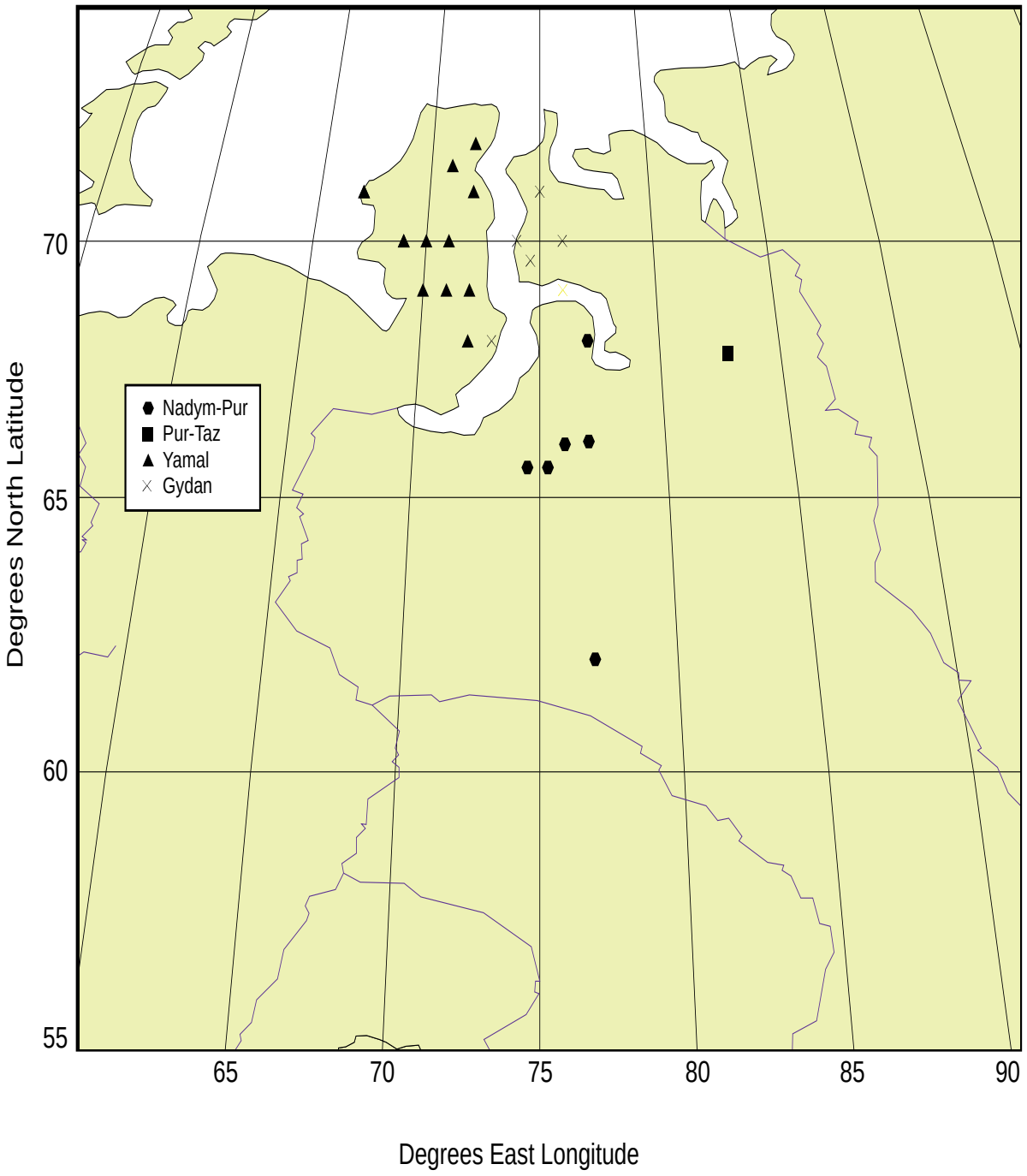
Source: Energy Information Administration, Office of Oil and Gas

Figure 2B. Location of Fields Producing from the Upper Cretaceous (All Areas) West Siberian Basin.



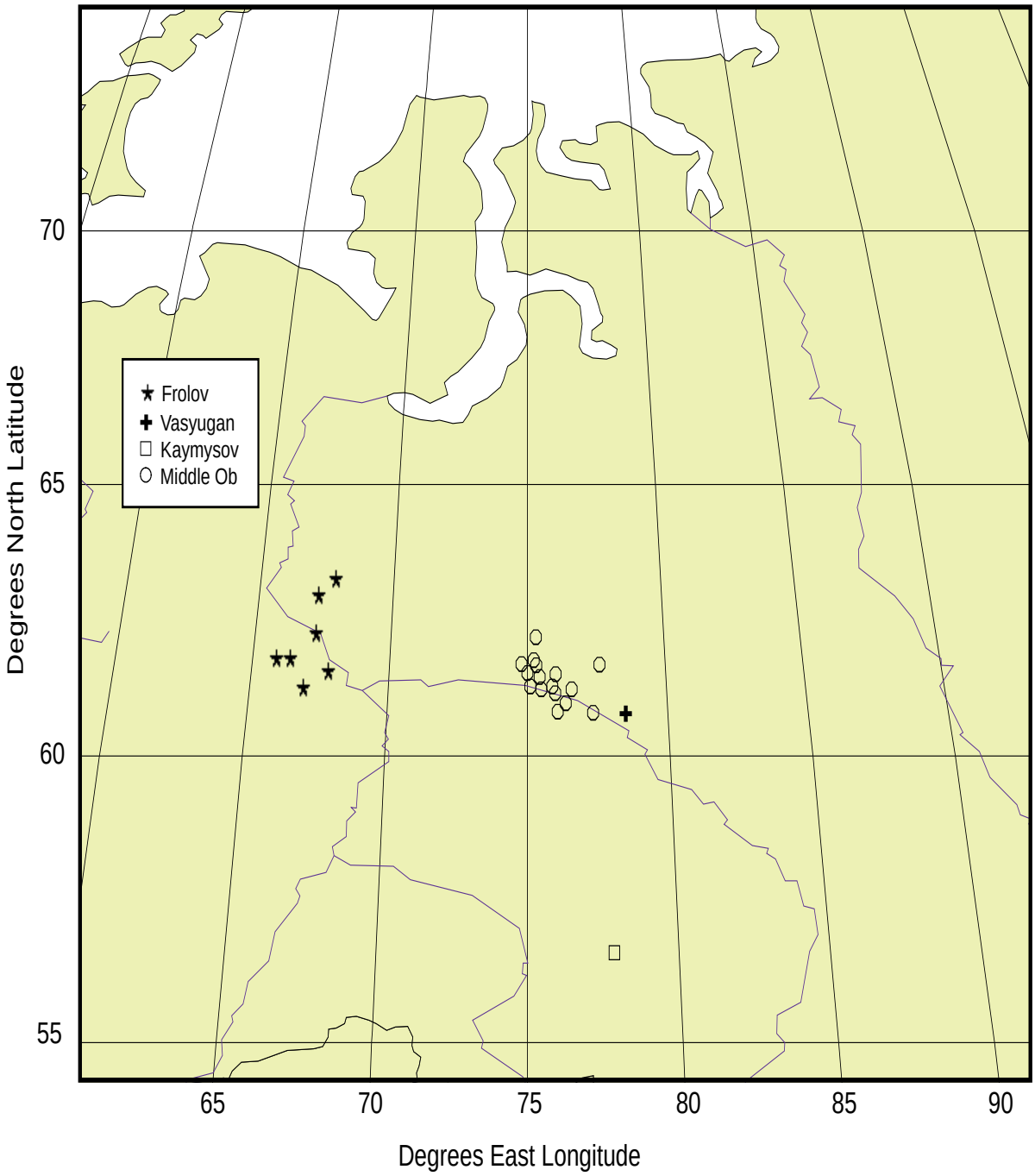
Source: Energy Information Administration, Office of Oil and Gas

Figure 3B. Location of Fields Producing from the North Albian - Aptian Interval (North Area) West Siberian Basin



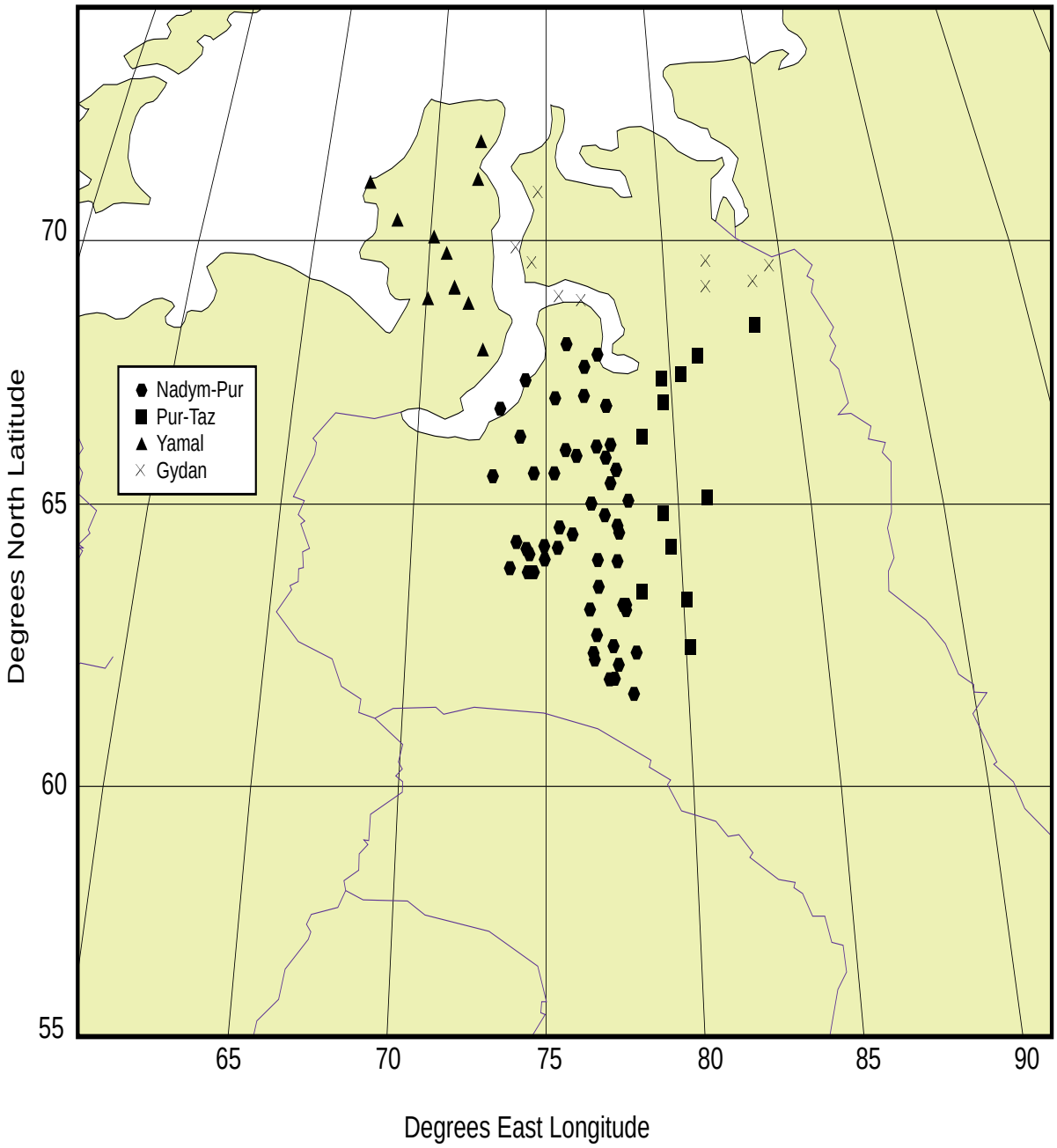
Source: Energy Information Administration, Office of Oil and Gas

Figure 4B. Location of Fields Producing from the Albian-Aptian Interval (South Area) West Siberian Basin.



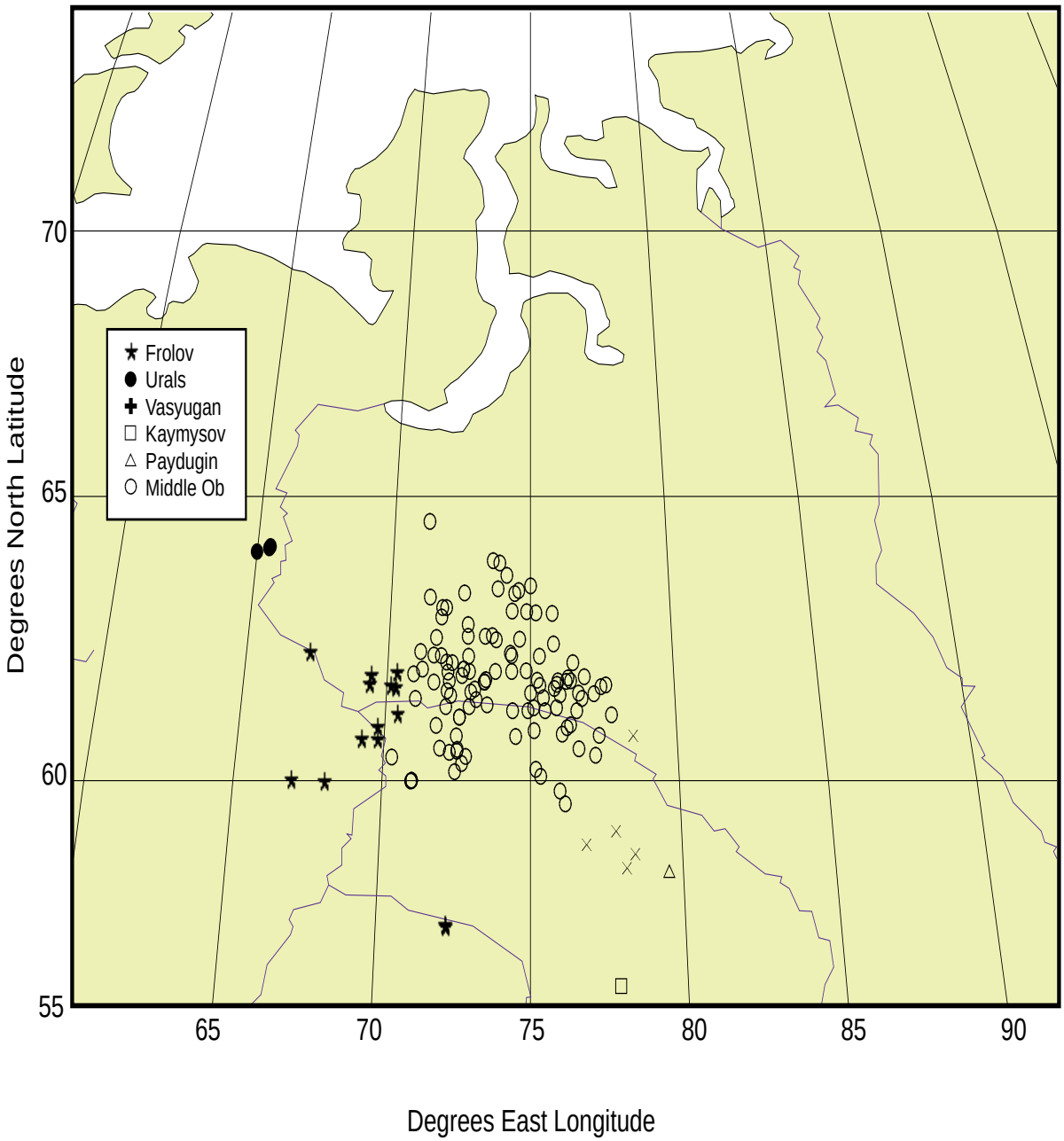
Source: Energy Information Administration, Office of Oil and Gas

Figure 5B. Location of Fields Producing from the Neocomian Interval (North Area) West Siberian Basin.



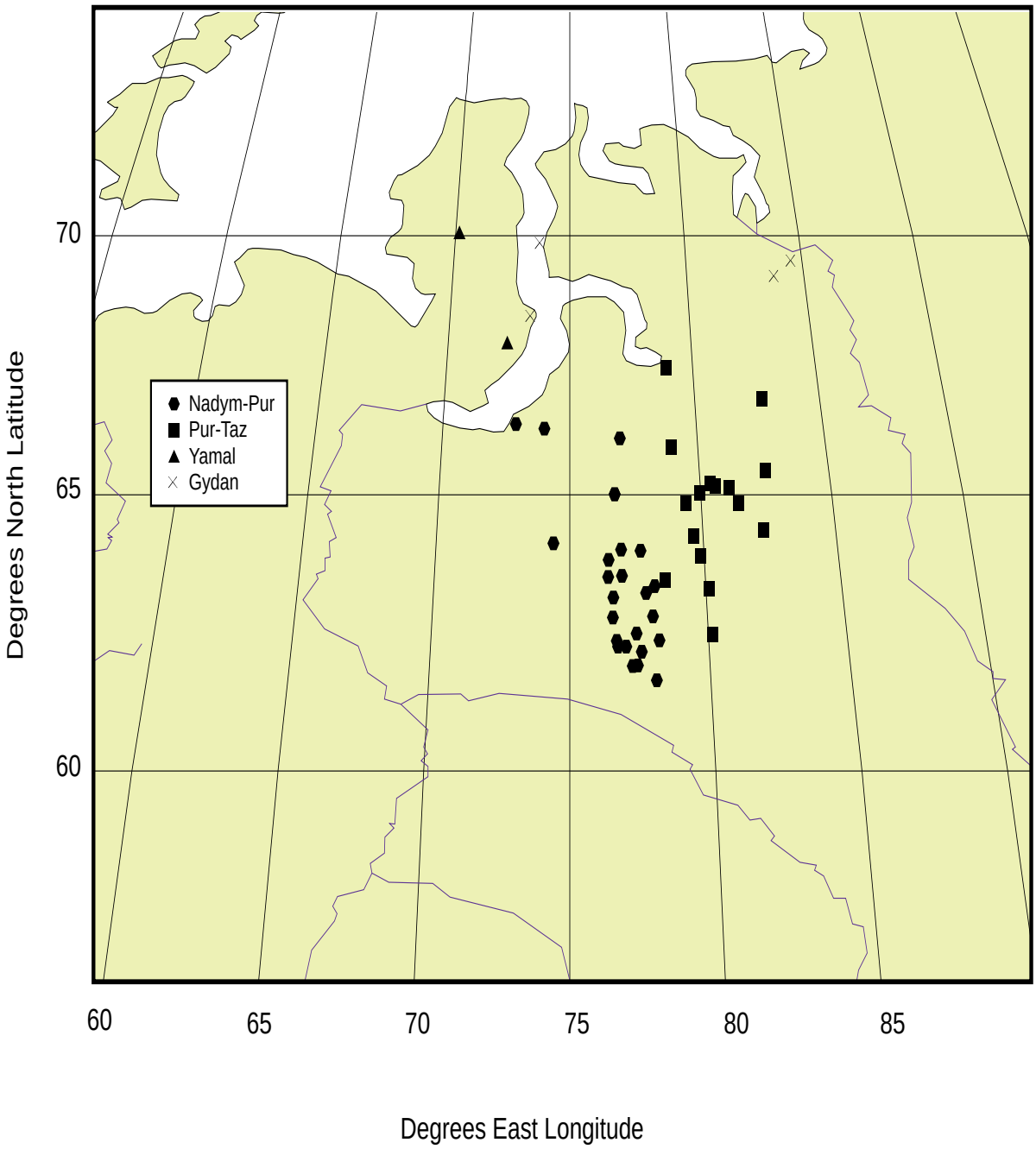
Source: Energy Information Administration, Office of Oil and Gas

Figure 6B. Location of Fields Producing from the Neocomian Interval (South Area) West Siberian Basin.



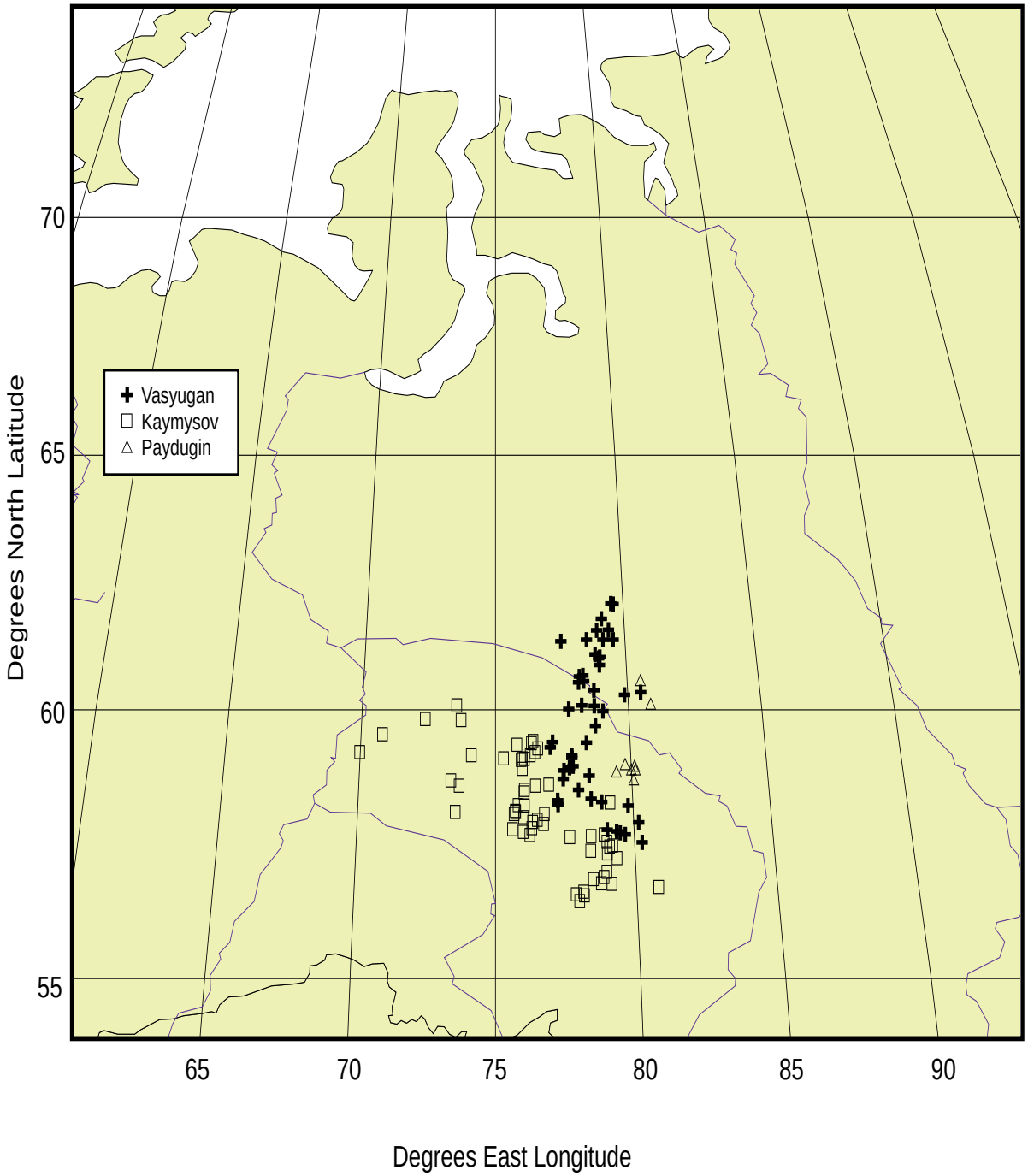
Source: Energy Information Administration, Office of Oil and Gas

Figure 7B. Location of Fields Producing from the Jurassic Interval (North Area) West Siberian Basin.



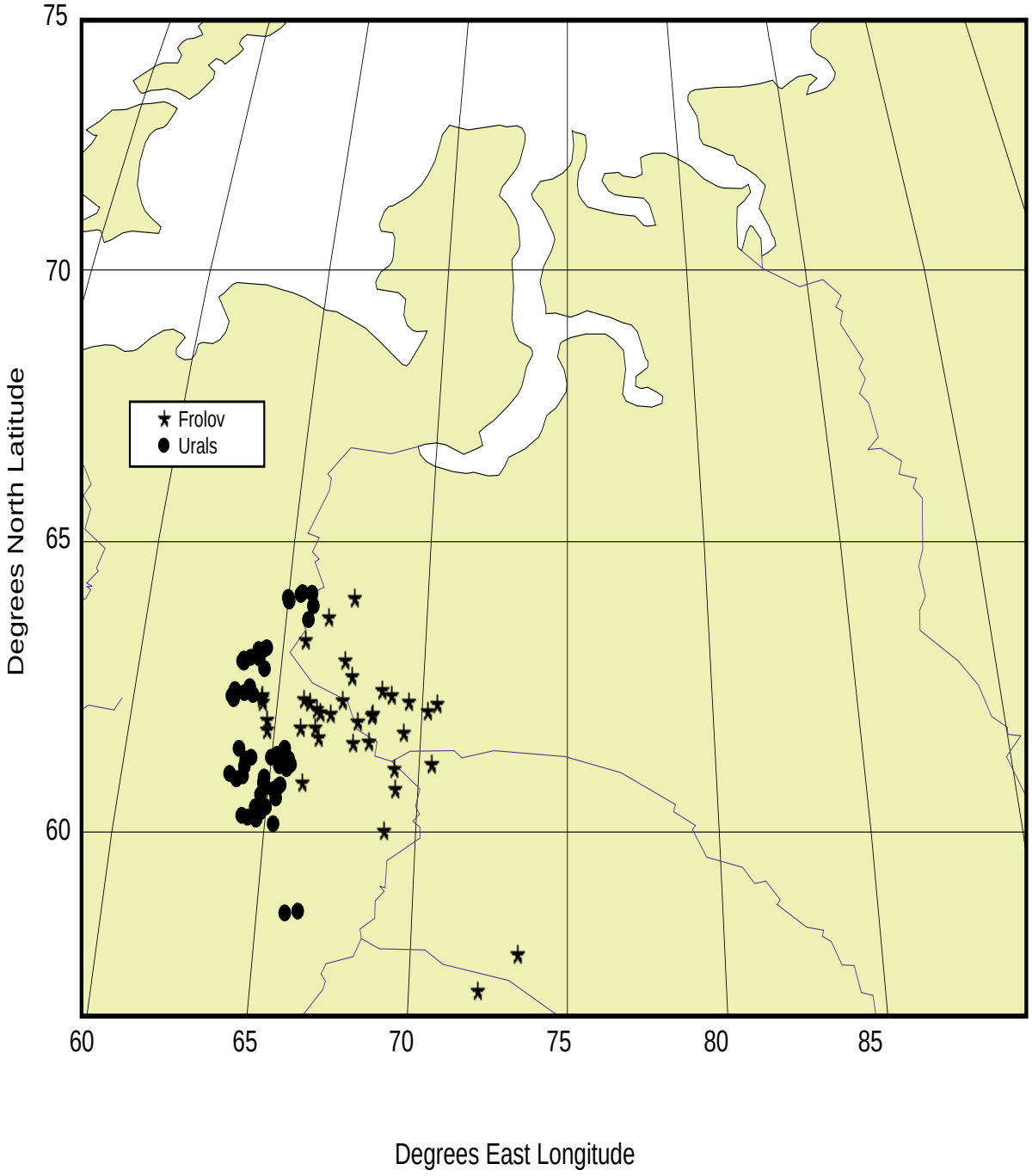
Source: Energy Information Administration, Office of Oil and Gas

Figure 8B. Location of Fields Producing from the Jurrasic Interval (South Area) West Siberian Basin.



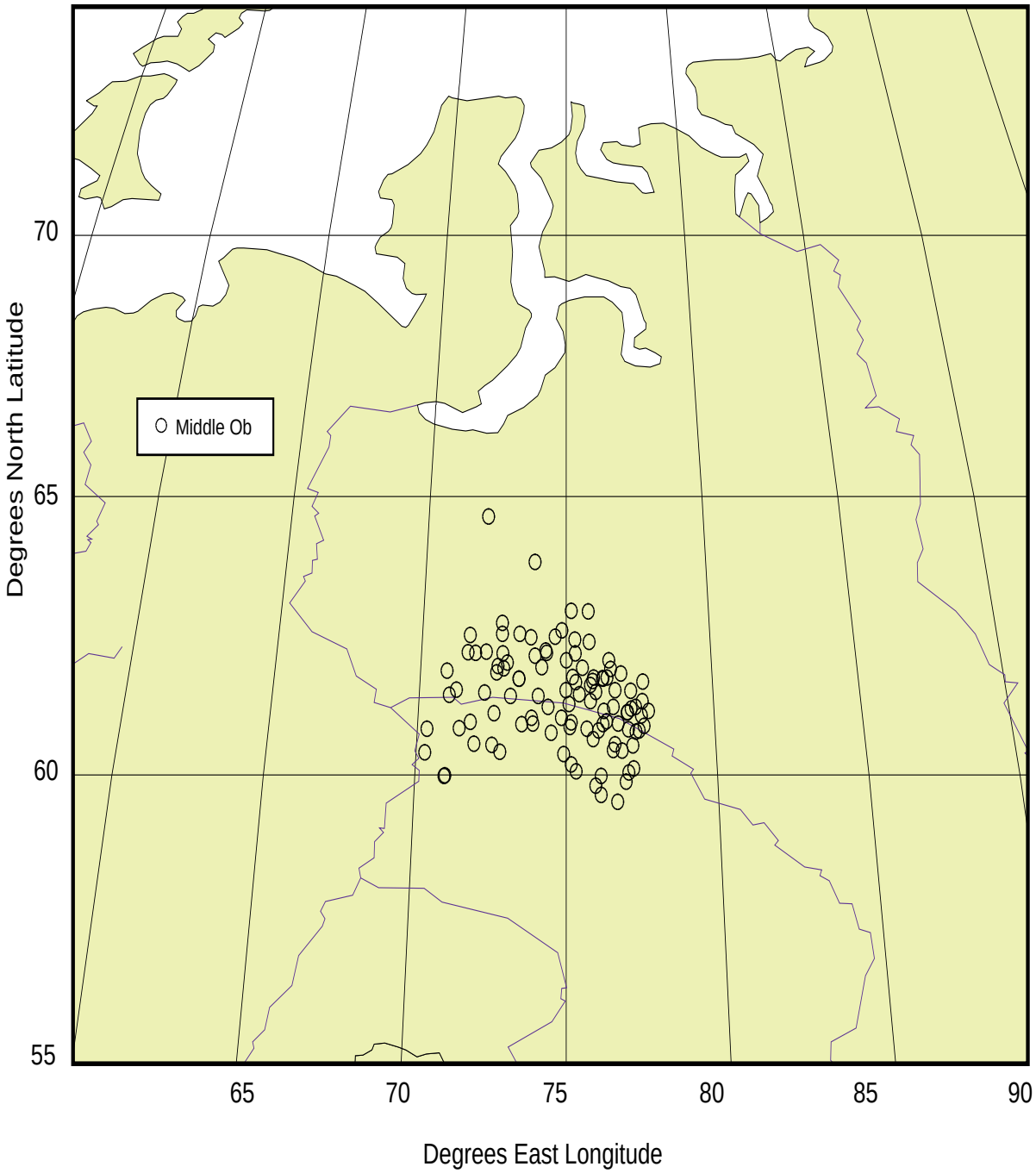
Source: Energy Information Administration, Office of Oil and Gas

Figure 9B. Location of Fields Producing from the Jurassic Interval (West Area) West Siberian Basin.



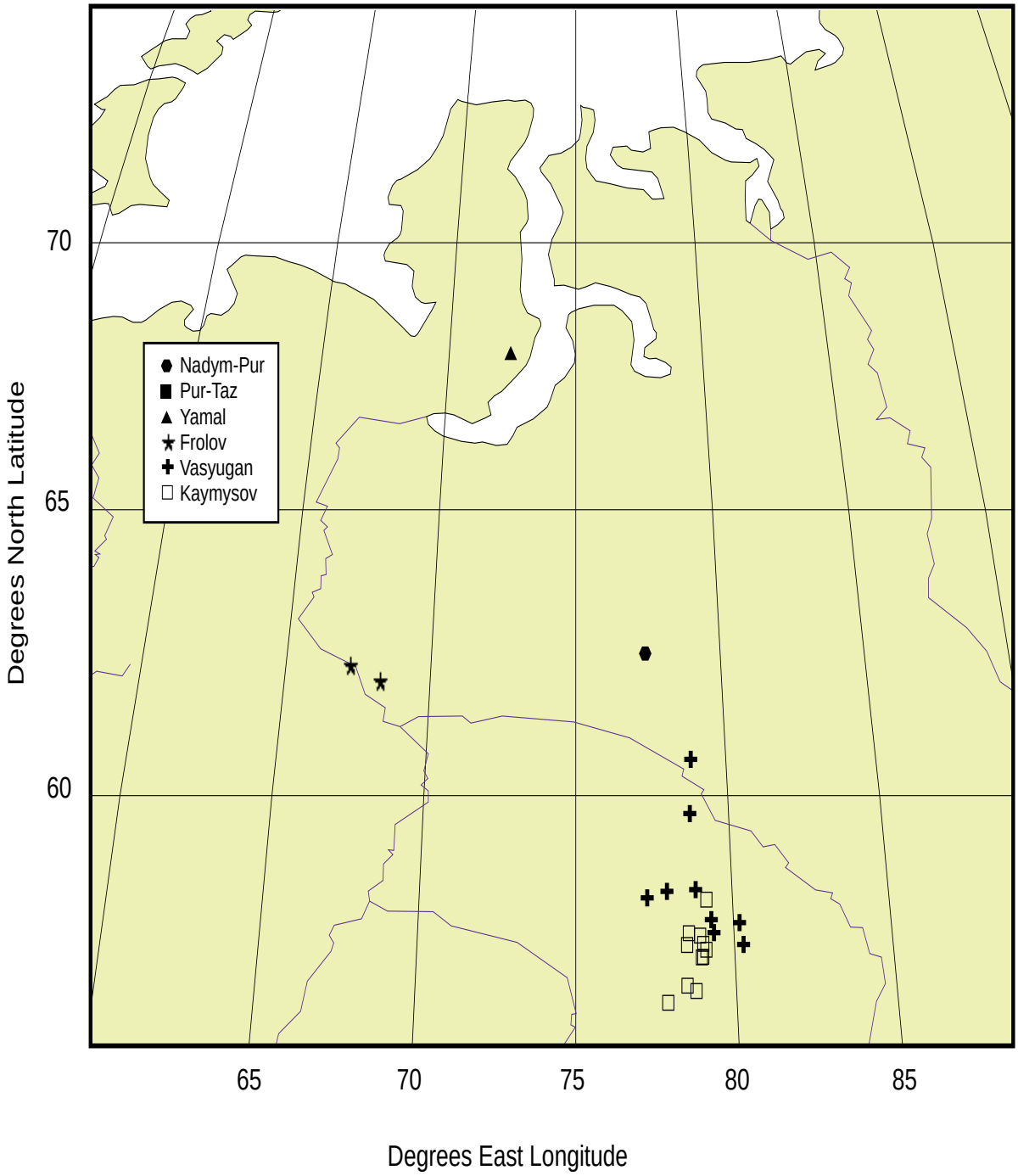
Source: Energy Information Administration, Office of Oil and Gas

Figure 10B. Location of Fields Producing from the Jurassic Interval (Middle Ob Region) West Siberian Basin.



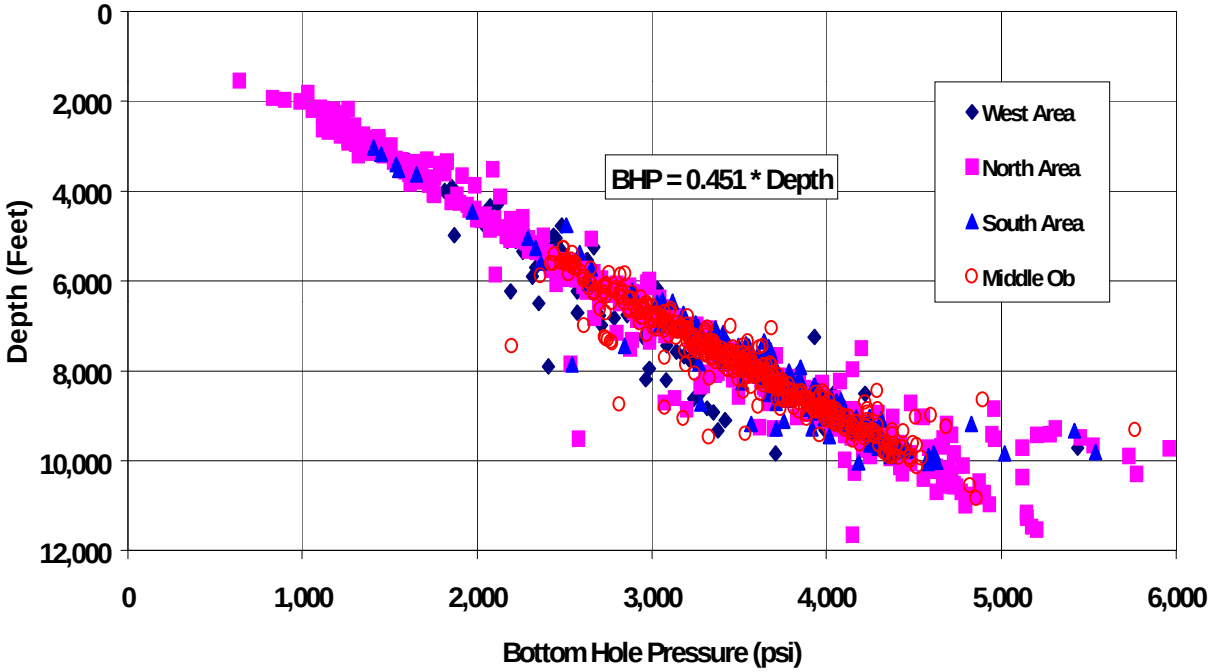
Source: Energy Information Administration, Office of Oil and Gas

Figure 11B. Location of Fields Producing from the Triassic-Paleozoic Interval (All Areas) West Siberian Basin.



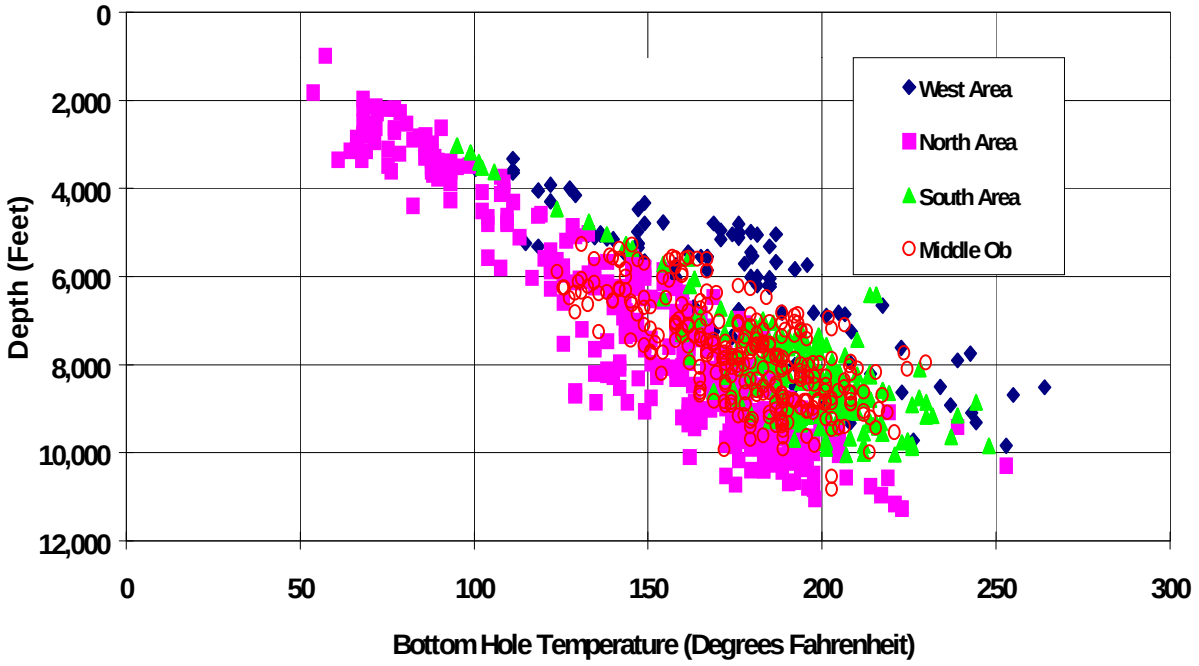
Source: Energy Information Administration, Office of Oil and Gas

Figure 12B. Measured Bottom Hole Pressure (BHP) at Reported Depth, West Siberian Basin.



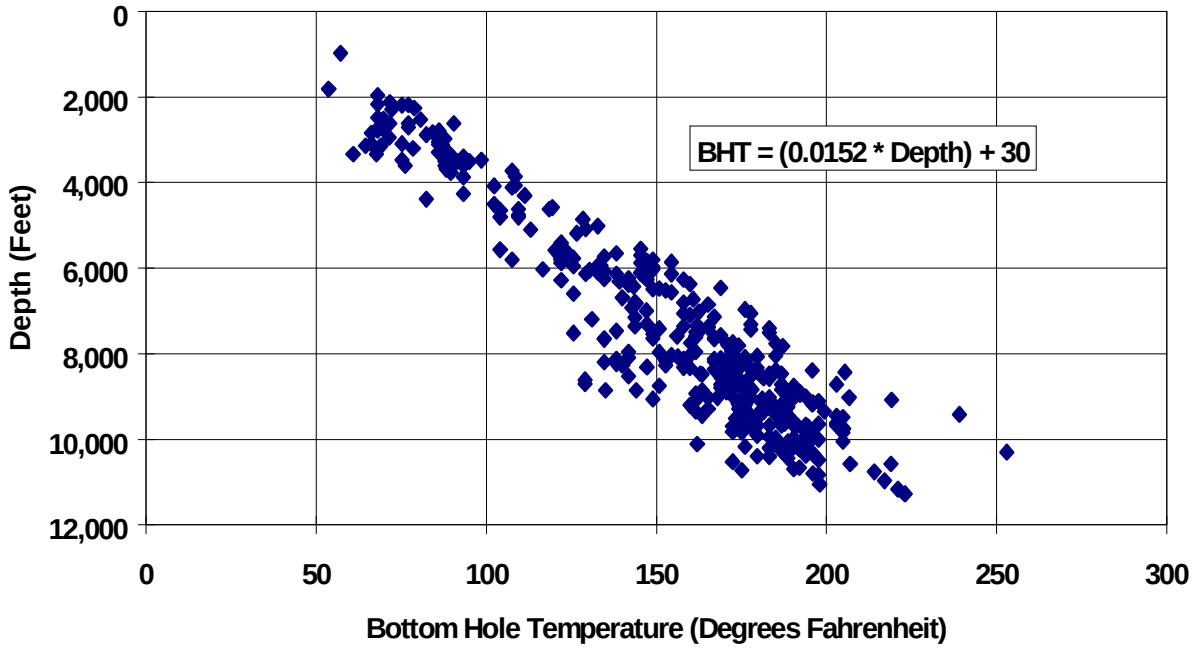
Source: Energy information Administration, Office of oil and Gas.

Figure 13B. Measured Bottom Hole Temperature (BHT) at Reported Depth, West Siberian Basin.



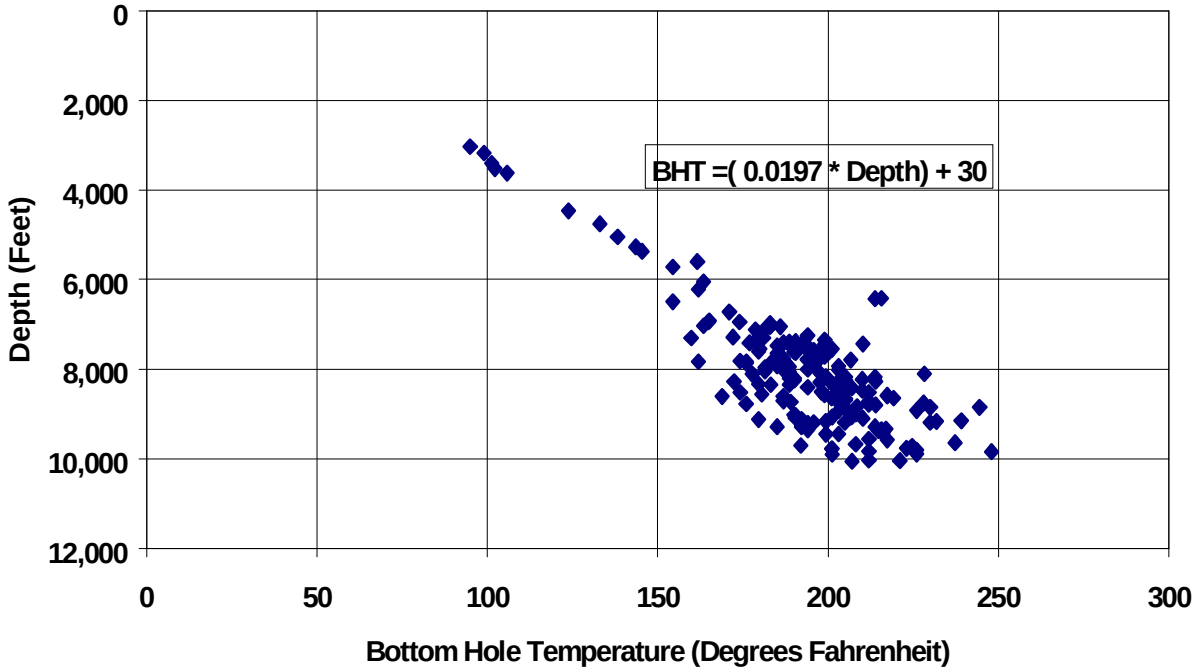
Source: Energy Information Administration, Office of Oil and Gas.

Figure 14B. Bottom Hole Temperature (BHT) at Depth for the North Area, West Siberian Basin.



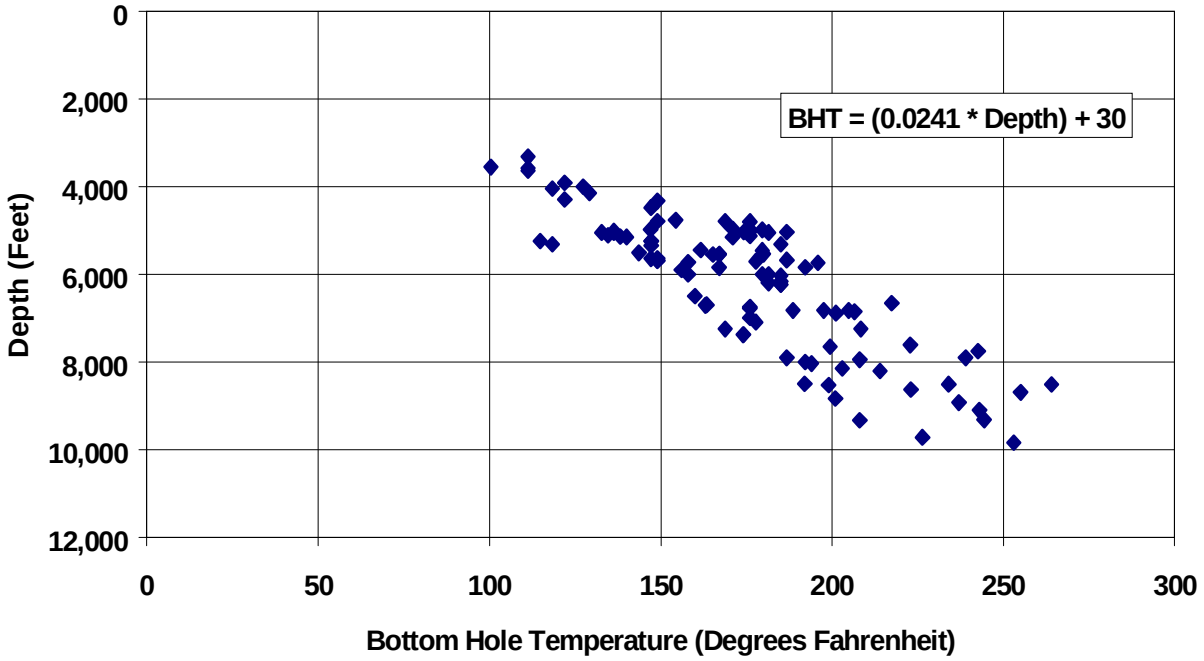
Source: Energy Information Administration,Office of Oil and Gas.

Figure 15B. Bottom Hole Temperature (BHT) at Depth for the South Area, West Siberian Basin.



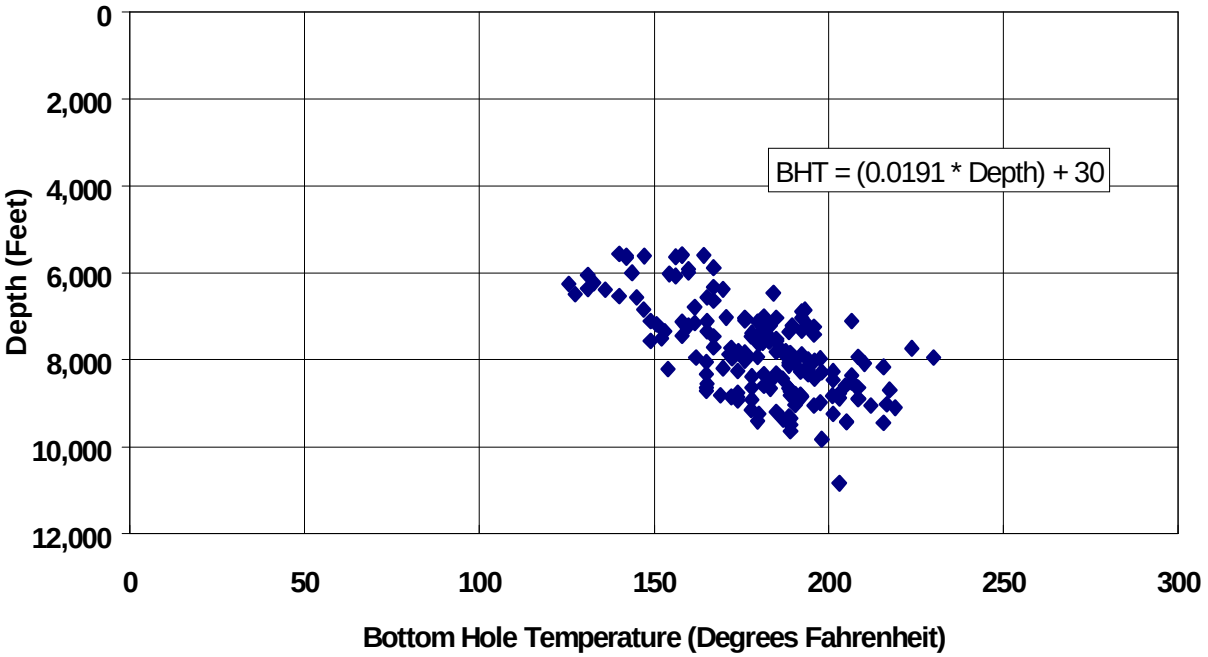
Source: Energy Information Administration, Office of Oil and Gas.

Figure 16B. Bottom Hole Temperature (BHT) at Depth for the West Area, West Siberian Basin.



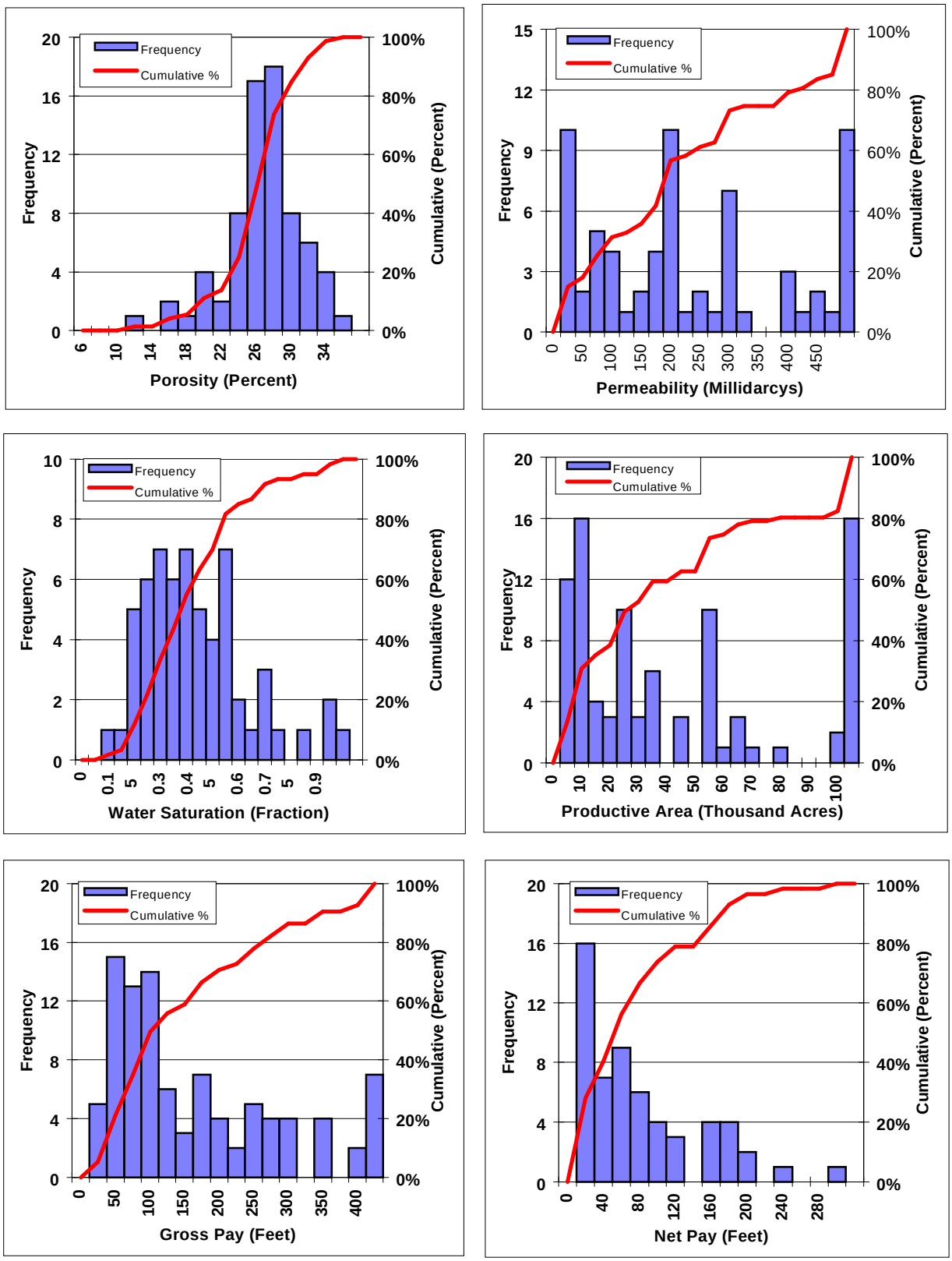
Source: Energy Information Administration, Office of Oil and Gas

Figure 17B. Bottom Hole Temperature (BHT) at Depth for the Middle Ob Area, West Siberian Basin.



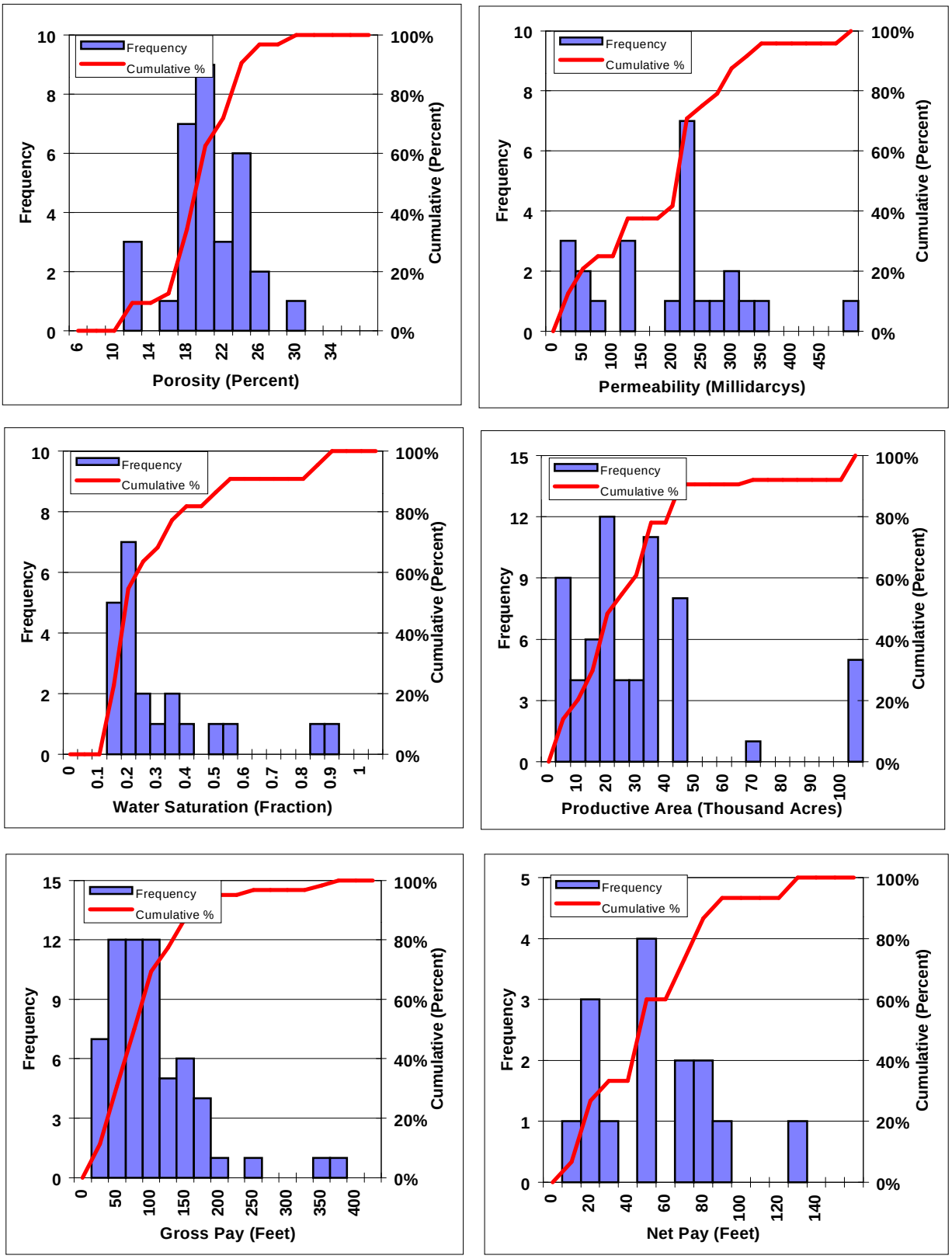
Source: Energy Information Administration, Office of Oil and Gas.

Figure 18B. Distribution of Reservoir Parameters in the Upper Cretaceous Interval (All Areas), West Siberian Basin.



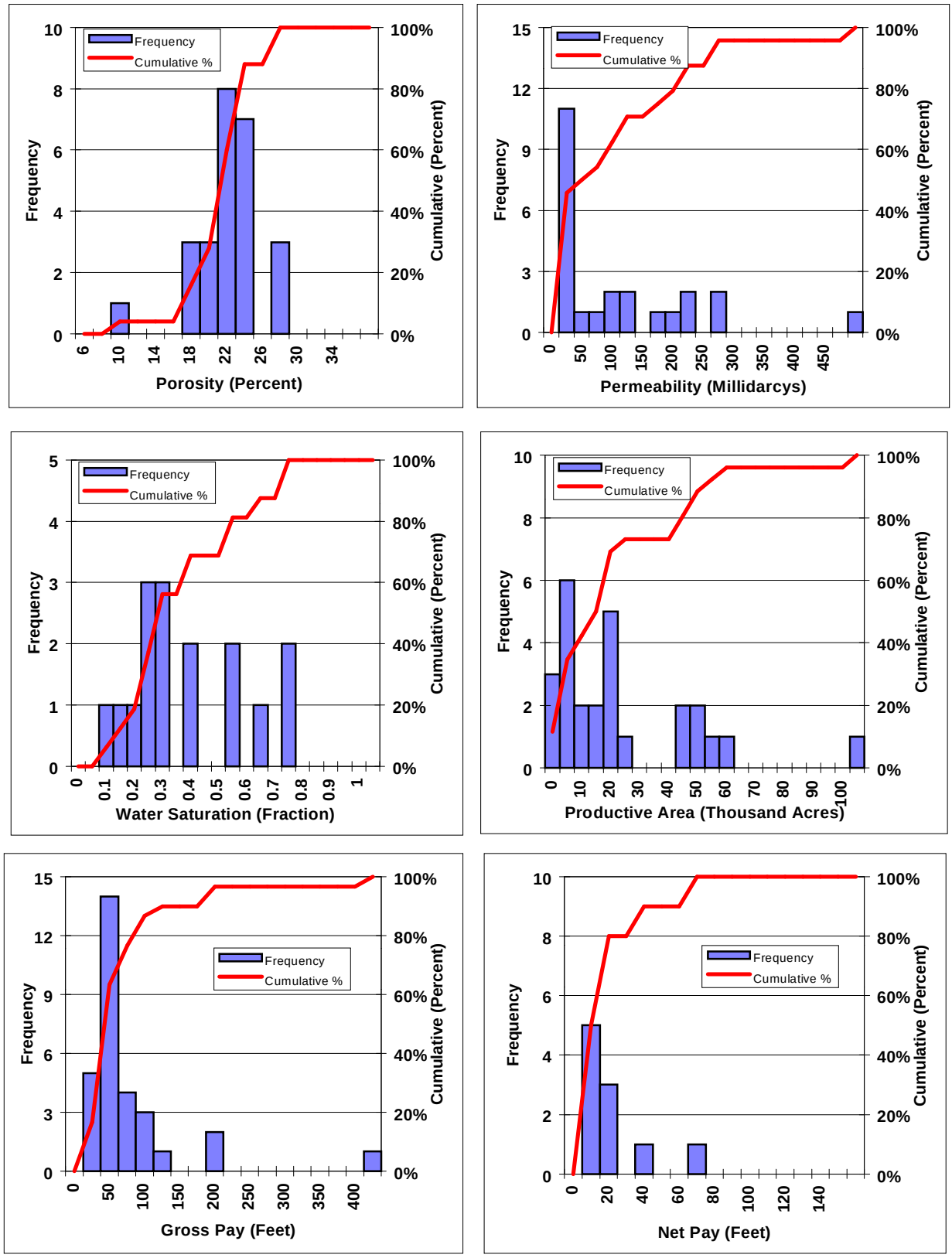
Source: Energy Information Administration, Office of Oil and Gas.

Figure 19B. Distribution of Reservoir Parameters in the Albian-Aptian Interval (North Area), West Siberian Basin.



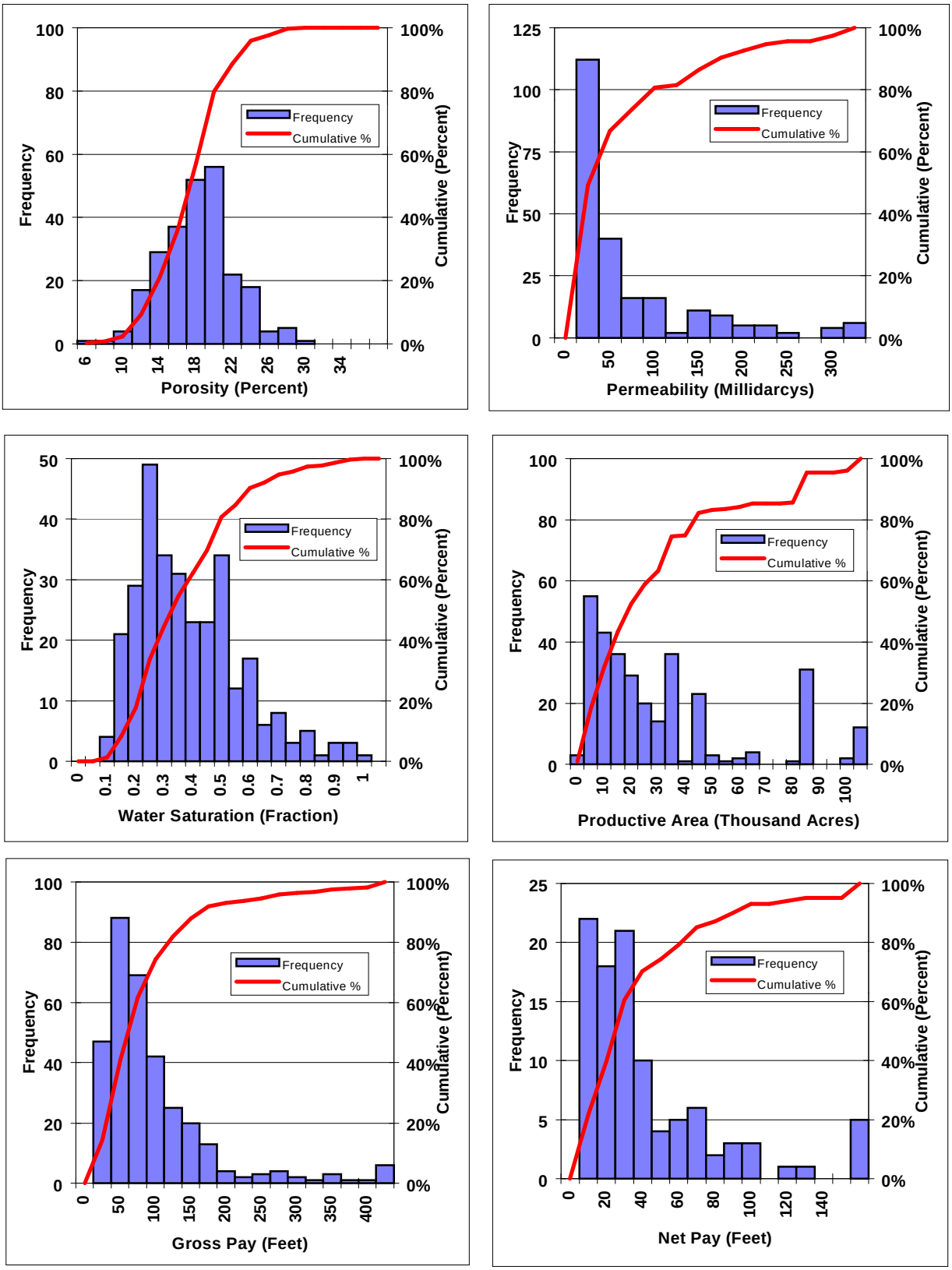
Source: Energy Information Administration, Office of oil and Gas.

Figure 20B. Distribution of Reservoir Parameters in the Albian-Aptian Interval (South Area), West Siberian Basin.



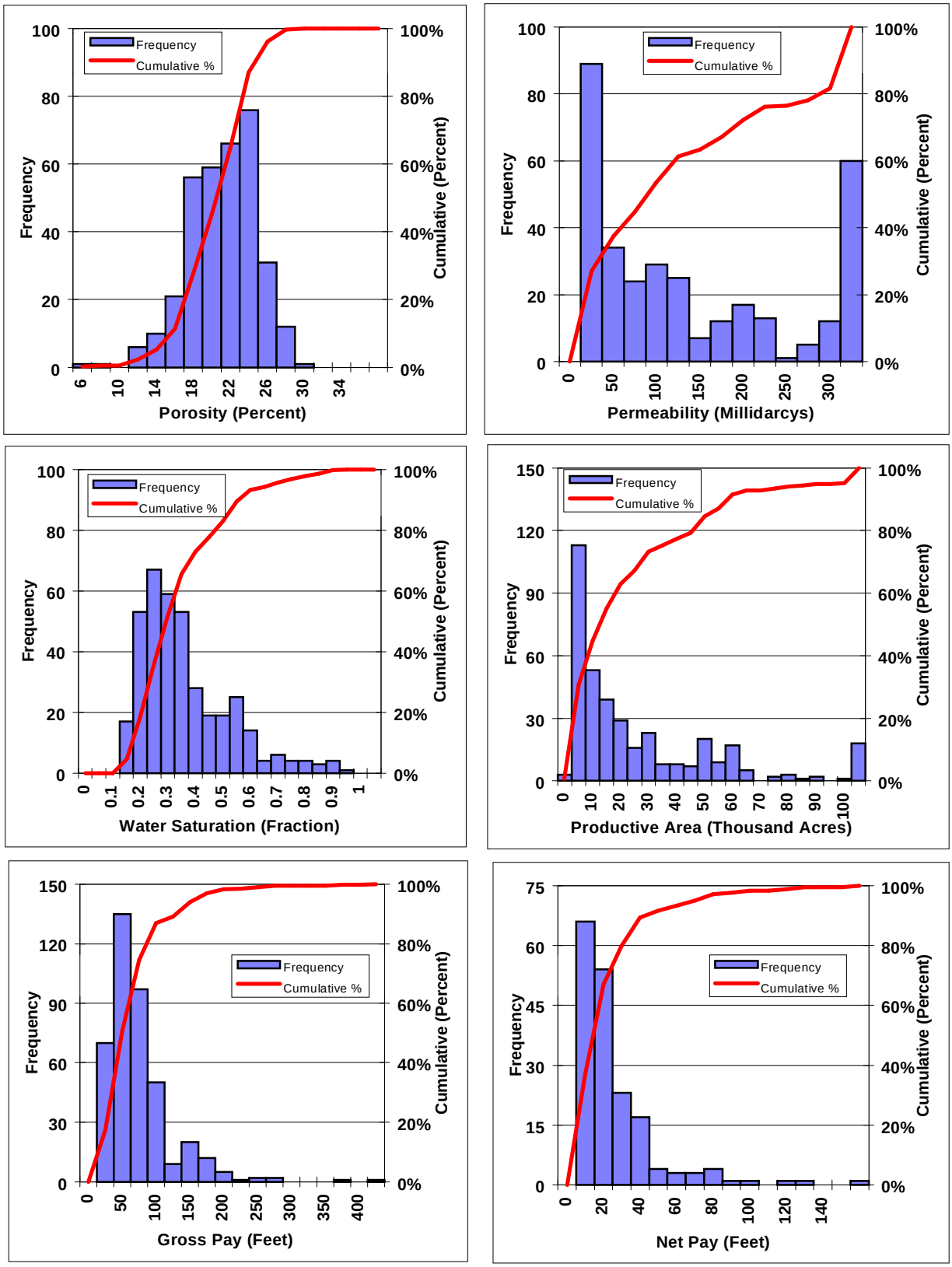
Source: Energy Information Administration, Office of oil and Gas.

Figure 21B. Distribution of Reservoir Parameters in the Neocomian Interval (North Area), West Siberian Basin.



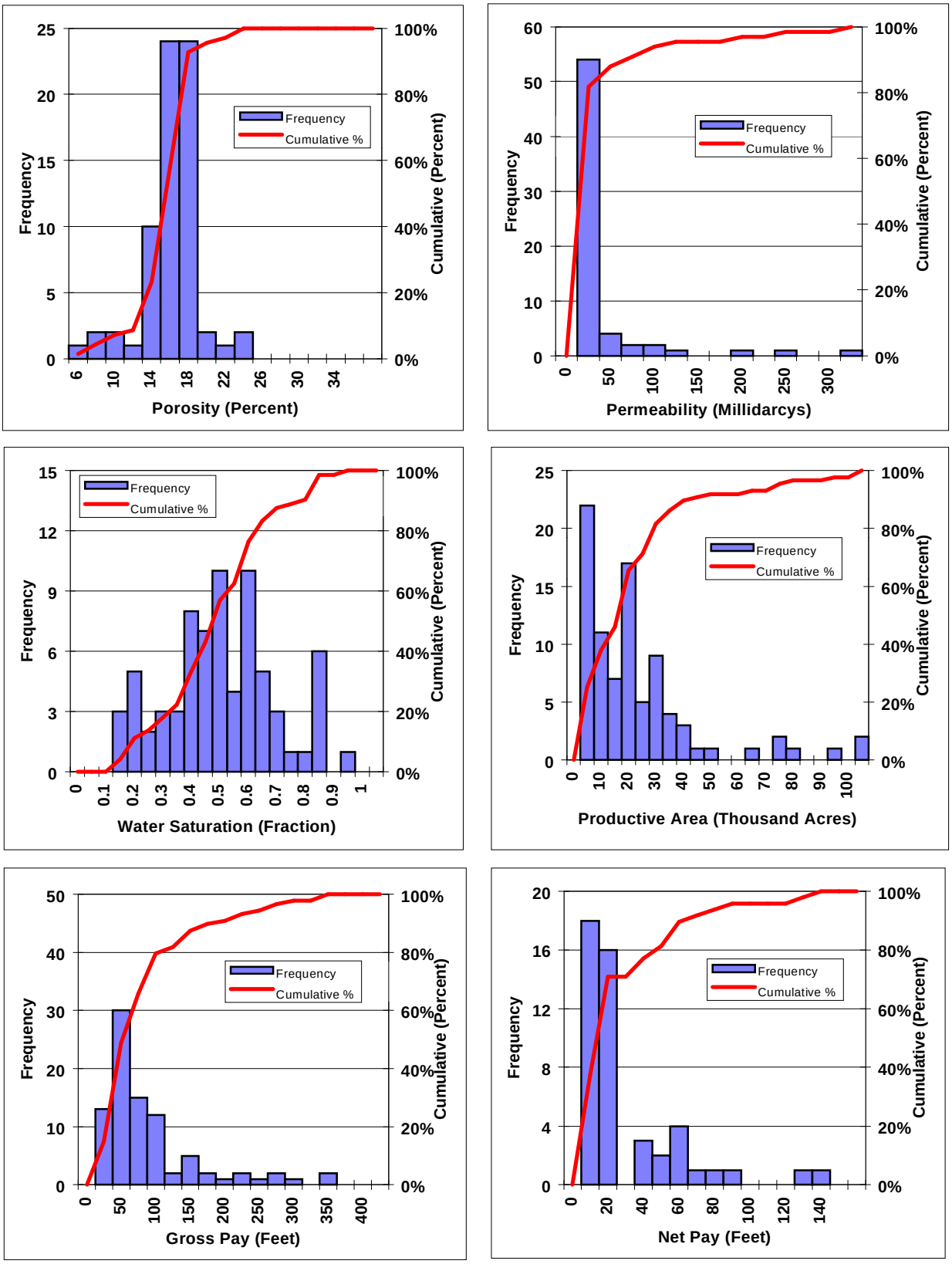
Source: Energy Information Administration, Office of oil and Gas.

Figure 22B. Distribution of Reservoir Parameters in the Neocomian Interval (South Area), West Siberian Basin.



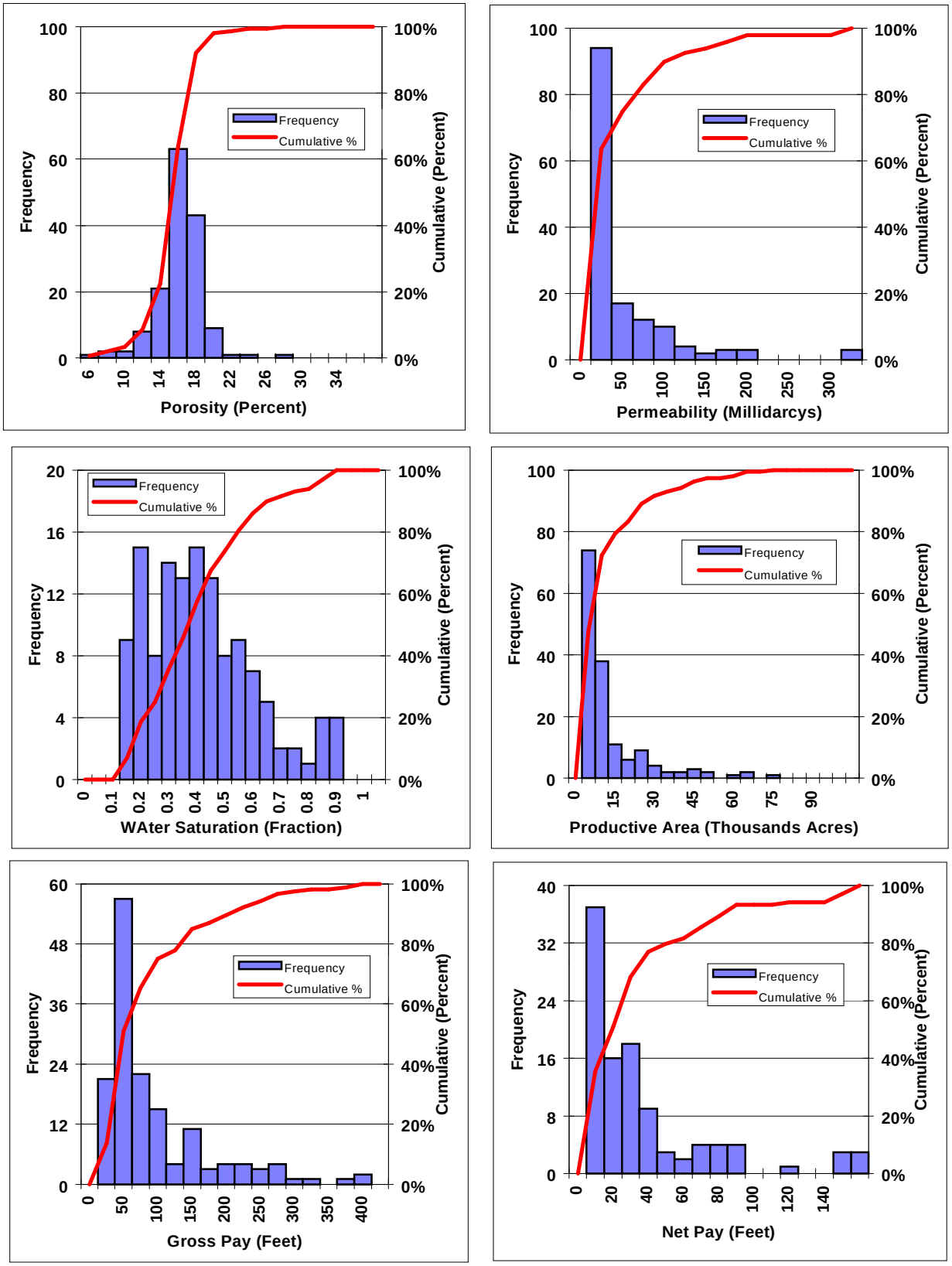
Source: Energy Information Administration, Office of oil and Gas.

Figure 23B. Distribution of Reservoir Parameters in the Jurassic Interval (North Area), West Siberian Basin.



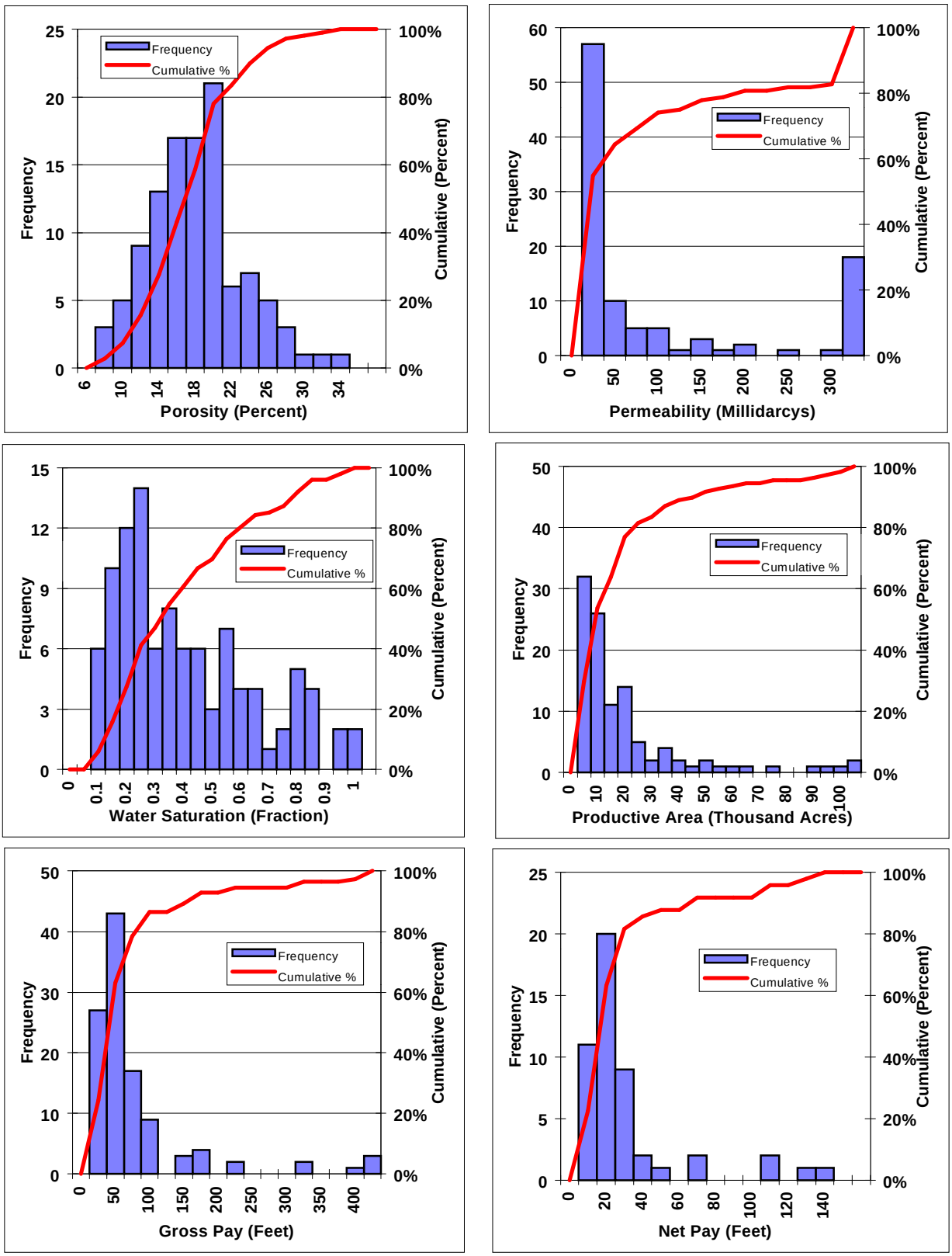
Source: Energy Information Administration, Office of oil and Gas.

Figure 24B. Distribution of Reservoir Parameters in the Jurassic Interval (South Area), West Siberian Basin.



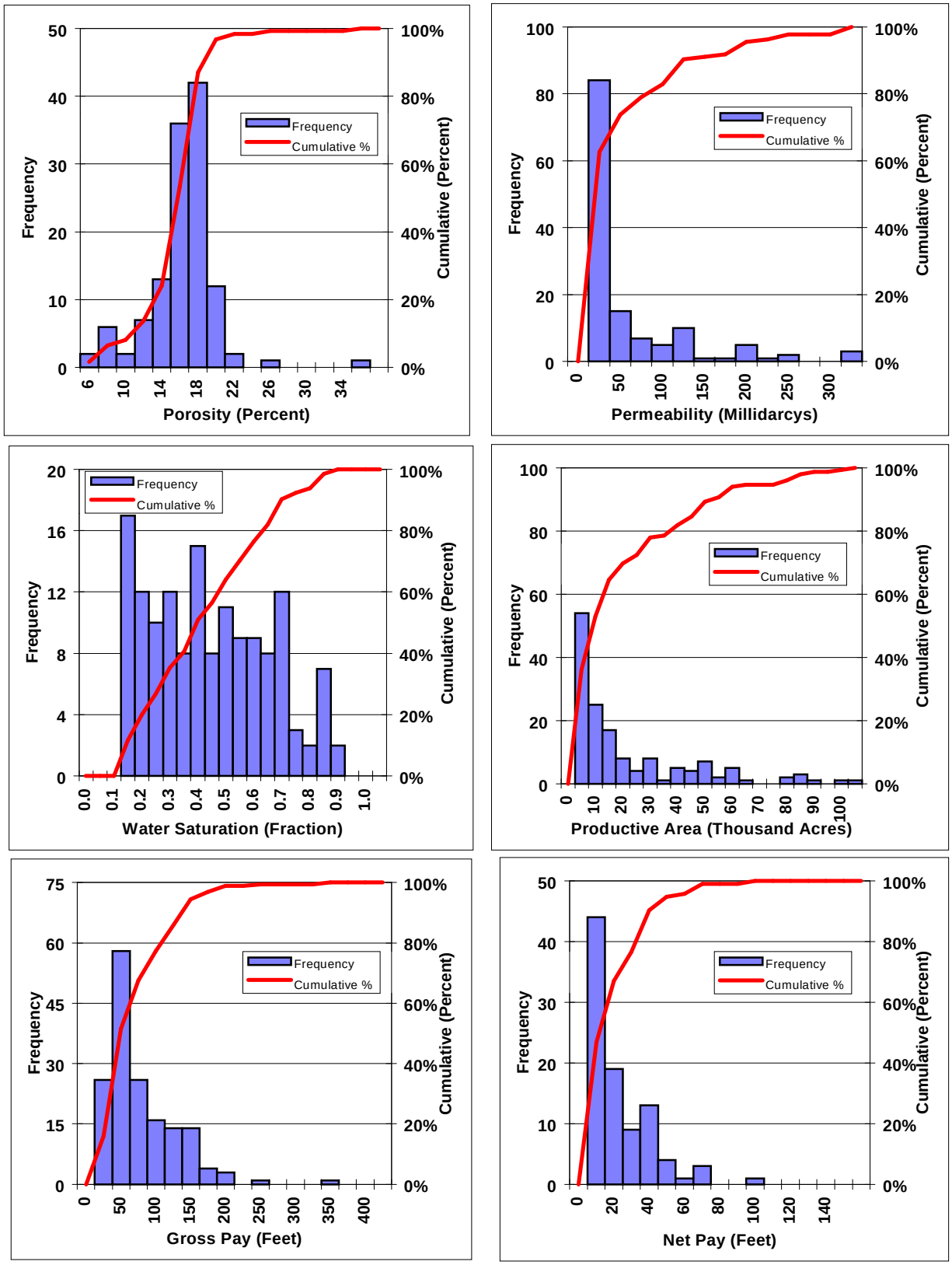
Source: Energy Information Administration, Office of oil and Gas.

Figure 25B. Distribution of Reservoir Parameters in the Jurassic Interval (West Area), West Siberian Basin.



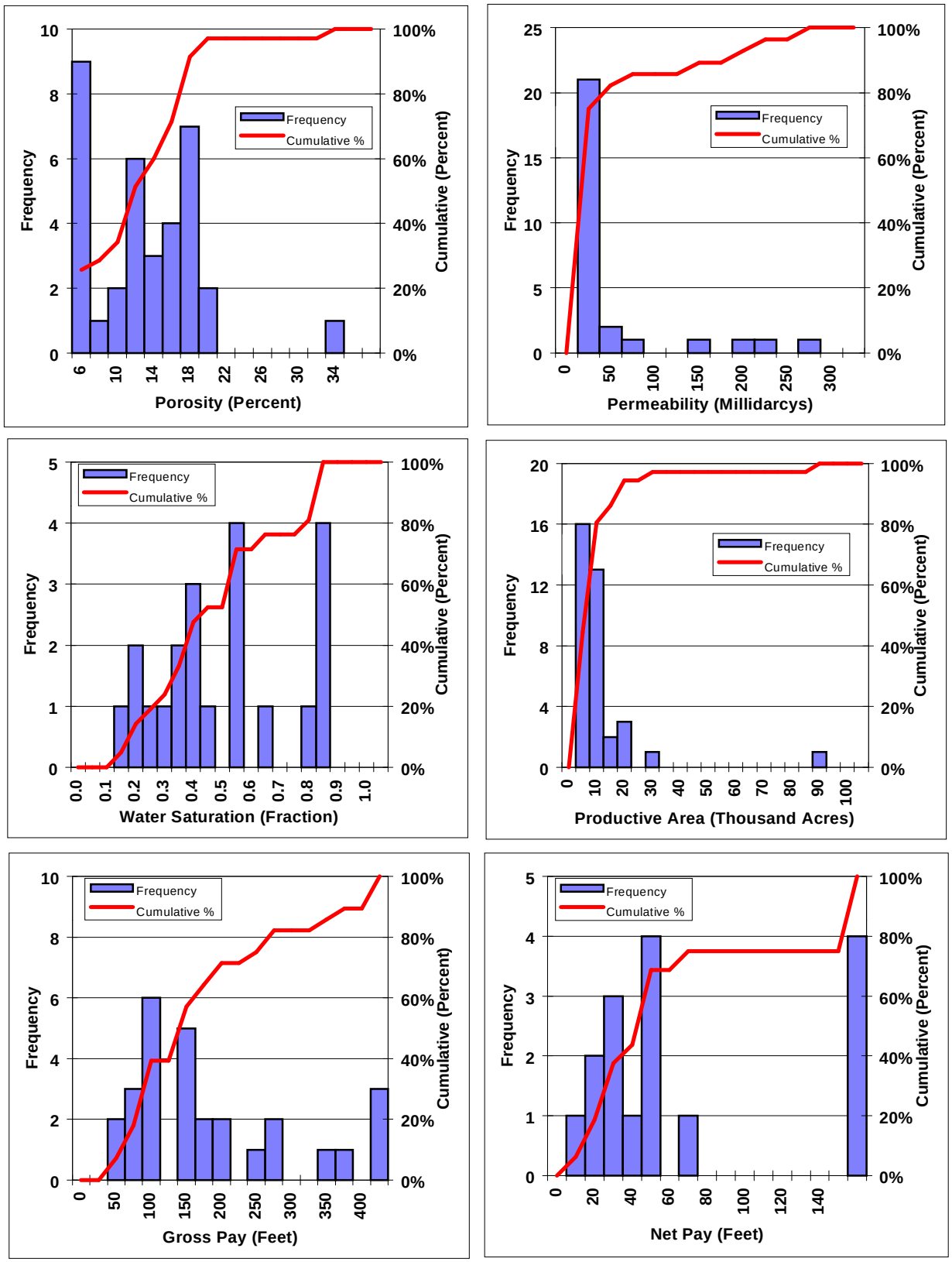
Source: Energy Information Administration, Office of oil and Gas.

Figure 26B. Distribution of Reservoir Parameters in the Jurassic Interval (Middle Ob Area), West Siberian Basin.



Source: Energy Information Administration, Office of oil and Gas.

Figure 27B. Distribution of Reservoir Parameters in the Triassic-Paleozoic Interval (All Areas), West Siberian Basin.



Source: Energy Information Administration, Office of oil and Gas.

Water Saturation

A limited amount of water saturation data was available. Since porosity data appears to be consistent within selected geologic intervals and permeability data are available, the correlation developed by Morris[1] and Timur[2] and updated by Coates[3] and Raymer[4] was used to calculate water saturations. This correlation did not hold true for all data combinations. The mode of the calculated water saturation was used as the most representative of the reservoir water saturation. The range of the water saturations was from 26.2 percent to 43.1 percent. The equation used to calculate water saturation is:

$$S_w = 100\ \theta^{2.25} / k^{0.5}$$

Where:

S_w = Irreducible water saturation (fraction)
θ = Porosity (fraction)
k = Permeability (millidarcy)

Productive Area

To estimate in-place hydrocarbons by reservoir, a method was developed to determine unknown areas using the available data. The available productive area data for reservoirs were presented in several forms, and reservoir areas were available for only a portion of the fields. Data from some fields were presented as the sum of all reservoirs in the field, while some sources reported the area of the largest reservoir. When a single value was reported for field area, it was assumed that the area represented the surface area of the field or the area of the reservoir of greatest areal extent in the field.

To estimate individual reservoir areas in fields with a single field area given, an equation was fitted to the ratio of the average reservoir area divided by the largest reservoir area in the field versus the number of reservoirs in the field for those fields with reported area data (**Figure 28B**). The equation determined from the graph provided a method of reducing the area of the largest reservoir (or total field area) to an average area of multiple reservoirs. The ratio determined from the following equation was multiplied by the area of the largest reservoir to determine the average area to be used for each reservoir in that field.

$$Ratio = 1.0501 * n^{-0.5459}$$

Where:

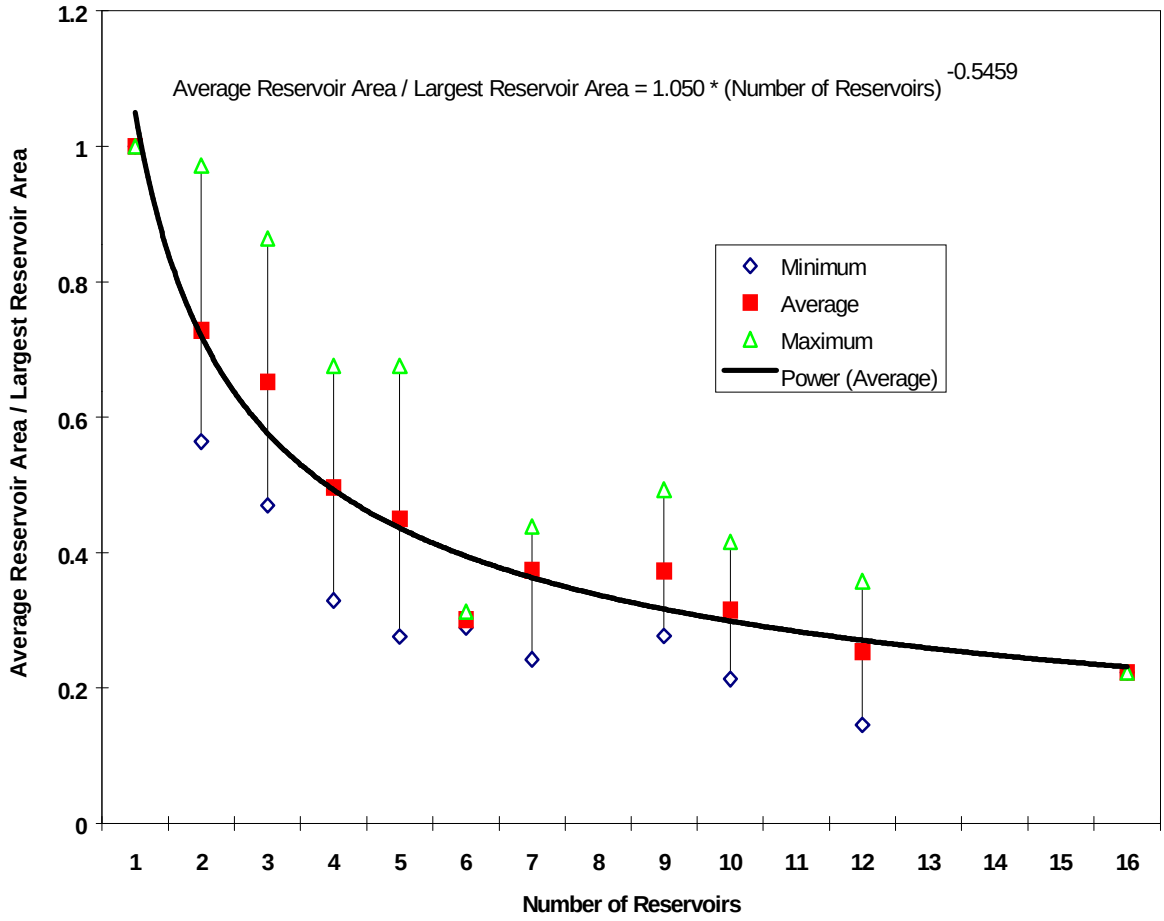
Ratio = Average reservoir area divided by area of largest reservoir
n = Number of reservoirs in field

Even with multiple reservoir areas reduced, the areas may be overstated because of depositional discontinuities that occur in sandstone reservoirs. Reported areas may be from seismic interpretation or exploration prospect mapping which has not been more closely defined by remapping after development drilling.

Reservoir Thickness

Gross pay thickness and net pay thickness were reported in the available data sources for some of the reservoirs. Other reservoirs had either gross or net pay reported. For a few reservoirs, no pay was reported. When both gross and net pay were given, a ratio of net pay to gross pay was calculated. If only gross pay was reported, the average net to gross ratio of the corresponding geologic interval was used to estimate the net pay. When neither gross nor net pay were reported, the gross pay was defined as the difference between the depth of the geologic unit being evaluated and the depth of the next deeper geologic unit. Then net pay was determined using the net to gross ratio. If depth information was not adequate, the average net pay for the geologic interval was used for hydrocarbon in-place calculations. The range of reported gross pay in the basin was from 4 feet to 1,600 feet with a net pay range of 3 feet to 400 feet.

Figure 28B. Correlation Function for Allocating Field Areas to Reservoir Areas, West Siberian Basin.



Source: Energy Information Administration, Office of Oil and Gas.

Fluid Properties

Reservoir fluid properties were determined using correlations prepared by Muchmore[5] for use with personal computer spreadsheet software. Most of the empirical correlations programed by Muchmore are from Kartoatmodjo,[6] who used a large data base to select the best correlation from various methods. Oil property correlations from Vasques and Beggs,[7] water property correlations from Meehan,[8] and rock compressibility correlation from Hall[9] were used in this analysis. These correlations were used to calculate all properties except oil and gas specific gravities. Average oil and gas specific gravities within the major geologic intervals and Regions were used instead of the correlations. The following are the equations used in the spreadsheet calculations. A list of the symbols and nomenclature follows the equations.

Oil Formation Volume Factor

Below bubble point pressure:

$$B_{of} = 0.98496 + 0.0001 * F^{1.5}$$

Where:

$$F = R_{sf}^{0.755} * \rho_g^{0.25} * \rho_o^{-1.50} + 0.45\ T$$

Above bubble point pressure:

$$B_{ofa} = B_{ofb} * e^{c_o(P_b - P)}$$

Oil Compressibility

Isothermal oil compressibility:

$$c_o = \frac{6.8257x10^{-5}}{P} * R_{sf}^{0.5002} * API^{0.361} * T^{0.76606} * \rho_g^{0.35505}$$

Crude Oil Gravity

Reported crude oil gravity was used when available. Averages of oil gravity by geologic intervals were used when there were no reported data. Reported oil gravity ranged from 33.5 degrees to 42.3 degrees API. The oil gravities of the major oil producing intervals were in the range of 36 degrees to 38 degrees API.

Solution Gas-Oil Ratio

For API gravity < 30 degrees:

$$R_{sf} = 0.05958 * \rho_g^{0.7972} * P^{1.0014} * 10^{13.1405\ API\ /\ (T + 460)}$$

For API gravity > 30 degrees:

$$R_{sf} = 0.03150 * \rho_g^{0.7587} * P^{1.0937} * 10^{11.2895\ API\ /\ (T + 460)}$$

Bubble Point Pressure

For API gravity < 30 degrees:

$$P_b = \left[\frac{R_{sf}}{0.05958 * \rho_g^{0.7972} * 10^{13.1405API/(T+460)}}\right]^{0.9986}$$

For API gravity > 30 degrees:

$$P_b = \left[\frac{R_{sf}}{0.0315 * \rho_g^{0.7587} * 10^{11.2895API/(T+460)}}\right]^{0.9143}$$

Gas Formation Volume Factor

$$B_g = \frac{5.04\ Z\ (T+460)}{P}$$

Oil Viscosity

Live oil above the bubble point:

$$\mu_{oa} = 1.00081 * \mu_{oBP} + 0.001127(P - P_b) * (-0.006517 * \mu_{oBP}^{1.8148} + 0.038 * \mu_{oBP}^{1.590})$$

Live oil below the bubble point:

$$\mu_{ob} = 0.06821 + 0.9824 * f + 0.0004034 * f^2$$

Where:

$$f = (0.2001 + 0.8428X10^{-0.000845 * R_{sb}}) * \mu_{od}^{(0.43 + 0.5185 * y)}$$

And:

$$y = 10^{-0.00081 * R_{sb}}$$

Live oil viscosity at the bubble point:

$$\mu_{oBP} = \mu_{ob}\ at\ R_{sb} = R_{si}$$

Dead oil viscosity:

$$\mu_{od} = 16X10^8 * T^{-2.8177} * (\log API)^{5.7526 * \log(T) - 26.9718}$$

Rock Compressibility

$$c_r = 13.172X10^{-6}\ \theta^{-0.4317}$$

Where:

θ = Porosity

Water Compressibility

$$c_w = \frac{A+(B * T)+(C * T^2)}{10^6} * GSC * SC$$

Where:

$$A = 3.8546 - (0.000134 * P)$$
$$B = -0.01052 + (4.77X10^{-7} * P)$$
$$C = 3.9267X10^{-6} - (8.8X10^{-10} * P)$$
$$GSC = 1 + (8.9X10^{-3}) + R_{sw}$$
$$SC = [-0.052 + (2.7X10^{-4} * T) - (1.14X10^{-6} * T^2) + (1.121X10^{-9} * T^3)] * \%NaCl^{0.7} + 1$$

Nomenclature

API= American Petroleum Institute.
B_{ofa}= Oil formation volume factor above bubble point pressure (reservoir barrels / stock tank barrel)
B_{ofb}= Oil formation volume factor at bubble point (reservoir barrels / stock tank barrel).
B_{of} = Oil formation volume factor below bubble point (reservoir barrels / stock tank barrel)
B_g = Gas formation volume factor (reservoir barrels / thousand cubic feet).
c_o = Isothermal oil compressibility (pounds / square inch^{-1}).
c_w = Water compressibility (pounds / square inch^{-1}).
c_r = Rock compressibility (pounds / square inch^{-1}).
P = Reservoir pressure (pounds / square inch).
P_b = Bubble point pressure (pounds / square inch).
R_{si} = Gas in solution at initial pressure (cubic feet / stock tank barrel).
R_{sb} = Gas in solution at bubble point pressure (cubic feet / stock tank barrel).
R_{sf} = Gas in solution at/or below bubble point pressure (cubic feet / stock tank barrel).
T = Reservoir temperature (degrees Fahrenheit).
Z = Real gas deviation factor.
ρ_o = Oil density (grams / cubic centimeter)
ρ_g = Gas specific gravity
μ_{oa} = Oil viscosity above bubble point (centipoise).
μ_{ob} = Oil viscosity below bubble point (centipoise).
μ_{oBP}= Oil viscosity at bubble point (centipoise).
μ_{od} = Dead oil viscosity (centipoise).
θ = Porosity (percent of rock volume).
F = Correlation number for calculating oil formation volume factor.
f = Correlation number for calculating live oil viscosity.
y = Correlation number for calculating live oil viscosity.
SC = Water salinity correction factor
GSC = Gas solubility in water correction factor.
%NACl = Percent sodium chloride in water.

References

1. R.L. Morris and W. P. Biggs, *Using Log Derived Values of Water Saturation and Porosity*, Trans. SPWLA (1967).

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